Holiday Scarcity & Winter Warnings

November 22-28, 2025

Executive Summary

The trading week ending November 28, 2025, showed a clear contrast between the usually low demand expected during the Thanksgiving holiday period and the structural weaknesses emerging across several North American grids. While overall load patterns reflected the seasonal decrease due to the holiday, notable reliability issues in the Northeast and Texas revealed the grid's shrinking margins. The main story of the week was not just the operational volatility—highlighted by ISO New England's capacity shortfall on November 24 and ERCOT's ongoing wind-related resource advisories—but also a key regulatory dispute in the PJM Interconnection that could reshape the future of load interconnection. The filing of a formal complaint by the PJM Independent Market Monitor against the Regional Transmission Organization concerning data center interconnections marks a milestone, directly challenging the industry's ability to support hyperscale load growth without risking reliability standards.

At the same time, the week highlighted the growing divide within the Western Interconnection, as the California ISO announced record-setting benefit metrics for its Western Energy Imbalance Market (WEIM), while the Southwest Power Pool moved forward with its governance framework for the Markets+ initiative. Amid these market design disputes, the North American Electric Reliability Corporation (NERC) issued a stark Winter Reliability Assessment, warning of increased risks of energy shortfalls in MISO, ERCOT, and New England—predictions that were quickly confirmed by real-time scarcity events in two of those regions during the reporting period. As the industry shifts into meteorological winter, the collision of regulatory tensions, fuel supply limitations, and rapid demand electrification has drained the system of its historical buffer, leaving market operators to manage a just-in-time grid that is becoming more vulnerable to unpredictable variables.

CAISO

Weekly Summary

The California ISO (CAISO) market operations for the week ending November 28, 2025, were marked by the continued displacement of thermal generation by renewable resources, a trend that has begun to fundamentally change the pricing dynamics of the autumn shoulder season. Operational data from that week shows that despite the colder weather across the broader West, solar penetration within the CAISO area remained strong, suppressing midday prices and causing a growing gap between day-ahead and real-time settlement points. This operational stability was highlighted by the release of the Q3 2025 Western Energy Imbalance Market (WEIM) Benefits Report, which recorded a record $412 million in gross economic benefits, strengthening the economic case for regional integration even as governance disputes complicate the move toward a unified day-ahead market.

However, the week was not without its challenges, especially concerning the management of ramping constraints and intertie congestion. The intersection of solar curtailment protocols and the need for flexible ramping products created distinct pricing spreads, particularly during the net-load ramp hours. Regulatory activity focused heavily on the ongoing development of the Extended Day-Ahead Market (EDAM), with stakeholders examining the implications of recent FERC guidance on seams issues between EDAM and the emerging SPP Markets+ footprint. The tension between maintaining state autonomy over resource adequacy and achieving the efficiency gains of a larger footprint remains the main policy focus driving CAISO's strategic decisions this week.

Detailed Market Operations and Price Trends

The operational landscape within CAISO for the reporting period showed the significant influence of renewable energy on wholesale price formation. Day-ahead prices at the Default Load Aggregation Point (DLAP) averaged about $51.18/MWh for the week, a figure that masks the substantial intraday volatility caused by the "duck curve" phenomenon. During peak solar production hours from 10:00 AM to 2:00 PM, real-time prices often fell, reflecting the abundance of zero-marginal-cost energy. Conversely, prices in the evening ramp periods increased as the system operator dispatched gas-fired resources to offset the rapid decline in solar output.

A key metric for the week was the performance of the Flexible Ramping Product (FRP). Analysis of bi-weekly market performance data shows that flexible ramp-up and ramp-down test failures remained very low, peaking at only 0.6% and 0.4%, respectively, in recent assessments. This operational success indicates that CAISO's market software is becoming more capable of managing uncertainty, a crucial asset as the region incorporates more variable energy resources. However, congestion rents exceeding $11.5 million in the recent period reveal ongoing transmission bottlenecks, especially on the Midway-Vincent route and the Malin-500 intertie, which is a vital connection for hydroelectric imports from the Pacific Northwest.

The relationship between natural gas prices and electricity rates remains a key factor. Data from the Energy Information Administration (EIA) released this week showed that natural gas use for electricity generation in California has experienced its largest year-over-year drop, directly linked to the increase in solar generation. This switch in fuel sources is not just an environmental achievement but also an important economic safeguard; by reducing dependence on gas-fired power, CAISO participants are somewhat protected from the fluctuations of the spot gas market, which saw prices spike this week due to the cold front affecting the rest of the continent.

Regulatory and Policy Developments

The regulatory environment this week was dominated by the release and subsequent stakeholder review of the WEIM Q3 2025 Benefits Report. The report's finding of $411.98 million in benefits—bringing the total to $7.82 billion over its lifetime—serves as a strong rhetorical point for CAISO in its competition with SPP. Notably, NV Energy gained the largest portion of these benefits ($103.81 million), highlighting the importance of regional connectivity for balancing authorities with diverse resource mixes. The environmental aspect of these benefits, represented by 14,221 metric tons of avoided CO_2 emissions from reduced curtailment, further supports the alignment between market operations and California's decarbonization goals.

Governance remains a contentious issue. The "West-wide Governance Pathways Initiative" continues to serve as the forum for addressing concerns from stakeholders who are cautious of California-centric control. The release of a FERC staff whitepaper on November 21, 2025, concerning seams issues, increased the urgency of these discussions. The whitepaper warned that the fragmented landscape—specifically the "islanding" of non-contiguous market participants in EDAM and Markets+—could require complex and inefficient transmission scheduling practices such as "drive-out, drive-through, and drive-in" transactions. This regulatory guidance indicates that federal regulators are closely watching the efficiency of the divided western market and may step in if seams issues compromise reliability or fair, reasonable rates.

WEIM/EDAM

Weekly Summary

The Western Energy Imbalance Market (WEIM) remains a success story in the West. The Q3 2025 Benefits Report, released this week, shows $411.98 million in gross economic benefits for the quarter, bringing the total since inception close to $8 billion. These savings result from the efficient transfer of surplus renewable energy across the large geographic area, enabling utilities to avoid curtailment and replace more costly fossil fuel generation.

However, the shadow of the governance dispute between WEIM/EDAM and SPP Markets+ looms large. While WEIM delivers proven real-time benefits, the transition to the Extended Day-Ahead Market (EDAM) is facing headwinds from entities wary of CAISO governance. The FERC staff whitepaper on western seams issues highlights the operational risks of a fractured day-ahead landscape, warning that inefficient scheduling between the two markets could erode reliability.

ERCOT

Weekly Summary

The Electric Reliability Council of Texas (ERCOT) went through a week of operational turbulence that contradicted the calm expected during Thanksgiving week. Operations were managed under a "Resource Advisory" for much of the period, a status required by a combination of unusually high peak loads, scheduled maintenance outages typical of autumn shoulder season, and, most importantly, significant errors in wind generation forecasting. Real-time prices showed extreme volatility, with noticeable differences between the Houston and South zones, pointing to severe transmission constraints blocking north-to-south power flows.

From a policy perspective, the week was marked by the state's ongoing aggressive intervention in the generation market. The Texas Energy Fund (TEF) completed its third major loan agreement, allocating $370 million to NRG Energy for developing new dispatchable gas capacity. This move reinforces the Texas legislature's goal to subsidize steel-in-the-ground reliability assets, a policy direction that continues to reshape the investment signals within ERCOT's energy-only market design. The contrast between scarcity pricing events and state-funded capacity expansion highlights the region's challenge in bridging the gap between intermittent renewable growth and dependable dispatchable baseload.

Operational Challenges and Price Volatility

The week's operational narrative was shaped by wind variability. On November 26, 2025, the system experienced a sharp shift in its fuel mix; as wind output declined during high-demand periods, natural gas generation increased rapidly to compensate. This sudden supply-side change caused the system-wide price to reach $87.45/MWh, a notable premium over the marginal cost of production, indicating the scarcity value of flexible dispatchable capacity. The volatility was even more evident at the nodal level. On November 25, pricing in the South Zone (LZ_SOUTH) spiked to $120.37/MWh at 18:00, while the Houston Zone (LZ_HOUSTON) traded at a much lower $70.79/MWh during the same period.

This zonal separation shows that the transmission backbone linking the generation-rich north and west to the southern load centers was operating at its thermal limit. The constraints blocked the flow of cheaper energy to the South Zone, leading to the dispatch of more costly local generation to satisfy demand. These transmission congestion costs are ultimately paid by consumers and act as a delayed indicator of infrastructure needs. Additionally, the issuance of the Resource Advisory on November 24 and 25 was a direct response to forecast uncertainty. ERCOT operators, cautious after past winter events, are taking extreme precautions, aggressively committing units to keep reserves above critical levels.

Infrastructure and Strategic Funding

The announcement about the Texas Energy Fund's loan to NRG Energy is an important market signal. The $370 million facility will fund the construction of a 455 MW gas-fired plant in the Houston area, a project that directly addresses the resource adequacy concerns highlighted by this week's pricing events. This is the third project to receive support, bringing the total capacity secured by the fund to over 3.5 GW. The strategic location of this new capacity near Houston is no coincidence; as shown by the price gap observed this week, Houston is a load pocket with limited import options. By encouraging generation within this constrained zone, the state aims to reduce the congestion premiums that spiked on November 25.

Stakeholder discussions this week also addressed the integration of large loads. With ERCOT increasingly meeting demand with solar, wind, and batteries—as shown in recent EIA data—the challenge of balancing this variable supply with the steady, high-density load profiles of data centers and crypto-mining facilities is becoming more pressing. The "Resource Advisory" status acts as a warning that while renewable capacity is expanding, the reliable, dispatchable capacity needed to support that intermittent generation during low-wind periods remains the system's Achilles' heel.

SPP

Weekly Summary

The Southwest Power Pool (SPP) market for the week ending November 28, 2025, demonstrated the extreme outcomes that come with a high-renewable energy grid. The region shifted between times of significant energy surplus, where prices dropped close to zero, and periods of scarcity caused by the rapid decline in wind output. On Thanksgiving Day, November 27, the real-time market saw prices fall to $4.98/MWh, driven by strong wind generation during the lowest holiday demand. This volatility underscores the operational challenge of managing the "wind drought" risk, a phenomenon the SPP Market Monitor has identified as an increasing concern for the upcoming winter season.

Beyond daily operations, the week was crucial for SPP's western expansion plans. The "Markets+" initiative, aimed at offering a day-ahead market solution to western utilities, entered a key phase of governance formalization. The Markets+ Interim Governance Task Force met on November 20 to establish a participatory structure, a necessary step to file a tariff that can compete effectively with CAISO's EDAM. These governance steps are vital as utilities across the West consider the trade-offs between SPP's independent board structure and CAISO's economic liquidity.

Renewable Penetration and Pricing Dynamics

SPP's pricing behavior this week exemplified renewable-driven economics. Earlier in the week, before the holiday, real-time prices at key nodes like SPS.VOLT.0180 ranged from $40 to $44/MWh, indicating a balanced supply stack. However, as the Thanksgiving holiday reduced demand, the persistent strong output from the region's large wind fleet drove prices to the floor. The drop to $4.98/MWh on November 27 highlights the cannibalization effect of renewables: when wind is dominant and load is low, the marginal unit is often a wind turbine bidding zero or negative to claim production tax credits, causing the clearing price to collapse.

The Market Monitor's report for Winter 2025 provided important context for these real-time observations. The report noted that wind resources set the marginal price in 38% of all intervals, up from 33% the previous year. This confirms that wind is no longer just a price-taker but a price-setter in SPP. While this reduces average wholesale costs, it also increases volatility. The Monitor also pointed out that the region's dependence on wind makes it especially vulnerable to "wind droughts"—long periods of low wind speed that often occur during extreme cold. With nameplate wind capacity now reaching 35,740 MW, the system's risk of common-mode failure (i.e., the wind stopping everywhere at once) remains a primary reliability concern.

SPP Markets+

Weekly Summary

SPP Markets+ is currently in a crucial development stage, separate from the operational SPP RTO. For the week ending November 28, 2025, the focus was solely on establishing governance and developing tariffs. The Markets+ Interim Governance Task Force (MIGTF) met to finalize the rosters and charters for the committees that will oversee the market's implementation. This bureaucratic groundwork is essential for the "Phase Two" development, which is now fully funded and progressing toward a go-live date.

The initiative is positioning itself as the "governance-first" alternative to CAISO's EDAM. Updates from the week show that SPP is actively seeking partnerships with entities in the Pacific Northwest, taking advantage of the dissatisfaction some stakeholders have with CAISO's state-appointed board. The involvement of organizations like BPA in the governance task force meetings indicates that the battle for the West's day-ahead market remains intense and unresolved.

Governance and Stakeholder Activity

The November 20 meeting of the Markets+ Interim Governance Task Force marked a significant milestone in the program's development. The agenda focused on transitioning from the interim structure to the permanent Markets+ Participant Executive Committee (MPEC). This body will hold substantial authority over market rules, a design feature meant to reassure participants that their interests will not be subordinated to those of the eastern SPP RTO members.

Key stakeholders driving this process include the Bonneville Power Administration (BPA), Western Area Power Administration (WAPA), and various investor-owned utilities like Arizona Public Service (APS) and Puget Sound Energy (PSE). The continued engagement of these major players indicates that, despite CAISO's reported benefits, a significant portion of the Western Interconnection remains committed to exploring the SPP alternative. The "Phase Two" funding, confirmed earlier in the year, provides the capital needed to build the software and legal infrastructure required for market launch, ensuring that Markets+ stays a viable competitor through 2026 and 2027.

MISO

Weekly Summary

The Midcontinent ISO (MISO) experienced a week marked by a regulatory win and cautious operations. The most notable development was FERC's approval of MISO's request to set a limit on its interconnection queue, capping the 2024 cycle at roughly 68 GW of new requests. This significant regulatory action recognizes the current queue process's paralysis and equips MISO to prioritize projects with higher chances of success. Operationally, the grid handled the Thanksgiving holiday load drop smoothly, though the heavy reliance on coal generation during off-peak hours on November 27 underscores the region's ongoing dependence on thermal baseload to offset wind variability.

The specter of the recent capacity auction results continued to influence market sentiment this week. With winter season clearing prices soaring to $33.20/MW-day—a substantial jump from the previous year's $0.75/MW-day—market participants are anticipating a much tighter supply-demand balance. This price signal aligns with the NERC Winter Reliability Assessment, which identified MISO as a high-risk region for reserve shortfalls, reinforcing the urgency of the queue reforms secured this week.

Queue Reform and Interconnection

FERC's acceptance of the interconnection queue cap marks a significant regulatory change. For years, the MISO queue has been overwhelmed with speculative projects, causing a backlog that delayed legitimate generation development. By limiting the intake to around 68 GW, MISO intends to match the study volume with its administrative and technical capacity. This move is contentious among developers, who say it creates barriers to entry, but regulators consider it necessary to bring order to the interconnection process. This reform is likely to speed up the timeline for "shovel-ready" projects, which is crucial given the upcoming capacity shortages highlighted in the planning resource auction.

Operations and Capacity

Daily operations for the week reflected the typical MISO fuel mix during shoulder months: a base of coal and nuclear, modulated by fluctuating wind output. On Thanksgiving Day, despite low load, coal remained the primary fuel source, indicating that wind output was insufficient to displace thermal units to the extent seen in SPP. Real-time LMPs settled around $26.22/MWh, a moderate level that reflects the stability provided by the thermal fleet.

However, the underlying capacity situation remains fragile. The increase in winter capacity prices signals that the surplus margin MISO has enjoyed for decades is disappearing. The retirement of coal units, driven by environmental regulations and economic factors, has not been fully offset by accredited replacement capacity. The 6 GW of wind that cleared the auction represents substantial nameplate capacity, but its credited value (ELCC) is lower, adding to the tightness. The MISO "Expedited Resource Addition Study" (ERAS) process, approved earlier this year, is the RTO's effort to accelerate generation additions to address this gap before the mid-decade reliability period.

PJM

Weekly Summary

The week ending November 28, 2025, was one of the most significant in recent history for the PJM Interconnection, not because of an outage but due to a regulatory filing questioning the core assumptions of load growth. On November 25, the Independent Market Monitor (IMM) submitted a complaint to FERC (Docket No. EL26-XX) claiming that PJM lacks the authority to connect large data center loads if doing so jeopardizes system reliability. This filing challenges the core of the "Critical Issue Fast Path" (CIFP) process, stating that the rush to support AI-driven demand is creating a class of "un-firm" service that violates fundamental principles of the PJM tariff.

This regulatory fight took place amid clear market tightness. Real-time prices surged repeatedly during the week, driven by colder-than-expected weather and thermal outages. Forward prices for 2026 delivery stayed steady around $70.15/MWh, reflecting a significant risk premium for future scarcity. The NERC Winter Assessment's identification of PJM as a region with quickly rising peak demand further confirmed the IMM's concerns about the shrinking reserve margins.

The Data Center Reliability Complaint

The IMM's complaint is a transformative document. It argues that PJM is effectively creating a "shadow market" for interconnection where large loads, such as data centers, are allowed to connect by promising to curtail consumption during emergencies. The Market Monitor contends that this "voluntary curtailment" is not a reliable resource and that interconnecting these loads increases the Loss of Load Expectation (LOLE) beyond the mandated 1-in-10 year standard. The complaint explicitly asks FERC to affirm PJM's authority—and obligation—to *deny* interconnection service when the grid cannot support the new load with firm generation and transmission.

This action halts the momentum of stakeholders pushing for faster interconnection rules. It forces a federal decision on whether economic development (speed-to-market for tech companies) can take precedence over the engineering realities of grid capacity. The implications are significant: if FERC supports the IMM, the pipeline of gigawatt-scale data centers in Virginia, Ohio, and Maryland could experience major delays, leading developers to build on-site generation or pay for large transmission upgrades upfront.

Market Operations and Price Signals

The operational situation of the week reinforced the IMM's theoretical points. PJM issued multiple "Post Contingency Local Load Relief Warnings," especially in the AEP zone, to maintain voltage stability on the 138 kV system. These alerts show that the transmission system is already near the limits of its safety margin in key corridors.

Pricing reflected this stress. The real-time market experienced periods of shortage pricing, and the forward curve for West Hub On-Peak power stayed high. The IMM's Q2 2025 State of the Market report, which was widely circulated this week, noted that capacity market prices had risen over 63% year-over-year, clearly indicating that the surplus capacity that historically kept PJM prices low has disappeared. The shift from a long capacity market to a tight one is causing the volatility seen this week, making the system very sensitive to any changes in weather or unit availability.

ISONE

Weekly Summary

ISO New England faced its most severe operational crisis of any North American market this week. On Monday, November 24, the region encountered a capacity shortfall in the hour ending 8:00 AM, caused by the unexpected loss of a major generation asset combined with a load forecast error. This incident compelled the system operator to activate emergency procedures to sustain operating reserves, causing real-time LMPs to soar above $100/MWh across the area.

This scarcity event acts as a grim warning for winter. The NERC Winter Reliability Assessment specifically identified New England as a high-risk region for energy shortages due to its gas-limited fuel mix. The events of November 24 showed that even during the shoulder season, losing a single contingency can push the system to the edge.

Operational Crisis and Pricing

The capacity shortage on November 24 was worsened by transmission constraints. A clear price gap developed in the Maine (ME) Load Zone, where binding limits on the Inner Rumford Export Interface trapped generation, lowering local prices compared to the rising Hub price. This disconnection was caused by planned outages on the 209 and 214-3 transmission lines. Although the 209 line was restored on November 25, the continued outage of the 214-3 line into December leaves the region at risk of further localized congestion.

Day-ahead prices for the week averaged $73.13/MWh at the Mass Hub, trading at a premium to the real-time average of $70.16/MWh. This premium indicates that traders are pricing in significant risk, hedging against the possibility of real-time spikes like the one seen on Monday. The fuel mix remains the primary vulnerability; with limited pipeline capacity, any increase in heating demand forces the electric sector to compete for gas molecules, driving up the marginal cost of generation.

NYISO

Weekly Summary

The New York ISO (NYISO) focused on long-term planning all week, releasing the "Power Trends 2025" report and updating the "Gold Book," which dominated stakeholder discussions. These documents depict a grid in transition, facing a split in demand scenarios. The "Higher Demand Scenario" predicts load growth driven by electrification and large industrial projects, such as the Micron facility, which could surpass scheduled resource additions.

Operationally, the week was characterized by severe congestion in New York City (Zone J). Real-time prices in NYC rose to $125.79/MWh on November 25, nearly double the price at the PJM interface, reflecting persistent transmission bottlenecks that prevent power from reaching the load pockets.

Planning and Reliability

The 2025 Gold Book highlights the tension between policy goals and reliability physics. The baseline forecast assumes significant electrification of heat and transportation, leading to higher winter peaks. However, the retirement of "peaker" plants in New York City due to DEC NOx regulations has removed critical capacity from the zone that needs it most. The NYISO's recent reports indicate that some of these aging fossil units may need to be kept online for transmission security, creating a conflict with the state's CLCPA mandates.

The congestion observed this week directly results from this dynamic. With limited local generation in Zone J, the system must import power across constrained interfaces. When those interfaces bind, prices in the city diverge sharply from the rest of the state. This "tale of two grids"—upstate surplus and downstate scarcity—remains the defining feature of the NYISO market.

AESO

Weekly Summary

Alberta's power market saw significant volatility this week, caused by tightening supply conditions. The daily average pool price climbed steadily from $40.84/MWh on Monday to $58.53/MWh by Wednesday. The most notable event occurred on November 27, when real-time prices spiked to $249.83/MWh in Hour Ending 08, far exceeding the forecast. This scarcity pricing highlights the province's sensitivity to generator availability and the limited interconnection capacity to import relief during tight periods.

IESO

Weekly Summary

Ontario's market remained fairly stable, with the Hourly Ontario Energy Price (HOEP) averaging about $41/MWh for the week. The nuclear fleet supplied the baseload, generating over 7,000 MW continuously, which protected the province from the gas price volatility impacting its US neighbors. The IESO is currently finishing its "Market Renewal Program," which will transition the province to a Locational Marginal Pricing (LMP) system—a significant change that will align Ontario's market design with the standard US RTO model.

NOTE: Vedeni Energy is conducting a survey to identify the key information and data that power industry professionals need most. Your responses will help develop a new newsletter or information service tailored for leaders and analysts in the power sector.

Responses are confidential and will be used in aggregate. Please complete the survey at https://vedeni.energy/vedeni-insights/

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