

Off-Season Heat Strains the East as Data-Center Rules Harden

October 10-16, 2026

Executive Summary

North American wholesale power markets were defined this week by a brief but genuine reliability scare in the East rather than by the calendar. Unseasonable mid-October warmth collided with the year's heaviest autumn generator maintenance to produce the week's pivotal day on October 13. In PJM, roughly 46 GW of planned and about 60 GW of total generation sat offline, pushing effective load to approximately 167 GW even as actual demand peaked near only 108 GW; real-time prices at the Western Hub briefly topped about \$1,500/MWh, and the U.S. Department of Energy issued an emergency order allowing units to run past environmental limits through October 16. MISO declared Conservative Operations the same day, set a record effective load near 135 GW and saw Indiana Hub prices around \$1,000/MWh, which limited the help it could send a more stressed PJM. The contrast elsewhere was stark: ERCOT ran mild and wind-rich to the point of curtailment, while CAISO managed wildfire-driven public-safety power shutoffs rather than load, underscoring how localized this strain was.

The more durable developments were regulatory, and they converged on a single theme: how to integrate large data-center loads. FERC accepted PJM's definition of a large load and a new Large Load Registry that took effect October 12 but rejected the proposed interim resource-adequacy obligation and the exclusion of such loads from the capacity demand curve, citing intrusion on state jurisdiction; it separately found MISO's expedited large-load study plan incomplete. Texas regulators weighed three co-location applications under the state's new siting framework, and in the West the competition between SPP's Markets+ and CAISO's extended day-ahead market intensified, with SPP defending Bonneville's Markets+ commitment and Arizona and desert-Southwest utilities weighing their options. State affordability politics and governance maneuvering added to the week, from a Pennsylvania intervention in a utility rate case to a newly formalized collaborative of PJM-state governors, while in Canada Alberta closed the first feedback window on its restructured market amid a contentious gas-only data-center connection debate and Ontario reset its regulated retail prices for the coming year.

CAISO

CAISO operated throughout the week without a publicly reported system-wide emergency, and the grid narrative was driven by fire weather rather than demand. The early-October heat event and the associated Restricted Maintenance Operations had wound down by about October 10, and the operator has reported no Flex Alerts or energy emergencies so far in 2026. In their place, Pacific Gas & Electric's Public Safety Power Shutoffs dominated: the utility issued all-clears from its October 9 de-energization on October 10, declared new shutoffs across several northern counties on October 11, and on October 13 warned of a further round beginning October 14 and

potentially lasting through October 17 across more than two dozen counties as offshore winds built. Verifiable daily real-time price series for the window were not publicly confirmable, but mild autumn demand kept energy costs unremarkable relative to the summer peak.

Policy and governance activity centered on long-range planning and large loads. CAISO held a stakeholder meeting on October 15 on its draft 2027-2029 Infrastructure Policy Roadmap, with comments due in mid-November, and continued to advance its Large Loads Initiative between scheduled sessions. At the state level, the California Public Utilities Commission again postponed its decision on a 250 MW PG&E-Google data-center

arrangement in San Jose, pushing the vote to October 29 in what has become the fourth delay. The Federal Energy Regulatory Commission's monthly open meeting on October 15 carried no marquee California-specific order, and continuing recap coverage of the operator's early-October stakeholder symposium framed a decade-long shift toward independent regional governance in the West.

WEIM/EDAM

WEIM and EDAM continued to provide broader coordination across the western region, and no new extended day-ahead market go-live or participant signing landed within the window; the day-ahead market began operations earlier in 2026 and has been adding entrants on a staggered schedule since. The week's activity was instead governance-focused. The Western Energy Markets Regional Issues Forum signaled that it will treat 2027 as a transitional year before dissolving in 2028, handing its functions to counterparts within the newly formed Regional Organization for Western Energy, the independent governance body emerging from the region's multiyear Pathways effort.

The broader governance narrative remained contested even as the market structure consolidated. Recap coverage from the region's recent symposium emphasized a movement away from longstanding skepticism of organized markets toward acceptance of independent western governance, while questions about that new organization's independence drew early scrutiny. Running alongside EDAM's expansion is an intensifying competition with SPP's Markets+ for western day-ahead participation, a dynamic reflected this week in public advocacy over the Bonneville Power Administration's market choice and in fresh cost-benefit studies by Arizona and desert-Southwest utilities, developments addressed in the Markets+ discussion below.

ERCOT

ERCOT's public operations messages did not indicate a system-wide energy emergency during a mild, wind-dominated shoulder-season week, and no scarcity pricing materialized. North Hub real-time daily averages ranged from roughly \$12/MWh on October 11 to about \$51/MWh on October 14, with the midweek rise tracking higher demand; weekly average load climbed to approximately 62.5 GW from about 57.7 GW the prior week, above the five-year band, and daily peaks reached near 79 GW on October 14. The defining operational theme was abundant wind, at times exceeding what the transmission system could deliver, which forced curtailments by October 15 and, together with solar, briefly pressed some prices

toward or below zero. The all-time demand record of roughly 91 GW set in July was not approached.

The week's principal regulatory event was the Public Utility Commission of Texas open meeting on October 15, where the commission took up three data-center co-location applications under the state's recently enacted large-load siting framework, pairing a West Texas solar project, the operator of the Comanche Peak nuclear plant, and a Haskell County wind farm with prospective large loads. The outcomes of those matters were not publicly confirmed by week's end and are best treated as heard rather than decided. At the stakeholder level, the Protocol Revision Subcommittee met on October 14 and advanced a set of revision requests, including one addressing 765 kV transmission outage priority and modeling timelines, reflecting the market's continuing focus on large-load interconnection and West Texas transmission capacity.

SPP

SPP's Integrated Marketplace operated without a publicly identified region-wide emergency, and the week was quiet for formal governance, with neither a Board of Directors nor a Markets and Operations Policy Committee meeting convened. The most concrete stakeholder development came on October 12, when the organization's cost-allocation review team postponed a vote on a potential replacement for SPP's longstanding highway-and-byway transmission cost-allocation methodology as the group neared the end of its mandate; staff presented a baseline-and-incremental allocation approach, with related discussion of the twelve-coincident-peak program. Reports of a brief real-time price spike tied to a drop in wind output could not be confirmed as falling within the window and are not treated as established here.

A cluster of administrative and member-facing sessions was held mid-week, including credit-practices, large-load process, and education meetings, but none produced market-moving decisions. SPP's historic western RTO expansion, completed earlier in 2026, generated no new in-window membership developments, and the region's most active debate has shifted to the day-ahead market choice facing western utilities, which plays out through the separate Markets+ initiative. With no board-level action and no significant regulatory filing surfacing in the window, the week reinforced a pattern in which SPP's existing footprint runs steadily while the organization's strategic energy is concentrated on its western day-ahead ambitions.

SPP Markets+

Markets+ remained in pre-launch implementation, on track to begin operations in 2027, and therefore had no live daily real-time prices; the week's activity was advocacy and analysis rather than a funding or tariff milestone. The centerpiece was a white paper SPP released on October 14 arguing that Markets+ represents a proven path for the West and that the Bonneville Power Administration should retain the 2025 decision to join it, contending that the design already satisfies the criteria Bonneville's new administrator has said he intends to examine before confirming the commitment.

Supporting momentum came from the desert Southwest. Arizona's major utilities reaffirmed a preference for Markets+ in responses to state regulators, citing larger projected annual savings than under the competing extended day-ahead market, while the Arizona Electric Power Cooperative and the Western Area Power Administration disclosed a joint study weighing the two options. Markets+ seams and state-committee sessions were held mid-week, but no new FERC tariff filing or Phase Two funding event occurred within the window. The contest with CAISO's extended day-ahead market for western day-ahead participation remained the defining storyline, with the Bonneville decision widely viewed as the pivotal swing.

MISO

MISO's market operated without a widely reported system-wide emergency for most of the week, but October 13 proved pivotal. The same unseasonable warmth and heavy autumn maintenance that strained the East prompted the operator to declare Conservative Operations, and peak effective load reached roughly 135 GW, exceeding the prior record of about 133 GW set in August 2023. Real-time prices at the Indiana Hub climbed to around \$1,000/MWh. Tight conditions within MISO limited the exports it could offer neighbors and therefore constrained the imports available to a more severely stressed PJM, though MISO managed through its own conservative-operations and maximum-generation procedures without needing a federal emergency order.

On the regulatory front, FERC found MISO's proposed expedited study path for large loads, a 120-day track for loads of at least 200 MW paired with dedicated zero-injection generation, incomplete as filed, directing the operator to justify its deviations from standard interconnection rules. MISO's separate request to accelerate study of roughly 71 GW of its legacy generator-interconnection queue awaited a FERC decision expected just after the window closed. Transmission

planning also drew attention, as the operator's latest expansion-plan cost estimate was pegged at about \$14.7 billion, with large-load additions such as data centers cited as a principal driver, while capacity and resource-adequacy matters remained quiet.

PJM

PJM was the epicenter of the week's reliability strain. On October 13, with roughly 46 GW of planned and about 60 GW of total generation offline for autumn maintenance, unseasonable heat pushed effective load to approximately 167 GW, the twelfth-highest such reading since 2016, even though actual peak demand reached only about 108 GW. Real-time prices at the Western Hub briefly topped roughly \$1,500/MWh. At PJM's request, the U.S. Department of Energy issued an emergency order on October 12 under Section 202(c) of the Federal Power Act, effective October 13 through 16, permitting designated units to run past environmental permit limits and, as a last resort, allowing large loads to be directed to on-site backup generation ahead of a maximum-emergency declaration. PJM also recalled maintenance outages, issued capacity and maximum-generation alerts, and called on demand response.

The week's more structural story was data-center policy. Although the underlying order was dated October 9, FERC's action on PJM's large-load interconnection package dominated the week's coverage as the new Large Load Registry took effect on October 12. The commission accepted a definition of large load set at 50 MW or more at a single site and the registry itself, but rejected the proposed interim resource-adequacy service and the exclusion of large loads from the capacity demand curve, citing intrusion on state retail-rate jurisdiction, and directed a compliance filing within thirty days. State engagement intensified in parallel: Pennsylvania Governor Josh Shapiro petitioned on October 15 to intervene in a PPL rate complaint centered on data-center cost allocation, and PJM-state governors moved to formalize a collaborative seeking a greater role in market governance, even as the region's planning process logged roughly \$868 million in new transmission-cost adjustments.

ISONE

ISO New England ran a normal fall shoulder-season operating pattern with no in-window system emergency and no fresh weekly price publication; the most recent official figures reflect September data and predate the reporting window. The more notable operational context was the region's forward reliability signal, with the operator having previously flagged a negative operable-capacity margin for the tightest fall week in early November as planned transmission outages continue. The

week's headline development was external: on October 13 the U.S. Department of the Interior moved in federal court to rescind its approval of the 704 MW Revolution Wind project, which had installed its final turbine in September and already delivers power to the grid, injecting fresh uncertainty into New England's offshore-wind pipeline.

Several discrete transactions and filings shaped the week. FERC approved the sale of FirstLight's U.S. generation portfolio, including the Northfield Mountain pumped-storage plant, to Hull Street Energy, and a developer closed roughly \$850 million in financing for a 1,200 MWh battery project in Chelsea, Massachusetts, now targeting commercial operation in late 2027. ISO-NE made routine FERC filings on October 15 covering its third-quarter capital budget and 2027 regional cost recovery. Capacity-market reform advanced toward November stakeholder votes on seasonal accreditation rather than resolving within the window, while Massachusetts affordability politics, particularly the contested efficiency-program budget, continued to dominate the regional policy conversation.

NYISO

NYISO had a quiet week operationally, with no in-window price release or operational advisory and mild autumn demand across the state. Substantive activity concentrated in planning and interconnection. On October 11 the operator's final draft Reliability Needs Assessment drew criticism from New York City and the New York Power Authority over how it presented candidate solutions to looming downstate reliability needs, building on earlier findings of base-case deficiencies and keeping the city's peaker-plant rules and repowering questions in focus.

Interconnection economics drew attention the same day, as a NYISO study estimated roughly \$216 million in deliverability upgrades for a 180 MW battery project on Staten Island, or about \$1,200 per kilowatt, a class-year study figure whose final cost allocation will depend on which projects remain in the study group. No capacity auction, demand-curve decision, or board or committee meeting fell within the window, and no clearly in-window state regulatory or nuclear action could be confirmed; New York's broader advanced-nuclear and reliability-planning initiatives remained ongoing background rather than fresh developments this week.

AESO

Alberta's market operated without a publicly reported system-wide emergency during the week. The province's Restructured

Energy Market remained in its rules-drafting phase, and the week's live regulatory beat was the October 16 deadline for written feedback on the market's first rules-engagement window, which had opened in late September and featured a hybrid stakeholder session on October 6; the system operator's formal response to that feedback is expected at the end of November. Pool prices had been elevated earlier in the month, but a complete price series for the week was not yet published, and the available weekly data through October 11 showed an average near \$60/MWh driven largely by a spike that fell just before the window opened.

The most visible policy debate concerned how large loads will connect to the grid. Coverage on October 10 highlighted pushback against the system operator's framework, rooted in a proposal issued in June, that would require data centers to be powered by natural-gas-fired generation in order to meet round-the-clock reliability and electrical-island requirements, effectively excluding standalone renewables and batteries. Solar, storage, and environmental advocates argued the approach is short-sighted and emissions-intensive, while the provincial government defended it on reliability grounds against a backdrop of roughly 20,000 MW of requested data-center capacity. No in-window decision from the Alberta Utilities Commission or major utility announcement could be verified.

IESO

Ontario's renewed wholesale market, operating on a day-ahead and real-time basis since its mid-2025 launch, continued normal operations, though no specific in-window provincial price figures were available from reputable sources. The week's clearest regulatory event was the Ontario Energy Board's October 15 update to the Regulated Price Plan and its accompanying wholesale-market price forecast for the November 2026 through October 2027 period, the board's annual reset that takes effect on November 1, although the new retail-rate figures themselves were not independently confirmable by week's end.

The system operator itself had little fresh in-window activity, with no stakeholder sessions or trade-press developments dated within the week and long-lead procurement and small-modular-reactor milestones belonging to earlier months. The industry's gathering point was the Ontario Energy Conference on October 13 in Toronto, where the sector's annual awards recognized Hydro One as company of the year amid a period of leadership change atop both the system operator and Hydro One. Procurement refinements and capacity-accreditation work

remained active policy threads but produced no in-window decisions.

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