

BPA Day Ahead Market Study

Day Ahead Market Workshop

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Portland, Oregon



Energy+Environmental Economics

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Key Topics

- 1. E3's Market Studies for WMEG and BPA**
- 2. Response to specific points raised by Public Power Council**
 - Hurdle Rates and Friction Between Market Seams
 - Day-ahead vs. Real-time Price Differences
 - Fast-Start Pricing
 - Scarcity Pricing
 - Greenhouse Gas Accounting

E3's Market Studies for WMEG and BPA



Energy+Environmental Economics

E3 Western Market Exploratory Group (WMEG) Cost-Benefit Study, September 2022 – May 2023

- + 25 Western Utilities formed WMEG and retained E3 to analyze the impact of different potential day ahead market footprints and features
- + E3 led study work from Sept 2022 through May 2023, incorporating **significant input and review from the utility participants** (including utilized confidential data from each WMEG member)
- + WMEG participants represented a **diverse array of public and investor owned utilities**, Western geographies, and resource mixes, including many entities that chose to participate in Markets+

Benefits considered:

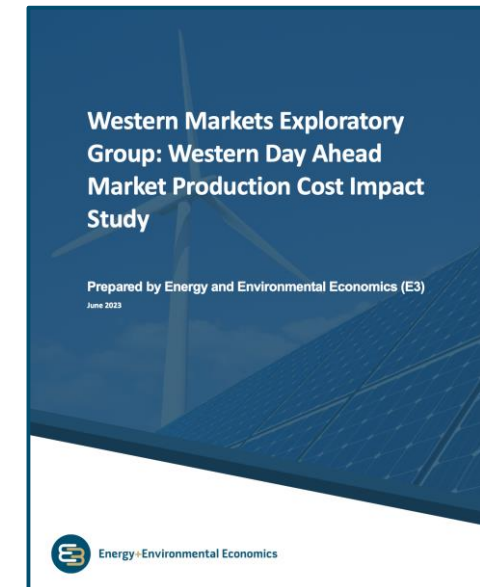
Variable production costs

Benefits *not* considered:

Resource adequacy capacity savings
Clean energy procurement savings
Efficient regional transmission planning
Grid reliability
Consolidated Balancing Area operations

Utility Participants in WMEG study included:

Arizona Electric Power Cooperative	PacifiCorp
Arizona Public Service	Platte River Power Authority
Avista Corp	Portland General Electric
Balancing Authority of Northern CA	Public Service New Mexico
Black Hills Energy	Puget Sound Energy
Bonneville Power Administration	Salt River Project
Chelan County PUD No. 1	Seattle City Light
El Paso Electric Company	Tacoma Power
PUD #2 of Grant County	Tri-State G&T Association
Idaho Power Company	Tucson Electric Power
Los Angeles Dept. of Water & Power	Xcel Energy Colorado
NorthWestern Energy	Western Area Power Administration.
NV Energy	



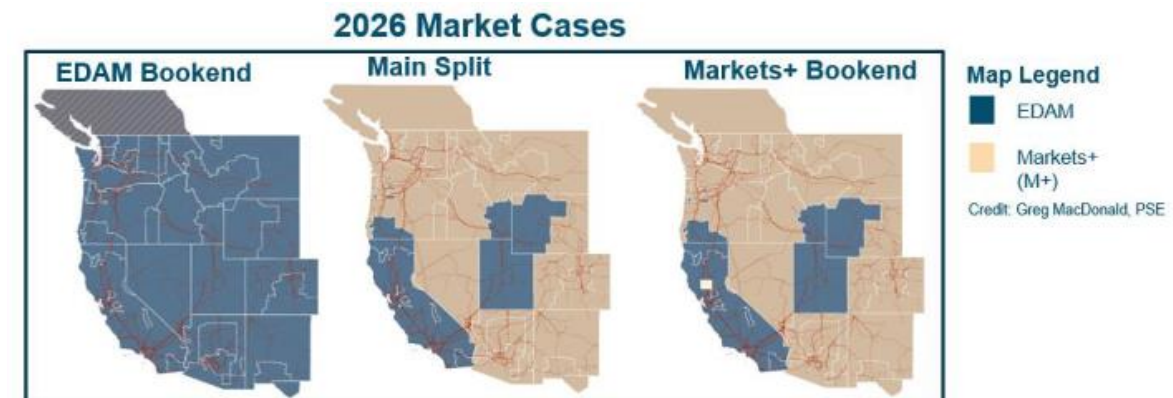
E3 WMEG Study (2022-2023): Methodology and Results

Methodology

- + E3 used industry best practice methodology, agreed to by all WMEG members, for evaluating the benefits of alternative market designs and footprints
- + Conducted detailed hourly PLEXOS production simulations for both the day-ahead (DA) and real-time (RT) operational stages
- + “Adjusted Production Cost” benefits methodology accounts for each market participant’s unique resource portfolio by pricing imports and exports at the endogenous zonal market price
- + Congestion revenue (on internal transmission within each market) was allocated based on the zonal location where congestion occurred
 - For congestion on the seam between markets, congestion was allocated among the market participants based on their share of total market load
- + WA and CA assumed to be together in Western Climate Initiative GHG market

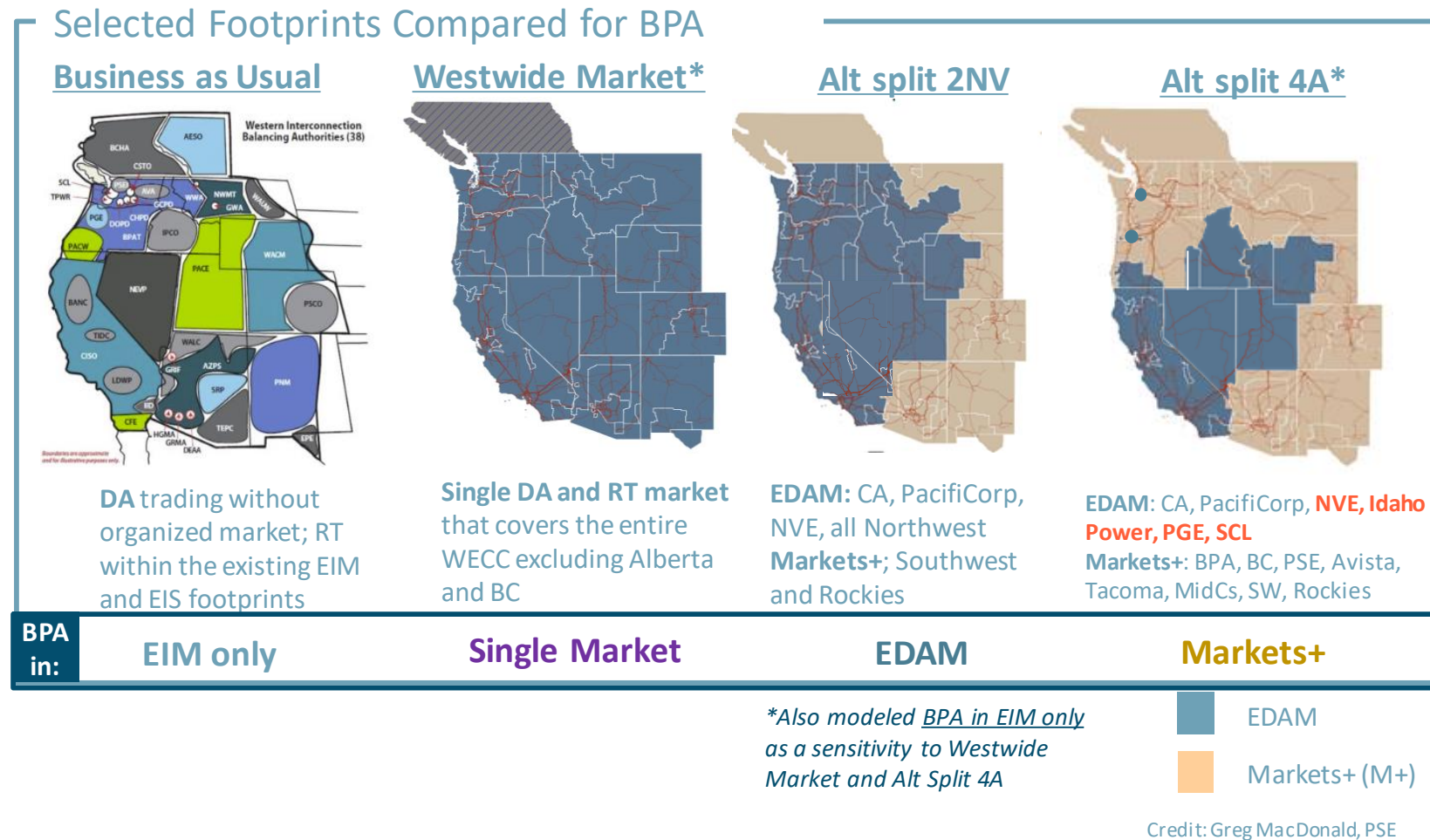
Results

- + Regionwide adjusted production costs **decline by \$60 million** in the EDAM Bookend case (vs. 2026 BAU case)
- + Regionwide costs **increase by \$218 million** in the Markets+ Bookend case
- + BPA’s adjusted production costs decline by \$113 million (vs. BAU) in the EDAM Bookend case, and by \$25 million in the Main Split case
 - For the 2026 case, BPA benefits from joining EDAM are **\$90 million greater** than from Markets+



BPA WMEG Follow-up Study work, 2023 - 2024

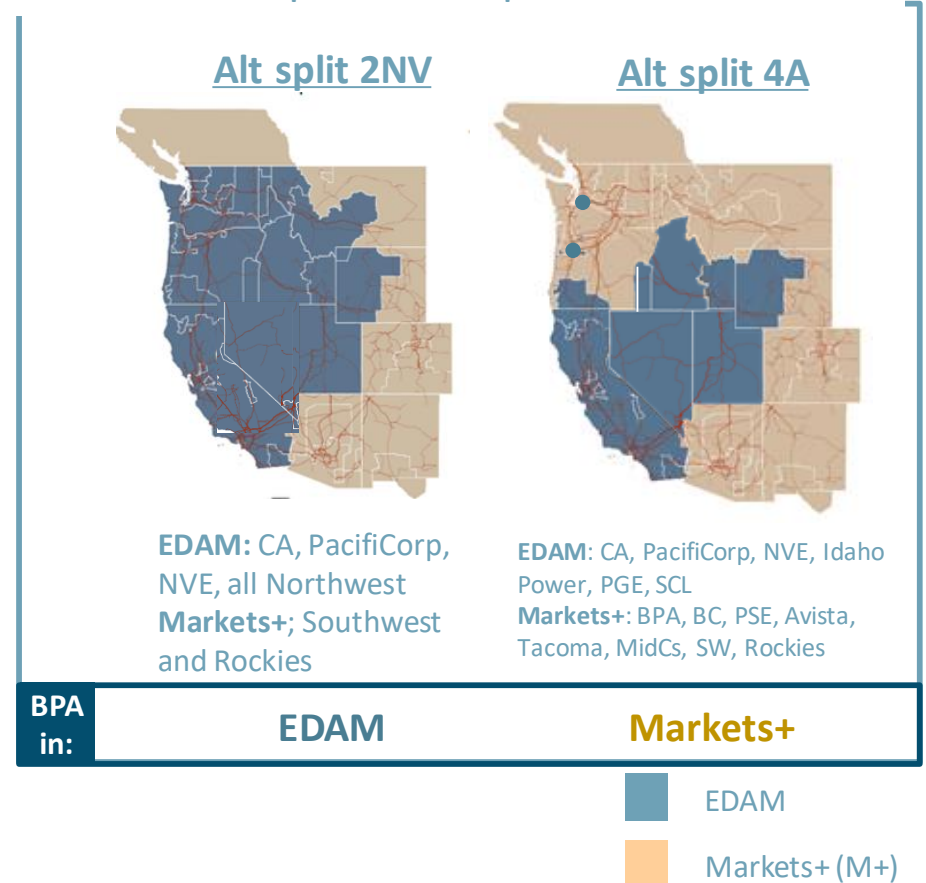
- After the WMEG work was completed, BPA retained E3 for ongoing support to explore additional alternative scenarios
- E3 worked very closely with BPA's team to identify the scenarios of interest to develop key assumptions for the cases
- Additional cases included sensitivities to hydro levels, hurdle rates, and market footprint
- Key case results (Alt Split 2NV vs. 4A):
 - For the 2026 case, BPA benefits from joining EDAM are **\$165 million greater** than from Markets+
 - For the 2030 case, BPA benefits from joining EDAM are **\$193 million greater** than from joining Markets+
 - For the 2035 case, BPA benefits from joining EDAM are **\$216 million greater** than from joining Markets+)



The primary driver of lower Bonneville benefits in Markets + is reduced market revenues due to lower market prices

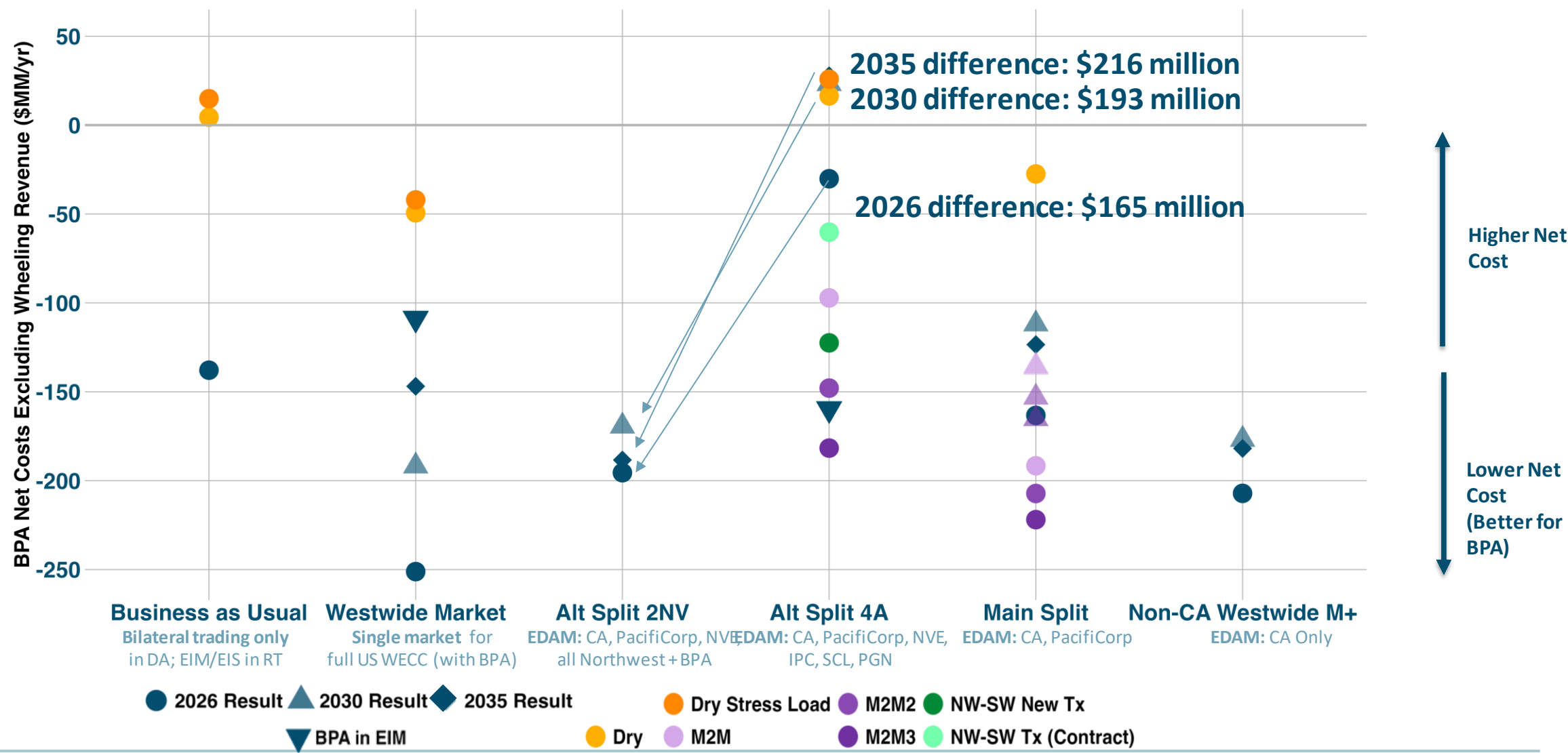
- + BPA is a net seller of energy, with very low marginal production cost
- + Scenarios with higher prices prevailing for BPA yield more net revenue from sales
- + In the Alt Split 4A Case, BPA joins Markets+ along with PowerEx, PSE, Avista, Grant County PUD, Chelan County PUD, Tacoma, and Northwestern
 - Plus 400 MW of Markets+ dedicated transmission to the Southwest portion of Market+
 - Hurdle rates are applied to reflect the cost of transmission charges & market risk to cross the market seam into EDAM
- + The Pacific Northwest portion of M+ has more hydro sellers than buyers, and limited transmission out without a market seam hurdle
- + BPA joining Markets+ results in lower, flatter prices - and lower market revenues for BPA, than when BPA is in EDAM (which has more net purchasers seeking flexibility)

Selected Footprints Compared for BPA

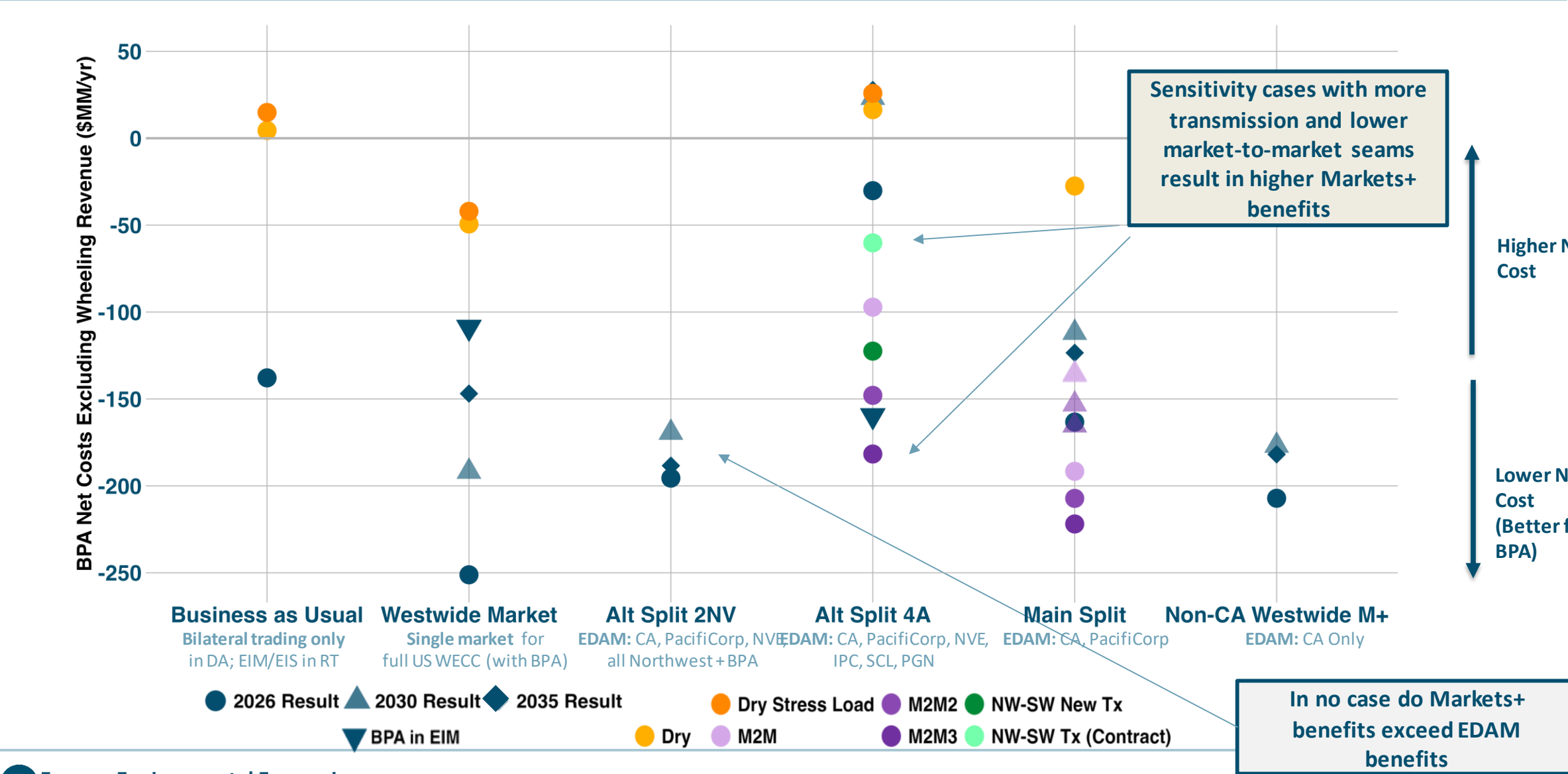


Credit: Greg MacDonald, PSE

Core cases show very high benefits for BPA joining EDAM vs. Markets+



BPA sensitivity study cases did not change the core conclusion that Bonneville would benefit more from joining a larger market



2. Response to specific points raised by Public Power Council



Comparison of E3 and PPC study methodologies

E3 Methodology

- + E3 conducted a fundamentals-based market study using a rigorous, best-practice methodology agreed to by WMEG members
- + WMEG members contributed to and thoroughly vetted the PLEXOS production simulation model
- + Market benefits determined by multiplying price and quantity pairs calculated by PLEXOS
- + Price and quantity pairs are internally consistent for model years 2026, 2030 and 2035 based on the regional resource portfolios in each year
- + Price and quantity pairs reflect transmission constraints between zones across the Western Interconnection

PPC Methodology

- + PPC methodology is based on a selective review of historical price trends, not a rigorous and internally consistent market study
- + Methodology is non-standard and non-transparent
- + Price and quantity pairs are not internally consistent, do not reflect specific regional resource portfolios, do not incorporate transmission constraints, do not reflect market depth

Hurdle Rates and Friction Between Market Seams



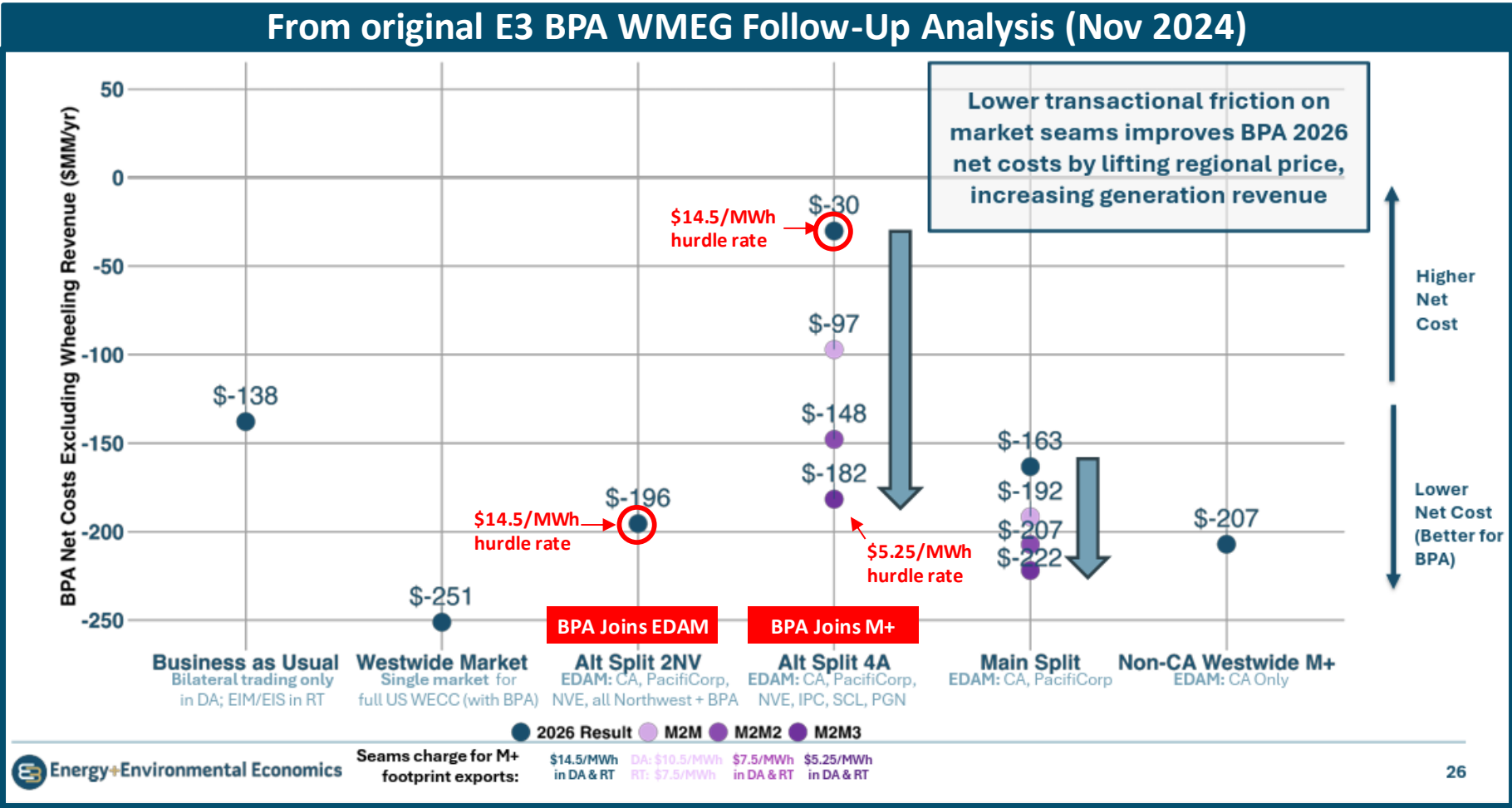
PPC suggested the WMEG study used unrealistically high “hurdle rates” on market seams between EDAM & M+. We disagree.

PPC asserts that E3’s modeling used unrealistically high hurdle rates between adjacent markets

“The drastic differences in anticipated cost savings from changing the assumed hurdle rates stem from how the incremental hurdle rates applied to exports and imports reduce or increase modeled trade between regions. In these scenarios, every MWh of trade between market footprints is subjected to the same “hurdle rate.” This outcome is an unrealistic assumption given the structure of both day-ahead markets and the continuation of a robust bilateral forward market overlay, and it is completely inconsistent with observed trading behavior today.”

- + **In production simulation models, hurdle rates are \$/MWh charges placed on the border between two markets to reflect actual charges and transactional friction that impede economic transactions**
 - Hurdle rates will typically make the prevailing local price in the upstream or exporting market be lower, and the “downstream price” in the importing market higher
- + **The \$15/MWh hurdle rate was determined by the WMEG stakeholder group. It represents a combination of transmission wheeling charges (~\$5)/MWh and market friction or risk adders associated with cross-seam transactions (\$10/MWh)**
- + **Price data from neighboring Eastern markets (PJM-MISO, PJM-NYISO, NYISO-ISONE) show sizable persistent day ahead price spreads, which indicates that it may be overly optimistic to assume that two abutting organized markets fully moderate the impact of seams over time with experience.**
- + **PPC's case comparison is inappropriate as it compares a Markets+ case with low inter-market hurdle rates to an EDAM case with high inter-market hurdle rates**

PPC asserts that BPA benefits are only \$14 million greater in EDAM vs. M+, if E3 Study assumed \$5/MWh hurdle rates. This is incorrect.

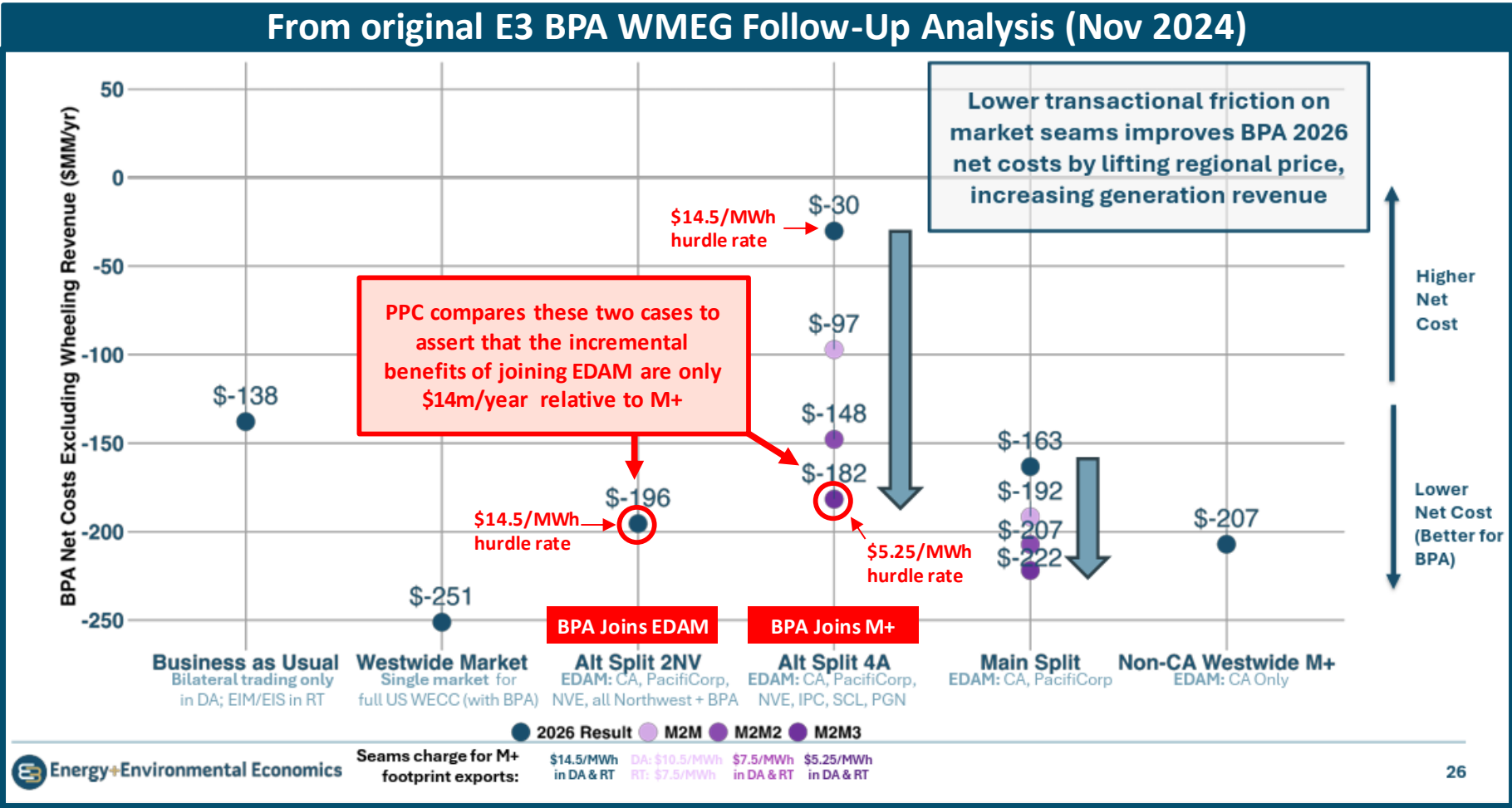


*added annotations

The \$15/MWh hurdle rate was determined by the WMEG members as appropriate and likely representative of cross-seam market friction

It is driven by a combination of both transmission wheeling charges (~\$5), as well as \$10/MWh for a market friction or risk adders associated with the risk of an entity choosing to take on the risk of scheduling an export from M+ to EDAM before the price in either market is known

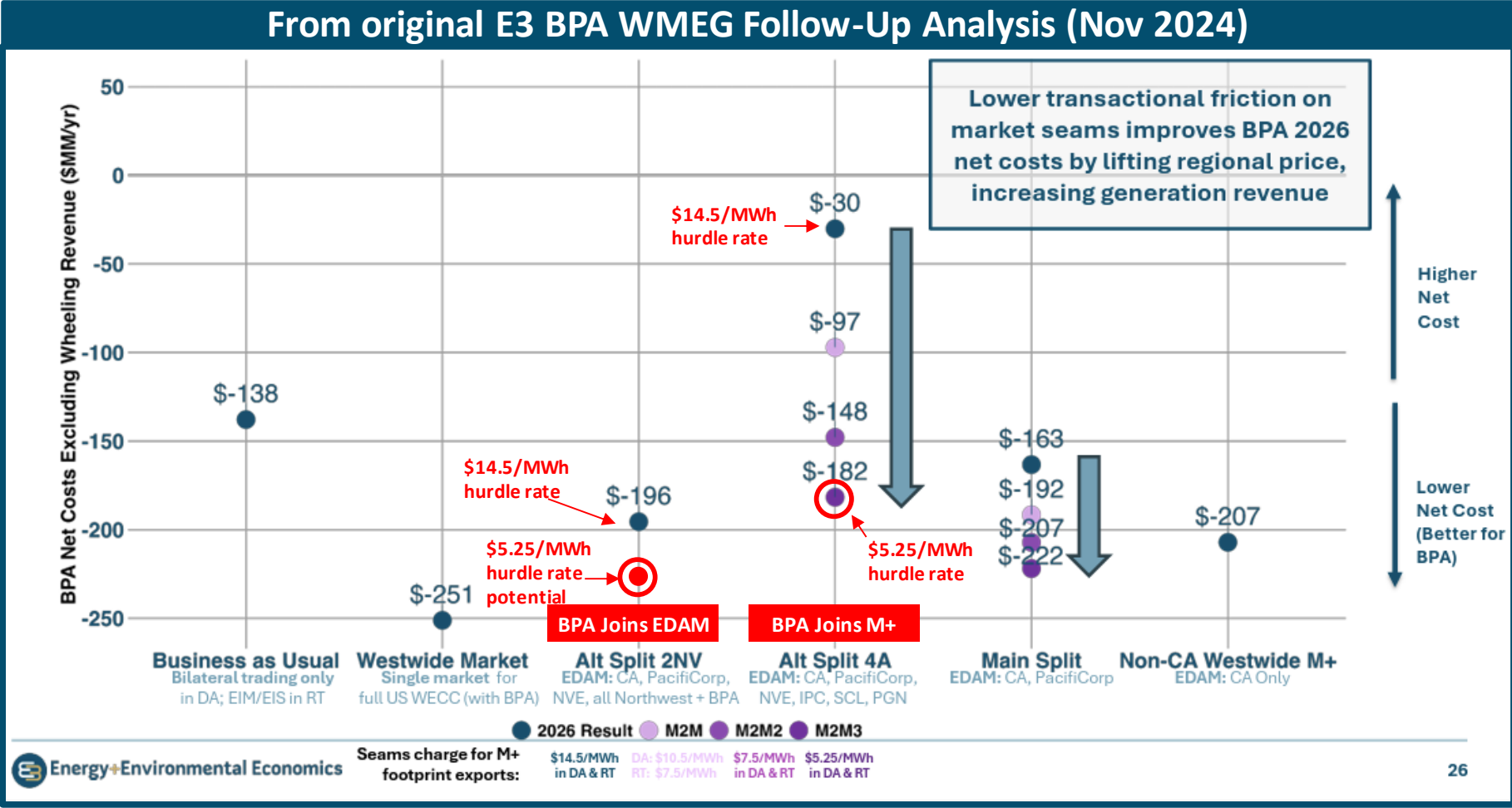
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These two cases (Alt Split 4A M2M3 vs. Alt Split 2NV) are fundamentally not comparable due to different hurdle rate assumptions on market seams

*added annotations

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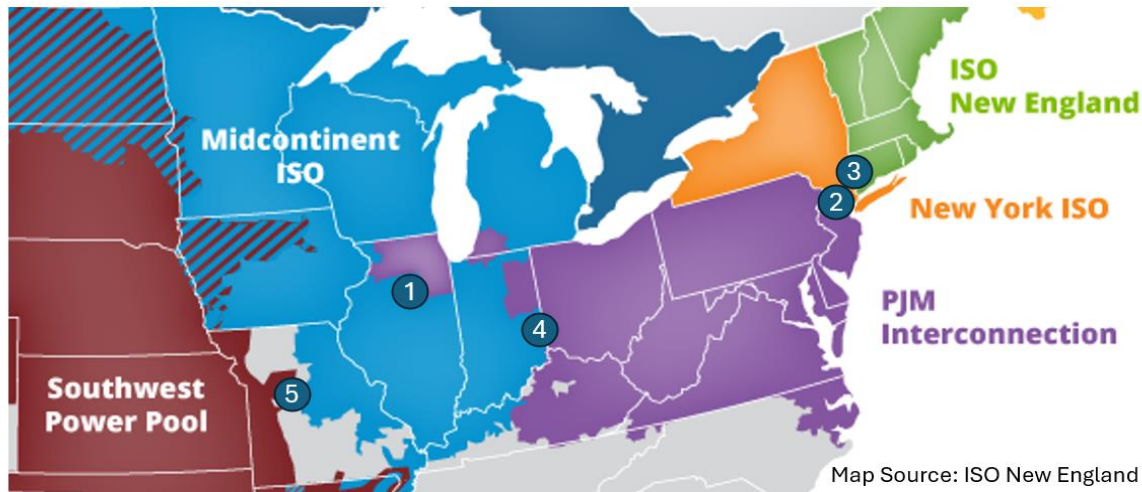
*added annotations

A case where BPA joins EDAM and faces a low hurdle rate to external trades would result in more benefits to BPA

A reasonable guess is that BPA benefits would be in between a higher hurdle rate case and a full Westwide market case (illustrated to left)

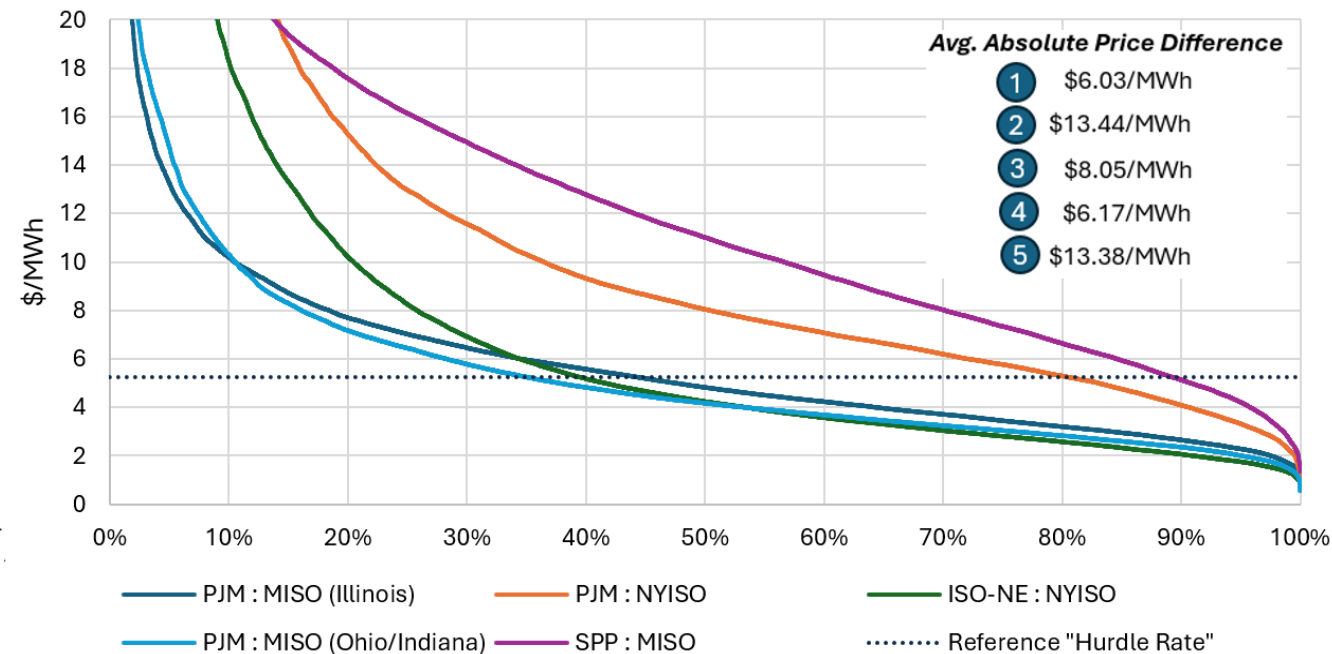
Seams challenges: There are significant and persistent price differences at the seams between markets in the East

- + Real-world data from neighboring eastern markets support the notion that there are significant friction that prevents trading and price convergence
- + These types of price separations would otherwise suggest high levels of interregional intertie utilization



- 1 PJM : MISO (Illinois) – COMED/AMEREN IL
- 2 PJM : NYISO – PSEG/HUD VL (ZONE G)
- 3 ISONE : NYISO – CONNECTICUT/HUD VL (ZONE G)
- 4 PJM : MISO (Indiana/Ohio) – DEOK/INDIANAPOLIS P&L
- 5 SPP : MISO – SPP SOUTH HUB/ENTERGY ARKANSAS

Duration Curves of Rolling 24-Hour Avg. Absolute Price Differences Across Markets Seams ('23-'25)



Seams challenges: existing seams are **underutilized** in Eastern markets despite the fact that significant price spreads exist

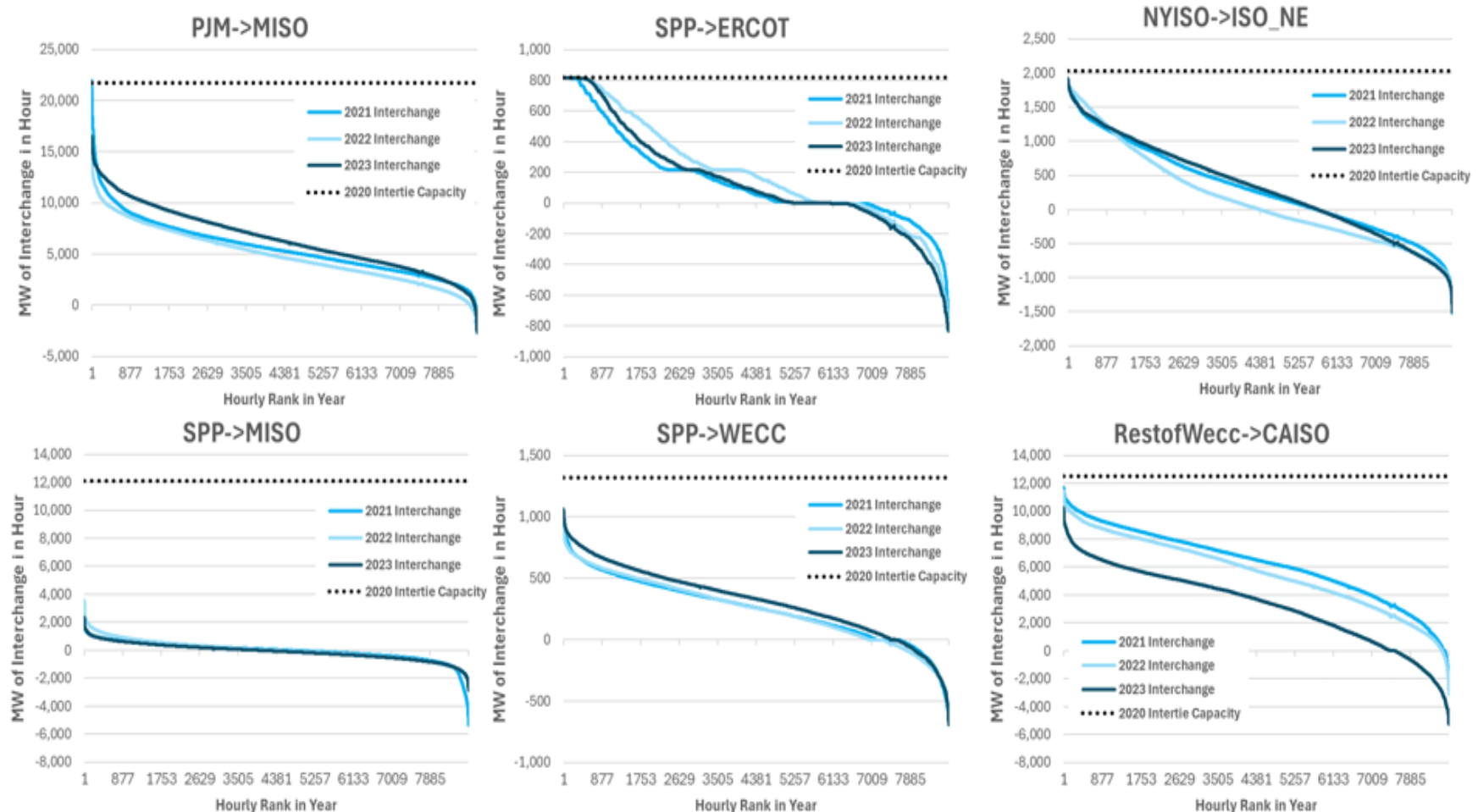
+ Interregional intertie capacity has historically been underutilized, leaving economic savings and resiliency benefits unrealized

+ If existing seams were frictionless, we would expect to see:

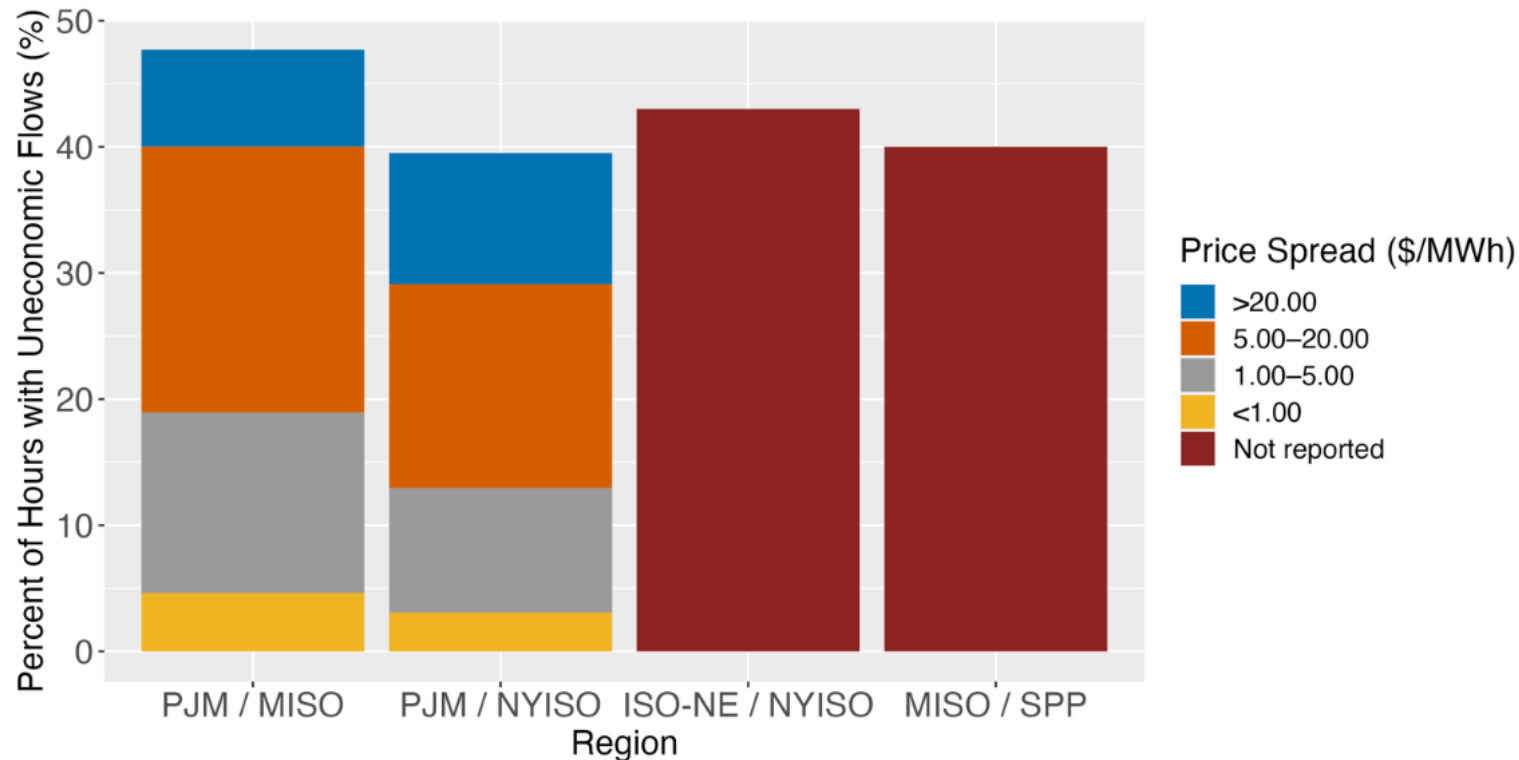
- (a) no persistent price spreads between adjacent markets, or
- (b) persistent transmission congestion

+ In fact, we see the opposite: persistent high price spreads and few economic transactions

Interregional Hourly Interchange MW vs. Intertie Capacity



Seams challenges: a large share of transactions across existing seams are **uneconomic**



- + NREL analysis finds nearly 50% of interregional flows in 2022 were “uneconomic”
- + “Uneconomic” means the transaction flows against the hourly LMP price spreads
- + In nearly 10% of hours, the uneconomic price spreads exceed \$20/MWh

Figure 2. Hours with uneconomic power flow across major interregional seams in 2022

Price spread means the difference in average hourly locational marginal prices between regional interfaces

Day-ahead vs. Real-time Price Differences

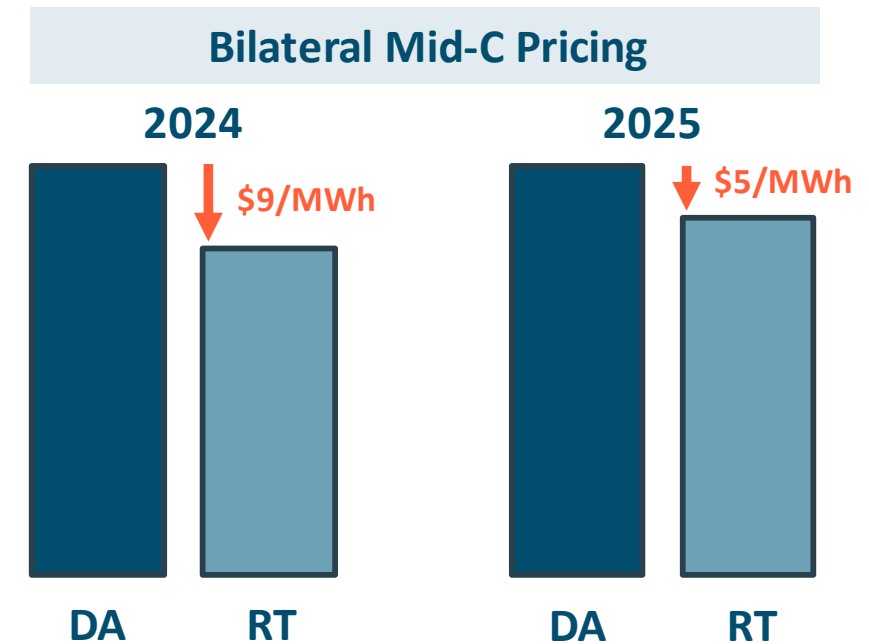


Day-Ahead vs. Real-Time Price Differences

PPC asserts that differences between historical Day-Ahead Mid-C bilateral pricing and Real-Time WEIM pricing is predictive of expected price differences between Markets+ and EDAM

"From 2021 through 2025, Western Energy Imbalance Market (WEIM) real time market prices for Pacific Northwest balancing areas averaged \$10–20 per megawatt-hour (MWh) below the Mid-Columbia day-ahead bilateral price. That gap cannot be simply explained by organized market efficiency gains; it reflects design choices ... The design features that suppress WEIM prices (no fast-start pricing, capped scarcity mechanisms, BAA-level mitigation, operator out-of-market actions) carry forward into EDAM's day-ahead price formation."

- + Comparing Day-Ahead Mid-C bilateral prices and Real-Time WEIM prices is inappropriate as these are two different products, traded in different timeframes, through different mechanisms (bilateral vs. centralized)
- + The differences reflect risk premiums, block-energy conventions, liquidity, commitment considerations, and more.
- + Previous analysis from E3 also found that Mid-C prices are affected by California's CO₂ pricing, with a \$1/metric ton increase in the price equating to a \$0.41/MWh increase for Mid-C³
- + In fact, in 2024, average Day-Ahead Mid-C prices were greater than average Real-Time Mid-C prices by approximately \$9/MWh¹ and in 2025 the price difference was \$5/MWh²



Day-Ahead vs. Real-Time Price Differences (Cont.)

PPC asserts that E3's model cannot be trusted because it does not accurately reflect bilateral Mid-C day-ahead prices

"This suggests that the impact of "seams" and incremental hurdle assumptions are overstated in the production cost modeling and other factors are not materially represented. A model with assumptions that get the sign wrong on the central observable relationship should not anchor a \$100 million claim."

- + The question facing BPA and other market participants – and the question E3 evaluated for the WMEG members including BPA – is "What is the production cost difference between joining EDAM and joining Markets+?"
- + Modeling market dynamics and price formation under the status quo of a bilateral Mid-C market was not a significant consideration in the WMEG study
- + Day-ahead and real-time prices in EDAM and Markets+ in E3's modeling reflect expected relationships
- + PPC agrees with WMEG members and other observers in stating "PPC does not believe the status quo of bilateral trading is a sustainable future." (page 24)

Fast-Start Pricing



Fast Start Pricing Impact

PPC claims that “[w]ithout fast-start pricing ... markets undervalue physical capacity resources and dilute the investment signals needed to build them”, based on paper funded by PPC and PowerEx.

1. PPC relies on a study that materially overstates the impact of fast-start pricing

- Claimed \$20/MWh value for fast-start pricing is not based on reviewing hours when fast-start units were operating, ***not a market study***.
- The actual impact of fast-start pricing is much lower. SPPs Market Monitoring Unit found that there "was very little change in revenues to fast start units due to the new fast-start pricing" in 2022, with estimated increases of 1.5% and 0.5% for the DA and RT, respectively.
- It is logically inconsistent to assert that a \$20/MWh price delta between EDAM and Markets+ would persist with a \$5/MWh hurdle rate

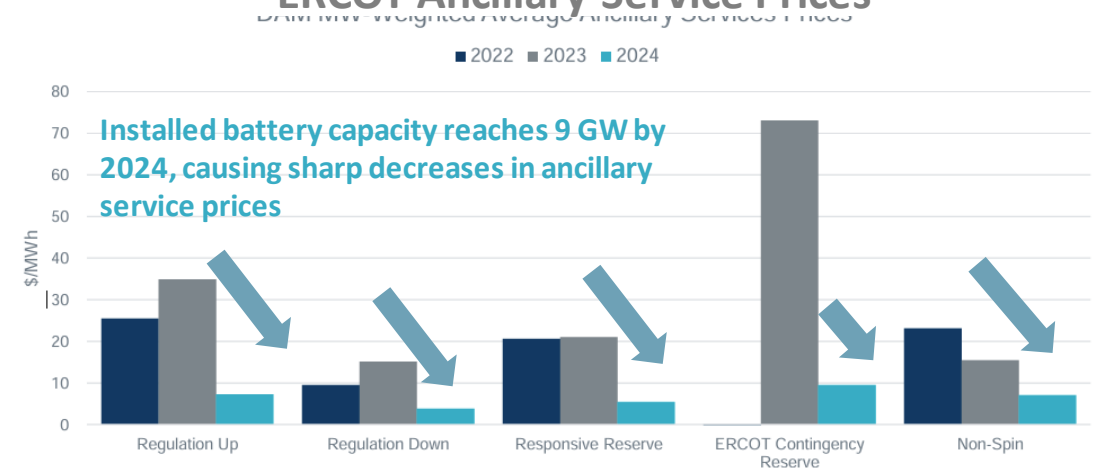
2. Increased competition will likely limit BPA’s ability to benefit from fast-start pricing in either market over time

- Growth in flexible, fast-start batteries in CA and AZ has led to declines in ancillary service prices and real-time volatility
- SPP observed a sizable decrease in the utilization of fast start resources in 2025 compared to previous years¹
- NW market will have ample supply of flexible hydro and the M+ portion of the NW becomes a flexible generation pocket

3. All of E3’s Markets+ cases included an adder for fast-start pricing in the Markets+ footprint (but not EDAM)

- Increases Markets+ benefit for BPA by \$30 million in 2026

Example of Price Impact of Battery Additions: ERCOT Ancillary Service Prices



Source: <https://www.ercot.com/files/docs/2025/01/27/9-3-commercial-markets-update.pdf>

Scarcity Pricing

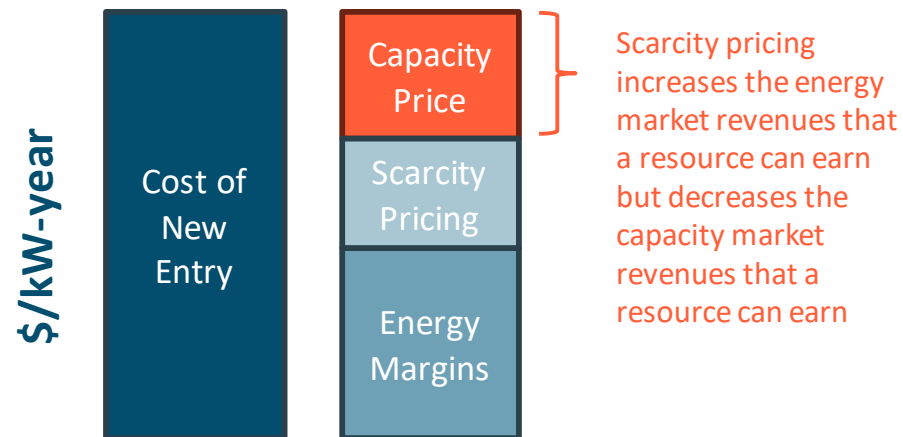


Scarcity Pricing

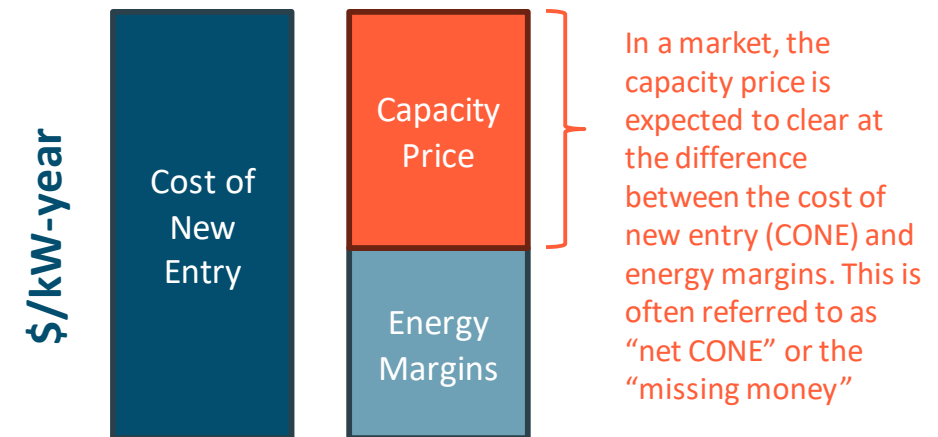
PPC claims that Markets+ contains superior scarcity pricing, which increases the value of BPA surplus sales and dilutes investment signals for new capacity

- + Scarcity pricing in the energy market is one way to send economically efficient price signals for investment – the other is through a capacity product. In a market, if scarcity pricing increases, the value of the capacity product will decrease.
- + BPA, as a seller of surplus capacity should be indifferent between lower energy and higher capacity pricing vs. higher energy pricing and lower capacity pricing.
- + Additionally, periods in which BPA is likely to have surplus hydro generation are structurally more likely to be periods of low scarcity. And vice versa, years where BPA has low hydro and is likely to be a net buyer will structurally have more scarcity.

Market Design with **High** Energy Scarcity Pricing



Market Design with **Low** Energy Scarcity Pricing



Scarcity pricing should have only a small impact, if any, on BPA surplus sales revenue

Greenhouse Gas Accounting



Carbon Pricing

PPC claims that EDAM market rules enable clean generation in non-GHG-regulated regions to bid to be attributed as imports to GHG regulated regions (in CA & WA) too easily because EDAM doesn't require those resources to "demonstrate delivery". PPC claims this is estimated to reduce EDAM market prices by up to \$5/MWh, and reduce BPA savings by \$2-25 million vs. M+

+ This overstates the impact of GHG pricing on BPA's benefits in EDAM vs. M+ and misses GHG-related value to being in the same market as California

- **Applied to overly large BPA sales volume.** PPC applies its assumed GHG price difference to a large volume of BPA surplus sales (4-5 TWh annually), but much of BPA's volume is transacted bilaterally under BPA's status as an Asset Controlling Supplier
- **GHG Pricing in California would still affect BPA revenue if BPA is in Markets+.** BPA will not be able to monetize its carbon-free attributes in sales to Arizona, and California will remain the largest market and largest source of value for GHG-free power even if BPA is in Markets+.
- **In M+, BPA would face a market seam for making low-GHG sales to CA.** A market seam that increases the cost and reduces the risk of selling hydro to California could inhibit BPA's ability to monetize the low carbon attributes of its sales

Thank You

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