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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):** With the $1 billion-per-year PCM tabled, reliability improving, and thermal units responding without subsidies, 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 what might prevent them in the future—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 a daunting task. At times, what begins as technical analysis ends in anecdote or finger-pointing, especially when the stakes are high and transparency is limited.

This Texas Oil and Gas Association (TXOGA) white paper aims to shed light on ERCOT's daily operations—not through abstraction or averages, but through lived examples. TXOGA presents a series of real days in ERCOT's recent history—some routine, others turbulent, and a few unexpectedly revealing—to illustrate how the grid actually works. We examine these moments from both the grid operator's and the generator's perspectives to clarify what's changed, what's working, and where policy attention should turn next. Our concern, as representatives of the state's largest electricity consumers, is ensuring that reliability and cost are not treated as tradeoffs—but as dual imperatives.

This is not a technical whitepaper. It is a practical narrative grounded in data entirely from ERCOT and informed by experience. Our goal is to provide fresh insights into how Texas' electricity market functions, how it is evolving, and what's required to secure a future that is reliable, resilient, and affordable.

This paper uses a number of ERCOT-specific market and reliability terms that may be unfamiliar to some readers. A glossary of key terms is included in Appendix A 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. It was busy, but not volatile. In fact, it was exactly the kind of day that ERCOT is built to handle—quietly, reliably, and efficiently.

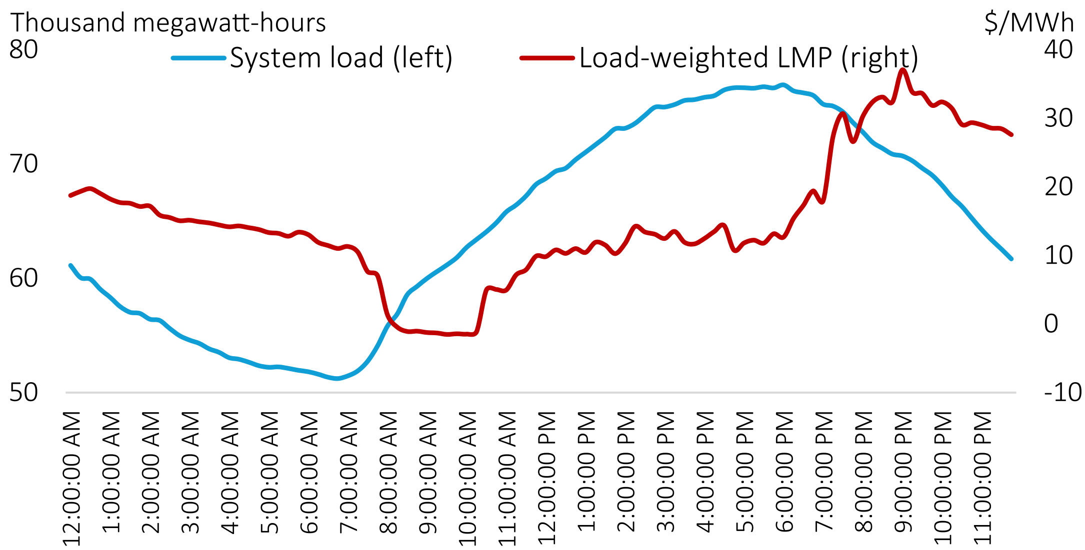
And yet, by historical standards, it wasn't ordinary at all. System load approached 77,000 MW in the evening, a level that would have been a record-setting peak just four years ago. Still, prices remained low, volatility was minimal, and no grid alarms were triggered. What made the day notable was precisely its normalcy.

Midnight to Sunrise (00:00 – 06:00)

System-wide demand declined steadily from around 61,000 MW to 52,000 MW. Wind provided a robust and consistent contribution throughout the early hours, generating more than 26% of total load. Nuclear and coal held steady, while natural gas units cycled down—dropping from ~23% to ~20% of total generation. Solar had not yet come online.

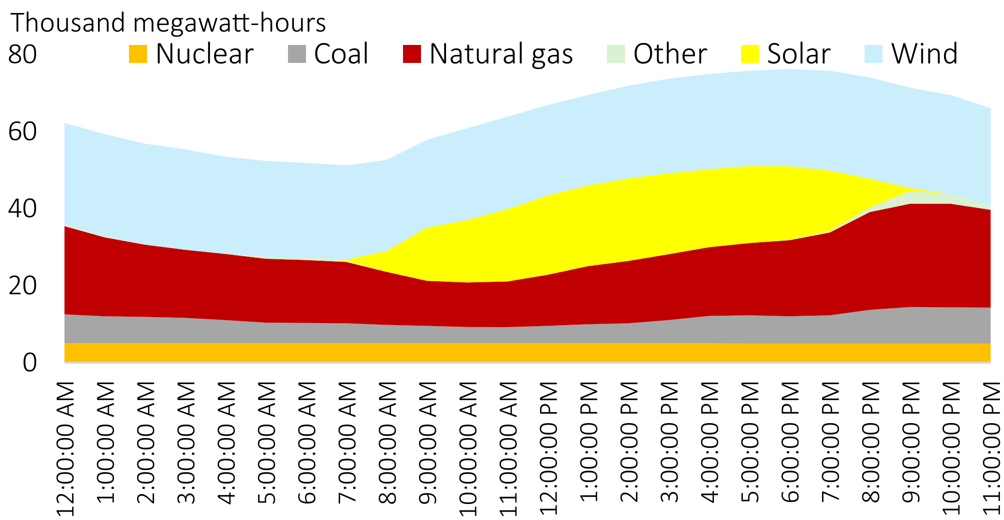
This mix allowed ERCOT to keep natural gas generators in reserve or on partial output, positioning them to ramp as needed. With sufficient reserves online and low net load variability, real-time prices ranged between $15–$20/MWh and remained free of scarcity adders.

Figure 1. Load, Locational Marginal Price (LMP) and Generation by Fuel Type: June 22, 2025



How to Read These Charts

*The **blue line** represents ERCOT system load (real-time demand). The **stacked areas below** it show actual generation by resource type that was dispatched to meet that demand. Together, they illustrate how supply sources respond to changing system needs.*



Morning Ramp (06:00 – 10:00)

As Texans began the day, demand eclipsed 60,000 MW. Wind output declined modestly, but solar ramped up beginning shortly after 7:00 a.m., and natural gas flexed downward for system stability. By 10:00 a.m., gas provided nearly one-fifth of all ERCOT generation, down from nearly 40 percent overnight.

ERCOT's Security-Constrained Economic Dispatch (SCED) system coordinated this transition, optimizing every five minutes to dispatch the lowest-cost resources while maintaining reserves. Day-ahead forecasts tracked actual load within 1.5%, reducing the risk of last-minute operational surprises.

Midday Plateau (10:00 – 16:00)

Load stabilized just over 70,000 MW. This period featured the most balanced generation mix of the day:

- Solar reached peak output, contributing around 30% of system generation.
- Wind generation continued to supply ~35%.
- Natural gas plants operated efficiently in support, providing load-following flexibility and reserve services.

The renewable share of generation peaked at nearly 67%, illustrating how ERCOT's portfolio can leverage favorable weather and resource diversity. Despite high demand, prices remained below $15/MWh. No reliability events or market interventions were required.

Evening Ramp (16:00 – 21:00)

As the sun set, solar generation declined rapidly. Load, however, continued to rise—peaking near 77,000 MW between 5:00 and 6:00 p.m. Wind maintained a strong presence, contributing over 25% of generation even into the evening.

Natural gas plants ramped back up to meet net demand. Prices rose modestly, reaching $25–$35/MWh at the peak, but remained well below scarcity thresholds. Ancillary services were sufficient, and operators did not need to take any emergency actions.

Nightfall (21:00 – 24:00)

As demand tapered to around 65,000 MW, wind output remained solid and natural gas units began to back down. With lower evening temperatures and declining system stress, ERCOT operators began releasing some ancillary service obligations. Prices fell back to the mid $20s/MWh.

What June 22 Tells Us

This was a quiet success story — a day when steady baseload support, flexible ramping, and well-positioned reserves kept the system balanced without drama:

- 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, demonstrates that ERCOT's reformed energy-only market, supported by steady baseload resources and flexible ramping capacity, can meet high-load summer conditions with both affordability and resilience. It was a textbook example of what a successful, balanced day looks like.

Chapter 2: When Flexibility Defines Normal

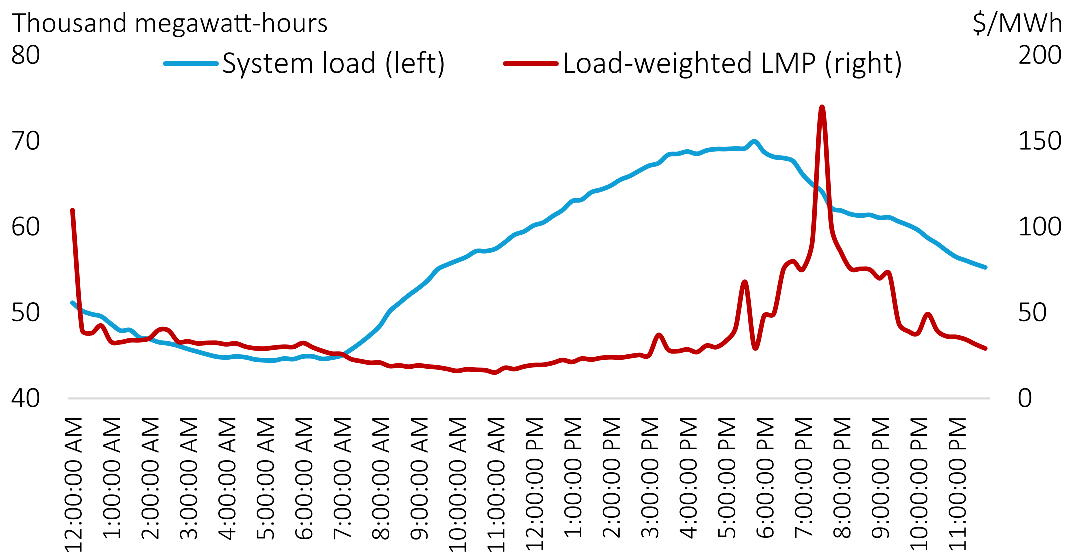
In Chapter 1, we saw ERCOT at its most stable: a high-load summer day balanced by sufficient output from renewables, with dispatchable generation in support of system flexibility.

But not every normal day looks like that.

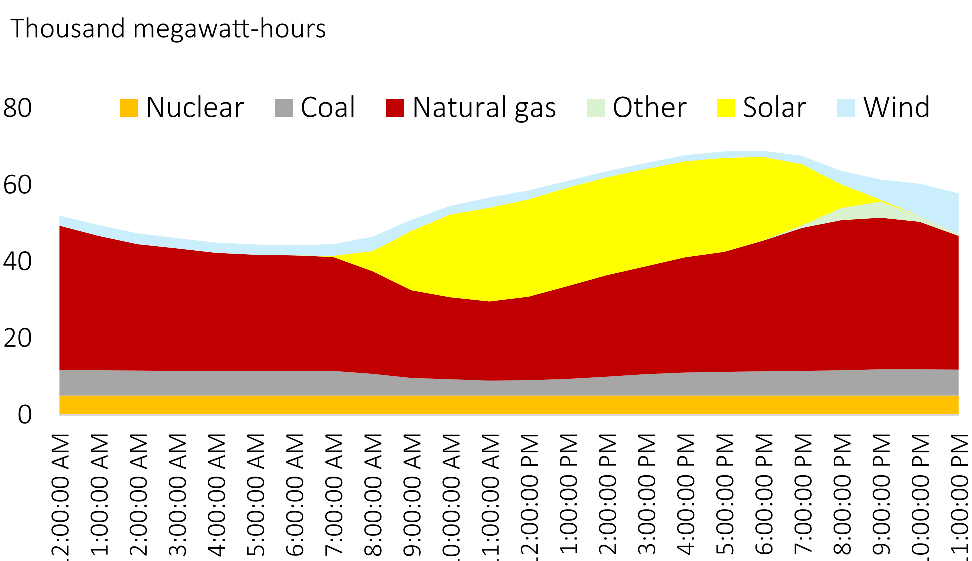
In a grid increasingly shaped by the availability of wind and solar, “normal” often means something more dynamic. It’s not just about meeting demand—it’s about matching the shape of demand with resources that can respond in real time. When renewables underperform, natural gas generators must react with speed and precision. The system must stay balanced. And prices must reflect what it takes to do so.

May 31, 2025, was one of those days. Although it was not marked by peak demand, a grid emergency, or extreme weather, it illustrates how the ERCOT market relies on flexible generation to maintain reliability—and how those resources respond. Compared to June 22, wind contributed less, solar output was steady, and natural gas again carried the reliability role. Notably, the pricing peak lagged the system load peak, reflecting the timing of reserves and dispatchable ramping needs rather than demand alone.

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. System demand fell to a nighttime minimum near 45,000 megawatts. Wind contributed modestly, averaging less than 5% of generation through the early hours. Natural gas filled the gap, ramping up to provide as much as 73% of total supply, while prices began the day at $58/MWh and steadily declined.

By sunrise, solar output began to rise. As it climbed through the morning, prices dropped further, reaching their lowest point of the day around 10 a.m., just below $17/MWh. Load, meanwhile, rose steadily—but the system remained in balance.

Midday Stability

At midday, solar generation provided more than 40 percent of total ERCOT output. Wind was almost absent—hovering around 2%—but with low net load, prices stayed grounded in the $20 to $30/MWh range. Natural gas generators maintained partial output, holding capacity in reserve.

To the casual observer, it may have looked like a quiet day. But system conditions were setting up for a different kind of challenge.

The Evening Turn

At 6:00 p.m., solar output began a predictable descent. Within two hours, more than 15,500 megawatts of solar had exited the system. Wind, still hovering around 1,600 MW, failed to rise to the occasion. Net load climbed sharply.

The grid now needed fast, dispatchable generation—and the market made that clear. Real-time LMPs jumped from $29/MWh at 4 p.m. to $48 by 6 p.m., then surged to $100/MWh by 7:45 p.m.

While ERCOT had procured reserves and forecasted the solar drop, real-time conditions proved tighter than expected. Wind underperformed, net load climbed faster than forecast, and marginal generators priced accordingly. These were not scarcity prices—no Operating Reserve Demand Curve (ORDC) adders were triggered. ORDC is the mechanism that increases prices when operating reserves fall short—but they reflected genuine tightness in dispatchable capacity.

Natural gas-fired generation ramped from around 20,000 MW at midday to nearly 40,000 MW by evening—doubling across the system. This output was a command response with timely, controllable energy that keeps the lights on when the sun sets and the wind is late.

This ramp alone delivered 20 gigawatt-hours of incremental energy—roughly equivalent to New York state’s average daily generation.

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

Restoring Balance

As the sun set and temperatures fell, system demand began to decline. Wind picked up modestly, and gas generators gradually reduced output. By 11 p.m., prices had eased to the low $30s, and the grid returned to its overnight posture.

It was, once again, a normal night in ERCOT.

The Other Shape of Normal

May 31 wasn't extreme. It was simply a different kind of normal—one that required flexibility rather than abundance. The system needed resources that could respond fast and precisely to changing conditions, and those resources delivered.

The market worked. Prices reflected the challenge. And the lights stayed on.

That's the essence of modern reliability: not just having enough generation, but having the right kind—available at the right time—and a market structure that rewards it for showing up when needed.

In ERCOT, **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 fast.

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, while strong mid-afternoon, declined after 6 p.m. Wind was already low and contributed less than 7% during critical hours.

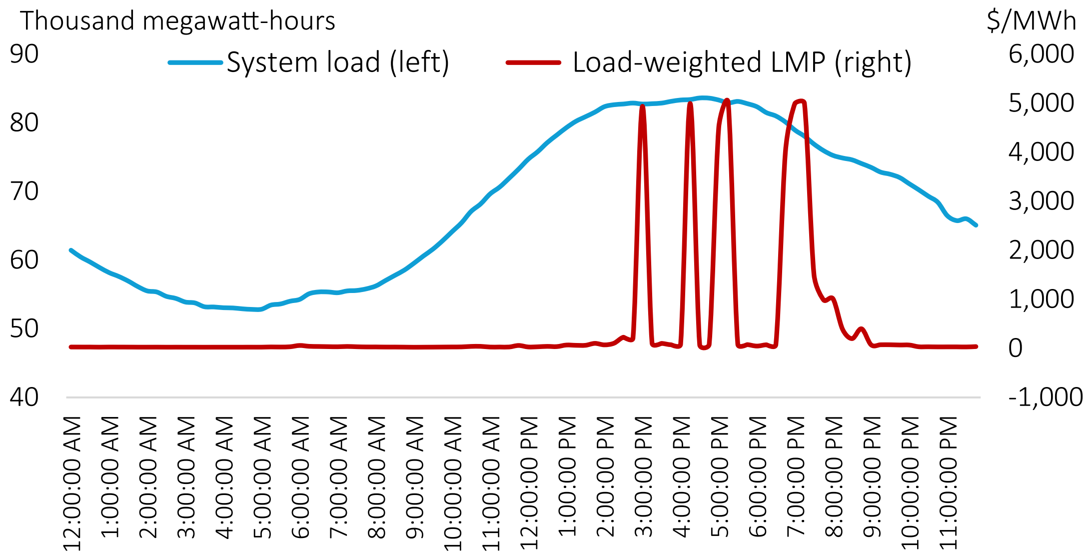
ERCOT operators saw the warning signs:

- 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 market failure—it was scarcity pricing, by design. The Operating Reserve Demand Curve (ORDC) activated, sending a blunt signal to every available generator: ramp if you can, or risk outages.

The 'spike-dip-spike' pattern shows how ERCOT prices respond to 5-minute reserve conditions. A brief tightening — from wind underperformance or a unit derating — can cause a sharp price increase, which then eases once reserves stabilize, even if load remains high. That's why prices don't always climb smoothly with demand.

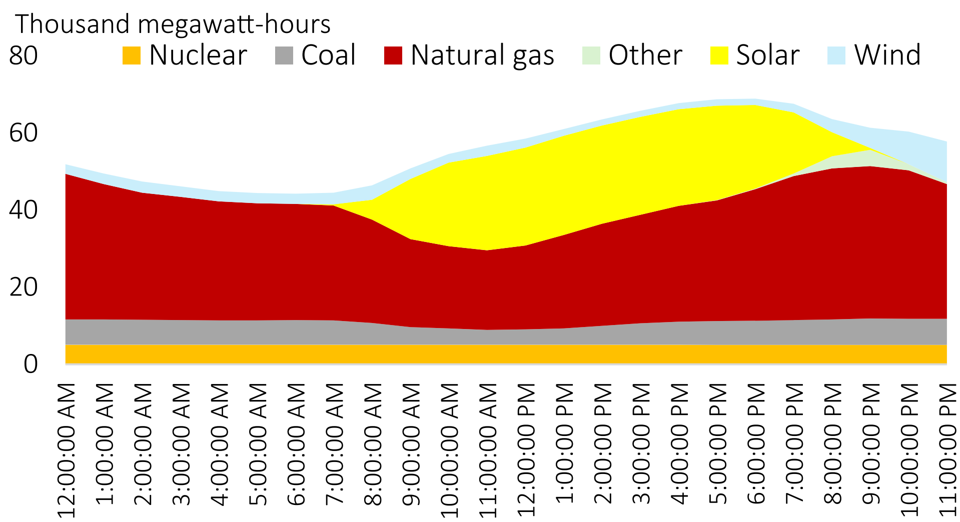
Figure 3a. Load, Locational Marginal Price (LMP): August 24, 2023



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



Natural gas-fired generators ramped sharply. Some operated continuously; others were dispatched specifically for the 5–8 p.m. window. Non-spin reserves were clearly deployed, including approximately 466 MW of traditional non-spin and 464 MW of ECRS-Slow reserves. Additional ancillary services committed in real time included over 290 MW of primary frequency response, 170 MW of under-frequency response, and nearly 100 MW of regulation reserves — indicating a coordinated response across multiple reliability layers. This was a day when the grid bent, but didn't break—largely because it leaned heavily on dispatchable resources under tight conditions.

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

Less than two years later, a similar pattern unfolded. On May 31, 2025 – the day we discussed in Chapter 2 -- the evening load peaked just under 70,000 megawatts—a full 14,000 MW lower than in August 2023. But operationally, the gris stress appeared familiar:

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

And yet the outcome was fundamentally different.

Real-time prices rose, but only briefly—and peaked around $100/MWh. No ORDC scarcity adders were triggered, no emergency deployments were needed, and the system rebalanced smoothly. Gas-fired generation again did the heavy lifting, flexing in response to load by as much as 19,000 MW over the course of the day.

What Changed Between 2023 and 2025

Solar and wind penetration had grown modestly over the two years, but not enough to explain the dramatically calmer price profile. The real differences were structural:

- **New flexible capacity** entered the market, including natural gas peakers and battery storage, with TEF-backed additions—including 122 MW at Kerrville, 456 MW at Wharton, Rock Island Generating in Colorado County, and two Calpine Freestone peakers—expected online beginning in 2026.
- **Ancillary service procurement** became more conservative, supporting ramping and flexibility needs.
- **Improved forecasting and operational planning** gave ERCOT better visibility—and more time to prepare.
- **Generator offer behavior** evolved, with thermal units increasingly participating in real-time markets without needing maximum price incentives.

Notably, the difference wasn't on the demand-side, which has continued to grow. In response, available resources have increased both in volume and flexibility.

From Scarcity to Stability

August 2023 illustrated how ERCOT's energy-only market delivers sharp scarcity signals to protect reliability when capacity is tight. May 2025 showed how that same market, strengthened by targeted reforms and growing flexibility, could manage similar stress with measured price signals and consistent performance. Both days required fast, responsive generation, but the recent one obviated the need the $5,000/MWh LMP price cap.

A Grid That's Learning

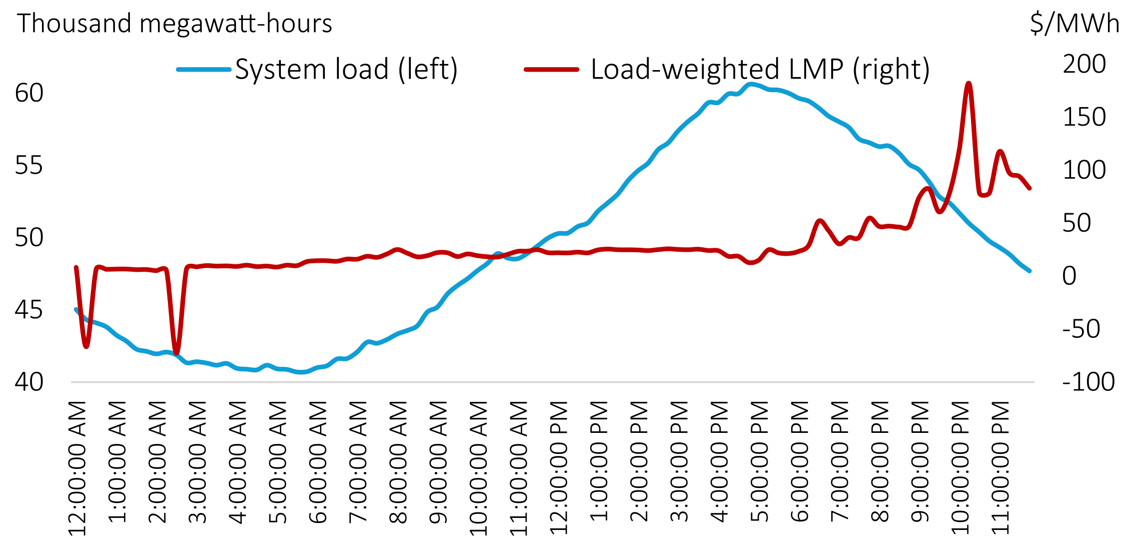
ERCOT didn't change its core design—it refined it. And it worked. This signifies a grid that's adapting and learning —growing in complexity, capacity, and composure. The key insight is that, with the right tools and balanced planning, scarcity becomes a signal—not a crisis.

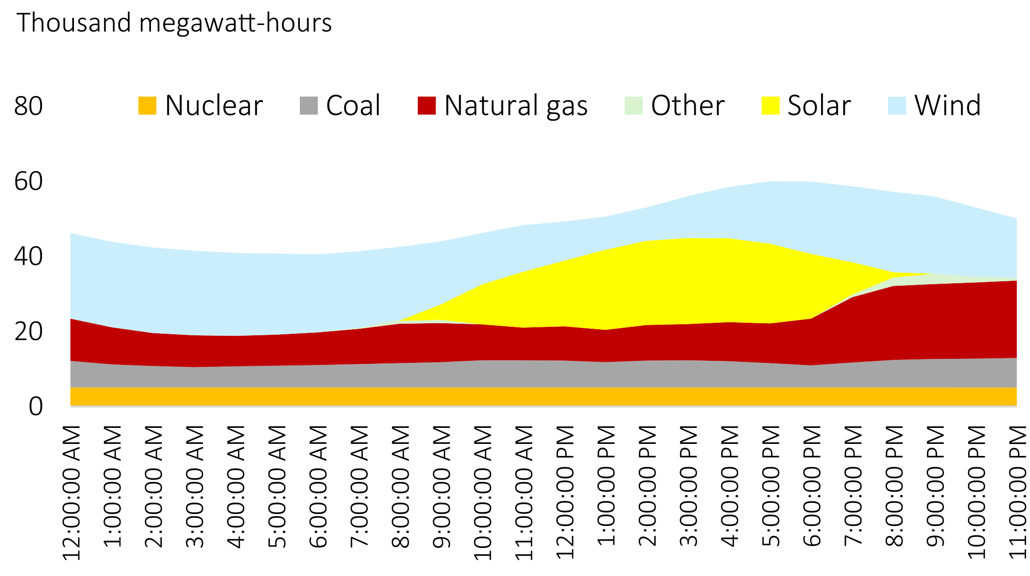
Chapter 4: The Net Peak Has Become the Real Peak

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

Why? Because the grid's net peak, not its gross peak, created the tightest moment of the day.

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





A Spring Day with a Familiar Shape

March 29 began without drama. Load climbed steadily, never approaching summer highs. Solar generation rose quickly, topping 22.9 GWh at 3:00 PM. Wind was productive during the day, averaging above 18 GWh, and gas plants cycled in the background.

By mid-afternoon, the system looked stable. Prices hovered between $20 and $40/MWh, and forecasts closely matched actuals.

Then Solar Fell—and Net Load Rose

After 6:00 PM, solar output began a steep decline, falling from 17.2 GWh at 6 PM to near zero by 9 PM. Meanwhile, wind declined slightly, remaining elevated but insufficient to offset the evening ramp. As solar vanished and electricity demand persisted into the evening hours, net load spiked.

To meet this shifting load, natural gas-fired generation ramped rapidly, doubling from about 10 GWh at 3 PM to over 20 GWh by 9 PM. As net load rose, load-weighted real-time LMPs climbed steadily, peaking at $181.59/MWh at 10:15 PM.

There was no reliability alert and no scarcity pricing event. But the system was tight, and the market sent a clear price signal for dispatchable flexibility.

What Is Net Peak, and Why Does It Matter?

ERCOT's gross system load had already begun to decline by 7:00 PM. But net load—total demand minus renewable output—reached its net peak (the day's highest point of net load) after sunset, when:

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

This net peak is now among the most important operational and economic moments on the ERCOT grid. It defines when fast-ramping capacity is most critical, and when market prices respond.

The Grid Has Changed—So Must Our Risk Lens

March 29, 2025, demonstrates that:

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

Rethinking Peak Planning in ERCOT

From Gross Load to Net Load

For decades, ERCOT focused on gross peak demand—usually the highest load on a sweltering summer afternoon—as the benchmark for reliability planning. But as solar generation has grown, the true point of system stress has shifted.

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

On March 29, 2025, for instance:

• Gross load peaked near 60,700 MW around midday

• But net load peaked at 7:30 PM, when solar had vanished and wind stayed low

• That's when LMPs 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 can miss the risk if they ignore **timing and ramping needs**

Reliability in today's ERCOT isn't about having "enough" generation— It's about having it at the right time.

Prices over $180/MWh weren’t triggered by outages or emergencies. They were the result of a grid performing as designed—signaling the need for flexible dispatchable generation as the sun went down.

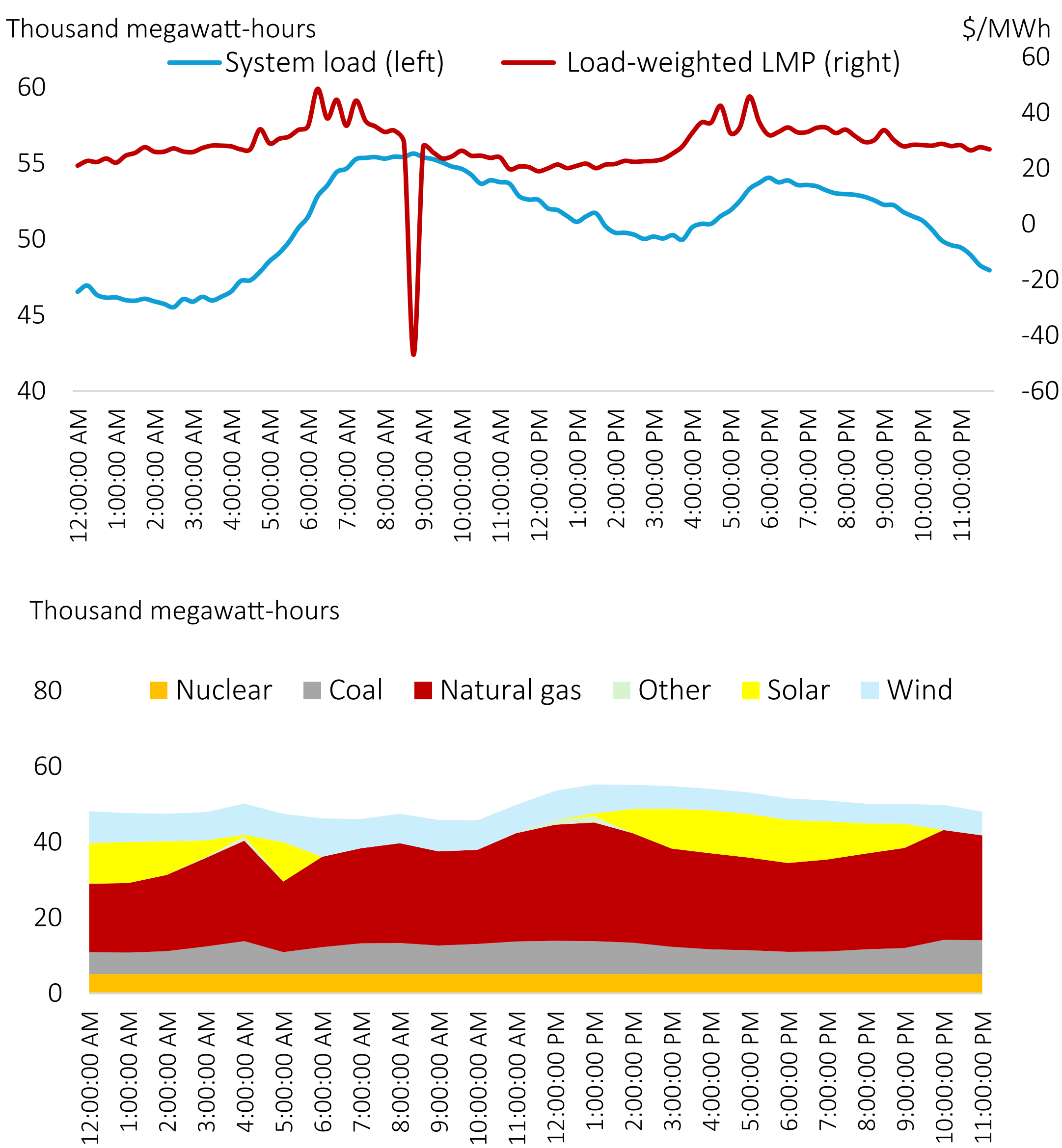
Redefining “Peak” in a High-Renewables World

In years past, price spikes aligned with the highest point of daily demand. Now, they increasingly align with net peaks, when dispatchable generation must step in to replace falling renewables.

This spring evening shows that even non-summer days can stretch the system—and why ERCOT’s market design must continue to value and enable flexible, responsive resources.

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



Why Did Prices Dip Before 9 AM?

This was not a data error. The brief collapse into negative prices reflects a momentary oversupply: committed dispatchable units were already online while demand was still flat and solar output had yet to begin. With supply briefly exceeding load, prices fell before recovering as the morning ramp took hold.

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 electric heating systems kicked in. Load peaked just after 8:00 AM at more than 55,800 megawatts—a solid winter morning peak. Wind output was strong overnight but dropped by half as the morning progressed. Solar remained limited, typical for a December profile.

Yet in the ERCOT control room, things were calm.

Ramping Without Alarms

Operators watched the morning ramp unfold much as they had expected. Wind, which supported the system overnight, fell from more than 10,000 MW before sunrise to under 6,000 MW by early afternoon. Solar contributed modestly, peaking around 11,400 MW midday. Yet the bulk of the ramping burden fell to natural gas.

Natural gas-fired generators flexed between 18,100 MW and 31,400 MW, essentially mirroring the reverse of renewables' decline.

Despite rapid changes in renewable output and a steep rise in load, there were no emergency alerts, no deployment of non-spin reserves, and no real-time reliability actions. Locational Marginal Prices (LMPs) tracked the load curve, peaking around $48/MWh in the morning—never signaling scarcity.

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 stayed well below critical thresholds.

Most importantly, the system showed wintertime discipline—quiet operations that don't make headlines but speak volumes. This wasn't a stress test. It was a real-world demonstration of routine resilience.

Why Thermal Still Matters

December 6 was a reminder that when solar is weak and wind declines, dispatchable thermal generation—especially natural gas—is essential. These resources carried the system through its coldest hours and tightest ramp periods. Without gas generators' flexibility and scale, the steady success of December 6 could have turned into a far more difficult story.

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

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 Texas Legislature through ERCOT and the Public Utility Commission of Texas (PUCT) implemented a suite of reforms aimed at strengthening winter grid reliability. The smooth performance on December 6, 2024, reflects many of these efforts working in practice.

1. Cold Weather Preparedness Standards (SB 3)

- Power generators must now weatherize for extreme cold.
- The PUCT and Railroad Commission of Texas (RRC) enforce inspections and compliance.
- Fuel supply infrastructure is also subject to winterization requirements.

Impact: Increased availability of thermal units during winter ramps.

2. Conservative Operational Posture

- ERCOT routinely maintains higher operating reserves in winter.
- Seasonal risk assessments now account for temperature-sensitive demand.
- Reliability Unit Commitments (RUCs) are used more proactively.

Impact: Fewer surprises during cold morning and evening ramps.

3. Emergency Response Enhancements

- Improved communications 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.

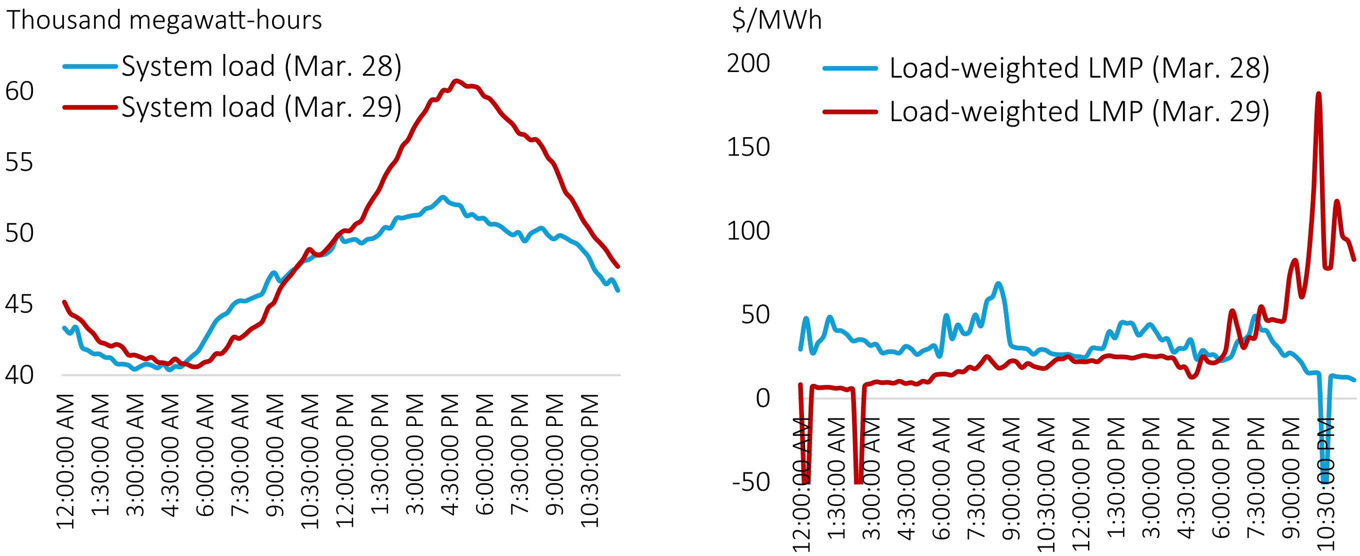
4. Texas Energy Fund (TEF) Support. TEF projects were still in development as of 2024. By 2025, loans had been approved for Kerrville, NRG Wharton, Rock Island Generating, and Calpine's Freestone peakers—together representing several hundred MW of dispatchable capacity slated for 2026–2027.

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

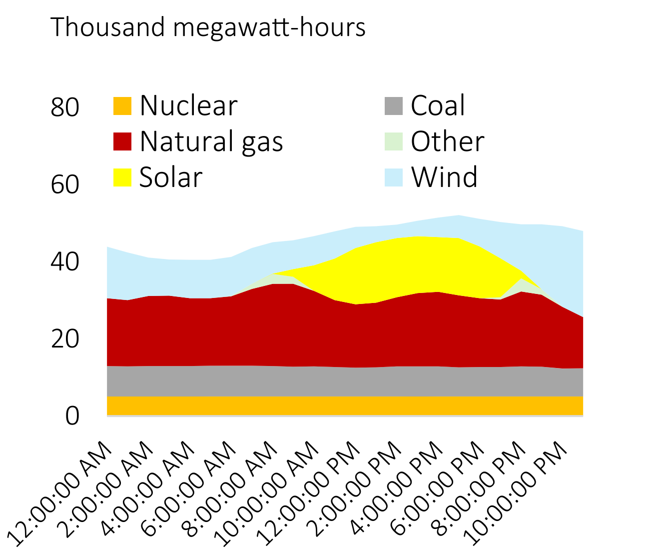
ERCOT's grid performed steadily on March 29, 2025, as described in Chapter 4. Prices rose above $180/MWh during the evening ramp, but overall, the system stayed on track. Natural gas units responded. Wind arrived later in the day. The transition from day to night was tight—but controlled.

Yet just one day earlier, on March 28, load conditions looked remarkably similar through midday. But market outcomes diverged dramatically: 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



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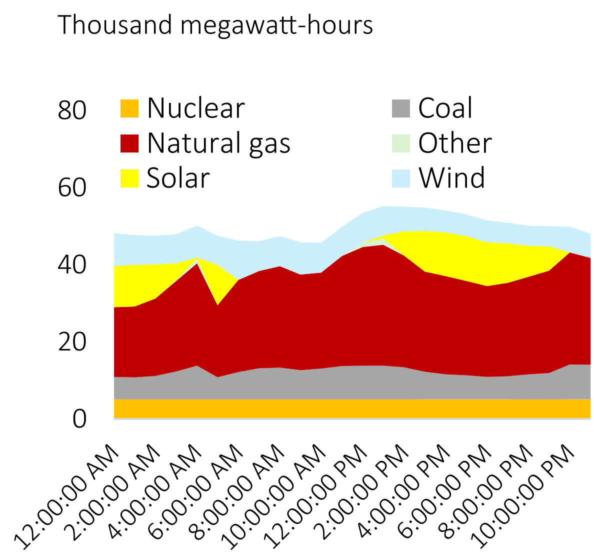


A Day of Operational Ease

March 28 was operationally calm, thanks to a mix of conditions that reduced system stress during the critical evening hours:

- Higher thermal generation: Natural gas output was more than 50% higher than on March 29, giving the system flexibility, inertia, and ramping capability as solar declined.
- Smoother renewable profiles: Wind and solar generation were both lower and steadier, reducing net load swings and easing dispatch requirements.
- A more gradual evening transition: Higher baseline dispatch and relatively flat load made the solar fade manageable, with no signs of price or reliability strain.
- More conservative load forecasting: ERCOT's day-ahead forecast slightly overestimated demand on March 28 but underestimated it on March 29—contributing to tighter margins and higher price sensitivity.

ERCOT's Market Rewards Precision

These two days—virtually identical in gross load and renewable share—underscore how minor operational mismatches can cause amplified price effects. ERCOT's real-time market reacts sharply to:

- Shifts in the timing and flexibility of dispatchable generation
- Rapid net load changes, especially at solar sunset
- Market confidence (or lack thereof) in resource sufficiency

One Day Apart—But a World of Difference.

On March 29, evening prices spiked. The price rise didn't result from any single failure but from a convergence of factors: slightly higher net load, delayed wind arrival, and reduced natural gas headroom. Compared with the calm of March 28, it illustrates ERCOT's evolving challenge: reliability and price no longer depend solely on how much generation is available, but on whether it's ready at the exact moment it's needed.

When Precision Matters – What Drives Divergence on Similar Days?

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 lies in the grid's heightened sensitivity to operational precision—especially during the evening ramp.

Market Sensitivity Drivers

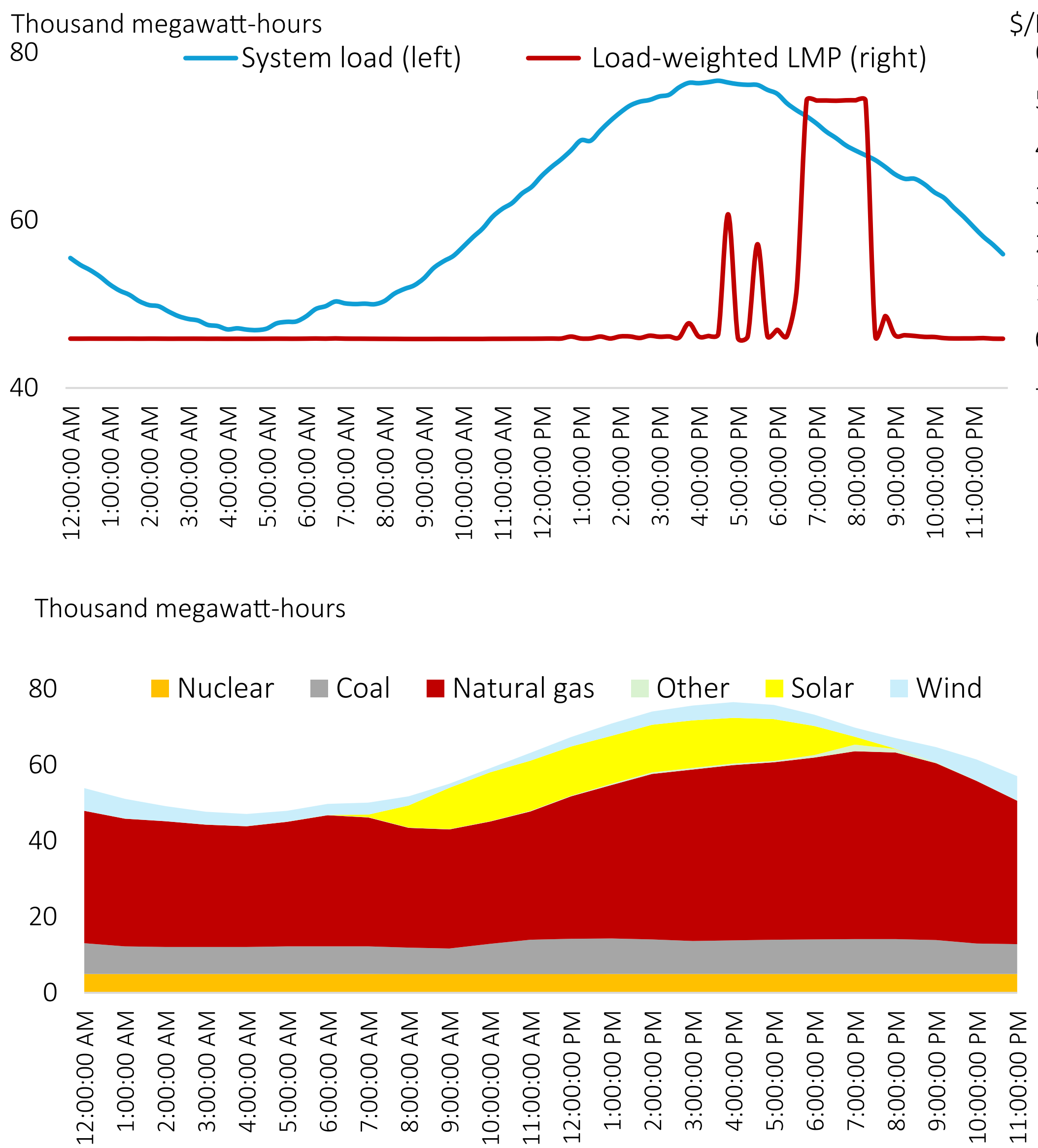
- **Forecast Error.** A 2–3% miss in wind or solar output near sunset can leave 1,000–2,000 MW unserved—just as dispatchable resources are needed most.
- **Delayed Dispatch.** Gas units often need 15–30 minutes to start and reach output. If not committed in advance, they may ramp too late to stabilize prices.
- **Ramp Rate Limits.** Some thermal and storage units can't ramp as quickly as net load rises when solar fades, steepening the evening challenge.
- **Market Confidence.** Even if resources are available, uncertainty about timing or sufficiency can drive ERCOT to price conservatively—raising LMPs to incentivize immediate action.

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 vanished. At 6:38 PM, ERCOT declared an Emergency Energy Alert Level 1 (EEA1)—signaling that reserves had dropped below 2,300 MW and urgent conservation was needed. Just 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 depleted
- Demand continued climbing into sunset

ERCOT operators had few tools left. Conservation requests blanketed the media, and Texans were asked 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 clear demonstration of how the Operating Reserve Demand Curve (ORDC) steps in:

- Raise prices before the grid hits crisis.
- Signal the true value of reserves when they are scarce.
- Provide earnings for resources that show up.

On August 30, it did all three. As prices rose towards $5,000/MWh over multiple intervals, every available MW was called into action. No blackouts occurred. The system held.

Holding Together by the Megawatt

ERCOT's avoidance of outages didn't stem from surplus—it came from the fact that thermal generators were already online, conservation kicked in promptly, and there were no surprise outages. Even still, It was a near-miss, as one tripped unit or missed dispatch could have flipped the story from success to crisis.

What August 30 Still Teaches

- High demand alone isn't fatal—it's the combo of high load, low renewables, and thin reserves that bites.
- Conservation worked—but it's not a scalable reliability tool.
- Scarcity pricing did its job—signaled emergency, mobilized supply, preserved the grid.

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.

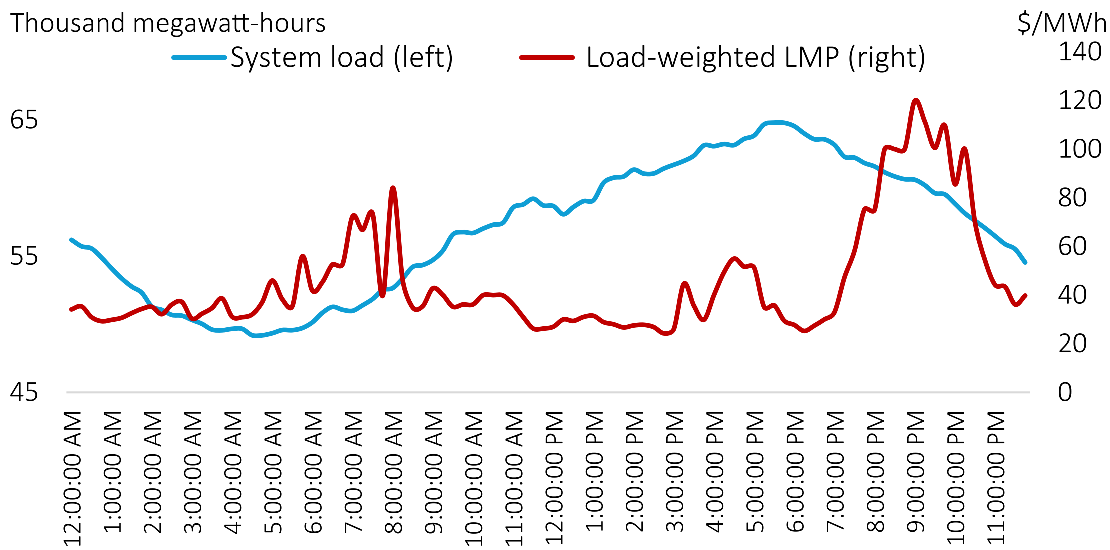
But this can't be ERCOT's main line of defense.

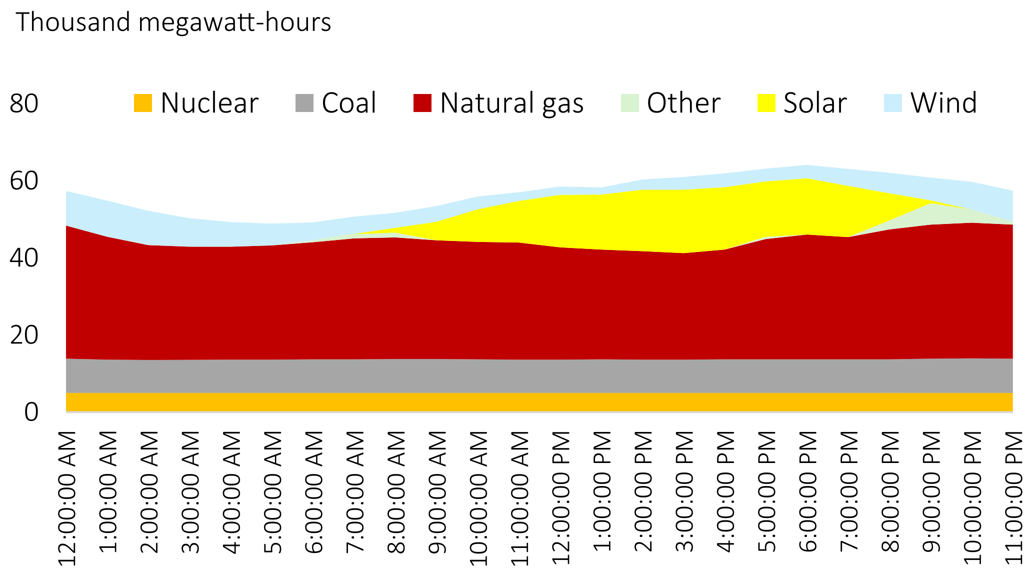
Chapter 8: The Hidden Risk Hour – When Net Load Runs High Before Sunrise

Some days, the ERCOT grid tightens not at sunset, but in the quiet hours before most Texans wake. **June 11, 2025**, was one of those days.

By 7:00 AM, net load—the portion of demand not met by renewables—had already surged. Dispatchable resources supplied over 89% of ERCOT's generation, even though total system demand hadn't yet peaked. Wind was weak. Solar hadn't arrived. And the grid needed flexibility now—not later.

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





vered on. But

demand spike,

Traditional reliability planning emphasizes **summer afternoons** and **winter mornings**. But June 11 revealed a new risk window: early summer mornings, when renewable output is minimal but demand ramps steadily. This day illustrates that:

- **Net load ramps aren't confined to evenings**
- **Morning flexibility needs are growing**, especially when wind underdelivers overnight
- **Operational headroom can vanish quickly**, before solar contributes meaningfully

"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."

Pricing Without a Crisis

Unlike scarcity events or emergency pricing days, June 11 delivered a clear early signal—and the market responded. Natural gas generation responded, and prices eased by mid-morning.

But this episode shows that ERCOT's operational stress points are now dynamic, shifting with renewable patterns and consumer behavior—not fixed to legacy peak hours. The key question is how prices balance out: renewables reduce average costs but shift the timing of stress. Without them, the peak would be more predictable but almost certainly more expensive.

Key Discussion – Renewables and Price Balance

Renewables reduce average wholesale prices by displacing higher-cost generation, but they also shift when the grid is most stressed. Without renewables, peak prices would likely be higher and occur at more traditional late-afternoon hours. With renewables, average costs fall—but operational stress emerges dynamically, especially during sunset ramps or low-renewable mornings.

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 it's a reminder: the modern grid doesn't wait for solar to rise or wind to show up. Flexibility now begins at dawn.

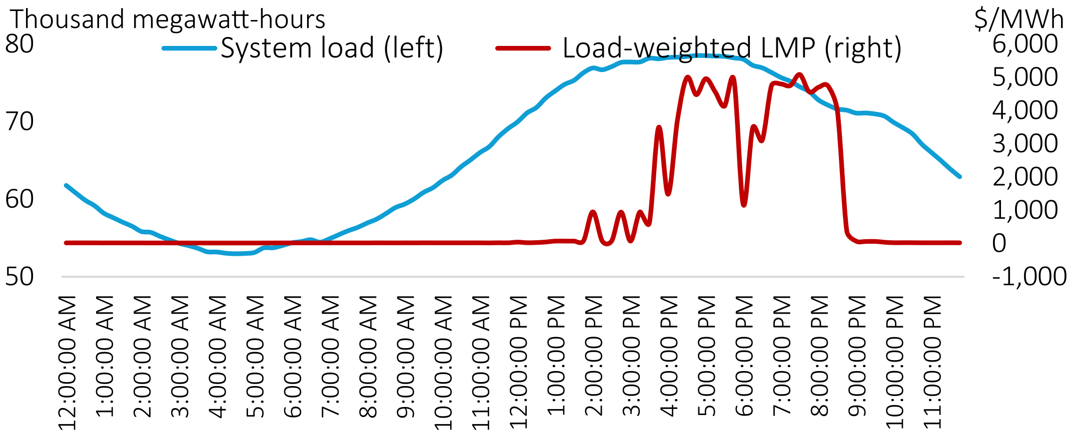
Chapter 9: A Demand Day, or a Dispatch Day?

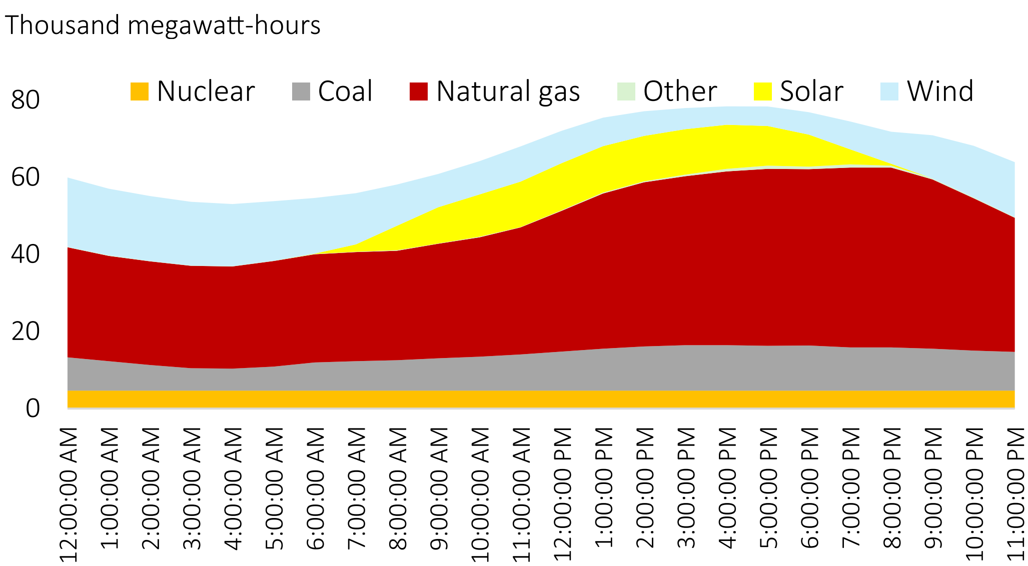
June 20, 2023 didn't break load records. Total demand peaked around 79,000 MW—a high summer level, but not unprecedented.

And yet, real-time prices repeatedly surged, hitting $5,000/MWh in multiple 15-minute intervals between 3:30 PM and 8:00 PM. 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





Interpreting the Price Line
The flat portion of the red line is not zero. For most of the day, load-weighted LMPs were around **\$20–25/MWh**. Because evening scarcity pushed prices above \$5,000/MWh, the chart scale compresses these values, making them appear near zero. Coal, nuclear, and gas units were earning at those levels throughout the day.

What Is "Morning Net Load Tightness"?

Net Load = Gross Load – (Wind + Solar)

At 7:00 AM on June 11:

- 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 signal available to incentivize ramping

Planning Implication: It's not just how high load goes. It's when it rises—and what else is available to meet it.

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When Demand Isn't the Driver

June 20 revealed a different truth: scarcity can arise from dispatch, not just demand.

In the afternoon, solar peaked then declined, while wind output dropped below 10% of installed capacity. With renewable contributions shrinking, dispatchable thermal plants were left to carry the evening ramp—while already near full output.

ERCOT's Operating Reserve Demand Curve (ORDC) began triggering adders as reserves fell. And because the gap wasn't due to a surprise outage, but to a combination of tight reserves and flat dispatch flexibility, prices spiked preemptively.

Dispatch-Based Scarcity in Action

This wasn't a forecasting miss. It was a confidence issue—one where the grid saw what was coming and had to act anyway.

Key indications from the data:

- **Net load climbed steeply** between 5:00 and 7:00 PM
- **Natural gas-fired generation maxed out near 46,600 MW**, offering limited upside
- **Wind dropped below 5,000 MW**, a fraction of what was needed
- **Prices hit $5,000/MWh repeatedly**—despite stable demand

This wasn't about "demand being too high." Rather, it was about the dispatch stack being too flat.

When the Stack Can't Stretch

What's a Dispatch-Based Scarcity Event?

A condition where:

- Dispatchable resources are near maximum output
- Renewables are falling (or stagnant)
- Reserves shrink—without a change in demand
- ORDC triggers **scarcity pricing** to secure rampable headroom

On June 20:

- Load ≈ 79,000 MW
- Gas ≈ 45,000 MW
- Wind ≈ 3,000 MW
- Scarcity pricing spiked—even without new outages

Policy Relevance:

"When renewables fade and thermal is already committed, you don't need a crisis to trigger $5,000 prices. You just need a grid with nowhere left to ramp."

A Market Signal—Not a System Failure

Importantly, ERCOT operated effectively:

- No emergency actions were needed
- Reserves dipped—but did not vanish
- The market did its job: signaled scarcity, mobilized flexibility, and preserved reliability

But from a policy perspective, June 20 was a precautionary warning that 1) dispatchable headroom is finite; 2) reserve scarcity can emerge from normal conditions; and 3) volatility arises not just from demand—but from the shape of the stack.

What This Day Still Teaches

- It's not the magnitude of load, but the margin of flexibility that matters.
- Scarcity pricing can hit $5,000 even on well-forecasted days.
- More capacity doesn't help unless it can ramp and respond.

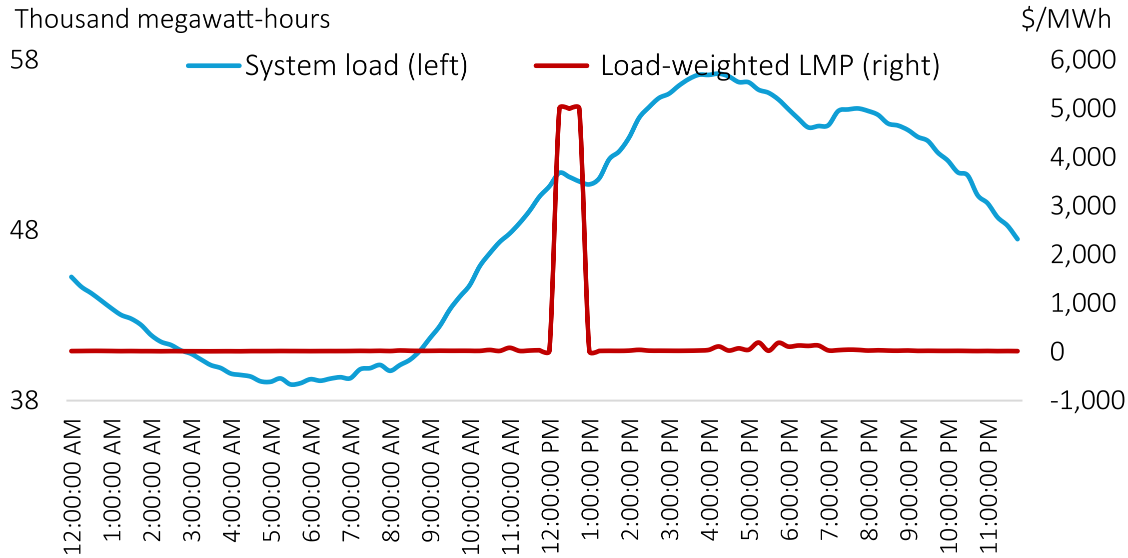
Chapter 10: A Spike Without a Storm

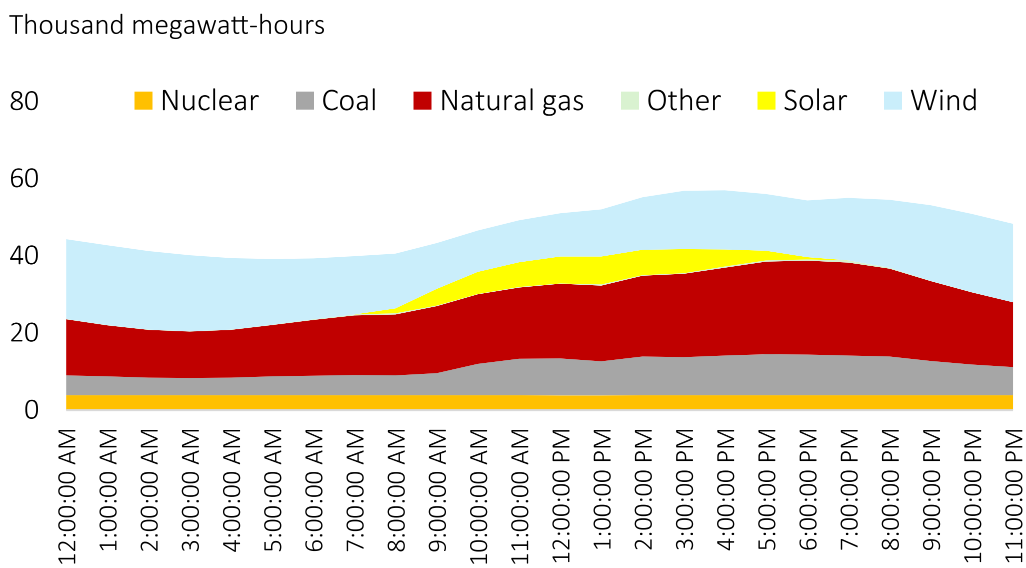
October 22, 2023, was not a day anyone expected to be noteworthy.

- It was a mild autumn Sunday.
- Load peaked around 57,000 MW, well below summer or winter extremes.
- Wind and solar were both present and contributing meaningfully.
- No weather warnings, grid alerts, or operational emergencies were issued.

And yet, at 12:15 PM, ERCOT's real-time load-weighted price jumped to $5,000/MWh—the system's market cap.

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





A Calm Day—Until It Wasn't
For most of the day, load followed a gentle arc. Solar generation increased smoothly in the morning, peaking around 11:30 AM. Wind output hovered between 10,000 and 14,000 MW. Gas-fired generation and coal held steady.

From an operations standpoint, this was boilerplate. So what triggered the price spike? The answer likely lies not in physical scarcity—but in market mechanics.

What Likely Happened
The price spike occurred just after system net load had crested and was beginning to decline. Load remained steady. Renewable output held constant. Ancillary service deployments were low. And neither a reserve price adder nor a reliability adder was present.

That points away from broad market scarcity—and toward a localized, transient disruption. The most plausible explanation: a sudden derating or withdrawal of a major dispatchable unit, triggering momentary uncertainty in the real-time market. This kind of event can force ERCOT to rapidly re-optimize dispatch using a limited set of available resources—potentially triggering a brief price spike to the market cap, even in the absence of a system-wide shortfall.

When ERCOT prices hit the $5,000/MWh system cap, **every generator producing energy in that settlement interval receives that price for their output**. This is how ERCOT's single clearing price design works: it rewards all resources online at the same time as the marginal unit. In this case, because the spike lasted only one 5-minute interval, the total payout was limited—but the signal was dramatic.

But just as quickly, the system regained balance. By the next interval, prices had fallen back to $21/MWh—a return to normalcy that underscores how brief real-time dislocations, not structural scarcity, can still drive outsized price signals.

It's Not Always About Load

This day underscores a key market truth: You don't need record demand for record prices. You just need the right 15 minutes.

- Load never exceeded 57,200 MW
- Wind and solar were available
- There were no declared emergencies

But still—prices hit the cap.

Lesson: Even in a high-renewables grid, ERCOT remains vulnerable to brief imbalances in reserves, unit dispatch coordination, or unexpected outages. And the market reacts immediately.

When prices hit the cap, every generator producing energy in that moment receives the cap price—whether or not they were the marginal unit that caused the spike.

What October 22 Tells Us

- Scarcity pricing can occur in quiet hours—not just at peak or during extreme weather
- Midday can be vulnerable, especially when solar ramps are shifting and contingency reserves are thin
- Markets are sensitive to timing, commitment, and confidence, not just raw megawatt counts

This day was not a crisis. It was a reminder that a few missing megawatts—or just one mistimed dispatch—can trigger scarcity pricing at the system cap—even without broader instability. In that sense, October 22 was a lesson in how a system can remain reliable—and still be expensive for a moment.

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

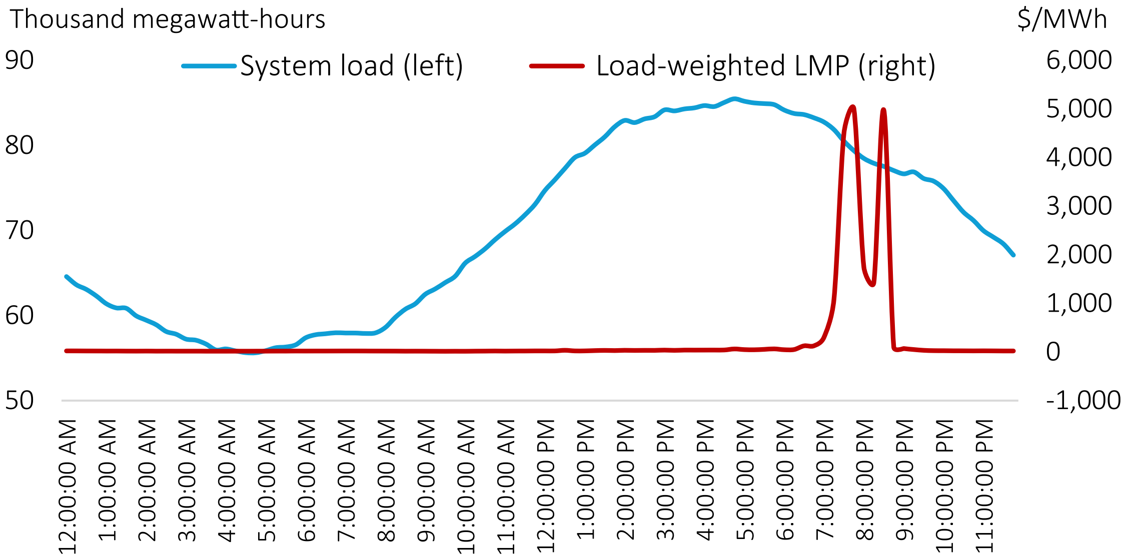
Even in a well-functioning grid with stable load and strong thermal performance, pricing can still spike dramatically—if conditions tighten just enough at just the wrong time.

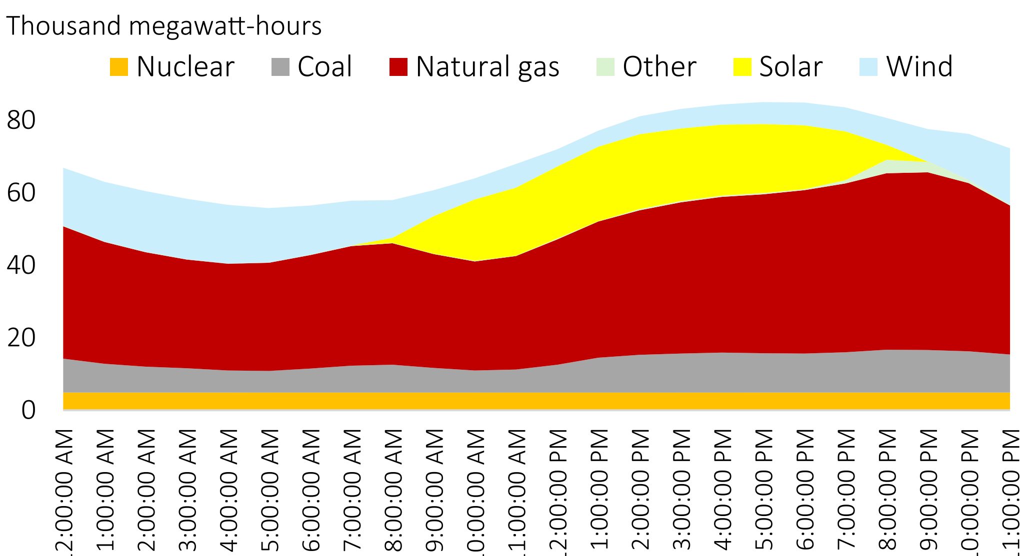
A High-Load Summer Evening

ERCOT's system load climbed through the afternoon, peaking above 86,000 MW shortly after 6:00 PM. This was one of the highest loads of the summer, driven by persistent heat across the state. Solar generation delivered strongly throughout the day, providing over 11,000 MW at peak before falling sharply after sunset.

Wind hovered near 10,000 MW in the morning but declined in the afternoon, offering limited help during the evening ramp. That left dispatchable thermal generation—especially natural gas units—to manage the net load increase.

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





Scarcity Despite Stability

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). Hitting that cap has a powerful impact on how generators operate:

1. Maximized Generator Dispatch. When real-time prices approach or hit the cap:

- All available thermal generators are **strongly incentivized to come online**, even if operating costs are high.
- Some peaking units that normally sit idle may finally become economical.
- Dual-fuel and less-efficient assets may also dispatch if qualified.

2. Delayed Commitments Can Be Costly. If generators delay startup waiting for a better price signal or clearer forecast, they risk:

- Missing the interval entirely, forfeiting high revenues
- Being penalized if they fail to deliver after self-committing or clearing in ancillary markets

3. Strategic Withholding or Gaming Risks. Price caps are meant to limit total exposure for consumers, but they also define the ceiling for generator revenues:

- Some generators may withhold capacity in earlier intervals to maximize returns during scarcity.
- This makes market monitoring essential to ensure behavior remains consistent with reliability goals.

4. Investment Signals and Revenue Sufficiency. While infrequent, cap-level prices:

- Contribute significantly to annual generator revenue
- Justify continued investment in flexible, fast-start units
- Offset the absence of a centralized capacity market

Bottom line: When prices hit the cap, it's the market saying: *"We need you now."* And generators are expected to be ready—fast, firm, and fully responsive.

Although system conditions did not trigger a reliability alert or emergency action, the market hit a key inflection point just after 7:00 PM. In a span of two hours, real-time prices eclipsed $4,000/MW during four 15-minute intervals and hit the cap price of $5,000/MWh at 7:30 PM. Why?

- Reserve margins narrowed, not because of outages, but due to the rapid decline in renewables.
- Gas units were already near full dispatch, limiting ramping flexibility.
- The Operating Reserve Demand Curve (ORDC) triggered scarcity adders, signaling that additional capacity—if available—was urgently needed to avoid risk.

- Importantly, the high prices were *not* due to forecast misses or operational surprises. They were a reflection of a tight but orderly market responding to real-time scarcity conditions exactly as designed.

The Value of Responsive Generation

Natural gas generators carried the day. Between 5:00 and 8:00 PM, natural gas-fired output ramped by nearly 6,000 MW—offsetting both the solar decline and weak wind. Coal and nuclear remained steady, and battery storage (while present) offered limited peak-hour support.

This kind of performance reinforces the ongoing value of thermal resources for reliability—even in an evolving grid with growing renewables and storage. The ability to respond quickly, predictably, and at scale during tight hours is what earns dispatchable fleets their premiums.

Policy Insight: Scarcity Pricing Works—But It's Not Always Comfortable

August 20 offers an important lesson: scarcity pricing is not a market failure. It's a feature. The system worked, and consumers remained served. But the discomfort of seeing $5,000/MWh prices—even briefly—underscores the need for:

- More responsive resources, especially fast-ramping technologies
- Thoughtful ancillary service procurement to bridge renewable drop-offs
- Consideration of how and when scarcity signals should be softened or sharpened

This Was a Success—And a Warning

No outages occurred. No emergency reserves were deployed. But ERCOT walked a narrow line, and the prices told the story.

August 20 showed that even in a grid with strong capacity and clear forecasts, sunset can test the system's limits. The pricing signal didn't mean failure—it meant just enough success to avoid it.

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

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 failed to 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 heavy load and high net peak ramping, yet LMPs remained calm.
- **June 11, 2025:** Dispatchable generation carried 89% of load at sunrise, but prices hovered near $50/MWh.

Real-time market prices alone often don't capture operational tightness—especially under ERCOT's evolving reserve posture.

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

Peak system load is no longer the defining moment. Instead, **net peak**—the point when solar fades and wind is unavailable—now dictates ramping needs and reliability challenges.

- May 31, June 11, and March 29 each saw extreme net load ramps without corresponding gross peaks.

This reframes planning and resource adequacy around *timing and flexibility*, not just capacity.

3. Natural Gas Generation Remains Indispensable

On high-renewable days, thermal units led by natural gas backed off. On high net load days, they ramped up. Their flexibility and availability—often unseen in policy summaries—remain essential to ERCOT's hour-by-hour reliability.

4. Scarcity Has Been Replaced by Silent Costs

Scarcity pricing occurred rarely. But that doesn't mean costs disappeared. They simply shifted to:

- Larger reserve procurement
- More frequent pre-contingency RUCs
- Increased ancillary service reliance

These mechanisms maintained reliability—but masked operational stress behind stable prices.

5. Curtailment Risk Is Growing

On October 22 and June 22, prices turned negative as renewable output exceeded system needs. Oversupply—especially in shoulder seasons—is now a more common risk than shortage. The IMM references this only briefly. But the grid-level data show that **managing surplus is as important as managing scarcity**.

What This Means for Policy: TEF, PCM, and HB 3356

The Texas Energy Fund (TEF): A Forward-Looking Resource
Operational improvements observed in late 2024 and 2025 — such as scarcity-free extreme load days, seamless winter morning ramps, and controlled summer net-load transitions — occurred before TEF-backed capacity entered service. The first TEF-funded projects—including 122 MW in Kerrville, 456 MW at Wharton, Rock Island Generating, and Calpine's two Freestone peakers—are approved but not expected online until 2026–2027.

- **Evidence:** The stability to date has come from existing resources, batteries, and ERCOT's conservative operations.
- **Implication:** With a second tranche of TEF funding now approved, evaluation should remain forward-looking — ensuring that investments target flexible, dispatchable resources and clearly distinguish between the stability ERCOT has already achieved and the additional contributions TEF projects are expected to deliver once they come online.

The Performance Credit Mechanism (PCM): The Right Call for Now
In December 2024, the Public Utility Commission of Texas unanimously **tabled the proposed $1 billion-per-year PCM**, finding limited reliability benefit relative to cost.

- **Evidence:** Thermal resources are already responding without subsidies, ancillary service reforms have improved system flexibility, and scarcity pricing is rare because the market is working — not failing.

- **Implication:** The PUC's decision reflected the data: rather than layering on PCM, future mechanisms should be judged by whether they add real reliability value—or simply compensate resources already performing.

HB 3356: A Case Against Static Modeling
HB 3356, debated in the 2025 legislative session, would have imposed retroactive firming requirements on renewables based solely on 2023 data. Our 2024–2025 evidence shows a more dynamic system: fewer price spikes, smoother ramps, and rapid operational improvements.

- **Evidence:** Reliability stress points shift with renewables and demand patterns, underscoring the danger of backward-looking, static models.

- **Implication:** Both Federal and state policymakers alike have rejected retroactive approaches. The Trump administration declined such changes under OBBBA, and the Texas Legislature similarly set aside HB 3356 in favor of forward-looking reforms in HB 1500.

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

- **Refine the Operating Reserve Demand Curve (ORDC):** Move from step changes to a smoother, risk-based curve tied to loss-of-load probabilities. This would improve price formation, strengthen incentives, and avoid artificial scarcity pricing.

- **Advance Real-Time Co-Optimization (RTC):** ERCOT's market does not yet co-optimize energy and ancillary services, obscuring the true cost of reserves. RTC will address this by internalizing trade-offs and aligning price signals with operational needs. The PUC was directed in 2019 to implement RTC "as soon as practical." Market trials are set for May 2025, with go-live scheduled for December 5, 2025—about six months earlier than the original mid-2026 estimate.

A Final Word: One Day at a Time

The IMM's annual review remains essential. But dispatch-level storytelling reveals what it 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 of market structure with bottom-up assessments of real-time behavior. That is how policy 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.

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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.

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 mechanism that raises wholesale energy prices when operating reserves fall below certain thresholds. ORDC adders are applied on top of the energy price and are paid to all generators producing energy at that moment, rewarding resources that are online during scarcity.

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 (as of August 2025)

Project / Unit Name	County	Fuel Type	Capacity (MW)	Expected In-Service	Notes
Kerrville (KPUB)	Colorado	Gas-IC	122	2026	First TEF loan executed ($105M)
NRG Wharton (THW GT 345)	Harris	Gas-GT	456	2026	TEF loan approved ($216M)
Rock Island Generating	Colorado	Gas-IC	TBD (~100+)	2027	TEF-supported; loan signed
Calpine Freestone Peaker 1	Freestone	Gas-GT	TBD (~100+)	2026	TEF-supported
Calpine Freestone Peaker 2	Freestone	Gas-GT	TBD (~100+)	2026	TEF-supported

sources: ERCOT Monthly Outlook for Resource Adequacy (MORA) (October 2025); PUCT TEF loan approvals and announcements.