No More Handshake Deals: EDAM, DAME, and the Rewiring of Western Power Markets

EDAM Launch Report

May 2026

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Executive Summary

On May 1, 2026, the western United States crossed a threshold it had been approaching for over a decade. CAISO's Extended Day-Ahead Market (EDAM) went live, bringing the first centralized day-ahead market clearing mechanism to balancing authorities outside California. Simultaneously, CAISO's Day-Ahead Market Enhancements (DAME) overhauled price formation for every participant in the ISO's market, introducing new products, new settlement structures, and a fundamentally different approach to pricing flexibility and uncertainty.

This report examines what changed, what the early pricing data tells us, and what EDAM's expansion means for power, capacity, and renewable energy certificate (REC) markets across the West. The conclusion is straightforward: the bilateral, handshake-driven western power market is giving way to a centralized, LMP-based regime, and the implications for pricing, investment signals, and market structure will compound as the footprint expands through 2030.

The Bottom Line

EDAM is a deflationary force for energy and capacity costs across the West in aggregate; that is the $1.2 billion annual savings story. But the distributional effects are uneven. Bilateral traders and high-cost peaking resources lose margin. Flexible resources that can provide DAME's new Imbalance Reserves (IR) and Reliability Capacity (RC) products gain new revenue streams. Renewable developers with strong transmission access to EDAM BAAs benefit from reduced curtailment and broader market reach. The capacity and RA landscape is in genuine flux, with a potential EDAM-integrated program emerging as the successor to the current patchwork.

For RECs, the math is simple: more dispatch means more supply, and GHG-integrated energy pricing captures an increasing share of the clean energy premium that RECs once carried alone. Unbundled voluntary REC values face structural headwinds; bundled products benefit from EDAM's expanded delivery capabilities.

The biggest single variable remains Bonneville Power Administration (BPA). Its transmission network, hydro fleet, and geographic position make it the keystone of western market structure. Everything else, pricing, basis, capacity constructs, REC dynamics, flows downstream from whether the West ends up with one market or two.

Part 1: What Actually Launched on May 1

EDAM, The Market Itself

EDAM extends CAISO's existing day-ahead optimization engine to non-CAISO balancing authority areas. For participating entities, all generation and load must either bid or self-schedule into the day-ahead market, and these commitments are then re-optimized in real time through the existing Western Energy Imbalance Market (WEIM).

This sounds incremental on paper. In practice, it is a structural shift. Western utilities outside CAISO have historically relied on bilateral contracts, manual scheduling, and limited real-time coordination through the WEIM. Day-ahead operations were siloed by region, lacked automation, and were managed through a patchwork of individual Open Access Transmission Tariffs (OATT) arrangements. EDAM replaces this with a single, co-optimized day-ahead clearing process that produces financially binding schedules, congestion prices, and transfer schedules across participating BAAs.

The key design elements that made this politically achievable:

Voluntary participation with no exit fees. Any WEIM participant can elect to join EDAM based on its own assessment and timeline. This is not an RTO; there is no all-or-nothing commitment. If a participant decides EDAM is not working, it can leave without financial penalty. This feature was essential to securing early commitments from entities with diverse regulatory environments and political sensitivities.

Resource Sufficiency Evaluation (RSE). Before the day-ahead market clears each day, every EDAM participant must demonstrate it has sufficient energy, capacity, flexibility, and transmission to meet its obligations. The RSE has tiered consequences; entities that fail can still self-schedule but lose access to EDAM's optimization benefits and economic transfers. This is emphatically not a resource adequacy program. It is a daily operational gate, not a forward investment signal. The distinction matters enormously for how we think about capacity markets (more on this below).

Transmission framework. EDAM requires transmission service providers to make transmission for market transfers available while preserving existing firm OATT rights. Transmission customers with firm rights can self-schedule through the day-ahead market. Congestion revenue allocation was redesigned in mid-2025, triggered by PacifiCorp's OATT filing at FERC in January 2025, moving away from allocating all congestion revenue to the BAA where the constraint originated. FERC approved the revised model, which better accounts for parallel flow impacts, in August 2025. Notably, PacifiCorp's filing was the first OATT revision enabling EDAM participation, and it directly triggered the congestion revenue allocation redesign.

GHG compatibility. The design uses a GHG Reference Pass to establish baseline dispatch and export limits for energy flowing into states with greenhouse gas pricing programs (primarily California's cap-and-trade and Washington's Climate Commitment Act). The GHG component of LMPs (MGHG) applies only to CAISO pricing nodes; on launch day, MGHG was zero for all PacifiCorp hours. This creates an asymmetry in price formation between GHG and non-GHG hubs that has direct implications for where clean energy flows and how it gets valued.

DAME, The Price Formation Overhaul

DAME receives less attention than EDAM but arguably has a more immediate impact on market participants, because it applies to *every* CAISO participant regardless of whether they have joined EDAM.

Imbalance Reserves (IR Up/Down). This is the headline product. IR is a new day-ahead ancillary service procured in the Integrated Forward Market (IFM) to cover forecast uncertainty between day-ahead and real-time. It is procured on an hourly basis, with requirements set based on locational historical and forecasted uncertainty of wind, solar, and load. Transmission capacity is reserved to ensure IR is deliverable in real time.

Why does this matter? Historically, CAISO operators manually inflated demand forecasts in the Residual Unit Commitment (RUC) process to clear additional supply as a hedge against DA-to-RT uncertainty. These were out-of-market actions, opaque, discretionary, and not reflected in transparent price signals. IR moves this uncertainty pricing into the IFM, making it visible, competitive, and location specific. The result: day-ahead prices will embed more of the flexibility premium that previously only appeared in real-time volatility.

Reliability Capacity (RC Up/Down). Procured through an updated RUC process, RC addresses real-time load deviations from day-ahead schedules. It is the backstop behind IR; if the IFM plus IR does not fully position the system for real-time, RC ensures additional capacity is committed.

LMP decomposition. Locational Marginal Prices now decompose into four components: Marginal Cost of Energy (MCE), Marginal Cost of Loss (MCL), Marginal Cost of Congestion (MCC), and Marginal Cost of Greenhouse Gas (MGHG). Critically, the system-wide energy component has been eliminated. With EDAM, marginal energy cost calculations shift to the balancing authority area level, a significant change for anyone running settlement analysis, congestion modeling, or basis forecasting.

Settlement complexity. Over 100 charge code updates, more than 50 new reports, new bidding requirements, and updated validation rules. This is not a one-time implementation. Tariffs, charge codes, and uplift methodologies will continue to evolve as new participants onboard, transmission arrangements mature, and coordination with SPP's Markets+ develops. Front, middle, and back-office teams all face materially higher complexity.

Part 2: What the Launch Day Data Tells Us

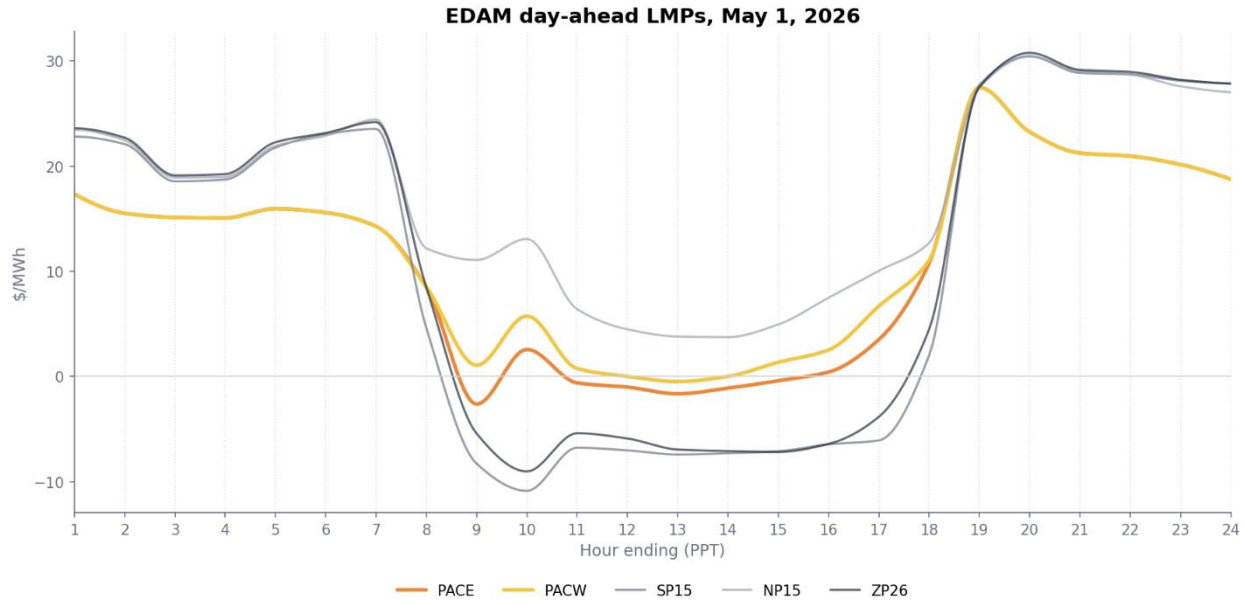
CAISO published day-ahead LMP data for May 1, 2026 across five pricing hubs: PACE (PacifiCorp East), PACW (PacifiCorp West), NP15, SP15, and ZP26.

The Duck Curve Migrates East

The PacifiCorp hubs showed a recognizable duck curve pattern, with depressed midday prices driven by solar penetration and a steep ramp into the evening peak, but notably more muted than what CAISO experienced.

PACE dipped to -$2.63/MWh in hour 9 and peaked at $27.48/MWh in hour 19. PACW's trough was shallower at -$0.48/MWh in hour 13 before reaching $27.48/MWh in hour 19.

The CAISO hubs diverged sharply from each other: SP15 touched -$10.88/MWh in hour 10 before peaking at $30.45/MWh in hour 20, while NP15 never went negative at all, bottoming at $3.74/MWh in hour 14. PACE was negative for six hours (hours 9, 11-15); SP15 was negative for nine consecutive hours (hours 9-17).



PacifiCorp's inaugural participant, Mike Wilding, noted that during the 90-day parallel operations phase leading up to launch, price formation consistently met expectations, with the right shape showing peaks in the morning and afternoon. The live results appear to confirm that assessment.

Early Convergence, Persistent Basis

The spread between PACE and SP15 at SP15's trough hour (hour 10) was $13.45/MWh: SP15 sat at -$10.88/MWh while PACE was positive at +$2.57/MWh. This tells a nuanced story. The magnitude of the spread reflects the depth of California's midday solar oversupply; SP15 went deeply negative while PacifiCorp, with its coal and gas baseload, stayed near zero or slightly negative. But the duck curve shape in PacifiCorp's pricing at all, with a clear midday trough and evening ramp, demonstrates that solar surplus in California is influencing prices in adjacent BAAs through the EDAM optimization.

Perhaps more striking: at hour 19, all five hubs converged to within $0.25/MWh of each other, with PACE at $27.48, PACW at $27.48, NP15 at $27.51, SP15 at $27.72, and ZP26 at $27.52. This near-perfect convergence occurred at the transition hour between solar decline and evening peak. One hour later at hour 20, CAISO hubs pulled away to $30+/MWh while PacifiCorp hubs dropped to $23.25/MWh, a $7.20 spread reflecting the California evening ramp that PacifiCorp's generation mix could not follow. Meaningful basis persists, driven by transmission constraints, the GHG adder, and the simple reality that only two of the dozens of potential EDAM BAs are currently participating.

The GHG Asymmetry

The MGHG component was zero across all hours for PacifiCorp hubs on launch day. This is by design; EDAM's GHG framework only adds the greenhouse gas cost component to LMPs at CAISO nodes. But it creates an interesting dynamic: a generator in PacifiCorp territory selling energy into California via EDAM transfers effectively sees the GHG value flow into the energy price at the

CAISO delivery point, not at the source. For clean energy generators specifically, this means the "green premium" in energy prices is geographically concentrated in GHG-priced states, while the REC (tracked through WREGIS) remains a separate instrument with its own pricing dynamics.

What PacifiCorp Brings to the Table

PacifiCorp adds nearly 12 GW of owned generation capacity to the EDAM optimization, with a mix that includes roughly 5.2 GW of wind, 4.5 GW of coal, 3.9 GW of gas, 3.6 GW of solar (with paired storage), and 1.2 GW of hydro, per the utility's 2025 IRP. The utility operates two distinct service territories: Pacific Power (PACW) covers Northern California, Oregon, and Washington and is a net importer; Rocky Mountain Power (PACE) covers Utah, Wyoming, and Idaho and is a coal-dominant net exporter. CAISO already sources a significant share of its imports from PacifiCorp territory, so existing transmission relationships provide a natural foundation for EDAM flows.

Part 3: The Footprint Race

Where We Stand Today

As of May 2026, the western day-ahead market landscape is splitting into three camps:

EDAM (CAISO): Approximately 170 GW of committed capacity serving 90 GW of non-coincident peak load. CAISO alone contributes 44 GW of that peak. The onboarding pipeline runs from PacifiCorp (May 2026) and PGE (October 2026) through PNM, BANC, LADWP, and Turlock Irrigation District (2027) to Imperial Irrigation District (2028). Entities publicly leaning toward EDAM include NV Energy (whose PUC approved EDAM participation in April 2026), Idaho Power, and BHE Montana (PowerWatch).

Markets+ (SPP): Approximately 117 GW of committed capacity. BPA, which owns and operates 75% of the Pacific Northwest's high-voltage transmission, is the anchor entity, having chosen Markets+ despite projections showing higher annual savings from EDAM participation. BPA cited governance concerns and long-term rate impacts as decisive factors. Markets+ is scheduled to go live in October 2027.

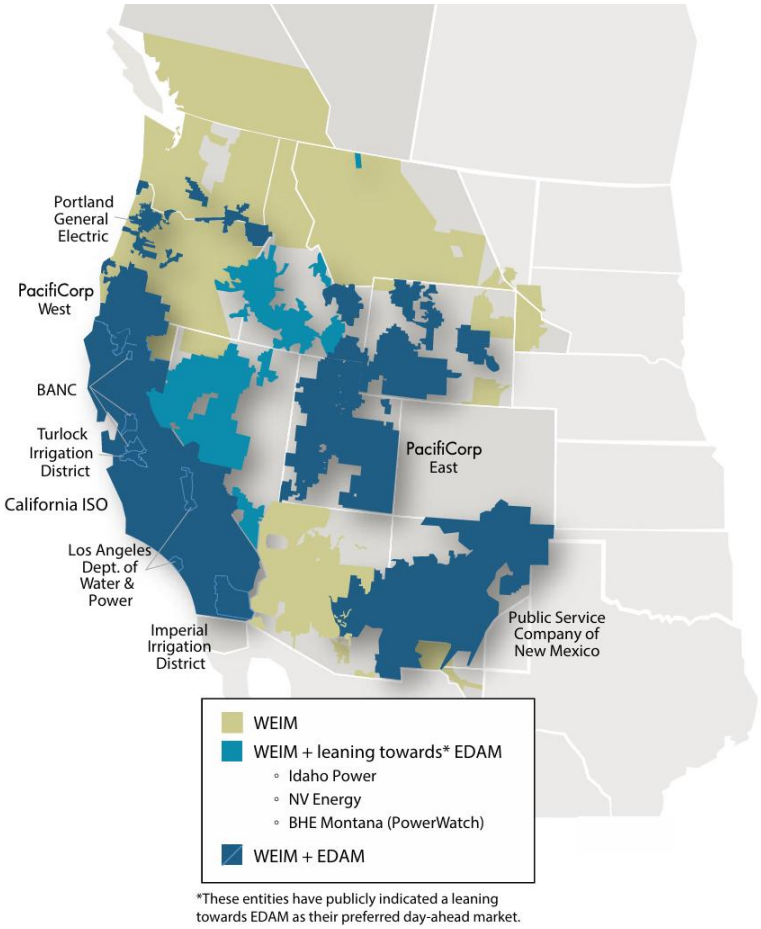


Figure 1: EDAM Map (Source: CAISO)

SPP West/SPP: Roughly 77 GW, including WAPA and Basin Electric entities in the Eastern Interconnect that will be co-optimized with SPP.

By the end of the decade, over 360 GW of western capacity will participate in some form of organized day-ahead market or RTO, a dramatic transformation from a region that, as recently as 2023, was overwhelmingly bilateral.

BPA Is the Swing Variable

BPA's decision to join Markets+ rather than EDAM is the single most consequential market-structure choice in the West. BPA's transmission network is the backbone of the Pacific Northwest; its choice does not just affect its own BAA but determines the market seam topology for every entity in the region. Entities operating within BPA's transmission footprint that prefer EDAM now face a significant market seam to navigate, particularly given that PGE and PacifiCorp (both EDAM-committed) operate adjacent to BPA.

The governance evolution is the key variable that could eventually shift BPA's calculus. If ROWE (the Regional Organization for Western Energy, expected live in 2028) demonstrates genuine independence from California, BPA's primary stated objection to EDAM would be substantially addressed. But "eventually" is not a timeline; it is an aspiration. For now, the West is headed toward a two-seam market.

Part 4: Power Market Implications

Price Convergence and Basis Compression

The WEIM already demonstrated that real-time price convergence follows participation expansion; the pattern should repeat in the day-ahead timeframe but with substantially larger volumes at stake. As the EDAM footprint grows from PacifiCorp alone (today) to include PGE, PNM, LADWP, and others, day-ahead basis between major western trading hubs (MONA, MEAD, SP15/NP15) should structurally tighten.

Bilateral traders who have historically captured spread between these hubs, particularly on predictable peak-season flows, will see those margins compress. This is the energy-market analog of what happened when eastern ISOs expanded: price discovery moves from bilateral relationships to a centralized optimization, and the informational advantage that bilateral players earned from asymmetric visibility erodes.

DA-RT Spreads: A Cross-Market Story

A common expectation is that EDAM and DAME will structurally narrow DA-RT spreads. The reality is more nuanced. Within a given hub, say DA SP15 versus RT SP15, the fundamentals driving real-time volatility have not changed: the same transmission constraints exist, the same forecast uncertainty around solar, wind, and load persists, and the same physical events (plant trips, cloud cover, heat storms) will continue to drive real-time price spikes that day-ahead scheduling cannot fully anticipate. DAME's Imbalance Reserves price some of that forecast uncertainty into the day-ahead market, which should modestly reduce the magnitude of RT deviations by pre-positioning flexible capacity. But transmission remains the binding constraint, and EDAM does not build new lines.

Where spreads are more likely to narrow is across markets: the basis between DA SP15 and RT PACE, for example, or between DA NP15 and DA PACW. These flows already existed bilaterally, but EDAM replaces manual scheduling, imperfect information, and bilateral friction with a centralized optimization that sees both systems simultaneously. The result is more efficient cross-BAA price discovery in the day-ahead timeframe, which compresses the informational rent that bilateral traders previously earned from asymmetric visibility. For participants positioned around the CAISO-PacifiCorp interface specifically, this is a meaningful change; for within-CAISO spread traders, it is not.

The location-specific nature of IR procurement adds a secondary effect. Congestion related to Imbalance Reserve procurement will materialize where forecast uncertainty is greatest, typically zones with high wind and solar penetration and variable load profiles. For PacifiCorp, this means the eastern territory (PACE), with its significant wind portfolio and weather-driven load variability, could see new congestion patterns that did not exist under bilateral scheduling. But until new transmission is built, the physical delivery constraints that drive the largest real-time spreads will persist regardless of how well the day-ahead market is designed.

Curtailment Reduction Supports Solar-Hour Pricing

One of EDAM's clearest value propositions is the ability to route excess renewable production from one BAA to demand in another, reducing curtailment. This is particularly relevant for California's chronic midday solar surplus. Curtailments and negative prices concentrate during solar hours (roughly HE9-HE16), not during traditional off-peak nighttime hours; the duck curve has inverted the old peak/off-peak paradigm in California. Modeling work from multiple participating entities has consistently shown that EDAM's footprint, with direct connectivity between California's solar surplus and PacifiCorp's load centers, is more effective at absorbing renewable energy than Markets+, where limited transmission connectivity between the Pacific Northwest and the Desert Southwest leads to higher curtailment rates.

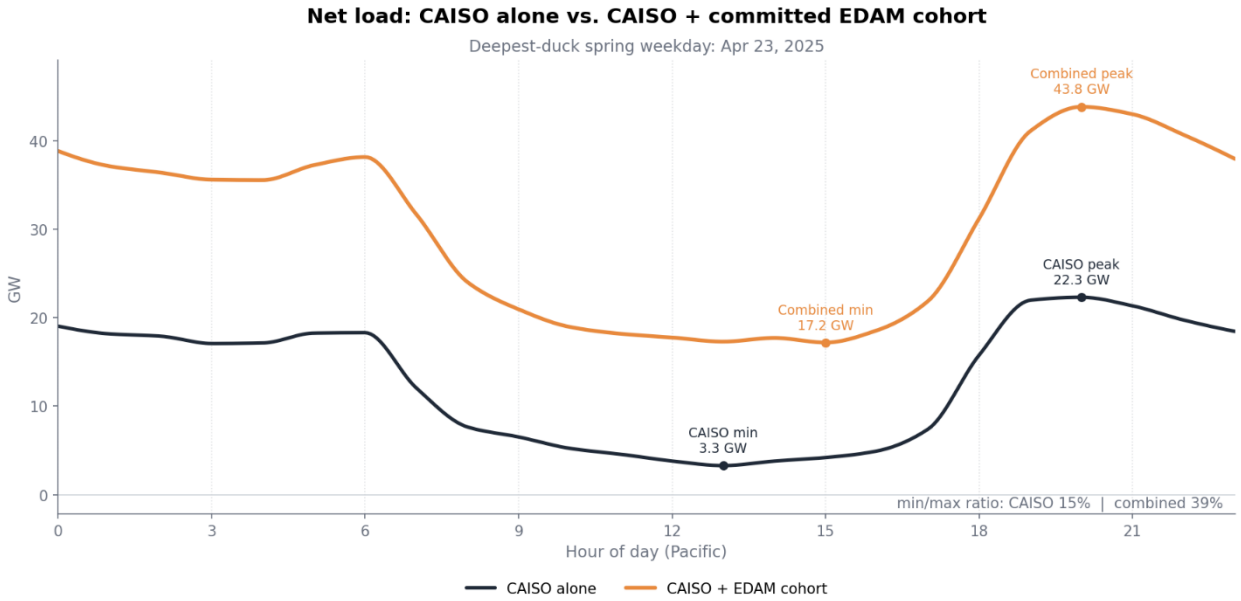


Figure 2: CAISO & CAISO + EDAM Net Load

The practical effect: fewer zero or negative-price hours in CAISO during spring solar oversupply (putting a structural floor under midday prices), combined with lower daytime prices in receiving BAAs like PacifiCorp (which displace gas generation). Both effects were visible in the May 1 LMP

data, where SP15 was negative for nine consecutive solar hours (HE9-HE17) while PACE stayed near zero or slightly negative.

To quantify this: on a deep-duck spring day, CAISO's net load drops to roughly 3.3 GW at midday before ramping to 22.3 GW in the evening. Adding the committed EDAM cohort raises the combined midday net load floor to approximately 17.2 GW against an evening coincident peak of 43.8 GW, lifting the min-to-max ratio from 15% (CAISO alone) to 39% (combined footprint).

The structural driver is straightforward: non-CAISO EDAM entities have far less solar saturation than California, so their net loads stay elevated during solar hours, effectively absorbing CAISO's surplus and flattening the duck curve across the footprint. The combined footprint's midday floor of 17.2 GW represents a fivefold increase over CAISO's 3.3 GW trough, dramatically reducing the volume of energy that must be curtailed or sold at negative prices.

EDAM Access Charge Replaces Traditional Wheeling

A detail that has received less attention but matters significantly for asset developers and BESS investors: under the EDAM tariff framework (approved by FERC in ER24-1746), the traditional OATT wheeling charge structure between EDAM Balancing Authorities is replaced by the EDAM Access Charge, which is structured to facilitate, rather than penalize, economic transfers across BAA boundaries. Combined with day-ahead LMPs at generator nodes, this opens up economic contracting opportunities for storage assets sited inside the EDAM footprint. Capacity swaps and tolling agreements can now be written against actual settlement points rather than approximated hub prices. However, ancillary services remain siloed by the Balancing Authority at launch, so the cross-BAA contracting benefit applies to energy and reserves, not AS.

Part 5: Capacity and Resource Adequacy, Two Programs for Two Markets

EDAM's RSE Is Not RA

This point cannot be overstated. EDAM's daily Resource Sufficiency Evaluation tests whether a participant has enough resources committed for the next operating day. It does not drive long-term investment signals, require forward capacity procurement, or create tradeable capacity obligations. It is an operational check, not a market.

For the CAISO BAA, the existing RA program (mandated by the CPUC for load-serving entities) continues to operate as before. But for non-CAISO EDAM participants, there is currently no organized capacity construct analogous to PJM's RPM, ISO-NE's FCM, or even CAISO's own bilateral RA framework. This gap is EDAM-specific; it does not apply to the broader West.

WRAP Proceeds, But With a Smaller Footprint

The Western Resource Adequacy Program (WRAP), operated by SPP and governed by the Western Power Pool, is very much alive. Sixteen participants are committed to binding operations starting Winter 2027/2028, representing over 58 GW of peak load. The committed group includes major entities: Arizona Public Service, Avista, BPA, Chelan County PUD, Constellation, Idaho Power, NorthWestern Energy, Powerex, Puget Sound Energy, Salt River Project, Seattle City Light, and Tacoma Power, among others. The Western Power Pool has characterized this as sufficient critical

mass to proceed with binding operations, and WRAP remains one of the largest RA programs in the country by participant load.

However, WRAP's path to binding was not smooth. In April 2024, participants notified WPP they would not elect to move to a binding program for Summer 2026, citing supply chain delays, interconnection backlogs, and load growth that outpaced their ability to procure qualifying capacity. The RAPC subsequently approved a revised transition plan that pushed back the binding deadline to Winter 2027/2028, temporarily reduced deficiency charges for participants that are short on capacity, and introduced diversity sharing between subregions to lower planning reserve margins. Even under the binding program, deficiency charges phase in gradually through Winter 2028/2029.

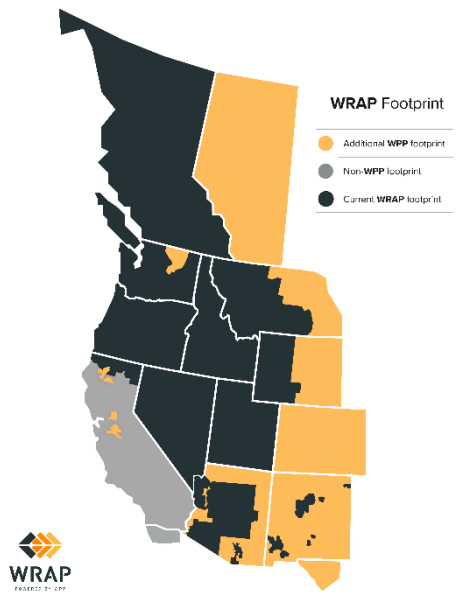


Figure 3: WRAP Footprint (Source: WPP)

Separately, six entities withdrew from WRAP ahead of the October 2025 deadline: PacifiCorp, Calpine, Eugene Water & Electric Board, NV Energy, PGE, and PNM. The withdrawing entities are overwhelmingly EDAM-aligned. Their departure does not threaten WRAP's viability for its remaining participants, but it does narrow the program's geographic diversity. WRAP was designed to capture RA benefits from load diversity across the full West; with the EDAM-leaning utilities gone, the remaining footprint is concentrated in the Pacific Northwest, Northern Rockies, and Desert Southwest (via APS and SRP), with less representation from the Intermountain West and Southern California.

The Western Power Pool has left the door open, with exiting participants able to rejoin as late as September 2026 for the Winter 2027/2028 binding season. And notably, Idaho Power & Seattle City Light appear on both lists: it is a committed WRAP participant and is publicly leaning toward EDAM, suggesting some entities may attempt to participate in both frameworks or are hedging their bets.

The EDAM RA Gap

The result of the WRAP departures is that six major EDAM-aligned utilities now have no binding forward RA program. EDAM's RSE provides a daily operational check, but it does not substitute for the kind of forward planning and compliance framework that WRAP provides its participants. Recognizing this gap, a coalition of EDAM and EDAM-leaning utilities, led by PacifiCorp and NV Energy, proposed a new resource adequacy program in a March 2026 letter to the Western Energy Market's Body of State Regulators. The envisioned footprint spans from the Pacific Northwest to the upper Rockies, down to New Mexico, and back through Southern California.

This is early stage; the proponents themselves have emphasized they are not arriving with a fully baked design. A draft design document is targeted for mid-2026, with an open stakeholder process to follow. CAISO is serving as a consultant to the group. But the trajectory is clear: the EDAM footprint is likely to develop its own capacity construct, potentially under ROWE's governance once that entity is operational in 2028. Until then, these BAAs will be managing their capacity and reliability individually, without a regional compliance backstop.

What This Means for Capacity Pricing

The West is heading toward a two-track RA landscape. WRAP participants (largely Markets+-aligned) will have binding forward capacity obligations starting Winter 2027/2028, with deficiency charges phasing in over the transition period. EDAM participants outside CAISO currently have no equivalent framework, though one is allegedly in the works.

For the EDAM footprint, the near-term impact is mildly bearish for capacity values. Load diversity across a broader footprint reduces the aggregate planning reserve margin needed to maintain a given reliability standard. The Energy Strategies benefits study estimated up to $557 million annually in avoided capacity investments from shared reserves and harmonized procurement, a substantial reduction in aggregate capacity demand.

However, if the emerging EDAM, non-CAISO, RA program develops into a binding forward obligation with common planning standards, it could create the most liquid and transparent capacity market the non-ISO West has ever had. That would be transformative for capacity price discovery and investment signals, particularly for flexible resources that can provide the imbalance reserves and reliability capacity products created by DAME.

For CAISO-internal RA, the expansion of EDAM is modestly bearish on system RA prices because the effective supply pool available during stressed conditions grows. Local RA in transmission-constrained areas (LA Basin, Bay Area, San Diego) remains relatively insulated from this effect.

Part 6: REC Market Implications

EDAM does not directly change how Renewable Energy Certificates are issued, tracked, or retired. RECs remain separate instruments tracked through WREGIS, with pricing driven by state RPS compliance requirements and load. But EDAM changes the economic context in which RECs are generated and valued, through three channels.

More Dispatch = More RECs

Every MWh of renewable energy that EDAM routes to load in a neighboring BAA, instead of being curtailed, generates a REC that otherwise would not have existed. The EDAM benefits study projects 2.92 million metric tons of annual CO_2 reduction from a West-wide footprint, much of it from displacing gas generation with renewables that would otherwise be curtailed. More renewable MWh dispatched means more WREGIS certificates issued. On the margin, this increases REC supply and is modestly bearish for bundled & unbundled REC prices in the western region.

GHG Pricing Erodes the Standalone REC Premium

As EDAM's GHG framework increasingly prices the "clean" attribute of energy directly into LMPs at delivery points in GHG-regulated states, more of the green premium gets captured in energy prices rather than in the separate REC instrument. A renewable generator in PacifiCorp territory selling into CAISO via EDAM already captures GHG-attributed energy value; the unbundled REC that remains after stripping the energy carries less incremental value than it would in a world without GHG-integrated energy pricing.

This trend is not new; it has been developing since the WEIM introduced GHG attribution. But EDAM accelerates it by extending GHG-aware optimization into the day-ahead timeframe where the vast majority of energy transacts.

State RPS Compliance Dynamics Shift

EDAM enables more efficient cross-BA renewable dispatch, which means states with ambitious RPS targets get access to a broader renewable supply pool for compliance purposes. California (60% by 2030), Oregon (100% by 2040), and Washington (100% by 2045) may find compliance REC tightness modestly eased as EDAM facilitates deliverable renewable energy from a larger geographic footprint.

However, this effect is heavily mediated by state-specific REC eligibility rules; vintage requirements, technology restrictions, geographic constraints, and deliverability standards all vary. States that restrict eligible RECs to in-state or in-region generation will not see the same supply relief as states with broader eligibility.

Bundled Wins, Unbundled Loses

As organized markets expand in the West, the structural trend favoring bundled power purchase agreements with RECs over stripped, unbundled certificates should accelerate. Corporate buyers increasingly demand bundled products for "additionality" claims, and EDAM makes it mechanically easier to deliver bundled renewable energy across BA boundaries. More supply of deliverable bundled products puts further downward pressure on the bundled PCC RECs in California.

Part 7: What Comes Next

Near-Term (2026–2027)

The operational data from EDAM's first months will be closely scrutinized. Pricing patterns, RSE performance, congestion revenue allocation outcomes, and settlement accuracy will determine whether committed entities stay on schedule and whether leaning entities accelerate their timelines. PGE's October 2026 onboarding will be the first test of multi-entity EDAM operations outside PacifiCorp.

DAME's new products will take several months to establish stable price patterns. Expect Imbalance Reserve prices and congestion patterns to be volatile and somewhat unpredictable initially as market participants, CAISO's optimization engine, and the underlying requirement calculations all calibrate. CAISO CEO Elliot Mainzer has indicated the ISO plans to address post-launch refinements through a robust stakeholder process, working alongside ROWE.

Medium-Term (2027–2028)

The 2027 onboarding wave, including PNM, BANC, LADWP, and Turlock, will meaningfully expand EDAM's footprint and, critically, add the first participants from the Desert Southwest (PNM) and Southern California (LADWP). This adds geographic and resource diversity that the current PacifiCorp-only footprint lacks.

Markets+ goes live in October 2027, creating the two-seam reality the West has been debating for years. The operational performance of both markets, and the management of seams between them, will be the dominant topic in western energy market policy.

The new EDAM RA program design process will be underway. If it produces a credible, binding forward capacity construct by 2028, it would fundamentally change the investment signal landscape for the non-CAISO EDAM footprint.

Long-Term (2028–2030)

ROWE takes over governance of EDAM and WEIM from CAISO. The success or failure of this governance transition will determine whether the remaining undecided entities, most importantly BPA, reconsider their market choices. If ROWE demonstrates genuine independence and effective governance, the case for a single unified western market strengthens considerably.

By 2030, over 360 GW of western capacity will be in organized day-ahead markets. Whether that capacity operates in one market or two, and what the seams between them look like, is the question that will define western power market structure for a generation.

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