Federal Emergency Powers in SPP, a Capacity Backstop in PJM

July 25-31, 2026

Executive Summary

North American wholesale power markets were shaped this week less by the coasts than by a heat dome parked over the central United States and the Desert Southwest, and by the emergency and market-design responses it provoked. The most striking action came on July 26, when the U.S. Department of Energy invoked Federal Power Act Section 202(c) to issue an emergency order authorizing the Southwest Power Pool to dispatch specified units and tap backup and behind-the-meter generation ahead of a Level 3 energy emergency, an order that runs through August 3. Arizona utilities that transact through the Western Energy Imbalance Market set all-time peak-demand records on July 25 as Phoenix reached 117 degrees, with Salt River Project peaking near 9,072 MW and Arizona Public Service near 9,053 MW. ERCOT, meanwhile, moved through a record weekly-average load without issuing conservation appeals, helped by record solar output and heavy battery discharge, while California and the Northeast saw comparatively ordinary conditions as the most acute heat stayed inland.

The more consequential developments, however, were structural, and nearly all traced back to the same force: the accelerating growth of large, data-center-driven load against a tightening supply picture. On July 27 the PJM Board directed two filings at the Federal Energy Regulatory Commission, one establishing a one-time reliability backstop procurement to close a roughly 6,800 MW capacity shortfall and another creating an Interim Resource Adequacy Service that would curtail new large loads that fail to bring their own generation. The same theme surfaced in ERCOT's forecast that peak demand could nearly double by 2032, in MISO's debate over coal retirements versus battery buildout, and in Ontario's move to impose data-center reliability standards. Layered atop the operational drama, the Western Energy Markets organization on July 30 published its first quarterly benefits report to include Extended Day-Ahead Market results, marking an early milestone for the West's still-young day-ahead footprint.

CAISO

The California ISO operated through the week without a publicly reported system-wide emergency, and its own footprint saw comparatively muted conditions even as extreme heat gripped the interior West. The late-July heat dome was centered on the Desert Southwest and central United States rather than California, with the sharpest load and price pressure appearing in neighboring balancing areas; forecasts pointed to California heat building only in early August, just beyond this window. Real-time price movement across the ISO was accordingly modest, and no Flex Alert, energy emergency, or grid stress event was recorded within the period, leaving CAISO's week defined more by administration than by operations.

Institutional and regulatory activity carried the week for CAISO. The ISO set a downward adjustment to its 2026 FERC-related billing rate, moving it from roughly $0.1172 toward $0.0997 per unit effective with the October trade date, and opened registration for its October 6 stakeholder symposium in Sacramento. FERC's mid-July directive ordering CAISO and the Southwest Power Pool to file a joint report on Western seams and operational coordination by September 30 drew continued attention in-window, sharpening the backdrop for competing Western market designs. At the state level, the California Public Utilities Commission advanced a cluster of Pacific Gas and Electric matters, including a retail load arrangement tied to a large computing customer and a transmission certificate, while

CAISO held its routine market performance and planning forum on July 30.

WEIM/EDAM

The Western Energy Imbalance Market and Extended Day-Ahead Market footprint, treated separately from CAISO's own balancing area, hosted the week's principal Western load event. As the heat dome settled over the Southwest, Arizona entities that participate in the real-time market set all-time demand records on July 25, with Salt River Project reaching roughly 9,072 MW and Arizona Public Service roughly 9,053 MW during the late-afternoon peak, both exceeding their prior August 2025 records. The shared real-time market provided the geographic diversity and dispatch coordination that helped Western balancing areas manage those record loads, and SRP re-set its record later in the week as the heat persisted.

The headline institutional development was the July 30 debut of the Western Energy Markets quarterly benefits report featuring the first Extended Day-Ahead Market performance data since that market went live with PacifiCorp on May 1. The release, accompanied by an EDAM monthly performance assessment posted July 29, marked an early public checkpoint for the day-ahead footprint and fed the July 30 market performance forum. No new membership commitments, go-lives, or EDAM tariff filings at FERC were recorded within the window; the West's next entrants remain on future timelines, leaving the reporting milestone and the record Southwest demand as the week's two verifiable developments.

ERCOT

ERCOT spent the week under a sustained triple-digit heat wave yet moved through it without issuing conservation appeals, a performance the grid operator and observers attributed to record solar output averaging near 14.7 GW and battery discharge approaching 12,000 MW during peak hours. The all-time instantaneous demand record of roughly 91,300 MW, set on July 22 and 23 just ahead of the window, dominated in-window commentary, while a new weekly-average load record near 71.9 GW for the week ending July 24 underscored how firmly consumption has stepped up year over year. Notably, reporting consistently emphasized that the system met these loads without scarcity pricing events or emergency conditions, a sign of how much the solar-plus-storage fleet has changed summer operations in Texas.

The forward-looking story drew the most attention. ERCOT projected that peak demand could nearly double to around 175,000 MW by 2032, driven overwhelmingly by data centers and other large loads seeking interconnection, and its chief executive cautioned that future peaks will not be absorbed as easily as this summer's. The Texas Energy Fund again featured in the narrative, with roughly 5,000 MW of new gas-fired capacity approved across several projects and additional megawatts under review at the Public Utility Commission, framed as part of the state's answer to load growth. Syndicated coverage late in the week reinforced the same tension: a grid meeting record demand comfortably today but facing a far steeper test as computing load scales through the end of the decade.

SPP

The Southwest Power Pool was the site of the week's single most significant cross-market event. On July 26 the U.S. Department of Energy issued Emergency Order No. 202-26-37 under Section 202(c) of the Federal Power Act, authorizing SPP to dispatch specified generation and to call on backup and behind-the-meter resources before or during a Level 3 energy emergency in order to avert firm load shed; the order took effect immediately and is set to expire late on August 3. The action followed a July 24 loss of imported power that left the pool with minimal reserves as the heat dome pushed loads higher across a footprint serving roughly 20 million people in parts of 17 states, and it extended an already elevated posture in which SPP's western region had been running under a conservative operations advisory.

Market conditions reflected the strain. Spot prices in the mid-continent spiked during the heat, with reporting citing levels above $500/MWh near the Nebraska-Iowa boundary as wind output underperformed and transmission congestion bound, even as the emergency order gave operators additional headroom. Beyond the immediate event, SPP continued its extensive transmission and stakeholder agenda, carrying forward planning and market-enhancement work from its mid-July committee cycle. The combination of a federal emergency authorization and triple-digit-driven scarcity made SPP the clearest illustration this week of how quickly Western and central grids can move from tight to critical when imports falter during extreme heat.

SPP Markets+

SPP's Markets+ initiative, the utility's separate Western day-ahead market offering, had a quiet week with no verifiable in-window developments. The effort remained in its implementation phase, without a live market, and no new funding agreements, participant commitments, phase milestones, or tariff actions at FERC were recorded between July 25 and July 31. The most recent concrete participation commitments, involving Pacific Northwest publicly owned utilities, predate the window, and no Markets+-specific stakeholder outcome surfaced during the period.

The relevant backdrop for Markets+ was instead a seams question raised just before the window and discussed throughout it. FERC's mid-July order directing CAISO and SPP to file a joint report on Western grid coordination by September 30 bears directly on how Markets+ and the competing Extended Day-Ahead Market will interact across their shared boundary, and it kept the strategic contest for the West's day-ahead future in view even in a week without discrete Markets+ news. Reported plainly, the initiative advanced on its existing trajectory rather than through any new in-window action.

MISO

The Midcontinent ISO operated through the week without a widely reported system-wide emergency, though the same central-U.S. heat that stressed neighboring grids touched its footprint. MISO maintained severe-weather alerts and warned that loads could climb with temperatures, but price movement early in the window was described as muted, and the most acute stress and scarcity pricing occurred in adjacent SPP rather than within MISO itself. The contrast underscored how transmission topology and resource mix left MISO comparatively steady even as the regional heat produced emergency conditions next door.

Policy activity was more substantive than operations. MISO announced on July 26 that it will abolish most transmission-use charges on energy storage resources when they draw from the grid to charge, a change expected to improve the economics of battery operation across the footprint. Later in the week, MISO-area state regulators surfaced a sharpening divide over resource adequacy, splitting on whether extending the lives of coal plants is a necessary bridge or whether accelerated battery deployment can meet the same need at comparable cost as demand rises. No new long-range transmission or MTEP milestone landed within the window, leaving the storage-charge reform and the coal-versus-battery debate as the week's defining threads.

PJM

PJM produced the week's most consequential Eastern development when its Board, on July 27, directed two filings at FERC in response to a capacity shortfall exposed by the July 14 base residual auction that cleared at the prevailing price cap. The first would establish a one-time reliability backstop procurement, with a bid window spanning late September to late October and results expected in early December, carrying a proposed cost cap of roughly $555 per megawatt-day, above the temporary $325 level, to attract resources against a shortfall estimated near 6,800 MW. The second would create an Interim Resource Adequacy Service under which new large loads that do not bring their own generation online by mid-2027 could face curtailment ahead of broader emergency load management, a direct response to forecasts of roughly 70 GW of new large load by 2038 against far smaller retirements.

Market operations were unremarkable by comparison, as PJM's all-time demand record from early July stood untouched and the late-July heat centered west of its footprint, leaving prices contained. Stakeholder work remained active, with senior committees meeting on July 28 to consider measures on generation deactivation notification, an expedited interconnection track, flexible resources, and reliability-must-run arrangements. The Board's directives had not yet reached FERC by week's end but were expected within a few weeks, positioning PJM's capacity-adequacy and large-load debates as the center of gravity for the Eastern Interconnection heading into August.

ISONE

ISO New England had a genuinely quiet week, with no substantive in-window market, regulatory, interconnection, or stakeholder development to report. The Northeast heat and near-record demand that defined earlier July fell outside this window, and the region saw normal summer operations without a notable load or price event between July 25 and July 31. The only in-window public item from the ISO was a non-substantive culture post, underscoring how little of consequence moved during the period.

The broader policy context for New England continued to develop on longer timelines rather than through in-window action. The region's capacity-market reform, including the shift toward a prompt, seasonal forward capacity auction, remained on its previously established regulatory path following filings late last year and partial FERC acceptance in the spring, with no new step recorded this week. FERC's mid-June show-cause proceeding on large-load and data-center interconnection continues to apply to ISO-NE, but the period produced only ongoing commentary rather than a confirmed filing, leaving the week appropriately characterized as thin.

NYISO

The New York ISO's most material development was the return to service of the Champlain Hudson Power Express on July 25, when the 1,250-MW high-voltage direct-current line from Quebec resumed delivering power to New York City after nearly a month offline. The line had been sidelined by its second cable fault since entering service, an outage that began in early July, and its restoration reinstated a major import path into the city at a valuable moment in the summer. The event stood out in an otherwise unremarkable operating week, as the sharpest Northeast heat had passed before the window and the grid saw no in-window emergency.

Policy attention in New York remained fixed on the state's first-in-the-nation statewide moratorium on new hyperscale data centers, enacted just ahead of the window and the subject of continued analysis throughout it, a measure that speaks directly to how large computing loads will be governed in a constrained system. Capacity-market administration and reliability planning proceeded on their normal cadence, and FERC's large-load show-cause order continues to apply to NYISO with responses due later in the year. Beyond the CHPE restoration and the data-center debate, the week produced little discrete market news.

AESO

Alberta's market operated without a publicly reported system-wide emergency during the window, and no verifiable in-window pool-price spike or demand record emerged, as the province's heat-driven demand story had largely played out earlier in July. The Alberta Electric System Operator's transition toward a restructured energy market continued in the background on its established schedule, with rule development and participant-readiness work ongoing rather than reaching a discrete public milestone this week. The result was a low-activity period defined by continuity rather than by new operational events.

The most notable in-window item was methodological: AESO signaled it will update its long-term supply-adequacy metrics to reflect a changing resource mix, incorporating wind and solar into reserve-margin calculations for the first time alongside storage, total load, and evolving demand patterns. On the corporate side, Edmonton-based Capital Power, a major merchant participant in the Alberta market, declared its dividends with a two percent increase to the common payout on July 28 and reported second-quarter results on July 29. Taken together, the adequacy-methodology update and the generator's routine capital-return and earnings cycle framed an otherwise light week for the province.

IESO

Ontario's renewed wholesale market, live since the Market Renewal Program went into effect in the spring of last year, continued normal operations through the window without an in-window system emergency, capacity-auction result, or long-term procurement award. The Independent Electricity System Operator's activity centered on refining the renewed market's rules rather than on operations or new procurements, and no discrete price or demand event was recorded for the period. As in Alberta, the week reflected steady administration of a maturing market design.

Two rule-making threads defined the IESO's week. The operator moved to apply new reliability standards to large data-center loads through connection assessments, establishing voltage ride-through expectations that govern when computing loads must remain connected during disturbances and when their backup systems may disconnect, ahead of formal market-rule amendments. Separately, the IESO's enforcement since mid-2025 of a 100-MW-per-minute ramp limit on battery energy storage, which it plans to codify through 2026 market-rule changes, drew stakeholder questions about whether the constraint reflects modern battery capabilities and how the change is being governed. Both items placed data-center interconnection and storage integration at the center of Ontario's renewed-market agenda.

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