Presentation to: Houston Energy Transition Initiative (“HETI”)

Texas Power Market & Industry Assessment

Texas Power Accessibility, Reliability and Affordability Report

FTI CONSULTING

HOUSTON ENERGY TRANSITION INITIATIVE

August 10, 2026

Important Information About This Report
Limit on Report Access and Distribution

The **Texas Power Accessibility, Reliability, and Affordability Report** (“Final Report”) has been prepared for the **Greater Houston Partnership’s Houston Energy Transition Initiative (“HETI”)** pursuant to the terms of the Engagement between **FTI Consulting Inc.** (“FTI”) and the HETI in relation to the Houston regional power market study.

This Final Report is not to be referred to or quoted, in whole or in part, in any registration statement, prospectus, public filing fund raising, loan agreement, or other agreement or any other document without the prior written approval of FTI:

- The reader of this Final Report understands that the work performed by FTI was performed in accordance with instructions provided by HETI and was performed exclusively for the HETI’s sole benefit and use and may not be relied upon in any way by anyone else;
- The reader of this Final Report acknowledges that this Final Report was prepared at the direction of the HETI and may not include all procedures deemed necessary for the purpose of the reader;
- In consideration of FTI allowing the reader access to the Final Report, the reader agrees that it does not acquire any rights as a result of such access that would not otherwise have had and acknowledges that FTI does not assume any duties or obligations to the reader in connection with such access;
- The reader agrees to release FTI and its personnel from any claim by the reader that arises as a result of the reader having access to the Final Report;
- The reader agrees that the Final Report is not to be referred to or quoted, in whole or in part, in any registration statement, prospectus, public filing, loan agreement, or other agreement or document and agrees not to distribute the Draft Report without FTI’s prior written consent.

Table of Contents

Glossary

Glossary

Term	Definition
4CP	Four Coincident Peak
AAS	Associate of Applied Science
AI	Artificial Intelligence
ASDC	Ancillary Service Demand Curve
BESS	Battery Energy Storage System
BLS	Bureau of Labor Statistics
BYOG	Bring Your Own Generator
CAGR	Compound Annual Growth Rate
CAISO	California Independent System Operator
CCGT	Combined Cycle Gas Turbine
CCUS	Carbon Capture, Utilization & Storage
CDR	Capacity, Demand, and Reserves Report
CHP	Combined Heat and Power
CIAC	Contribution in Aid of Construction
CIP	Critical Infrastructure Protection
CLR	Controllable Load Resource
COD	Commercial Operations Date
DPP	Definitive Planning Phase
DR	Demand Response
DRRS	Dispatchable Reliability Reserve Service

Term	Definition
ECRS	ERCOT Contingency Reserve Service
EEA	Energy Emergency Alert
EIA	U.S. Energy Information Administration
EIM	Energy Imbalance Market
EPC	Engineering, Procurement, and Construction
EPG	Electric Power Generation
ERAS	Expedited Resource Addition Study
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
ERS	Emergency Response Service
FERC	Federal Energy Regulatory Commission
FTI	FTI Consulting Inc.
FTR	Financial Transmission Rights
GDP	Gross Domestic Product
GIA	Generator Interconnection Agreement
GIM	Generator Interconnection or Modification
GIS	Generator Interconnection Studies
GW	Gigawatt
HCC	Houston Community College
HE	Hour Ending

Term	Definition
HETI	Houston Energy Transition Initiative
HPC	High Performance Computing
HVAC	Heating, Ventilation, and Air Conditioning
IA	Interconnection Agreement
IR	Interconnection Request
IRR	Internal Rate of Return
ISO	Independent System Operator
ISO-NE	ISO New England
kV	Kilovolt
kW	Kilowatt
LCRA	Lower Colorado River Authority
LDES	Long Duration Energy Storage
LFL	Large Flexible Load
LLI	Large Load Interconnection
LLIS	Large Load Interconnection Study
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LTRA	Long-Term Reliability Assessment
M	Million

Glossary (Cont.)

Term	Definition
MISO	Midcontinent Independent System Operator
MORA	Monthly Outlook for Resource Adequacy
MW	Megawatt
NCLR	Non-Controllable Load Resources
NERC	North American Electric Reliability Corporation
NEUE	Normalized Expected Unserved Energy
NSRS	Non-Spinning Reserve Service
NYISO	New York Independent System Operator
PCM	Performance Credit Mechanism
PGRR	Protocol Guide Revision Request
PJM	PJM Interconnection (Pennsylvania-New Jersey-Maryland)
PPA	Power Purchase Agreement
PUCT	Public Utility Commission of Texas
QSA	Qualified Scheduling Authority
REP	Retail Electric Providers
RICE	Reciprocating Internal Combustion Engine
RRA	Regional Resource Assessment
RRS	Responsive Reserve Service
RTC+B	Real-Time Co-Optimization plus Battery
RTO	Regional Transmission Organization

Term	Definition
SB 3	Senate Bill 3
SB 6	Senate Bill 6
SCED	Security Constrained Economic Dispatch
SIS	System Impact Study
SPP	Southwest Power Pool
SSO	Sub-Synchronous Oscillation
STEP	System Transmission Expansion Program
T&D	Transmission and Distribution
TDS	Transmission, Distribution, and Storage
TDSP	Transmission and Distribution Service Provider
TSP	Transmission Service Provider
TX	Texas
TxEF	Texas Energy Fund
U.S.	United States
UFLS	Under-Frequency Load Shedding
VPPA	Virtual Power Purchase Agreement
WECC	Western Electricity Coordinating Council

Executive Summary

Executive Summary: Overview

Houston's Power Market is adapting to unprecedented load growth while strengthening reliability, affordability, and competitiveness.

Over the past decade, Greater Houston and the Texas Gulf Coast have faced 18 federally-declared disasters, including hurricanes, floods, extreme freezes, heat waves, and destructive wind events. Responding to those austere climate conditions set Texas on a trajectory that has proven to be prescient a decade later. Load growth is slated to grow at an unprecedented rate as data center, industrial, and advanced manufacturing activity grow their presence on the grid for the foreseeable future.

Texas and ERCOT invested substantially in transmission, a diverse generation mix, storage, and large load planning enablement. The result of those efforts has been the development of a market with a more disciplined large-load planning framework and customer flexibility. Greater Houston in particular has established itself as a region well-suited for continued investment.

There are a number of areas where this Report attempts to highlight how ERCOT and Greater Houston have improved since Winter Storm Uri struck in 2021, marking a nadir for the area's preparedness:

- **Infrastructure Depth supports resilience:** Houston combines flexible procurement with dense power infrastructure, creating a 19.6 month speed advantage from IR to COD compared to peer region averages.
- **$30.2B Transmission Program addresses grid constraints:** ERCOT has invested in a 2,500 mile, 765-kV network that creates a long-term transmission backbone, and scaled its battery fleet rapidly to 14GW, among other measures, to strengthen Texas' grid.
- **Generation Investment is scaling and diversifying to meet prospective load growth:** Texas is growing its capacity appreciably across a host of generation sources, including natural gas (slated capacity has grown from 34GW to 64GW in the last year), solar (157GW to 165GW), and integrated storage.
- **Houston supports scaling through its versatility:** Houston combines the ability to pair load flexibility with access to industrial grade power and competitive land and utility costs, creating an advantage nationally and in-state versus markets like DFW.
- **Houston combines affordability, flexibility, and industrial scale infrastructure:** Houston pairs competitive land and utility costs with industrial grade power, procurement flexibility, demand response, and resource diversity, allowing industrial customers optionality to lower effective power costs relative to other large load markets.

The result of all these efforts is a Houston power market that is more affordable, better prepared, more flexible, and more resilient than it was before Uri, while continued investment remains necessary to keep pace with extreme weather and unprecedented load growth. Protecting affordability will be central to future competitiveness. As capital is deployed, the region's ability to manage infrastructure cost allocation will be critical to maintaining the Texas Gulf Coast's cost advantage.

Greater Houston enters the next phase of power demand growth with a distinctive combination of generation diversity, infrastructure, market flexibility, investment and cost management tools. Continued, disciplined investment will be required, but the region's strengths position it to accommodate large load growth while safeguarding reliability and affordability.

FTI CONSULTING

Executive Summary: Competitiveness & Market Position of Texas

TX's power market structure, infrastructure depth, industrial clustering, and energy workforce create a flexible operating environment for large-scale projects. However, rising load growth, weather exposure, and grid constraints require careful risk considerations.

TX Power Markets Offer Distinct Risk and Flexibility Profiles

- ERCOT dominates Texas with high procurement flexibility but greater price volatility.
- Compared with PJM and NYISO, ERCOT and MISO give large industrial users more flexibility through supplier choice, bilateral contracts, hedging, and demand response.

Competitive Power Markets Expand Procurement Flexibility

- ERCOT gives large customers supplier choice and flexible procurement to manage cost and operations.
- Houston's dual-market position expands procurement options beyond what is typically available in NYISO, CAISO, or ISO-NE load pockets.

TX Infrastructure Depth Supports Project Scalable Execution

- TX's integrated power, gas, transportation, and port infrastructure creates a strong operating environment for large industrial projects.
- Houston specifically, offers infrastructure at a scale that peer regions on the East and West coast cannot match.

TX Gulf Coast Industrial Clustering Reduces Structural Cost and Execution Risk

- TX's ERCOT and MISO South combines deep industrial density, logistics, and power infrastructure investment.
- The Gulf Coast reduces execution risk relative to less-developed industrial corridors in other regions.

TX Energy Workforce for Industrial Growth

- Broad-based employment depth across fuels, transmission, energy efficiency, motor vehicles, and power generation supports access to skilled labor for large-scale energy and industrial projects.
- Few regions match Texas' labor scale across fuels, transmission, generation and skilled trades.

Key Risks to Consider in Gulf Coast

- Houston / Texas Gulf Coast power users face rising reliability and cost risks from extreme weather, load growth, and grid congestion.
- These risks are not unique to Texas; peer regions including PJM, NYISO, CAISO, and the Southwest market face similar load growth and deliverability pressures.

FTI CONSULTING

Executive Summary: Demand Response Economics & Market Impact

ERCOT's market structure allows flexible load to serve as a cost-management tool and recurring value stream. For Houston industrial customers, this can create an advantage versus regions where customer-level flexibility is more constrained.

Three Revenue Channels Stack Together

- ERCOT's energy-only market rewards flexibility through scarcity arbitrage, ancillary service payments (RRS, ECRS, Non-Spin), and 4CP cost avoidance.
- Together, these stack into a recurring revenue stream that materially lowers a flexible load's effective cost of power.

Scarcity Pricing Pays Real Money

- When system lambda exceeds $1,000/MWh, price-responsive industrial loads have cut consumption by up to 75% during scarcity events.
- The energy-only design produces sharp, predictable price signals that make flexibility a measurable earnings lever.

Registered Capacity Overstates Delivery

- ERCOT has 505 registered NCLRs totaling 10+ GW, but only ~2.5–4.0 GW typically respond during peak events.
- Nameplate registration dramatically overstates what actually arrives when the grid calls.

4CP Is the Dominant Flexibility Lever

- ERCOT estimated ~3,500 MW of load reduction across 2023 4CP intervals and ~2,500 MW in 2024; larger than all other DR programs combined.
- Customers self-curtail to lower next year's transmission charges, making 4CP the highest-impact lever in Texas.

Flexibility Proven During Emergencies

- ERCOT manually deployed 1,593 MW of NCLRs during the September 2023 EEA Level 2 event, and ERS was activated twice that year.
- Industrial flexibility is a documented reliability resource called on under real system stress, not a theoretical one.

SB 6 Makes Flexibility Dispatchable

- Self-curtailment outside SCED isn't captured in economic dispatch and can distort price formation, a concern Potomac Economics has flagged.
- SB 6 directs ERCOT to build a DR program, shifting flexibility toward market-integrated participation.

FTI CONSULTING

Executive Summary: Interconnection Performance & Infrastructure Readiness

ERCOT's Batch Zero framework converting queue activity into project advancement, along with Houston's diversified demand base and CenterPoint's execution role strengthen the region's position as a premier geography for large-load plant development.

Restudy loops define ERCOT timelines

- Only 1.3% of ERCOT's 410 GW queue has been energized. New large requests in the same zone can restart the clock.
- Energization timelines should be built from documented actuals, not published tariff targets.

MISO Transmission Timelines Exceed Loads

- New transmission in MISO Texas could take up to 7–10 years to build. Study reforms cannot close the gap that has been created.
- Transmission construction, not the interconnection study, sets the energization timeline in MISO Texas.

CIAC Is the Swing Cost Variable

- Transmission upgrade costs are the largest and least predictable exposure in both markets. MISO co-located cases have exceeded $200/kW.
- CIAC must be stress-tested as a hard capital line item in every project pro forma.

ERCOT Leads on Batch Reservation

- ERCOT is the only U.S. market with a filed, board-governed batch capacity reservation process. No other ISO has reached this level of implementation.
- For 2027–2028 energization targets, ERCOT-served sites hold a structural advantage over PJM and MISO.

Houston Demand Sources Are Diversified

- Load growth is driven by data centers, industry, population, and electrification in parallel. No single sector dominates the forecast.
- Diversified demand reduces downside risk and supports more stable long-term revenue expectations.

ERCOT Queue Is Advancing, Not Accumulating

- Signed IAs grew from 491 to 583 projects while the Full Study backlog declined. The pipeline is graduating projects, not collecting them.
- Renewable supply and industrial gas capacity are both progressing through the same queue at the same time.

Executive Summary: Reliability Assessment

ERCOT's metrics have strengthened since Winter Storm Uri, but reliability risk remains elevated as load growth, peak-hour scarcity, and transmission constraints pressure ERCOT and MISO Texas, requiring deliverable capacity and proactive customer-side mitigation.

ERCOT Improved, but Risks Remains

- ERCOT reliability has improved post-Winter Storm Uri, but risk has shifted from reserve margin adequacy to hour-by-hour energy availability and deliverability.
- SB 3 weatherization, ECRS, and capacity additions reduce modeled scarcity risk, but ERCOT remains exposed in winter mornings, summer evenings, and extreme weather.

MISO Texas Faces Greater Reliability Pressure

- MISO planning studies identify tightening reserve conditions and potential reliability need in future years, including within MISO South.
- Both Entergy Texas and MISO are responding through utility resource planning, generation additions, transmission investment, and regional planning processes.

Load Growth is Outpacing Firm Capacity

- Rapid load growth from data centers, industrial demand and electrification are outpacing firm, dispatchable capacity additions.
- Both ERCOT and MISO Texas face planning uncertainty as large load additions pressure reserve margins and increase the need for deliverable resources.

Peak-Hour Risk is Increasing

- Reliability risk is increasingly concentrated during peak-risk hours when demand is high and renewable output is limited.
- Winter morning heating load, summer evening solar ramp-down, battery duration limits, and thermal outages create periods where reserves may tighten quickly.

Deliverability is the Key Bottleneck

- Transmission and deliverability constraints remain a critical reliability bottleneck, particularly for Houston, South Texas, and Southeast Texas load centers.
- Even where system-wide capacity exists, local constraints can limit the ability to move power to high-growth industrial areas during scarcity conditions.

Customer-Side Mitigation Is Critical

- Large industrial customers should proactively evaluate customer-side mitigation strategies as curtailment, price volatility, and planning risk increase.
- On-site generation, backup power, storage, demand response, interruptible service, and hedging will be increasingly important for reliability and cost management.

Executive Summary: Industrial Load Growth & Generation Investment Dynamics

ERCOT's relative advantage to large-load growth lies in the mechanisms to effectively manage uncertainty: load validation, batch interconnection studies, customer-funded upgrades, demand response, and flexible load integration.

Large Loads Redefine Planning Risk

- Historical peak growth has been manageable, but large single-site projects can change ERCOT requirements quickly.
- System planning must account for nonlinear load growth, not just historical CAGR.

Queue Discipline Protects Competitiveness

- The large-load queue should be treated as a planning signal, instead of a forecast.
- Compared to other large-load growth regions, ERCOT's load validation and batch-study approach offers a more transparent path to managing uncertainty and protecting existing customers from costs tied to speculative demand.

Peak Forecasts Depend on Conversion

- Historical trends reach only about 100 GW by 2030, while higher cases require faster large-load materialization.
- Customer procurement, hedging, and resilience strategies should be designed to work across both moderate and aggressive ERCOT growth outcomes.

TEXAS ENERGY FUND

TxEF Narrows, But Does Not Close, the Gap

- Known TxEF-supported additions help, but a large residual capacity need remains after finalized loans, grants, and diligence-stage projects.
- ERCOT still needs market-led generation, storage, transmission, demand response, and customer-side resilience.

Resource Mix Matters for Reliability

- Renewable and storage additions support energy supply, but firm-capacity exposure remains during scarcity, winter, and evening ramp conditions.
- Houston customers should evaluate effective capacity during high-risk hours, not nameplate capacity alone.

Houston Industrials Can Shape the Outcome

- Long-term offtake, cogeneration, storage, flexible operations, and demand response can reduce customer exposure while supporting ERCOT reliability.
- HETI can position Houston as both a major load center and a reliability partner.

Executive Summary: Senate Bill 6

SB 6 creates a more transparent framework for integrating large-load growth into grid planning by clarifying demand signals, assigning infrastructure costs to their sources, and enabling more informed investment and reliability decisions.

Demand Becomes Explicit in System Planning

- SB 6 brings large industrial demand into the grid planning process earlier and more transparently.
- This shifts planning away from assumptions and toward a clearer understanding of when and where large loads are expected to materialize.

Grid Impacts Are Clearly Assigned

- The legislation ties the cost of interconnection and grid impacts more directly to the loads that create them.
- This clarifies financial exposure and changes how large energy users evaluate grid-based versus on-site solutions.

Infrastructure Trade-Offs Become Visible

- With demand timing and cost responsibility defined, different infrastructure pathways can be compared more directly.
- Transmission upgrades, on-site generation, and demand-side resources can be evaluated on similar footing.

Demand-Side and Clean Options Gain Traction

- Long-duration storage, flexible load, and on-site generation become part of the economic decision set rather than peripheral tools.
- These options become more credible as substitutes for traditional wires or peaking resources when grid costs rise.

Reliability Is Shared, Not Centralized

- SB 6 formalizes a limited role for demand-side reliability during system stress while preserving normal operational autonomy.
- This recognizes that large industrial loads can support reliability without being continuously operated by the grid.

Incentivizes Investment into Energy Tech

- SB 6 creates an environment where cost control, resilience, and emissions reduction can align for industrial centers like Houston.
- Lower-carbon solutions emerge as natural outcomes of better planning and clearer economic signals, rather than as compliance requirements.

A. Competitiveness & Market Position

Executive Summary: Competitiveness & Market Position of Texas

TX's power market structure, infrastructure depth, industrial clustering, and energy workforce create a flexible operating environment for large-scale projects. However, rising load growth, weather exposure, and grid constraints require careful risk considerations.

TX Power Markets Offer Distinct Risk and Flexibility Profiles

- ERCOT dominates Texas with high procurement flexibility but greater price volatility.
- Compared with PJM and NYISO, ERCOT and MISO give large industrial users more flexibility through supplier choice, bilateral contracts, hedging, and demand response.

Competitive Power Markets Expand Procurement Flexibility

- ERCOT gives large customers supplier choice and flexible procurement to manage cost and operations.
- Houston's dual-market position expands procurement options beyond what is typically available in NYISO, CAISO, or ISO-NE load pockets.

TX Infrastructure Depth Supports Project Scalable Execution

- TX's integrated power, gas, transportation, and port infrastructure creates a strong operating environment for large industrial projects.
- Houston specifically, offers infrastructure at a scale that peer regions on the East and West coast cannot match.

TX Gulf Coast Industrial Clustering Reduces Structural Cost and Execution Risk

- TX's ERCOT and MISO South combines deep industrial density, logistics, and power infrastructure investment.
- The Gulf Coast reduces execution risk relative to less-developed industrial corridors in other regions.

TX Energy Workforce for Industrial Growth

- Broad-based employment depth across fuels, transmission, energy efficiency, motor vehicles, and power generation supports access to skilled labor for large-scale energy and industrial projects.
- Few regions match Texas' labor scale across fuels, transmission, generation and skilled trades.

Key Risks to Consider in Gulf Coast

- Houston / Texas Gulf Coast power users face rising reliability and cost risks from extreme weather, load growth, and grid congestion.
- These risks are not unique to Texas; peer regions including PJM, NYISO, CAISO, and the Southwest market face similar load growth and deliverability pressures.

Overview of U.S. Power Market

U.S. power markets are organized across a mix of competitive wholesale markets, bilateral utility structures, and regional balancing authorities. These differences shape how power is dispatched, priced, procured, and planned across each region.

Northwest

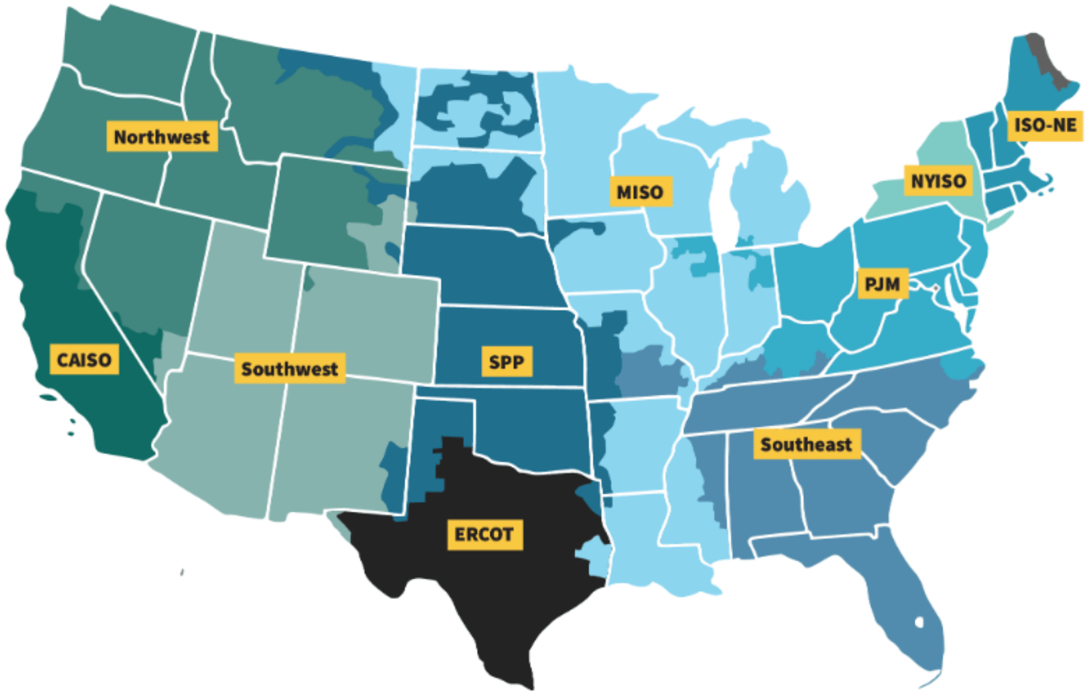
- Consists of multiple balancing authorities across a large Western Electricity Coordinating Council ("WECC") footprint that coordinate generation, transmission, and reserves, with a system heavily supported by hydro resources.

CAISO

- Runs California's competitive wholesale power market, manages grid reliability and transmission planning, and operates both core electricity markets and the Western Energy Imbalance Market ("EIM").

Southwest

- Covers parts of the WECC Southwest with a generation mix centered on coal, gas, and nuclear resources serving a roughly 42 GW summer peak.



ISO-NE

- Manages New England's wholesale electricity, capacity, and congestion markets while operating the regional high-voltage grid and procuring capacity through forward auctions.

NYISO

- Runs New York's wholesale power and capacity markets, oversees the state's transmission grid, and manages persistent congestion into New York City and Long Island.

PJM

- Operates a large competitive wholesale electricity market across 13 states and D.C., with energy, capacity, and ancillary services markets supported by centralized dispatch and long-term planning.

SPP

- Manages transmission and organized wholesale markets across 14 states, including day-ahead, real-time, reserve, and transmission congestion rights markets.

ERCOT

- Oversees most of Texas's electric load through an energy-only wholesale market with day-ahead, real-time, and ancillary services, while also managing system reliability and retail switching.

MISO

- Operates transmission and centralized wholesale markets across parts of 15 Midwest and Southern states, with added ancillary services and expanded operations through MISO South, which includes a portion of Southeast Texas.

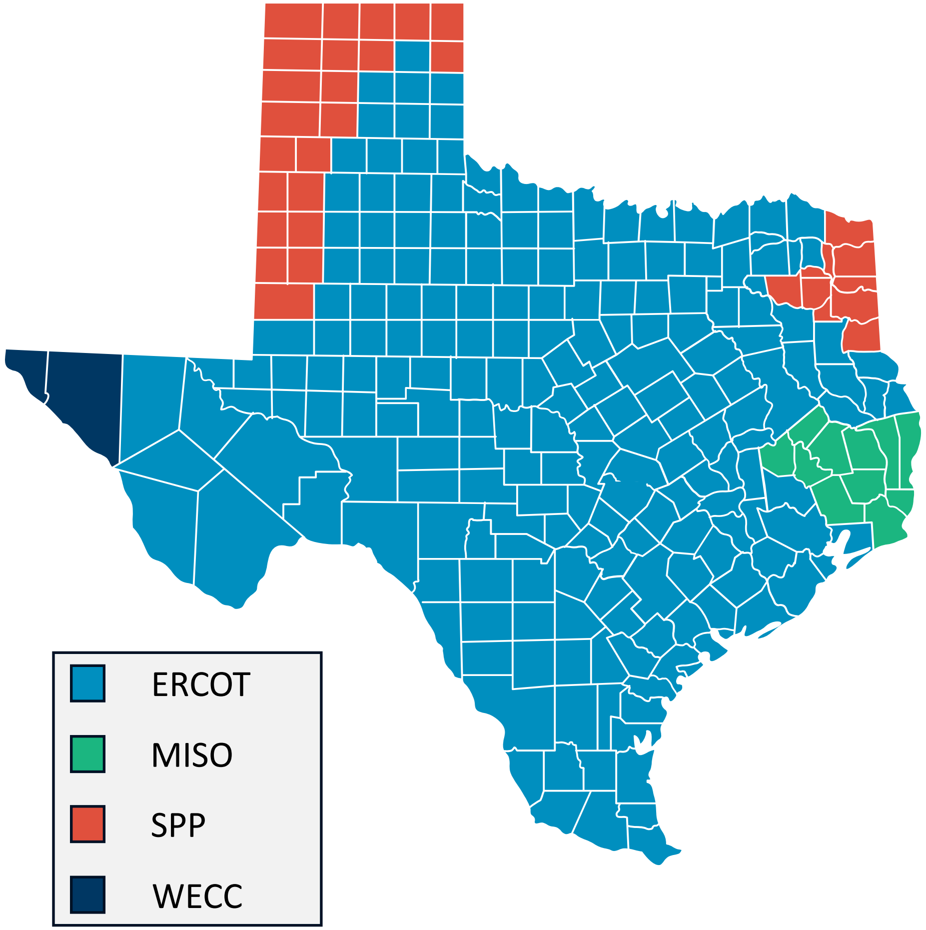
Southeast

- Functions primarily as a bilateral, vertically integrated electricity market where most physical power sales occur directly between utilities rather than through organized wholesale markets.

Source: FERC

Overview of Texas’ Power Market

Houston sits at the intersection of ERCOT and Entergy TX/MISO territories, a unique dual-market position that enables flexible load siting, transmission optionality, and infrastructure resilience unavailable elsewhere in Texas.



- ERCOT operates almost entirely within Texas on a largely isolated grid and relies on an energy-only market design with no centralized capacity market.
- Reliability and investment signals are driven by energy prices and ancillary services, with scarcity pricing causing sharp price spikes during tight system conditions.
- The market increasingly favors flexible, fast-responding resources, where higher volatility creates risk but also a richer toolkit to manage and monetize it.
- Houston’s role as ERCOT’s largest load center and LNG export hub drives the rapid growth in data centers, LNG, and electrification, combined with high wind, solar, and storage penetration. This makes ERCOT a high-risk, high-reward market.

- MISO spans a large multi-state footprint from the Gulf Coast through the Midwest and is the wholesale power market in which Entergy’s Texas operations participate, combining competitive energy markets with a formal, seasonal capacity market.
- In addition to day-ahead and real-time energy markets, MISO uses capacity auctions to ensure sufficient accredited resources are available to meet planning reserve margins.
- Thermal retirements and rising demand have tightened reserve margins, increasing the importance of capacity revenues as a forward investment signal.
- Compared with ERCOT, the MISO market provides lower energy price volatility and more predictable revenues, favoring assets that can secure both energy and capacity value.

- SPP borders ERCOT to the north and includes the Texas Panhandle, while WECC lies to the west and connects through limited DC ties and regional power flows.
- Neither market relies on ERCOT-style scarcity pricing; SPP has no centralized capacity market, while WECC regions emphasize resource adequacy and system balancing.
- Prices in these markets are more influenced by congestion, curtailment, and renewable output than by reserve shortages.
- For Texas, SPP and WECC primarily function as spillover markets, shaping congestion patterns, renewable export opportunities, and long-term transmission strategy, with lower risk and lower returns than ERCOT.

Sources: ERCOT, FERC, MISO, SPP, WECC, EIA, CAISO

Competitive Power Market Access Creates Procurement and Operating Flexibility

Access to organized competitive markets broadens the power supply toolkit, enabling customers and projects to combine supplier choice, bilateral PPAs, market purchases, hedges, demand response, and load-shifting strategies to manage cost, reliability, and growth.

Market Access Model	Procurement Flexibility	Operational Flexibility
ERCOT **Competitive Retail Choice + Energy-Only Wholesale Market**	▪ ERCOT's competitive market structure provides large Texas load customers with procurement flexibility by allowing eligible customers to contract with competing Retail Electric Providers ("REPs"), rather than relying solely on a vertically integrated utility tariff. ▪ This gives customers the ability to tailor power procurement around their operating profile, risk tolerance, and sustainability objectives through a range of structures, including fixed-price supply contracts, market-indexed products, block-and-index arrangements, renewable PPAs / VPPAs, and financial hedges.	▪ ERCOT's energy-only market design creates strong real-time price signals that can enhance operating flexibility for large load customers. ▪ Rather than treating load as fixed, customers with the ability to shift production, reduce consumption during scarcity events, operate behind-the-meter resources, or participate in curtailment programs can optimize operations around market conditions. For large industrial users, data centers, battery operators, or other energy-intensive facilities, this flexibility can translate into several economic benefits.
MISO South (Texas) **Wholesale RTO Access in Southeast Texas; Retail Remains Utility-Led**	▪ Entergy Texas / Southeast Texas customers can benefit from MISO's organized wholesale market, but the procurement model is materially different from ERCOT's competitive retail structure. ▪ Customers in Entergy Texas's service territory are generally served through the regulated utility framework, with Entergy Texas managing generation supply, purchased power, transmission access, and MISO market participation on behalf of its customers. From a customer perspective, this means flexibility is typically achieved indirectly through regulated tariffs, utility procurement, bilateral arrangements, special contracts, riders, demand response programs, or utility-led resource planning, rather than through full retail choice.	▪ MISO market participation supports day-ahead / real-time energy, operating reserves, Financial Transmission Rights ("FTRs"), and regional transmission planning; large-load customers can benefit from demand response, interruptible load structures, and coordinated reliability / congestion management.

Implication for Procurement / Siting: ERCOT offers broader retail supplier optionality and market-linked procurement structures. ERCOT may provide greater procurement flexibility and direct market exposure, but it also requires customers to manage price volatility, congestion risk, and hedge strategy more actively. MISO South Texas offers regional wholesale market access and transmission / reliability benefits, but customer-level flexibility is more dependent on utility arrangements and tariff design.

Sources: ERCOT, MISO

Region’s Infrastructure Depth Lowers Supply Chain Friction and Supports Scale

Houston’s proximity to the Ship Channel, deep natural gas markets, and established logistics networks can reduce complexity, shorten lead times, lower supply chain friction, and support long-term expansion.

1 Power Market Optionality

- ERCOT access gives large customers more options to manage power supply and cost. Customers can use retail supply contracts, bilateral PPAs, market purchases, financial hedges, demand response, and load-shifting to better match power procurement with their operations, budget, and reliability needs. This provides flexibility to help reduce exposure to price volatility while allowing customers to optimize when and how they consume power.

2 Energy Infrastructure Density

- Extensive transmission, generation, natural gas pipeline, and industrial energy infrastructure can help lower interconnection, fuel supply, and reliability risks. The region’s established grid and energy network can support large industrial loads by improving access to power supply, backup fuel options, and nearby generation resources. Additionally, infrastructure depth can help reduce development complexity and support future project expansion.

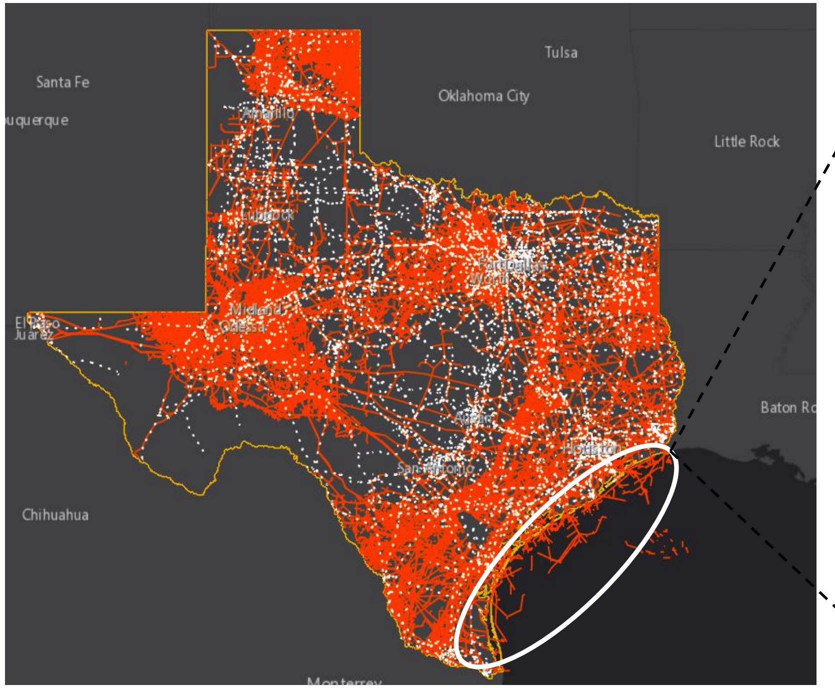
3 Logistics Connectivity

- Houston and The Gulf Coast ports, navigation channels, highways, rail, and industrial corridors can support efficient movement of equipment, feedstock, and finished products. The region’s logistics network can help reduce transportation bottlenecks and improve access to suppliers, customers, and export markets. This connectivity can also improve project execution certainty and support long-term operating flexibility.

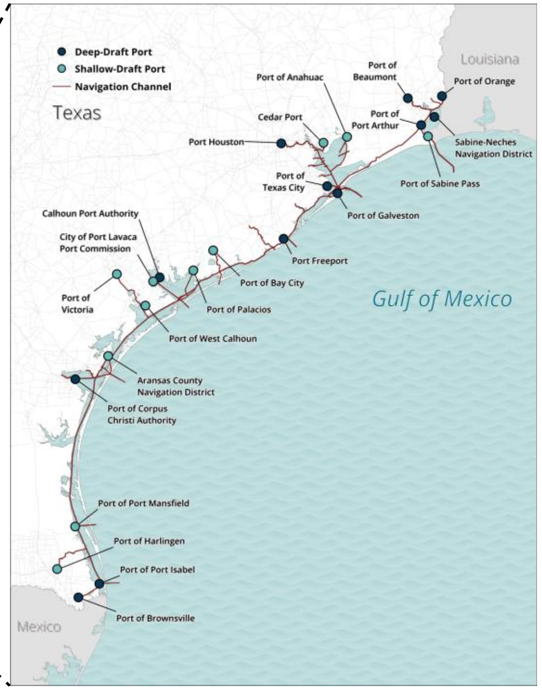
4 Scalable Operating Environment

- Market depth and physical infrastructure can support phased development, future expansion, and stronger supply chain resilience. Access to established power markets, energy networks, logistics, and suppliers allows projects to scale as operating needs evolve, helping to reduce execution risk and provide flexibility to manage future growth and supply chain disruptions.

Texas Infrastructure Map (*w/ Transmission and Natural Gas Pipelines*)



Map of Ports in Gulf of Texas



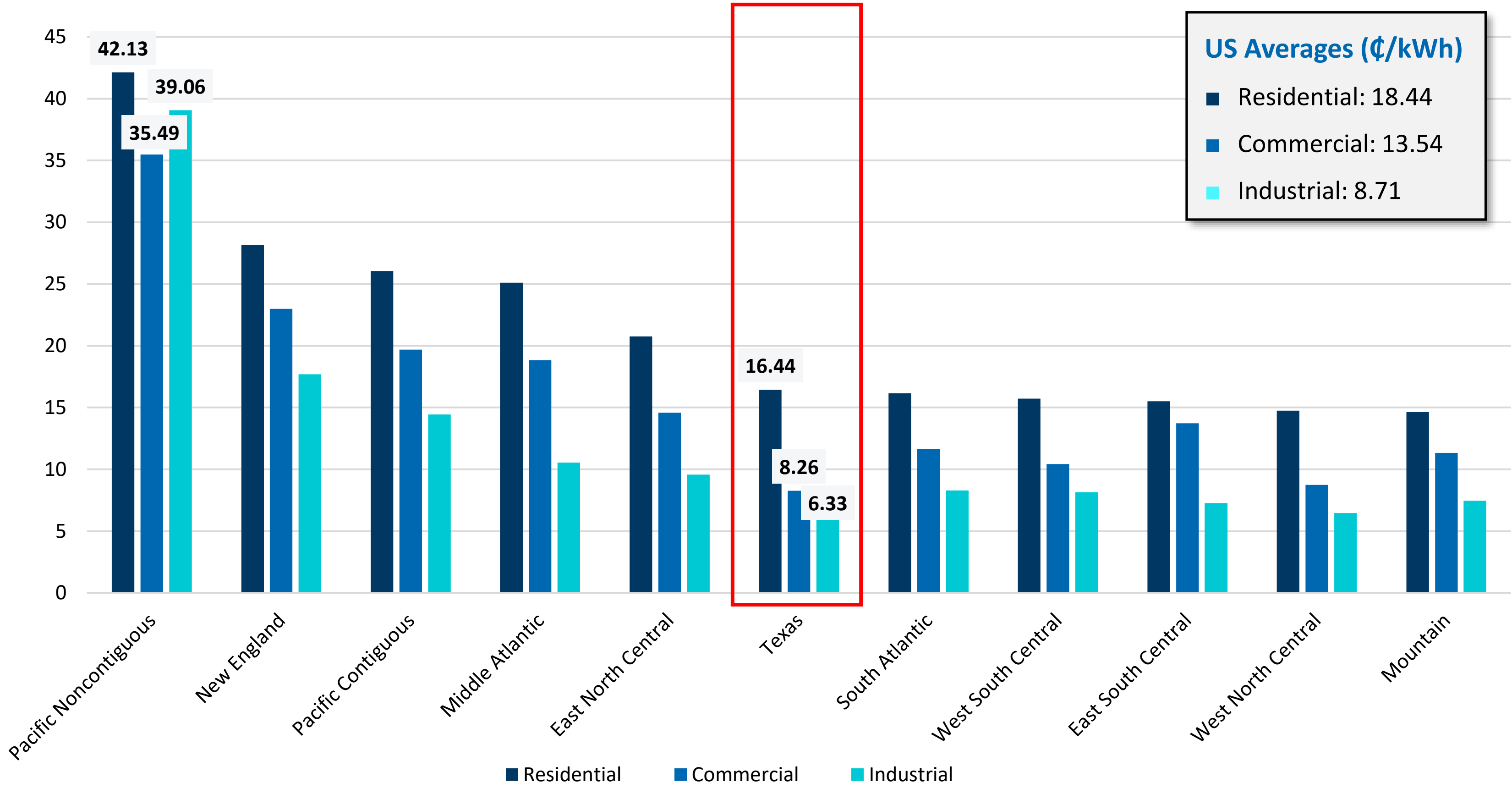
Implication: Texas’ infrastructure depth helps move large projects from siting to execution by reducing separate power, fuel, logistics, and supplier coordination risks.

Source: ERCOT

Texas Maintains a Competitive Power Cost Position Across U.S. Regions

Texas currently ranks among the lower-cost U.S. markets for residential, commercial, and industrial electricity.

Average Price of Electricity as of May 2026 (¢/kWh)



Key Commentary

- Texas remains a lower-cost market across residential, commercial, and industrial electricity relative to many U.S. regions.
- Industrial rates are particularly competitive, reinforcing Texas' cost advantage for energy-intensive and large-load customers.
- Rapid load growth makes protecting affordability increasingly important as infrastructure investment scales.
- SB 6 strengthens large-load accountability and demand flexibility, protecting customers from price surges, cost shifting, and grid instability.

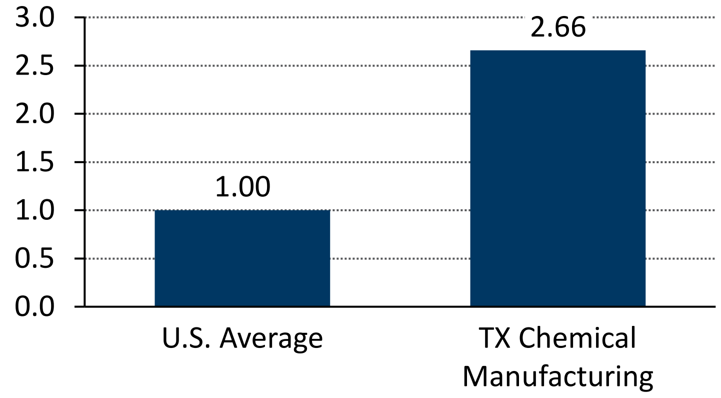
Sources: EIA, Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector

FTI CONSULTING

Industrial Clustering Creates Structural Cost and Execution Advantages

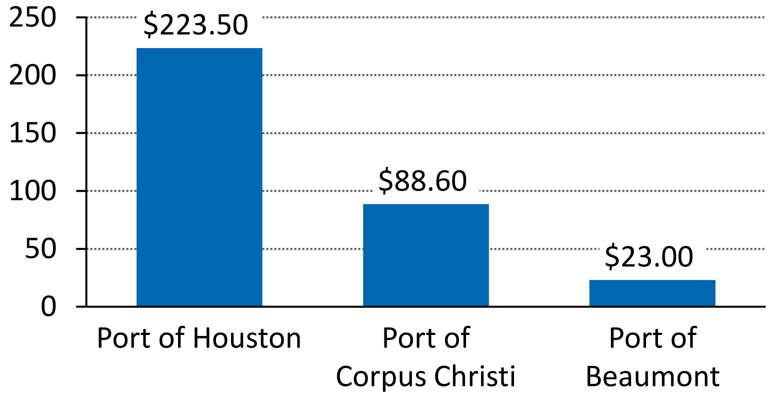
Texas's ERCOT and MISO South footprint combines market access with deep Gulf Coast industrial, logistics, and energy infrastructure, reducing cost friction and improving execution certainty for large-scale projects.

1 Industrial Concentration Signals Supplier and Labor



- Texas basic chemical production is ~2.6x more concentrated than the U.S. average and contributes over one-third of national basic chemical GDP and exports, highlighting the scale of the state's industrial base. This concentration creates a deep regional ecosystem of experienced operators, specialized vendors, EPC contractors, maintenance providers, and industrial customers. For large projects, this can improve access to qualified labor, reduce reliance on out-of-market suppliers, support faster issue resolution, and lower execution risk during both construction and operations.

2 Gulf Coast Trade Volumes ($ Billion)



- Large port trade volumes and deep Gulf Coast channels support the movement of heavy equipment, project materials, feedstock, and finished products at industrial scale. The region's co-located ports, highways, rail networks, and industrial corridors provide multiple transportation pathways, which can reduce dependence on a single route or mode of transport. This logistics depth can help lower bottlenecks, improve delivery certainty, reduce construction and operating delays, and support access to domestic and export markets.

3 Dual-Market Power Advantage

~19.6 Months
ERCOT Speed Advantage from IR to COD compared to peer region averages.

$30B
MISO Investment focused on strengthening transmission and grid reliability.

- Houston and the Gulf Coast are positioned to support large-load growth through MISO South's utility-led planning which helps match grid upgrades to where reliability, load growth, and interconnection needs are emerging. With ERCOT's market-based procurement model, Batch Zero process and project-specific interconnection framework, the region can offer faster grid access and greater confidence in power availability. For industrial large-load customers, this means clearer connection timelines, a more reliable operating environment, and the ability to begin production sooner with less grid-related uncertainty.

Physical Infrastructure Advantage : Dense power, gas, pipeline, port, rail, highway, and industrial corridors can reduce interconnection, fuel supply, logistics, and execution risks for large projects. This supports phased development and long-term expansion as project needs evolve.
Execution Implications: Market depth plus physical infrastructure can improve cost visibility, supplier access, and execution certainty key considerations for energy-intensive industrial growth in Texas.

Sources: Berkeley Lab, MISO

Skilled Workforce Supports Both Legacy and Emerging Energy Industries

Texas's energy competitiveness rests on maintaining and expanding employment across the full energy spectrum, from oil and gas to renewables and grid infrastructure. This diversified growth model supports economic resilience and workforce stability.

Workforce Scale: Texas employed 990,052 energy workers in 2024, the largest energy workforce of any U.S. state. This represents 11.7% of total U.S. energy employment, meaning more than one in nine U.S. energy jobs is located in Texas. Energy employment accounts for 7.1% of total Texas employment, confirming energy as a core pillar of the state economy.

Conventional Energy Employment: Texas remains the nation's center of conventional energy employment, with 310,185 fuels jobs, representing 29.4% of U.S. fuels employment. Employment is concentrated in oil and petroleum (193,175 jobs) and natural gas (96,116 jobs).

Renewable Power Employment: Texas supports 71,818 electric power generation jobs, with significant renewable employment including 28,124 wind jobs and 18,022 solar jobs. Roles span construction, operations, maintenance, and project development.

Grid and Infrastructure Workforce: Texas employs 213,076 workers in transmission, distribution, and storage, accounting for 14.6% of U.S. transmission, distribution, and storage ("TDS") employment. This includes 152,435 traditional T&D jobs, 9,455 storage jobs, and 49,208 smart grid and advanced systems roles.

Energy Efficiency Employment: Texas employs 182,506 workers in energy efficiency, representing 7.7% of U.S. efficiency employment. Key areas include efficient lighting (59,197), HVAC (38,604), and high-efficiency heating and cooling (41,596).

Electricians: The BLS projects ~81,000 new electrician openings annually through 2034, growing 9% faster than any other occupation, driven by grid expansion, data centers, and an aging workforce.

Welders: The American Welding Society projects a shortage of 330,000 welding professionals by 2028, requiring ~82,500 new hires per year, also being driven by the need for large-load growth and power buildout.

Awarded 123 petroleum engineering degrees in 2024–25; ranks #1 undergraduate and #2 graduate nationally.

6% of McCombs MBA graduates entered energy roles (Class of 2024); ExxonMobil and RWE among top recruiters.

Energy is a top destination for graduates, supported by a dedicated Master of Energy Economics program.

Known as the "Energy University" UH estimates an annual economic impact of $2.2 billion on the Texas economy.

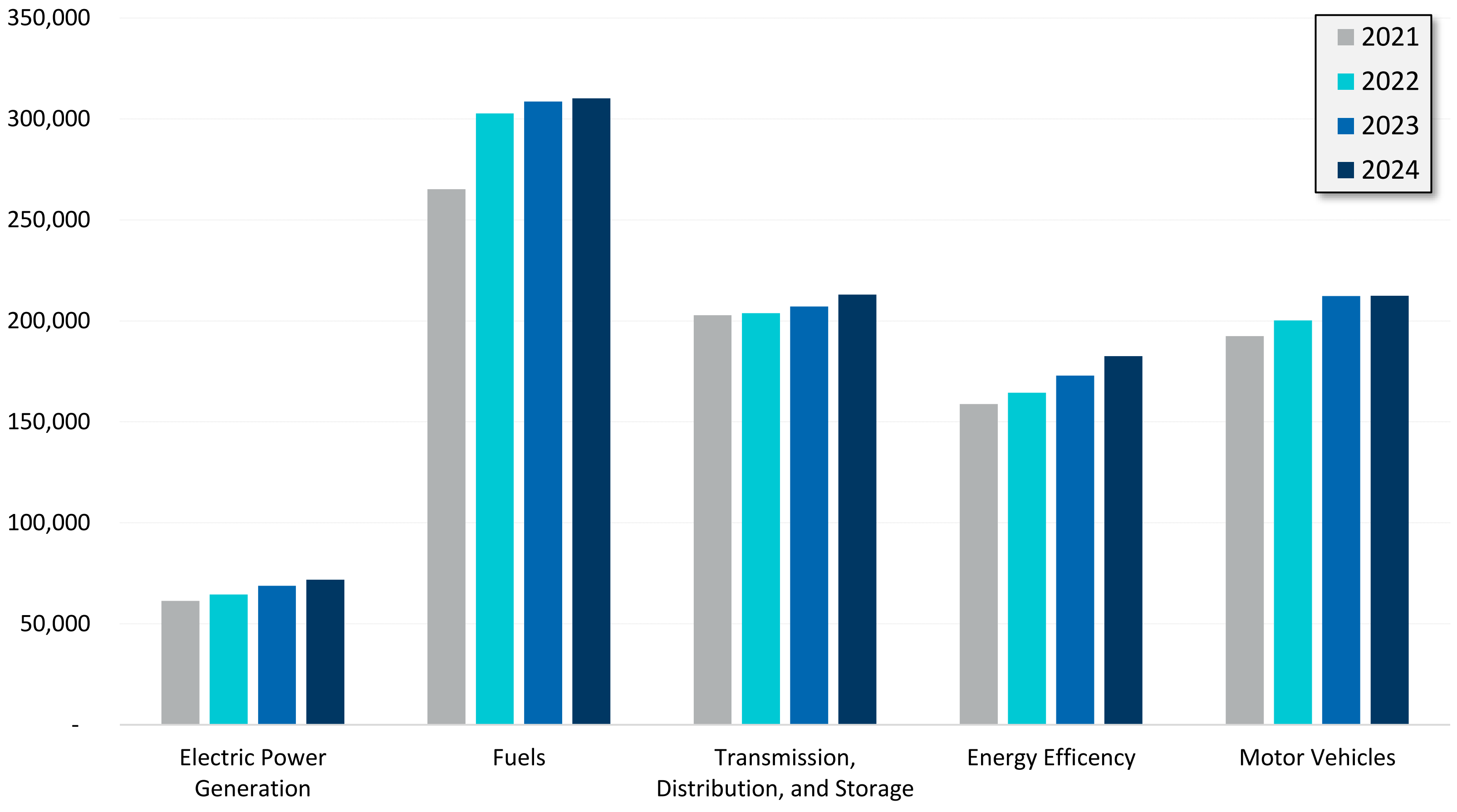
HCC offers an AAS in Welding Technology and electrician training programs directly feeding the Gulf Coast's industrial workforce pipeline.

Sources: U.S. Department of Energy, UT, TAMU, Rice, UH, BLS

Skilled Workforce Supports Both Legacy and Emerging Energy Industries (Cont.)

Texas added 109,000+ energy jobs from 2021–2024, nearing 1M workers while increasing its share of U.S. energy employment to 11.7%. Growth was broad-based across segments, with energy consistently representing ~7–8% of state employment.

Energy & Employment in Texas (People)



Key Commentary

2024 - Present

- Texas energy employment reached 990,052 workers, the highest level across the four-year period, while increasing its share of U.S. energy jobs to 11.7%.
- Employment remained highly diversified, with Fuels, TDS, Energy Efficiency, and Motor Vehicles each exceeding 180,000 jobs.
- The construction industry currently faces a shortage of over ~300,000 workers, a gap that is expected to widen as much as 40%, as the existing workforce is projected to retire by 2031.

2023

- Texas employed 969,801 energy workers, adding 33,999 jobs year-over-year (+3.6%).
- The state accounted for 11.6% of U.S. energy jobs, while energy's share of total Texas employment rose to 7.7%, the highest across the reports.
- Job growth was broad-based, with Fuels, TDS, and Motor Vehicles each exceeding 200,000 jobs, supported by gains in Electric Power Generation "(EPG") and Energy Efficiency.

2022

- Texas energy employment increased to 936,476 workers, driven by the largest annual gain in the period (+55,785 jobs, +6.3%).
- The state represented 11.5% of U.S. energy jobs, continuing a steady upward trend in national share.
- All major energy segments expanded, with Fuels exceeding 300,000 jobs, signaling broad-based sector growth.

Sources: U.S. Department of Energy, HPM

Risks to Consider in Houston / Texas Gulf Coast Market

Extreme weather shocks and surging data center demand are driving sharp price volatility, congestion, and mounting reliability pressure across ERCOT. Long-dated transmission investments are shifting market focus towards who absorbs risk and cost.

Power Market Exposure: Volatility, Congestion & Basis Risk

- Winter Storm Fern drove single-day congestion rent as ERCOT high as $65.5M on January 25, with ancillary service prices spiking 4–5x from December levels before collapsing back to near-zero in a mild February.
- The West Texas Export Interface is projected to generate up to $245M in annual congestion rent by 2027 under sensitivity cases, reflecting persistent basis risk between generation-heavy West Texas and load centers.

Grid Reliability & Load Growth Pressure

- ERCOT's 2031 demand forecast jumped from 150 GW to 218 GW in a single year, driven almost entirely by data center load.
- ERCOT is now tracking over 450,000 MW of proposed generation and roughly 410,000 MW of proposed large load.
- Over 7,300 MW of coal and gas generation has retired since 2018, and the renewable resources replacing it sit farther from demand centers.

Interconnection & Upgrade Uncertainty

- ERCOT is tracking 238.6 GW of large load interconnection requests, that is more than three times 2024 volume, yet only 7,502 MW have been approved to energize since January 2022.
- Supporting infrastructure is massive but slow: $30.21 billion in transmission projects are planned through 2031, including the first-ever 765-kV lines in ERCOT, a voltage class that is being developed faster than the rest of the U.S.

Climate & Infrastructure Vulnerability

- January alone saw 17 ERCOT system notifications, including an Emergency Notice from simultaneous generation loss and transmission failures in San Antonio and Houston.
- The shift toward inverter-based resources has required ERCOT to approve six synchronous condensers specifically to shore up grid strength in West Texas, where stability risk during disturbances is highest.

Cybersecurity & Supply Chain Risk

- ERCOT now requires every market participant to complete a two-track attestation covering both corporate ownership ties to China, Russia, Iran, or North Korea, along with a five-year lookback on grid equipment sourced from companies linked to those countries, with updates required every 180 days.
- Texas has separately expanded its prohibited technology list to include additional Chinese-linked hardware and AI platforms.

Sources: ERCOT, Texas Scorecard, Community Impact, StateScoop

Risk Mitigants Underway in Houston / Texas Gulf Coast

Coordinated investments in transmission, storage, demand response, and load validation are strengthening Houston's ability to accommodate large-scale electrification and large load growth.

765-kV backbone expansion

- The ~2,500 mile 765-kV network creates a long-term transmission backbone designed for ERCOT's next phase of growth, addressing structural congestion challenges rather than relying solely on incremental upgrades.
- Higher-voltage infrastructure improves long-distance transfer capability an estimated 1.5-3 GW from generation-rich regions into major load centers, strengthening Houston's access to statewide resources.

SB 6 curtailment authority

- Large-load curtailment on new >75 MW loads creates a new reliability buffer for ERCOT, allowing certain loads to reduce demand during emergency conditions before more disruptive system actions are required.
- Houston's growing data center footprint benefits from a framework that links expansion with reliability obligations, supporting continued development while protecting system performance.

Storage growth

- ERCOT's battery fleet has scaled rapidly to ~14GW, enough to become a meaningful reliability resource that is not matched in other peer regions.
- Batteries help dampen scarcity pricing and congestion-driven volatility by injecting capacity during the most stressed periods of the day.
- The concentration of new battery projects near the Gulf Coast and Houston region directly supports one of ERCOT's most constrained load pockets.

Load validation efforts

- ERCOT is moving from speculative load forecasting to validated project pipelines, improving confidence that transmission is built for committed demand rather than theoretical requests.
- Stronger validation requirements help filter non-viable projects from the queue, producing more realistic load forecasts and transmission investment decisions.

CenterPoint/ERCOT planning alignment

- Closer coordination between CenterPoint and ERCOT is improving visibility into Houston's rapidly expanding data center pipeline, allowing transmission needs to be identified earlier in the development cycle.
- Shared planning assumptions reduce the risk of transmission bottlenecks emerging after customer commitments have already been made and allow for clarity from Interconnection Request ("IR") to COD for large load customers.

Sources: BakerBotts, ERCOT, Modo Energy, Nira Energy

B. Demand Response Economics & Market Impact

FTI CONSULTING

Executive Summary: Demand Response Economics & Market Impact

ERCOT's market structure allows flexible load to serve as a cost-management tool and recurring value stream. For Houston industrial customers, this can create an advantage versus regions where customer-level flexibility is more constrained.

Three Revenue Channels Stack Together

- ERCOT's energy-only market rewards flexibility through scarcity arbitrage, ancillary service payments (RRS, ECRS, Non-Spin), and 4CP cost avoidance.
- Together, these stack into a recurring revenue stream that materially lowers a flexible load's effective cost of power.

Scarcity Pricing Pays Real Money

- When system lambda exceeds $1,000/MWh, price-responsive industrial loads have cut consumption by up to 75% during scarcity events.
- The energy-only design produces sharp, predictable price signals that make flexibility a measurable earnings lever.

Registered Capacity Overstates Delivery

- ERCOT has 505 registered NCLRs totaling 10+ GW, but only ~2.5–4.0 GW typically respond during peak events.
- Nameplate registration dramatically overstates what actually arrives when the grid calls.

4CP Is the Dominant Flexibility Lever

- ERCOT estimated ~3,500 MW of load reduction across 2023 4CP intervals and ~2,500 MW in 2024; larger than all other DR programs combined.
- Customers self-curtail to lower next year's transmission charges, making 4CP the highest-impact lever in Texas.

Flexibility Proven During Emergencies

- ERCOT manually deployed 1,593 MW of NCLRs during the September 2023 EEA Level 2 event, and ERS was activated twice that year.
- Industrial flexibility is a documented reliability resource called on under real system stress, not a theoretical one.

SB 6 Makes Flexibility Dispatchable

- Self-curtailment outside SCED isn't captured in economic dispatch and can distort price formation, a concern Potomac Economics has flagged.
- SB 6 directs ERCOT to build a DR program, shifting flexibility toward market-integrated participation.

FTI CONSULTING

Three Economic Channels for Monetizing Flexibility in ERCOT

For industrial customers with interruptible or shiftable processes, ERCOT turns flexibility from a resiliency tool into a measurable earnings and cost-avoidance lever. Channels are: 1) Price arbitrage, 2) Ancillary service payments, and 3) Transmission cost avoidance.

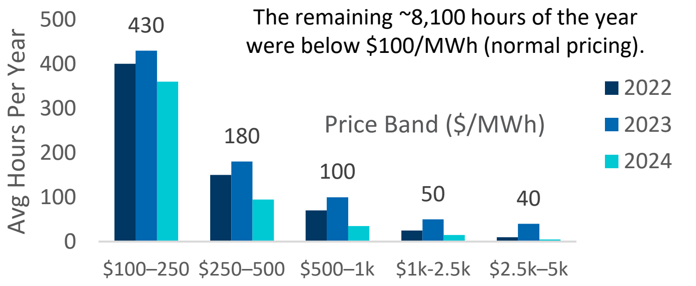
1 Real-Time Price Arbitrage

$1,000+/MWh

The price flexible loads earn per MWh during scarcity hours, when ERCOT pays a premium for power.

Reduced consumption during scarcity intervals avoids the highest real-time prices. ERCOT's energy-only design produces sharp, predictable price signals during tight conditions.

Hours per Year by ERCOT Real-Time Price Band



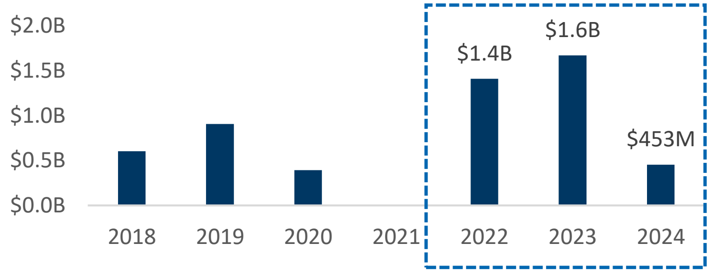
2 Ancillary Service Payments

$3.5B+

***Total payments** to ancillary service providers in ERCOT from 2022-2024, for being available to support the grid.*

Register as a Load Resource and bid into ERCOT's ancillary markets to earn capacity payments for being available to curtail when needed. **ERCOT paid out $1.67B across these markets in 2023 and $453M in 2024.**

ERCOT Ancillary Service Payouts



3 4CP Transmission Cost Avoidance

$20–50K/MW-yr

*Transmission **cost savings per MW** for transmission-voltage industrial customers reducing demand during the four summer peak intervals.*

Curtail for 3-6 hours on the ~20 summer days when ERCOT is likely to peak and lock in 12 months of lower transmission charges. **Typical savings: $20–50K per MW per year, or $2–5M annually for a 100 MW load.**

2024's Four Peak Intervals

Peak Date	Day	Load at Peak	Temp (D/H)	RT Price ($/MWh)
June 19th	Wed	78,600	102°F / 98°F	$120
July 23th	Tue	80,200	104°F / 100°F	$165
Aug 20th	Tue	85,500	107°F / 102°F	$2,400
Sep 4th	Wed	79,800	103°F / 99°F	$145

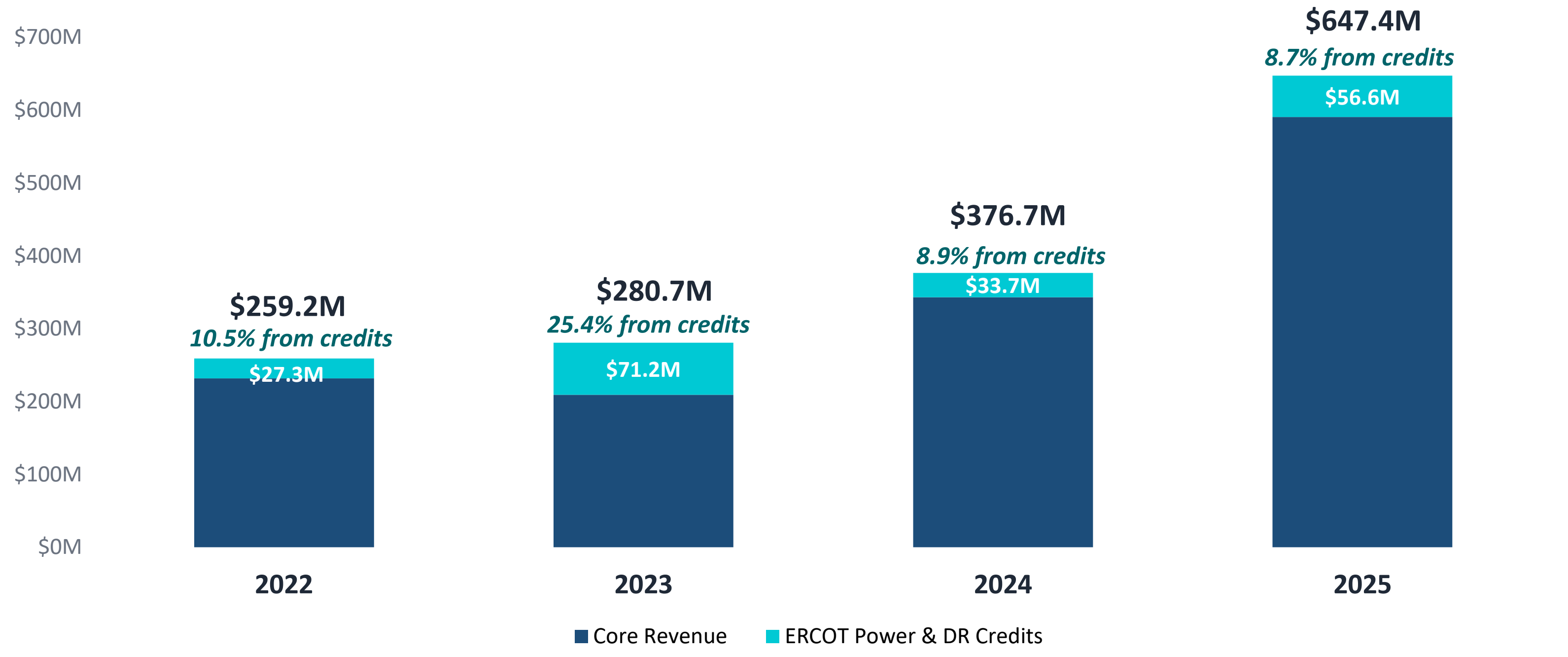
Each peak occurred at 5 PM (Hour Ending 17)

Sources: Potomac Economics State of the Market Reports for ERCOT (2022, 2023, 2024); ERCOT public market data and methodology documentation

Company Spotlight: Riot Platforms | Turning Operational Flexibility into Revenue

Riot earned ~$190M in demand response credits over the last four years and capitalized on its energy expertise to secure its first AI/HPC (High-Performance Computing) lease with AMD (10-year, 50 MW, $630M+).

Riot Platforms Revenue ($M, unless stated otherwise)



AUG 2022: Strategy proven
First year executing all three monetization channels: manual curtailment, ancillary services, and 4CP.

AUG 2023: $32M in a month
Curtailed 95%+ of load during summer heat wave. Single-month credits exceeded all of 2022 combined.

JAN 2024: Winter resilience
Earned $3.3M during Texas cold snap. Proved DR economics work in winter scarcity, not just summer heat.

JAN 2026: AMD Lease
AMD AI/HPC Phase 1 underway at Rockdale. Bitcoin-era flexibility infrastructure now anchors a premium data center.

The Three Mechanism Playbook

1. **Manual Curtailment**: Sell power back when the ERCOT spot price exceeds Riot's fixed PPA price.
2. **Ancillary Services**: Capacity payments for selling ERCOT the option to control Riot's load.
3. **4CP transmission avoidance**: Curtail during four summer peaks; lower transmission charges next year.

Key Commentary

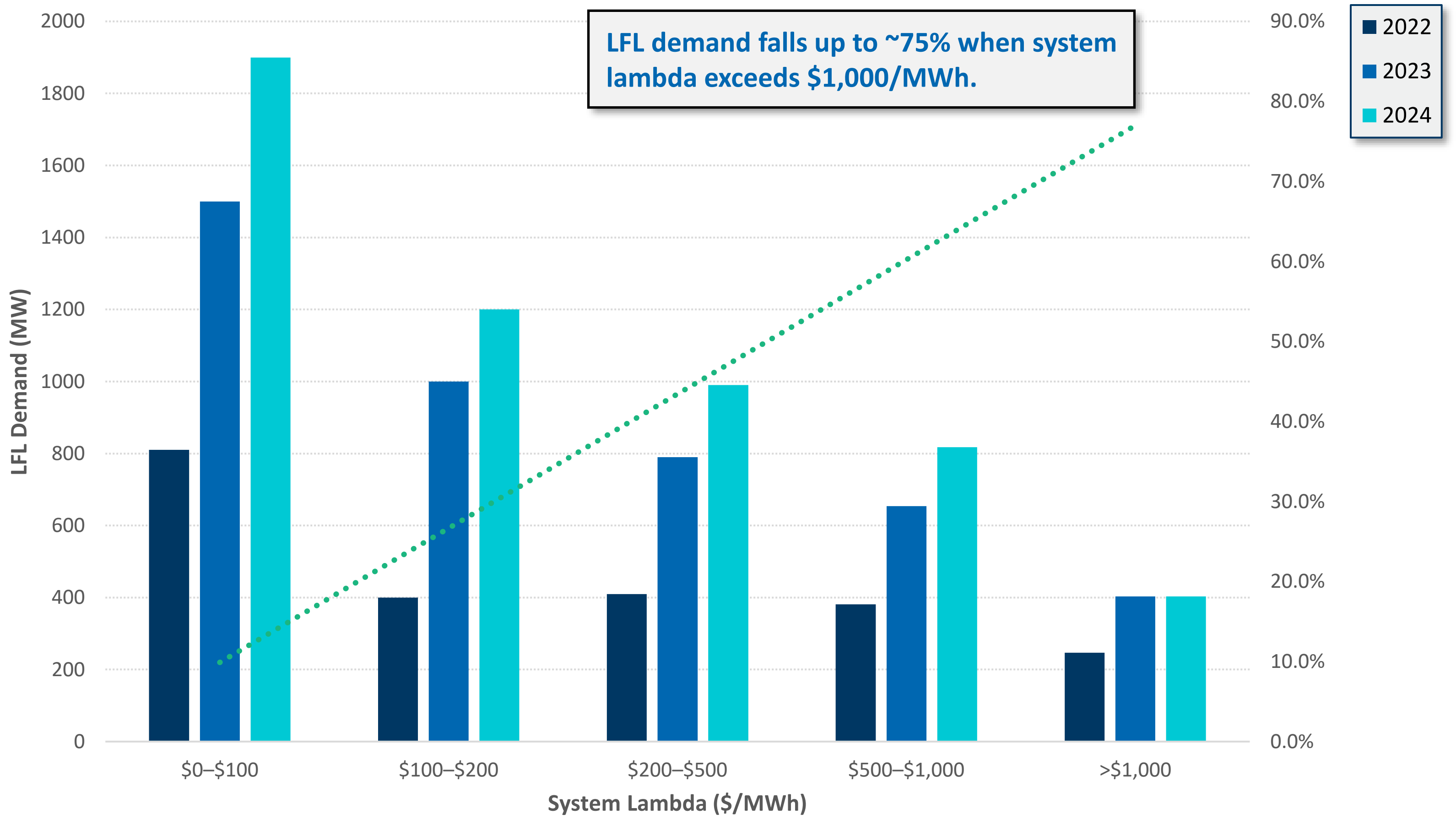
- ERCOT credits contribute 9–25% of Riot's annual revenue depending on weather and price volatility. In scarcity years (2023), this single revenue line exceeds a quarter of total company revenue.
- Riot demonstrates how large flexible loads can turn real-time power price volatility into a monetization opportunity, using curtailment, credits, and demand response to enhance revenue resilience while supporting grid reliability.
- This flexibility also strengthens Riot’s operating model. When electricity prices rise and Bitcoin mining becomes less profitable, Riot can shift from consuming power to monetizing its ability to reduce demand. This creates a natural hedge against power price volatility and helps protect margins during periods when energy costs would otherwise pressure profitability.

Sources: Riot Platforms 10K in 2022, 2023, 2024, and FY 2025 power credits estimated as +68% YoY vs. FY 2024 per FY 2025 earnings release. AMD lease announced January 2026 (Phase 1 commenced).

Flexible Loads Respond to Price

Large flexible loads (“LFL”) in ERCOT cut consumption by ~79% when real-time prices exceed $1,000/MWh — and the responding fleet has more than doubled since 2022.

Flexible Demand and Real-Time Prices



Key Commentary

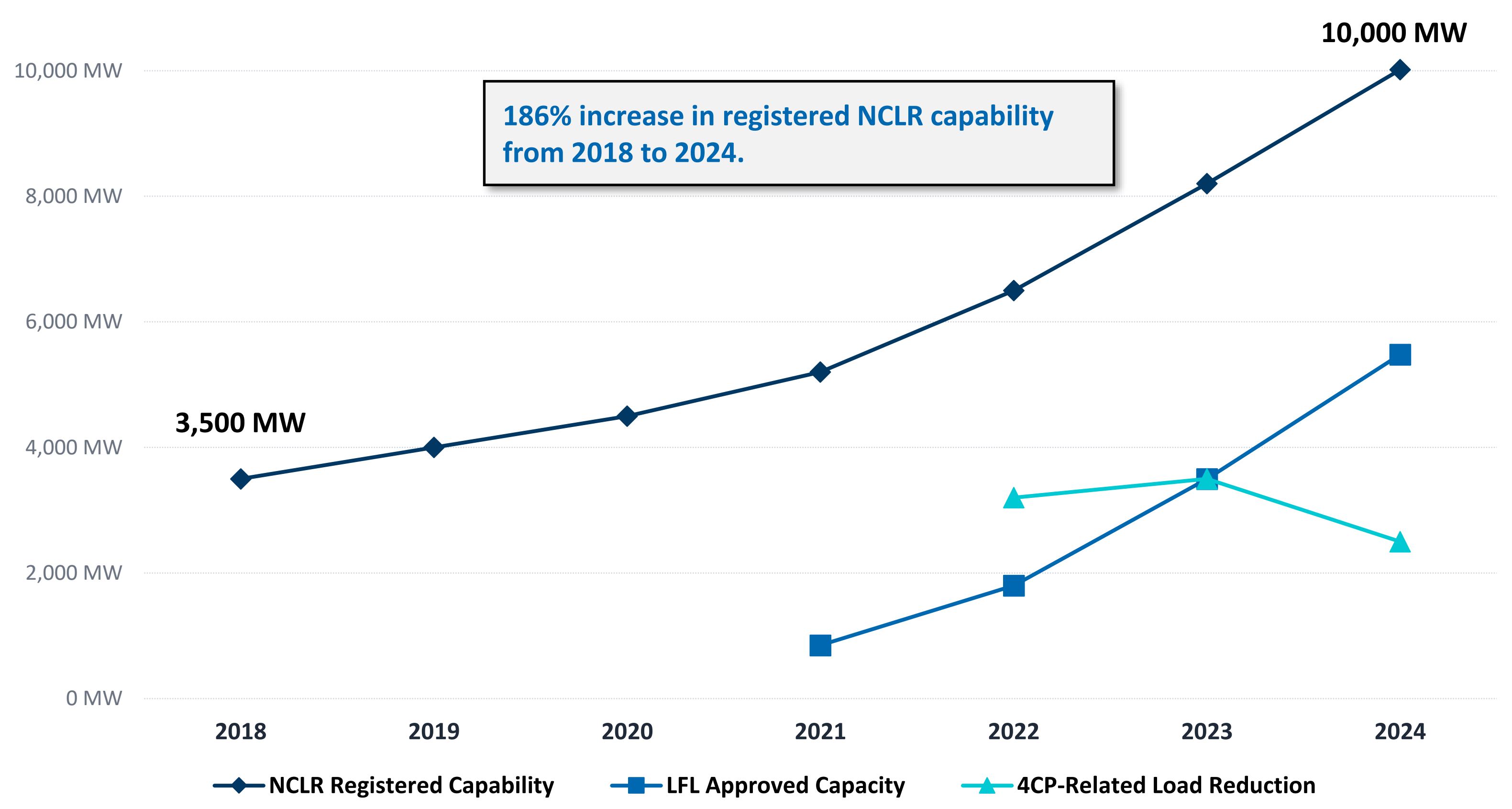
- ERCOT large flexible loads, defined as new or existing loads of 75 MW or more capable of curtailing during grid stress, reached 3,600+ MW of non-coincident demand and 3,200+ MW of simultaneous demand by year-end 2024, creating a meaningful base of price-responsive demand.
- LFL demand reduces up to ~75% when system lambda exceeded $1,000/MWh, demonstrating that flexible load can materially respond during scarcity intervals.
- Qualified Load Resources can participate in SCED and provide ancillary services including RRS, ECRS, Non-Spin, Reg-Up, and Reg-Down, creating direct revenue pathways for interruptible operations.
- 4CP management remains a major cost-avoidance lever, with ERCOT estimating ~2,500 MW of load reduction during 2024.
- For industrial customers with interruptible or shiftable processes, ERCOT converts operational flexibility into a measurable commercial advantage through three main channels:
  - Avoiding high real-time energy prices by reducing load during scarcity intervals,
  - Earning ancillary service revenue through programs such as RRS, ECRS, and Non-Spin, and
  - Reducing transmission cost exposure through Four Coincident Peak (“4CP”) management.

Sources: ERCOT; Potomac Economics, 2024 and 2023 State of the Market Reports for ERCOT

Industrial Demand Response Capacity Has Nearly Tripled Since 2018

Registered DR capability has nearly tripled since 2018, from ~3,500 MW to 10,000+ MW, driven market reforms, crypto and data center load growth, and new ancillary products (ECRS); actual market participation is lower, with FERC reporting ~4.1 GW in 2024

ERCOT Industrial DR Capacity by Participation Type (MW), 2018-2024



Key Commentary

The Pool has Tripled

- Registered industrial DR capability has grown from ~3,500 MW in 2018 to 10,016 MW in 2024, a ~3x expansion driven by three distinct waves of market reform and customer demand.

Three Growth Waves

- Post-Uri reforms (2021–2022) raised ancillary procurement and reserve requirements. The LFL/crypto boom (2022–2023) brought 5,000+ MW of new flexible load into the queue. ECRS launch (June 2023) added a fifth ancillary product with significant revenue upside.

Registered Capacity Overstates Deployment

- Of the 10,016 MW NCLR pool, only ~2.5–4 GW typically responds during peak events, and ~1.9 GW clears in ancillary markets on a typical day. The gap reflects economic choice, not policy failure — most participation is driven by 4CP economics, not real-time dispatch.

LFL is Driving the Next Wave

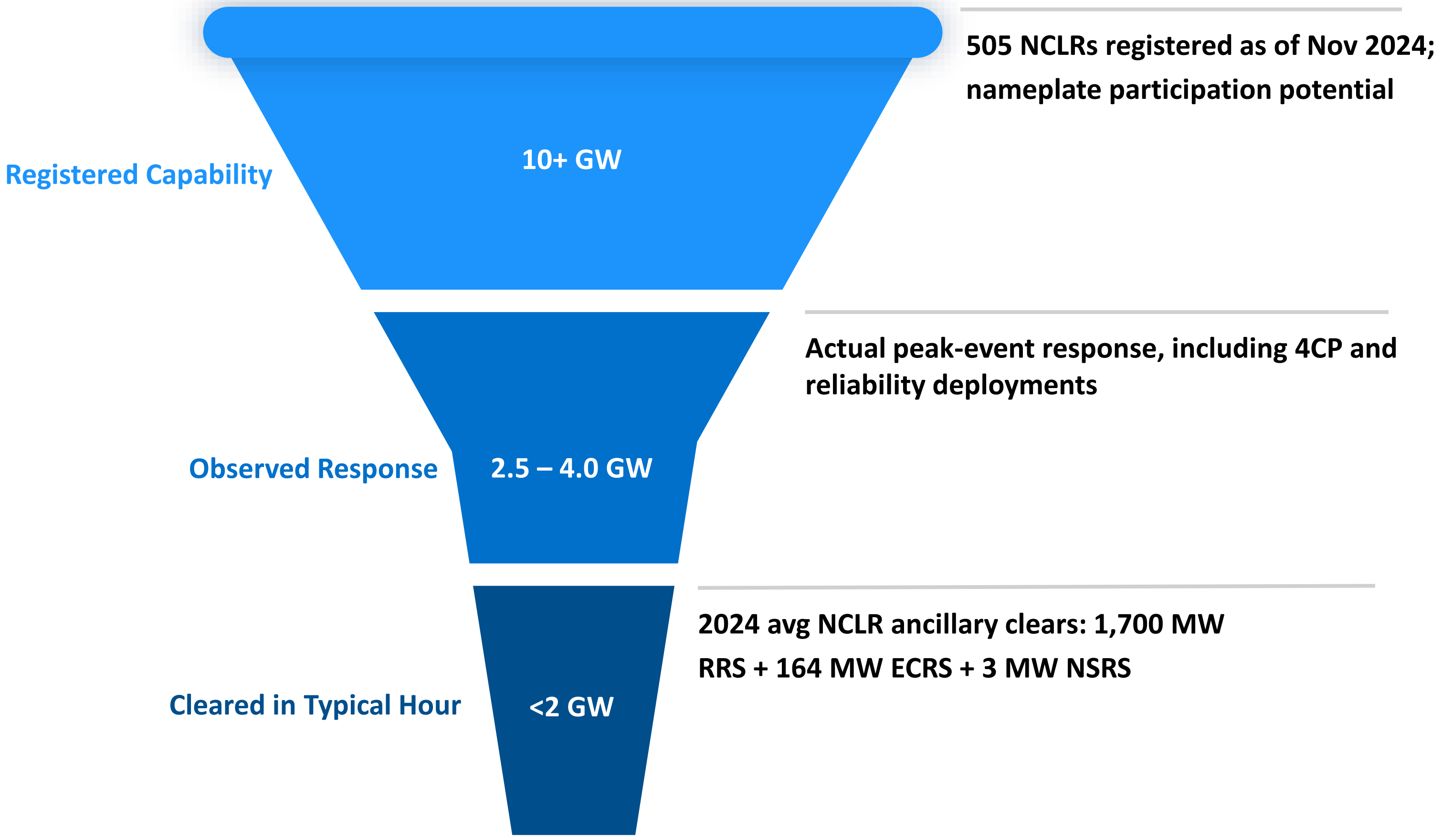
- EIA projects approved LFL capacity will reach ~9,500 MW by year-end 2025 — a 73% YoY jump. As more data centers and crypto facilities interconnect under the LFL program, the industrial DR pool is positioned to grow another 50%+ over the next 12 months.

Sources: Potomac Economics ERCOT SOM Reports (2018-2024); ERCOT NCLR data; EIA STEO (Sept 2024); ERCOT LFLTF updates. Pre-2024 NCLR figures estimated

FTI CONSULTING

Registered Flexibility Significantly Exceeds Dispatchable Load Capacity

The 10+ GW NCLR pool represents broad theoretical flexibility, but actual availability narrows sharply to ~2.5–4 GW during peak events and under 2 GW in typical hours, reflecting a structural gap between potential and dispatchable load flexibility.



Key Commentary

Registration is Optional

- NCLR registration creates the option to participate, not the requirement. Of 505 registered NCLRs, only ~25 actively clear in a typical hour.

The 80% Gap is Structural

- Resources deploy only when economics justify; ~80% of registered capacity sits idle on a typical day. The gap reflects rational economic choice, not market failure.

Registered Capacity Overstates Deployment

- In 2024, 4CP self-curtailment delivered 2,500 MW vs. ~1,867 MW cleared in ancillary markets. The largest contribution operates outside ERCOT's real-time dispatch.

Converting Passive to Dispatchable is Next

- SB 6 introduces new authority for ERCOT to direct large loads during emergencies, signaling a structural shift in how this capacity is integrated.

Dispatchable Flexibility Remains Limited

- Curtailable Load Resources (“CLRs”), which ERCOT can dispatch in real time, represented a relatively small share of total flexibility in 2024, averaging 118 MW of cleared capacity across RRS, ECRS, and NSRS. As a result, most load flexibility currently functions as market optionality rather than fully dispatchable grid capacity.

Sources: ERCOT NCLR registration data (November 2024); Potomac Economics, 2024 and 2023 State of the Market Reports for ERCOT

C. Interconnection Performance & Infrastructure Readiness

Executive Summary: Interconnection Performance & Infrastructure Readiness

ERCOT's Batch Zero framework converting queue activity into project advancement, along with Houston's diversified demand base and CenterPoint's execution role strengthen the region's position as a premier geography for large-load plant development.

Restudy loops define ERCOT timelines

- Only 1.3% of ERCOT's 410 GW queue has been energized. New large requests in the same zone can restart the clock.
- Energization timelines should be built from documented actuals, not published tariff targets.

MISO Transmission Timelines Exceed Loads

- New transmission in MISO Texas could take up to 7–10 years to build. Study reforms cannot close the gap that has been created.
- Transmission construction, not the interconnection study, sets the energization timeline in MISO Texas.

CIAC Is the Swing Cost Variable

- Transmission upgrade costs are the largest and least predictable exposure in both markets. MISO co-located cases have exceeded $200/kW.
- CIAC must be stress-tested as a hard capital line item in every project proforma.

ERCOT Leads on Batch Reservation

- ERCOT is the only U.S. market with a filed, board-governed batch capacity reservation process. No other ISO has reached this level of implementation.
- For 2027–2028 energization targets, ERCOT-served sites hold a structural advantage over PJM and MISO.

Houston Demand Sources Are Diversified

- Load growth is driven by data centers, industry, population, and electrification in parallel. No single sector dominates the forecast.
- Diversified demand reduces downside risk and supports more stable long-term revenue expectations.

ERCOT Queue Is Advancing, Not Accumulating

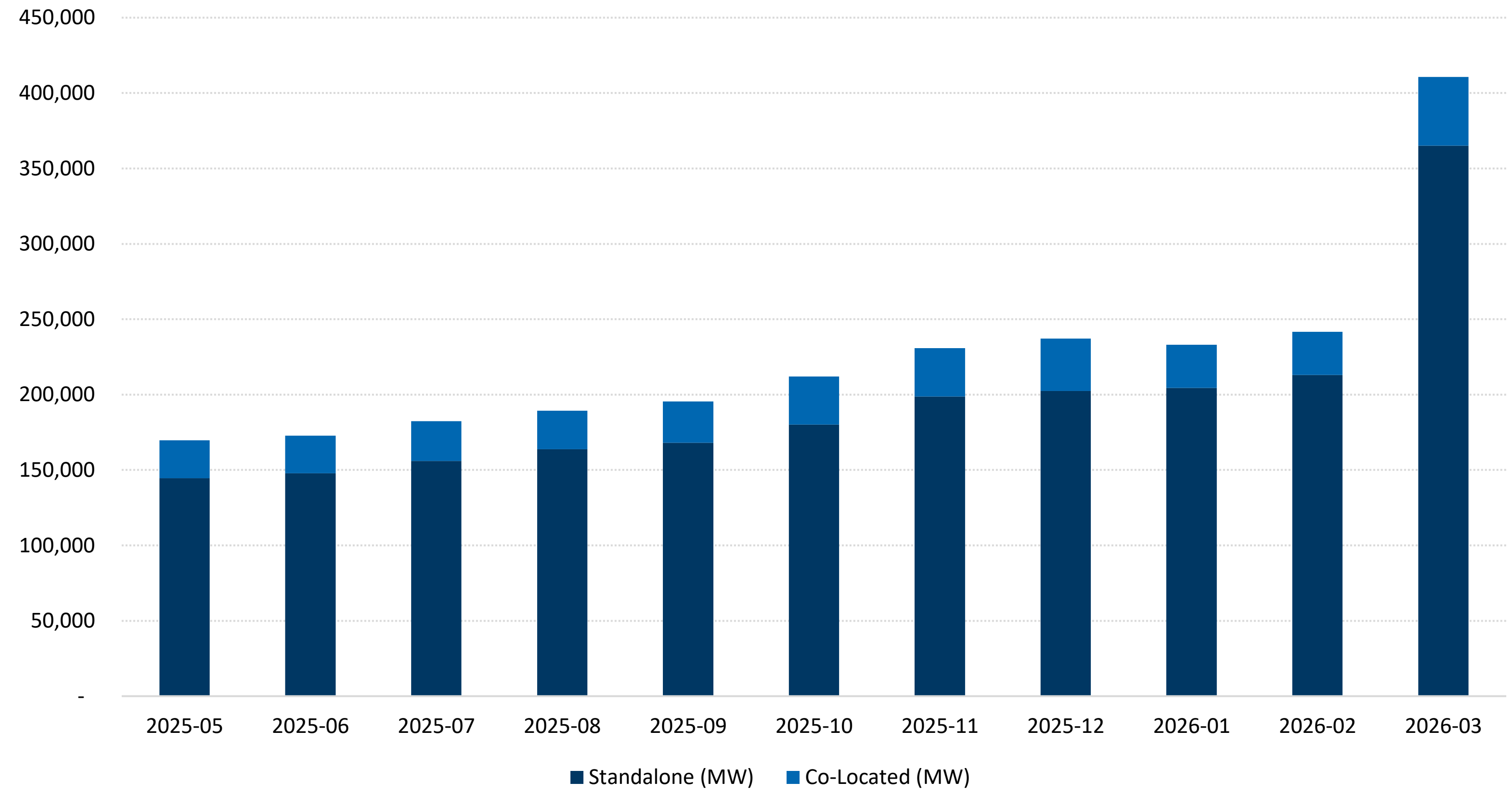
- Signed IAs grew from 491 to 583 projects while the Full Study backlog declined. The pipeline is graduating projects, not collecting them.
- Renewable supply and industrial gas capacity are both progressing through the same queue at the same time.

35

Driving a Shift Toward 765-kV Backbone Transmission

The scale and concentration of new load in ERCOT now exceed what the existing grid was built to handle. Sustained growth in large, power-intensive projects is driving the need for high-capacity, long-distance 765-kilovolt transmission to maintain reliability.

Large Load Queue Last 12 Months (MW)



Key Commentary

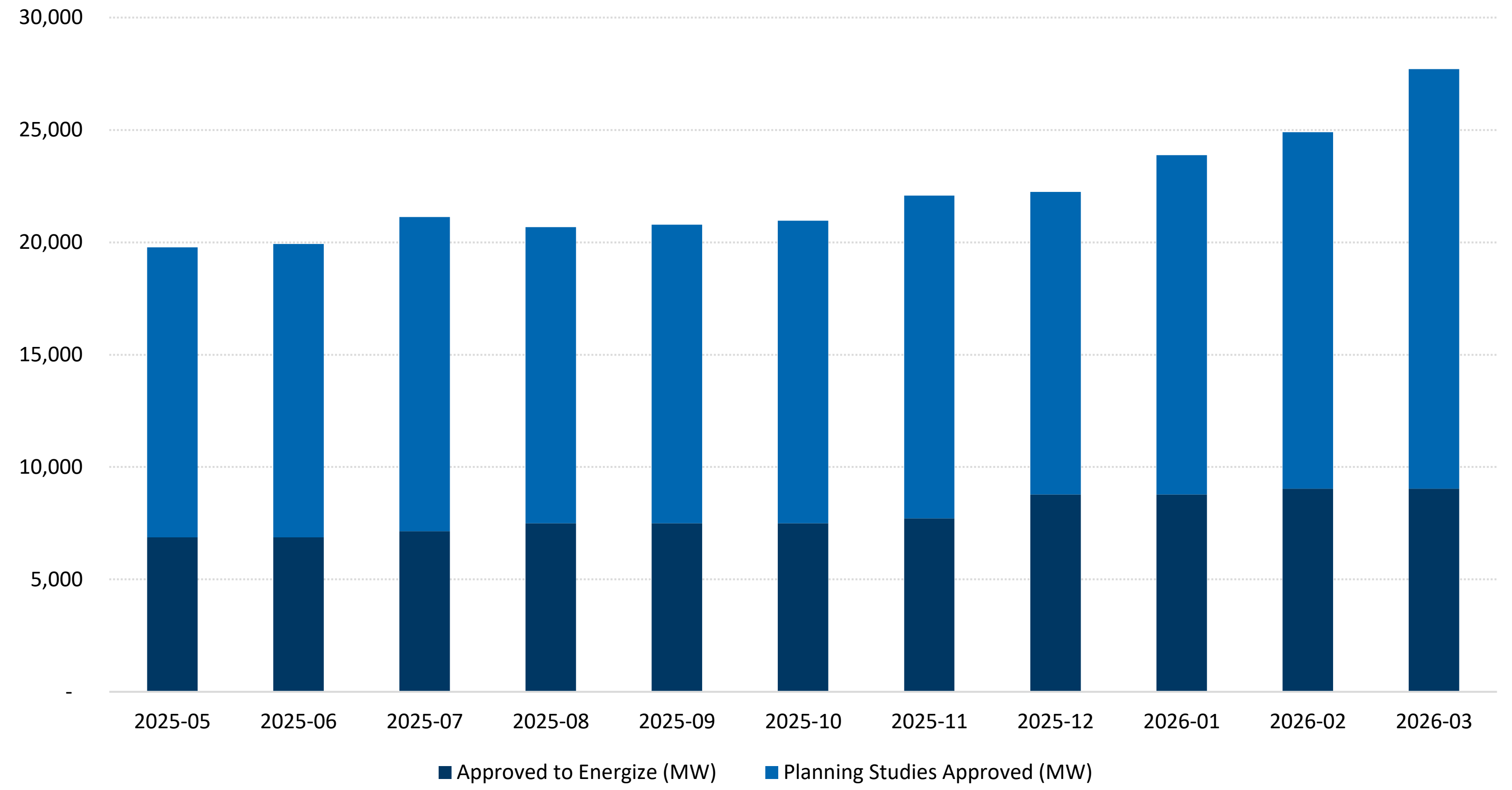
- Over the last twelve months, ERCOT's large load queue has expanded rapidly, reflecting a surge in interconnection requests from data centers, industrial electrification projects, LNG export facilities, and advanced manufacturing.
- ERCOT's first 765-kV transmission lines, three import paths into the Permian Basin, were approved by the PUCT on April 24, 2025, with a broader statewide Strategic Transmission Expansion Plan (TX 765-kV STEP) in active development. By 2032–2034, MISO's $21.8 billion Tranche 2.1 765-kV backbone is expected to enter service, placing it roughly one full construction cycle behind Texas.
- ERCOT has explicitly stated that 765-kilovolt transmission provides substantially higher transfer capability, reduces congestion costs, lowers electrical losses, and improves system coordination during outage conditions.
- Higher-voltage infrastructure can deliver significantly more power with fewer losses than lower-voltage alternatives, which becomes increasingly important as large loads move from the queue into operation.
- From a system economics perspective, reduced congestion and lower losses improve overall grid efficiency and help moderate wholesale electricity price volatility over time.

Sources: ERCOT, March 3, 2026 Greater Houston Partnership Energy Initiative presentation; ERCOT, Long-Term Load Forecast Update (2025–2031) and Methodology Changes

ERCOT Approval and Planning Process

ERCOT is redesigning its planning and approval framework to proactively plan for demand growth. Forward-looking transmission planning and earlier capacity reservation are reducing delays and creating a more investable environment.

ERCOT Approval Process Last 12 Months (MW)



Key Commentary

- In response to the rapid expansion of the large load queue, ERCOT has updated its transmission planning and load approval framework over the last twelve months. Planning decisions are increasingly anchored to expected future load growth rather than relying solely on existing system demand.
- By planning infrastructure around forecasted load, ERCOT can advance construction of substations and backbone transmission facilities before constraints fully materialize. This approach improves the likelihood that new loads can be accommodated on schedule and reduces the risk that insufficient transmission capacity becomes a bottleneck for economic growth.
- ERCOT has also revised its interconnection approval process by reserving transmission capacity within batch transmission studies. This change materially reduces the risk that later interconnection requests will force previously approved infrastructure back into restudy. Historically, restudies have been a major source of delay and uncertainty in the ERCOT market, often invalidating existing plans and resetting project timelines.
- From a financial perspective, these process changes directly protect returns. Proactive planning shortens the lag between capital deployment and asset utilization, improving capital efficiency.

Sources: ERCOT, March 3, 2026 Greater Houston Partnership Energy Initiative presentation; ERCOT, Long-Term Load Forecast Update (2025–2031) and Methodology Changes

Houston Readiness and Advantage

The Houston Area's alignment between committed load, ERCOT planning, and utility execution reduces demand and regulatory uncertainty, supporting underwriting confidence, lowers execution risk, and improves long-term investment outcomes.

1

ERCOT's future long-term load forecasting approach will incorporate identifiable, site-specific demand, including transmission service provider submissions, contract-backed loads, officer-letter commitments, and approximately 55 GW of expected data center demand by 2030. This approach will prioritize loads that have advanced beyond speculative interest and are sufficiently developed to inform future engineering and planning decisions.

- For investors, this materially reduces demand uncertainty. When a grid operator plans around named and committed loads, future capacity additions are far more likely to be utilized and earn an economic return.
- As a result, one can justify lower risk premiums, tighter credit assumptions, and more confident valuation frameworks than in markets where growth forecasts are still largely conceptual.

2

Houston-area grid growth is being driven simultaneously by data centers, industrial expansion, population growth, residential electrification, and transportation infrastructure. ERCOT and regional planning materials show these demand sources scaling in parallel rather than relying on a single dominant sector.

- This diversification meaningfully reduces exposure to sector-specific downturns. Even if one demand category slows, other sources of load growth continue to support overall system utilization.
- This improves downside-case modeling outcomes and stabilizes long-term revenue expectations. Assets backed by diversified demand are better suited for longer-duration capital, higher leverage, and longer-tenor debt.

3

CenterPoint Energy's active role in ERCOT rulemaking, including participation in large-load and batch-study reforms, places Houston's primary utility ahead of the regulatory learning curve. Rather than reacting to finalized rules, the utility is already aligned with ERCOT's evolving planning framework.

- Projects that experience delays often suffer IRR erosion through higher carry costs, delayed revenue generation, and extended capital deployment periods.
- CenterPoint's alignment with ERCOT's process increases the probability that projects in the Houston region move through interconnection and planning stages on more predictable timelines.

4

The combination of ERCOT's detailed demand forecast and CenterPoint's institutional alignment transforms Houston's grid advantage from a qualitative narrative into a measurable planning reality. Investors can see how much demand is being planned for, where it is expected to materialize, and how the utility and grid operator are preparing for it.

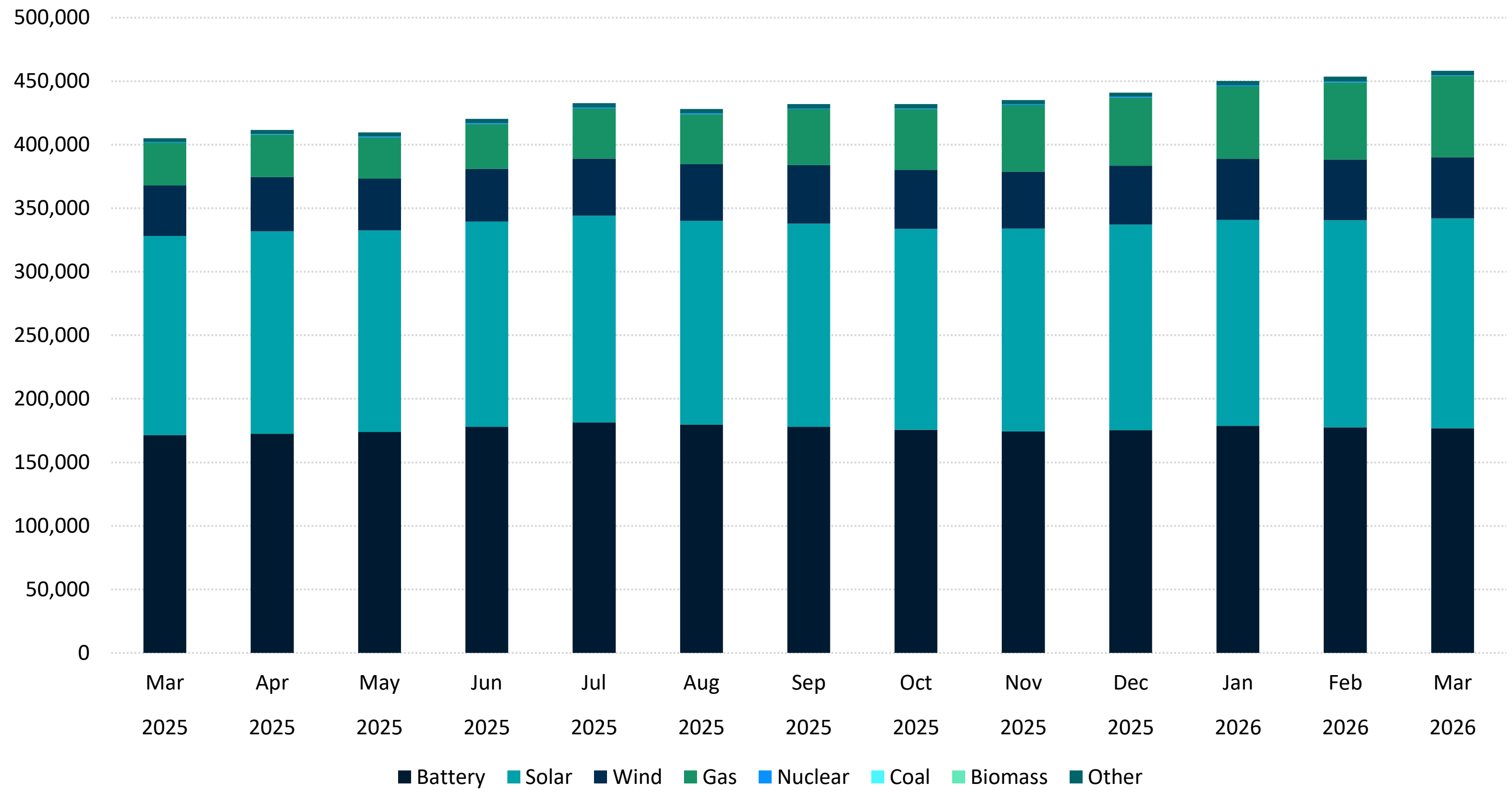
- This allows grid readiness to be modeled as a concrete underwriting variable rather than a subjective assumption.
- In capital allocation decisions, this type of clarity improves conviction, strengthens investment committee discussions, and reduces reliance on optimistic assumptions. Ultimately, it supports better risk-adjusted returns, even if headline returns are similar to those in more constrained markets.

Sources: ERCOT, March 3, 2026 Greater Houston Partnership Energy Initiative presentation; ERCOT, Long-Term Load Forecast Update (2025–2031) and Methodology Changes

Resource Adequacy & Load Growth

The composition of ERCOT's queue growth tells the real story: solar and batteries dominate, while gas capacity nearly doubled in response to industrial load demand. Together, they reflect a system expanding energy, flexibility, and firm supply at the same time.

Monthly Capacity by Fuel Type (MW)



Key Commentary

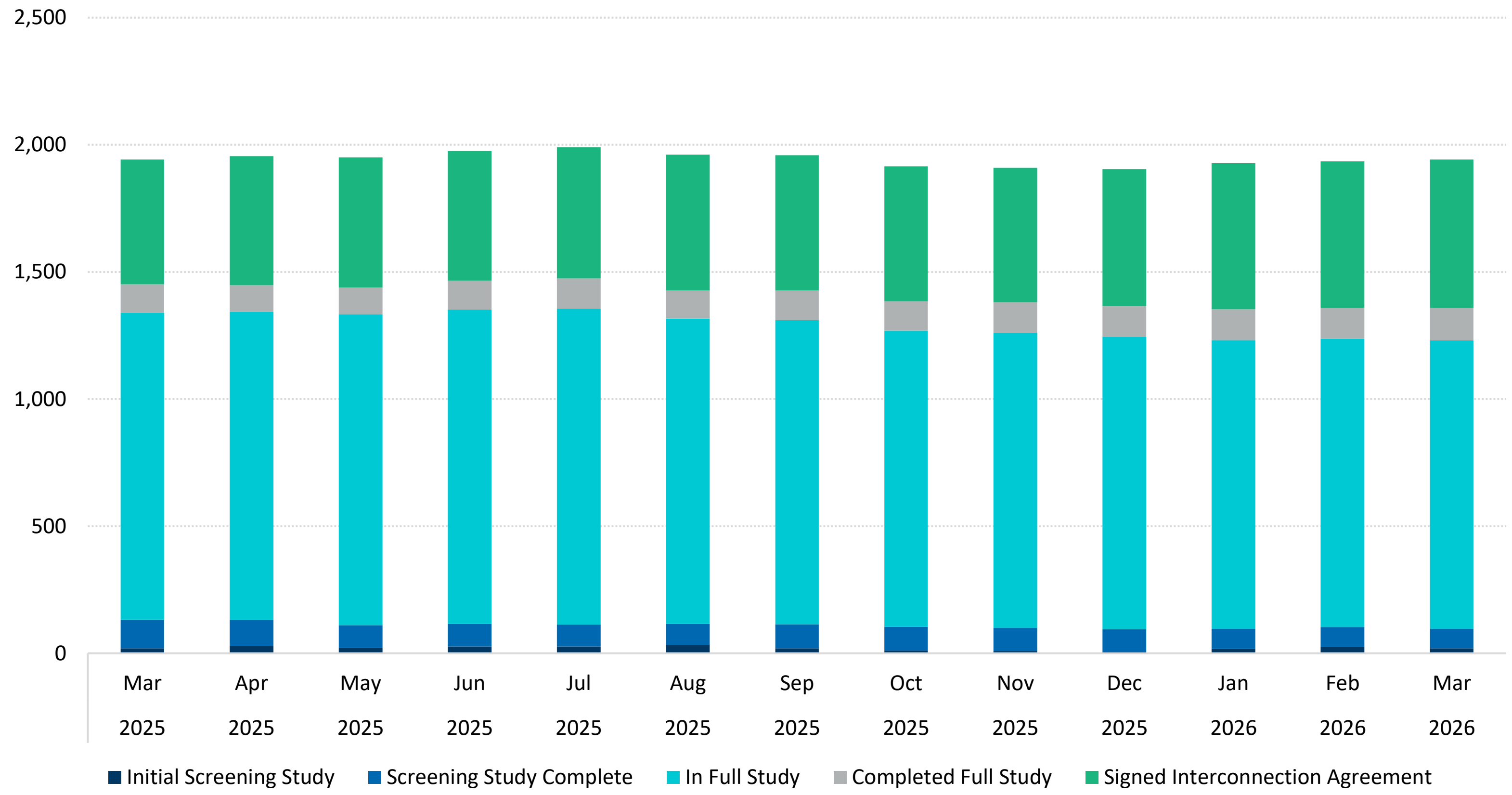
- ERCOT's interconnection queue grew from roughly 400 GW to 457 GW from March 2025 to 2026. Solar and gas growth increased higher than battery in the queue, as gas grew from ~34 GW to ~64 GW and solar rose from ~157 GW to ~165 GW. Batteries capacity, however, held steady around ~170–177 GW. This balance reflects an already-priced market reality: solar and storage are often deployed as complementary resources, with batteries shifting surplus midday solar into evening hours.
- The rapid growth in gas capacity likely reflects growing industrial load demand versus return to merchant gas economics. In an energy-only market, gas capacity typically grows this quickly when tied to a catalyst, and here that catalyst is large industrial load using BYOG structures to secure firm, on-demand power.
- Wind grew modestly, not from lack of interest but from transmission constraints in West Texas and the Panhandle, making infrastructure the limiting factor.
- Taken together, the queue shows ERCOT absorbing both sides of the system with renewable and storage capacity providing the energy and flexibility the grid needs to integrate variable generation cleanly. Conversely, the gas growth provides the dispatchable backup that large industrial loads require.

Source: ERCOT

Milestones Turn Queue Into Capacity

ERCOT's renewable and storage pipeline supports reliability only if projects advance through key milestones. The streamlined study process delivers interconnection agreements in a fraction of the time required in PJM or MISO energy markets.

Major Generator Interconnection or Modification ("GIM") Milestone Status LTM



Note: Chart does not include Small Generator

Key Commentary

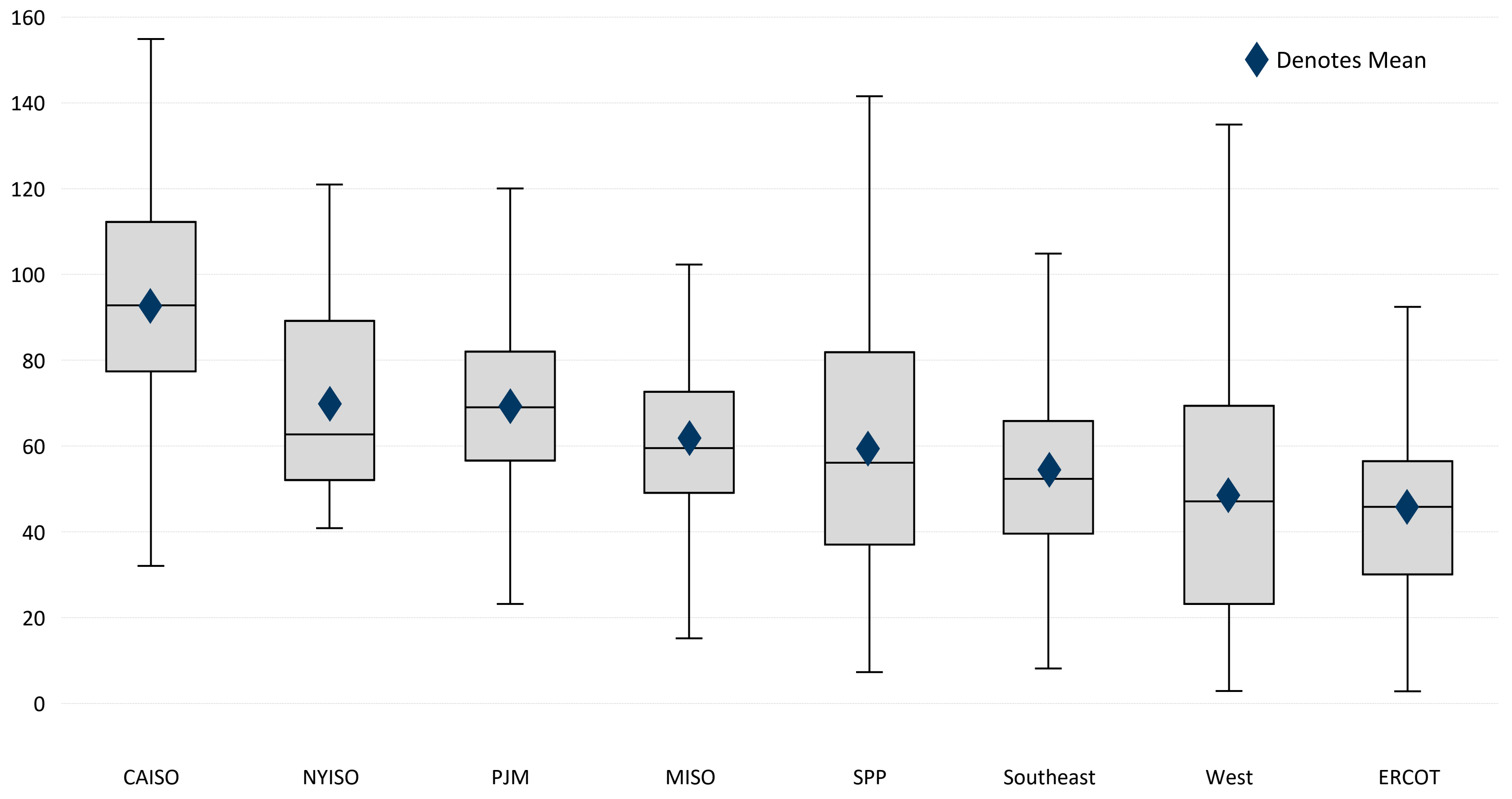
- The 12-month GIM milestone trend from the March 2026 GIS report tracks 2,013 active projects across the pipeline, showing how milestone distribution has shifted over the past year.
- The most important number is Signed Interconnection Agreements, which grew from 491 to 583 projects (March 2025–March 2026), a net addition of 92 projects that have cleared the full study process and hold a committed transmission path.
- "In Full Study" declined from 1,207 to 1,135 over the same period, confirming the queue is advancing, not just accumulating. Overall pipeline capacity grew from ~405 GW to ~458 GW in parallel, demonstrating real throughput.
- ERCOT's interconnection timeline is materially shorter than peer markets. While PJM and MISO study-to-IA timelines have stretched to 3–4+ years under cluster study reform backlogs, ERCOT's connect-and-manage approach compresses median processing times to under two years for projects advancing through GIM milestones. That speed advantage means signed IAs in ERCOT translate to near-term deliverable capacity rather than multi-year backlog, creating a more investor-favorable environment while directly supporting the reliability of the renewable and storage pipeline.

Sources: ERCOT, Carbon-Direct, Modo Energy

ERCOT's Speed-to-Power Advantage

Houston stands to be one of the largest beneficiaries of ERCOT's speed advantage, as faster infrastructure deployment, growing dispatchable capacity, and expanding grid investments create an increasingly attractive market for large-load development.

Time from IR to COD by Region (Months) 2021 - 2025[1]



Key Commentary

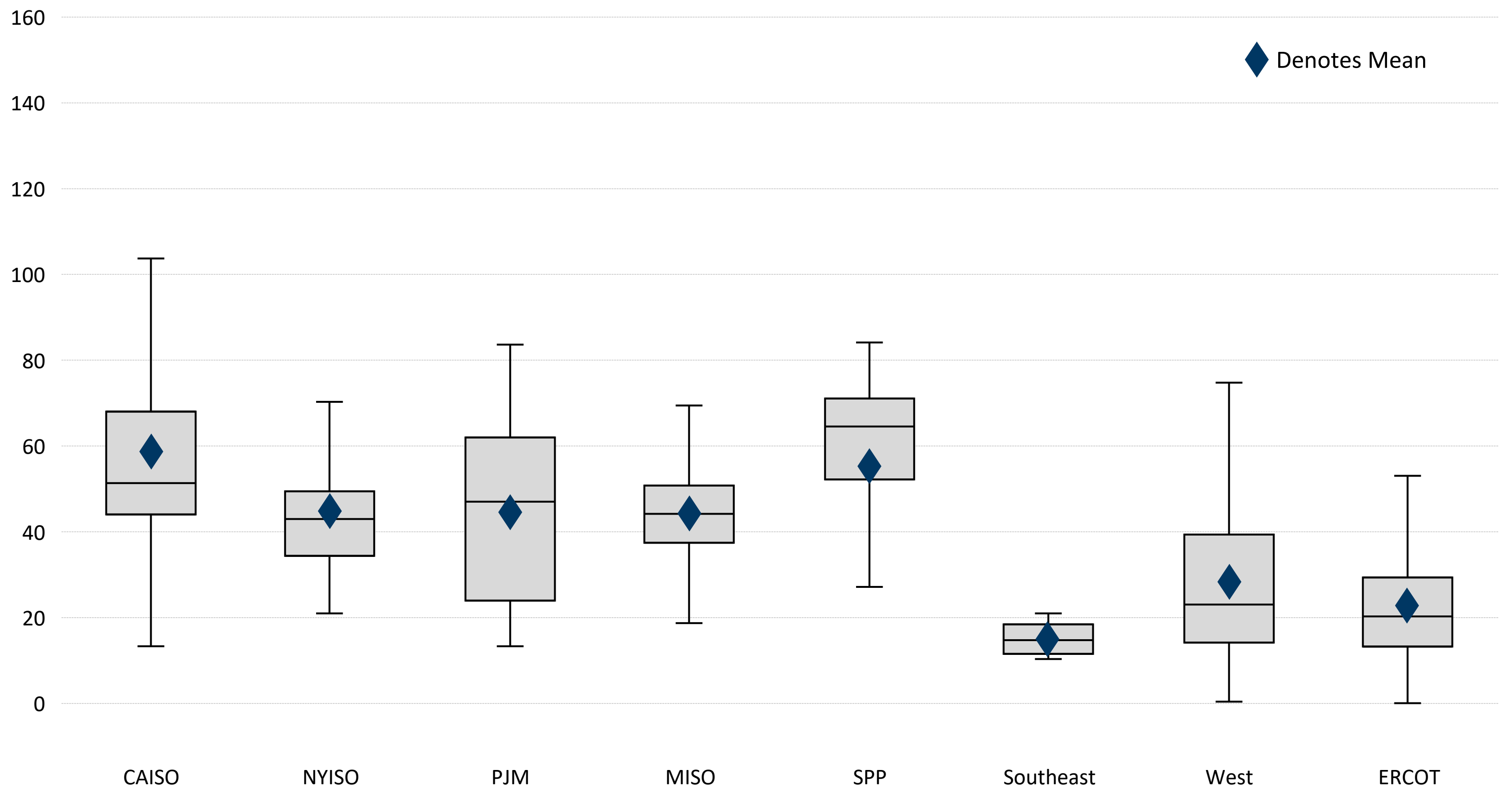
- ERCOT provides the shortest end-to-end development timeline among major organized power markets, averaging ~46 months from IR to COD more than 20 months faster than PJM and NYISO and nearly four years faster than CAISO.
- The compressed timeline reflects efficiency across the entire project lifecycle, including interconnection studies, transmission planning, permitting, construction, and commissioning, rather than a single process improvement. The smooth timeline helps to align project expectations with the realistic completion dates
- For hyperscale data centers, advanced manufacturing facilities, and other power-intensive customers, ERCOT's accelerated development timelines reduce schedule risk, improve investment certainty, and increase confidence that required generation and grid infrastructure will be available in parallel with facility construction and commissioning schedules.
- Combined with Houston's concentration of new generation development and transmission investment, ERCOT's expedited project delivery framework creates one of the most attractive environments in North America for large-scale load expansion.

(1) Based on In-Service Year
Source: Berkeley Lab

ERCOT Accelerates Interconnection Agreement Certainty

By compressing interconnection study timelines to less than half the duration of many peer ISOs, ERCOT enables faster and more predictable load-serving solutions for industrial and data center development.

Time from IR to IA by Region (Months) 2021 - 2025[1]



Key Commentary

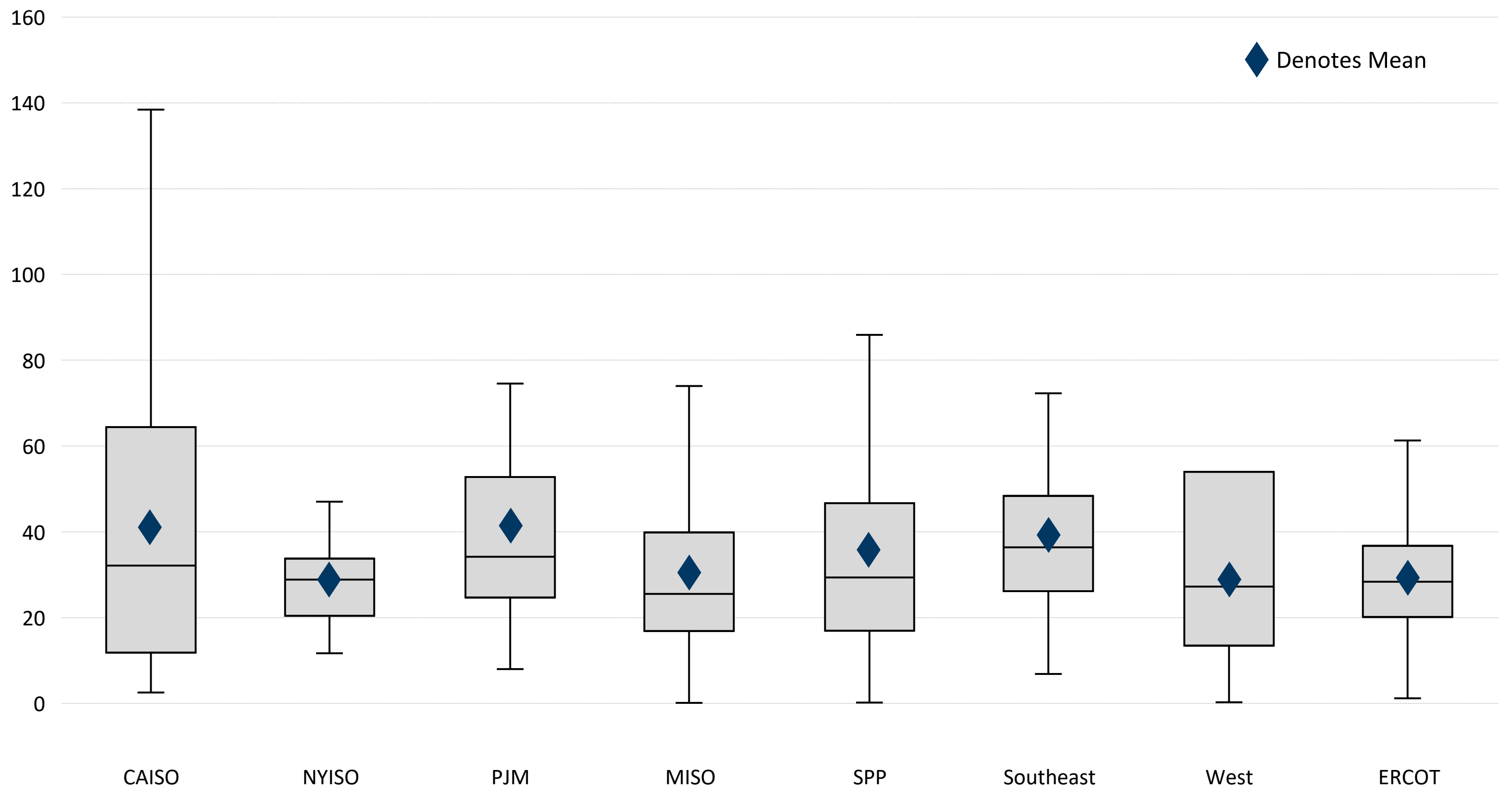
- ERCOT's average timeline from IR to IA is only ~23 months, roughly half the duration observed in PJM (~44 months), MISO (~44 months), NYISO (~45 months), ISO-NE (~47 months), SPP (~55 months), and CAISO (~58 months) only lagging behind Southeast(~16 months) due to the much smaller demand.
- The advantage extends beyond process efficiency; ERCOT's Batch Zero planning framework allows transmission upgrades, load growth, and generation additions to be evaluated in parallel, reducing uncertainty and accelerating the path from request to agreement.
- While many organized markets continue working through multi-year interconnection backlogs, ERCOT's streamlined study process has positioned Texas as one of the few regions capable of accommodating large-scale load growth on commercially relevant development timelines.
- The combination of faster interconnection processing, proactive transmission planning, and continued generation investment creates a structural advantage for ERCOT, enabling large-load customers to secure power infrastructure more quickly and with greater certainty than many peer regions.

(1) Based on Year of IA
Source: Berkeley Lab

ERCOT Converts IAs Into Capacity

While some markets face delays after interconnection approval, ERCOT continues to move projects through permitting and construction on timelines that support growing load demand.

Time from IA to COD by Region (Months) 2021-2025[1]



Key Commentary

- At ~29 months from IA to COD, ERCOT outperforms CAISO (~41 months), PJM (~41 months), Southeast (~40 months), and SPP (~36 months), highlighting a more efficient project delivery environment.
- The relatively compressed IA-to-COD timeline suggests that permitting, transmission development, and project execution activities are generally progressing without the bottlenecks that are increasingly common in other regions.
- For large-load customers, faster project delivery translates to greater confidence that planned generation and network upgrades will materialize on commercially relevant timelines.
- Unlike markets where interconnection approvals are only the beginning of a lengthy development cycle, ERCOT demonstrates an ability to efficiently translate signed agreements into operational assets allowing large load off takers a true speed to power advantage.
- ERCOT's speed advantage does not end at interconnection approval, projects reach commercial operation in ~29 months after signing an IA, indicating that permitting, construction, and infrastructure development are progressing efficiently enough to keep pace with the state's rapidly growing load base.

(1) Based on In-Service Year
Source: Berkeley Lab

Queue Composition Reflects Simultaneous Growth

The queue is processing projects rather than just accumulating them, with Signed Interconnection Agreements rising and Full Study backlogs decreasing. Batch Study and Batch Zero accelerate that progress further by eliminating the structural flaw that historically stalled approvals, giving Houston and Gulf Coast operators the predictable energization timelines that capital decisions require.

- Battery and solar together hold over 75% of all queued capacity, growing from roughly 400 GW to 457 GW between March 2025 and March 2026. Their co-dominance reflects a market that has already priced in the operational pairing renewables require, which is that solar delivers during daylight and battery shifts that energy into the evening peak.
- At the same time, gas capacity nearly doubled from 34 GW to 64 GW, suggesting a strong link to large-load development and firm supply requirements. It is indicative of large industrial loads entering the queue through BYOG, bringing their own dispatchable generation to secure early energization. Both growth stories are running through the same queue, at the same time.

- Signed Interconnection Agreements grew from 491 to 583 projects in just over 13 months while the Full Study cohort decreased from 1,207 to 1,135, confirming the funnel is graduating projects rather than accumulating them. The same milestone process is advancing both renewable supply and BYOG-linked industrial gas projects toward committed transmission paths simultaneously.
- The old single-study process threatened this by allowing any new queue entry to invalidate studies already underway. Batch Study and Batch Zero fix that structural flaw by compiling applications together and reserving capacity upfront, giving Houston and Gulf Coast industrial operators a predictable energization timeline they can make capital decisions against.

- The old single-study process created restudy loops that delayed approvals by years. Batch Study fixes this by compiling applications together and reserving capacity upfront, while Batch Zero distinguishes firm projects from those needing reallocation. The reform addresses the right problem: the inability of the old process to preserve capacity assignments as the queue changed.
- Operationally, DRRS pays fast-starting gas to cover the hours solar cannot deliver, RTC+B co-optimizes the battery fleet to smooth the solar-to-evening handoff, and CLR grants industrial customers early energization in exchange for curtailability. Together these tools ensure the queue advances into a grid built to serve renewable integration and industrial load growth at the same time.

Source: ERCOT

Costs and Cost Allocation

ERCOT now forces large loads to lock in transmission risk up front, while MISO Texas defers it, which creates cheaper entry but far greater late-stage cost volatility. In both markets, CIAC is the swing variable that can make or break Gulf Coast project economics.

Cost Item	ERCOT	MISO Texas
Application / Study Fee	\$100K minimum (SB 6) + separate TSP fee	\$7,000 flat non-refundable D1 + D2 deposit at application deadline
Financial Security / Deposit	\$50,000/MW at Intermediate Agreement (20% refundable)	\$8,000/MW M2 deposit (doubled Jan. 2024); \$8,000/MW additional for Provisional Study
Non-Refundable Conversion	Full \$50,000/MW converts non-refundable at IA execution	Up to \$1.6M forfeited for a 200 MW project at GIA stage; tariff-mandated, no discretion
Transmission Upgrade / CIAC	Customer pays all costs above capped TSP allowance; prior TSP backstop eliminated post-Dec. 31, 2025	Customer pays all network upgrade costs; co-located cases documented exceeding \$200/kW
Re-study Cost Risk	High — 1 GW+ loads in same zone invalidate prior studies with no refund of fees paid	High — late-stage upgrade cost escalation documented across DPP cycles from study errors and scope changes
Curtailment Obligation	Mandatory for loads ≥75 MW interconnecting after Dec. 31, 2025	Non-firm step-up only; firm service step-up proposed Q2 2026

Key Commentary

- ERCOT's cost structure has permanently shifted to the customer, with the largest single exposure being the CIAC obligation at IA execution. The prior framework no longer applies to agreements executed after December 31, 2025.
- MISO Texas carries lower upfront costs but concentrates financial risk in the back half of the process, where upgrade cost unpredictability is a documented and persistent problem. Where ERCOT requires the full financial commitment at IA execution, MISO's DPP structure escalates penalties the deeper a project advances without completing
- MISO members are experiencing an unprecedented surge in large-load interconnection requests, and MISO acknowledges that the rapid increase of large loads is adding directly to cost pressures on the system.
- Across both markets, CIAC exposure is the single most important underwriting variable for Gulf Coast energy-intensive development. After 2026, only large loads that have executed an interconnection agreement satisfying PUCT Project 58481 requirements will be included in ERCOT's Large Load Forecast.
- Investors must treat transmission upgrade costs as a defined, stress-tested capital line item in project proformas and model scenarios where re-study events reset cost exposure with no refund of prior study fees already paid.

Sources: ERCOT, MISO

FTI CONSULTING

Large Industrial Customer Interconnection in ERCOT vs. MISO Texas

ERCOT's delays are structural, with the Batch Study intended to reserve capacity and fix the project timeline for early entrants. MISO's constraint is different, as transmission construction timelines of 7-10 years largely determine when large loads can be energized.

Milestone	ERCOT	MISO Texas
Applicability Threshold	≥75 MW at single site; two-year exemption eliminated under PGRR115 (Dec. 15, 2025)	No formal MW threshold; large loads routed through GI DPP process; NERC draft guidelines suggest 50–75 MW
Application Window	Rolling — submit to TSP any time; ERCOT assigns LLI-# and schedules kickoff	Annual DPP deadline (Oct. each year); no mid-cycle rolling entry for standard process
Required Studies	LLIS: steady-state, dynamic/transient stability, short-circuit, SSO if applicable; QSA required before energization eligibility	DPP Phase 1 (Preliminary SIS) → Phase 2 (80-day target) → Phase 3 (135-day target) → GIA execution (150-day target)
Published Review Clock	10 BD preliminary; 10 BD final (extendable +20 BD)	373 days tariff target across all phases to GIA
Actual Observed Timeline	Restudy loop = years without reservation; 9,042 MW energized out of 410 GW tracked (~1.3%) as of April 2026	676–1,511 days actual vs. 373-day target; Phase 1 alone reached 793 days in 2021 cycle
Infrastructure Build Times	Large load: 1.5–3 years to build	New generation: 4 years; new transmission: 7–10 years
Expedited Path	Batch Zero: target protocol effective Aug. 1, 2026; energization 2027–2028; cycles run every ~6 months	ERAS: ~3 months to GIA (rolling through May 2027, 68-project cap); Firm Service Step-Up proposed Q2 2026

Key Commentary

- ERCOT's documented timeline problem is structural, and the Batch Study is the designed solution with a board-approved governance clock. The core failure of the serial single-study model is the absence of capacity reservation: large new requests (often 1 GW+) in the same transmission zone can invalidate prior study results and restart the clock, with no limit on how many times this can occur. The Batch Study resolves this by clustering all submitted requests every approximately six months, studying them together, and reserving allocated capacity to prevent future restudies.
- MISO Texas faces a documented structural mismatch between how fast large loads can be built and how long transmission infrastructure takes. Even if MISO achieves its 373-day tariff target, the transmission infrastructure required to serve full firm load cannot be completed on the same timeline as the load itself.
- Both markets document a severe and widening gap between queue entry and confirmed energization that directly affects how Gulf Coast project finance timelines should be modeled.
- For Gulf Coast investors, interconnection approval, CIAC certainty, and confirmed energization must each be treated as distinct, sequential milestones with timelines built from documented actuals, not published tariff targets that neither market has consistently achieved.

Sources: ERCOT, MISO

FTI CONSULTING

Benchmark against other major U.S. markets

Across U.S. power markets, large-load interconnection is consistently slow and customer-funded, but structural reform varies widely. At ~24 months median study-to-IA, ERCOT is nearly half PJM's ~40-month average and well below MISO's 3–4-year range.

ercot

- Batch Zero is the first U.S. load interconnection protocol governed by a Board-sanctioned process with defined voting milestones, a target effective date of August 1, 2026.
- Batch Zero establishes discrete study windows with predetermined intake and output dates, giving large load customers clear visibility into queue timing that open-queue ISOs like MISO, PJM, and SPP cannot match.
- Batch Zero locks capacity at the time of study intake, securing a queue position that cannot be displaced by later applicants within the same window.

MISO

- MISO applies its generation-focused Definitive Planning Phase (“DPP”) framework to large loads and remains in stakeholder development for a load-specific interconnection process.
- MISO has articulated desired outcomes (speed to reliable power, interconnection reliability requirements, and reliable operations) but has not filed a load-specific batch framework with FERC.
- The proposed Firm Service Step-Up (pending Q2 2026) is intended to mitigate timeline mismatch risk but does not provide capacity reservation equivalent to ERCOT’s Batch Study.

pjm

- PJM faces the most acute capacity pressure from data center demand and operates the largest geographic footprint of any U.S. ISO.
- Its April 2026 interconnection cycle applies to generation only, with no load-specific study framework in place.
- PJM’s historical average timeline to commercial operation exceeds eight years, reflecting serial backlog, multi-state permitting complexity, and unresolved large-load curtailment and service rules.

SPP

- SPP is the most advanced FERC-jurisdictional market on load-specific process design, with its HILL and CHILL tracks providing expedited paths for qualifying large loads.
- MISO explicitly cites SPP’s HILL process as an industry reference point for load-specific interconnection design.
- Despite this leadership, SPP’s smaller footprint limits its relevance as a primary benchmark for Gulf Coast industrial scale compared to ERCOT, MISO, or PJM.

Key Commentary

- For Gulf Coast industrial investors, the national comparison leads to a clear conclusion. ERCOT is currently the most structurally advanced and legible interconnection market for large industrial load, driven by SB 6, a filed Batch Zero protocol, and a board-approved governance timeline that enables near-term capacity reservation.
- This gives ERCOT-served Gulf Coast sites a meaningful locational advantage over PJM and MISO, especially for projects targeting 2027–2028 energization windows, where Batch Zero is the only framework explicitly designed to align capacity reservation with execution timelines.

Sources: ERCOT, MISO, PJM, SPP

D. Reliability Assessment

FTI CONSULTING

Executive Summary: Reliability Assessment

ERCOT's metrics have strengthened since Winter Storm Uri, but reliability risk remains elevated as load growth, peak-hour scarcity, and transmission constraints pressure ERCOT and MISO Texas, requiring deliverable capacity and proactive customer-side mitigation.

ERCOT Improved, but Risks Remains

- ERCOT reliability has improved post-Winter Storm Uri, but risk has shifted from reserve margin adequacy to hour-by-hour energy availability and deliverability.
- SB 3 weatherization, ECRS, and capacity additions reduce modeled scarcity risk, but ERCOT remains exposed in winter mornings, summer evenings, and extreme weather.

MISO Texas Faces Greater Reliability Pressure

- MISO Texas faces a more severe reliability outlook than ERCOT, with higher frequency, longer duration of reliability events, and unserved energy risk emerging by 2028–2029.
- Declining reserve margins, local MISO South constraints, and an aging thermal fleet increase the risk of reliability events.

Load Growth is Outpacing Firm Capacity

- Rapid load growth from data centers, industrial demand and electrification are outpacing firm, dispatchable capacity additions.
- Both ERCOT and MISO Texas face planning uncertainty as large load additions pressure reserve margins and increase the need for deliverable resources.

Peak Hour Risk is Increasing

- Reliability risk is increasingly concentrated during peak-risk hours when demand is high and renewable output is limited.
- Winter morning heating load, summer evening solar ramp-down, battery duration limits, and thermal outages create periods where reserves may tighten quickly.

Deliverability is the Key Bottleneck

- Transmission and deliverability constraints remain a critical reliability bottleneck, particularly for Houston, South Texas, and Southeast Texas load centers.
- Even where system-wide capacity exists, local constraints can limit the ability to move power to high-growth industrial areas during scarcity conditions.

Customer-Side Mitigation Is Critical

- Large industrial customers should proactively evaluate customer-side mitigation strategies as curtailment, price volatility, and planning risk increase.
- On-site generation, backup power, storage, demand response, interruptible service, and hedging will be increasingly important for reliability and cost management.

Comparative Analysis

Relative to other reliability-stressed regions such as PJM and parts of WECC, Houston benefits from a faster-moving legislative response and well-advanced resource studies, plus new generation, storage, and transmission investments.

NERC Long-Term Resource Assessment, 2025: Executive Summary

Assessment Area	2026	2027	2028	2029	2030	Risk Summary
MISO						Projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements. The recently approved Expedited Resource Addition Study (ERAS) process is expected to result in additional resources in the MISO system beginning in 2028 that are not included in the model for the 2025 LTRA. Timely implementation of ERAS resources will eliminate reserve margin shortfall and improve expected unserved energy metrics.
SPP						Demand forecasts outpace resource additions, leading to falling reserve margins. Scenarios with low wind and high generator forced outages identify energy shortfall risks. SPP’s Expedited Resource Adequacy Study is attracting additional resources.
ISO-NE						Strong demand growth and persistent winter natural gas infrastructure limitations pose energy shortfall risk in extreme winter conditions.
NYISO						Planned retirements of peaking generators create localized system adequacy needs as described in the NYISO 2025 Q3 Star Report.
PJM						Current projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements. The anticipated resource margin falls below the Reference Margin Level starting in 2029. Recently approved new generation projects for expedited interconnection under the PJM Reliability Resource Initiative were not far enough along to include in the LTRA risk analysis.
SERC-East						Current projections for resource additions do not keep pace with escalating demand forecasts and planned generator retirements. With projected resources, supply shortfalls would occur in below-normal winter temperatures, resulting in unserved energy.
ERCOT						Probabilistic unserved energy metrics for 2026–2027 have improved since 2024 but continued rapid load growth outpaces projected resource additions in later years. To mitigate increasing resource adequacy risks from load growth, Texas lawmakers have granted ERCOT operators additional authority to curtail new large loads if necessary to prevent grid emergencies. Texas lawmakers also established funding programs to expedite new resources that address reliability needs.
WECC- Basin						Demand forecasts outpace resource additions and expected retirements, leading to falling reserves. Resource additions nearing completion are predominantly solar, leading to a more variable resource mix. Unserved energy risk is in summer.
WECC- Northwest						Rapid forecasted demand growth is driving the need for more resources. Resource additions nearing completion are predominantly solar PV, battery, and wind, leading to a more variable resource mix. Periods of unserved energy are projected for both summer and winter.

Gray = Normal Risk
Yellow = Elevated Risk
Red = Highest Risk

Key Commentary

- While ERCOT and MISO face “High Risk” NERC classifications by 2028 and 2029, respectively, these pressures are increasingly broad-based across multiple major regions, including PJM, SPP, NYISO, ISO-NE, and parts of SERC and WECC.
- These are tied to common nationwide problems: load growth, generation retirements, interconnection delays, and transmission constraints outpacing the buildout of firm and flexible resources.
- ERCOT in particular has moved faster than many peer jurisdictions to add supply, storage, and transmission needed to support continued load growth.
- Texas lawmakers have assumed outsized roles to solve for reliability issues, including funding measures and authorizing curtailment ability to ERCOT operators.
- MISO and SPP have created Expedited Resource Addition / Adequacy Study processes to fast-track interconnection for capacity that addresses near-term resource adequacy needs, and FERC has approved both frameworks.
- PJM is developing an “Expedited Interconnection Track” proposal with a similar goal of accelerating critical capacity additions.
- MISO’s ERAS is farthest along of the 3 processes.

Source: NERC Long-Term Resource Assessment

Evaluation of **ERCOT** Reliability Metrics – Frequency and Duration

ERCOT's reliability risk is increasingly an energy availability and deliverability issue, not just a reserve margin issue, with the highest risk concentrated during winter mornings, summer evenings and extreme weather events.

Assessment Area	Evaluation
Reliability Risk Classification	ERCOT is classified as **Elevated Risk from 2026-2028**, meaning resources are adequate under normal conditions but vulnerable during extremes. By **2029–2030**, ERCOT moves to High Risk, indicating expected energy shortfalls exceed adequacy targets. This suggests reliability risk is expected to worsen as load growth, weather exposure and resource availability challenges compound.
Event Frequency	EEA probabilities remain below ERCOT's 10% threshold, suggesting near-term risk remains manageable under most conditions. However, winter months show higher risk than summer, with January 2025 reaching an **8.51% EEA probability during HE 0800**. This indicates reliability events are more likely during cold-weather periods when demand rises and generation availability may be stressed.
Event Duration	**LOLH increases from 0.95 hours/year in 2027 to 3.64 hours/year in 2029, nearly a 4x increase**. This suggests scarcity conditions may extend across more hours as load growth, renewable variability, battery duration limits and outage risks compound. Longer-duration events are especially concerning because they can strain emergency reserves, demand response and backup generation.
Severity of Energy Shortfalls	ERCOT's Normalized Expected Unserved Energy ("NEUE") (expected curtailment, MWh) rises from **5,865 MWh in 2027 to 17,053 MWh in 2029, a 191% increase**. This indicates that when scarcity occurs, the amount of unmet load could become materially larger. For Houston utilities and large-demand customers, this points to greater potential operational disruption during high-stress periods.
Reserve Margin vs. Energy Adequacy	ERCOT's anticipated reserve margin remains strong at **28.2% - 31.8%, well above the 13.75% Reference Margin Level**. However, reserve margins can mask energy adequacy risk because installed capacity may not be available during the specific hours when demand, outages and renewable underperformance overlap. This makes probabilistic, hour-by-hour reliability analysis more important than reserve margin analysis alone.
Peak-Risk Hour Concentration	Highest risk is concentrated in **winter mornings and summer evenings**. Winter risk peaks around **hour ending ("HE") 0700–0900**, when heating demand is high and solar output is minimal; summer risk peaks around **HE 2100**, when solar declines while A/C, data center and industrial loads remain elevated. These windows are important because they reflect the hours when demand is high but flexible, dispatchable resources are most needed.
Mitigation and Deliverability Factors	Texas' SB 6 expands ERCOT's ability to curtail large loads, making demand response a key reliability tool, with expected growth to **53.1 GW by 2030**. The TX 765-kV STEP program could improve transfer capability by **600 - 3,000 MW per path**, supporting delivery of West Texas generation to Houston and other load centers. Demand response and transmission expansion may reduce reliability risk, but large-load customers should still expect greater curtailability and planning requirements.

Sources: NERC Long-Term Resource Assessment, MISO Summary, Tables 1-2 (January 2026); MISO Annual LOLE Study (2024-2026), MISO Regional Resource Assessment (RRA) (2024), MISO Planning Resource Auction (2024-2026)

Evaluation of **MISO Texas** Reliability Metrics – Frequency and Duration

MISO reliability risk is expected to become more frequent and longer in duration than ERCOT, with the most acute concern beginning in 2028–2029 as reserve margins decline, winter risk intensifies and MISO South's local reliability constraints limit system flexibility.

Assessment Area	Evaluation
Frequency of Reliability Events	MISO reaches **High Risk by 2028**, one year earlier than ERCOT, signaling that reliability events could become more frequent sooner. The reserve margin falls from **11.0% in 2026 to 8.6% in 2029**, leaving less cushion to absorb demand spikes, forced outages or renewable underperformance. As the margin tightens, smaller disruptions that may have been manageable in prior years could increasingly trigger scarcity conditions.
Duration of Reliability Events	MISO's **Loss of Load Hours ("LOLH") of 6.61 hours/year in 2029** is meaningfully higher than ERCOT's **3.64 hours/year**, suggesting reliability events may last longer when they occur. This implies MISO Texas could face more extended periods of system stress, rather than only short-duration scarcity intervals. Longer-duration events are especially concerning because they can strain emergency resources, demand response and fuel availability over multiple hours.
Severity of Unserved Energy	MISO's **Normalized Expected Unserved Energy ("NEUE") of 42.39 ppm (expected curtailment in MWh per TWh) in 2029** is approximately **2.3x worse than ERCOT's 18.84 ppm**, indicating a deeper potential energy shortfall. This means reliability events may not only occur more often but could also result in a larger amount of unmet load. For large industrial customers, this raises the risk of more material operational disruption if load shed or emergency curtailment is required.
Reserve Margin Deterioration	Reserve margins are projected to fall below **the 8.5% Reference Margin Level by 2029** and decline to a **critically low 4.3% by 2030**. This trajectory materially reduces the system's ability to manage forced outages, high load, transmission constraints or fuel supply disruptions. By 2030, the margin may leave limited flexibility for contingency events, making reliability increasingly dependent on timely new generation, demand response and transmission support.
Localized MISO South Risk	MISO South faces different operational challenges than MISO North, including **voltage and local reliability issues in load pockets.** These constraints can create localized reliability stress even when broader MISO system conditions appear manageable. For Southeast Texas, this means reliability risk depends not only on total regional capacity, but also on whether power can be delivered to specific load centers during peak conditions.
Winter Risk Intensification	Reliability risk is shifting from summer-only concerns toward **greater winter exposure**, driven by growing solar penetration and cold-weather stress. Winter Storm Elliott and Winter Storm Heather demonstrated that extreme cold can simultaneously increase demand and reduce generator availability. This is particularly important as winter morning risk rises, when heating load is elevated, solar output is limited and thermal fleet performance becomes critical.

Sources: NERC Long-Term Resource Assessment, MISO Summary, Tables 1-2 (January 2026); MISO Annual LOLE Study (2024-2026), MISO Regional Resource Assessment (RRA) (2024), MISO Planning Resource Auction (2024-2026)

Evaluation of **ERCOT** Reliability Metrics – Causes

ERCOT remains vulnerable to reliability events during periods when demand growth, extreme weather, thermal outages, transmission constraints, and low renewable output overlap, particularly when heating demand peaks and solar output is limited in the winter.

Cause	Reliability Implications
Unprecedented Demand Growth	ERCOT peak demand is projected to grow from **94.7 GW in 2026 to 154.1 GW by 2035**, driven by large load additions from data centers, crypto mining and industrial manufacturing. Houston / Gulf Coast load growth is expected to be a key pressure point. Load composition by 2035: Data centers (50%), Cryptocurrency mining (17%), Industrial manufacturing (15%)
Resource Mix Transformation	ERCOT's near-term additions are weighted toward **solar and battery storage**, while coal retirements reduce dispatchable, fuel-on-site capacity. While these resources provide meaningful support, they are more exposed to weather, time-of-day availability and duration limits. This increases risk when demand is high, solar declines, batteries are depleted, or wind underperforms.
Unplanned Thermal Outages	Thermal outages remain the largest outage driver, representing **approximately 85% of total outages**, with observed unavailable capacity ranging from **7.0 GW to 15.2 GW**, including elevated outage levels during spring maintenance and weather events. Because ERCOT still relies on thermal generation for dispatchable capacity, forced outages can quickly tighten reserves when load is elevated or renewable output underperforms.
Extreme Weather Events	Extreme weather can pressure demand and supply simultaneously. Winter storms which increase heating demand while reducing generation availability through frozen equipment, fuel disruptions, derates and operating constraints **can drive 10+ GW of combined system impact**. ERCOT relies more heavily on thermal generation, wind, and stored energy. Precedent events include Winter Storms Uri (2021), Elliott (2022), Heather (Jan 2024), Cora/Enzo/Kingston (Jan-Feb 2025).
Low Renewable Output and BESS Limitations	Low wind output can materially reduce available supply during summer evenings and winter mornings, while BESS state-of-charge limitations can **reduce expected availability by 2–6 GW during prolonged system stress**. This creates a reliability gap when renewable output falls before sufficient flexible or dispatchable resources are available to replace it.
Transmission Constraints	South Texas export constraints can limit deliverability of coastal wind resources, including **curtailment of 500+ MW,** making transmission availability a recurring reliability risk. Additionally, when generation exists on the system, constrained transmission can prevent that capacity from reaching load centers during scarcity conditions.
Extended Equipment Outages	Long-duration outages across coal, gas and battery assets **remove nearly 2.0 GW of capacity** from the system, reducing reserve flexibility during peak risk periods. Multi-year outages are notable because they reduce the dependable resource base before short-term weather or outage conditions are even considered.

Sources: NERC Long-Term Resource Assessment, ERCOT Summary, Tables 1-2; ERCOT Monthly Outlook for Resource Adequacy, January 2025 – July 2026.

Evaluation of **MISO Texas** Reliability Metrics – Causes

MISO Texas / Southeast Texas faces reliability risk when aging thermal generation, fuel supply interruptions, extreme weather, transmission constraints and rapid load growth overlap, particularly during summer evening peaks and winter cold weather events.

Cause	Reliability Implications
Aging Thermal Fleet and Forced Outages	▪ MISO Texas / Southeast Texas depends heavily on thermal generation, making **fleet age, forced outage rates and seasonal availability** key reliability indicators. Older gas and thermal units may face higher failure risk, derates and longer repairs, especially during peak demand or extreme weather. Because these units provide **dispatchable capacity when renewable output is low or demand spikes**, outages can quickly tighten reserves and increase reliance on imports or emergency actions.
Rapid Load Growth from Data Centers / Industrial Customers	▪ Large industrial customers, manufacturing projects and data centers are increasing demand faster than new generation and transmission can be added. This growth can tighten reserve margins, increase local deliverability needs and place additional pressure on utility planning. Southeast Texas is particularly exposed given its concentration of **industrial load and potential data center growth.**
Evening Peak Net Load Risk	▪ Reliability risk is increasingly shifting to **late afternoon and evening hours**, when demand remains high but solar output begins to decline. Battery storage can help bridge part of the ramp, but duration limits reduce its ability to cover extended scarcity periods. Without sufficient dispatchable capacity, MISO Texas may face greater exposure to **evening peak stress.**
Extreme Weather Events	▪ Winter storms can create simultaneous pressure on **load and generation availability**. Extreme cold can increase heating demand while causing forced outages from frozen equipment, fuel supply issues and reduced plant performance. Events such as Winter Storm Uri highlighted the need for **stronger cold-weather readiness** and contributed to enhanced EOP-012 reliability standards.
Spring / Fall Maintenance Risk Windows	▪ Shoulder-season maintenance periods are becoming more important because planned outages can reduce **available dispatchable capacity**. If demand is elevated or renewable output underperforms during these periods, the system has less flexibility to absorb unexpected outages. This risk is more pronounced in MISO South because transmission constraints can limit support from other MISO regions.
North-South Transmission Constraint	▪ Transmission limitations between MISO North / Central and MISO South can restrict the ability to move **surplus capacity into the South** during tight conditions. This **creates localized resource adequacy risk**, where MISO South may face reliability pressure even if the broader MISO system has available capacity. The constraint also limits emergency support during periods of high load, generator outages or fuel supply stress.
Natural Gas Fuel Supply Interruptions	▪ Gas-heavy markets such as Entergy Texas depend on **continuous just-in-time natural gas delivery** to keep thermal units available. During extreme weather, gas supply interruptions or competing demand from heating load can reduce generator availability. This increases the risk of **energy deficiencies when dispatchable capacity is most needed.**

Sources: NERC Long-Term Resource Assessment, MISO Summary, Tables 1-2 (January 2026); MISO Annual LOLE Study (2024-2026), MISO Regional Resource Assessment (RRA) (2024), MISO Planning Resource Auction (2024-2026)

FTI CONSULTING

Key Impacts of Reforms on System Reliability Overview

Post-Winter Storm Uri reforms in Texas (SB 3) and ERCOT market design changes (ECRS market design launch), plus large capacity additions to the ERCOT grid (+65 GW since pre-Winter Storm Uri), have reduced modeled scarcity risk.

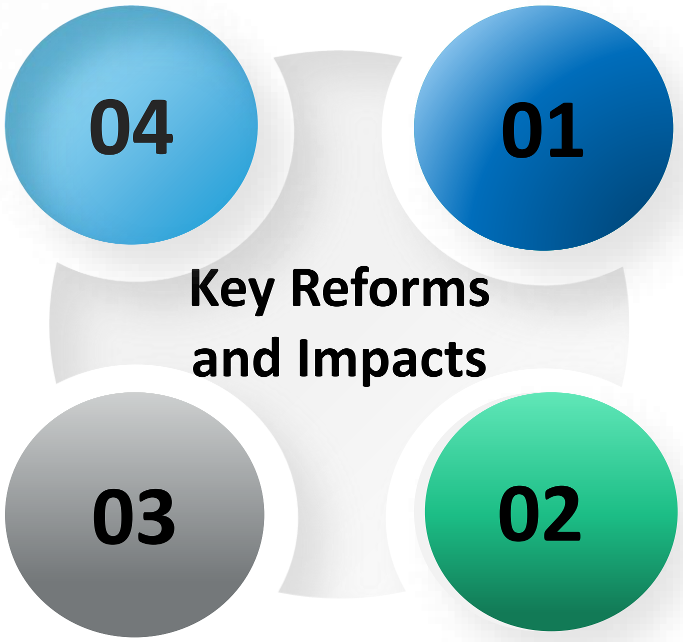
Reliability Metrics Show Clear Improvement

- Reserve margins have increased significantly while peak-hour EEA probability has declined, indicating lower modeled scarcity risk relative to the pre-reform period.

Metrics	Pre-Reform Avg (2019-2021)	Post-Reform Avg (2024-2026)	Improvement
Reserve Margin	9.27%	42.01%	**+353%**
EEA Probability (Peak Hour)	13.36%	1.39%	**-90%**
Installed Capacity	77.98 GW	128.66 GW	**+65 GW**

Capacity Additions Improved Resource Adequacy

- The ERCOT Independent Market Monitor reported that ERCOT has **added approximately +65 GW of installed capacity since the pre-Uri period**, including roughly 14 GW entering service in 2024. These additions have expanded the resource base available to meet peak demand, increased reserve margins, and reduced tight system conditions.



Weatherization Standards Reduced Extreme-Weather Outage Risk

- SB 3 established **mandatory weatherization requirements for generation facilities and supported firm fuel supply arrangements**, improving ERCOT's ability to withstand severe cold-weather events. These reforms help reduce the likelihood of weather-related thermal outages by requiring generators to prepare for regional cold-weather thresholds and maintain greater confidence in fuel availability during winter storm conditions. **Post-SB 3, ERCOT now assumes an 80-90% success rate** in reducing weather-related thermal outages during extreme cold events compared to pre-reform conditions.

ECRS Added a New Layer of Emergency Reserves

- The launch of Emergency Condition Responsive Service ("ECRS") created an **additional reserve product that can be deployed during Energy Emergency Alert ("EEA") events**, strengthening ERCOT's ability to respond before controlled outages are required. ECRS **works alongside other emergency resources**, including Large Load Curtailment and TDSP Load Management Programs, **to provide ERCOT with a broader set of tools** to balance the system during tight operating conditions and reduce the likelihood of firm load shed.

Potential Future Market Reforms Could Further Support Dispatchable Reliability

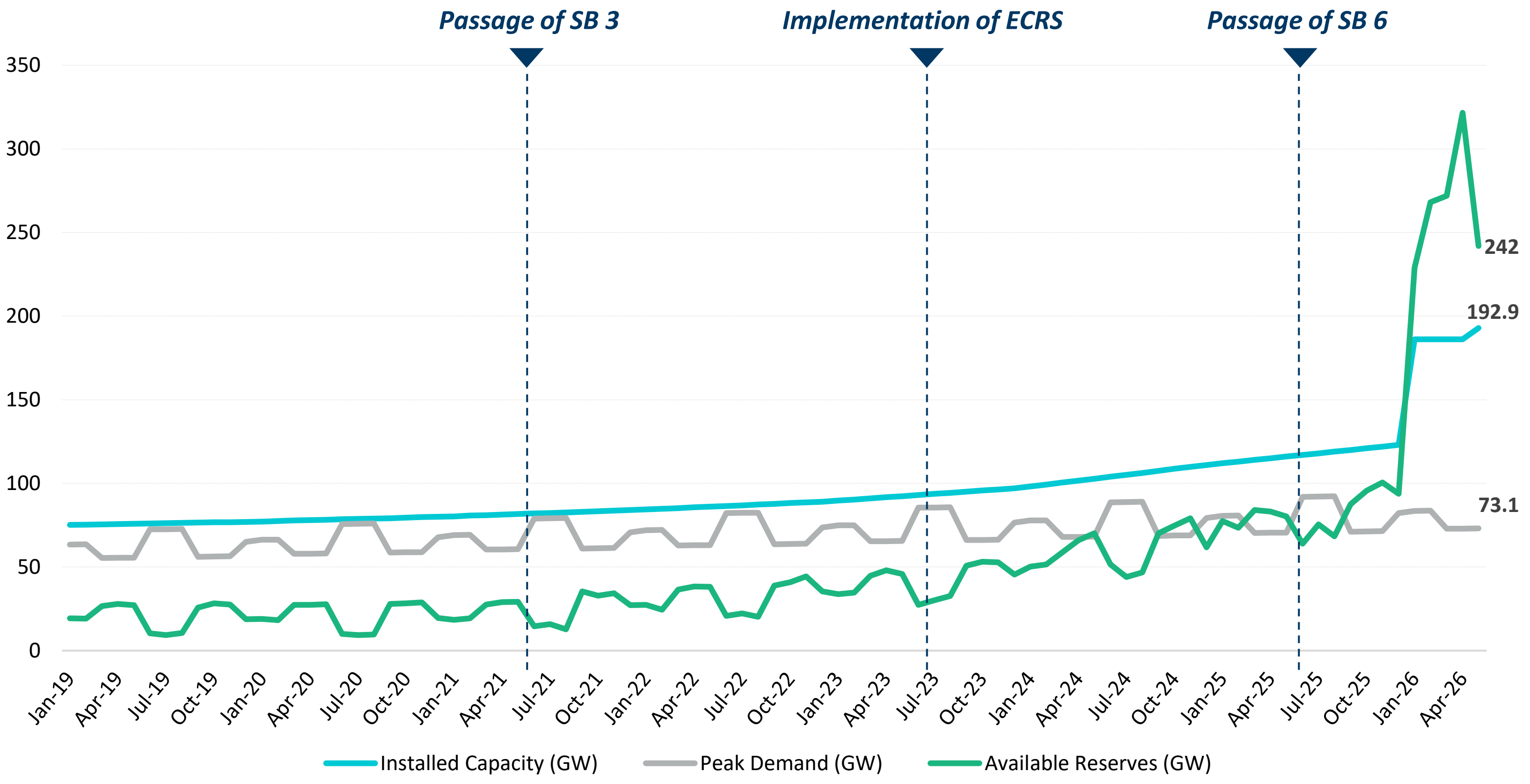
- *While SB 3, ECRS, and capacity additions have already reduced modeled scarcity risk, future market reforms such as a Performance Credit Mechanism ("PCM"), if reconsidered or implemented, could further incentivize resource availability during high-risk hours.*
- *However, PCM should be treated as a potential future enhancement rather than a current reliability driver, given that the PUCT shelved the proposal in late 2024 and shifted near-term focus to other market-design initiatives.*

Sources: ERCOT Monthly Outlook for Resource Adequacy ("MORA") 2022-2026; Capacity, Demand and Reserves Report (2015-2025); 2020 ERCOT Reserve Margin Study Report; 2024 State of the Market Report (Potomac Economics); ERCOT Winter Weather Readiness; ERCOT 2025-2026 Winter Reliability Assessment; 2024 Reliability Performance and Regional Risk Assessment.

Impact of Reforms on System Reliability – Load and Capacity Metrics

Post-Winter Storm Uri reforms in Texas (SB 3) and ERCOT market design changes (ECRS market design launch), plus large additions of solar and storage to the ERCOT grid (14 GW in 2024 alone), have reduced modeled scarcity risk.

ERCOT System Reliability Over Time (GW) – Load and Capacity Metrics (2019 – 2026)



Key Commentary

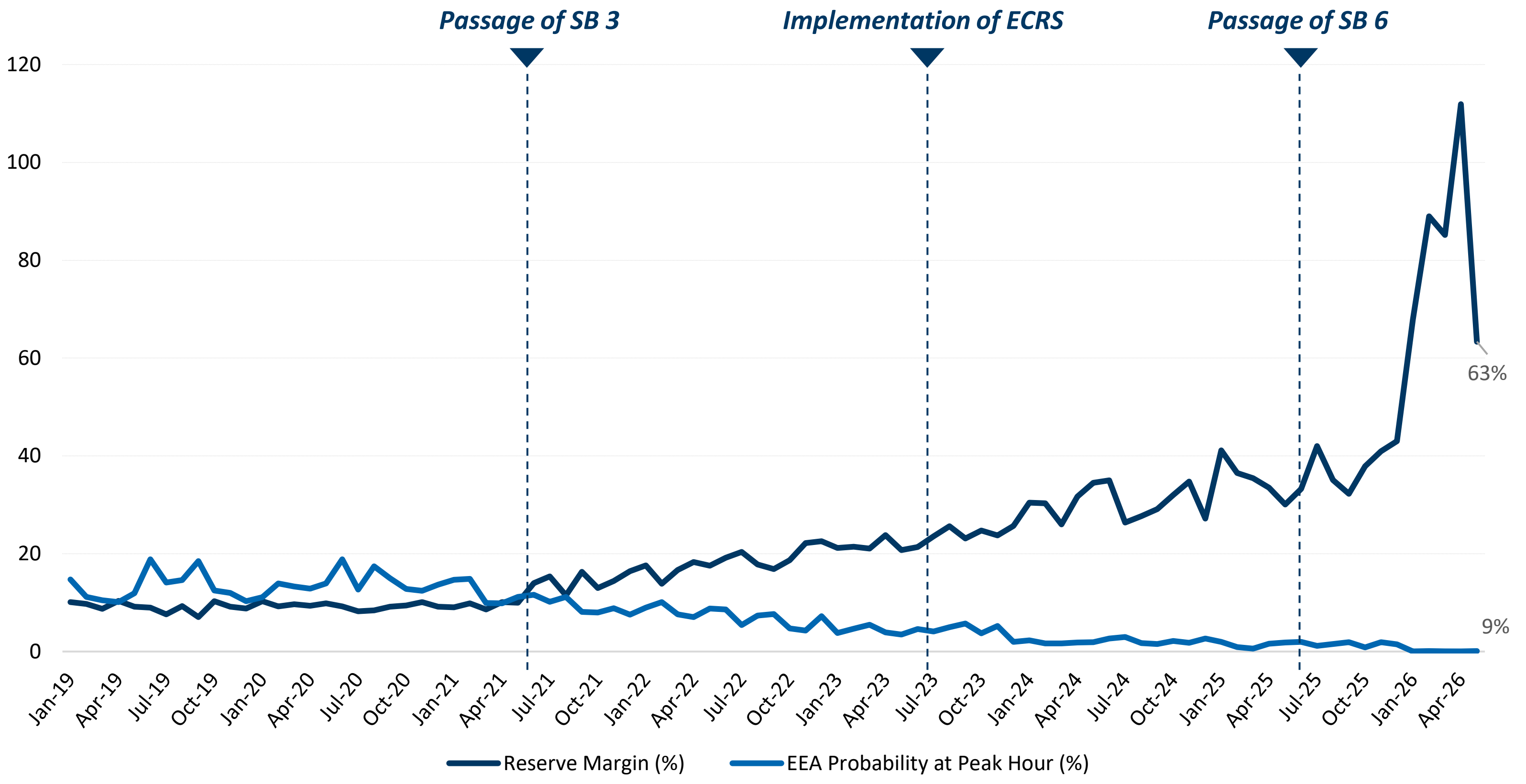
- Post-Winter Storm Uri reforms, including SB 3, improved ERCOT reliability by strengthening weatherization standards, operational preparedness, and oversight of critical power and gas infrastructure. ERCOT's launch of ECRS further improved reliability by adding a fast-response reserve product to help manage sudden changes in load, renewable output, or generator availability.
- At the same time, rapid solar and storage additions have expanded ERCOT's resource base and increased available reserves, helping reduce modeled scarcity risk versus the immediate post-Uri period. Battery storage is especially important because it can shift excess solar generation into evening peak hours and respond quickly during tight system conditions.
- However, reliability remains a moving target. Peak demand continues to rise due to industrial growth, data centers, electrification, and population growth. As a result, ERCOT's reliability outlook increasingly depends on ensuring new capacity is not only added, but also firm, deliverable, and available during peak-risk hours.

Sources: ERCOT Monthly Outlook for Resource Adequacy ("MORA") 2022-2026; Capacity, Demand and Reserves Report (2015-2025); 2020 ERCOT Reserve Margin Study Report; 2024 State of the Market Report (Potomac Economics); ERCOT Winter Weather Readiness; ERCOT 2025-2026 Winter Reliability Assessment; 2024 Reliability Performance and Regional Risk Assessment.

Impact of Reforms on System Reliability – Reserves and EEA Probability Metrics

Reserve margins have climbed and EEA probability has dropped in the wake of legislation and ERCOT reforms. However, healthy reserve margins could mask potential capacity shortfall when anticipating significant load additions.

ERCOT System Reliability Over Time (%) - Reserves and Energy Emergency Alert ("EEA") Probability Metrics (2019 - 2026)



Key Commentary

- Post-Uri legislation and ERCOT market reforms have improved system reliability by increasing reserve margins and reducing the probability of Energy Emergency Alerts ("EEA") during peak hours. SB 3 strengthened weatherization and reliability requirements, while ECRS added a fast-response reserve product to help ERCOT manage sudden supply / demand imbalances.
- Higher reserve margins suggest ERCOT has built a deeper resource buffer, reducing modeled scarcity risk versus the immediate post-Uri period. The decline in EEA probability also indicates that ERCOT is less likely to enter emergency operating conditions during peak-risk periods.
- However, stronger reserve margins should not be viewed as a complete solution. Reserve metrics can mask potential capacity shortfalls if large load additions from industrial growth, data centers, electrification, and population growth materialize faster than firm, dispatchable, and deliverable capacity can be added.

Sources: ERCOT Monthly Outlook for Resource Adequacy ("MORA") 2022-2026; Capacity, Demand and Reserves Report (2015-2025); 2020 ERCOT Reserve Margin Study Report; 2024 State of the Market Report (Potomac Economics); ERCOT Winter Weather Readiness; ERCOT 2025-2026 Winter Reliability Assessment; 2024 Reliability Performance and Regional Risk Assessment.

Residual Reliability Risks for Large Industrial Customers – ERCOT

ERCOT's large industrial customers face curtailment, tightening peak hour power availability, delayed grid upgrades, and growing price risk, amid broader uncertainty from a large, slow moving interconnection queue backlog.

SB 6 Mandatory Curtailment Framework

- ERCOT now has authority to curtail large loads before emergencies, condition of interconnection approval
- Large industrials face forced curtailments, noncompliance penalties, uncertain compensation frameworks

Load Realization, Queue Uncertainty

- ERCOT applying 49.8% data center realization factor
- 70+ GW in interconnection queue (Dec 2025) with uncertain timing creates volatility in reserve margin projections and planning

Time of Use Energy Risk

- Summer evening peak demand results in a highest risk hour ending at 9pm CT
- Solar output ramps down ~20,000+ MW as the sun sets
- High load from data centers, cooling, industrial use
- Battery storage discharge duration is ~1-2 hours

Cybersecurity

- Behind-the-meter resources create more attack vectors
- Data center concentration increases targeted attack value
- Compliance with CIP Standards = compliance costs

Low Inertia and Frequency Stability

- Large industrial loads face higher automatic disconnect risk as inverter-based generation (85% of new capacity) reduces grid inertia, accelerating frequency decay and Under-Frequency Load Shedding ("UFLS")

Climate/Weather Risk

- Frequency and duration of Winter Storms, heat waves could increase
- Hurricanes and wildfires could cause infrastructural damages; potential preventative outages

Transmission Constraints

- Constraints in power export north from windy coastal regions
- 765-kV system online in late 2020s to ease constraints
- Switchable Generation Resources can be routed to SPP; yielding planning uncertainty

Fuel Availability

- Coal retirements (~1,440 MW by 2029) eliminate on-site fuel storage
- Just-in-time natural gas delivery → single point of failure
- Mitigated by ERCOT's growing solar, storage, gas, and demand-side resource mix

Customer-Side Mitigation Considerations: Customer-side mitigation measures include onsite generation and backup power systems, dual fuel capability, energy storage for demand response participation, automated load curtailment controls, and interruptible service contracts that provide compensation.

Source: ERCOT

Residual Reliability Risks for Large Industrial Customers – MISO Texas

MISO Texas faces a more severe reliability outlook than ERCOT, driven by deeper capacity shortfalls, transmission constraints, higher industrial demand, and storm risk, requiring more urgent and proactive customer-side mitigation measures overall going forward.

Load Growth > Resource Adds

- MISO summer peak 2026-2035: 127 GW → 143.7 GW
- 18 GW of data center load projected by 2035
- Load growth accelerating faster than resource adds
- Accredited thermal capacity decreased by 8.8 GW in 2025

MISO Expedited Resource Addition Study

- In response to projected reserve margin crisis, ERAS studies generation needs
- 20+ GW nameplate by summer 2030
- ERAS projects not yet in commercial operation,; potential timing delays

Time of Use Energy Risk

- ERAS queue is predominantly solar and battery resource
- Solar output, battery discharge ramps down in summer evenings; load high
- Continuous operation critical in petrochemicals and refining; high safety and process consequences

Entergy Texas Fleet Age

- Entergy Texas thermal fleet aging
- Forced outage rates trend higher for older units
- Unplanned outages compound reserve margin shortfall

Capacity Market Obligations

- MISO capacity prices are rising in scarcity (resource shortfall drives up auction clearing prices)
- Capacity market payment obligations: Industrial customers as Load-Serving Entities must procure capacity 3+ years ahead

Climate/Weather Risk

- Hurricane-prone region.
- Transmission and generation infrastructure vulnerable to winds, flooding, storm surge.
- Hurricane season overlaps with summer peak demand, affecting reliability planning.

Transmission Constraints

- North-South MISO constraint MISO North faces export constraints to MISO South during emergencies.
- Southeast Texas cannot rely on MISO-wide resource pool during local stress.
- Localized reliability risk higher than MISO average.

Natural Gas & Infrastructure Demand

- Power generation, LNG exports and industrial feedstock in the Southeast Texas Industrial Corridor all compete for natural gas
- Price spikes and supply constraints exist during peak periods

Customer-Side Mitigation Considerations: Customer- and utility-side mitigation includes investing in capacity market resources like on-site generation and CHP systems, along with transmission upgrades, MISO planning participation, and a diversified approach to hedging energy and capacity costs.

Source: MISO

Additional Reliability Considerations

Additional issues to address include generator performance during winter weather events, emergency demand response capabilities, governance, ownership, and the allocation of costs associated with load and data center growth.

1. Winter Performance and Emergency Response

- Federal investigators found that **75.6%** of Uri's unplanned outages were tied to freezing and fuel issues.
- Weatherization and fuel-assurance reforms targeted these winter outages. ERCOT now procures **Emergency Response Service** from loads and generators to reduce consumption or increase generation before firm load shed becomes necessary, and its demand-response framework also includes Load Resources and voluntary load response.
- ERCOT completed 4,588 weatherization inspections as of April 2026 and reported no reliability events requiring controlled outages since 2021, including more severe post-Uri cold events like Elliott, Heather, and Fern.

Key Takeaways: ERCOT has operationally evolved since Uri, with mandatory preparedness standards, recurring inspections, and a multi-year operating record with fuel availability and without rolling outages.

2. Governance, Responsibility, and Cost Allocation

- ERCOT has formalized the interconnection process to address these concerns.
- The **Nodal Protocol Revision Request (NPRR1234)** and the accompanying **Planning Guide Revision Request (PGRR115)** were approved in May 2025 and implemented in December 2025 to create a formal large load interconnection process and operating standards.
- In ERCOT, limited network upgrades triggered in interconnection; **transmission providers** pay for any incremental costs needed to connect generators.

Key Takeaways: ERCOT now has a formalized interconnection framework for large loads, and SB6 directs the PUCT to develop large load cost-sharing rules; promising signs needing real-world case studies.

3. Split Ownership of Onsite Storage

- This concern is founded; storage owned separately or optimized for market revenues may not be contractually obligated to ride through the host's load emergencies.
- **Third-Party Leasing / Energy-as-a-Service** is a model for collocated data centers that avoids split ownership with ERCOT. A third party owns, operates, and monetizes the battery, but leases land from the data center. EaaS provides fixed monthly capacity or shared energy savings, while ERCOT only sees the third-party developer as the registered entity.
- If two or more entities truly share ownership, ERCOT requires an approved **joint management agreement** to designate a single scheduling entity.

Key Takeaways: While ERCOT has rules for co-located large loads and joint management arrangements, and Texas has started to regulate co-location more, but commercial and operational risk is not fully resolved.

Source: ERCOT

E. Industrial Load Growth & Generation Investment Dynamics

FTI CONSULTING

Executive Summary: Industrial Load Growth & Generation Investment Dynamics

ERCOT's relative advantage to large-load growth lies in the mechanisms to effectively manage uncertainty: load validation, batch interconnection studies, customer-funded upgrades, demand response, and flexible load integration.

Large Loads Redefine Planning Risk

- Historical peak growth has been manageable, but large single-site projects can change ERCOT requirements quickly.
- System planning must account for nonlinear load growth, not just historical CAGR.

Queue Discipline Protects Competitiveness

- The large-load queue should be treated as a planning signal, instead of a forecast.
- Compared to other large-load growth regions, ERCOT's load validation and batch-study approach offers a more transparent path to managing uncertainty and protecting existing customers from costs tied to speculative demand.

Peak Forecasts Depend on Conversion

- Historical trends reach only about 100 GW by 2030, while higher cases require faster large-load materialization.
- Customer procurement, hedging, and resilience strategies should be designed to work across both moderate and aggressive ERCOT growth outcomes.

TEXAS ENERGY FUND

TxEF Narrows, But Does Not Close, the Gap

- Known TxEF-supported additions help, but a large residual capacity need remains after finalized loans, grants, and diligence-stage projects.
- ERCOT still needs market-led generation, storage, transmission, demand response, and customer-side resilience.

Resource Mix Matters for Reliability

- Renewable and storage additions support energy supply, but firm-capacity exposure remains during scarcity, winter, and evening ramp conditions.
- Houston customers should evaluate effective capacity during high-risk hours, not nameplate capacity alone.

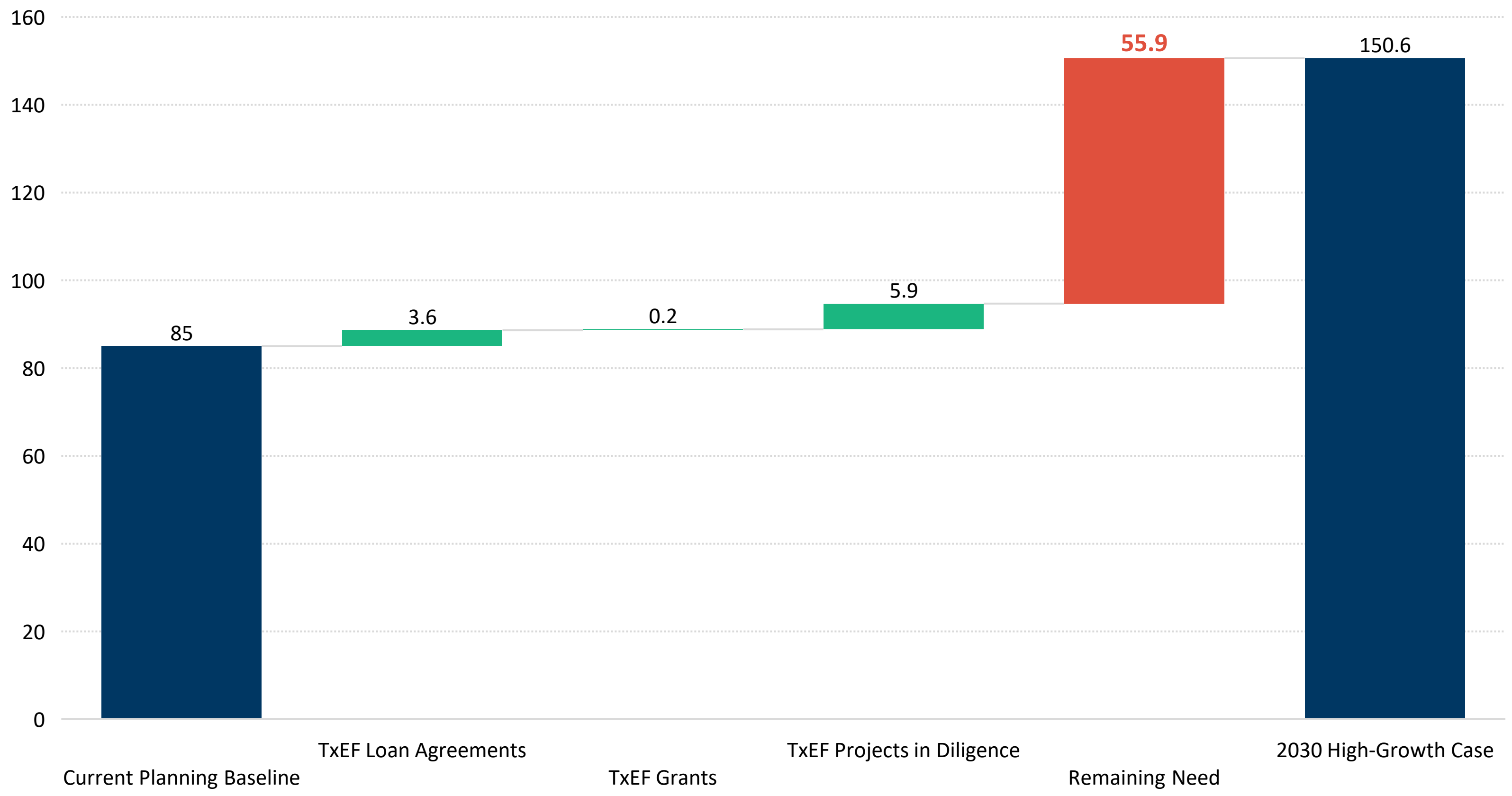
Houston Industrials Can Shape the Outcome

- Long-term offtake, cogeneration, storage, flexible operations, and demand response can reduce customer exposure while supporting ERCOT reliability.
- HETI can position Houston as both a major load center and a reliability partner.

Capacity Needs Require Multiple Levers

A high-growth ERCOT case implies roughly 65 GW of incremental capacity need by 2030. While known TxEF-supported additions reduce the gap, more than 55 GW still requires broader market, grid, and customer-side solutions.

ERCOT Capacity Bridge to 2030 High-Growth Case (GW)[1]



Key Commentary

- ERCOT's high-growth case implies a move from roughly 85 GW today to 150.6 GW by 2030, creating about 65 GW of incremental capacity need before known TxEF-supported additions. After finalized loans, grant-supported capacity, and selected projects in diligence, the residual need remains roughly 56 GW.
- Closing the remaining gap will require more than state-backed dispatchable generation. ERCOT will need a portfolio response that combines market-led generation investment, accelerated storage deployment, transmission expansion, industrial demand response, and customer-side resilience.
- For Houston industrial customers, the most actionable levers are not limited to waiting for new grid-scale generation. Large customers can reduce exposure by supporting long-term offtake, expanding on-site generation or cogeneration, deploying battery storage, and identifying flexible processes that can participate in ERCOT demand-response or emergency-curtailment programs.
- Transmission and deliverability are equally important: new capacity only improves Houston-area reliability if it can reach major load centers during stressed operating hours. HETI can help advocate for infrastructure that supports the Houston Load Zone and critical industrial corridors, not just ERCOT-wide nameplate capacity additions.

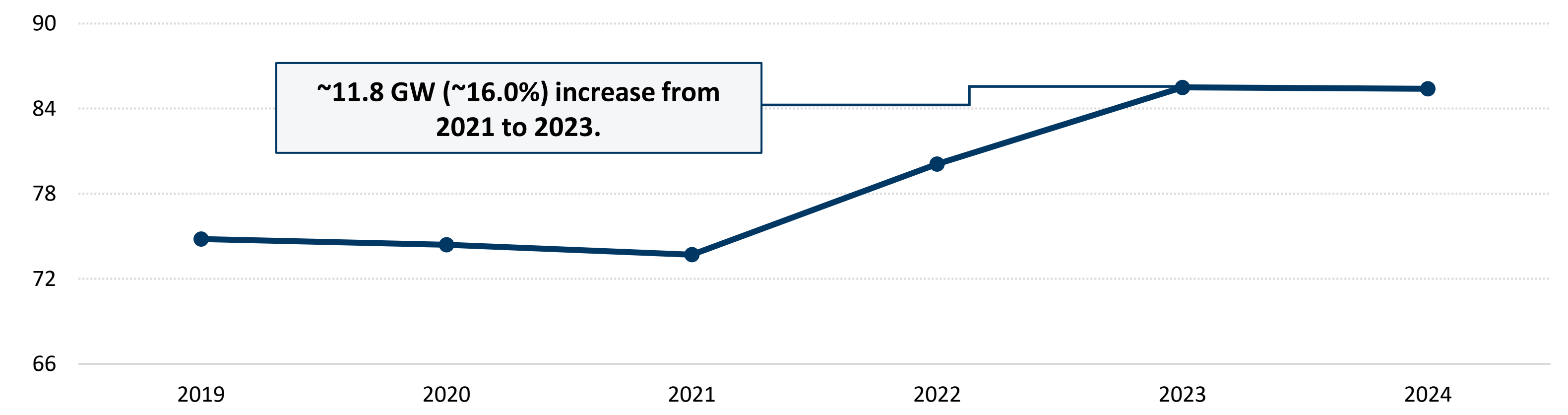
(1) Capacity bridge is illustrative and should not be read as an ERCOT procurement target.

Sources: ERCOT 2025 Long-Term Load Forecast materials; ERCOT Capacity, Demand and Reserves Report; PUCT Texas Energy Fund

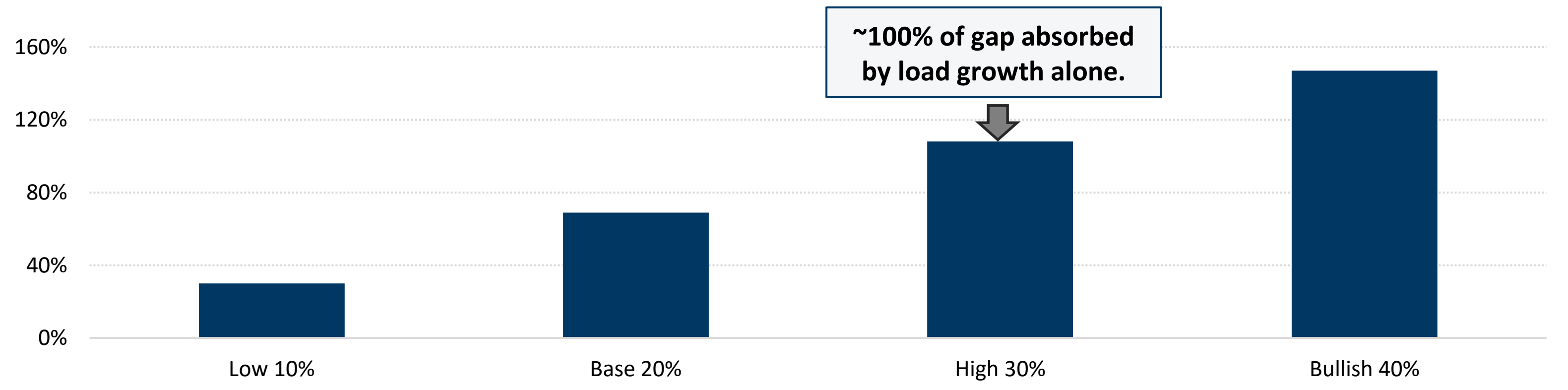
Large Loads Re-define ERCOT Planning

ERCOT's realized peak growth has been manageable, but large single-site load additions can change system requirements quickly if projects materialize faster than generation and transmission.

Observed Summer Peak Demand (GW)



Large-load Materialization Scenarios through 2030 (% of Incremental Capacity Need)



Key Commentary

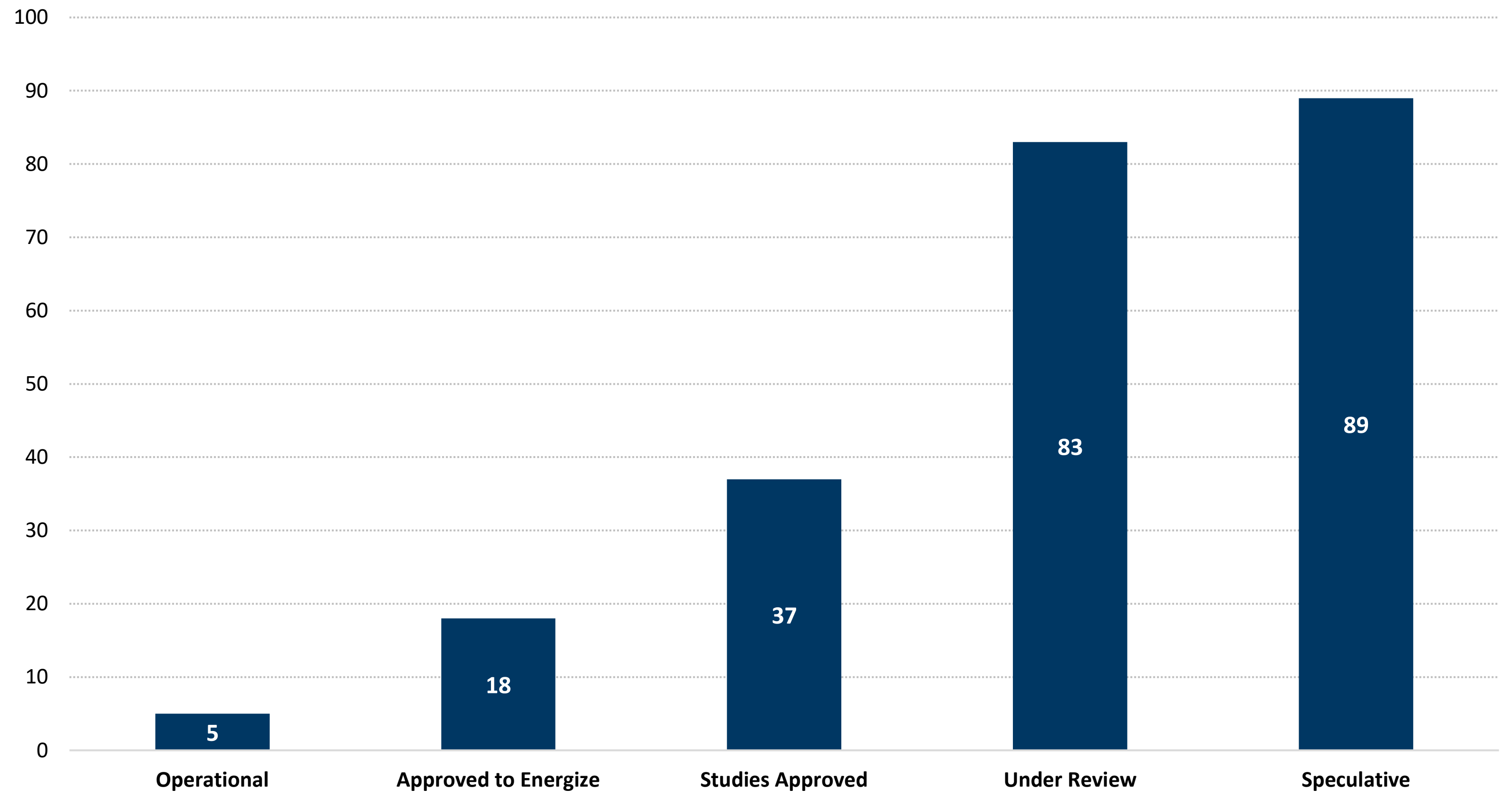
- ERCOT's historical peak-demand trend shows a system that has grown steadily, while the large-load queue indicates a potential step-change in demand if data centers, industrial electrification, LNG, and manufacturing projects advance on compressed timelines.
- This distinction matters because industrial loads do not arrive like residential growth. A single large facility can add hundreds of MW at a specific node, creating local deliverability, interconnection, and reserve implications that are not captured by system-wide CAGR alone.
- Houston industrial customers should treat the large-load outlook as a strategic planning variable and prepare for a market where even partial load conversion affects price volatility, congestion, and firm supply availability, even when the largest new projects are not located in the Houston Load Zone.
- Customers with flexible processes, on-site resources, or long-term offtake capability can convert ERCOT volatility into commercial advantage, while less flexible customers may need stronger hedging and resilience strategies.

Sources: ERCOT Yearly Peak Demand Records; ERCOT Large Load Interconnection Status Updates; FTI analysis.

Queue Size Requires Load Discipline

The 233 GW large load interconnection queue should be treated as a risk-weighted planning signal, with advanced projects informing investment while speculative requests are screened before costs spread.

Queue Size (GW)[1]



Key Commentary

- Advanced-readiness projects inform planning, while speculative requests need screening for site control, financing, power, and interconnection readiness before driving commitments or cost allocation.
- The real question is whether enough demand materializes to tighten ERCOT, while speculative projects still shape transmission planning and cost recovery.
- Much speculative growth is data centers and large flexible loads, which add water exposure: cooling demand can strain drought-prone supply, making water a siting and screening criterion alongside power and interconnection.
- The risk is two-sided: under-planning brings scarcity and reliability stress, while over-planning around phantom load socializes infrastructure and water costs onto ratepayers and erodes competitiveness.
- Governance should define who validates large-load and data center requests and how costs are allocated, so demand drivers, not existing ratepayers, fund capacity for uncertain projects.
- A disciplined load-validation framework, backed by transparent cost-allocation governance, shields existing customers from uncertain projects while letting credible demand connect on growth-supporting timelines.

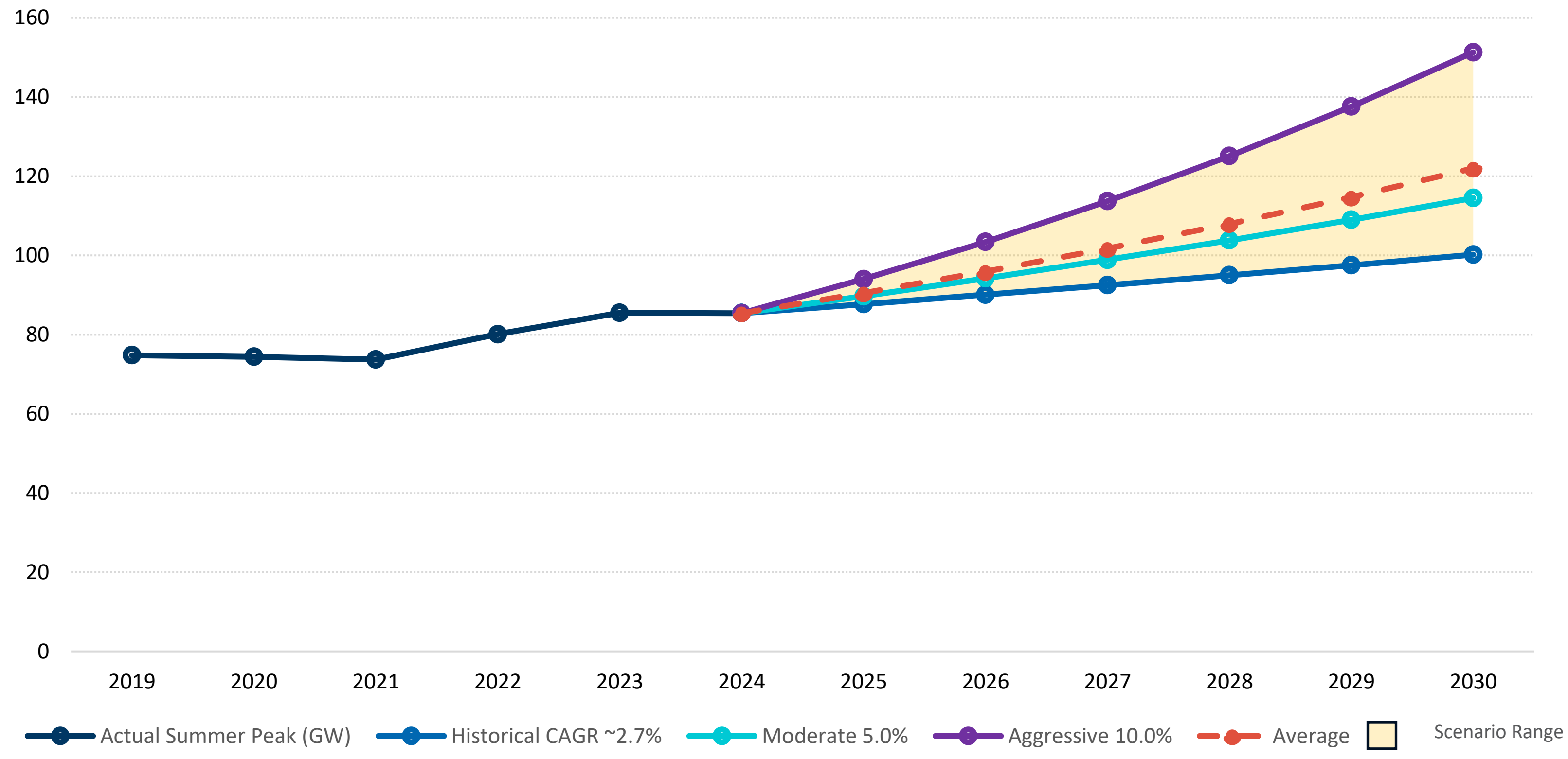
(1) Queue category values are rounded. ERCOT is refining how large loads are counted in the interconnection queue (Batch Zero framework; transition toward executed-agreement-based gating), category totals may shift in future updates.

Sources: ERCOT Large Load Interconnection Status Updates; ERCOT Board materials

Peak Forecasts Depend on Load Conversion

Historical peak growth reaches only about 100 GW by 2030, so higher-growth sensitivities depend on accelerated large-load materialization rather than continuation of recent system-wide peak trends.

Peak Forecasts (GW) as of December 2025



Key Commentary

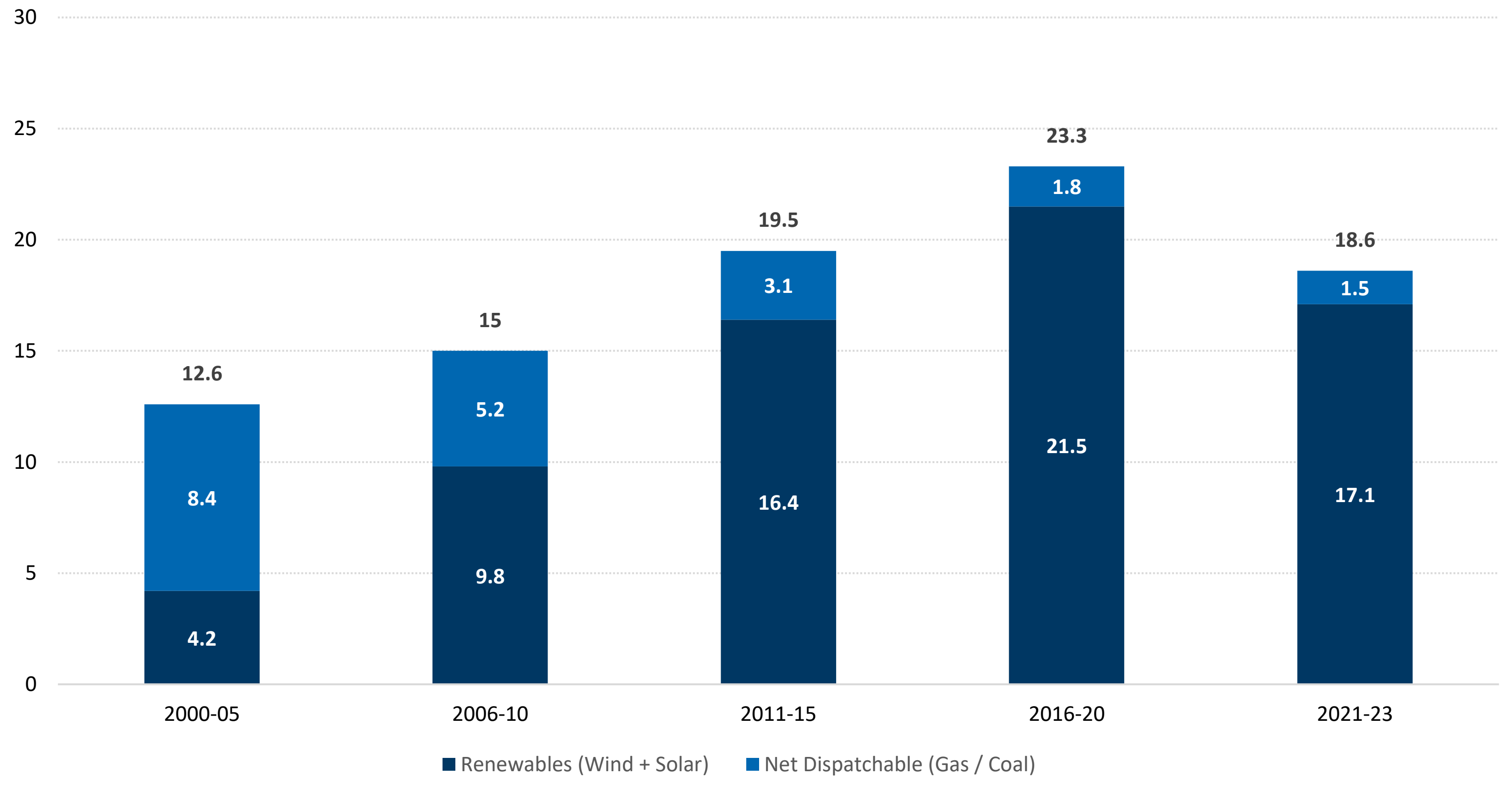
- ERCOT's historical peak-demand trajectory reaches only ~100 GW by 2030, well below higher-growth sensitivities. Those require a step-change in large-load materialization. EPRI estimates Texas data centers alone could add 8–21 GW by 2030, a meaningful but partial driver of the upside case.
- For Houston industrial customers, the planning risk is not simply higher demand, but uncertainty around the pace, location, and credibility of new load. Procurement, hedging, resilience, and flexibility strategies should be designed to work across both moderate and aggressive ERCOT growth cases.
- The widespread between historical, moderate, and aggressive scenarios supports a balanced policy message: Texas should prepare for high-load outcomes, but major infrastructure investment should be tied to substantiated demand milestones, transparent project-readiness standards, and clear cost-allocation discipline.
- For HETI, the implication is to position Houston's industrial base as both exposed to ERCOT-wide growth risk and capable of helping manage it. Flexible operations, customer-side generation, storage, long-term offtake, and industrial demand response can reduce customer exposure while supporting system reliability as load growth materializes.

(1) Values are rounded, point-in-time figures. ERCOT is revising large loads count and forecast (Batch Zero framework; post-2026 gating to agreements per PUC 58481; pending PUC transparency rules, Dec 2026). Shaded range reflects Historical-to-Aggressive dispersion, not confidence interval, and is subject to HETI validation. EPRI data center estimate reflects TX nominal IT capacity only, not facility load or peak-coincident demand.
Sources: ERCOT Yearly Peak Demand Records; ERCOT 2025 Long-Term Load Forecast materials; ERCOT CDR Report; EPRI; FTI analysis.

Resource Mix Drives Reliability Exposure

ERCOT has attracted renewable and storage investment at scale, but firm-capacity exposure remains during scarcity, winter, and evening net-load ramp conditions.

ERCOT Capacity Added by Period (GW)[1]



Key Commentary

- ERCOT's market has attracted substantial new capacity, but the investment mix has increasingly skewed toward renewables rather than net dispatchable generation. From 2011–2023, renewable additions materially outpaced dispatchable additions, including 17.1 GW of renewables versus only 1.5 GW of net dispatchable capacity in 2021–2023.
- This buildout has strengthened ERCOT's energy supply during many hours and supported Texas's low-cost power advantage, but it does not fully address reliability risk during scarcity events, winter weather, low-renewable-output periods, or evening net-load ramps when industrial customers are most exposed.
- For Houston industrial customers, the key planning issue is not nameplate capacity alone, but effective capacity during the hours that matter. Resources that produce significant annual energy may still provide limited protection against scarcity-hour pricing, outage risk, congestion, or operational disruption if output is not available when demand peaks.
- The strategic implication is that Houston should support a balanced reliability portfolio: continued renewable and storage growth, paired with firm dispatchable resources, flexible ramping capability, transmission deliverability, demand response, and customer-side resilience.

(1) Net dispatchable capacity reflects gas / coal additions net of retirements where applicable; renewable capacity reflects wind + solar additions.
Sources: EIA Form 860 / Electric Power Monthly; ERCOT Capacity, Demand and Reserves reports; Potomac Economics 2024 State of the Market Report for ERCOT

FTI CONSULTING

Texas Energy Fund ("TxEF") Narrows The Gap

The known TxEF-supported pipeline totals about 9.6 GW when finalized In-ERCOT loans, the LCRA Completion Bonus Grant, and selected projects still in due diligence are combined, representing roughly 16% of the illustrative 60 GW incremental need.

Known TxEF Pipeline by Commitment Status[1]

Pipeline Category	Projects & Applications	MW
Finalized In-ERCOT loan agreements	6 signed loan projects	3,564
Additional selected applications in due diligence	12 applications	5,861
Total Known TxEF In-ERCOT Loan Pipeline	18 projects & applications	**9,425**
LCRA Timmerman Completion Bonus Grant	1 grant project	188
Total TxEF-supported Capacity	**19 projects & applications**	**9,613**

Finalized TxEF In-ERCOT Loan Agreements

Project	Technology	MW	TxEF loan	Status
KPUB Rock Island	Natural gas	122	$105M	***Summer 2027***
NRG TH Wharton	Simple cycle	456	$216M	***Summer 2026***
NRG Cedar Bayou	CCGT	721	$562M	***2028***
NRG Greens Bayou	Simple cycle	455	$370M	***2028***
Constellation Pin Oak	Simple cycle / peaker	460	$278M	***Online May 2026***
CPV Basin Ranch	CCGT	1,350	$1.12B	***2029***
Total		**3,564**	**$2.65B**	

Projects in Houston Load Zone   Projects in South Load Zone

Key Commentary

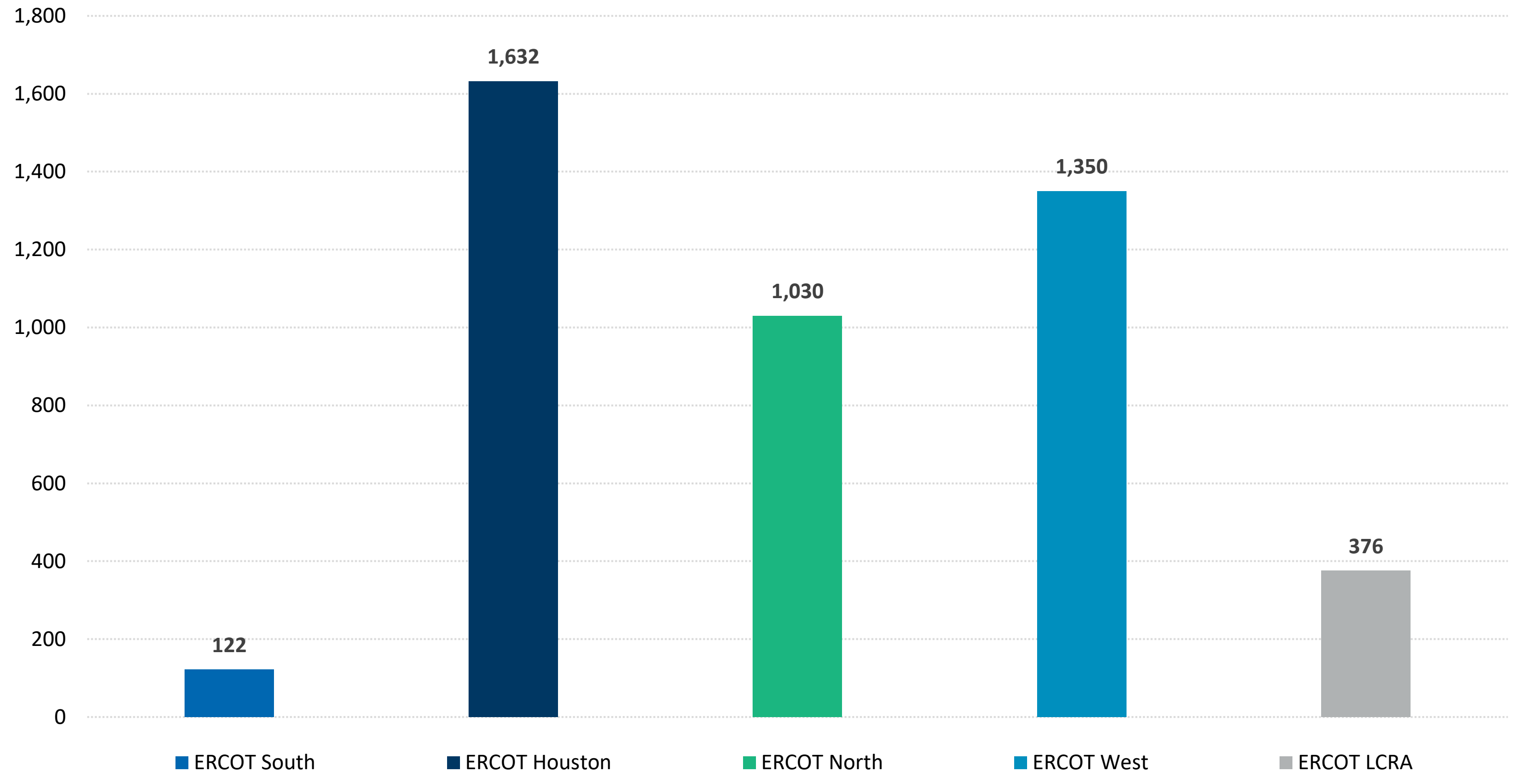
- TxEF has moved from concept to execution, with finalized In-ERCOT loan agreements supporting 3,564 MW of new dispatchable generation and one Completion Bonus Grant supporting an additional 188 MW. However, the broader ~9.6 GW TxEF-supported pipeline includes selected projects that remain in due diligence and should not be presented as fully closed capacity.
- Even assuming all selected / diligence projects reach completion, the known TxEF-supported pipeline would cover only roughly 16% of the illustrative 60 GW incremental need, reinforcing that TxEF is a meaningful market correction but not a complete adequacy solution.
- For Houston industrial customers, TxEF is valuable because several projects are located in or near major load centers, including the Houston Load Zone; however, customers should still plan for market tightness if load growth outpaces project execution, interconnection, fuel availability, or equipment availability.
- The policy takeaway is that TxEF should be paired with load validation, deliverability planning, industrial offtake, storage, and demand response so that new capacity is not only financed, but also firm, deliverable, and available during high-risk operating hours.

(1) Due-diligence projects are not guaranteed to close; LCRA Timmerman is a separate Completion Bonus Grant project and is excluded from the In-ERCOT loan-pipeline subtotal
Sources: PUCT Texas Energy Fund; Governor of Texas TxEF project announcements

Houston's Competitive Advantage Grows with TxEF-Funded Capacity

Houston has emerged as the largest beneficiary of TxEF funding, with approximately 1.7 GW of new dispatchable capacity supporting the region's role as Texas' premier hub for industrial growth and large-load development.

TxEF Capacity funded by ERCOT Load Zone (MW)[1]



Key Commentary

- TxEF funding is heavily concentrated in the Houston and South load zones, directing new dispatchable generation toward the state's fastest-growing industrial and large-load markets.
- Houston and the South load zone alone accounts for approximately 1.7 GW of funded capacity, positioning the region as the largest beneficiary of ERCOT's effort to accelerate new generation development.
- The geographic alignment of TxEF-supported projects with existing petrochemical, manufacturing, LNG, and emerging data center demand creates a favorable environment for large-load customers seeking power availability and long-term reliability.
- Alongside funding new generation capacity, Texas is investing in transmission resilience through initiatives such as the Steel Anchor Project, creating a more robust infrastructure foundation that supports rising industrial demand, improves reliability, and strengthens the Houston region's attractiveness for large-load customers.
- Because all funded projects are natural gas-fired resources, the program directly increases ERCOT's ability to serve load during high-risk summer and winter peak hours when reliability concerns are most acute.

(1) Based on project stated nameplate capacity
Sources: PUCT Texas Energy Fund; Governor of Texas TxEF project announcements, LCRA

Financing Determines Reliability Value

TxEF can leverage public capital into private investment, but technology mix determines whether new MW provide baseload energy, ramping support, or reserve value.

Technology	TxEF Economics	Reliability Role	Houston Industrial Implication
CCGT / H-Class	~$1.39M/MW total cost; ~60% TxEF loan coverage	Efficient energy + firm capacity for sustained high-load conditions	Best fit for long-duration industrial load and offtake-backed projects.
Simple-cycle peaker	~$0.79M/MW total cost; lower capex; fast scarcity response	Peaking and ramping support during summer evenings or scarcity intervals	Reduces price spikes; useful where flexible capacity matters more than baseload energy.
RICE / modular peaker	$120k/MW grant example; fast-build, modular deployment	Fast-start reserves; can be sited closer to constrained load pockets	Supports resilience and local deliverability; potential fit for industrial backup / microgrid strategies.

Capital Leverage

$1.67
Total project value per $1 TxEF

$15B
Total Investment if $9B deployed

11-19 GW
Illustrative dispatchable capacity potential

17-29%
Share of 60 GW incremental need covered

Implication for Houston Industrial Customers: New capacity only protects industrial customers if it is firm, deliverable, and available during high-risk hours. Houston customers should pair TxEF-backed supply with offtake, hedging, on-site resources, and flexible operations to reduce scarcity pricing.

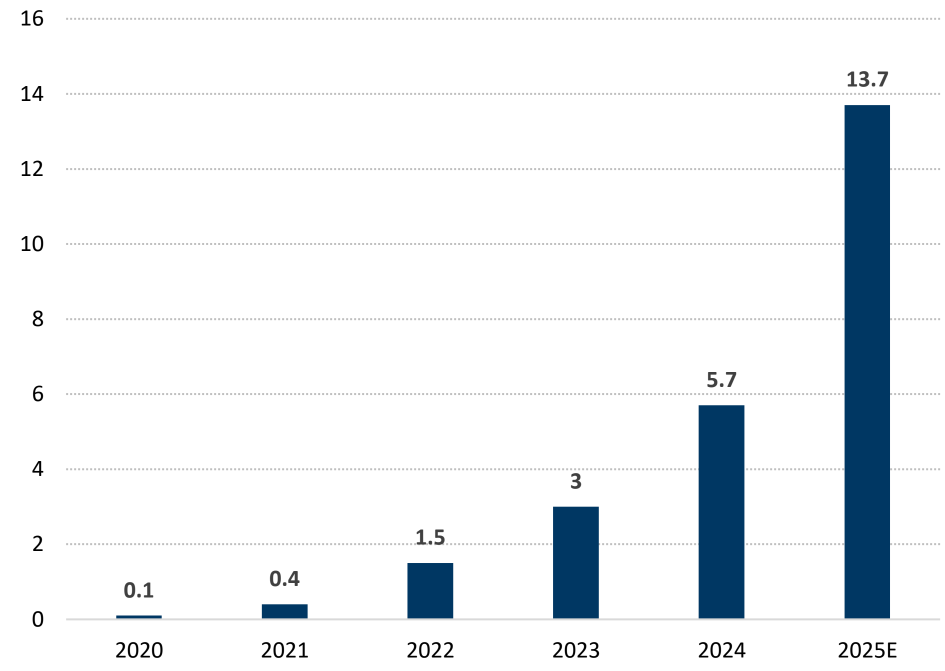
Sources: PUCT Texas Energy Fund; Governor of Texas TxEF project announcements.

Storage Strengthens ERCOT's Flexibility

Battery capacity is scaling rapidly in ERCOT, strengthening short-duration reliability while preserving the need for firm resources during extended stress events.

Where Storage Helps	Where Firm Capacity Remains Needed
1. **Summer Evening Ramp:** Batteries can charge during high-renewable or lower-price hours and discharge as solar output falls in the evening, helping ERCOT manage the net-load ramp created by rising solar penetration.	1. **Multi-day Weather Events:** Most ERCOT batteries are designed for short-duration discharge, typically 2–4 hours, which limits their usefulness in sustained winter events or multi-day low-renewable periods.
2. **Ancillary Services:** Fast-response batteries are well suited for frequency response and reserve products. During recent winter events, batteries provided meaningful ancillary service support, including up to 88% of regulation up during peak hours in Winter Storm Elliott.	2. **Cold-weather Performance Risk:** Battery performance can degrade in extreme cold, and state-of-charge risk becomes more important if resources discharge early in an extended event.
3. **Scarcity Mitigation:** Storage can reduce short-duration price spikes by injecting energy during tight intervals, improving near-term reliability and reducing volatility during summer peak conditions.	3. **Industrial Continuity:** Storage can reduce near-term volatility and help manage summer scarcity, but Houston resilience still requires firm supply, on-site backup, and demand flexibility. On-site storage can be customer-owned, third-party, or split-ownership, each differing in who controls dispatch and captures value.

ERCOT Utility-Scale Battery Storage Capacity (GW)



Implication for Houston Industrial Customers: Storage can reduce near-term volatility and help manage summer scarcity intervals, but Houston industrial resilience still requires firm supply, on-site backup options, demand flexibility, and operating protocols for extended weather-driven stress.

Sources: ERCOT GIS / Resource Adequacy materials; Potomac Economics 2024 State of the Market Report for ERCOT; FTI analysis.

Industrials Can Monetize Flexibility

Houston industrial customers face high outage costs, but their load scale, cogeneration assets, and operational flexibility create tools to manage ERCOT volatility.

Primary Exposure for Industrial Customers		
Risk	**Why It Matters**	**Relevance to Houston Customers**
Scarcity pricing	The $5,000/MWh cap can flow into unhedged or partially hedged exposure during tight reserve intervals.	Large industrial loads consume enough power for short-duration price spikes to have material cost impact.
Operational outages	Shutdown, restart, safety, and lost-production costs can exceed the commodity price impact of the power event itself.	Petrochemical, refining, LNG, and advanced manufacturing facilities often require continuous operations.
Congestion & deliverability	ERCOT-wide generation additions may not resolve local Houston Load Zone constraints if power cannot reach critical load pockets.	Houston's industrial base depends on deliverable reliability, not just total ERCOT-wide capacity additions.
Load growth uncertainty	Data centers and large industrial projects can tighten market conditions even if only part of the queue materializes.	Houston industrials share ERCOT-wide grid capacity with new large loads racing to secure interconnection.

Customer-Side Response Levers		
Lever	**Practical Application**	**Strategic Value**
Contracting scale	Use long-term offtake, bilateral contracts, hedges, and structured PPAs to improve supply certainty.	Can reduce price exposure while helping new generation projects become financeable.
On-site resources	Deploy or optimize cogeneration, backup generation, storage, and microgrid-style resilience for critical operations.	Reduces dependence on grid-only reliability during scarcity or weather-driven events.
Flexible operations	Identify curtailment windows, load-shifting opportunities, maintenance timing, and emergency operating protocols.	Converts operational flexibility into a reliability and cost-management tool.
Market participation	Aggregate flexible load into demand response, ancillary services, or future reliability products.	Creates system value while potentially monetizing flexibility that is currently underutilized.

Implication for Houston Industrial Customers: Houston industrial customers' scale creates exposure to scarcity pricing, congestion, and reliability events, but it also gives them tools to manage ERCOT volatility. By pairing contracting scale, cogeneration, backup generation, storage, and flexible operations, Houston industrials can reduce outage risk while creating system value through demand.

Sources: ERCOT Load Resource program materials; Potomac Economics 2024 State of the Market Report for ERCOT; ERCOT market rules.

Houston's Position in ERCOT Growth

Houston can support credible industrial and data center growth while protecting reliability and industrial competitiveness through disciplined planning, flexible demand, and targeted infrastructure investment.

1. VALIDATE LOAD

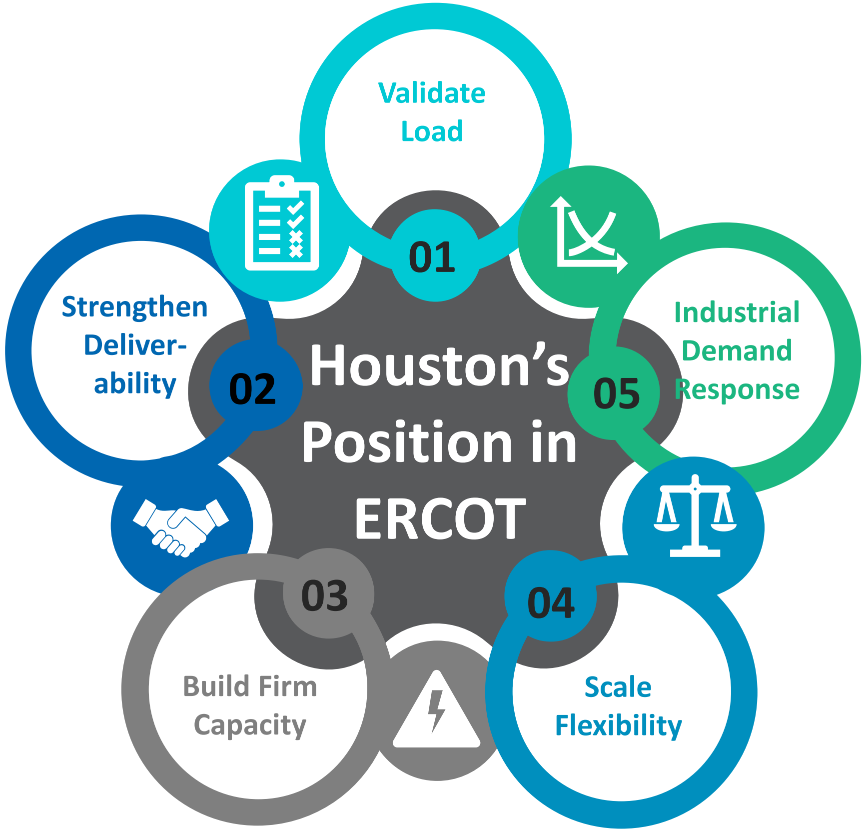
Houston can strengthen its ERCOT growth case by ensuring new industrial load is supported by **substantiated demand documentation**. This helps **separate committed load from speculative interconnection activity** and **reduces the risk of transmission upgrades driven by phantom demand**. This is especially important given Houston's concentration of industrial, port, petrochemical, data center, and electrification-related demand.

2. STRENGTHEN DELIVERABILITY

Houston's growth depends not only on new generation, but also on **delivering power to key load pockets**. Targeted transmission investment in the Houston Load Zone can **reduce congestion, improve generation access, and support growth around the Ship Channel and industrial corridors**. Houston's Load Zone benefits from proximity to Gulf Coast generation assets and established industrial-grade infrastructure, giving advanced manufacturers and hyperscalers more confidence in power availability at scale.

3. BUILD FIRM CAPACITY

As Houston-area load grows, ERCOT will need more firm and dispatchable capacity to support reliability during peak-risk hours. **Continued deployment of Texas Energy Fund projects** can help add resources available when intermittent generation or imports are constrained. For Houston, firm capacity is critical because industrial customers require high reliability and have limited tolerance for curtailment or outages.



5. ACTIVATE INDUSTRIAL DEMAND RESPONSE

Houston can close a key reliability gap by aggregating large industrial customers into ERCOT demand response programs. Industrial demand response can provide **a faster reliability resource than new-build generation or transmission** where customers have operational flexibility or backup systems. Greater participation can reduce peak-risk exposure, lower system stress, and strengthen Houston's reliability narrative for industrial growth.

4. SCALE FLEXIBILITY

Houston's industrial base creates a strong opportunity to scale flexible load solutions, **including storage, behind-the-meter generation, curtailment, and load shifting.** These resources can help customers manage power cost exposure while supporting ERCOT during tight supply conditions. For data centers and advanced manufacturers choosing between Houston and competing markets like DFW, the ability to pair load flexibility with access to industrial-grade power and competitive land and utility costs provides a meaningful total cost of ownership advantage.

Source: ERCOT

F. Senate Bill 6 Policy Assessment

Executive Summary: Senate Bill 6

SB 6 creates a more transparent framework for integrating large-load growth into grid planning by clarifying demand signals, assigning infrastructure costs to their sources, and enabling more informed investment and reliability decisions.

Demand Becomes Explicit in System Planning

- SB 6 brings large industrial demand into the grid planning process earlier and more transparently.
- This shifts planning away from assumptions and toward a clearer understanding of when and where large loads are expected to materialize.

Grid Impacts Are Clearly Assigned

- The legislation ties the cost of interconnection and grid impacts more directly to the loads that create them.
- This clarifies financial exposure and changes how large energy users evaluate grid-based versus on-site solutions.

Infrastructure Trade-Offs Become Visible

- With demand timing and cost responsibility defined, different infrastructure pathways can be compared more directly.
- Transmission upgrades, on-site generation, and demand-side resources can be evaluated on similar footing.

Demand-Side and Clean Options Gain Traction

- Long-duration storage, flexible load, and on-site generation become part of the economic decision set rather than peripheral tools.
- These options become more credible as substitutes for traditional wires or peaking resources when grid costs rise.

Reliability Is Shared, Not Centralized

- SB 6 formalizes a limited role for demand-side reliability during system stress while preserving normal operational autonomy.
- This recognizes that large industrial loads can support reliability without being continuously operated by the grid.

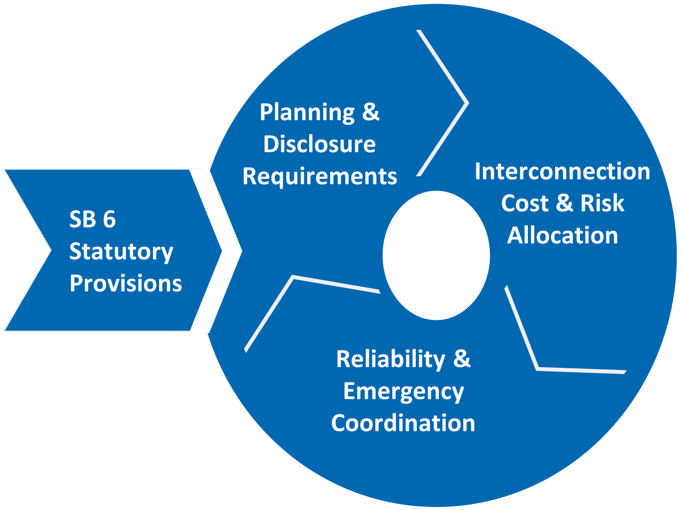
Supports Efficient Infrastructure Investment

- SB 6 provides clearer demand signals and cost responsibility help to utilities, generators, and large customers to make better-informed investment decisions.
- Incentivizes a broad set of economically competitive reliability solutions, including generation, storage, flexible load, and on-site resources.

Overview of Texas Senate Bill 6 ("SB 6") Policy

SB 6, enacted June 2025, establishes a structured planning and cost-allocation framework for large loads (>75 MW) in ERCOT, strengthening interconnection discipline to support reliability and reduce infrastructure-related risk for large industrial projects.

Overview of Texas Senate Bill 6 Policy



1 Planning & Disclosure Requirements

- Directs the Public Utility Commission of Texas ("PUCT") to establish uniform planning standards for large load interconnections in ERCOT.
- Applies to new or expanded interconnections above a defined threshold (>75 MW).
- Requires large load customers to disclose substantially similar interconnection requests inside or outside Texas that could materially alter or delay the proposed project.
- Standards are explicitly required to support business development while minimizing stranded infrastructure costs.

2 Interconnection Cost & Risk Allocation

- Requires large load customers to contribute to the recovery of reasonable interconnection and transmission costs incurred by the servicing utility.
- Applies consistently across investor-owned utilities, municipal utilities, and electric cooperatives.
- Clarifies that costs associated with serving large, incremental loads should not be broadly socialized to existing customers.

3 Reliability & Emergency Coordination

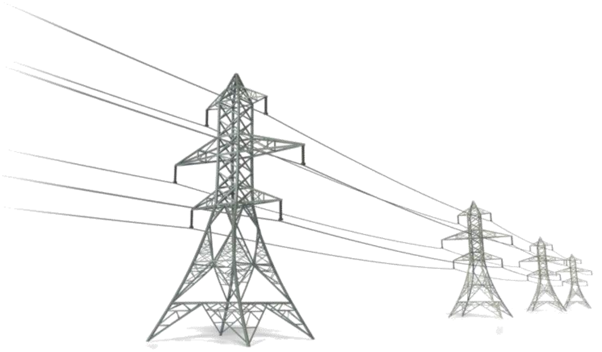
- Expands ERCOT and PUCT authority to coordinate with or direct certain large loads during grid emergencies, under defined conditions.
- Applies primarily to new or expanded large loads and specific co-located configurations capable of serving at least 50% of on-site demand.
- Limits intervention to before or during emergency periods and after market-based tools are exhausted, preserving ERCOT's market design by restricting intervention to narrow reliability circumstances.

Sources: SB-6, Baker Botts, Balch & Bingham, McGuireWoods

Hardened Resilience for Houston's Infrastructure

In the wake of Winter Storm Uri, Texas formalized its reliability planning during the 89th Legislative Session with the passage of Senate Bill 6. SB 6 allowed additional approved financing to support new dispatchable power plants as they move toward operation.

Energy-Only Market



Before 2021, Texas operated as an energy-only market. If there was a shortage, prices spiked, which was supposed to "signal" companies to build more plants.

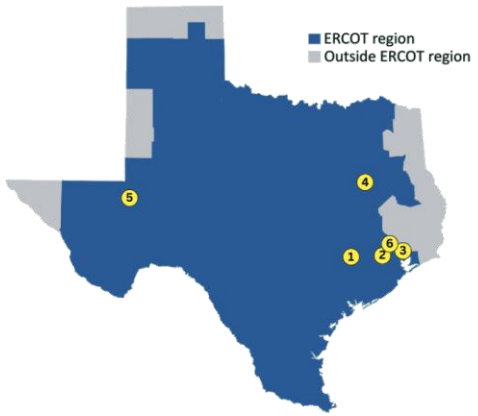
- **The Flaw:** This system didn't account for extreme, once-in-a-decade weather events.
- **The Result:** During Winter Storm Uri in February 2021, ERCOT faced severe reliability challenges due to multiple factors, including limited dispatchable capacity availability, widespread weather-related outages, and insufficient winterization across parts of the power and fuel supply system.

SB 6: Policy Support Role

Introduced during the 88th and passed in the 89th Legislative Session, Senate Bill 6, fundamentally changed how Texas ensures grid reliability.

- **Focus:** Planning for large electric loads, interconnection standards, stranded-cost protection, transmission cost allocation review, and large-load demand management / curtailment.
- **Funding:** SB 6 can make the grid environment more favorable for the kinds of reliability-oriented generation investments that Texas Energy Fund ("TxEF") (passed in Senate Bill 2627) was trying to finance.

April 2026: Turning on the Lights



As of April 2026, SB 6 has enabled the TxEF program to deploy capital for multiple multi-billion-dollar construction projects.

- **Loan Distribution:** As of April 10th, the PUC has already approved 6 loans equating to over $2.65 billion for new natural gas generation, with 8 more in review.
- **Upcoming Capacity:** Approximately 3,564 MW of new power is currently under development through these loans. For instance, NRG Energy's 456 MW gas plant in Houston began operations in 2026.

Sources: SB-6, Attorney General, TxEF, PUC

Long-Term Competitiveness, Resilience, and Grid-Responsive Growth

SB 6 positions large-load growth as a managed grid asset by tying cost responsibility, on-site flexibility, and resilience planning to ERCOT reliability needs.

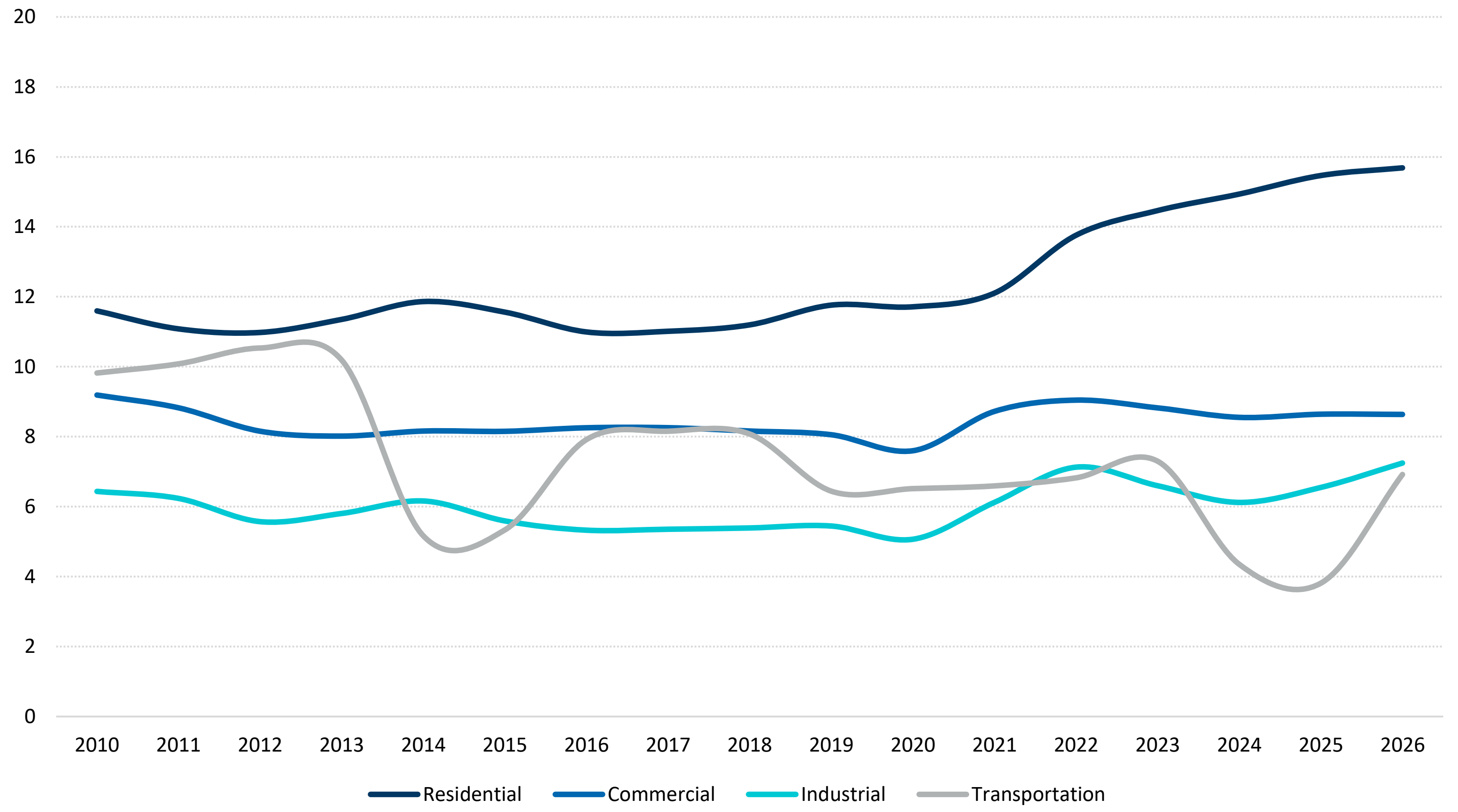
	SB 6 Rule	Houston / Gulf Coast Effect
Competitiveness	SB 6 requires the Public Utility Commission ("PUCT") to establish explicit planning and interconnection standards for large loads (≥75 MW), with the stated purpose of minimizing stranded infrastructure costs while maintaining reliability.	■ **Predictable cost exposure:** Large industrial customers are required to disclose load size and timing earlier in the process, enabling utilities to plan more proactively and reducing the risk of unexpected transmission upgrades or broader cost recovery. ■ **Cost causation alignment:** SB 6 amends Section 35.004 to assign interconnection costs more directly to the large loads that create them, limiting cross-subsidization while creating a clearer economic signal for demand-side solutions such as on-site generation, storage, and flexible operations. ■ For Houston's power-intensive industries, SB 6 can support competitiveness by improving large-load planning, increasing cost transparency, and encouraging investments that reduce grid impacts and long-term power cost exposure.
Resilience	Under Section 37.0561, ERCOT may direct certain large loads with on-site generation to deploy that capacity or curtail demand during grid emergencies, bringing new industrial loads into formal reliability planning rather than leaving them outside coordinated system control.	■ **Emergency-only ERCOT authority:** ERCOT may direct certain large loads with on-site resources to curtail or self-supply during grid emergencies, after market tools have been exhausted. ■ **Recognition of on-site resources ≥50% of load:** SB 6 formally recognizes behind-the-meter resources that serve a majority of load, even if they do not export power, bringing them into planning without requiring wholesale market participation. ■ For Houston's industrial facilities, this makes resilience more formalized and grid-responsive. On-site resources can become part of a defined reliability framework, helping reduce exposure to heatwaves, storms, and system stress events.
Grid-Responsive Growth	SB 6's Section 37.0561 requires large-load planning to minimize stranded infrastructure costs while maintaining reliability, supporting more orderly industrial growth through demand-side and behind-the-meter resources.	■ **Demand-side solutions are prioritized:** By making large loads financially responsible for grid impacts, SB 6 strengthens the case for on-site generation, storage, efficiency, and flexible operations that can reduce peak-driven infrastructure needs. ■ **Flexible resources align with reliability requirements:** SB 6 supports more orderly growth across Houston and the Gulf Coast by requiring large loads to align interconnection investments with credible demand while enabling flexible demand and behind-the-meter generation to help meet ERCOT reliability needs. ■ For Houston and the Gulf Coast, this creates a pathway where industrial growth, reliability, and potential decarbonization objectives can be better aligned.

Sources: SB 6, ERCOT, UT

Protecting Industrial Cost-Competitiveness

From the 89th Legislative session, SB 6 Section 39.170 shifts grid reliability from price spikes onto planned demand reductions, ensuring large power users help stabilize the system instead of passing costs onto residential customers.

Historical Texas Electricity Rates (¢/kWh)



Key Commentary

- Historically, ERCOT has dealt with steady, predictable growth. However, starting in 2022, there was an unprecedented surge in Large Flexible Loads, primarily driven by Bitcoin miners and massive AI data centers.
- Prior to 2021, average residential rates were roughly 11.3¢ per kWh. Now, in 2026, rates have climbed to over 15.5¢ per kWh, 26.65% increase in the span of five years, compared to that of industrials which saw a 16.93% increase.
- Before SB 6, large new customers like data centers could keep using power during grid emergencies, while homes were shut off or prices skyrocketed. Section 39.170 ensures new large customers can be turned down or off when the grid is under stress.
- SB 6 gives ERCOT the authority to treat large-load demand response as a planned, enforceable reliability tool instead of something driven by extreme prices. The Large Load Demand Management Service puts that authority into practice.
- The impacts of this authority to ERCOT could be far-reaching. The ability to avoid rate surges delivers a clear advantage to large load customers compared to other markets, enabling more reliable and affordable OPEX planning.
- Similarly, ERCOT's ability to attract customers with predictable pricing empowers it to better forecast and allocate future transmission investment in an impending and significant load growth climate.

Sources: EIA, SB 6

Overview of Broader Lessons Learned

SB 6 aligns reliability and affordability by ensuring large loads internalize the grid costs they create, making behind-the-meter generation, storage, and demand flexibility the lower-risk path to both cost control and clean energy goals.

Reliability Driver | Decarbonization Driver | Dual Driver

Planning Transparency Is a Prerequisite for Clean Infrastructure

- **SB 6 Provision:** §35.004(b) — Mandatory load disclosure and forecasting for large industrial customers (≥75 MW).
- **Overview:** SB 6 demonstrates that credible load disclosure and forecasting must come before incentives or mandates.
- **Implication:** Future decarbonization policies, especially for long-duration storage and clean firm generation, should anchor eligibility and cost recovery to transparent, verifiable planning inputs rather than assumed demand growth. Policies that rely on assumed demand growth increase regulatory and utilization risk, while those anchored in verifiable planning inputs provide more bankable revenue frameworks.

Cost Causation Can Drive Decarbonization

- **SB 6 Provision:** §35.004(c-1) — Causation-based allocation of transmission upgrade costs to triggering loads.
- **Overview:** By assigning interconnection costs to the loads that create them, SB 6 changes investment behavior without direct subsidies.
- **Implication:** LDES and demand-side flexibility become complementary tools to transmission and clean generation by helping manage peak demand, reduce infrastructure needs, and improve clean energy integration. Because SB 6 requires large loads to internalize certain transmission upgrade costs, it may improve the investment case for behind-the-meter generation, storage, and demand-side flexibility by turning avoided grid spend into a more direct cost-savings driver.

Non-Exporting Storage Must Be Policy-Recognized to Scale

- **SB 6 Provision:** §35.006(d) — Limits ERCOT dispatch authority over non-exporting on-site storage to grid emergencies only.
- **Overview:** SB 6 explicitly recognizes non-exporting on-site resources and limits ERCOT control to emergencies.
- **Implication:** Future LDES policies should preserve operational autonomy, avoid forcing market participation prematurely, and align dispatch authority strictly with reliability need. Because SB 6 clarifies that non-exporting storage is not subject to routine market dispatch, it eliminates a key source of regulatory uncertainty that has historically discounted LDES valuations and constrained scale deployment.

Technology Neutrality Preserves Innovation Pathways

- **SB 6 Provision:** §35.007 — Fuel- and technology-neutral reliability obligation framework for new large loads.
- **Overview:** SB 6's refusal to pick fuels or technologies ensures that reliability obligations can be met with evolving solutions rather than legacy capacity.
- **Implication:** As Texas considers clean firm generation, and long-duration storage, SB 6 suggests that governance and planning rules should precede technology-specific programs. Because SB 6 avoids prescribing fuels or technologies, it preserves real option value for investors, enabling capital to rotate toward advanced thermal, LDES, or hybrid solutions as cost curves mature, rather than being stranded in policy-favored assets.

Sources SB 6, ERCOT, UT

Resources

Section A: Competitiveness & Market Position

1) Electric Reliability Council of Texas. *ERCOT Reports and Market Data*. ERCOT.
2) StateScoop. *Texas Energy, Grid, Cybersecurity, and Infrastructure Coverage*. StateScoop.
3) Texas Scorecard. *Texas Energy and Grid Reliability Coverage*. Texas Scorecard.
4) U.S. Department of Energy. *United States Energy and Employment Report*. U.S. Department of Energy.
5) University of Houston. *Energy University Economic Impact and Workforce Materials*. University of Houston.
6) University of Texas at Austin. *McCombs School of Business MBA Employment Report*. University of Texas at Austin.
7) Texas A&M University. *Petroleum Engineering Program Degree and Ranking Materials*. Texas A&M University.
8) Rice University. *Master of Energy Economics Program Materials*. Rice University.
9) Community Impact. *Texas Data Center, Energy Demand, and Infrastructure Coverage*. Community Impact.
10) Federal Energy Regulatory Commission (FERC). *Electric Power Markets*
11) Potomac Economics. *State of the Market Report*
12) Midcontinent Independent System (MISO). *Market Participation Overview*
13) Modo Energy. *MISO Capacity Market BESS*
14) Syso Technologies. *MISO Capacity Auction Results*
15) Southwest Power Pool (SPP). *Market Design Overview*
16) U.S. Energy Information Administration (EIA). *Monthly Wholesale Update*

Section A: Competitiveness & Market Position (Cont.)

17) California Independent System Operator. (CAISO). *Benchmarking against NYISO, PJM & ISO-NE*

18) Entergy Texas. *Step ahead*

19) Berkeley Lab. *Interconnection Queue Dataset & Summarized Data Files, through 2025*

20) U.S. Bureau of Labor Statistics. *Electricians*

21) The Fabricator., The Welder. *"Outlook, trends, and pay for the welding workforce according to AWS data"*

22) U.S. Energy & Employment Report. 2024 & 2025

23) Houston Public Media. *"Texans struggle to recover from disasters because of construction worker shortage survey finds"*

24) Baker Botts. *"Texas Senate Bill 6: Understanding the Impacts to Large Loads and Co-Located Generation"*

Section B: Demand Response Economics & Market Impact

1) Potomac Economics. *State of the Market Reports for the ERCOT Electricity Markets (annual editions 2018-2024). Potomac Economics, Ltd.*
2) Potomac Economics. *ERCOT Nodal Monthly Reports and IMM Quarterly Reports (2024-2025). Potomac Economics, Ltd.*
3) Electric Reliability Council of Texas. *Summer 2025 Operational and Market Review. ERCOT, September 15, 2025.*
4) Electric Reliability Council of Texas. *NCLR Registration Data, 4CP Methodology Documentation, and LFLTF Status Updates. ERCOT.*
5) Electric Reliability Council of Texas. *Load Resource Overview and Changes Introduced With RTC+B. ERCOT, July 2025*.
6) U.S. Energy Information Administration. *Short-Term Energy Outlook. U.S. Department of Energy, September 2024.*
7) Public Utility Commission of Texas. *Texas Senate Bill 6 and PURA Section 39.360. State of Texas, enacted June 2025.*
8) Riot Platforms, Inc. Annual Report (Form 10-K) and FY 2025 Earnings Release. Riot Platforms, Inc.
9) Ascend Analytics. *Understanding the ERCOT Contingency Reserve Service (ECRS). Ascend Analytics, February 2024.*
10) GridStatus. *Predicting Coincident Peaks in ERCOT's 4CP Program. GridStatus, July 2025.*
11) Modo Energy. *ERCOT Battery Energy Storage Systems and Ancillary Service Analysis. Modo Energy.*
12) Baker Botts L.L.P.. *Bitcoin and Large Loads in ERCOT. Baker Botts, April 2023.*
13) Yes Energy. *Exploring Complex ERCOT Load Growth Dynamics. Yes Energy, February 2026.*
14) Texas Blockchain Council. *Large Flexible Load Task Force Briefing. Texas Blockchain Council, September 2022.*

Section C: Interconnection Performance & Infrastructure Readiness

1) Electric Reliability Council of Texas. *Greater Houston Partnership Energy Initiative Presentation*. ERCOT, 3 Mar. 2026.
2) Electric Reliability Council of Texas. *Long-Term Load Forecast Update (2025–2031) and Methodology Changes*. ERCOT, 2026.
3) Electric Reliability Council of Texas. *ERCOT Interconnection Queue and Large Load Queue Data*. ERCOT, 2025–2026.
4) Electric Reliability Council of Texas. *Generator Interconnection or Modification (GIM) Milestone Status Report*. ERCOT, 2025–2026.
5) Berkeley Lab. *Interconnection Queue Dataset & Summarized Data Files, through 2025*
6) Midcontinent Independent System (MISO). *Long Range Planning*
7) Modo Energy. *MISO Interconnection Queue for Battery Storage*
8) Carbon Direct. *“New analysis of power grid interconnection queues in PJM and ERCOT”*
9) Berkeley Lab. *Interconnection Queue Dataset & Summarized Data Files, through 2025*
10) Midcontinent Independent System (MISO). *Generator Interconnection Queue Improvement PAC 2023-2026*
11) Midcontinent Independent System (MISO). *Large Load Additions*
12) Insidelines Pennsylvania – New Jersey – Maryland (PJM). *2025 Year in Review*
13) Insidelines Pennsylvania – New Jersey – Maryland (PJM). *“PJM Board Outlines Plans to Integrate Large Loads Reliably”*

Section D: Reliability Assessment

1) Electric Reliability Council of Texas. *Capacity, Demand and Reserves Report*. ERCOT, 2015–2025.
2) Electric Reliability Council of Texas. *ERCOT Monthly Outlook for Resource Adequacy (MORA)*. ERCOT, 2022–2026.
3) Electric Reliability Council of Texas. *ERCOT Monthly Outlook for Resource Adequacy (MORA)*. ERCOT, Jan. 2025–July 2026.
4) Electric Reliability Council of Texas. *ERCOT Reserve Margin Study Report*. ERCOT, 2020.
5) Electric Reliability Council of Texas. *ERCOT Summary, Tables 1–2*. ERCOT, Jan. 2026.
6) Electric Reliability Council of Texas. *ERCOT Winter Weather Readiness*. ERCOT, 2025.
7) Electric Reliability Council of Texas. *ERCOT 2025–2026 Winter Reliability Assessment*. ERCOT, 2025.
8) Midcontinent Independent System Operator. *MISO Annual LOLE Study*. MISO, 2024–2026.
9) Midcontinent Independent System Operator. *MISO Planning Resource Auction*. MISO, 2024–2026.
10) Midcontinent Independent System Operator. *MISO Regional Resource Assessment (RRA)*. MISO, 2024.
11) Midcontinent Independent System Operator. *MISO Summary, Tables 1–2*. MISO, Jan. 2026.
12) North American Electric Reliability Corporation. *Long-Term Reliability Assessment*. NERC, Jan. 2026.
13) Potomac Economics. *2024 State of the Market Report*. Potomac Economics, 2024.
14) North American Electric Reliability Corporation. *2024 Reliability Performance and Regional Risk Assessment*. NERC, 2024.

Section E: Industrial Load Growth & Generation Investment Dynamics

1) Electric Reliability Council of Texas. *Yearly Peak Demand Records*. ERCOT.
2) Electric Reliability Council of Texas. *Large Load Interconnection Status Updates*. ERCOT.
3) Electric Reliability Council of Texas. *Board Materials*. ERCOT.
4) Electric Reliability Council of Texas. *2025 Long-Term Load Forecast Materials*. ERCOT, 2025.
5) Electric Reliability Council of Texas. *Capacity, Demand and Reserves Report*. ERCOT.
6) Electric Reliability Council of Texas. *ERCOT GIS and Resource Adequacy Materials*. ERCOT.
7) Electric Reliability Council of Texas. *Load Resource Program Materials*. ERCOT.
8) Electric Reliability Council of Texas. *ERCOT Market Rules*. ERCOT.
9) Energy Information Administration. *Form EIA-860*. U.S. Energy Information Administration.
10) Energy Information Administration. *Electric Power Monthly*. U.S. Energy Information Administration.
11) Potomac Economics. *2024 State of the Market Report for the ERCOT Electricity Markets*. Potomac Economics, 2024.
12) Public Utility Commission of Texas. *Texas Energy Fund Materials*. PUCT.
13) Office of the Texas Governor. *Texas Energy Fund Project Announcements*. Office of the Texas Governor.

Section F: Senate Bill 6 Policy Assessment

1) Balch & Bingham LLP. *Texas Senate Bill 6 Policy and Regulatory Analysis*. Balch & Bingham LLP.
2) Baker Botts LLP. *Texas Senate Bill 6 Policy and Regulatory Analysis*. Baker Botts LLP.
3) Electric Reliability Council of Texas. *ERCOT Reliability, Planning, and Large Load Materials*. ERCOT.
4) McGuireWoods LLP. *Texas Senate Bill 6 Policy and Regulatory Analysis*. McGuireWoods LLP.
5) Office of the Attorney General of Texas. *Texas Senate Bill 6 and Grid Reliability Materials*. Office of the Attorney General of Texas.
6) Public Utility Commission of Texas. *Texas Energy Fund Materials*. PUCT.
7) Texas Legislature. *Senate Bill 6*. 89th Legislature, 2025.
8) University of Texas at Austin. *Energy Policy and Texas Grid Materials*. University of Texas at Austin.
9) U.S. Energy Information Administration. *Electricity Data and Historical Texas Electricity Rate Materials*. EIA.
10) Public Utility Commission of Texas. *Texas Energy Fund Materials*. PUCT.
11) Collaborative Optimization & Management of Power Allocation – Surface & Subsurface strategies (COMPASS). *SB6 Explained Section by Section*
12) Electric Choice. *Electricity Prices by State – Texas*
13) Electric Reliability Council of Texas. *89th Legislative Session April 2026 Status*

Experts with Impact™

FTI CONSULTING™