Bonneville Reconsiders Markets+ as Data-Center Load Redraws Transmission Plans

September 5-11, 2026

Executive Summary

North American wholesale power markets settled into a milder, shoulder-season pattern during September 5-11 as the early-month Western heat wave crested and receded. In California and the broader Southwest, forecast demand climbed toward the high-40-gigawatt range mid-week and Southern California's SP15 hub posted its firmest day-ahead prints since late August, yet grid operators moved through the event without Flex Alerts or energy emergencies and with comfortable reserve margins. Elsewhere the week was notably quiet: ERCOT ran a routine, sub-record week in the mid-80-gigawatt load range, and the Northeast and Midwest markets—having set demand records and, in MISO's case, declared a maximum-generation emergency in the days just before the window—cooled as temperatures moderated and prices eased from their early-September peaks. Across the eleven markets surveyed, no operator reported a system-wide scarcity event during the seven days in question.

The more consequential developments were structural, concentrated in the West and in transmission planning. The Bonneville Power Administration reopened one of the region's defining questions, with new Administrator Travis Kavulla signaling in a September 3 letter—reported widely during the week—that the federal power marketer may abandon its 2025 commitment to SPP's Markets+ in favor of CAISO's Extended Day-Ahead Market, citing the larger market's depth and the cost of operating across a seam; a draft decision is expected by year-end, with a regional governance framework due from the Regional Organization for Western Energy by the end of November. Data-center load, meanwhile, continued to reshape long-range planning: MISO's draft 2026 transmission expansion surged past 17 billion dollars, Ohio regulators asked PJM to use a state-directed approach to interconnect a ten-gigawatt computing campus with co-located gas, and FERC conditionally accepted tariff changes tied to SPP's Western expansion. Regulatory activity in the Northeast rounded out the week, including a FERC ruling on ISO New England's refund rules and a Maine challenge to transmission incentive adders.

CAISO

CAISO's week was dominated by an early-September heat wave that built across California and the Southwest, crested mid-week, and gave way to relief by Friday. Forecast peak demand reached roughly 47,400 megawatts on Wednesday, September 9, and about 45,200 megawatts the following day, comfortably within the roughly 67,600 megawatts of available capacity the operator cited and well below the system's all-time record of 52,061 megawatts set in September 2022. Prices firmed accordingly: the Southern California SP15 hub cleared near 87.69 dollars per megawatt-hour for the 6 p.m. hour on Tuesday, September 8, its highest day-ahead print since late August, with solar output estimated in the 17-to-18-gigawatt range and the evening net-load ramp serving as the principal pressure point. The operator managed the event without issuing a Flex Alert or an energy emergency alert, and no verified post-event settlement data confirming realized real-time peaks had been published by the close of the week.

Beyond operations, CAISO's week was quiet on the regulatory and governance fronts. No FERC order, California Public Utilities Commission decision, or major tariff filing specific to the operator surfaced within the seven-day window, and CAISO's own meeting calendar—reissued September 9—confirmed that no Board of Governors, Western Energy Markets Governing Body, or committee sessions were held during the period, with the next meetings scheduled for October 20-21. The active tariff threads that continue to shape the market, including the day-ahead market enhancements and the EDAM congestion-revenue provisions, remained in their earlier procedural postures rather than advancing this week. In practical terms, the heat event served mainly as a stress test of the operator's existing day-ahead and imbalance-reserve constructs rather than as an occasion for new policy.

WEIM/EDAM

The Western Energy Imbalance Market and the Extended Day-Ahead Market continued to provide real-time and day-ahead coordination across the West, and the early-September heat lifted spot prices throughout the footprint in step with the California conditions described above. With EDAM having gone live on May 1 with PacifiCorp as its first participant, regional attention increasingly centered on the market's competitive standing rather than on daily operational metrics, for which separate in-window price actuals were limited. Portland General Electric's anticipated entry, targeted for October 1, remained the next concrete implementation milestone, though no fresh confirmation of that timeline emerged during the week.

The defining development was the Bonneville Power Administration's public reconsideration of its market path. In a September 3 letter to the Regional Organization for Western Energy, reported during the week, BPA Administrator Travis Kavulla laid out governance and market-design criteria that could lead the federal power marketer to choose EDAM over SPP's Markets+, the offering it had selected in 2025. Kavulla framed the evaluation around the durability of market rules, market depth and liquidity, and the reliability and efficiency effects at market seams, and pointed to the scale gap between the two options—roughly 39 gigawatts of generation and 48 gigawatts of demand under EDAM against about 19 gigawatts each for Markets+. Bonneville, which markets roughly a third of the Northwest's power and operates some 15,000 circuit-miles of high-voltage transmission, plans a draft decision by the end of 2026 and has cited an end-of-November deadline for the regional governance framework that would need to be in place, making the coming weeks pivotal for the West's market architecture.

ERCOT

ERCOT experienced a routine, non-emergency shoulder-season week, with load running several gigawatts below its summer records and no conservation appeals or emergency alerts in evidence. Peak hourly load reached roughly 85,900 megawatts on Thursday, September 10, modestly above forecast, with average daily load near 72,000 megawatts and comparable peaks projected for the following days—well beneath the all-time record of 91,090 megawatts set on July 22, 2026. Real-time energy prices tracked these unremarkable conditions and were not associated with any notable scarcity or congestion event, though granular settlement-price detail for the individual days of the week was not readily available in published form. In short, the grid operated comfortably within its margins throughout the period.

In-window news flow from Texas was correspondingly light. The Public Utility Commission of Texas held an open meeting on Friday, September 11, though specific agenda outcomes bearing on the wholesale market were not yet reflected in ERCOT's published materials, and the grid operator's only formal announcement during the week was the minor debut of a communications podcast. The dominant Texas policy threads of 2026—the large-load and data-center interconnection process approved earlier in the year and the state-directed audit of data-center demand due late in the year—remained active in the background but produced no new filings within the window. On balance, ERCOT's week was defined more by the absence of stress than by any single development.

SPP

SPP's integrated marketplace operated without a publicly identified region-wide emergency during the week, and the operator's most consequential recent operational story—resource-adequacy stress in its newly integrated Western balancing authority area—continued to reverberate. Just ahead of the window, SPP's board had approved a temporary tariff measure for the Western area following three energy emergency alerts over the summer of 2026, a period during which imports covered the shortfall on nearly every tight day from spring into late summer; that stopgap, designed to sunset ahead of broader market changes, framed the backdrop for the week even though the board action itself preceded the reporting period. As the first RTO operating across both the Eastern and Western interconnections, SPP's near-term challenge remains managing the seams and adequacy of its expanded Western footprint.

The clearest in-window regulatory milestone came from FERC, which conditionally accepted market-based-rate tariff revisions filed by the Tri-State Generation and Transmission Association to reflect its participation in SPP's Western RTO expansion, in a determination reported around September 10-11 under dockets ER20-681-016 and ER26-1861-001. The action advanced the mechanical integration of Western entities into SPP's market structures and underscored the steady, filing-by-filing progress of the RTO West build-out. Beyond that acceptance, SPP's core stakeholder and transmission processes continued at their established cadence, with no board or major committee meeting falling squarely within the seven-day window.

SPP Markets+

Markets+, SPP's separate day-ahead market offering for the West, remained in its implementation phase and therefore generated no live daily price signals of its own, leaving its news defined by participation and governance questions. The program's viability turns heavily on the commitment of anchor participants, and the week's developments cut directly against that foundation. No new second-phase filing, funding agreement, or participant commitment emerged during the period, and SPP's Western newsroom carried no fresh releases within the window, so the week's Markets+ story was told almost entirely through the lens of a single prospective participant.

That participant was the Bonneville Power Administration, whose public reconsideration of whether to remain with Markets+ or shift to CAISO's EDAM—detailed in reporting during the week and anchored on Administrator Kavulla's September 3 letter—directly threatens the market's depth and liquidity. Both outside analysts and the agency itself have noted that a Bonneville departure would materially reduce the pool of resources optimizing through Markets+, and with the scale comparison so lopsided in EDAM's favor and Bonneville targeting a year-end draft decision, Markets+ enters the autumn facing a genuine question about whether it can retain the critical mass needed to launch as envisioned. SPP and Markets+ proponents had not issued a formal in-window response to the reconsideration by the close of the week.

MISO

MISO's market moderated over the week after an intense start to September that fell just outside the reporting window. In the days immediately preceding the period, the operator had declared a maximum-generation emergency and set an all-time September demand record of roughly 123 gigawatts amid a regional heat dome; by September 5-11, temperatures had eased and wholesale prices had declined from those peaks, with no new records, emergencies, or notable congestion events reported within the window. The week thus offered a return to normal late-summer operating conditions rather than any fresh operational strain.

The substantive MISO developments were in planning and interconnection. Reporting on September 7 indicated that the operator's draft 2026 transmission expansion plan had climbed past 17.3 billion dollars across some 562 projects—a steep escalation from earlier drafts of roughly 8.8 billion and 15 billion dollars over the course of the year—driven in significant part by data-center-related load growth in the Midwest. At the same time, stakeholders renewed and amplified their call for MISO to pause acceptance of a new 2026 generator interconnection cycle, arguing that a multi-year backlog of incomplete studies, some dating to 2020, should be cleared before additional projects are added; MISO signaled it plans to pare restudies in response. Both threads point toward the operator's December board decision, when the expanded transmission portfolio is slated for a vote, and both remain inseparable from the broader large-load reliability question MISO placed before FERC in late August.

PJM

PJM entered the reporting window as the prior week's extreme heat gave way to milder conditions. The operator had run hot-weather operations and posted peaks as high as roughly 152,500 megawatts on September 1 before storms and cooler air brought demand down, and by the September 5-11 period temperatures had moderated and wholesale prices had retreated from their early-month highs, with no records, emergencies, or significant congestion events reported inside the window. Forward power curves quoted mid-week placed calendar-year 2027 on-peak values in the mid-80-dollar-per-megawatt-hour range, reflecting a market that had normalized after the heat.

The week's marquee structural development linked PJM's twin pressures of data-center growth and interconnection reform. On September 7, the Public Utilities Commission of Ohio asked PJM to invoke the state agreement approach—a mechanism under FERC's Order 1000 that lets a state direct and fund transmission outside the normal regional cost-allocation process—to facilitate the interconnection of a ten-gigawatt data-center campus with a co-located gas generator, a project associated with a roster of technology and infrastructure partners. The request neatly joined the load-growth and transmission-build threads that have defined PJM's year. Hanging over all of it was the FERC-imposed end-of-September deadline for PJM to adopt governance and stakeholder reforms or have them imposed, a settlement process that was active throughout the window even though it produced no dated ruling or filing during the seven days in question.

ISONE

ISO New England experienced a mild shoulder-season week, with no heat events, demand records, or notable congestion, and no unusual price activity in evidence across the period. The one pricing item to surface was retrospective rather than daily: a report published September 8 indicated that total energy-market costs in the spring of 2026 reached roughly 1.46 billion dollars, up about 16 percent year over year, with higher emissions costs identified as the primary driver. Beyond that seasonal accounting, the operator's real-time market ran an ordinary early-autumn profile.

Regulatory and legal activity supplied the week's substance. On September 10, FERC found ISO New England's existing rules for correcting erroneous payments and charges to market participants inadequate and supported proposed tariff changes to remedy the gap. Separately, the Maine Office of the Public Advocate and the Maine Public Utilities Commission asked FERC to terminate the return-on-equity adder that transmission owners receive for participating in the regional operator, a complaint docketed as EL26-103-000 with comments due September 21 and opposed by the region's transmission owners. And in a long-running commercial dispute, Massachusetts utilities and Hydro-Québec exchanged competing lawsuits over deliveries curtailed on the New England Clean Energy Connect line during a severe January 2026 winter storm, a conflict that bears on the value and reliability of one of the region's principal clean-energy import paths.

NYISO

NYISO likewise saw a quiet operating week, with mild early-autumn conditions producing no heat events, demand records, or congestion of note and no in-window daily peak-price activity worth flagging. With summer's reliability tests behind it, the operator's attention shifted from real-time operations toward interconnection administration and the procedural work of its cluster-study process.

That process furnished the week's principal development. At a special Management Committee meeting reported around September 10-11, members narrowly voted down an appeal by the Alliance for Clean Energy New York concerning the 2024 transitional cluster study—NYISO's first study conducted under its reformed interconnection process—thereby upholding the original study's findings. The dispute had centered on cost and expense allocations within National Grid territory and had, by NYISO's own account, nearly derailed the inaugural cluster study, making the appeal's defeat a consequential procedural marker for how the new process will treat contested cost outcomes. On a smaller scale, a joint NYISO and National Grid filing for a second amended small-generator interconnection agreement tied to the Dolan Solar project appeared on FERC's docket during the week, a routine reminder of the steady individual-project activity underlying the broader cluster reforms.

AESO

Alberta's market operated without a publicly reported system-wide emergency during the week, against a backdrop of prices that remain well off their historical highs even after a late-summer rebound. Market commentary published September 9 pegged the August 2026 average pool price at roughly 45.70 dollars per megawatt-hour, up about 46 percent from July but still down modestly year over year, and noted sharp, short-lived volatility late in August that briefly lifted hourly prices toward the price cap before they collapsed back below the low-30-dollar range within days. That pattern of low average prices punctuated by brief spikes has continued to pressure generator economics and to sharpen the stakes of Alberta's broader market redesign.

Two developments stood out within the window. On September 10, AESO posted notice that the WST1 Westlock unit, operated by DAPP Power, will be mothballed for twelve months effective November 4, a further sign of attrition among existing resources. And trade reporting on September 9 highlighted the debate around AESO's 2026 Long-Term Outlook, in which the operator's higher demand projections—driven by data centers and other large loads—drew stakeholder criticism that the preliminary scenarios may not adequately capture the scale, location, and structure of prospective data-center development. Both threads feed the central Alberta story of the year, the transition to the Restructured Energy Market, with locational marginal pricing and market-readiness stakeholder sessions scheduled for the days just after the window.

IESO

Ontario's renewed wholesale market continued normal operations throughout the week, with no heat or load events, records, or price anomalies surfacing in publicly available in-window reporting. The genuinely quiet period offered little in the way of datable operational developments, and the province's market activity for September 5-11 is best characterized as routine.

Policy and stakeholder activity was similarly sparse within the window. No Ontario Energy Board media release, IESO board meeting, or provincial-government energy announcement fell strictly within the seven days, with the nearest items—an Ontario Energy Board report to the minister recommending distributed-energy net-billing and storage rate changes, and updated bulk-system transmission plans—dated in the first days of September, just ahead of the period. The province's defining longer-term threads, including the Market Renewal Program, the capacity auction, and its extensive nuclear refurbishment and small-modular-reactor program, remained active but produced no in-window milestone. In sum, IESO recorded one of the quieter weeks among the markets surveyed.

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