

A Day In the Life of ERCOT

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Executive Summary – A Day in the Life of ERCOT

Understanding Reliability Through Dispatch-Level Insights

This report departs from traditional market reviews by examining **11 operational days** in the Electric Reliability Council of Texas (ERCOT) region—each selected to illustrate grid behavior under stress, normalcy, or transition. Instead of relying solely on monthly averages or aggregate metrics, it walks through what **ERCOT operators and generators see in real time**—when to ramp, when to hold, when to call reserves—and how price signals align (or don't) with grid needs.

For quick reference, key terms used in this report are defined in [Appendix A](#).

Key Takeaways

1. Price Formation Gaps Persist

Real-time locational marginal prices (LMPs) do not always reflect actual operational tightness. On some days, prices spike without scarcity alerts; on others, prices stay calm despite extreme dispatch needs. ERCOT's growing reliance on ancillary services and conservative operations may be masking stress behind stable prices — suggesting that headline market prices alone no longer fully reflect the system's reliability risks.

2. Net Load Drives the Modern Grid

Ramping needs around sunrise and sunset now define system stress more than peak demand. Grid planning and market design should evolve to prioritize **timing and flexibility**, not just capacity.

3. Thermal Generation Remains Critical

Natural gas-fired units remain the backbone of ERCOT reliability—flexibly backing off during surplus and surging during net load ramps. This role deserves more explicit recognition in reliability metrics — for example, incorporating flexibility and reserve contributions alongside energy adequacy — and in market design to ensure transparent, efficient compensation for these services.

4. Scarcity Replaced by Silent Costs

Few days triggered scarcity pricing in 2024–2025. But costs have shifted into **ancillary services, pre-contingency commitments**, and **uplift charges**, which stabilize the system invisibly but add expense.

5. Curtailment Is the New Risk

Negative or near-zero prices from oversupply appeared more often than scarcity events, underscoring how abundant renewable generation and required levels of dispatchable capacity can together depress prices, even as reliability risks persist elsewhere in the system. Oversupply now poses a coordination and investment risk, especially in shoulder seasons.

Policy Implications

- **Texas Energy Fund (TEF):** Operational improvements in 2024–2025 occurred before TEF-backed resources entered service. ERCOT has since identified multiple TEF-supported projects—including Kerrville (122 MW), NRG Wharton (456 MW), Rock Island Generating (Colorado County), and two Calpine Freestone peakers—that are slated to come online beginning in 2026–2027. Policymakers

should distinguish between stability already achieved and the future contributions these TEF projects are designed to deliver.

- **Performance Credit Mechanism (PCM):** Although the \$1 billion-per-year PCM has been tabled, PCM-type constructs could re-emerge under a different name or framing if conditions change (e.g., extreme load growth, political pressure after a future event). Policymakers should ask whether future mechanisms add real reliability value—or simply duplicate what the market is already delivering.
- **HB 3356 Lessons:** HB 3356’s retroactive firming requirements were based on static 2023 modeling. By mid-2025, system behavior had already shifted. This underscores the need for evidence drawn from dispatch-based behavior, not backward-looking averages, in policymaking.

Preface

Texans usually think about electricity at two moments: when the power goes out, and when their bills go up. For policymakers, however, understanding why those moments occur—and how they might be prevented—requires navigating a web of complex data, operational decisions, and system constraints. On any given day, identifying cause and effect in ERCOT’s grid can be daunting. Technical analysis often blurs into anecdote or finger-pointing, especially when the stakes are high and transparency is limited.

This report is written for a broad audience: policymakers, regulators, large electricity consumers, and industry stakeholders who need a clearer view of how ERCOT’s grid operates in practice. It is intended as a complement to the Independent Market Monitor’s annual State of the Market reports—less about averages and long-term metrics, and more about how the system actually performs under real-time stress.

This white paper by the Texas Oil and Gas Association (TXOGA) aims to make ERCOT’s operations more tangible. Instead of focusing on abstractions or system-wide averages, we examine real days in ERCOT’s recent history—some routine, others turbulent, and a few unexpectedly revealing. These case studies highlight how the grid actually works in practice. Looking through the eyes of both operators and generators, we seek to clarify what has changed, what is working, and where policy attention should turn next.

Our perspective is shaped by the fact that TXOGA members are among the state’s largest electricity consumers. Reliability and cost cannot be treated as tradeoffs—they are dual imperatives. The lessons from ERCOT’s daily operations show that transparency, efficiency, and flexibility are just as critical to affordability as they are to keeping the lights on.

This is not a technical manual. It is a practical narrative grounded in ERCOT data and informed by real-world experience. Our goal is to provide clear, data-driven insights into how Texas’ electricity market functions, how it is evolving, and what is required to secure a future that is reliable, resilient, and affordable.

For readers less familiar with ERCOT’s terminology, Appendix A includes a glossary of key market and reliability terms for quick reference.

Chapter 1: A Normal Day in the Life of ERCOT

On June 22, 2025, Texans flipped on lights, cranked up air conditioners, and powered industrial facilities across the state—relying on the ERCOT grid to deliver electricity seamlessly. The day was hot but not extreme, busy but not volatile. In fact, it was exactly the kind of day ERCOT is built to handle—quietly, reliably, and efficiently.

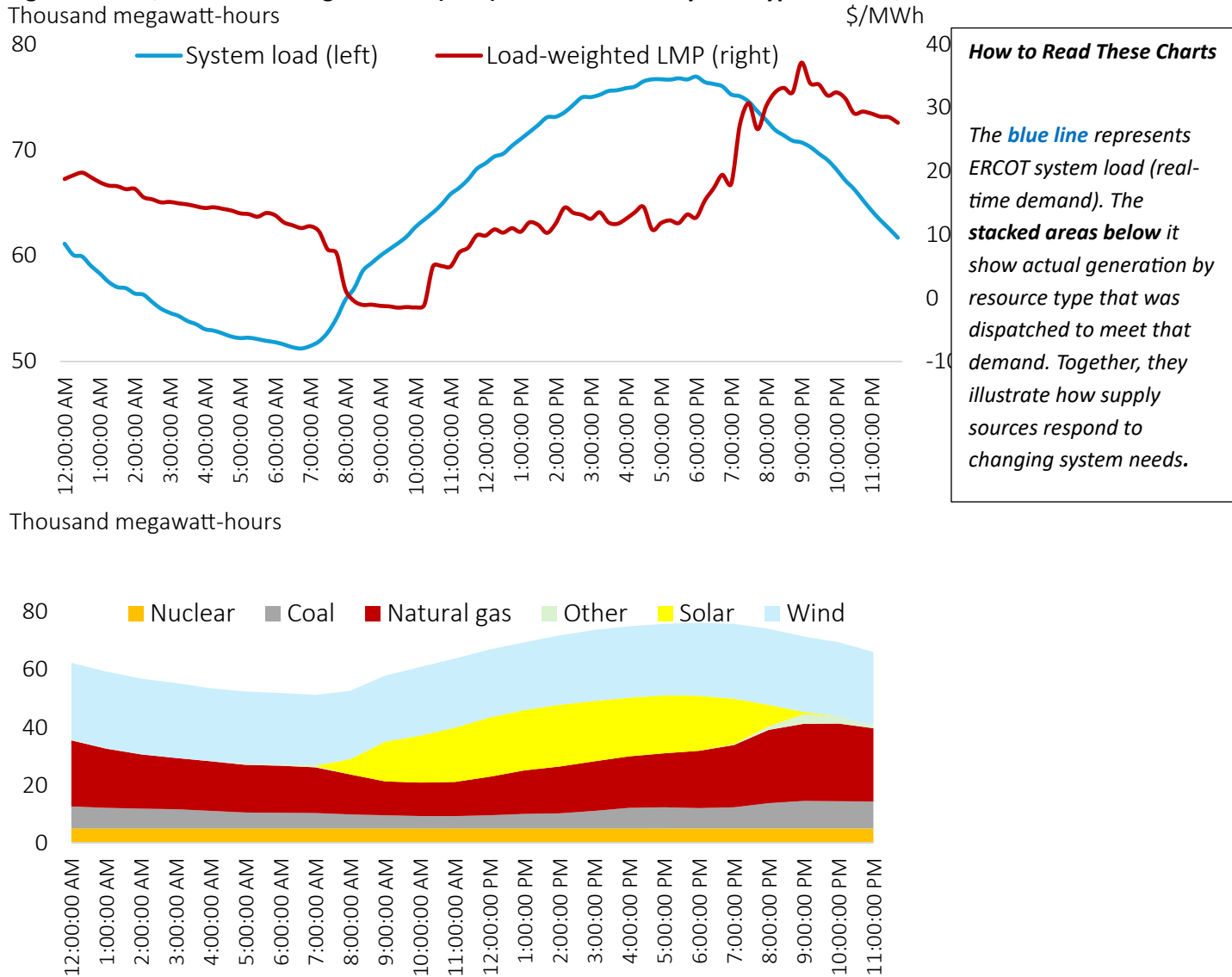
And yet, by historical standards, it was far from ordinary. Evening load approached 77,000 MW—a level that would have been a record-setting summer peak just four years earlier. Still, prices remained low, volatility was minimal, and no grid alarms were triggered. What made the day notable was precisely its normalcy.

Midnight to Sunrise (00:00 – 06:00)

Demand eased from about 61,000 MW to 52,000 MW. Wind provided a steady 26% of total load, while nuclear and coal output held constant. Natural gas units cycled down from roughly 23% to 20% of generation as solar had not yet begun producing.

This mix allowed ERCOT to keep gas units partially online, positioned to ramp later as needed. With reserves sufficient and variability low, real-time prices hovered between \$15–20/MWh—free of scarcity adders.

Figure 1. Load, Locational Marginal Price (LMP) and Generation by Fuel Type: June 22, 2025²



² All data shown are from ERCOT public extracts unless otherwise noted. Load is taken from EIA's hourly ERCOT series, since hub-level loads in ERCOT's SCED reports do not reconcile exactly to the system total. ERCOT's Physical Responsive Capability (PRC) and System Lambda track closely with the hub-weighted LMPs shown here and are not graphed separately to avoid redundancy and scale distortion, though they are considered in the discussion.

Morning Ramp (06:00 – 10:00)

As Texans started their day, load climbed past 60,000 MW. Wind output dipped slightly, but solar ramped up quickly after sunrise, enabling natural gas generation to flex downward for stability. By 10:00 a.m., gas provided only about one-fifth of ERCOT generation, down from nearly 40% overnight.

ERCOT's Security-Constrained Economic Dispatch (SCED) managed this handoff every five minutes, dispatching the lowest-cost mix while maintaining reserves. Load and generation tracked closely, with less than 1.5% average deviation—showing minimal real-time balancing pressure.

Midday Plateau (10:00 – 16:00)

Load leveled just above 70,000 MW, supported by one of the most balanced generation mixes of the day:

- Solar peaked at roughly 30% of generation.
- Wind contributed around 35%.
- Natural gas filled in flexibly and provided reserves.

The renewable share reached nearly 67%, illustrating how ERCOT can leverage favorable weather and resource diversity. Despite high demand, prices stayed below \$15/MWh. No reliability events or interventions occurred.

Evening Ramp (16:00 – 21:00)

As solar declined sharply, load climbed toward its peak near 77,000 MW between 5:00 and 6:00 p.m. Wind remained strong, still supplying more than 25% of generation into the evening.

Gas plants ramped to cover the net load, keeping the system balanced. Prices rose modestly into the \$25–35/MWh range but remained far below scarcity thresholds. Ancillary services were adequate, and no emergency actions were required.

Nightfall (21:00 – 24:00)

As demand fell back toward 65,000 MW, wind output held steady while gas units cycled down. With temperatures easing and system stress receding, ERCOT operators began releasing some ancillary service obligations. Prices settled in the mid-\$20s/MWh.

What June 22 Tells Us

This was a quiet success story — a day when steady baseload, flexible ramping, and well-positioned reserves kept the system balanced:

- Prices remained modest.
- Wind and solar delivered steadily.
- Natural gas provided reliability and ramping support.
- Nuclear and coal provided steady baseload support, with little variation across the day.
- Ancillary services were pre-positioned and sufficient.

- Forecasts aligned with actual conditions.
- No emergency interventions were required.

June 22, 2025, shows how ERCOT’s energy-only market—supported by a balanced mix of renewables, flexible natural gas, and steady baseload—can meet high summer load with both affordability and resilience. It was a textbook example of reliability in practice.

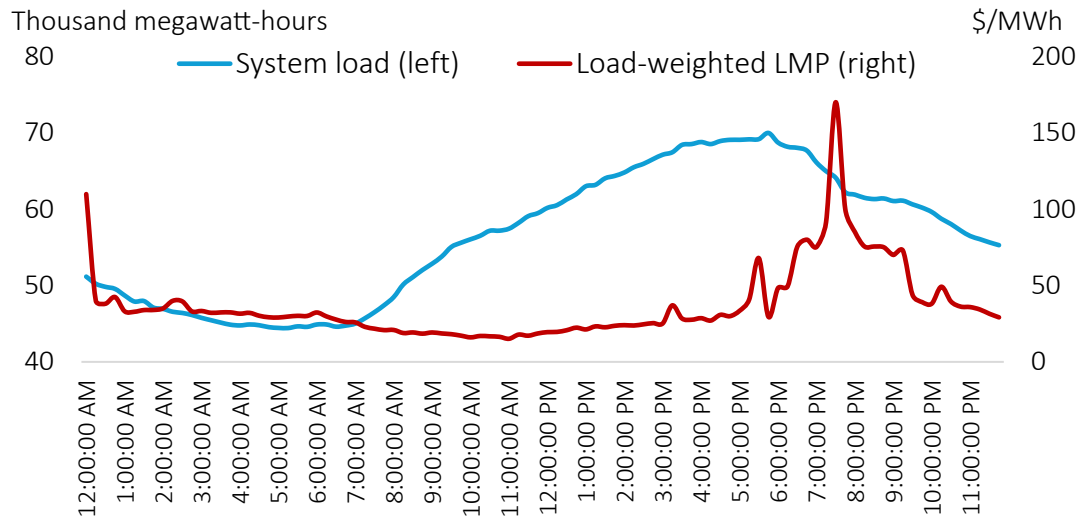
Chapter 2: When Flexibility Defines Normal

In Chapter 1, we saw ERCOT at its most stable: a high-load summer day balanced by strong renewable output, with dispatchable generation quietly supporting system flexibility. But not every “normal” day looks like that.

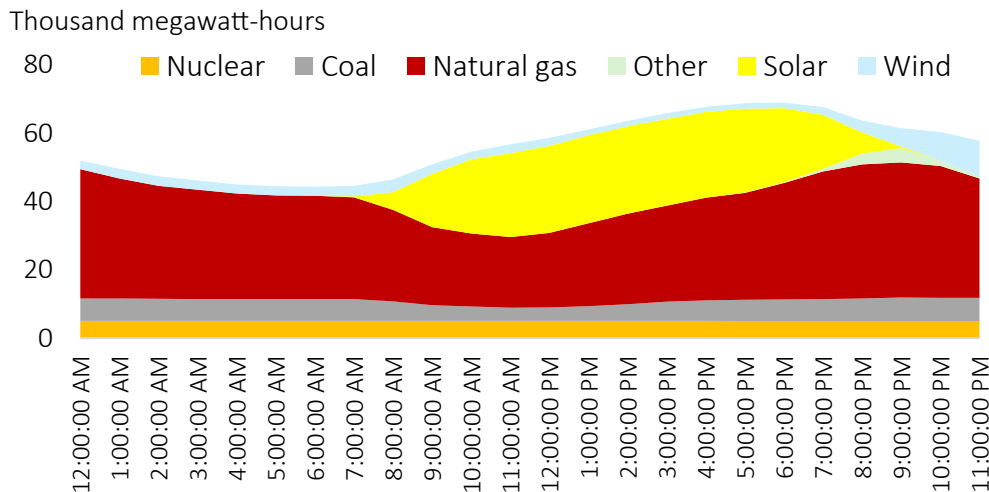
In a grid increasingly shaped by wind and solar, normal often means something more dynamic. Reliability is not just about meeting demand—it’s about matching the shape of demand with resources that can respond in real time. When renewables underperform, natural gas must fill the gap quickly and precisely. The system must stay balanced, and prices must reflect what it takes to do so.

May 31, 2025, was one of those days. There was no peak demand record, no grid emergency, and no extreme weather. Instead, it was an ordinary day that revealed how much ERCOT depends on flexibility. Compared with June 22, wind contributed less, solar output was steady, and natural gas again carried the reliability role. Notably, the day’s price peak lagged the system load peak, showing how reserves and ramping needs—not just demand—drive outcomes.

Figure 2. Load, Locational Marginal Price (LMP) and Generation by Fuel Type: May 31, 2025



Why Don't Prices Always Peak with Demand?
In ERCOT, wholesale prices are set by marginal conditions, not just system load. If reserves tighten or ramping needs surge, prices can spike even after demand has peaked. Conversely, when reserves are sufficient, prices may stay flat even at high load.



A Calm Start

The day began uneventfully. Demand fell to a nighttime minimum near 45,000 MW. Wind contributed less than 5% of generation, while natural gas filled the gap—providing as much as 73% of supply. Prices opened at \$58/MWh and declined steadily as solar began to rise after sunrise. By 10:00 a.m., solar had pushed prices to their daily low, just under \$17/MWh, while load continued its steady climb.

Midday Stability

At midday, solar provided more than 40% of ERCOT's total generation. Wind hovered at ~2%, leaving natural gas to cover the balance. Prices remained anchored in the \$20–30/MWh range. To the casual observer, conditions looked uneventful—but they were setting up for an evening test.

The Evening Turn

At 6:00 p.m., solar output began its predictable decline. Within two hours, more than 15,500 MW of solar had fallen offline. Wind, still near 1,600 MW, failed to rise. Net load surged.

Real-time prices followed: climbing from \$29/MWh at 4:00 p.m. to \$48 by 6:00 p.m., then spiking to \$100 by 7:45 p.m. No Operating Reserve Demand Curve (ORDC) adders were triggered—reserves never dropped into scarcity. Instead, the price rise reflected genuine tightness in dispatchable capacity as generators priced opportunity costs.

Natural gas responded decisively. Output doubled from ~20,000 MW at midday to nearly 40,000 MW by evening. That ramp alone delivered about 20 gigawatt-hours of incremental energy—roughly equal to New York State's average daily generation. It was a clear demonstration of controllable capacity stepping in precisely when needed.

There was no emergency, no load shed, and no out-of-market action. Just a sharp net load ramp, met with speed and discipline.

Restoring Balance

As temperatures fell and demand eased, wind output improved modestly. Gas units gradually scaled back, and by 11:00 p.m. prices had settled in the low \$30s. The system returned to its overnight posture.

The Other Shape of Normal

May 31 wasn't extreme. It was simply a different kind of normal—one that depended on flexibility rather than abundance. The market worked: resources responded, prices signaled tightness, and the system stayed in balance.

That is the essence of modern reliability in ERCOT: not only having enough generation, but having the right kind, available at the right time, with a market structure that rewards it for showing up when needed.

In today's grid, **flexibility is reliability.**

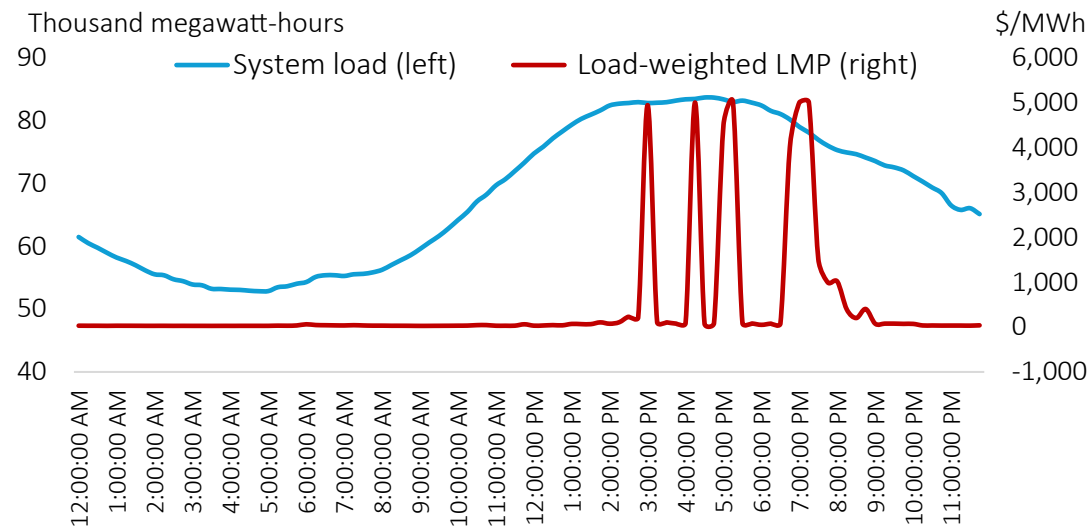
Chapter 3: A Grid That’s Changing – Lessons from Price Spikes, Then and Now

One of the clearest windows into ERCOT’s evolution is how the system behaves under stress—when demand rises, renewables fade, and dispatchable capacity must respond quickly. Two summer evenings—separated by less than two years—tell that story well.

August 24, 2023 – A Grid at the Edge

It was a typical Texas summer peak. By 4:30 p.m., systemwide load neared **84,400 megawatts**, one of the highest levels of the year. The air was thick and hot. Solar production was strong in mid-afternoon but declined sharply after 6 p.m. Wind was already low and contributed less than 7% during critical hours.

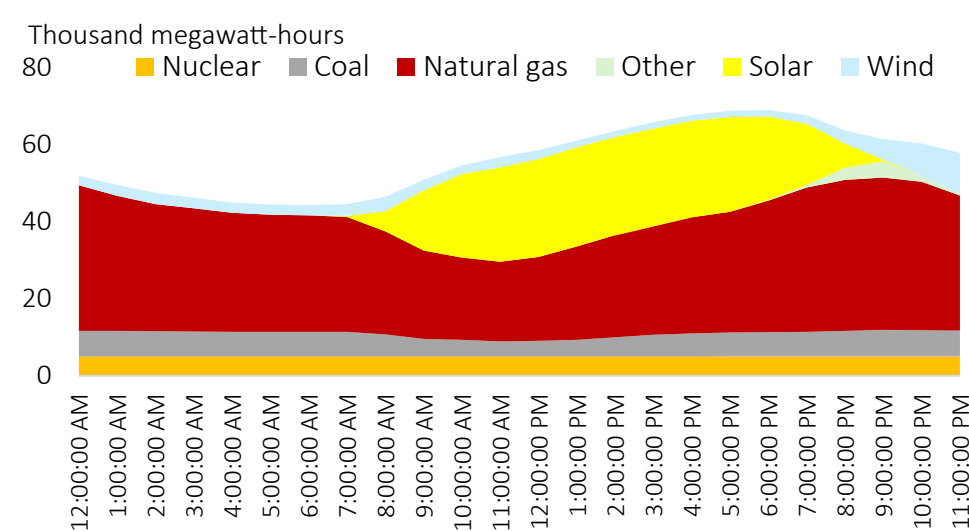
Figure 3a. Load, Locational Marginal Price (LMP): August 24, 2023



How to Interpret Price Spikes

ERCOT prices update every 5 minutes and reflect real-time system conditions. Sharp spikes can occur when reserves tighten suddenly — for example, from renewable underperformance, a unit trip, or a reserve adjustment. Prices may fall back quickly once reserves stabilize, even if demand remains high. This creates short-lived peaks rather than a smooth ramp with load.

Figure 3b. Generation by Fuel Type: August 24, 2023



ERCOT operators saw the warning signs:

- Reserve margins tightening
- High demand sustained into the evening
- Minimal renewable headroom
- Fast-responding thermal units already near full output

As net load climbed and flexible capacity stretched thin, prices ratcheted up. Between 3:30 and 7:45 p.m., real-time load-weighted LMPs reached or approached \$5,000/MWh during four separate 15-minute intervals.

This wasn't a forecast miss or a coding error. It was the product of:

- Tight reserves pulling high-priced offers onto the margin, amplified by the Operating Reserve Demand Curve (ORDC).
- A relatively small fleet of batteries bidding based on **opportunity costs**—holding back energy for expected higher scarcity later in the evening, which briefly gave them market power at sunset.
- Price-responsive demand briefly dropping out at high prices, then reentering as prices fell, reinforcing a “spike-dip-spike” pattern.

The grid bent but did not break, held together by dispatchable capacity and coordinated ancillary service deployments.

May 31, 2025 – The Same Stress, a Different Response

Less than two years later, a similar operational pattern unfolded. Load on May 31, 2025 – as we discussed in Chapter 2 – peaked just under 70,000 megawatts— lower than in August 2023, but the challenge looked familiar:

- Solar fell rapidly after 6:00 p.m.
- Wind remained stubbornly low
- Net load rose sharply

This time, however, the outcome was different. Real-time prices rose into the evening but topped out around \$100/MWh. No ORDC adders were triggered, no emergency deployments were required, and the system rebalanced smoothly. Natural gas-fired output again carried the day, flexing upward by nearly 19,000 MW.

What Changed Between 2023 and 2025

The calmer outcome reflected more than just differences in load:

- **Battery storage had expanded significantly**, making sunset less dependent on a handful of units with temporary market power.
- **Ancillary service procurement was more conservative**, creating a cushion to cover ramping needs.
- **Forecasting and operations improved**, giving ERCOT better visibility and more time to prepare.

- **Generator offer behavior evolved**, with both batteries and thermal units participating more actively in real time, reducing the need for scarcity pricing to bring them forward.

From Scarcity to Stability

August 2023 showed how ERCOT's energy-only design delivers sharp scarcity signals when reserves thin. May 2025 showed how the same design, supported by new flexibility and more deliberate operations, could manage similar stress with measured price outcomes. Both days required fast, responsive generation—but the latter did not need \$5,000/MWh outcomes to keep the system secure.

Yet this greater stability did not come free. More conservative procurement and pre-contingency commitments have shifted costs into ancillary services and out-of-market actions. What consumers avoided in visible scarcity pricing, they are now paying in quieter, structural ways.

A Grid That's Learning

ERCOT refined its operational structure, with greater tools at its disposal. The challenge going forward is calibration: how to keep enough margin to manage uncertainty amid rapid load growth without over-procuring reserves that raise costs but provide no reliability improvement. With balanced planning and flexible resources, scarcity becomes a signal—not a crisis.

Chapter 4: The Net Peak Has Become the Real Peak

When most people think about grid stress, they imagine record-breaking demand on the hottest summer day. But on March 29, 2025, ERCOT faced a very different challenge: moderate overall demand, no emergency alerts—and yet real-time prices climbing above \$180/MWh in the evening.

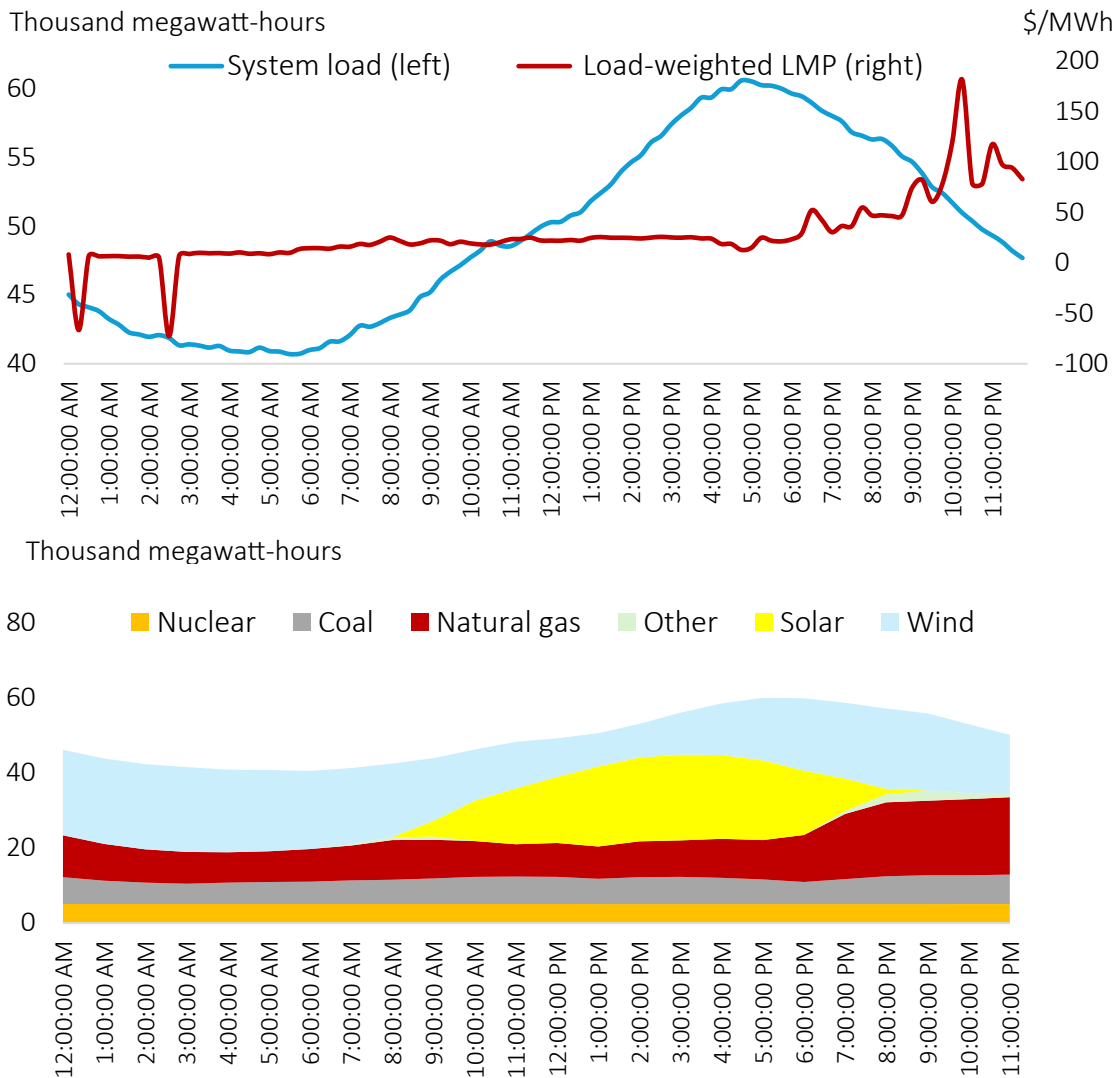
The reason? The system's *net peak*, not its gross peak, defined the tightest moment of the day.

A Spring Day with a Familiar Shape

March 29 began without drama. Load climbed steadily but never approached summer highs. Solar rose quickly, topping 22.9 GWh at 3:00 p.m. Wind was strong through the day, averaging more than 18 GWh. Gas plants cycled in the background.

By mid-afternoon, the system appeared stable. Prices held between \$20 and \$40/MWh, and forecasts closely tracked actuals.

Figure 4. Load, Locational Marginal Price (LMP) and Generation by Fuel Type: March 29, 2025



Then Solar Fell—and Net Load Rose

After 6:00 p.m., solar output dropped steeply—from 17.2 GWh at 6:00 p.m. to near zero by 9:00 p.m. Wind also declined slightly, staying elevated but insufficient to cover the evening ramp. As solar vanished and demand held steady into the evening, net load spiked.

Natural gas-fired generation doubled, climbing from ~10 GWh at 3:00 p.m. to over 20 GWh by 9:00 p.m. Real-time, load-weighted LMPs rose in parallel, peaking at \$181.59/MWh at 10:15 p.m.

There was no reliability alert, no scarcity adders, and no emergency deployment. The tightness was clear in the price signal alone.

What Is Net Peak, and Why Does It Matter?

ERCOT’s gross system load had already begun to decline by 7:00 p.m. But net load—the portion of demand not met by renewables—continued to rise, hitting its highest point of the day after sunset, when:

- Solar dropped off completely
- Wind dipped from daytime levels
- Evening demand remained strong

This “net peak” is now one of the most critical operational and economic moments on the ERCOT grid. It defines when fast-ramping capacity is essential, and when prices respond most sharply.

The Grid Has Changed—So Must Our Risk Lens

March 29, 2025, highlights three realities of today’s ERCOT system:

- System stress doesn’t require record demand
- Timing and flexibility are more valuable than raw capacity
- Planning must account for net demand profiles, not just traditional summer peaks

Prices over \$180/MWh weren’t the product of outages or scarcity adders. They were the result of the market working as intended—signaling the value of flexible, dispatchable generation as the sun went down.

Redefining “Peak” in a High-Renewables World

In years past, price spikes aligned with gross peaks—the highest points of daily demand. Increasingly, they align instead with net peaks, when renewables decline and dispatchable resources must step in at scale.

This spring evening underscores a fundamental shift: even days without extreme weather or record demand can test ERCOT’s limits. Reliability planning and market design must continue evolving to value flexibility where and when it is most needed.

Rethinking Peak Planning in ERCOT

From Gross Load to Net Load

For decades, ERCOT planned around *gross peak demand*—the highest system load, typically on a sweltering summer afternoon. But with rapid solar growth, the true point of system stress has shifted.

Net load—total demand minus wind and solar—is now the clearest indicator of when the grid is tightest.

On March 29, 2025:

- Gross load peaked near **60,700 MW** around midday.
- Net load peaked after **7:30 p.m.**, when solar had vanished and wind stayed low.
- That was when prices exceeded **\$180/MWh**, even though overall demand was lower.

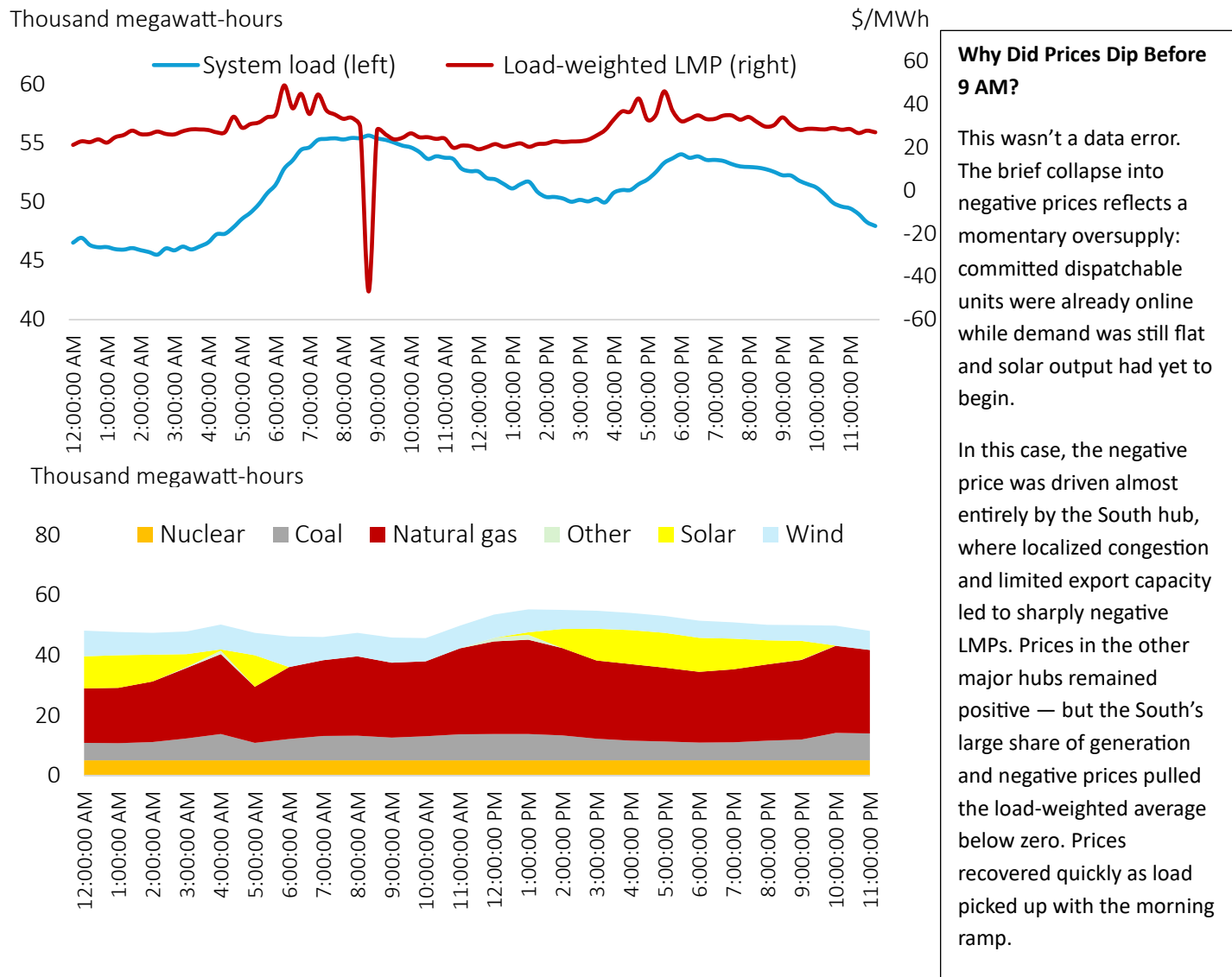
Why it matters:

- Reserve margins must now cover the *evening ramp*, not just the midday peak.
- *Flexibility, not just capacity*, is what keeps the grid stable.
- Traditional metrics miss risk if they ignore *timing and ramping needs*.

Reliability in today’s ERCOT isn’t about having “enough” generation overall—it’s about having it at the right time.

Chapter 5: Winter Without Crisis – The Quiet Strength of Thermal Reliability

Figure 5. Load, Locational Marginal Price (LMP) and Generation by Fuel Type: December 6, 2024



In Texas, winter electricity stories are often remembered for what went wrong. But on December 6, 2024, the story was about what went right.

It was a chilly morning across the state. Demand rose quickly as homes and businesses powered on and heating systems engaged. Load peaked just after 8:00 a.m. at more than 55,800 MW—a solid winter morning peak. Wind output was strong overnight but fell by half as the day unfolded. Solar, limited by the December sun, added modestly to the mix.

Yet in the ERCOT control room, conditions stayed calm.

Ramping Without Alarms

Operators saw the morning ramp play out much as expected. Wind, which had supplied more than 10,000 MW before sunrise, declined below 6,000 MW by early afternoon. Solar peaked near 11,400 MW around midday.

The ramping burden fell squarely on natural gas. Gas-fired generation flexed between 18,100 MW and 31,400 MW, effectively mirroring the decline in renewable output.

Despite rapid shifts in resources and a steep rise in load, no emergency alerts were issued. Non-spin reserves were not deployed. Prices rose with demand, peaking near \$48/MWh, but never approached scarcity thresholds.

This Is What Success Looks Like

The market functioned as designed:

- Natural gas ramped up steadily, maintaining reliability through both the morning and evening load transitions.
- Reserve margins remained healthy throughout the day.
- Prices responded to load but remained far below scarcity levels.

Most importantly, the system showed wintertime discipline—quiet operations that didn't make headlines but demonstrated resilience.

Why Thermal Still Matters

December 6 was a reminder that when solar is weak and wind fades, dispatchable thermal generation—especially natural gas—remains essential. These resources carried the system through cold morning peaks and evening ramps. Without their flexibility and scale, a routine winter day could have been much more difficult.

A New Baseline for Reliability

ERCOT's consistent performance reflected:

- Continued investment in winterization by generation fleets
- Stricter cold-weather protocols
- Conservative procurement of reserves
- Operational learning since Winter Storm Uri

Though modest in scale, the day matters because it demonstrates that reforms since Uri prevent winter risk from being load-dependent. Rather than a high-demand crisis, it was a normal winter morning where everything worked. That's what progress looks like in Texas.

ERCOT's Post-Uri Winter Reforms

After the February 2021 Winter Storm Uri, ERCOT, the Legislature, and the Public Utility Commission of Texas (PUCT) implemented a suite of reforms to strengthen winter reliability. The steady performance on December 6, 2024, reflects these efforts in action.

1. Cold Weather Preparedness (SB 3)

- Generators must weatherize for extreme cold.
- The PUCT and Railroad Commission (RRC) inspect and enforce compliance.
- Fuel supply infrastructure is also subject to winterization standards.

Impact: Greater availability of thermal units during winter ramps.

2. More Conservative Operations

- Higher operating reserves are routinely carried in winter.
- Risk assessments now account for temperature-sensitive demand.
- Reliability Unit Commitments (RUCs) are used more proactively.

Impact: Fewer surprises during cold morning and evening peaks.

3. Stronger Emergency Response

- Improved coordination with utilities and large industrial consumers.
- Expanded emergency reserves, including fast-start gas and voluntary demand response.
- Refined deployment protocols for non-spin reserves and backup generation.

Impact: More tools available—and deployed earlier—to stabilize the grid.

4. Texas Energy Fund (TEF)

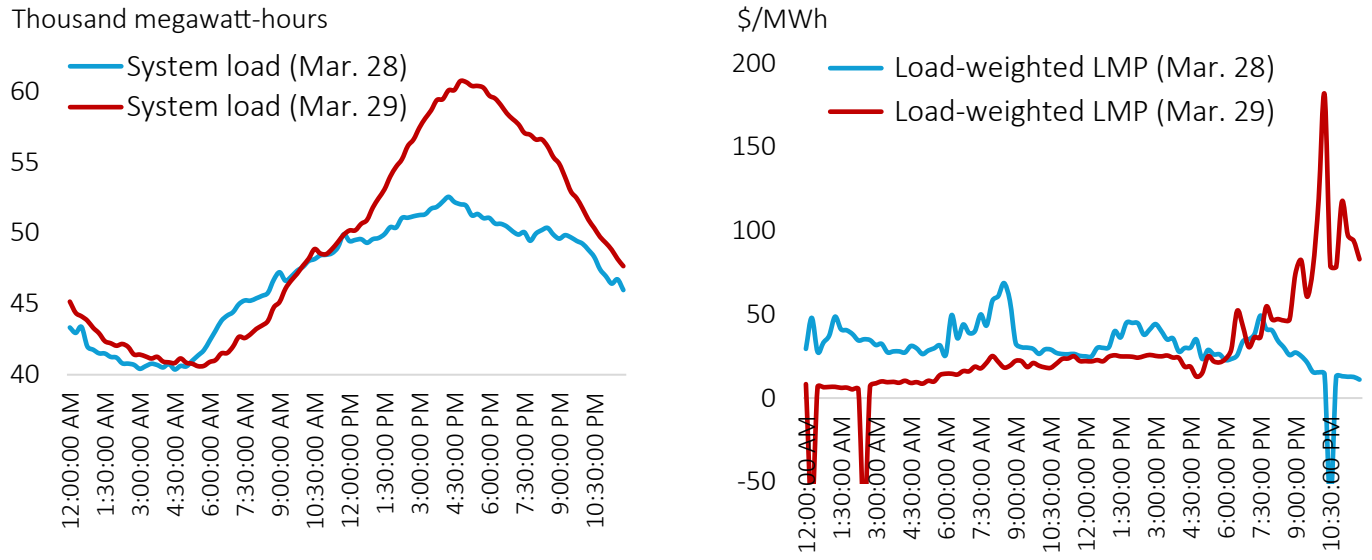
- TEF projects were still in development in 2024.
- By 2025, loans were approved for Kerrville, NRG Wharton, Rock Island Generating, and Calpine's Freestone peakers—several hundred MW of dispatchable capacity slated for 2026–27.

Chapter 6: A Day That Looked Similar—Until It Didn't

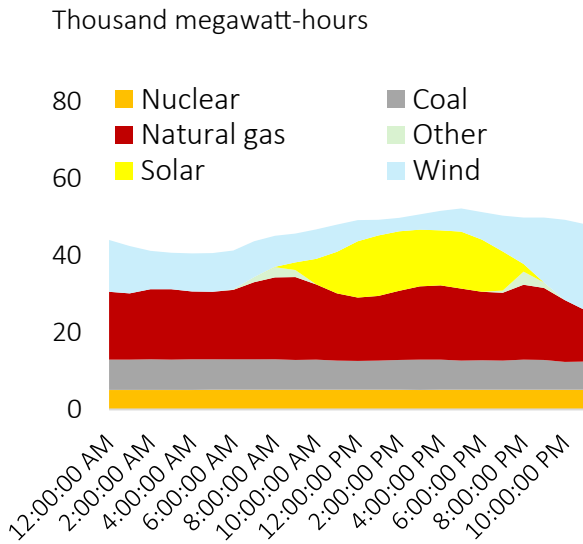
ERCOT's grid performed steadily on March 29, 2025, as described in Chapter 4. Prices rose above \$180/MWh during the evening ramp, but overall, the system stayed on track. Natural gas units responded, wind output strengthened late, and the transition from day to night was tight but controlled.

Yet just one day earlier, on March 28, load conditions looked remarkably similar through midday. But market outcomes diverged: real-time prices never exceeded \$69/MWh.

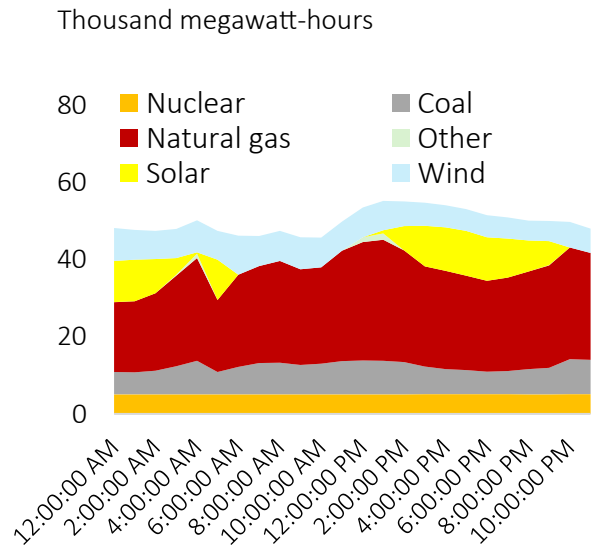
Figure 6. Load and Locational Marginal Price (LMP): March 28 versus March 29, 2025



Generation Mix: March 28, 2025



Generation Mix: March 29, 2025



A Day of Operational Ease

March 28 unfolded calmly, thanks to conditions that eased stress during the evening hours:

- **Higher thermal generation:** Natural gas output was more than 50% higher than on March 29, providing added flexibility, inertia, and ramping capacity as solar declined.
- **Smoother renewable profiles:** Wind and solar were lower overall but steadier, reducing swings in net load.
- **A more gradual evening transition:** Higher baseline dispatch and flatter demand kept the solar fade manageable.

ERCOT's Market Rewards Precision

The two days underscore how gross load similarity can mask very different operational conditions. Real-time prices responded not to the total amount of generation, but to:

- The timing and flexibility of dispatchable headroom
- Rapid net load changes, especially around sunset
- Market confidence in whether resources were sufficient and ready to respond

One Day Apart—But a World of Difference

On March 29, evening prices spiked—not because of record demand, but due to a convergence of small factors: slightly higher net load, delayed wind arrival, and reduced gas headroom. Compared with the calm of March 28, it shows that ERCOT's challenge is no longer defined by how much generation exists, but whether it is positioned to respond at the exact moment it is needed.

When Precision Matters – Why Similar Days Diverged

Two days. Nearly identical weather. Similar load and renewable generation. Yet real-time prices surged on March 29 while staying moderate on March 28. The difference highlights ERCOT's heightened sensitivity to *operational precision*—especially during the evening ramp.

Market Sensitivity Drivers

- **Forecast Error:** A 2–3% miss in wind or solar near sunset can leave 1,000–2,000 MW uncovered—right when dispatchable resources are needed most.
- **Delayed Dispatch:** Gas units often require 15–30 minutes to start and reach full output. If not committed in advance, they may arrive too late to contain price spikes.
- **Ramp Rate Limits:** Some thermal and storage units can't accelerate as quickly as net load rises during the solar fade, steepening the challenge.
- **Market Confidence:** Even if resources exist, uncertainty about timing or sufficiency can lead ERCOT to price conservatively—lifting LMPs to ensure immediate action.

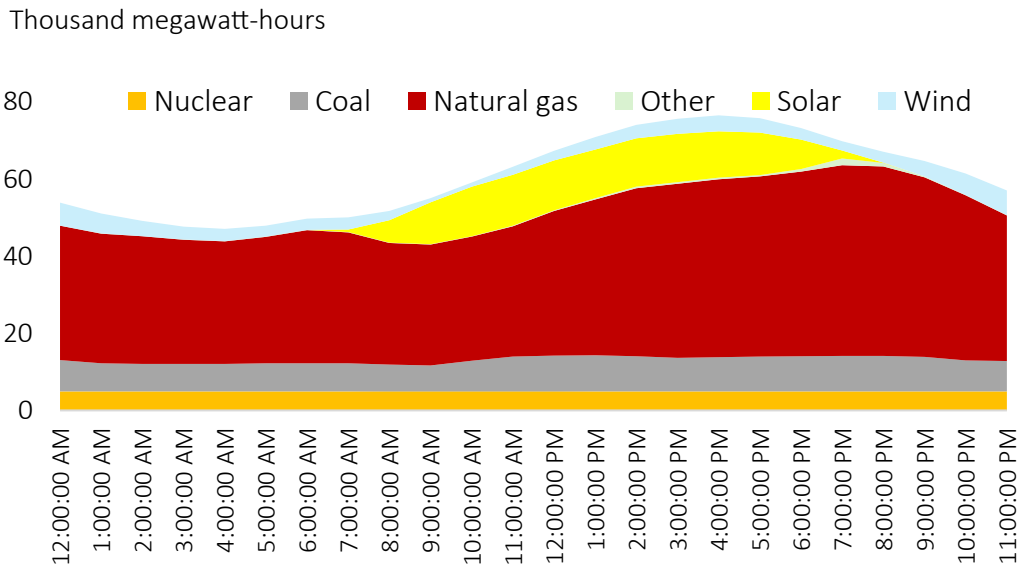
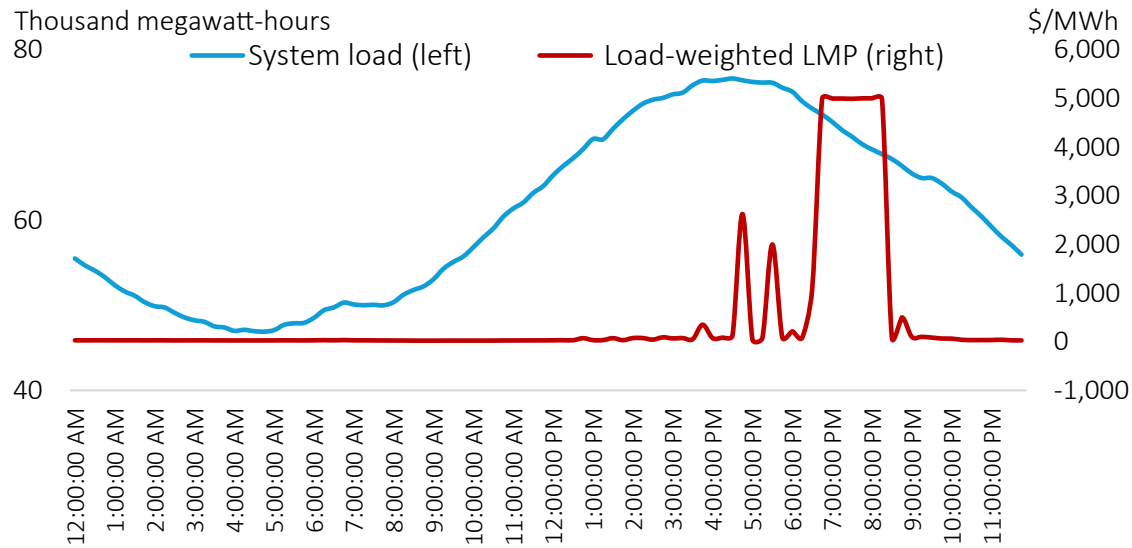
In today's ERCOT, small mismatches in timing—not just total capacity—can make the difference between a calm evening and a price surge.

Chapter 7: Emergency Alert – A Day the Grid Walked a Razor’s Edge

ERCOT had issued hot-weather warnings before—but August 30, 2023, was different.

By late afternoon, demand eclipsed 76,000 MW. Solar output faded. Wind stalled. Dispatchable reserves dwindled. At 6:38 PM, ERCOT declared an Emergency Energy Alert Level 1 (EEA1)—signaling reserves below 2,300 MW and calling for urgent conservation. Minutes later, real-time prices neared \$5,000/MWh.

Figure 7. Load, Locational Marginal Price (LMP) and Generation by Fuel Type: August 30, 2023



The Anatomy of a Crisis in Motion

The setup for scarcity was textbook:

- Strong solar at midday, but its expected decline after 7:30 PM left a gap just as demand stayed high.
- Minimal wind—fewer than 3,000 MW at peak demand
- Natural gas units, already running, had limited headroom to ramp
- Non-spin reserves were exhausted
- Batteries temporarily shifted risk, but with short duration could not eliminate it
- Demand continued rising into sunset

ERCOT operators had few tools left. Conservation alerts spread across the state, and Texans were urged to power down.

Scarcity Becomes the Signal

This wasn't an equipment failure or forecasting miss. It was a stress test of ERCOT's market design—and a demonstration of how the Operating Reserve Demand Curve (ORDC) is meant to function:

- Raise prices before reserves are fully depleted.
- Signal the true value of remaining capacity.
- Reward resources that can still respond.

On August 30, it did all three. As prices rose towards \$5,000/MWh across multiple intervals, every available megawatt was pulled into service. No blackouts occurred. The grid held.

While this event occurred under the pre-RTC ORDC framework, the underlying lesson remains relevant under today's RTC+B design: scarcity pricing—now embedded through ASDCs—still functions to signal thinning reserves and mobilize supply before reliability is compromised.

Holding Together by the Megawatt

ERCOT avoided outages not because surplus capacity was waiting in reserve, but because:

- Thermal generators already online held steady.
- Conservation requests reduced enough demand at the margin.
- No large, unexpected outages occurred.

Even so, it was a near-miss. One tripped unit or missed dispatch could have flipped the story from success to failure.

What August 30 Still Teaches

When Scarcity Is the Signal – ORDC in Action

What Triggered the Crisis on Aug. 30, 2023?

- Reserves fell below 2,300 MW
- EEA1 alert issued
- Real-time prices rose ~\$5,000/MWh
- Conservation requests deployed

Why It Matters: ERCOT has no forward capacity market. Its energy-only market relies on real-time prices to:

- Signal reliability needs
- Compensate fast-responding generation
- Encourage long-term investment

Policy Implications: August 30 shows both the strength and fragility of scarcity-based reliability:

- Price volatility is real—but rare
- Investment signals can be strong—but unpredictable
- Political pressure rises when price spikes hit headlines

Bridge to Reform: This event highlights arguments for:

- Greater dispatchable energy
- ORDC reform—smoother risk-based pricing
- Backstop dispatchable procurement—to handle rare but severe tight hours

Key Takeaway: The system held—but just barely. August 30 showed that market-based reliability can work—until it doesn't. The question for policymakers is no longer *if* scarcity should be priced—but *how much* and *how often* we can safely rely on it.

- High demand alone isn't the threat—it's the combination of high load, low renewables, and thin reserves.
- Conservation worked, but it is not a scalable reliability tool.
- Scarcity pricing functioned as designed: it signaled emergency, mobilized supply, and preserved reliability.

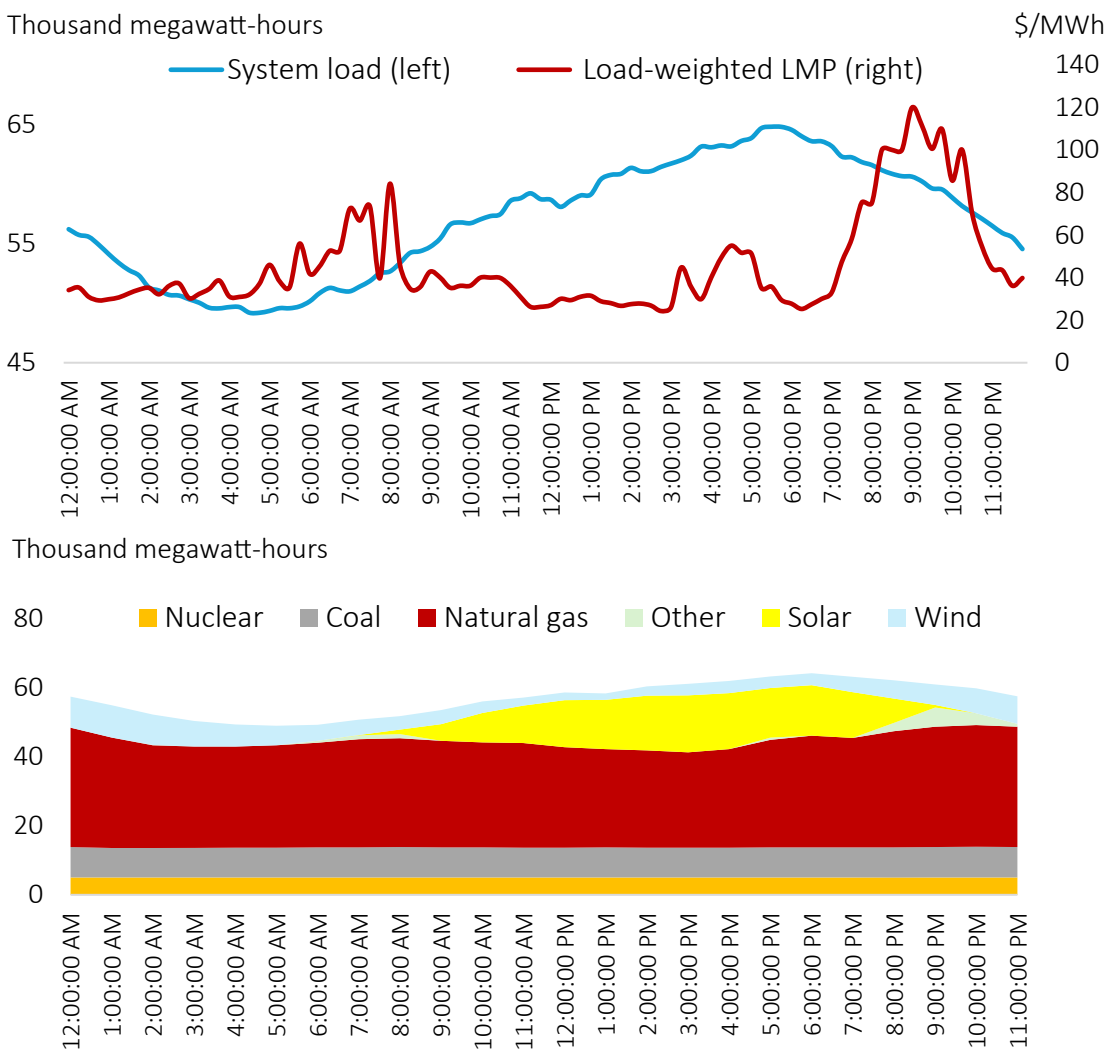
But this cannot remain ERCOT's first line of defense.

Chapter 8: The Hidden Risk Hour – When Net Load Runs High Before Sunrise

Some days, ERCOT's grid tightens in the quiet hours before most Texans wake. June 11, 2025, was one of those mornings.

By 7:00 a.m., net load—the portion of demand not met by renewables—had already surged. Dispatchable resources supplied more than 89% of ERCOT's generation even though total demand had not yet peaked. Wind was weak. Solar had not arrived. And the system needed flexibility immediately—not later in the day.

Figure 8. Load, Locational Marginal Price (LMP) and Generation by Fuel Type: June 11, 2025



A Different Kind of Peak

The morning began with demand nearing 51,000 MW and climbing steadily as homes and businesses powered on. But unlike the familiar evening ramps of spring and summer:

- Wind fell below 3,000 MW—less than 5% of installed capacity
- Solar was only beginning to register on the system
- Natural gas units were already running near optimal output by 7:00 AM

As load continued rising, real-time prices exceeded \$80/MWh—even without outages, a demand spike, or an emergency alert. Reserve indicators such as Physical Responsive Capability (PRC) showed tightening conditions consistent with the price signal, even though gross load was moderate.

The Hidden Morning Risk

Traditional reliability planning has emphasized summer afternoons and winter mornings. But June 11 revealed a new window of vulnerability: early summer mornings, when renewable output is minimal but load ramps steadily. This day illustrates that:

- Net load ramps aren't confined to evenings
- Morning flexibility needs are growing, especially when overnight wind underperforms
- Operational headroom can disappear quickly, before solar makes a meaningful contribution

Pricing Without a Crisis

Unlike scarcity events or emergency alerts, June 11 showed how the market can send an early, moderate signal. Prices rose above \$80/MWh, natural gas ramped to cover the gap, and conditions stabilized by mid-morning as solar production increased.

The episode underscores that ERCOT's stress points are dynamic. Renewables lower average costs, but they also shift the timing of reliability risk. Without them, peaks might be more predictable—but almost certainly more expensive.

“THE GRID DIDN'T FALTER ON JUNE 11. BUT IT DID LEAN—HEAVILY—ON NATURAL GAS GENERATION TO CARRY THE SYSTEM THROUGH A LOW-RENEWABLES MORNING. AS TEXAS LEADS THE NATION IN SOLAR GROWTH, THE HOUR JUST BEFORE SUNRISE MAY QUIETLY BECOME ONE OF THE MOST CONSEQUENTIAL FOR GRID STABILITY.”

Key Discussion – Renewables and Price Balance

Renewables lower average wholesale prices by displacing higher-cost generation. But they also change *when* the grid is most stressed.

- **Without renewables:** Peak prices would likely be higher and concentrated in traditional late-afternoon hours.
- **With renewables:** Average costs fall, but operational stress emerges more dynamically—during steep sunset ramps or low-renewable mornings.

A caveat, however, is that intermittency imposes systemwide costs for reserves, ramping, and reliability interventions. These costs are less transparent in average prices but affect all consumers—driving today's debate over firming requirements.

What June 11 Tells Us

- Flexibility must be available around the clock
- Morning commitment decisions are becoming as critical as evening ones
- Net load must be tracked not just by magnitude, but by timing

On this day, ERCOT’s market worked—quietly, early, and effectively. But the lesson is clear: the modern grid doesn’t wait for solar to rise or wind to arrive. Reliability begins at dawn.

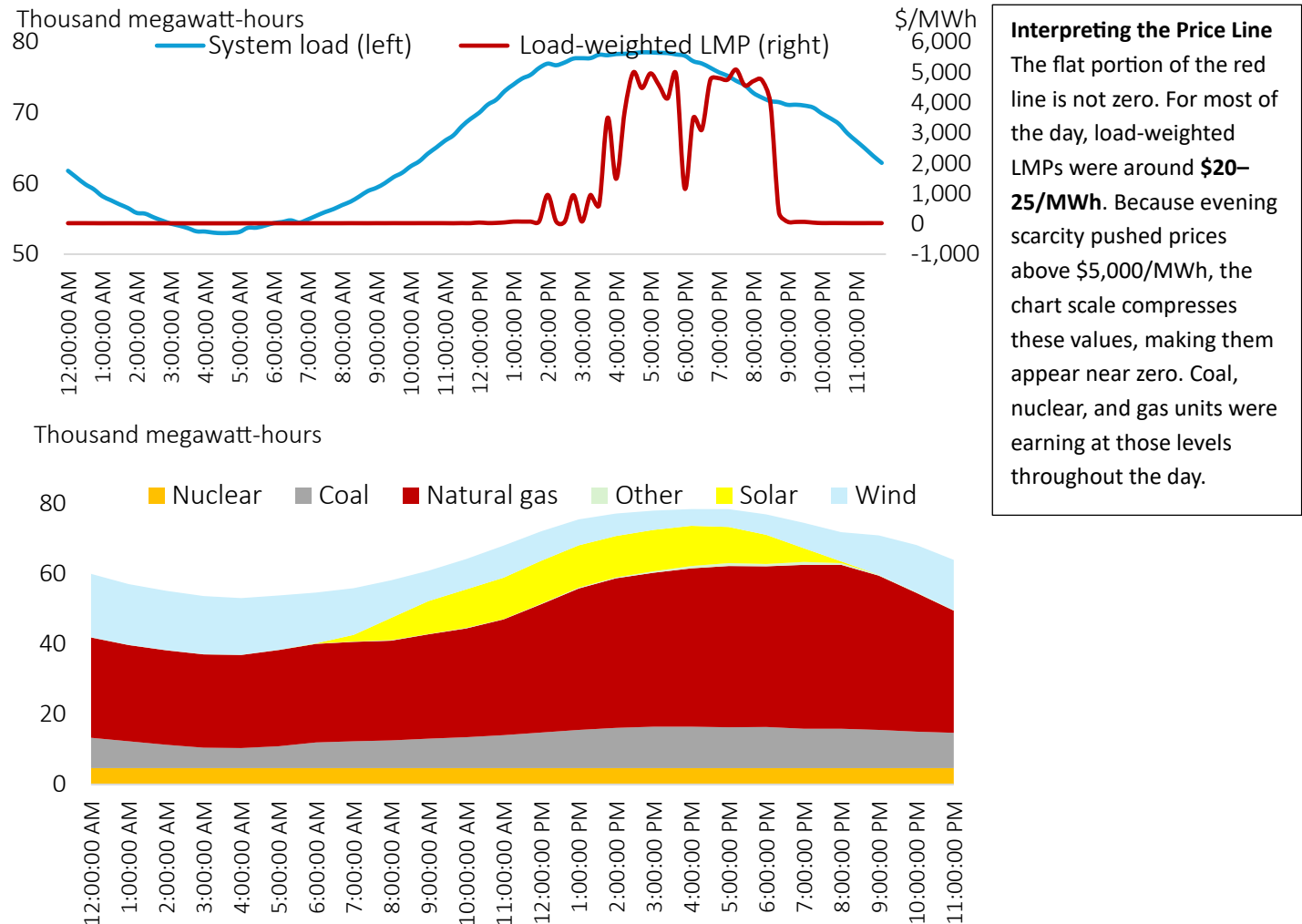
Chapter 9: A Demand Day, or a Dispatch Day?

June 20, 2023, didn’t break load records. Total demand peaked around 79,000 MW—a high summer level, but not unprecedented.

And yet, real-time prices surged repeatedly, hitting \$5,000/MWh in multiple 15-minute intervals between 3:30 and 8:00 p.m. There were no major forced outages. No load shed. No EEA alerts.

So why did the grid behave like it was on the brink?

Figure 9. Load, Locational Marginal Price (LMP) and Generation by Fuel Type: June 20, 2023



When Demand Isn't the Driver

June 20 revealed a different truth: scarcity can arise from dispatch constraints, not just from high demand. In the afternoon, solar peaked then faded, while wind dropped below 10% of installed capacity. With renewables falling away, dispatchable thermal units carried the evening ramp—but many were already near full output.

As reserves tightened, ERCOT's Operating Reserve Demand Curve (ORDC) began adding scarcity premiums. The system wasn't responding to a sudden outage or forecast miss. It was reacting preemptively to a flat dispatch stack and thin headroom.

Dispatch-Based Scarcity in Action

The data showed a grid stretched, not broken:

- Net load climbed steeply between 5:00 and 7:00 p.m.
- Natural gas maxed near 46,600 MW, leaving little room to ramp further.
- Wind dropped below 5,000 MW—far short of expectations.
- Prices spiked to \$5,000/MWh repeatedly, despite stable demand.

This wasn't about "demand being too high." It was about dispatchable headroom running thin.

A Market Signal—Not a System Failure

Importantly, ERCOT worked as designed:

- No emergency actions were taken
- Reserves dipped—but were not depleted
- Scarcity pricing sent the signal: bring every available megawatt forward

What This Day Still Teaches

- It's not the magnitude of load that matters most—it's the margin of flexibility that matters.
- Scarcity pricing can reach the cap even on well-forecasted days.

When the Stack Can't Stretch

What Is Dispatch-Based Scarcity?

A condition where:

- Dispatchable resources are already near maximum output
- Renewables are flat or falling
- Reserves shrink—even if demand is steady
- Scarcity pricing adds push prices higher to secure rampable headroom

On June 20, 2023:

- Load ≈ **79,000 MW**
- Gas ≈ **45,000 MW**
- Wind ≈ **3,000 MW**
- Scarcity pricing spiked to the cap—without outages or surprises

Policy Relevance

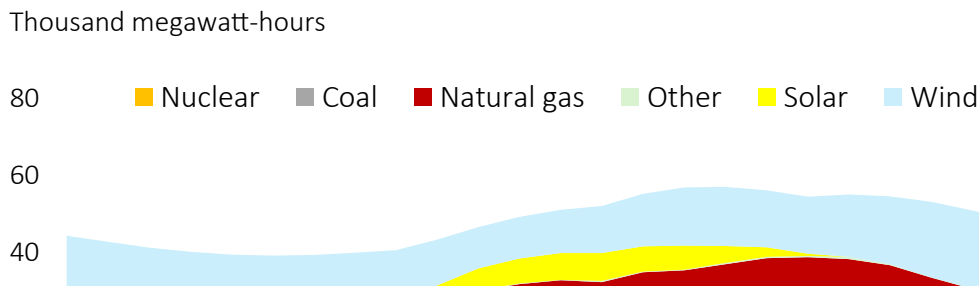
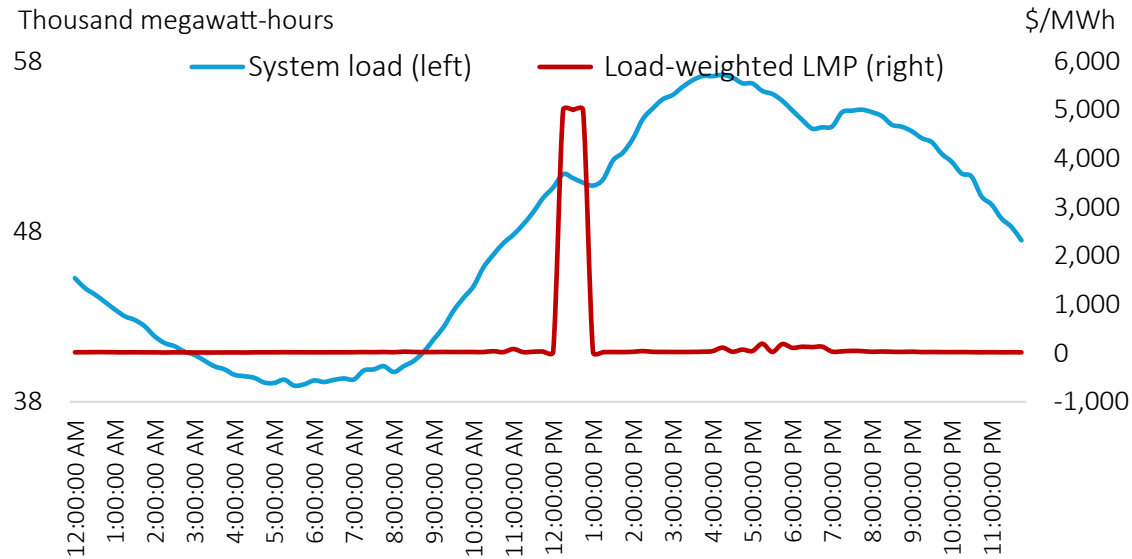
When renewables fade and thermal is already committed, ERCOT doesn't need a crisis to hit \$5,000/MWh. It only needs a stack with no room left to ramp.

- Additional capacity only improves reliability if it can ramp and respond at the right moment.

Chapter 10: A Spike Without a Storm

On October 22, 2023, ERCOT’s real-time prices briefly surged to the \$5,000/MWh cap on what otherwise appeared to be a quiet day. Load never exceeded 57,200 MW, renewables were contributing steadily, and no reliability alerts or emergency actions were issued. At first glance, it looked like another case of volatility disconnected from system conditions.

Figure 10. Load, Locational Marginal Price (LMP) and Generation by Fuel Type: October 22, 2023



What Is “Morning Load Tightness”

Net Load = Gross Load – (Wind + Solar)

At 7:00 a.m. on June 11, 2025:

- Gross Load ≈ **51,000 MW**
- Wind + Solar ≈ **4,600 MW**
- Net Load ≈ **46,400 MW** — nearly as high as evening levels

Why It Matters

- Many dispatchable units aren’t optimized for pre-dawn ramping.
- Reserve margins can erode quietly—before headlines or conservation alerts.
- Market prices become the only tool to signal and incentivize ramping.

It’s not just how high load goes. It’s *when* it rises—and what resources are available to meet it.

The explanation, however, was not scarcity. ERCOT later confirmed that a failure in its Market Management System (MMS) prevented the Security-Constrained Economic Dispatch (SCED) from processing several resources' energy offers and bids. Between 12:15 and 1:09 p.m., SCED produced invalid prices, and a subsequent attempt to correct the data failed before settlement. The result was that the erroneous \$5,000/MWh prices became final and were later sent to ERCOT's Board of Directors for review and correction.

This episode underscored a different vulnerability. Reliability did not hinge on physical conditions that day but on the integrity of ERCOT's market software. As ERCOT implemented Real-Time Co-Optimization beginning in December 2025, October 22 highlights the importance of ensuring that market systems are resilient. Just as transmission and generation must be hardened against extreme events, the software that clears offers, bids, and dispatch instructions must be robust, transparent, and supported by fallback processes to prevent errors from becoming binding. October 22 was not a day of scarcity but a reminder that in a grid managed by algorithms, software errors can be as disruptive to markets as storms are to wires.

While October 22, 2023, showed how a system error could send prices to the cap in calm conditions, the following summer offered a very different lesson: even when ERCOT's systems function properly, scarcity pricing can still emerge in a grid that is tight but balanced.

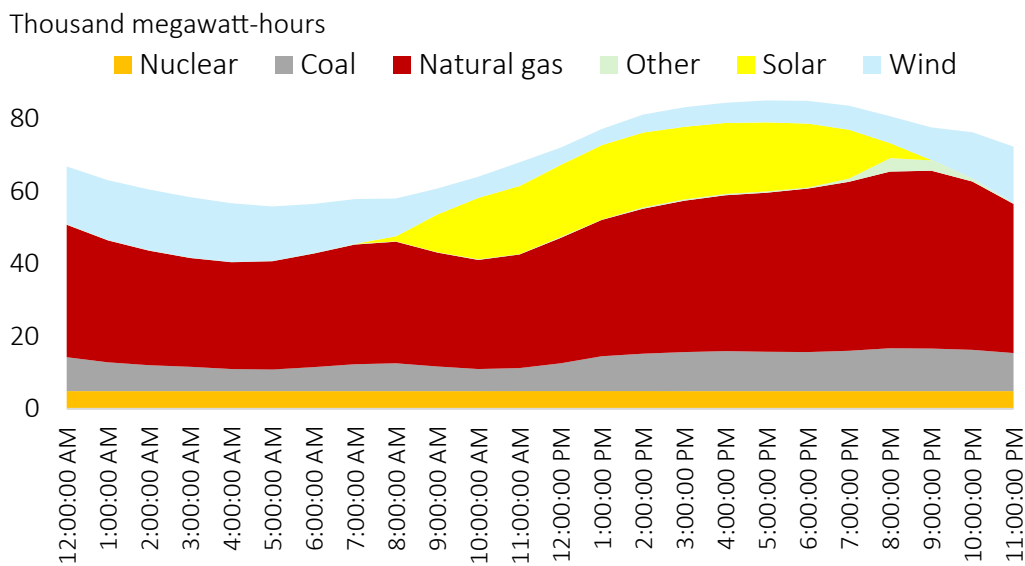
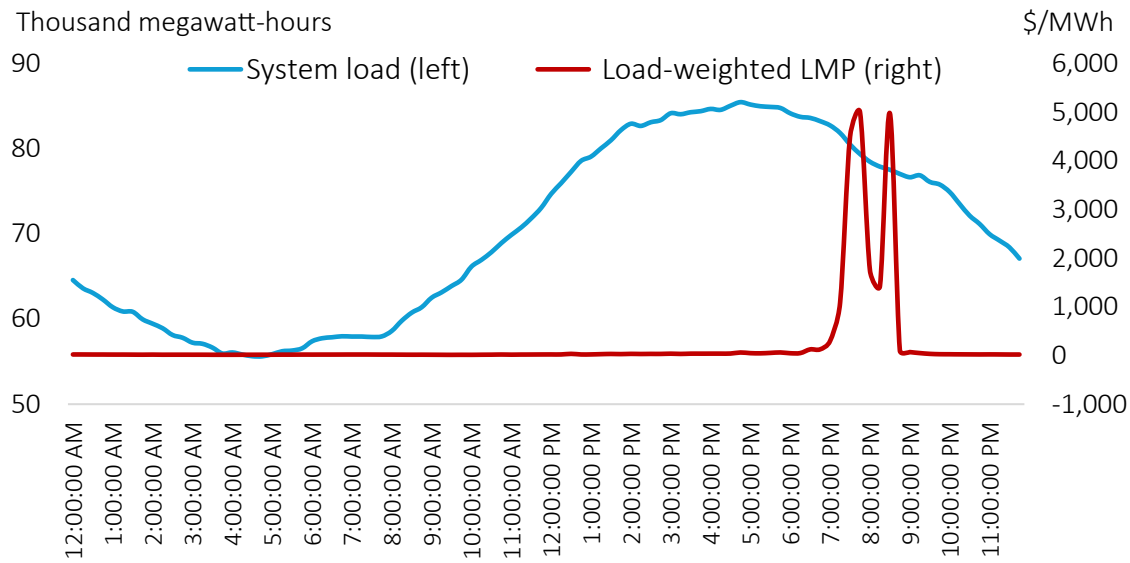
Chapter 11: Scarcity Pricing in a Tight But Balanced Grid – August 20, 2024

August 20, 2024, marked ERCOT's highest-ever demand day, with system load reaching 89.5 GW during the evening peak. Unlike 2023, when similar conditions prompted repeated conservation alerts and volatile price swings, this day stood out for how the system managed record demand without emergency actions.

Through the afternoon, solar delivered strongly, topping 11,000 MW at its peak before falling quickly after sunset. Wind provided about 10,000 MW in the morning but weakened during the evening ramp, leaving dispatchable resources to carry the system through. Nearly every available thermal unit was already online, and more than 8,000 MW of new battery capacity provided an additional buffer that ERCOT did not have the previous summer.

Conditions remained stable, but by early evening the grid reached an inflection point. As reserves narrowed with solar output dropping away, real-time prices began to climb. Between 7:00 and 8:00 p.m., scarcity adders under the Operating Reserve Demand Curve (ORDC) pushed prices above \$4,000/MWh several times, briefly hitting the \$5,000/MWh cap. Importantly, this was not the result of operational surprises, outages, or forecasting errors. It was the market functioning as designed: a tight but orderly grid signaling scarcity when reserves fell.

Figure 11. Load, Locational Marginal Price (LMP) and Generation by Fuel Type: August 20, 2024



Natural gas generation provided the backbone of the response, ramping nearly 6,000 MW between 5:00 and 8:00 p.m. to cover both declining solar and weak wind. Coal and nuclear remained steady, while batteries added targeted support at the net peak, improving short-duration flexibility. This combination allowed ERCOT to meet record demand without deploying emergency reserves, but still requires considerable dispatchable capacity during periods of prolonged stress.

The lesson from August 20 is that scarcity pricing is not a failure of the market but a feature. Prices rose because reserves tightened, not because the system faltered. Consumers were served, and reliability was maintained. Yet the brief run of \$5,000/MWh prices underscored the challenge ahead: as load continues to grow, ERCOT will need more responsive resources, thoughtful ancillary service procurement, and careful attention to how scarcity signals are calibrated.

August 20 was a success—but also a warning. The grid held, thanks to strong thermal performance and new storage, but it did so on a narrow margin. In a system increasingly defined by evening ramps and renewable variability, the balance between stability and scarcity remains as delicate as ever.

What Happens at \$5,000/MWh?

How Price Caps Shape Generator Behavior

ERCOT’s energy-only market is designed to let prices rise sharply when reserves are scarce—up to a system-wide offer cap of \$5,000/MWh (as of 2024). On August 20, prices briefly touched the cap even though the grid remained orderly. This illustrates how scarcity pricing works when reserves tighten, not because of outages or operational surprises, but because supply and demand margins narrow.

1. All Units Are Pulled Forward.

- Thermal generators already online push output to the maximum.
- Peakers that normally sit idle may finally become economical.
- Batteries discharge strategically into the evening ramp.

2. Timing Is Everything.

- Delaying startup or discharge risks missing the high-price interval.
- Resources that respond quickly capture the bulk of scarcity revenues.

3. Market Signals, Not Failures.

- Cap prices are rare but legitimate—they indicate reserves have grown thin.
- The ceiling both protects consumers from unlimited exposure and defines the top end of generator earnings.

4. Investment and Incentives.

- Even brief scarcity events contribute materially to annual revenues.
- These signals justify investment in flexible, fast-start capacity and storage.
- They help balance an energy-only market that lacks a formal capacity payment.

Bottom line: When prices hit \$5,000/MWh, it isn’t a breakdown—it’s the market working as designed. The system is signaling: *“Reserves are scarce—bring everything you have, now.”*

Chapter 12: Seeing the Grid More Clearly – What a Day Can Teach That Averages Cannot

The daily stories in this report—from volatile afternoons in 2023 to the record-setting but orderly peak of August 2024—highlight how ERCOT’s grid can swing between stability and strain in a matter of hours. Each episode illustrates a different piece of the puzzle: how reserves are procured, how price signals form, how batteries and renewables reshape operations, and how operator conservatism can steady the system but mask underlying risks. Taken together, they show that reliability is not a single condition but a moving balance—between old and new resources, between policy choices and market incentives, and between the physical grid and the computer systems that now run it.

The [2024 State of the Market Report \(SOTM\)](#) from Potomac Economics, ERCOT’s Independent Market Monitor (IMM), offers a valuable system-wide view of ERCOT—tracing long-term price signals, reserve costs, reliability interventions, and policy performance. It tallies averages, identifies incentive gaps, and evaluates whether the market is meeting reliability goals.

But the grid isn’t lived in averages.

It’s lived in moments.

Why We Looked at Days, Not Months

This report took a different approach. Rather than analyze monthly averages or system-wide aggregates, we asked a simple question: What happens on the grid when reliability is tested in real time?

We followed 11 days through the lens of ERCOT’s control room and generators’ decisions:

- A day when renewables carried the load, showing how wind and solar can reliably displace thermal generation under favorable conditions.
- A day with record thermal dispatch before sunrise, underscoring how baseload and gas units anchor reliability during low-renewable hours.
- A day when prices hit \$5,000/MWh, illustrating how a brief imbalance or unit trip can trigger scarcity pricing at the market cap.
- A day when flexibility—not scale—mattered most, as rapid ramping proved more valuable than sheer megawatt capacity.
- A day with curtailment and negative prices, reflecting oversupply from renewables against flat demand.
- A day when everything worked quietly—and well, demonstrating that ERCOT’s design can deliver stable outcomes without drama.
- A day when solar’s expected sunset decline became a stress point, as low wind and high demand left little margin when solar dropped away.
- A day when net load surged before dawn, with low renewables forcing dispatchable units to cover nearly the entire system.

- A day with tight conditions despite moderate demand, showing that operational precision, not just high load, drives reliability risk.
- A day when gas generators bore nearly the entire load, highlighting their central role in balancing the grid when renewables lag.
- A day when forecast errors—not demand—drove volatility, demonstrating how small misses in renewable or load projections can cascade into sharp price swings.

By grounding our analysis in dispatch-level data, we observed how the grid has actually performed under stress, how prices respond to risk, and whether today's market tools are working as intended.

What We Learned

From these operational case studies, five core insights emerge:

1. Price Formation Remains Incomplete

On several days, prices did not fully reflect the severity—or calm—of system conditions:

- June 20, 2023: Prices spiked without any scarcity alert or reliability deployment.
- August 20, 2024: The grid operated under record load and a steep peak ramp, yet LMPs remained stable until reserves tightened.
- June 11, 2025: Dispatchable generation carried 89% of load at sunrise, but prices hovered near \$50/MWh.

Real-time market prices correctly reflect SCED math, but not always the underlying operational tightness created by ERCOT's reserve posture, operator conservatism, or procurement choices. Incorporating indicators such as Physical Responsive Capability (PRC) and reserve margins offers a more complete picture of reliability risk.

2. Net Load, Not Gross Load, Drives Today's Risk

Peak system load is no longer the defining stress point. Instead, net peak—the point when solar fades and wind is unavailable—now dictates ramping needs and price pressure.

The nature of this risk has shifted quickly: in 2019, adequacy concerns followed thermal retirements; by 2021, solar was cushioning summer peaks; in 2023, evening net peak scarcity became the defining challenge; and by 2025, batteries added significant depth. Planning today requires flexibility over raw capacity.

3. Natural Gas Generation Remains Indispensable

On high-renewable days, thermal units backed off. On high net load days, they ramped sharply. Natural gas remains the backbone during multi-hour net peaks, not because of sheer capacity, but because of its flexibility and availability. Batteries increasingly share this role, but gas continues to provide the margin that keeps the system balanced.

4. Scarcity Has Been Replaced by Silent Costs

Scarcity pricing occurred rarely. But costs did not disappear—they shifted to:

- Larger ancillary service procurement,
- More frequent pre-contingency RUC deployments, and
- Increased reliance on conservative operations.

This posture has reduced volatility but at a price: higher structural costs for reserves and reliability interventions. The challenge is calibrating how much conservatism is necessary to protect reliability without overspending.

The challenge for policymakers is not whether conservatism has value, but how much is truly necessary—enough to secure reliability without locking consumers into avoidable costs.

5. Curtailment Is Becoming More Common

On October 22 and June 22, prices turned negative as renewable output exceeded system needs. Curtailment is operationally manageable, but its rising frequency underscores the need for transmission planning and efficient integration of renewable resources.

These five lessons highlight how ERCOT’s reliability challenges have shifted—from scarcity pricing toward hidden costs, from gross load to net load, and from static peaks to dynamic ramps. They also show how the system is evolving: natural gas remains essential, batteries are emerging, and renewables are changing both price formation and curtailment risk. The question for policy is whether current reforms are aligned with these realities—or whether they risk chasing yesterday’s problems.

The Performance Credit Mechanism (PCM): Tabled for Good Reason

In December 2024, the PUCT tabled the \$1 billion-per-year PCM, concluding it offered limited reliability benefit relative to cost. While tabled, the underlying policy question has not disappeared, and PCM-type constructs could re-emerge under a different name or framing if conditions change (e.g., extreme load growth, political pressure after a future event). This makes it all the more important that future proposals be grounded in dispatch-level evidence rather than static modeling.

- Evidence: Thermal resources are already responding without subsidies; ancillary service reforms and RTC implementation are addressing flexibility needs.

Stability vs. Cost – The Conservatism Tradeoff

What ERCOT Gains

- Fewer scarcity events
- Lower price volatility
- More predictable operations

What ERCOT Pays

- Higher ancillary service procurement
- More pre-contingency RUCs
- Increased systemwide costs for reserves

The Balance

Conservative operations have made ERCOT steadier, but not cheaper. The challenge is calibrating how much conservatism is necessary—enough to protect reliability, but not so much that Texans overpay for hidden stability.

- Implication: Future mechanisms should be judged by whether they add distinct reliability value, not simply compensate resources already performing.

HB 3356: A Case Against Static Modeling

HB 3356 would have imposed retroactive firming requirements on renewables using 2023 data. Evidence from 2024–25 shows a more dynamic system with fewer price spikes and smoother ramps.

- Evidence: Reliability stress points shift as the mix evolves.
- Implication: Backward-looking static models misrepresent today's grid; forward-looking, adaptive reforms are more effective.

Recommendations for Market Design and Oversight

As ERCOT evolves, oversight should stay grounded in operational reality:

- Tie reforms to real-time needs, not hypothetical scarcity.
- Expand performance metrics beyond prices to include net load, ramp rates, and curtailment.
- Target investment where flexibility gaps persist.
- Integrate case-study vignettes into evaluations, alongside top-down averages.

Priority Reforms

- Modernize the reserve scarcity framework: Transition from administratively defined scarcity step functions to smoother, risk-based demand curves tied explicitly to probabilistic loss-of-load metrics. Under the pre-RTC framework, this applied to the Operating Reserve Demand Curve (ORDC). With the December 2025 implementation of Real-Time Co-Optimization (RTC+B), scarcity pricing is now embedded through service-specific Ancillary Service Demand Curves (ASDCs). Ongoing calibration should ensure these curves reflect marginal reliability value without embedding artificial scarcity.
- Evaluate and refine Real-Time Co-Optimization (RTC+B): Now implemented as of December 2025, RTC+B internalizes energy and ancillary service trade-offs in real time, aligns price signals more closely with operational conditions, and improves price formation transparency. Policymakers should allow RTC+B's effects to mature and assess whether it delivers improved efficiency before layering additional reliability mechanisms.

Framing the Tradeoff

Conservative operations have reduced volatility, but at the cost of higher ancillary procurement and pre-contingency commitments. The policy challenge is not whether conservatism is useful, but how much is truly necessary—striking a balance between securing reliability and avoiding persistent over-procurement that drives costs without improving outcomes.

These recommendations align with concerns raised by the Independent Market Monitor regarding scarcity curve calibration, reserve procurement levels, and the pace of technology integration.

A Final Word: One Day at a Time

The IMM’s annual review remains essential. But dispatch-level storytelling reveals what averages cannot: how stress emerges, how operators respond, and how success—or strain—is built in just a few critical hours. Future policy should balance top-down tracking with bottom-up assessments of real-time behavior. That is how reforms can stay aligned with what the grid actually needs—tested in real time, proven one day at a time.

Appendix A: Definitions

This glossary provides concise definitions of specialized market and reliability terms used throughout the paper. It is intended as a quick reference for readers who may not be familiar with ERCOT-specific terminology.

Ancillary Services (AS): Reliability tools ERCOT procures beyond energy to keep the grid stable, such as reserves, frequency response, and regulation.

Ancillary Service Demand Curves (ASDCs): Service-specific demand curves used in ERCOT's RTC+B framework to embed scarcity pricing within real-time co-optimization. ASDCs replace the prior ORDC structure and determine reserve scarcity pricing through ancillary service clearing rather than standalone energy adders.

ERCOT Contingency Reserve Service (ECRS): An ancillary service introduced in 2023 that provides reserves to respond to sudden, large supply-demand imbalances (such as a generator trip). ECRS resources must be able to fully deploy within 10 minutes, but unlike faster services, they are not required to respond instantly to frequency changes.

- **ECRS–Slow (ECRS-S):** Resources that can deploy within 10 minutes but do not provide immediate frequency response (e.g., demand response, certain thermal units).

Locational Marginal Price (LMP): The wholesale market price of electricity at a specific location, reflecting both energy costs and transmission constraints.

Load-Weighted Locational Marginal Price (Load-Weighted LMP): An average of locational marginal prices (LMPs) across ERCOT, weighted by the amount of demand at each location. Reflects the effective wholesale price that consumers collectively pay.

Net Load: Total system demand minus renewable generation, highlighting the load that must be met by dispatchable resources.

Non-Spin Reserve (Non-Spin): Capacity that can be brought online within 30 minutes to meet unexpected needs.

Operating Reserve Demand Curve (ORDC): A former ERCOT reserve scarcity pricing mechanism that increased real-time energy prices as operating reserves declined. Replaced in December 2025 by service-specific Ancillary Service Demand Curves (ASDCs) under RTC+B.

Performance Credit Mechanism (PCM): A proposed reliability mechanism (now tabled) that would have paid dispatchable generators for being available during scarcity events.

Physical Responsive Capability (PRC): The system's ability to respond quickly to sudden outages or demand changes, often measured in MW of responsive reserves.

Primary Frequency Response (PFR): The automatic, near-instantaneous adjustment of generator output or load in response to changes in grid frequency, typically occurring within seconds of a disturbance. PFR helps stabilize frequency before other reserves are deployed.

Regulation Services (RegUp/RegDown): Ancillary services that fine-tune supply-demand balance on a second-to-second basis.

- **Regulation Up (RegUp):** Increases generation or decreases load when system frequency is falling.
- **Regulation Down (RegDown):** Decreases generation or increases load when system frequency is rising.

Reliability Deployment Adder (RDA): A price uplift applied when ERCOT directs out-of-market actions (such as deploying reserves or committing units for reliability). Paid to all generators producing energy during these periods, ensuring they are compensated for operating in stressed conditions.

Reserve Price Adder (RPA): An automatic price uplift that increases wholesale energy prices when operating reserves fall below specific thresholds. Paid to all generators producing energy at that time, since their output is critical when reserves are scarce.

Responsive Reserve Service (RRS): A specific ancillary service providing quick-acting capacity to arrest frequency decline when generation trips offline. RRS often relies on **under-frequency response**, where generators or loads automatically respond to a frequency drop.

Texas Energy Fund (TEF): A state-backed financing mechanism to support investment in new dispatchable generation capacity.

Under-Frequency Response: An automatic control that rapidly increases generation or decreases load when grid frequency drops below a set threshold. This immediate, involuntary action helps stabilize the system and is a core component of Responsive Reserve Service.

Uplift Costs: Charges allocated to market participants to cover out-of-market actions or reliability deployments not fully priced into energy markets.

Appendix B: Texas Energy Fund (TEF) – Approved Projects

Last Updated: 12/23/2025

In-ERCOT Generation Loan Program Awards

App-#	Recipient	Project	Project Description	Award Date	Total Award Amount	Amount Expended
APP-00000201	Kerrville Public Utility Board PFC	Rock Island Generating (RIG)	A 122 MW Simple Cycle Natural Gas facility located in the ERCOT South Load Zone.	7/1/2025	\$105,000,000.00	\$100,000.00
APP-00000017	NRG Energy, Inc.	NRG THW GT LLC	A 456 MW Simple Cycle Natural Gas facility located in the ERCOT Houston Load Zone.	7/31/2025	\$215,562,922.00	\$186,570,133.62
APP-00000016	NRG Energy, Inc.	NRG Cedar Bayou 5 LLC	A 721 MW Combined Cycle Natural Gas facility located in the ERCOT Houston Load Zone	9/26/2025	\$561,901,530.00	\$253,481,697.88
APP-00000128	Calpine Corporation	Pin Oak Creek Energy Center, LLC	A 460 MW Simple Cycle Natural Gas facility located in the ERCOT North Load Zone.	10/13/2025	\$278,326,377.66	\$229,144,597.33
APP-00000031	Competitive Power Ventures and GE Vernova	CPV Basin Ranch, LLC	A 1,350 MW Combined Cycle Gas Turbine facility located in the ERCOT West Load Zone.	10/28/2025	\$1,124,800,000.00	\$190,802,601.00
APP-00000018	NRG Energy, Inc.	NRG Greens Bayou 6, LLC	A 455 MW Simple Cycle Natural Gas facility located in the ERCOT Houston Load Zone.	11/20/2025	\$369,999,977.00	\$89,823,556.31

Total Disbursed to Date: \$949,922,586.14

Completion Bonus Grant (CBG) Program Awards

App-#	Recipient	Project	Project Description	Award Date	Total Award Amount	Amount Expended
APP-00000283	Lower Colorado River Authority (LCRA)	Timmerman Power Plant Unit 1	A 188 MW Simple Cycle Natural Gas facility located in the ERCOT LCRA Load Zone.	11/10/2025	\$22,560,000	\$0

Total Disbursed to Date: \$0

Section 403.0245(b) of the Texas Government Code requires a state agency that awards state grants in an amount greater than \$25,000 to make available to the public on the agency's website (<https://www.txenergyfund.texas.gov>) the purposes for which the grant was awarded.

UNIT NAME	INR	UNIT CODE	COUNTY	FUEL	ZONE	IN SERVICE	INSTALLED CAPACITY RATING (MW)	MAR. 2026 MORA
1528 Planned Thermal Resources with Executed SGIA, Air Permit, GHG Permit, Proof of Adequate Water Supplies, Financial Commitment, and Notice to Proceed								
1529 BASRANCH (TEF)	25INR0008		WARD	GAS-CC	WEST	2028	-	-
1530 CEDAR BAYOU 5 (TEF)	23INR0029		CHAMBERS	GAS-CC	HOUSTON	2027	-	-
1531 CEDARVALE GAS	25INR0710		WARD	GAS-IC	WEST	2026	-	-
1532 COYOTE SPRINGS AGR1	24INR0645		REEVES	DIESEL	WEST	2025	9.9	9.9
1533 ENCHANTED ROCK NEWPP	22INR0546		HARRIS	GAS-IC	HOUSTON	2026	30.0	30.0
1534 NRG THW GT 345 (TEF)	24INR0482		HARRIS	GAS-GT	HOUSTON	2026	-	-
1535 PIN PEAKING ENERGY CENTER 1 (TEF)	26INR0049		FREESTONE	GAS-GT	NORTH	2026	-	-
1536 PIN PEAKING ENERGY CENTER 2 (TEF)	26INR0109		FREESTONE	GAS-GT	NORTH	2026	-	-
1537 PYOTE GAS	25INR0718		WARD	GAS-IC	WEST	2026	-	-
1538 STAGHORN GAS	26INR0698		WARD	GAS-IC	WEST	2026	-	-
1539 ROCK ISLAND GENERATING (TEF)	27INR0321		COLORADO	GAS-IC	SOUTH	2027	-	-
1540 SADDLEBACK AGR1	24INR0646		REEVES	DIESEL	WEST	2025	9.9	9.9
1541 TIMMERMAN POWER PLANT PHASE 2	25INR0503		CALDWELL	GAS-IC	SOUTH	2026	-	-
1542 TIMMERMAN POWER PLANT PHASE 2B	26INR0735		CALDWELL	GAS-IC	SOUTH	2026	-	-
1543 Planned Thermal Resources Total (Nuclear, Coal, Gas, Diesel, Biomass)							49.8	49.8

sources: ERCOT Monthly Outlook for Resource Adequacy (MORA) (March 2026); PUCT TEF loan approvals and announcements.