Northwest **Power** and
Conservation Council

MEMORANDUM

TO: **Council Members**

FROM: **John Ollis, Manager of Planning and Analysis**

SUBJECT: **Western Markets Exploratory Group Study Summary**

BACKGROUND:

Presenter: Arne Olson, Senior Partner, and Jack Moore, Senior Director, Energy and Environmental Economics (E3)

Summary: Arne Olson and Jack Moore will provide an overview of the results from the Western Market Exploratory Group (WMEG) Cost Benefit Study performed by E3. The study was highlighted in an October 23, 2023 public workshop as one of the considerations in Bonneville Power Administration's upcoming determination on policy direction or subsequent decisions regarding day-ahead market participation.

Relevance: In addition to the resource strategy, 2021 Power Plan contained a Council recommendation for "Bonneville and the regional utilities along with their associations and planning organizations, work together and with others in the Western electric grid to explore the potential costs and benefits of new market tools…that contribute to system accessibility and efficiency." The WMEG study focuses specifically on variable production cost and market price impacts for a number of different market footprints and scenarios and highlights some system wide observations on market seams and importance of transmission connectivity.

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As presented in the December 2022 Council Meeting, utilities in the region are currently exploring two different organized day-ahead market options, one offering from the California Independent Service Operator (CAISO) and another from Southwest Power Pool (SPP). Moving towards an organized day-ahead market has the potential to improve efficiencies and provide other benefits to the region.

Workplan: 4.3.3 Track market efforts, including day-ahead market offerings and transmission planning to inform Council analysis.

Background: The Western Markets Exploratory Group is a group of 26 western utilities and one of the latest in a long history of efforts to understand the benefits of increasing regional coordination in the western power system. The WMEG cost benefit study was commissioned to provide WMEG members with "credible" information on the benefit of joining either Markets+ (SPP, day-ahead market offering) or Extended Day Ahead Market (CAISO, day-ahead market offering). Currently regional utilities conduct day-ahead market transactions on a bilateral basis, as they do in many other market timeframes. Outside those entities in the CAISO, the exception to this bilateral trading paradigm for much of the west has been the Western Energy Imbalance Market (operated by CAISO) and the Western Energy Imbalance Service (operated by SPP) in which the market participants bid in resources and load, and then the system operator can find the most cost-effective resources to serve demand throughout the market footprint.

The two day-ahead market offerings are in different stages in the process of standing up viable alternatives. For example, the CAISO EDAM filed a tariff with the Federal Regulatory Energy Commission (FERC) in August 2023 and estimated to go live in spring of 2026. SPP Markets+ is estimated to file a tariff with FERC in February 2024 with a transitional real-time service offering targeted go-live date of June 2024 and the day-ahead piece launching as soon as possible after. Different potential market participants within the region have participated in and funded developmental processes of both markets.

More Info: BPA Presentation in BPA October 23, 2023 Day Ahead Market Workshop
E3 Presentation in BPA October 23, 2023 Day Ahead Market Workshop
Markets Plus Offering
Extended Day Ahead Market Offering
Markets 101: December 2022 Council Meeting

WMEG Cost Benefit Study (CBS)

Northwest Power and Conservation Council
Power Committee Meeting

14 November 2023

Energy+Environmental Economics

Arne Olson, Senior Partner

Jack Moore, Senior Director

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Agenda

1. Study Background & Key Assumptions
2. System-Wide Model Results
3. Results for BPA

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1. **Study Background & Key Assumptions**
2. System-Wide Model Results
3. Results for BPA

Efforts to foster greater regional coordination have a long history in the West

1996-2002: Order 888 and first markets

- PJM, ISO-NE, NYISO, CAISO, ERCOT
- Western market attempts: InDeGo, RTO West, Grid West, Desert STAR

2002-2011: Western Hibernation

- Bilateral day-ahead trading at Mid-C, COB, Palo Verde, 4 Corners
- Real-time trading via phone calls

2011-2014: Re-awakening and Energy Imbalance Market

- Success of SPP's Energy Imbalance Service & MISO Day 2 Market
- 2011 WECC EIM study: $130 million annual benefits
- 2014: CAISO – PacifiCorp launch Western EIM

2014-present: EIM development

- Growth of EIM to cover most of Western Interconnection
- $1.5 billion annual benefits (2022)
- EIS expands to Front Range

2016 – present: Renewed interest in further coordination

- EDAM
- Markets+
- Western Resource Adequacy Program

Potential regional coordination benefits

+ Reduced cost of energy production through more optimized regionwide unit commitment and dispatch
+ Reduced renewable resource curtailment
+ Reduced greenhouse gas emissions
+ Investment savings from more optimal regionwide resource procurement
+ Investment savings due to reduced capacity need (due to load & resource diversity)
+ Day-Ahead Market price transparency increasing liquidity and reducing risk premium on investments
+ Transmission planning improvement
+ Reliability improvement

WMEG Cost Benefit Study (CBS)

- **Prepared for Western Markets Exploratory Group (WMEG), a group of 26 Western utilities**
- **The CBS was designed to provide WMEG members with credible information on the benefit of joining either Markets+ or EDAM**
- **The Study:**
  - **Simulates scenarios** with different potential **footprints** (of entities that could join each market) and different **features** of the currently proposed market designs
  - **Uses a detailed hourly PLEXOS production cost model of the WECC** that represents **both a day ahead (DA) stage of unit commitment and transactions and real-time (RT) operational stage**
  - **Utilizes confidential data from each WMEG member** to represent their systems in more rigorous detail than can be achieved with only public datasets
  - **Reports both the regionwide impact** to costs and revenues **and impact for the each WMEG member**

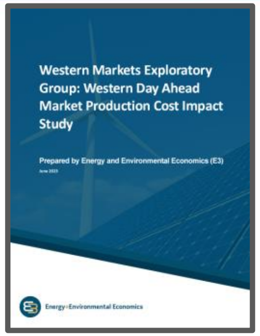
WMEG and the Northwest

- **The WMEG's group of 26 Western utilities supported the Cost Benefit Study (CBS) and provided key data and refined assumptions**
  - **Study participants from the Pacific Northwest included**: Avista Corp., Bonneville Power Administration, Chelan County PUD No. 1, PUD No. 2 of Grant County, Idaho Power Company, NorthWestern Energy, PacifiCorp, Portland General Electric, Puget Sound Energy, Seattle City Light, and Tacoma Power
  - Additional detail on WMEG study available here: https://docs.tep.com/wp-content/uploads/RPAC-Meeting-WMEG-Supplemental-Information-July-27-2023.pdf
- **The material here was also presented in BPA's Day Ahead Market Participation Workshop on October 23**
  - More information was provided by Bonneville here: https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/102323-dam-workshop-presentation.pdf

CBS Study Focus: Variable Production Cost and Market Price Impact

- **The Study's scope focuses on variable production costs and energy market prices**
  - Variable costs savings are one category among a range of potential benefits of regional markets often discussed, and they are one among many to consider when deciding whether to join either market
  - Individual benefits are based on (a) variable production cost savings (b) purchased power cost savings, plus changes in revenue from energy sales (due to higher sales quantity or higher prices)
- **The Study scope did not include calculating potential investment savings related to:**
  - (1) lower capacity needs due to peak load & resource diversity
  - (2) investment savings from either market enabling resource procurement over a wider geography, or
  - (3) coordinated regional transmission planning
- **Other market studies have shown those other benefit categories can create 2-10x the impact of production cost savings alone**
  - e.g., State-Led Study, CAISO SB 350 Study, MISO Value Proposition

Market Footprints for WMEG CBS (2026 Cases)


Western Markets Exploratory Group: Western Day Ahead Market Production Cost Impact Study

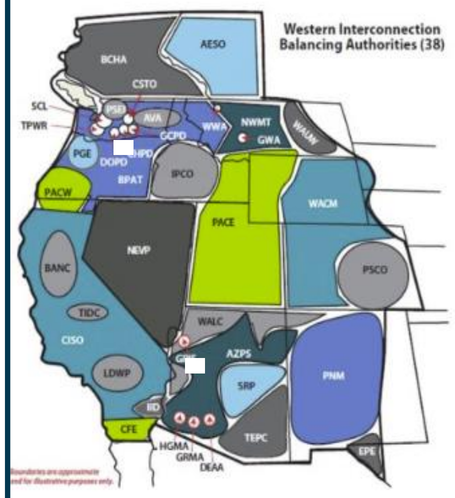
Prepared by Energy and Environmental Economics (E3)

Energy+Environmental Economics

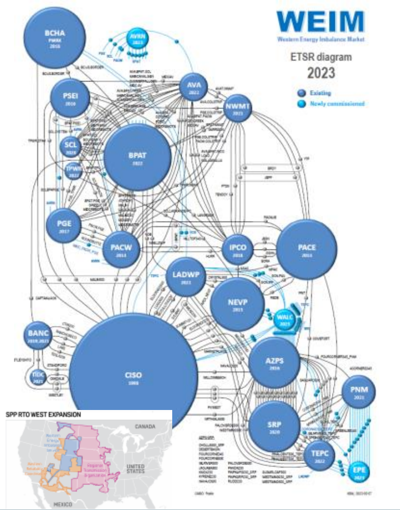
- **For 2026, the Core Scenarios compare a <u>BAU Case</u> with bilateral day-ahead trading only and EIM & WEIS in RT vs. a <u>West-wide EDAM Bookend Case</u> OR a <u>Main Split Case</u> with some entities participating in EDAM and others in Markets+**

Current Western Market (BAU)

Day Ahead



Real Time

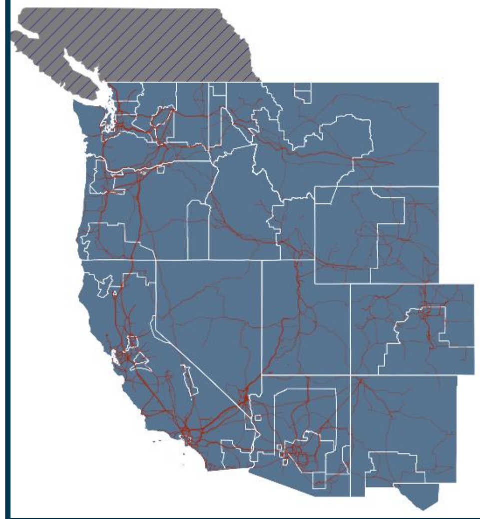


The **<u>BAU DA</u>** world: "bilateral" trading with transmission wheeling charges & transactional friction on trades crossing BAA boundaries using transmission reservations

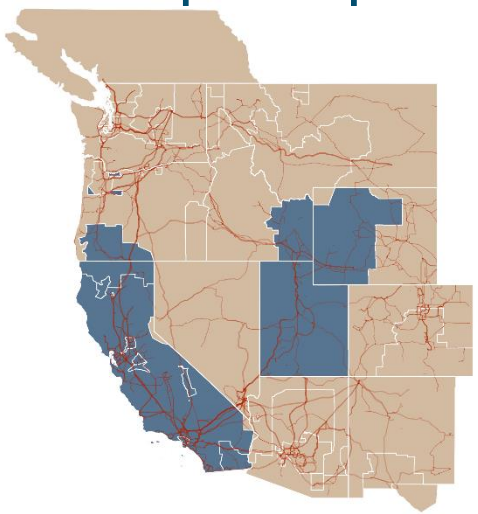
The **<u>BAU RT Case</u>** allows optimized trading within the existing EIM and EIS footprints (with no wheeling charges or transactional friction)

Potential Future Footprints (DA & RT)

EDAM Bookend



Main Split Footprint



Map Legend

- EDAM
- Markets+ (M+)

Credit: Greg MacDonald, PSE

*Note: A subset of members opted for modeling extra market cases of additional footprints

<u>EDAM Bookend:</u> a single DA and RT market covering the entire WECC excluding Alberta and BC

<u>Main Split:</u> two DA and RT footprints:

EDAM: PacifiCorp, CAISO LADWP, BANC, LADWP, TIDC, and IID;
Markets+: Rest of WECC (except AB)

http://www.oasis.oati.com/woa/docs/NEVP/NEVPdocs/E3_WMEG_Western_Day_Ahead_Market_Production_Cost_Impact_Study_-_June_2023.pdf

Market Features Modeled Distinctly

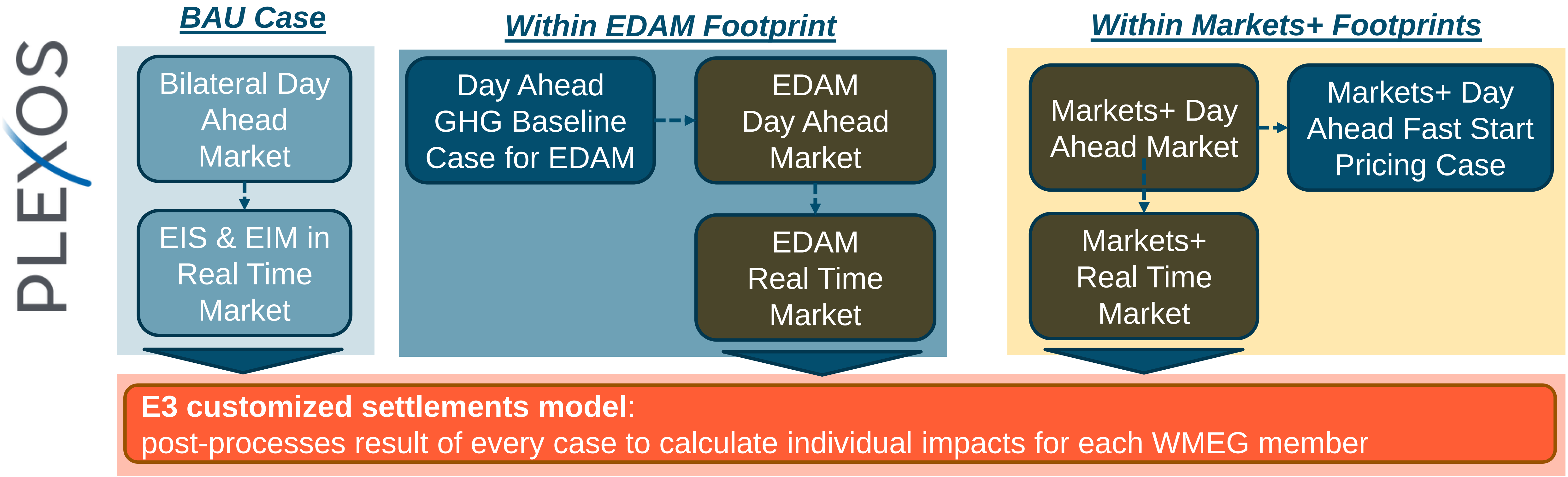
+ **Where possible, E3 reflected key features that differ in each market's proposed design that can be reflected as relevant distinctions in the simulation and post processing**

Market Feature	EDAM	Markets+
Fast Start Pricing	**No**	**Yes**
GHG Revenue Allocation	**GHG Revenue allocated to out of state generators in EDAM** that send incremental power to CA & WA (compared to the GHG Reference Case)	**GHG revenue not allocated among M+ generators;** Distribution of revenue for GHG imports are not specified in market design so are to be determined by the states
Transmission Availability	**In Base Case**: Modeled based on Zone-to-zone TTC with tie zones **In a sensitivity case (APP3):** Reduced transmission availability in BAU, in EDAM footprint & on market seams by 10%; kept M+ transmission the same as	**In Base Case**: Modeled based on Zone-to-zone TTC with tie zones **In a sensitivity case (APP3):** Maintained modeling based on zone-to-zone TTC levels to reflect potential ability of M+ to maximize transmission use

*Note: an additional difference in how the CBS models EDAM and M+ is in cases in which the Pacific Northwest (BPA and neighboring zones) were in EDAM (which was done in the EDAM bookend, and Alt Split 2 Case) BC hydro was modeled with trading primarily in daily peak/off peak hour blocks, per assumptions guidance provided by Powerex and approved by WMEG MC. In cases in which the Northwest is modeled in Markets+, and can trade with BC within M+ on contiguous lines, BC was modeled as trading with more hourly flexibility – dispatching in different amounts between its transmission and generation limits, but without any peak/offpeak block limitations.

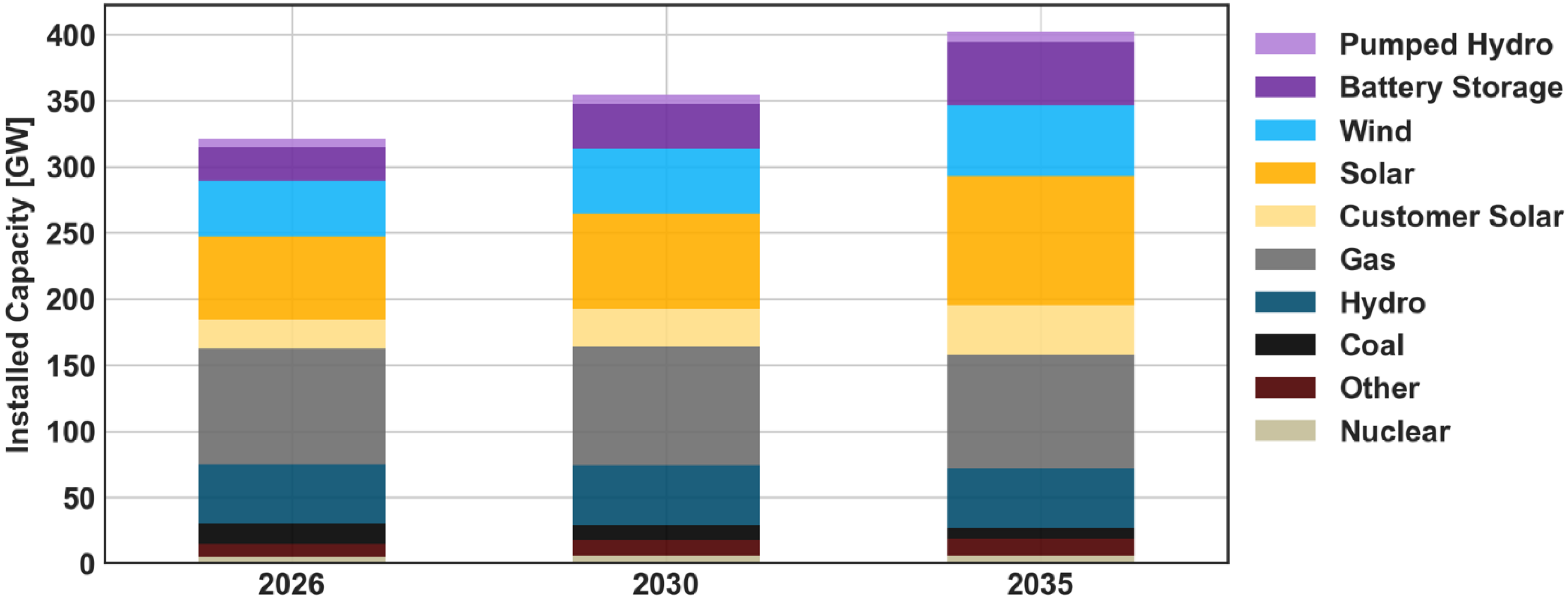
CBS Model Structure

- From September 2022 to May 2023, E3 simulated over 4,000 PLEXOS production cost runs for the Core CBS and Sensitivity Cases; E3 worked closely with Energy Exemplar to maximize efficiency of PLEXOS case runs and develop custom approaches including Fast start Pricing Case runs for Markets+
- Each simulation includes 8760 hourly modeling in both a day ahead (DA) and real time (RT) stage



Note: The Main Split & M+ Bookend cases modeled both EDAM and Markets+ simultaneously in different portions of the WECC Footprint

Total WECC Installed Capacity Modeled



The starting database for the study was the 2032 Anchor Data Set (ADS) created by the Western Electric Coordinating Council (WECC) with subsequent modifications for both WMEG member areas and non-WMEG areas

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Cost Impact of EDAM Bookend (2026)

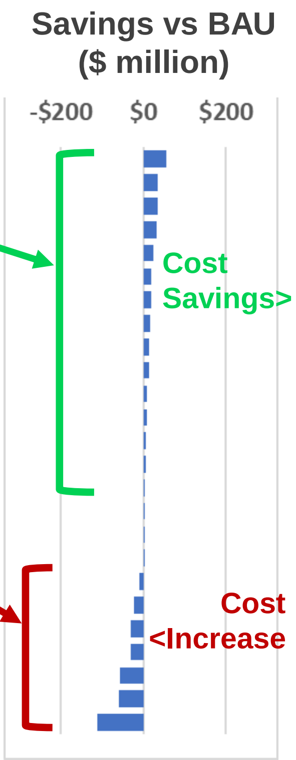
+ On a WECC-wide basis, the EDAM shows $60 million* cost reduction vs. BAU
+ Individual entity and regional results vary widely

Among WMEG Members

+ $20 million net cost increase overall

Among 25 WMEG members:

+ 18 entities with net cost savings (ranging from $0.5 to $55 million)
+ 7 entities with net cost increases (ranging from $10 to $111 million)



For Non-WMEG Entities

+ $80 million savings vs. BAU
  - Savings driven by reduced curtailment and reduced internal gas generation (replaced by imports from rest of market)
+ Non-WMEG Entities are primarily California-based (73% of load and 66% of gen capacity)

***$60 million WECC wide cost reduction for DA market represents 0.6% savings compare to $9.7 billion total production cost in BAU Case, which already reflects EIM/EIS markets in RT**

*WECC adjusted production costs represent the variable cost (fuel + VOM + startup) of dispatching generators in the US WECC, net of revenue from exports to Alberta or the Eastern Interconnection, plus the GHG wheeling cost for powered imported to GHG regulated areas (CA, WA, and CO state) not allocated as GHG net revenue to market generation

Cost Impact of Main Split Footprint (2026)

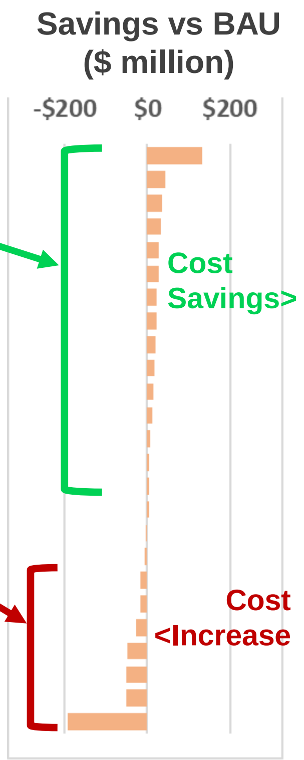
- On a WECC-wide basis, the Main Split shows $221 million more cost than BAU
- Individual entity and regional results vary widely

Among WMEG Members

- $26 million cost <u>savings</u> overall

<u>**Among 25 WMEG members:**</u>

- 16 entities with savings (ranging from $4 to $134 million)
- 9 entities with net cost increases (ranging from $0.3 to $190 million)



For Non-WMEG Entities

- $247 million net cost increase vs. BAU
  - Costs increase from higher internal gas generation to replace cost of imports from rest of market
- Non-WMEG Entities are primarily California-based (73% of load and 66% of gen capacity)

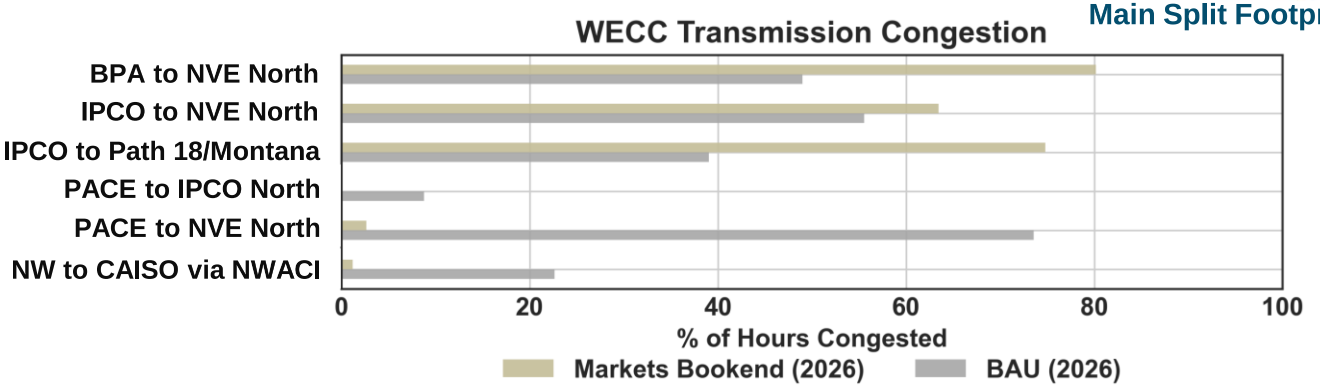
Markets+ Bookend case produces similar results as Main Split on a WECC wide basis and among WMEG members

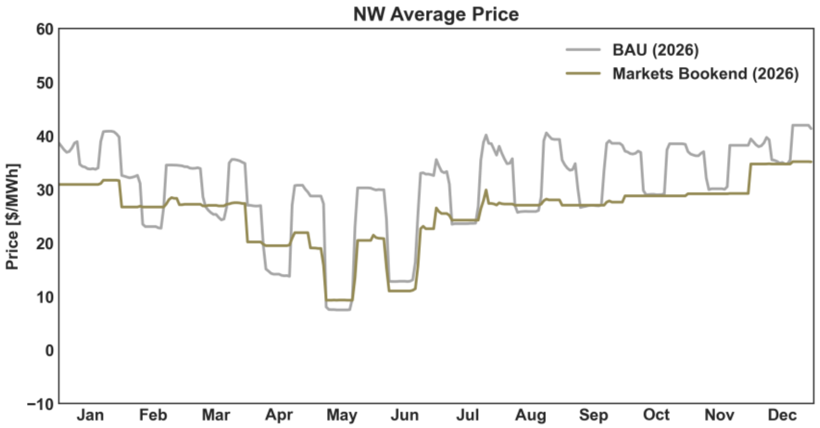
Results highlight importance of critical transmission lines for connecting Northwest & Southwest in Main Split Case

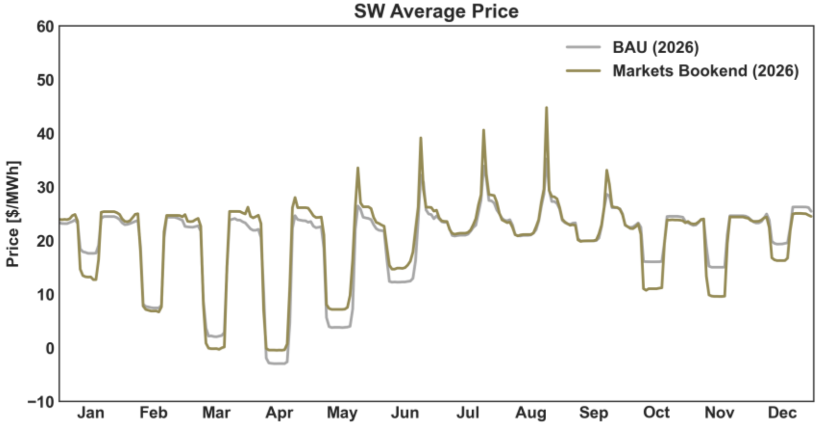
+ In the Main Split Footprint, transactions between the NW and SW portions of Markets+ depend heavily on key paths through ID, NV, and MT

- Otherwise, necessary to wheeling into and out of the EDAM footprint through California or PacifiCorp
- The Northwest portion of Market+ often has more local flexibility locally that it can use locally; transmission to the Southwest enables it to be more useful

Main Split Footprint





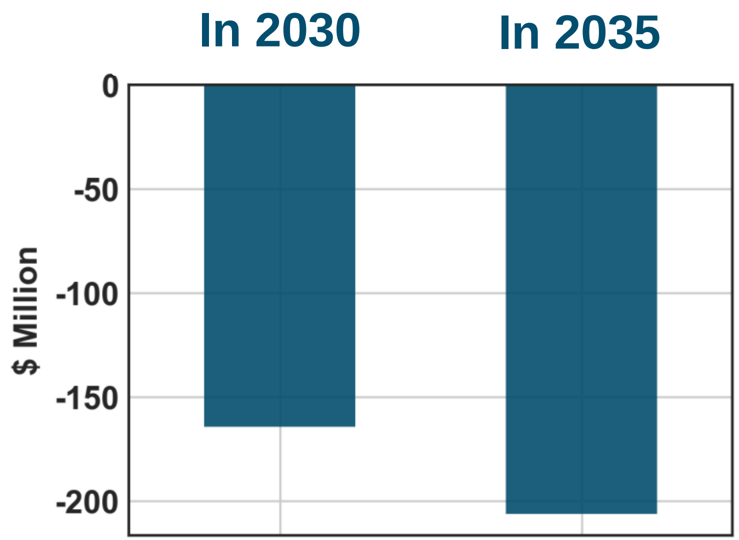


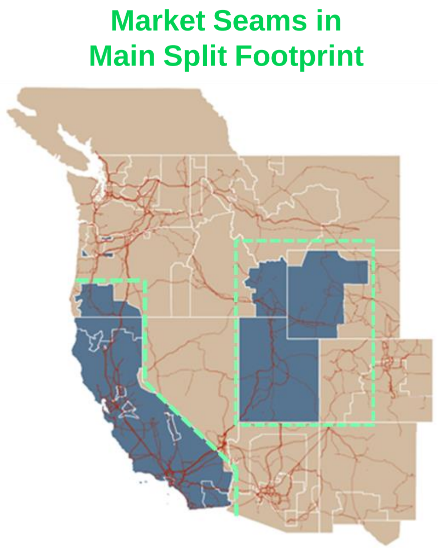
Improving Market-to-Market (M2M) coordination over seams can drive cost savings

+ **The WECC-wide cost increase in the Main Split Case was driven by a high cost of transactional friction over seams between the EDAM and Markets+ footprints**

+ **Lowering the cost to transacting between markets <u>reduced WECC-wide costs by over $150 million</u> per year in the 2030 and 2035 M2M Cases**
    - How to reduce cost of transacting between markets may take significant effort through market design and practices; this model result emphases that effort is worthwhile to pursue

WECC-wide annual cost change due to improved <u>Market to Market Coordination</u>





Note:
In the Main Split Cases, exports from each market were modeled based on the weighted average of transmission wheeling costs of the market participants, plus $10/MWh of total of transactional friction and congestion risk in DA and RT

In the M2M Cases, the cost of transactional friction was reduced to $6/MWh in DA and $3/MWh in RT, resulting in significant WECC-wide savings

Key Takeaways: System-Level Results

- **In this CBS study, <u>the overall range of impact is modest</u> compared to total system costs; other areas of potential market impact beyond production cost may be larger and merit more consideration**
  - Including load & resource diversity, investment savings from enabling wider resource procurement over a wider geography, coordinated regional transmission planning or investment, governance considerations
- **<u>Entity-specific benefits of each market vary widely</u>, so important to evaluate individual results by entity while also being mindful of opportunities for greater system-wide efficiency**
  - A single WECC market produces the lowest WECC-wide production cost, but with a wide range of results for individual entities (some positive, some negative); two markets (Main Split) also has a range of impact among WMEG members
- **If there are two markets, then it is important to focus on two key ways to improve efficiency:**
  - **(1) <u>Reducing seams cost and improve market-to-market coordination</u>:** especially in real-time, because an increasing share of new generation is dispatchable in RT, and DA net load forecast error is growing with wind & solar
  - **(2) <u>Improving intra-market transmission connectivity</u>:** Through participation of contiguous members or addition of new transmission connectivity, particularly to connect the Northwest and Southwest portions of the Market+ footprint

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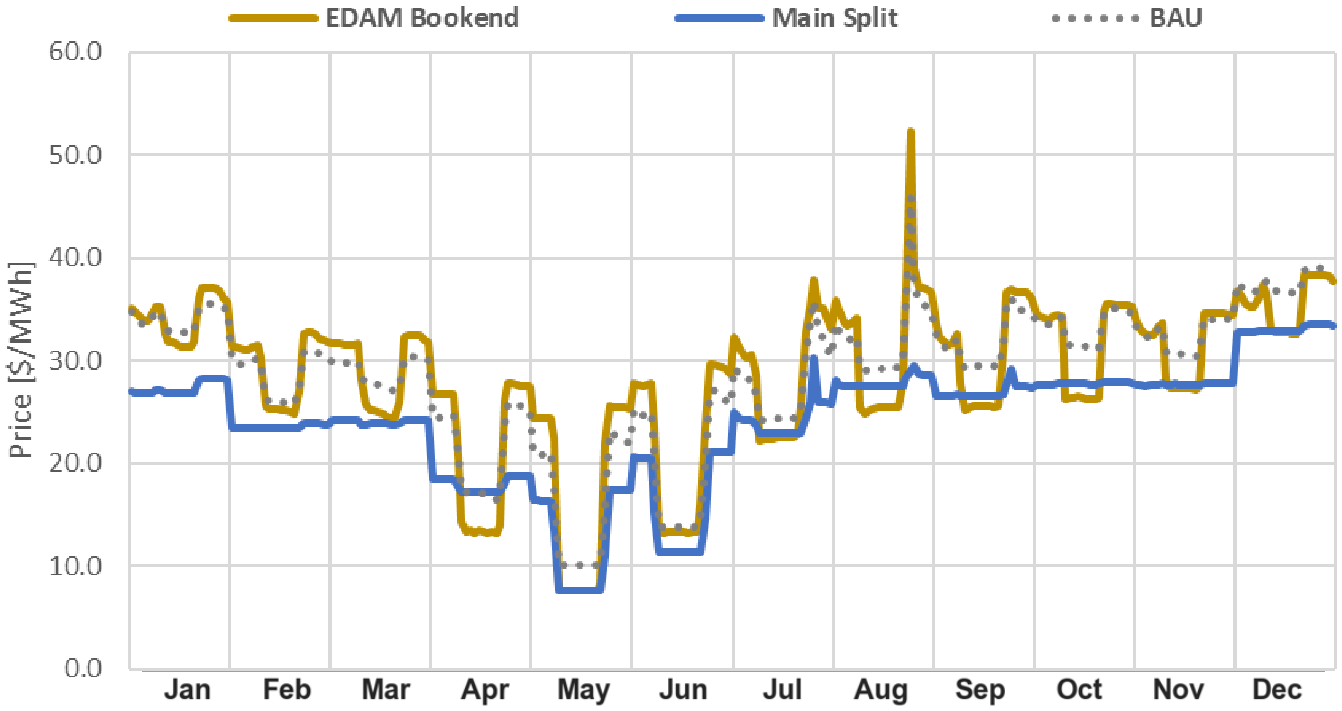
Individual Impact Results by Member

+ **Results were provided confidentially to individual WMEG members that funded CBS Study, but overall results show wide variation by market & case**
+ **The two primary factors influencing entity-specific benefits are:**
  - **Price changes vs. net market position**: Entities that net purchases benefit from market cases that reduces prices in their area; entities that are net sellers see lower revenue if prices go down (and more savings the market pushes prices up)
  - **Wheeling revenue changes and allocation**: Whether entities that currently receive transmission revenue from wheel-through or exports retain those in a market, and how market-to-market wheeling is allocated among entities
+ **Impact of market features on individual benefits:**
  - **Fast start pricing in M+** has mixed impacts to different entities. Puts pressure on trying to make sure units (even expensive ones) are running in any hours that is deemed fast start and then will get the price premium; fast start interacting with seams are a key uncertainty to define well
  - **GHG allocation for EDAM** can benefit some non-CA entities with low carbon gen that can be flexible (possibly even wind due to DA vs. RT forecast error); SPP M+ GHG allocation isn't yet determined so difficult to know
  - **Day Ahead flexibility reserves** did not have a significant magnitude of impact– assuming that offline units can typically provide them, the prices for these results remains low in most hours

Results Summary: Northwest Regional Prices

- **Compared to the BAU, the EDAM Bookend Scenario shows more intra-day variation**
  - Lower midday (solar hour) prices in many spring & fall months when CA or the Southwest can export smoothly to the Northwest
  - higher evening prices as the Northwest exports south after solar drops off
- **The Main Split Scenario resulted in lower, more flat prices for most months in the Northwest**
  - The Northwest is a net exporter in the BAU case with significant flexibility to ramp up and down intra-day
  - The assumed wheeling charge to exit Markets+ (plus market-to-market transactional friction) reduces NW exports to CA overall and lowered marginal prices; also BC is more flexible in this case
  - The flexibility of Northwest hydro resources modeled exceeds the needs for flex inside the local region and transmission to outside is limited within Markets+ footprint (through Idaho/NV to the Southwest), so NW hydro shifted within day to flatted intra-day prices
  - ***These prices would be net beneficial for NW entities that are net purchasers but reduce revenue for net sellers***
  - Hydro opportunity cost across days was not modeled and may add complexity (and potentially higher prices) not included here

Northwest Month-Hour Average Prices
2026 Day Ahead Cases (Avg of WA & OR zones)



This figure compares Month-hour average market prices in the EDAM Bookend & Main Split Case versus the BAU case, taking a simple average of the zonal price for all zones primarily in WA & OR state. Each section between gridlines represents 24 hours of a day within each month.

Results Summary: BPA-Specific Results

- **Results reflect changes in production cost for generators owned & contracted to the entity, as well as changed in the cost of energy purchases and revenue for energy sales (exports)**
  - Do not reflect potential changes to generation capacity or procurement decisions
  - BPA-specific results include congestion revenue related to market price differences on key paths that are constrained
- **Changes to wheeling revenue were also an important consideration for BPA**
  - The model treats wheeling charges (and revenue) in the BPA case as a variable cost that is applied to all exports from BPA (or trades that pass through the BPA transmission system) – these charges are waived inside each market footprint
  - In actual practice, the majority of BPA's current transmission wheeling revenue is for long-term contracts, which counterparties may continue to renew in a market scenario for different reasons

- **The results shown here indicate BPA's changes to net cost as an EDAM or Markets+ participant vs. BAU under two bookends:**

Bookend 1: Assumes all BPA wheeling revenues are variable and change in market cases

Bookend 2: Assumes all wheeling revenues are unchanged in market cases vs BAU

Actual outcomes would likely range between these bookends

BPA-Specific Results WMEG Core Cases 2026

	Case		
Cost/Benefit ($ millions)	BAU (2026)	EDAM Bookend (2026)	Main Split (2026)
Load Cost	921.7	944.0	923.6
Generation Cost	131.3	131.3	131.3
Reserve Cost	0.0	0.0	0.2
Generation Revenue	-1343.1	-1489.6	-1370.3
Reserve Revenue	0.0	0.0	0.0
Wheeling Revenue	-251.4	-5.5	-31.8
Congestion Revenue	-49.9	-60.1	-52.7
GhG Revenue	0.0	-0.1	-0.8
Net Cost	**-591.3**	**-480.1**	**-400.5**
Net Cost vs. BAU		***111.2***	***190.8***
Net Cost excl. wheeling	**-339.9**	**-474.6**	**-368.7**
vs. BAU		***-134.7***	***-28.8***

Note: negative values for net cost represent net revenue that accrue to BPA customers, so more deeply negative net cost values are better for BPA customers

Thank You

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Energy+Environmental Economics

Appendix

Energy+Environmental Economics

CBS Model Data & Assumptions

- E3 worked closely with UtiliCast and WMEG member staff to develop input and assumptions
- The starting database for the study was the 2032 WECC Anchor Data Set (ADS) with subsequent modifications
- Within WMEG Member Areas, WMEG members used confidential data to provide load forecast data, updated generator additions and retirement information, and transmission TTC values
- E3 worked with WMEG to confirm final fuel price & GHG assumptions used for the case
  - Avg 2026 gas prices: $3.17 at Sumas, $4.68 at Socal Citigate
  - 2026 GHG prices: $39/tonne in CA, WA, and CO with $17/MWh charge on imports to those states (based on assume 0.437 tons/MWh)
- For Non-WMEG Member Areas:
  - **CAISO** was modeled based on WECC ADS, with updates reflected based on PLEXOS data posted by CAISO (the study did not coordinate with CAISO to review or update)
  - **British Columbia (BC Hydro)** was modeled using guidance provided by PowerEx with a schedule of net daily export/import flow to the US; modeled with a mix of peak/offpeak trading and hourly flexibility in the BAU and EDAM cases; modeled with hourly trading flexibility in cases where the Northwest is in Markets+
  - **Alberta (via MATL DC tie) & SPP in Eastern Interconnection (via DC ties to WECC)** were modeled with hourly historical market prices (adjusted for forecasted gas price changes) and transmission wheeling charges; WECC zones could export to sell up to the line capability when external prices are higher & vice versa
  - **Merchant generation not owned or contracted to WMEG members** were modeled in the market of their BAA's location, but revenue & costs for these units were not allocated to the MWEG members

Key Market Features Modeled Similarly

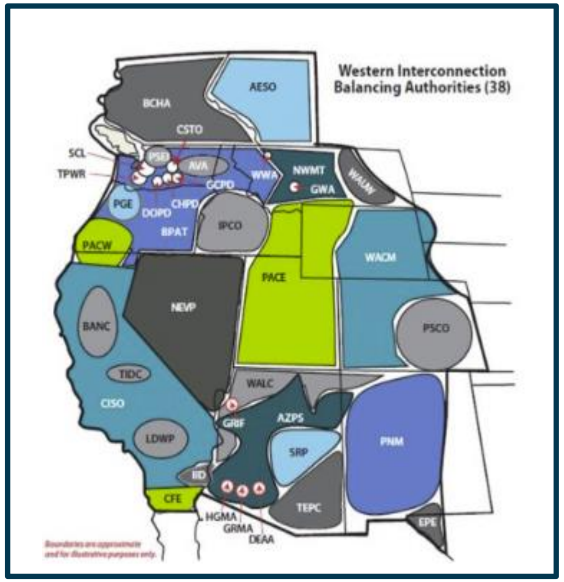
- **Based on discussion with WMEG members, other market features were reflected with similarly functionality for both markets**
  - The different market footprints, however, cause these features to have different results by market case

Market Feature	Markets+ & EDAM
Market Seams	Model market footprint-wide $/MWh export charged to exports from EDAM footprint or from M+ footprint
Imbalance Reserves	Model as Ancillary services product required to be held in DA stage in sub-regions of each market footprint (e.g., Southwest-M+); held for each BAA zone in BAU case Imbalance Reserve hourly quantities are calculated based on a determined percentile of the day ahead forecast error of net load in each zone (these quantities are reduced for EDAM or M+ footprint diversity)
Allocation of Transmission Congestion Revenue	Congestion rent allocation based on ownership share of lines/paths between zones

Market Footprints Considered in Core CBS Analysis

+ The Core CBS Study simulates 4 cases for 2026 to compare different DA market footprints

2026 BAU Case

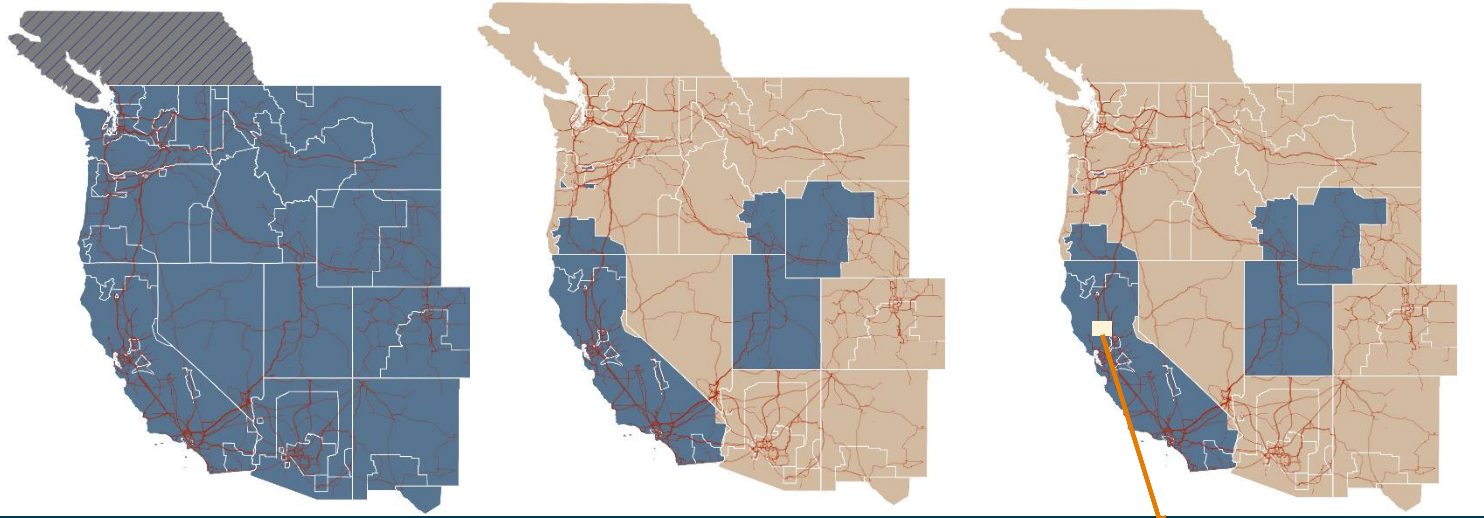


2026 Market Cases

EDAM Bookend

Main Split

Markets+ Bookend



Map Legend

- EDAM
- Markets+ (M+)

Credit: Greg MacDonald, PSE

*Note: A subset of members opted for modeling extra market cases of additional footprints

The **BAU Case** models DA bilateral trading with transmission wheeling charges & transactional friction on trades crossing BAA boundaries

In the real-time (RT) stage, the BAU case represents wheeling & friction-free trading within the existing EIM and EIS footprints

The **EDAM Bookend** models a single DA and RT market that covers the entire WECC excluding Alberta and BC

Trades inside the Market reflect the currently proposed EDAM design, and are simulated with no wheeling costs or friction

The **Main Split** Case models two separate DA and RT footprints:

EDAM: PacifiCorp, CAISO LADWP, BANC, LADWP, TIDC, and IID

Markets+: The rest of the US WECC & BC; simulated based on the current M+ design

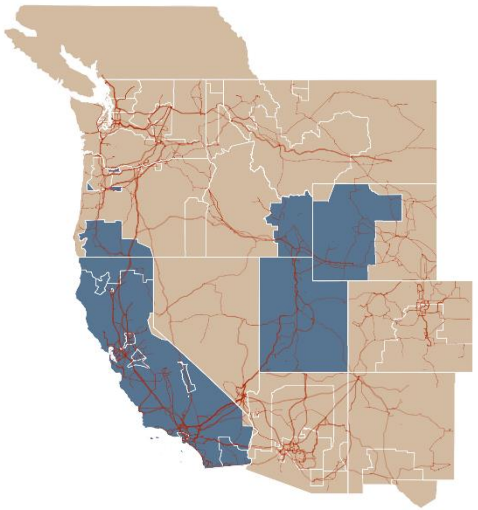
The **Markets+ Bookend** models two separate DA & RT footprints similar to the Main Split, except that the **WAPA SNR sub-BA is moved to M+**

Within each Market (M+ and EDAM) transactions do not face wheeling or friction but these charges are applied to trades on the seams between markets

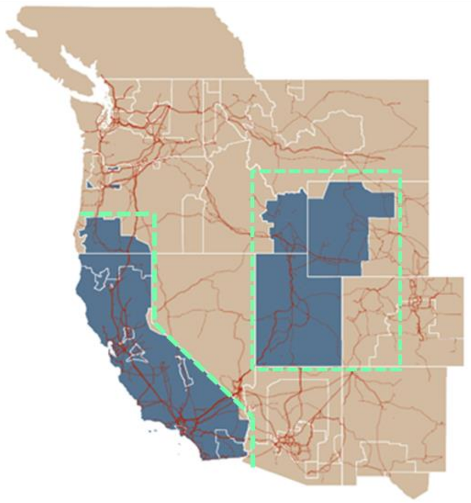
Increasing Market Integration Modeled in Core CBS

+ **The Core CBS simulates additional cases with increasing integration in 2030 and 2035**

Baseline: 2030 & 2035 Main Split

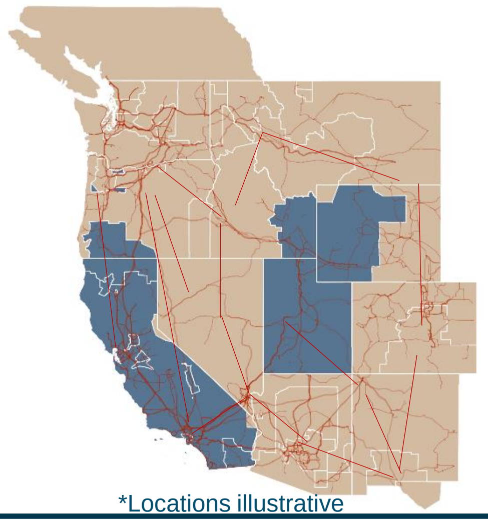


2030 & 2035 Market to Market Coordination



2030 & 2035 M2M plus Consolidated Balancing Authorities

2035 RTO Case



Map Legend

- EDAM
- Markets+ (M+)

Map Credit:
Greg MacDonald, PSE

The 2026 Main Split footprint was used as a consistent baseline for evaluating improved integration and coordination in later years

E3 modeled **2030 & 2035 Main Split** cases that reflect load growth, generation retirements additions, and updated fuel & GHG prices

The **2030 and 2035 Market to Market (M2M) Coordination** cases use the Main Split footprint for EDAM and Markets+, but reduce the transactional friction for trading over the seams between markets in DA and RT

The **2030 and 2035 M2M plus Consolidated Balancing Authority (M2M + CBA)** cases reflect the Main Split footprint with M2M coordination, but also add a market for co-optimized ancillary services (AS) procurement across sub-regions of each Market footprint

The **2035 RTO Case** models the Main Split footprint with M2M and CBA, but adds significant transmission to evaluate how each market may perform if additional transmission from coordinated planning enabled greater trading across the footprint

*The RTO Case transmission additions are specific to route location or used for cost-benefit evaluation of individual lines but rather used to explore how greater total Western transmission could impact trading and energy costs

Updated Hurdle Rate Assumptions by Scenario ($/MWh)

	2026	2030	2035
BAU	OATT Rate + $2 Marketing Friction on exports from zone or collection of zones that represent one entity. If an entity has a split zone, there is no hurdle between their zones.		
EDAM & Markets+ [without M2M Coordination]	**Within Market Footprint:** $0 **Seam: Wgtd Avg OATT Rate of Market* + $2 Friction + $8 Congestion Risk** for exports from a Zone that is in Market A to a Zone that is in Market B	**Within Market:** $0 **Seam: Wgtd Avg OATT Rate of Market+ $2 Friction + $8 Congestion Risk** for exports from a Zone that is in Market A to a Zone that is in Market B	**Within Market:** $0 **Seam: Wgtd Avg OATT Rate of Market+ $2 Friction + $8 Congestion Risk** for exports from a Zone that is in Market A to a Zone that is in Market B
M2M Coordination		**Within Market:** $0 **Seam: Wgtd Avg OATT Rate of Market + $2 Friction + $4 DA Congestion Risk (or $1 RT Congestion Risk)** for exports from Market A to a Zone that is in Market B	**Within Market:** $0 **Seam: Wgtd Avg OATT Rate of Market + $2 Friction + $4 DA Congestion Risk (or $1 RT Congestion Risk)** for exports from Market A to a Zone that is in Market B
M2M Coordination + CBA and AS Market		Within Market: $0 **Seam: Wgtd Avg OATT Rate of Market + $2 Friction + $4 DA Congestion Risk (or $1 RT Congestion Risk)** for exports from Market A to a Zone that is in Market B	Within Market: $0 **Seam: Wgtd Avg OATT Rate of Market + $2 Friction + $4 DA Congestion Risk (or $1 RT Congestion Risk)** for exports from Market A to a Zone that is in Market B
RTO			Within Market: $0 Full RTO / Enhanced Transmission Portfolio – Same hurdle rates as CBA+ASM and M2M case; key difference in the RTO case is different transmission buildout

***Weighted Avg OATT Rate of Market:** for each market case, exports out of the market over a seam will be charged a wheeling rate equal to the average OATT rate of the zones within that market footprint, weighted by the annual MWh of load within that zone. For example, if CAISO is 50% of the EDAM footprint, then 50% of the EDAM wheel-out rate will be based on the CAISO TAC charge, and 50% would be based on the OATT charge of the other BAAs in the EDAM footprint.

For 2026 Main Split Case, the EDAM footprint weighted average OATT is $9.53/MWh and the M+ footprint average OATT is $4.21/MWh, so the total hurdle rate is $19.53 for EDAM and $14.21/MWh for M+.

*In the 2026 Case and the EDAM & Markets+ Cases (and 2030/35 cases without M2M coordination): cross-market transactions assumed to occur as bilateral scheduled transactions prior to the DA market runs, before knowledge of the final market prices, so entails additional risk and would need more price premium for participants; In the 2030 and 2035 M2M cases, these transactions are assumed to occur within the market, so the DA congestion risk is assumed to be cut by 50%, and in real-time stage, coordination is assumed to remove the congestion risk.

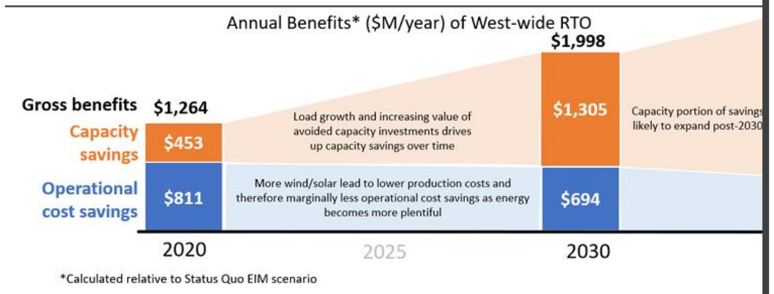
Recent Day Ahead Market Studies each provide different perspectives and pieces of the Western puzzle

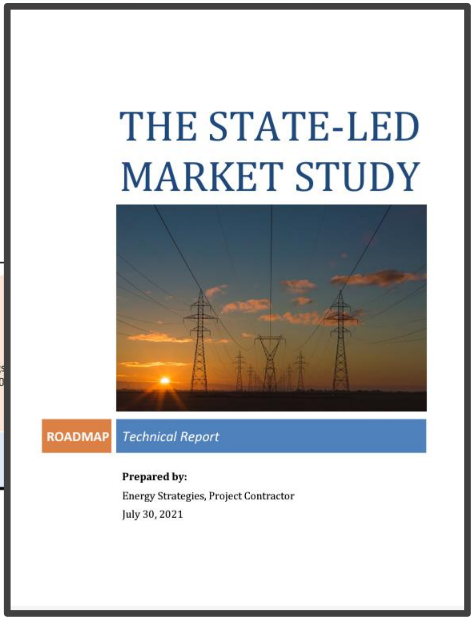
- **Four study all have provided recent looks at potential market footprints and functions**
  - **Energy Strategies:** State-Led Study
  - **Energy Strategies:** CAISO EDAM Benefit Study
  - **Brattle Group:** CAISO-PacifiCorp EDAM Benefit Study
  - **E3:** Day Ahead Market Study for Western Market Exploratory Group (WMEG)

Study Detail: Energy Strategies State-Led Study (June 2021)

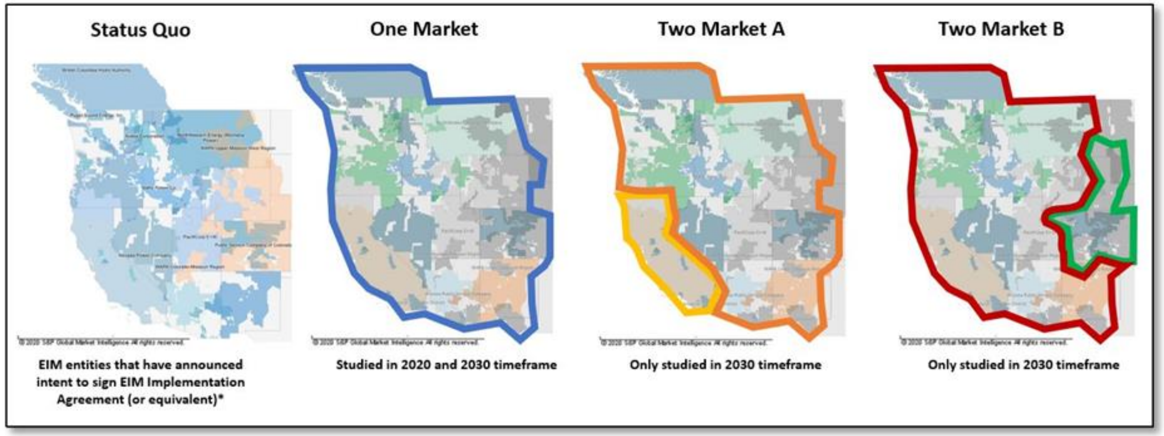
+ **Commissioned by Utah Office of Energy Development and funded by US DOE**
+ **Significant Assumptions & Findings:**
    - Single west-wide Day Ahead Market could bring **$246M** more benefits than 2 separate DA markets **($747M single market vs. $501M for 2 markets)**
    - By 2030, capacity-related savings from a West-wide RTO could produce nearly 2x the savings from operational benefits alone **($1305M with capacity savings vs. $694M operational cost alone)**
    - For production cost savings only (not capacity savings) **DA-only markets resulted in $95M in production cost savings for one market or $85M for two markets**
    - Note: study did not calculate potential savings transmission planning, reliability, and resource procurement to meet policy goals

State Led Study and EDAM Market Benefits Study: https://www.energystrat.com/new-insights-experience





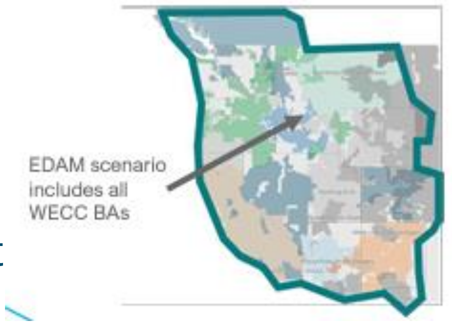
Market Footprints Considered in Study

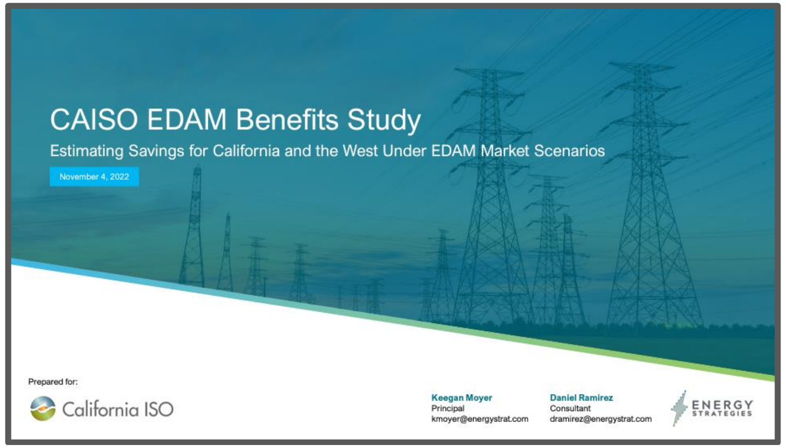


Study Detail: Energy Strategies CAISO EDAM Benefit Study (Nov 2022)

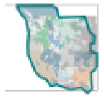
- **Prepared for CAISO using methodology developed for State Led Study with EDAM Specific inputs**
- **Significant Assumptions & Findings**
  - Model assumes WECC-wide EDAM allows CAISO to not face export limit on how much power can flow out, and increases ability to use transmission at $0 wheeling cost, and reduce imbalance reserve needs due to diversity
  - Shows **$543M West-wide operational (production) cost savings** vs. BAU case with EIM only, plus **$652M in capacity savings** [for $1.2B total], as well as nearly 3 million MT reduction in CO_2 emissions
  - **Allocation: $309M of total savings attributed to California vs. $886M for other Western States**
  - Imbalance reserve savings drive about 2/3 of total operational cost savings

CAISO EDAM Study: https://static1.squarespace.com/static/59b97b188fd4d2645224448b/t/64de69381a581b370f50e00f/1692297540615/Presentation-CAISO-Extended-Day-Ahead-Market-Benefits-Study.pdf





Area	Operational Savings ($M/year)	Capacity Savings ($M/year)	Total Savings ($M/year)
California	$214	$95	**$309**
Other Western States	$329	$557	**$886**
Total	$543	$652	**$1,195**

EDAM Scenario	Area	Operational Savings ($M/year)	Capacity Savings ($M/year)	Total Savings ($M/year)
West-wide EDAM w/o Imbalance Product 	California	$86	$95	**$181**
	Other Western States	$120	$557	**$677**
	Total	$206	$652	**$858**

Study Detail: Brattle CAISO-PacifiCorp EDAM Benefits Analysis (April 2023)

+ **Commissioned by PacifiCorp to simulate currently proposed EDAM market design in detail including resource sufficiency test and GHG treatment**

+ **Significant Assumptions & Results**
  - EDAM Footprint assumed to include CAISO, PacifiCorp, Idaho Power, LADWP, and BANC as participants
  - Modeled approximately 2 GW reduction in imbalance reserve needs in EDAM scenario vs. BAU
  - For 2032 Study year, showed **$438M in annual net EDAM Benefits** for all participants (*does not include capacity benefits*), driven by 51 TWh higher trading volume in footprint and improved capture of congestion and wheeling revenue
    - Of these net benefits, $181M savings accrue to PacifiCorp, driven by greater sales from dispatching lower cost Pac gas units & increased purchases at lower cost during low priced hours for EDAM
    - Approximately 650,000 reduction in GHG emissions for EDMA footprint

Simulations are based on 2032 as a proxy year to represent annual benefits for the first decade of EDAM operations

EDAM Benefits ($ millions/year)

Benefit Metric	Modeled EDAM Footprint
EDAM Benefits	
Adjusted Production Cost Savings	$134
EDAM Congestion Revenues	$269
EDAM Transfer Revenues	$409
Total EDAM Benefits	**$813**
Other EDAM Related Impacts	
Impact on Wheeling Revenues	-$103
TRR Settlements *[1]*	$0
Impact on EIM Congestion Revenues	-$16
Impact on CAISO DA Tieline Trading Value	-$57
Reduced Bilateral Trading Value *[2]*	-$199
Net EDAM Benefits	**$438**

Notes:
[1] TRR settlements (hold harmless for lost wheeling revenues) are zero for footprint
[2] Reduced bilateral trading values of exports and imports from the BAs of EDAM members, includes impacts on trades by third-party marketers.

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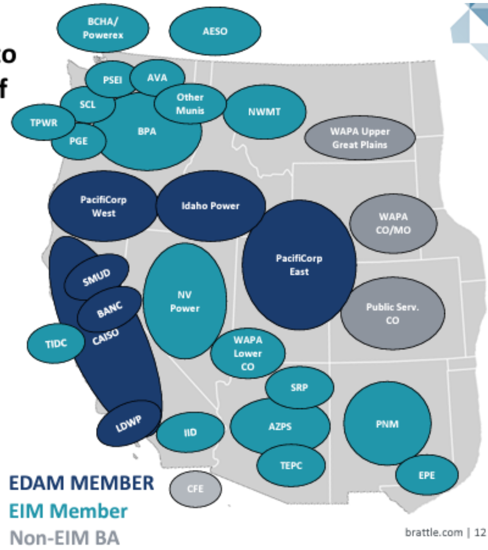

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