Portland General Electric Company
121 SW Salmon Street • 1WTC0306 • Portland, Oregon 97204
portlandgeneral.com

April 1, 2025

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

Re: **UE 452 – In the Matter of Portland General Electric Company, 2026 Annual Power Cost Update Tariff**

Dear Filing Center:

Portland General Electric Company (PGE) encloses for filing in the above reference matter the following: Direct Testimony of Darrington Outama and Elizabeth Pedersen (PGE/100), Jaki Ferchland and Casey Manley (PGE/200), and PGE Exhibits 101-102 and 201-203.

Pursuant to Schedule 125, PGE's initial filing herein reflects a preliminary 2026 net variable power cost (NVPC) forecast of $1,059.7 million. This results in an increase over 2025 NVPC of $50.6 million or an estimated average 1.6% customer price increase. The estimated increase in power costs is primarily driven by anticipated BPA transmission rate increases and federal tariffs on fuel purchases from Canada. Any change to prices would not be determined until late in 2025, as determined by final Commission approval for a January 1, 2026 rate effective date.

Confidential workpapers in support of this filing contain protected information and are subject to the General Protective Order No. 23-132 noticed March 28, 2025.

Please direct all formal correspondence, questions, and requests related to this filing to pge.opuc.filings@pgn.com.

Additionally, PGE requests that all data requests in this docket be submitted via Huddle and addressed to:

Jaki Ferchland
Portland General Electric Company
Senior Manager Rates & Regulatory Affairs
121 SW Salmon Street, 1WTC12
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The following are to receive notices and communications via email service list:

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Sincerely,

/s/ Jaki Ferchland

Jaki Ferchland
Sr. Manager Rates & Regulatory Affairs
Pricing, Tariff, and Power Costs

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 452

PGE 2026 Annual Power Cost Update Tariff

PORTLAND GENERAL ELECTRIC

Direct Testimony
Net Variable Power Costs

Direct Testimony of:

Darrington Outama, PGE

Elizabeth Pedersen, PGE

April 1, 2025

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I. Introduction

Q. Please state your names and positions with Portland General Electric Company (PGE).

A. My name is Darrington Outama. My position at PGE is Senior Director, Energy Supply.

My name is Elizabeth Pedersen. My position at PGE is Manager, Power Cost Forecasting & Analysis. Our qualifications are included at the end of this testimony.

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to provide the initial forecast of PGE's 2026 Net Variable Power Costs (NVPC). PGE's filing is consistent with the terms of its Commission-approved Schedule 125 tariff, which directs that PGE make this filing no later than April 1 each year. This initial filing for the power cost forecast goes through a series of updates as defined and listed within the tariff. As a result, the power cost forecast can and likely will change over the next seven months. This testimony starts the beginning of the months-long process during which PGE works with parties and through updates over time to determine a final NVPC forecast for 2026. At the end of this process, as indicated by the timeline described at the end of this section and as more detailed information is known, the final forecast will be reviewed for approval by the Commission. Any potential changes in customer rates from the Commission-approved adjustments to NVPC would take effect on January 1, 2026.

In this testimony, PGE also discusses refinements to its model, called "MONET" (the Multi-area Optimization Network Energy Transaction model), as well as other inputs. PGE compares in this testimony the initial 2026 NVPC forecast with PGE's 2025 NVPC forecast filed on November 15, 2024, inclusive of the impact of the Clearwater Wind Project

(Clearwater), as well as the NVPC in customer prices for 2025, and discusses why the per-unit expected NVPC cost has increased by $2.67 per MWh.[1]

Q. What is PGE's initial NVPC forecast for 2026?

A. Based on contracts and forward curves as of February 28, 2025, the initial 2026 NVPC forecast is approximately $1,059.7 million. This initial 2026 NVPC forecast represents an increase of approximately $84.8 million compared to a 2025 NVPC inclusive of Clearwater. On a load-adjusted basis, this is approximately a $50.6 million increase as shown in Exhibit 200, which describes the estimated base rate impacts for customers.

Q. Please explain the adjustment related to the Seaside battery energy storage system (Seaside) that occurred between the November 15, 2024 filing and this filing date.

Seaside was originally included in the 2025 NVPC from our November 15, 2024 filing. Its removal was the result of the Public Utility Commission of Oregon (OPUC or Commission) Commission Order No. 24-406 dated November 4, 2024. The order specified that if the cost of the Seaside investment was not approved for inclusion in customer prices in 2025 through a tracking mechanism, the related NVPC would be removed for the full 2025 NVPC forecast. Commission Order No. 24-454 ultimately did not authorize the recovery of the Seaside investment in prices through a tracking mechanism. PGE was invited by the Commission to seek recovery for its prudent investment in Seaside through a separate expedited filing in 2025 and is currently evaluating the timing of this filing. Thus, to match costs and benefits, PGE is forecasting Seaside in the 2026 NVPC forecast.

[1] The 2026 NVPC forecast per-unit cost is $48.3 per MWh which is approximately $2.67 more than the 2025 NVPC forecast per-unit cost of $45.6 per MWh from the November 15, 2024 filing.

Q. Is the modeling of Clearwater in MONET consistent with the Commission's decision in Docket UE 427?[2]

A. Yes.

Q. What are the primary factors driving the increase in NVPC forecast for 2026 relative to the NVPC forecast for 2025?

A. There are two primary drivers of the increase in the NVPC forecast for 2026 relative to 2025. First, the anticipated updates to BPA transmission rates through the BP-26 rate case results in a $24.6 million increase. Second, the tariffs announced by the federal government to be in place beginning April 2, 2025, will impact the purchase of Canadian natural gas, resulting in a $16.8 million increase in 2026.

Q. To what extent can PGE influence the primary factors driving the estimated increase in the 2026 NVPC?

A. As mentioned previously, there is little that PGE can do to influence the above factors, as they are driven by forces outside of PGE's control.

Q. Are there Minimum Filing Requirements (MFRs) associated with PGE's NVPC filings?

A. Yes. Commission Order No. 08-505 adopted a list of MFRs for PGE to follow in Annual Update Tariff (AUT) filings and General Rate Case (GRC) filings. The MFRs define the documents that PGE will provide in conjunction with the NVPC portion of PGE's initial (direct case) and update filings of its GRC and/or AUT proceedings. PGE Exhibit 101 contains the list of required documents as approved by Commission Order No. 08-505. We have included the MFRs required for our initial filing as part of our electronic work papers

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[2] *See In re Portland Gen. Elec., Renewable Resource Automatic Adjustment Clause (Schedule 122) (Clearwater Wind Project)*, Docket UE 427, Order No. 25-075 (Feb. 21, 2025).

and will submit the remainder of the MFRs within 15 days of this filing (i.e., April 15, 2025). We have designated the MFR documents as "confidential" or "nonconfidential." PGE also includes additional documents, not required by the Commission Order, in its MFRs that provides further supporting information.

Q. What is the timeframe for the 2026 NVPC updates in this docket?

A. The following identifies the schedule for subsequent 2026 NVPC power cost update filings in this docket:

- July – Power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; wind resource energy forecasts; load forecast; California Carbon Allowance (CCA) forward price curve; Wheatridge REC monetization benefits.[3]
- October – Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; CCA forward price curve; planned hydro maintenance outages; and loads.
- November – Two update filings: 1) update gas and electric forward curves; CCAforward price curve; final updates to power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; long-term customer optouts; Wheatridge REC monetization benefits; and 2) final update of gas and electric

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[3] Per Commission Order PGE monetized Wheatridge RECs by selling RECs generated through December 31, 2024, to residential and small commercial voluntary renewable portfolio options customers under Schedule 7 and Schedule 32. In 2025, there will be a small true-up. This update will be removed from subsequent AUT filings. *In re Portland Gen. Elec. Co., Renewable Resource Automatic Adjustment Clause (Schedule 122) (Wheatridge Renewable Energy Farm)*, Docket UE 370, Order No. 20-321 (Sep. 29, 2020).

forward curves; final update to Qualifying Facilities commercial operation dates; final update to the price of the power contract with Grant County.

II. MONET Model

Q. How does PGE forecast its NVPC for 2026?

A. As in prior dockets, we use our power cost forecasting model, called "MONET" (the Multi-area Optimization Network Energy Transaction model).

Q. Please briefly describe MONET.

A. PGE first developed this model in the mid-1990s and has since incorporated several refinements. Using data inputs, such as an hourly load forecast and forward electric and gas curves, the model minimizes power costs under "normal" conditions by economically dispatching plants and making market purchases and sales. To do this, the model employs the following data inputs:

- Retail load forecast, on an hourly basis.
- Physical and financial contract and market fuel (coal, natural gas, and oil) commodity and transportation costs.
- Thermal plants, with forced outage rates and scheduled maintenance outages, maximum operating capabilities, heat rates, operating constraints, emissions control chemicals, and any variable operating and maintenance costs (although not part of NVPC for ratemaking purposes, except as discussed below).
- Hydroelectric plants, with output reflecting current non-power operating constraints (such as fish habitat) and peak, annual, seasonal, and hourly maximum usage capabilities.
- Wind and solar power plants, with peak capacities, annual capacity factors, and monthly and hourly shaping factors.

- Energy storage facilities / batteries.
- Transmission (wheeling) costs.
- Physical and financial electric contract purchases and sales.
- Forward market curves for gas and electric power purchases and sales.

Using these data inputs, MONET simulates the dispatch of PGE resources to meet its customer load forecast based on the principle of economic dispatch; generally, any plant is dispatched when it is available, and its dispatch cost is below the market electric price. Thermal plants can operate in one of various stages – maximum availability, ramping up to maximum availability, starting up, shutting down, or off-line. Given thermal output, expected hydro, solar, and wind generation, and contract purchases and sales, MONET fills any resulting gap between total resource output and PGE's retail load with hypothetical market purchases (or sales) priced at the forward market price curve.

Q. How does PGE define NVPC?

A. NVPC includes wholesale (physical and financial) power purchases and sales (purchased power and sales for resale), fuel costs, and other costs that generally change as power output changes. PGE records its NVPC to Federal Energy Regulatory Commission (FERC) accounts 447, 501, 547, 555, and 565. Consistent with the methodology used in the 2025 NVPC forecast, for this 2026 NVPC forecast we have included certain variable chemical costs, lubricating oil costs, and forecasted federal production tax credits (PTCs). We exclude some variable power costs, such as certain variable operation and maintenance costs (O&M), because they are already included elsewhere in PGE's accounting. However, variable O&M is used to determine the economic dispatch of our thermal plants. Based on prior Commission decisions,[4] certain fixed costs, such as excise taxes and transportation charges, are also included in MONET. For the purposes of FERC accounting, these items are included with fuel costs in a balance sheet account for inventory (FERC 151); this inventory is then expensed to NVPC as fuel is consumed. The "net" in NVPC refers to net of forecasted wholesale sales of electricity, transmission, natural gas, fuel, and associated financial instruments.

Q. Do the MFRs provide more detailed information regarding the inputs to MONET?

A. Yes. The MFRs provide detailed work papers supporting the inputs to MONET used to develop our initial forecast of 2026 NVPC.

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[4] *In re Portland Gen. Elec. 2008 Annual Power Cost update*, Docket UE 192, Order No. 07-445 at 7 (October 17, 2007).

III. MONET Updates and Modeling Changes

Q. What MONET updates do you include in this AUT filing?

A. In this initial filing, PGE includes updates allowed under Schedule 125 as well as discussion of certain topics pertinent to the AUT. PGE will continue to update several of the items pursuant to Schedule 125 as this docket proceeds.

Q. How is this testimony structured?

A. We discuss the updates according to the following outline:

- Section III.A: Pending BPA Transmission Tariff Rate Case Outcome
- Section III.B: Federal Tariff Impacts
- Section III.C: Capacity Market Constraints
- Section III.D: Beaver Oil Fuel Stock Plans
- Section III.E: Colstrip Update
- Section III.F: Extended Day Ahead Market (EDAM) Update
- Section III.G: Washington Cap and Investment Program Modeling
- Section III.H: Other Items:
    1. Hydro Generation Update
    2. Westside Gas Correction
    3. NW Natural Call Option
    4. Miscellaneous
    5. Forthcoming Updates

Q. What is the net effect on PGE's initial 2026 NVPC forecast of the updates included in the initial MONET step-log?

A. The net effect of the updates reflected in the initial MONET step-log in PGE's initial 2026 NVPC forecast is $51.0 million compared to the base 2026 NVPC forecast.

Q. What load forecast does PGE use in this initial filing?

A. We use the 2026 retail load forecast consistent with the September 2024 forecast vintage used for the final 2025 test year forecast (Docket UE 435). Our forecast is approximately 21,946 thousand MWh of cost-of-service energy, or approximately 2,505.3 MW, an increase of 82 MW from the final 2025 test year forecast.

A. Pending BPA Transmission Tariff Rate Case Outcome

Q. Please summarize the relevant background on the BP-26 rate case proceeding, including past partial rates settlement agreements.

A. Bonneville Power Administration (BPA) is the largest wholesale transmission provider in the Pacific Northwest. PGE relies significantly on its transmission infrastructure to deliver reliable power to its customers. BPA is currently conducting a rate case, BP-26, to set wholesale power and transmission rates for October 1, 2025 through September 30, 2028. This is a 3-year rate period, longer than the typical 2-year period. BPA released its initial proposal on November 22, 2024.

Q. What potential impacts does BP-26 have on PGE transmission costs?

A. If BPA's initial proposed rate increase is implemented as proposed in BP-26 and without adjustment, PGE's monthly transmission bill would increase by approximately 22.9%, resulting in an increase of $24.6 million to forecasted NVPC.

Q. How does the use of BPA transmission benefit PGE's customers?

A. As the largest transmission provider in the Pacific Northwest, BPA's infrastructure is crucial for power transmission across the area, and PGE must utilize BPA's transmission system to ensure reliable delivery of power to our customers. Additionally, leveraging BPA's extensive transmission network allows PGE to access a wider range of power sources and maintain system stability, ultimately resulting in cleaner, more reliable electricity for our customers.

Q. What are the largest changes driving the 22.9% proposed increase to PGE's monthly transmission bill from BPA?

A. First, BPA is proposing an increase of 27% to the Long-term Firm Point-To-Point (PTP) rate. This rate is charged to customers for a guaranteed long-term reservation of transmission capacity, allowing PGE to reliably move power from specific points on the BPA grid.

Second, BPA is proposing a 30% increase to the Scheduling, Control and Dispatch (SCD) Long-Term Firm rate. The SCD Long-term Firm rate is associated with the Federal Columbia River Transmission System and covers key services associated with scheduling transmission, systems and services supporting operation of the balancing area, and systems and services supporting the dispatch center. When PGE uses Long-Term Firm transmission, it is charged the SCD Long-Term Firm rate.

Third, BPA is proposing a 130% increase to the Real Power Losses Capacity rate. The Firm Power and Surplus Products and Services (FPS) Real Power Losses Capacity charge are payments to BPA for procuring energy to make up for line losses incurred when PGE uses BPA's transmission lines to deliver reliable power to its customers.

Q. What is driving BPA's rate increases?

A. Based on information provided by BPA in their initial proposal, their transmission rate increase appears to be primarily driven by a shift in capital program funding strategy from debt-based to revenue-based financing.[5] This change aims to achieve their stated 60-40 debt-to-asset ratio goal by increasing cash flow to support BPA's significant investments in "Evolving Grid" projects[6] and a new Control Center while reducing existing debt. Additional factors contributing to the rate increases include higher transmission line expenses and the application of the Rate Distribution Clause (RDC). The RDC is a mechanism used by BPA to refund dollars collected that exceed rate case forecasts. These combined elements appear to form the basis of BPA's current rate adjustment proposal.

Q. What is PGE's engagement strategy or planned response to these proposed rate increases?

A. PGE has and will continue to meet weekly with other impacted investor-owned utilities (PacifiCorp, Avista, Puget Sound Energy, and Idaho Power) to align on BP-26 strategy and approach. The joint utilities are working together to submit a proposal within the BP-26 case advocating to reduce BPA's proposed increase to keep costs as low as possible for our customers while also ensuring reliable service. PGE recognizes that stakeholders to this 2026 AUT process also could engage meaningfully as stakeholders in the BP-26 process and would welcome their involvement.

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[5] This is "revenue financing" as defined by BPA. Specifically, BPA defines it as "raising funds through rates to recover the cost of directly paying for capital investments."
[6] See BPA's webpage on this topic: https://www.bpa.gov/energy-and-services/transmission/evolving-grid

Q. When will the BPA make their final decision on the BP-26 rate proceeding and when will the new rates go into effect?

A. BPA will issue the Final Record of Decision/Studies on July 24, 2025, and the new BPA transmission rates will go into effect on October 1, 2025. PGE will revise its 2026 NVPC forecast within the October 1, 2025 MONET update to reflect the new BPA transmission rates.

B. Federal Tariff Impacts

Q. Please summarize the White House announcement to impose tariffs on imported goods from Canada.

A. As of this filing, President Donald J. Trump intends to proceed with an executive order that will apply a 10% tariff on energy resources imported from Canada beginning April 2, 2025, which will have a direct impact on natural gas purchases and thus on NVPC.

Q. How were "energy resources" defined within the executive order?

A. "Energy resources" were defined as "crude oil, natural gas, lease condensates, natural gas liquids, refined petroleum products, uranium, coal, biofuels, geothermal heat, the kinetic movement of flowing water, and critical minerals, as defined by 30 U.S.C. 1606(a)(3)" within the executive order issued on January 20, 2025 that declared a National Energy Emergency.[7]

Q. How will these tariffs increase costs for PGE customers?

A. Similar to a tax, as both are imposed by government, a tariff applies only to imported products, which in this case is natural gas from Canada. As such, these tariffs will increase the cost of natural gas purchases needed to supply PGE's gas plants with fuel. PGE's gas plants provide crucial flexibility, quickly ramping up or down to balance variable renewable sources.

[7] See Exec. Order 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025).

They offer backup power during low renewable generation, meet peak demands, and support grid stability. This enables greater integration of renewables while ensuring reliable power supply for customers, supporting PGE's transition to cleaner energy.

Currently, Canada is the only gas-producing region with firm transport capacity to serve Pacific Northwest markets. PGE lacks viable alternatives until enhancements to existing infrastructure or new transport routes are developed to connect local markets to domestic production. PGE does not anticipate these alternatives to materialize in the near future.

Additionally, while power purchases sourced from Canada may also be subject to a tariff, PGE presently does not have long-term power purchase agreements where PGE is shown as the importer of record. Therefore, PGE does not anticipate an impact to customer costs associated directly with any power purchase agreements. However, British Columbia and the Pacific Northwest markets are tightly interconnected, and the tariffs will exert secondary cost pressure on the Mid-Columbia power trading market. As such, the impact of eventual electricity imports is difficult to assess at this time, and PGE has not included any estimates in this filing.

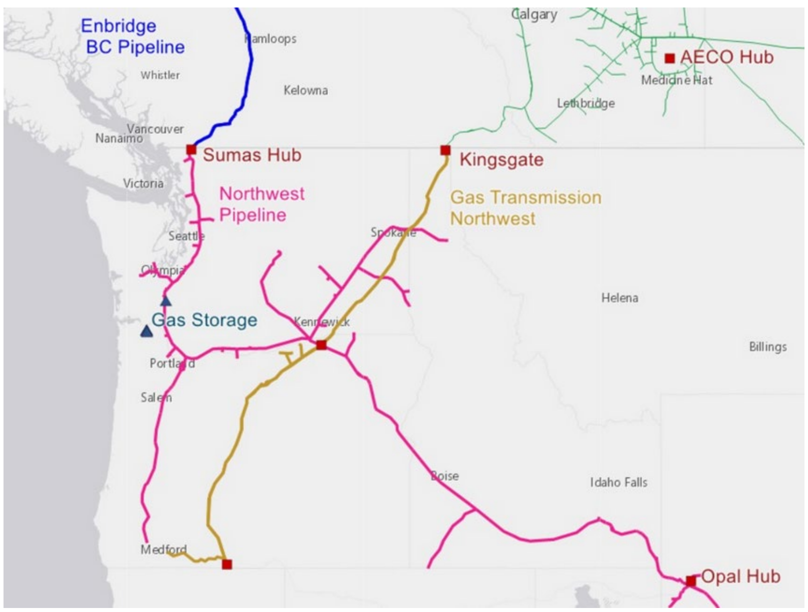
Q. Why does PGE lack viable alternatives to the supply of natural gas coming from Canada?

A. The Pacific Northwest relies predominantly on natural gas sourced from Canada given current pipeline infrastructure. Figure 1 depicts the natural gas pipelines in the region.[8] There are three sources of supply:

[8] See: https://www.nwcouncil.org/2021powerplan_natural-gas-regional-infrastructure-supply-and-demand/.

1) Natural gas sourced from British Columbia/Western Alberta and delivered to the location labeled “Sumas Hub”;
2) Natural gas sourced from “AECO Hub” in Alberta and delivered to the location labeled “Kingsgate”, and;
3) Natural gas sourced from the U.S. Rocky Mountain region and delivered to the location labeled “Opal Hub”.

Figure 1
Regional Natural Gas Pipelines



While there are three sources of supply, the supply from Canada makes up the majority of the supply.[9]

Q. Can you share more details on the makeup of PGE’s natural gas supply?

A. Yes. Specific to Canadian supply, PGE has firm pipeline rights giving PGE the capability to import approximately 73,305 MMBtu per day on the Northwest Pipeline and approximately

[9] The Northwest Power and Conservation Council notes 2/3rds of the gas consumed in the region is sourced from Canada. See: https://www.nwcouncil.org/2021powerplan_natural-gas-regional-infrastructure-supply-and-demand/.

120,000 MMBtu per day on the Gas Transmission Northwest Pipeline. Specific to U.S. supply, PGE has the capability to import approximately 30,000 MMBtu per day from the Rocky Mountain region on the Northwest Pipeline.

Q. You shared the increase in the cost of natural gas purchases will result from the application of the tariff to natural gas imports. Can you explain further?

A. Yes. Given the lack of a viable alternative to Canadian natural gas supply, PGE anticipates Canadian sellers to pass on the entire tariff cost to US buyers of natural gas.

Q. What actions can PGE take in the short-term to mitigate the impact on NVPC?

A. Very little. PGE cannot seek to substitute Canadian natural gas with other supplies. There is no incremental transport available to Rockies gas, which is the only domestic alternative source of natural gas.

Q. Have you included the impact of tariffs in your filing?

A. Yes. We applied the 10% federal tariffs to Sumas and AECO gas, resulting in a $16.8 million increase to forecasted NVPC.

C. Capacity Market Constraints

Q. Has PGE discussed capacity planning in prior NVPC forecast filings?

A. Yes. PGE described in detail in recent AUTs and GRCs the energy resource capacity landscape changes seen in the last two decades within the Western Electricity Coordinating Council (WECC) including the Western Power Pool (WPP) footprint, and how these changes impact PGE's ability to meet customer peak loads with market purchases.[10]

[10] *In re Portland Gen. Elec. Co. 2022 Annual Power Cost Update Tariff (schedule 125),* Docket No. UE 391, PGE Exhibit 100, Section III.A; *In re Portland Gen. Elec. Co. 2023 Annual Power Cost Update,* Docket No. UE 402,

Q. What are the most prominent impacts from the changing mix of energy resources in the WECC region?

A. First, the reduction in regional firm and dispatchable resources is causing a regional capacity shortage. This manifests in the form of extreme price volatility and more frequent occurrences of scarcity pricing during periods of weather-induced demand spikes or other market disruptions. This phenomenon has created a gap between how PGE dispatches its thermal plants in actual operations versus the economic dispatch in the MONET model. Second, even during times of relatively normal load conditions, the shift from firm and dispatchable resources to variable energy resources (i.e., wind and solar resources) has resulted in increased price volatility as observed in the day-ahead energy market due to wind and solar generation uncertainty.

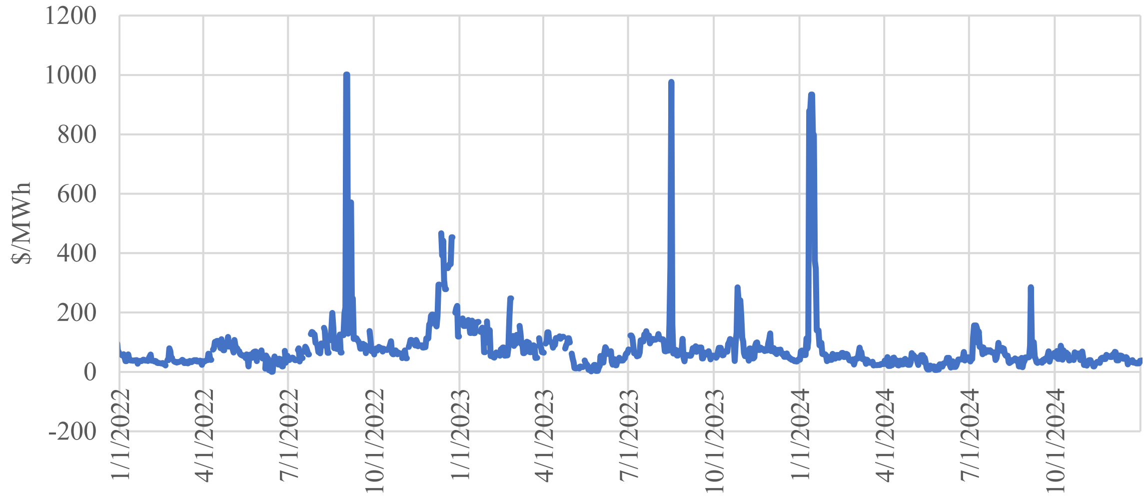
Q. Please provide an example of scarcity pricing during a weather-induced demand spike.

A. Figure 2 shows Day Ahead Mid-Columbia On-Peak prices over the past three years. Prices spiked above $150/MWh twelve days in 2024 alone during four distinct scarcity events. Scarcity conditions drove prices to the WECC soft price cap[11] of $1000/MWh three times over the past three years.

PGE Exhibit 100, Section III.A; *In re Portland Gen. Elec. Co. Request for a General Rate Revision and 2024 Annual Power Cost Update,* Docket No. UE 416, PGE Exhibit 300, Section III.B; *In re Portland Gen. Elec. Co. Request for a General Rate Revision,* Docket No. UE 435, PGE Exhibit 100, Section III.D.

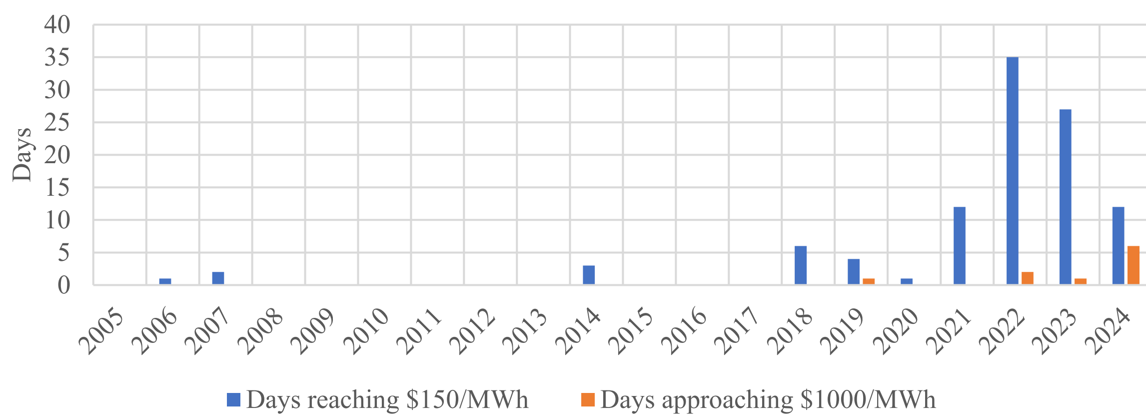
[11] "Staff Guidance on WECC Soft Price Cap," FERC (Jan. 25, 2023) https://www.ferc.gov/power-sales-and-markets/staff-guidance-wecc-soft-price-cap

Figure 2
Mid-Columbia On-Peak Prices
Day Ahead ICE Settlement



The recent level of scarcity-driven pricing experienced is meaningfully different than what was experienced in prior decades. Figure 3 shows the trends of scarcity-event pricing over the past 20 years, indicating that days reaching $150/MWh were rare prior to 2018 and that days approaching $1000/MWh did not happen prior to 2019.

Figure 3
Scarcity-Driven Pricing at Mid-Columbia
Day Ahead ICE Settlement



Q. What are the key factors driving scarcity pricing events?

A. While weather is often a primary driver of scarcity pricing due to its impact on customer demand and grid operations, transmission constraints also play a crucial role. Key factors include:

1. Weather extremes that increase demand and stress infrastructure;
2. Transmission congestion and availability issues;
3. Generation capacity limitations; and
4. Unexpected outages or derations of key resources.

For example, new transmission congestion on BPA's system exacerbated conditions during the August 2023 extreme heat event. Similarly, a decrease in the transmission capacity of the transmission line connecting the Pacific Northwest and California power grids restricted needed imports from California during the January 2024 extreme cold event. Scarcity pricing events can occur when there is inadequate transmission access to deliver capacity where and when it is needed.

Q. How does MONET account for transmission constraints in energy and capacity delivery?

A. MONET focuses primarily on economic dispatch optimization and does not model transmission constraints at a portfolio level.

Q. Is PGE currently exposed to potential capacity shortages during Summer 2026?

A. As provided in Figure 4 below, **[BEGIN CONFIDENTIAL]** [redacted]

[12] https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

[redacted]. [redacted].

[redacted]

[END CONFIDENTIAL]

Q. What approaches does PGE have to mitigate the capacity shortage issue in the short-term and how would these approaches be reflected in the initial 2026 NVPC forecast in MONET?

A. There are two potential approaches:

1. One approach is to enter into structured capacity agreements to maintain load serving reliability and help mitigate the exposure to weather-induced demand spikes.

This would be reflected through a placeholder contract in MONET while PGE looks to secure agreements. Then, once agreements are finalized, PGE would update MONET to reflect this new contract at the appropriate filing date.

2. A second possible approach is to deliberately withhold a portion of a marginal resource, i.e., Beaver or PW2 capacity to ensure reliability if experiencing a capacity shortage. This would be reflected in MONET's economic dispatch similar to how planned outages are modeled, thereby simulating the actions that PGE would take operationally.

Q. Which of the two strategies does PGE propose to implement for the 2026 AUT initial NVPC forecast modeling?

A. PGE is implementing the second strategy. Specifically, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** This approach withholds this generator's capacity from the deterministic economic dispatch in the MONET logic thereby simulating the actions that PGE would take operationally to ensure reliability.

Q. What is the NVPC impact of this proposed strategy?

A. The impact is a $4.2 million increase to NVPC.

Q. Will PGE release the MWs withheld as described above if PGE is able to implement the first strategy by executing a 2026 capacity contract?

A. Yes. If PGE executes a contract that covers the capacity need for 2026, PGE will release the MWs withheld through the method described above. If applicable, PGE will notify Parties, update the 2026 NVPC forecast in MONET, and provide documentation as soon as such contract was executed.

D. Beaver Oil Fuel Stock Plans

Q. Can you describe PGE's overall plans for transitioning the Beaver Generating Station to operate solely on natural gas?

A. PGE developed a comprehensive plan to transition the Beaver Generating Station away from diesel (i.e., oil) to operate solely on natural gas beginning in 2021, when PGE first upgraded Unit 4. PGE has since upgraded Unit 6 to run solely on natural gas in 2023, Unit 1 in Q2 2024, with Units 3 and 5 in Q2 and Q3 of 2025, respectively. The final phase of the transition will occur in 2026, with the upgrade of Unit 2. After PGE completes this final upgrade in 2026, Beaver will no longer have dual fuel capabilities and thus the oil PGE has on site will no longer be of use for back-up reliability purposes.

Q. What is PGE's plan for decommissioning the oil tanks?

A. In June 2024, PGE submitted an assessment of seismic stability of the tank farm study mandated by new Oregon Department of Environmental Quality rules. The DEQ accepted PGE's analysis, and in Q2 2025 PGE will submit a mitigation plan to the DEQ, which outlines that PGE will switch Beaver to natural gas and decommission the tank farm.

Q. What are PGE's plans for the remaining oil on site?

A. PGE plans to sell the oil in 2026, following the final Beaver upgrade. In Q1 2025**, [BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, the company that originally sold PGE the oil, initiated oil quality testing and preliminary sampling. They are expected to buy back all the usable oil at the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. In Q2 2026, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** intends to remove another sample of oil to complete their analysis and begin oil removal. The removal of the remaining oil inventory is scheduled to continue into the third quarter of 2026.

Q. How did PGE ensure the best price for customers for Beaver oil?

A. Before engaging **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, PGE conducted a market study to explore market liquidity and price. Ultimately, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** prevailed as the counterparty with the appetite for the quantity and the most competitive price, though negotiations are still ongoing.

Q. Will there be other costs associated with the transition away from oil?

A. Yes. PGE will be required to decommission the oil tanks and infrastructure. This, however, would not impact NVPC and PGE is diligently working to determine the most cost-effective and environmentally responsible approach for managing these assets as it transitions away from oil-based generation.

Q. Please describe how PGE plans to structure the sale of oil from the Beaver plant and how costs will be managed to minimize impact for customers.

A. PGE is evaluating a hedging structure that helps manage price risk exposure to spot diesel oil prices. Below is an outline of how PGE will structure the sale and the associated hedging strategy:

1. As discussed previously, the price of the physical sale of the oil will be at a discount to the spot market price for the Portland Low Rack. Given that the buyer indicated it will pick up the oil at the Beaver tank farm, the discount is representative of the oil transportation costs from the Beaver tank farm to the local distribution center. At the time of this filing, **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL].**

2. PGE will explore the use of financial products to hedge the risk of being offered a spot market price by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to assess whether these products will protect PGE's customers from a potential NVPC increase associated with a floating market diesel oil price.
3. PGE has approximately two million gallons of oil inventory, with a Weighted Average Cost of Oil (WACOO) of $2.49 per gallon. This results in a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** cost basis. As of this filing, using the prevailing relevant market price for oil at the Portland Low Rack price and inclusive of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** charges, the forecasted sale will result in a loss of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.
4. As mentioned previously, any salvage value from tanks or piping will be accounted for separately on the balance sheet and will not affect NVPC.
5. If PGE is able to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for the sale of the diesel oil, there will be no need for hedging price volatility risk.

This approach allows PGE to proceed with the sale in a prudent manner given uncertain market conditions by providing some financial certainty around the expected losses.

Q. How is PGE modeling this sale in MONET?

A. PGE will base oil sale pricing on New York Mercantile Exchange (NYMEX) forward curves with an estimated basis differential between Portland and New York as described in the Oil Forward MFR (Vol. 1– Forward Curves > Oil Curve). PGE will then reduce the future oil forward price with the discount, as defined above, by PGE's WACOO price. To calculate the final NVPC impact as estimated above, PGE will multiply the difference in prices by PGE's total oil volume.

Q. Are there plans to remediate or clean the site of any residual environmental impacts from historical oil use?

A. Yes. PGE is committed to addressing any environmental impacts resulting from historical oil storage and use at the site. Following the decommissioning of the tank farm, PGE will conduct a comprehensive environmental assessment to determine the extent of any potential contamination. Based on the findings of this assessment, PGE will develop and implement a remediation plan, if necessary, in accordance with all applicable environmental regulations and best practices.

Q. How will the removal of oil as a backup fuel effect the reliability of the Beaver Generating Station during periods of natural gas supply constraints?

A. The removal of oil as a backup at Beaver limits PGE's fuel supply options during natural gas supply constraints (e.g., pipeline blowouts, storage facility freezes, etc.). Historically, oil served as a critical backup, providing a secondary fuel source to maintain power generation when natural gas supplies were limited or disrupted.

As mentioned later in this testimony, the Northwest Natural (NW Natural) gas call option also allowed PGE to hold oil as a hedge against the possibility that the option was exercised such that PGE lost 30,000 Dth/day of natural gas supply. Not having this dual fuel option at Beaver increases the importance of the reliability benefits provided to customers by the North Mist gas storage facility, particularly since PGE relies on the combination of firm natural gas transportation contracts and natural gas storage from the North Mist facility to be the firm fuel sources for the combined operations of Port Westward 1, Port Westward 2, and Beaver.

Q. If oil provided additional reliability to PGE's thermal fleet, why did PGE choose to move away from dual fuel capability at Beaver?

A. The primary driver for the regulatory upgrades is the Oregon Department of Environmental Quality's (DEQ) implementation of the federal Clean Air Act's Regional Haze Rule. In August 2021, DEQ issued an order requiring PGE's compliance with reduced annual plant site emissions limits of Regional Haze pollutants. After the Beaver burner upgrades are complete, Beaver's nitrogen oxides (NOx) emissions rate will be significantly lower with an approximately 90% reduction, based on current design conditions.

Q. How does this transition align with PGE's broader decarbonization goals and state-mandated emission reduction targets?

A. This transition supports PGE's decarbonization goals by retaining operational flexibility of existing thermal assets, complying with more stringent environmental regulations, and meeting electricity demand while low carbon and carbon free energy is brought online.

Q. Has PGE evaluated and determined whether selling or burning the remaining oil reserves will have the lowest cost?

A. Yes. PGE conducted an internal analysis on selling the remaining oil inventory versus removing the oil via generation over summer and winter peaking events. The analysis indicated that the least-cost option for customers is selling the remaining inventory.

E. Colstrip Update

Q. Does PGE expect Colstrip to continue operating in 2026?

A. Yes. PGE forecasts Colstrip to remain operational in 2026 and expects to maintain its ownership stake in the facility beyond 2025. As such, PGE has forecasted Colstrip within MONET for 2026 NVPC.

Q. How does this compare to PGE's previous expectations for the plant?

A. Effective with PGE's 2018 general rate case, Colstrip's depreciable life was shortened from 2042 to 2030, consistent with Oregon Senate Bill 1547, Section 1. Then, following a proposal within PGE's 2021 Integrated Resource Plan (IRP) to accelerate depreciation from the end of 2029 to the end of 2025, PGE and Parties agreed to shorten Colstrip's depreciable life to 2025 within PGE's 2021 depreciation study.

Q. Did PGE update expectations for Colstrip in any other proceedings?

A. Yes. PGE's 2023 IRP filed under Docket LC 80 (LC 80) included the Reference Case assumption of Colstrip providing power to retail customers through the end of 2029. The 2023 IRP moved Colstrip's exit year from the end of 2025 to the end of 2029 "due to uncertainty in achieving a 2025 exit and higher certainty of a 2029 exit provided by SB 1547 requirements."[13] Additionally, PGE noted that while moving Colstrip's exit year to 2029 does not impact PGE's clean energy targets, exiting the plant sooner could impact capacity need values. The Commission acknowledged PGE's IRP through Commission Order No. 24-096, which included Colstrip through the end of 2029 as part of the Reference Case.

[13] *In re Portland Gen. Elec. Co. 2023 CEP and IRP, LC 80, PGE Response to Initial Comments (May 31, 2023).*

Q. Has PGE modified the modeling assumptions in MONET for Colstrip?

A. No. Beyond continuing to include Colstrip within MONET for 2026, PGE has not made any enhancements or changes to Colstrip's base modeling assumptions beyond standard plant parameter updates. However, to demonstrate the value Colstrip continues to provide customers, PGE has isolated the impact as a $75.2 million benefit to NVPC when comparing market purchases or forgone market sales in MONET with and without Colstrip. PGE also notes that consistent with assumptions in LC 80, the removal of Colstrip from our portfolio would result in the need for additional capacity, further increasing power costs beyond the isolated value Colstrip is forecasted to provide.

F. Extended Day Ahead Market (EDAM) Update

Q. What is EDAM?

A. The Extended Day-Ahead Market (EDAM) is an extension of the California Independent System Operator's (CAISO) existing Western Energy Imbalance Market (WEIM) into the day-ahead timeframe. EDAM is a market design framework that allows Balancing Authorities (BA) located in Western states outside of the CAISO balancing authority area (BAA) to participate in both CAISO's day-ahead and real-time markets. EDAM aims to improve grid reliability and increase the integration of renewable energy across participating BAs. FERC accepted revisions to CAISO's tariff to facilitate the implementation of EDAM, with EDAM provisions of the tariff fully in effect beginning in 2026.[14]

[14] *See Cal. Indep. Sys. Operator Corp.,* 185 FERC ¶61,210 (2023); *Cal. Indep. Sys. Operator Corp.,* Docket No. ER23-2686-001 (Apr. 30, 2024).

Q. How does participation in EDAM work?

A. Participation in EDAM is voluntary, and participants can terminate with six months' notice without paying exit fees. To participate, a BA must either already be a WEIM participant or join both day-ahead and real-time markets simultaneously.

In WEIM, generating resources are categorized as either participating (eligible to submit economic bids, offering to sell energy at specific prices) or non-participating (ineligible to submit economic bids) in the real-time market. Similarly in EDAM, generating resources must submit a schedule to CAISO**;** but this occurs the day before the operating day. This means that all generating resources (such as power plants and renewable generators) located within the participating BA's metered area are required to provide information about their availability and pricing for the next day's energy market.

This requirement supports a complete picture of available resources and their associated costs in the day-ahead market, allowing for more efficient market clearing and resource allocation. It is designed to increase market liquidity and improve overall market efficiency by having all resources participate in the day-ahead planning process.

Q. Is EDAM active?

A. EDAM is not yet active. CAISO's EDAM tariff has been approved by FERC and BAs can commit to EDAM by signing an Implementation Agreement. The tariff provisions to enable EDAM within a participating BAA are currently under FERC's review. It is anticipated to become active in May 2026.

Q. Has PGE made the decision to commit to EDAM?

A. Yes. PGE joined WEIM in 2017 after an extensive stakeholder engagement process. Since WEIM began operating in 2014, total gross benefits for all WEIM participants have been reported to be approaching $7 billion.[15] Based in part to the success of WEIM, PGE started exploring broader regional market options. PGE contracted The Brattle Group (Brattle) to perform a rigorous analysis using production cost modeling to identify both quantitative and qualitative benefits. This analysis evaluated the costs and benefits of PGE joining EDAM as part of a day-ahead market comparative analysis. PGE filed this analysis with the Commission in LC 80 and we are providing it as Exhibit 102. PGE signed an EDAM implementation agreement on July 2, 2024, to participate in EDAM on or before October 1, 2026. In addition, PGE intends to revise its Open Access Transmission Tariff (OATT) for participation in EDAM.

Q. How will customers benefit from PGE's participation in EDAM?

A. EDAM offers a compelling value proposition for customers and builds on both the success and proven WEIM platform. As discussed in more detail in Brattle's study, benefits of EDAM membership are anticipated to increase as more WEIM entities transition to the day-ahead market option. That being said, PGE does not anticipate immediate power cost reductions for customers in 2026 from EDAM participation because membership outside of the CAISO BAA will be limited to two entities: PacifiCorp and PGE, and PGE's participation in EDAM is limited to three months at the end of 2026. EDAM drives benefits for customers by offering the generating resources and transmission facilities in its metered boundary to the market. As more BAs participate, access to cheaper, cleaner, and more efficient generation increases, as does the opportunity to route power around congested transmission lines, which helps avoid

[15] Western Energy Markets, *Benefits*, https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

situations where generation cannot be used because of grid limitations. These tangible customer benefits are likely to materialize as the market matures and participation expands.

Q. Does the MONET model fully integrate EDAM benefits?

A. EDAM is an automation tool to capture the day-ahead trading optimization already assumed in MONET, and thus in the NVPC forecast. Brattle concurs with PGE's perspective. In their study, Brattle analyzed PGE's MONET modeling assumptions to assess if and how its simulated EDAM results compared with MONET's simulated day-ahead trading. Based on Brattle's review of MONET's assumptions, they concluded the following:

> MONET modeling captures PGE system operations and trading in a manner consistent with participation in EDAM…Although our model is more detailed, MONET…treats purchases and sales largely how they would be treated in the EDAM…[16]

As Brattle mentions, MONET has limitations. It is a single-stage, energy-focused model that does not account for the complexities involved in transitioning between different trading and operating periods and, therefore, does not fully capture real-world constraints and inefficiencies that impact the transition from day-ahead markets to real-time. PGE is making investments to integrate with EDAM, such as system upgrades and additional headcount, which will not be reflected in MONET or the AUT. Most refinements to the model related to joining EDAM will not be known until 2026, when EDAM implementation is finalized. However, PGE is assessed a grid management charge by CAISO for participation in WEIM, which is how CAISO recovers its operating costs from wholesale customers who participate in CAISO's markets. In EDAM, PGE will be assessed additional grid management charges

[16] PGE Exhibit 102, at 67-71.

by CAISO during EDAM participation. PGE estimates these additional charges to increase NVPC by approximately $2.5 million in 2026.

G. Washington Cap and Investment Program Modeling

Q. What is the history of the Washington Cap and Investment Program?

A. In 2021, Washington State passed the Climate Commitment Act, which established a comprehensive, market-based Cap-and-Invest Program aimed at reducing pollution and achieving the Greenhouse Gas (GHG) limits set in the state law. The program was launched on January 1, 2023. Thus, entities that are covered under the program started incurring emission compliance obligations January 1, 2023.

Since January 1, 2023, Washington State also passed Senate Bill 6058, which modifies the Climate Commitment Act in ways intended to support "linkage" with the California – Quebec carbon market. In 2024, Washington voters also rejected a ballot initiative (I-2117) designed to eliminate Washington's carbon market. These incremental policy actions effectively "firm up" the nascent Washington carbon market.

"Linkage" in this context refers to connecting the carbon market created by Washington's Climate Commitment Act (CCA) legislation with other regional carbon markets, creating a unified market for trading emissions allowances, and requiring policy alignment and coordination.

Q. PGE first introduced the Washington State Cap-and-Invest Program in Docket No. UE 416 (UE 416).[17] In UE 416, what was the outcome regarding costs associated with Washington's Cap & Invest Program?

A. Commission Order No. 23-386 adopted an all-party stipulation, which stated that PGE would remove its estimated Washington CCA carbon costs from the 2024 NVPC forecast, and that PGE would submit a deferral application to defer 2024 compliance costs associated with the Washington CCA. This deferred accounting application was subsequently filed under Docket No. UM 2308 (UM 2308).

Q. How did PGE address Washington CCA costs in 2025?

A. PGE did not include an estimate of these costs within the 2025 AUT and instead filed for reauthorization of UM 2308 to cover the period of January 1, 2025 through December 31, 2025.

Q. How does PGE intend to address Washington CCA costs in this 2026 AUT filing?

A. Rather than a forecast of costs in its NVPC filing, PGE intends to continue to use a deferral application as the tool for addressing compliance costs.

Q. Why does PGE plan to continue to defer Washington CCA carbon costs?

A. PGE believes a forecast of CCA carbon costs continues to have a high range of uncertainty. Given these uncertainties, PGE seeks to defer actual costs incurred rather than speculate and forecast costs that may not materialize. This approach allows PGE to accurately account for its obligations as they are determined, rather than relying on uncertain forecasts, which was a concern of parties to the UE 416 settlement.

[17] *See* UE 416, PGE Exhibit 300 (Feb. 13, 2023).

There remains important rulemaking(s) that can impact PGE's ability to minimize its exposure to Washington CCA compliance costs. Most noteworthy are the Washington State Department of Ecology's (Ecology) changes and pending decisions in its linkage rulemaking,[18] where PGE continues to support the formal adoption of reporting mechanisms first outlined in an industry supported paper known as the Electric Power Entities (EPE) Under the Climate Commitment Act (CCA) ("White Paper").[19]

Q. Can you share an example of a change or pending decision that is impactful to PGE?

A. Yes. A notable change is that the Washington CCA will require all importers of unspecified electricity to be Covered Entities,[20] regardless of the amount of unspecified electricity the entity imports. Currently, the threshold is 25,000 metric tons of CO2e.

Q. Since Washington's CCA program commenced in 2023, has PGE imported unspecified electricity into Washington State?

A. Yes. While PGE seeks to minimize imports of unspecified electricity into Washington, PGE did import **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of covered emissions into Washington during the 2023 reporting year, and most covered emissions were unspecified imports.

Q. Did PGE's 2023 emissions result in PGE becoming a Covered Entity?

A. No. Since the current compliance threshold is 25,000 tons per reporting year, PGE is not yet a Covered Entity as it did not report applicable emissions greater than 25,000 tons during the

[18] "WAC 173-446, Cap-and-Invest Program updates and Linkage," Ecology, https://ecology.wa.gov/regulations-permits/laws-rules-rulemaking/rulemaking/wac-173-441-446-linkage
[19] Letter from Joint Parties to Ecology, 23-02-051, (June 2023) ttps://apps.ecology.wa.gov/publications/documents/2302051.pdf
[20] In the Washington CCA, a Covered Entity must purchase or acquire allowances equal to their total annual GHG emissions. Each allowance permits the emission of one metric ton of CO_2e. Allowances can be obtained several ways including through auctions, secondary markets, offset credits, and free allocations.

2023 reporting year. However, if PGE incurred this same emission obligation from an unspecified source in a future year (after the linkage rule is finalized), PGE would become a Covered Entity and be responsible for paying carbon costs associated with each metric ton of unspecified electricity imported into Washington. Using the December 2024 auction settlement price of $40.26 as a price proxy, this obligation would result in a cost obligation of approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Can you share an additional example of the uncertainty that remains?

A. Yes. As noted in this testimony, PGE continues to support the formal adoption of reporting mechanisms first outlined in an industry supported White Paper. In its rulemaking comments,[21] PGE specifically highlights the importance of a lesser-of-analysis to show that electricity and any associated emissions sourced from a 'composite source Point of Receipt' (i.e., PGE's Mid-C scheduling point or any other hub that aggregates electricity from multiple sources before distributing it) are separately accounted for (i.e., no emission obligation for PGE). Without adopting this "lesser-of-analysis" method, electricity PGE sources from a "composite source Point of Receipt" such as Mid-C would represent unspecified electricity. If in its rulemaking, Ecology did not adopt the lesser-of-analysis method(s), PGE's compliance obligations could be considerably larger given it historically uses its Mid-C scheduling location as a source for imports into Washington State. Using 2023 reporting data as an example, PGE claimed **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of specified source emissions from resources with no CO2e emission factors. If PGE was required by Ecology rules to report the same amount of MWhs as

[21] Linkage Rulemaking Electricity Considerations
https://ecology.commentinput.com/comment/extra?id=KZc7tHYhu

unspecified emissions (i.e., an emission factor of 0.437 tons of CO2e per MWh), the obligation would result in **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of CO2e of unspecified source emissions in its 2023 filing. Using the December 2024 auction settlement price of $40.26 as a price proxy, this hypothetical obligation would result in a cost obligation of approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

Q. Please summarize how PGE would like to address costs incurred under the Washington CCA in 2026.

A. Rather than forecast costs that impact NVPC, PGE intends to continue to use a deferral application as the tool for addressing CCA compliance costs given continued uncertainty relating to linkage rules and associated unspecified electricity emissions obligations for Covered Entities.

H. Other Items

1. Hydro Generation Update

Q. Is PGE continuing to use the 10-year average hydro methodology utilized in UE 436 for this proceeding?

A. Yes. PGE continues to use this methodology. However, towards the end of PGE's 2025 AUT proceeding, PGE discovered some issues in the assumptions utilized, which we are correcting in this proceeding. Additionally, similar to other items based on historical averages (e.g., forced outage rates), PGE proposes rolling forward the 10-year data set to remove the oldest year (i.e., 2014) and include the most recent full year of actual results (i.e., 2023).

Q. In addition to rolling forward the 10-year average, what corrections and updates does PGE make to the 10-year average methodology?

A. As discussed below in detail, PGE makes the following corrections and updates to our hydro generation modeling:

1. Correct Canadian Entitlement-related modeling methodology.
2. Correct Encroachment-related modeling methodology.
3. Update Canadian Entitlement volumes.
4. Remove habitat, fish flow, and other related modeling adjustments.
5. Remove Sullivan turbine runner upgrade adjustment.

Q. Please describe the correction PGE makes for Canadian Entitlement and Encroachment.

A. In late 2024, PGE discovered that the U.S. Energy Information Administration (EIA) hydro power generation data utilized for setting the 10-year average includes power attributed to Canadian Entitlement and Encroachment (i.e., the EIA data is <u>not</u> reduced for these requirements). However, when developing the 10-year average used in UE 436, it was PGE's understanding that Canadian Entitlement and Encroachment were already removed. PGE had previously modeled hydro generated energy so that the total MWh owed for Canadian Entitlement was removed on an annual basis but remained in PGE's energy supply to model the shape of energy supply and demand more realistically during on-peak hours. In this AUT filing, PGE reverts to how it was modeled in 2024: Canadian Entitlement energy is removed from PGE's energy supply. Similarly, PGE also removes Encroachment energy from Mid-C generation.

Q. What is the NVPC impact of correcting for Canadian Entitlement and Encroachment?

A. Updating the model to intended Canadian Entitlement methodology results in a $3.1 million increase to NVPC, while updating the model to intended Encroachment methodology results in a $3.4 million increase to NVPC.

Q. Do any updates offset these correction steps?

A. Yes. In July 2024, Canada and the U.S. reached an Agreement-in-Principle (AIP) on key elements of a modernized Columbia River Treaty (Treaty). Prior to the finalization of the Treaty, BC Hydro, U.S. Army Corps of Engineers, and BPA have entered into interim arrangements to allow continued operations and implement some components of the Agreement-in-Principle. Thus, PGE plans to update Canadian Entitlement energy MWhs to reflect the agreement-in-principle between the disputing parties. As litigation is pending between Douglas PUD, Grant PUD, and BPA, these volumes are subject to change. Currently, PGE is modeling a 33% reduction to Canadian Entitlement obligations, as detailed in MFRs (Vol 5 – Contracts > Canadian Entitlement).

Q. What is the NVPC impact of updating energy MWhs attributed to Canadian Entitlement?

A. Updating energy obligations associated with Canadian Entitlement obligations to reflect the Agreement-In-Principle results in a $1.4 million decrease to NVPC.

Q. Please describe the hydro correction PGE is making related to spills for habitat and fish flow.

A. Currently, the hydro power generation at Oak Grove is adjusted down for flow requirements, snowmelt runoff releases, and winter flood flow releases. At Faraday, generation is reduced for diversion dam flow requirements and lake drawdown requirements. At River Mill, hatchery diversion requirements lower generation slightly. At the Pelton Reregulating Dam, spill required to meet dissolved oxygen requirements lowers generation, with PGE paying 50.01% of the cost of that hydro spill to the Confederated Tribes of Warm Springs. As the 10-year average data would already account for the historical effects of these adjustments, PGE proposes to remove these adjustments made to the data set (in the case of the spill at the Pelton Reregulating Dam, as the 10-year average hydro is net of spill, in order to capture only PGE's cost responsibility, 50.01% of this spill is added back into the portfolio to gross up Pelton Reregulating Dam generation numbers – for more information, see Vol 10 – New Items and Enhancements > Step B00f-Remove small hydro adjustments).

Q. What is the NVPC impact of removing these adjustments?

A. Removing these adjustments results in a $2.5 million decrease to NVPC.

Q. Does PGE propose any other hydro adjustments?

A. No, though PGE would like to call attention to Faraday generation. In the 2025 AUT, generation for Faraday in MONET was set to the volumes provided in the Faraday Repower Turbine Selection Study by Stantec rather than using a ten-year average with adjustments for Faraday's outages and upgrades. PGE proposes to continue using the Stantec study's volumes until more actuals are available for processing.

Q. What is the total NVPC impact of all hydro-related adjustments in this section?

A. All changes outlined above result in a $2.6 million increase to NVPC.

2. Westside Gas Correction

Q. What correction have you made to the "Gas Storage" worksheet?

A. PGE updated several equations on this worksheet to correct MONET in terms of how it dispatches Beaver and Port Westward 2 (PW 2).

Q. Is there a more detailed overview of these changes?

A. Yes, the more detailed overview of the changes can be found in the MFRs (see Vol 3 – Thermal>Thermal Plant Gas Storage Constraints).

Q. What effect did this correction have on overall NVPC?

A. The impact of the Gas Storage correction is a $2.5 million decrease to NVPC.

3. NW Natural Call Option

Q. Please describe the NW Natural gas call option in detail.

A. PGE and NW Natural have been parties to a Winter Peaking Agreement since 2010. With some restrictions on the total number of requests (i.e., the number of times the call can be exercised), the Winter Peaking Agreement provides NW Natural with a call option for up to 30,000 Dth/day during the Winter heating season (November 1 through March 31). Prior to the pricing amendment in 2024, NW Natural would pay PGE a price based on Ultra Low Sulfur Biodiesel when it elected to purchase the 30,000 Dth of natural gas. This pricing structure aligned well with PGE's dual fuel capability at Beaver, allowing PGE to hold oil as a hedge against the possibility of losing 30,000 Dth/day of natural gas supply. However, as described in this testimony, the dual fuel capability at Beaver will end in 2026. This loss of dual fuel capability met the conditions needed to renegotiate the pricing paradigm in the contract. PGE and NW Natural agreed to reprice based on the terms shared in PGE's MFRs (see Vol 3 – Thermal > Thermal Plant Gas Storage Constraints).

Q. How does the change in the NW Natural gas call option impact PGE's gas storage?

A. To account for the change in the NW Natural gas call option, PGE increases the ending February inventory balance at North Mist from 1.2 million Dth to 1.320 million Dth. This will increase NVPC by $0.7 million. PGE provides the details of its calculation in its MFRs (see Vol 3 – Thermal > Thermal Plant Gas Storage Constraints).

Q. Why is there an incremental increase in the North Mist inventory balance associated with the NW Natural gas call option agreement amendment?

A. PGE requires increased inventory in the winter given that after 2026 PGE can no longer rely on any amount of oil if NW Natural decides to exercise its option to purchase gas from PGE. Instead, PGE will match NW Natural gas purchases with a combination of power purchases and North Mist gas storage inventory. During 2026, PGE will rely predominantly on a combination of power purchases and North Mist gas storage inventory, coupled with availability of the one remaining Beaver unit with dual fuel capability and PGE's ability to operate it on fuel oil while staying ODEQ air permit compliant.

4. Miscellaneous

Q. What other changes to MONET are you proposing?

A. PGE performed maintenance on MONET's VBA code. One update corrects an edge case error related to Beaver 1-7 dispatch. The other removes outdated and unused code. Testing edge cases, correcting errors that may arise, and streamlining the workbook file by removing obsolete components are part of PGE's ongoing maintenance of the power cost model. A more detailed overview of these two items is available in the MFRs (see Vol 10 – New Items and Enhancements > Minor VBA Updates). The impact of this dispatch-related VBA code correction is $0.

Additionally, over the years, MONET has become increasingly complex. To simplify the model, PGE has removed outdated items that are no longer contributing to the NVPC forecast and other minor updates.

Q. Can you describe the other updates that fall under the "miscellaneous" category?

A. Yes. We corrected the peak system load formula on the "AS Load-net-VER" worksheet in MONET to include the entire total system load column on "AS Loads" instead of a fixed set of rows to accommodate leap years. We updated Clearwater capacities on the "VER Hourly MWa" worksheet to formulas instead of fixed values to reduce the number of places to update the same value. As per the terms of the "PaTu Wind QF" contract, it requires the implementation of the secondary pricing mechanism, so PGE must change the fixed values to formulas on the "PC Input" worksheet.

5. Forthcoming Updates

Q. Does PGE expect to update any items in future filings in this proceeding?

A. Yes. Power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; load forecast; wind and hydro production tax credit rates; and make any errata corrections to this initial filing in the July 15, 2025 filing.

IV. Qualifications

Q. Darrington Outama, please describe your qualifications.

A. I received a Bachelor of Science degree in Accounting from the University of Washington in 1996. I have over 25 years of experience with PGE working in accounting, financial planning, risk management, structuring and origination, and power operations. I have been involved in originating and pricing of custom products, asset acquisitions, as well as ad hoc project management including the 2012 Request for Proposals on behalf of PGE's customers. My current position is Senior Director Energy Supply. Prior to this I held positions as General Manager of Power Operations, Director of Financial Forecasting & Planning and Manager, Origination, Structuring and Fundamental Analysis.

Q. Elizabeth Pedersen, please describe your qualifications.

A. I received a Bachelor of Science degree in Industrial Engineering from Northwestern University, Chicago, IL in 2010. I also hold a Master of Science in Applied Statistics from Pennsylvania State University in 2016. I have worked for six years at PGE mainly as a Portfolio Optimization modeler in power operations. Currently, I am the manager of the Power Cost Forecast department. Prior to this role, I was a principal analyst on this team for 2 years. Before PGE, I worked at Intel as an industrial engineer supporting capacity and factory simulation models and later as a sales operations analyst.

Q. Does this conclude your testimony?

A. Yes.

V. List of Exhibits

<u>Exhibit</u>	<u>Description</u>
101	List of MFRs per Commission Order No. 08-505
102	Day-ahead market comparative analysis filed in OPUC Docket No. LC 80

Minimum Filing Requirements
July 7, 2008

General

The Minimum Filing Requirements (MFRs) define the documents to be provided by PGE in conjunction with the Net Variable Power Cost (NVPC) portion of the Company's initial (direct case) and update filings of its General Rate Case (GRC) and/or Annual Update Tariff (AUT) proceedings.

The term "Supporting Documents and Work Papers" as used here means the documents used by the persons doing the NVPC forecasting at PGE to develop the final inputs to Monet and the final modeling in Monet for each filing. This may include such items such as contracts, emails, white papers, studies, PGE computer programs, Excel spreadsheets, Word documents, pdf and text files. This will not include intermediate developmental versions of documents that are not used to support the final filing. Documents will be provided electronically where practical.

In cases where systems change or are replaced in the future, such as BookRunner, the MFRs will continue to provide substantially the same information as provided in PGE's 2009 GRC (UE-198).

PGE will take reasonable steps to ensure that the MFRs can be made available to CUB and ICNU at the time of the filing, rather than these parties having to wait for the OPUC to approve the protective order in the case.

Delivery Timing

In either an AUT year (April 1 initial filing) or a GRC year (Feb. 28 initial filing), at a minimum the following portion of the Direct Case Filing MFRs will be delivered with the initial filing:

- Summary Documents (Items 1-6)
- Modeling Enhancements and New Item Inputs (Item 14) – not applicable in AUT year
- Miscellaneous Item 15d - re: Testimony and Exhibits provided on the CD

The remainder of the Direct Case Filing MFRs will be delivered with the initial filing if practical, or no later than fifteen days after the filing (e.g. March 15 in a GRC year, April 15 in an AUT year).

For all update filings, Update Filing MFRs will be delivered with the update filing with the following exception. For the April 1 GRC Update Filing in a GRC year, the delivery of Item 23 will be made with the filing if practical, or no later than fifteen days after the filing (e.g. April 15).

Direct Case Filing

Applicability

- Applies to GRC Initial Filing (e.g. February 28) in a GRC year
- Applies to AUT Initial Filing (i.e. April 1) in a non-GRC year

Summary Documents

1. Monet model for the final step
2. Hourly Diagnostic Reports for the final step
3. Step Log showing NVPC effects of modeling enhancements, modeling changes, addition of new items or removal of items from the prior year rate proceeding (GRC or AUT), and other major updates that PGE believes the parties would want to see identified separately, such as updating the hydro study.
4. Output/Assumptions Summary Report comparable to that provided for the 2009 GRC
5. Executable files, any other files needed to run Monet, and installation instructions
6. Identification of the operating system PGE uses to operate Monet

Supporting Documents and Work Papers for the Following

7. Forward Curve Inputs. Consists of:
   a. Electric curve extract from Trading Floor curve file
   b. Gas curve extract from Trading Floor curve file
   c. Canadian/US Foreign exchange rate (F/X Curve) from Risk Management
   d. Model run for hourly shaping of monthly on/off-peak electric curve (Lydia Program)
   e. Oil forward curve
8. Load Inputs. Consists of:
   a. Monthly load forecast from Load Forecast Group
   b. Hourly load forecast from Load Forecast Group
   c. Copy of the loss study used by Load Forecast Group to develop busbar load forecast
9. Thermal Plant Inputs
   a. Capacities
   b. Heat Rates
   c. Variable O&M

      This includes any other cost or savings components modeled as part of Variable O&M, such as incremental transmission losses, SO_2 emission allowances (emission allowance $/ton price forecast, plant emission factors lb/MMBtu), etc.
   d. Forced outage rates
   e. Maintenance outage schedules and derations
   f. Minimum capacities
   g. Operating constraints
   h. Minimum up times
   i. Minimum down times
   j. Plant testing requirements
   k. Oil usage volumes
   l. Coal commodity costs
   m. Coal transportation costs
   n. Coal fixed fuel costs classified as NVPC items

      Includes items such as: Colstrip Fixed Coal Cost and the following Boardman costs: Rail Car Mileage Tax, Coal Sampling, Rail Car Lease, Rail Car Maintenance, Trainset Storage Fee, and Coal Car Depreciation
10. Hydro Inputs
    a. Monthly energy for all Hydro Resources

       This will include the results of PGE's most current study using the Pacific Northwest Coordination Agreement (PNCA) Headwater Benefit Study. Note that this program is not the property of PGE and should be obtained from the Northwest Power Pool. Provide the PGE version of the PNCA model inputs, so that if the Parties obtain the PNCA model, they would have the inputs needed to reproduce PGE's study.
    b. Description of logic for hourly shaping where applicable
    c. Usable capacities where applicable
    d. Operating constraints modeled
    e. Hydro maintenance derations
    f. Hydro forced outage rates (not currently modeled)
    g. Hydro plant H/K factors
    h. Spreadsheet demonstrating how the hydro energy final output from the PNCA study is adjusted to arrive at the monthly energy output on the PwrAEOut sheet
11. Electric and Gas Contract Inputs
    a. Copy of contract for each long-term (5-year or greater term) or non-standard power contract modeled in Monet.

       For some contracts, this may consist of a term sheet rather than a full contract, depending on what was deemed reasonably necessary by the power modelers to model the contract in Monet.
    b. BookRunner extracts for the test year of:

       Electric Physical Contracts
       Electric Financial Contracts
       Gas Physical Contracts

Gas Financial Contracts
F/X Hedge Contracts

c. Copy of each firm gas transportation or storage contract modeled in Monet
d. List of the PURPA QF contracts modeled in Monet
e. List of the long-term (5-year or greater term) or non-standard contracts modeled in MONET that were not included in PGE's most recent GRC or AUT.
f. Gas transportation input spreadsheet or its successor/equivalent
g. Website snapshots input to the gas transportation spreadsheet
h. Other Supporting Documents and Work Papers for contracts modeled in Monet, including any items showing on the Monet Cost and/or Energy Output reports not covered above. Could include structured contracts, option contracts, etc.
i. Coal contracts: Covered above under Thermal Plant Inputs
j. Amortizations of regulatory assets or liabilities modeled in the Contracts section of Monet

12. Wheeling Inputs
    a. Supporting Documents and Work Papers for all wheeling items modeled in Monet
13. Wind Power Inputs. Includes but not limited to:
    a. Monthly energy
    b. Hourly energy
    c. Maintenance
    d. Forced outage rates
    e. Integration costs, royalties, other costs and elements modeled
14. Modeling Enhancements and New Item Inputs
    a. Supporting Documents and Work Papers for all modeling enhancements and new items modeled in Monet.
    b. Includes modeling or logic changes, changes to the methodology used to compute data inputs or other type of enhancement to the Monet model.
    c. Modeling revisions, refinements, clean-ups etc. that do not affect NVPC under any conditions will not be considered to be modeling enhancements.
15. Miscellaneous
    a. Line Item Adjustments to Monet such as OPUC orders, settlement stipulations, others
    b. Identification of all transactions modeled in Monet that do not produce energy
    c. Items in Monet not covered elsewhere above
    d. For all testimony and exhibits provided on the CD in pdf format, provide the testimony in searchable pdf format, and provide any exhibits created in Excel in the original Excel format when available to PGE.

Historical Operating Data

16. Hourly extract of data from PGE's Power Scheduling and Accounting System showing actual hourly energy values for the most recent Four-Year Calendar Period of the following:
    a. Generation from each coal, gas, hydro and wind generating plant modeled in Monet. Note that Colstrip Units 3 and 4 generation is aggregated in PGE's system, and the Mid-C contract generation is similarly aggregated.
    b. Long-term (>5 years) electric contract purchases, sales and exchanges modeled in Monet.
17. Table showing the actual monthly generation of each PGE coal, gas, hydro and wind generating plant modeled in MONET, from the period 1998 through the last calendar year.
18. Monthly compilations of actual NVPC produced by PGE for the most recent calendar year.

Update Filings

19. Monet model for the final step
20. Hourly Diagnostic Reports for the final step
21. Step Log showing effect on NVPC of each update step since the last filing
22. Output/Assumptions Summary Report comparable to that provided for the 2009 GRC
23. For each Monet update step:
    a. Text description of update, including identification and location of input changes within Monet.
    b. Excel file containing Monet standard output reports (PwrCsOut, PwrAEOut, PwrEnOut) and PC Input sheets.
    c. Supporting Documents and Work Papers for the update step
24. For all testimony and exhibits provided on the CD in pdf format, provide the testimony in searchable pdf format, and provide any exhibits created in Excel in the original Excel format when available to PGE.

Portland General Electric
121 SW Salmon Street • Portland, OR 97204
portlandgeneral.com

March 21, 2024

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street, S.E.
P.O. Box 1088
Salem, OR 97308-1088

RE: RE XXX – PGE Informational Filing on Commitment to the California Independent System Operator's Extended Day-Ahead Market

Portland General Electric Company ("PGE" or "the Company") herby submits an informational filing on comparative analysis of the California Independent System Operator's ("CAISO's") Extended Day-Ahead Market ("EDAM"), an extension of PGE's current participation in the Western Energy Imbalance Market, and the Southwest Power Pool's Markets+ offerings.

After careful evaluation of both market proposals, PGE concludes that the CAISO's EDAM is the market that will provide the Company and its customers with the greatest economic, environmental, and reliability benefit. This decision includes consideration of market optimization benefit forecasts, implementation or transition costs, and alignment with Oregon statutes and PGE's corporate strategy.

PGE's analysis includes production cost modeling by The Brattle Group ("Brattle") for PGE's participation in both the EDAM and Markets+. PGE expects to see a customer benefit of $6.1-17.5 million in the EDAM compared to $8.3-8.7 million in Markets+. PGE also performed a qualitative analysis which evaluated both market designs according to six participation priorities. This analysis is enclosed in this filing.

A day-ahead market is an important market feature to PGE and the West. It effectively expands PGE's resource footprint and allows the Company to access a wider diversity of resources to lower costs, enhance reliability, and promote decarbonization. A day-ahead market can help deliver energy benefits for customers with optimized planning and economic dispatch of participating utilities' generation assets to balance supply and demand over a wider geographic region. This enables greater renewable penetration and integration across the West. Joining a day-ahead market aligns with meeting PGE's long-term imperatives of decarbonize, electrify, and perform as they will require incremental steps towards more diverse regional market solutions.

Should you have any questions or comments regarding this filing, please contact Pam Sporborg at Pam.Sporborg@pgn.com. Please direct all formal correspondence and requests to the following email address pge.opuc.filings@pgn.com

Sincerely,

\s\ *Shay LaBray*

Shay LaBray
Senior Director, Regulatory Affairs & Strategy

Enclosure

Portland General Electric

Comparative Analysis of the CAISO's EDAM and the SPP's Markets+

March 21, 2024

Table of Contents

Glossary of Abbreviations and Certain Defined References

APC	Adjusted Production Cost
BAA	Balancing Authority Area
BANC	Balancing Authority of Northern California
BAU	Business-as-usual
BPA	Bonneville Power Administration
Brattle	The Brattle Group
CAISO	California Independent System Operator
DEQ	Oregon Department of Environmental Quality
DSW	Desert Southwest
EDAM	Extended Day-Ahead Market
GHG	Greenhouse gas
IOU	Investor-Owned Utility
IPC	Idaho Power Corporation
LADWP	Los Angeles Department of Water and Power
MIP	Markets+ Independent Panel
MONET	Multi-area Optimization Network Energy Transaction
MPEC	Markets+ Participant Executive Committee
NVE	Nevada Energy
NVPC	Net Variable Power Cost
OATT	Open Access Transmission Tariff
PAC	PacifiCorp
Pathways Initiative	West-wide Governance Pathways Initiative
PGE or the Company	Portland General Electric Company
PNW	Pacific Northwest
RSE	Resource Sufficiency Evaluation
RTO	Regional Transmission Organization
SCL	Seattle City Light
SPP	Southwest Power Pool
VER	Variable Energy Resource
WECC	Western Energy Coordinating Council
WEIM	Western Energy Imbalance Market
WMEG	Western Markets Exploratory Group
WRAP	Western Resource Adequacy Program

1 Executive Summary

There are two energy market choices available to Portland General Electric Company ("PGE"): the California Independent System Operator's Extended Day-Ahead Market ("EDAM") and the Southwest Power Pool's Markets+. Based on PGE's quantitative and qualitative analysis, the EDAM is the preferred market choice to maximize the benefits of a day-ahead market for PGE's customers.

Building on PGE's experience in the California Independent System Operator's Western Energy Imbalance Market, a day-ahead market will deliver cost-savings and reliability benefits by economically dispatching participating utilities' generation assets to balance supply and demand over a wider geographic region. This will also enable greater renewable penetration and integration across the West while reducing the need for stand-by fossil fuel generation. Therefore, markets facilitate decarbonization efforts and can lower the overall greenhouse gas intensity of power traded across the Western Interconnection.

PGE contracted with The Brattle Group to model quantitative benefits for PGE's participation in each market offering. The results show PGE's participation in the EDAM of $6.1-17.5 million and Markets+ of $8.3-8.7 million compared to business-as-usual. PGE also performed a qualitative analysis of both market design proposals to assess consistency with PGE's strategy and state regulations. Based on the qualitative and quantitative comparative analysis, PGE has determined that the CAISO's EDAM provides a better value for PGE's customers through lower wholesale energy costs and a lower cost to entry when compared to Markets+. In addition, the comparative analysis determined that the EDAM was aligned with PGE's strategic long-term goals for a market solution based on market footprint diversity, congestion revenue, and implementation impact on existing processes.

The Southwest Power Pool's Markets+ offers several appealing features; however, the risks of migrating from a proven market, which provides benefits that PGE's customers receive today, to a market model that is not yet mature are not outweighed by these unique features. For the reasons discussed further herein, the recommendation from this analysis is for PGE to take the next steps necessary to join the EDAM.

2 Introduction

There are two energy market choices available to Portland General Electric Company ("PGE" or "the Company"): the California Independent System Operator's ("CAISO's") Extended Day-Ahead Market ("EDAM") and the Southwest Power Pool's ("SPP's") Markets+. PGE currently participates in the Western Energy Imbalance Market ("WEIM"), which is operated by the CAISO and supports over 80% of the load in the Western Interconnection. Since joining the WEIM in 2017, PGE has been a leader in developing regional solutions that incrementally advance western markets to lower costs for customers, enhance reliability, and promote decarbonization.[1]

To address regional resource adequacy challenges, PGE has committed to participating in the Western Resource Adequacy Program ("WRAP"), a unique program that enhances regional reliability through a six-month forward showing and operations program. PGE plans to be financially binding under the WRAP tariff in the summer of 2026.[2] The WRAP is a critical component to enhancing the region's reliability through collaboration. While the region is in the process of developing the capacity resources needed to meet reliable planning reserve margins, as the WRAP matures, PGE expects to see capacity savings from participating in this regionally diverse program.

The CAISO's EDAM and the SPP's Markets+ are the two options for day-ahead markets in the West. With the EDAM tariff having received FERC approval[3] and the SPP's Markets+ tariff having been approved by its governing panel, PGE has sufficient information to complete an evaluation of both options and make an informed decision between the two market offerings. Details on each of these market offerings are described in Section 3.

To evaluate these options, PGE contracted with The Brattle Group ("Brattle") to conduct a production cost study of the expected power cost benefits from both markets. The full results from the Brattle study are attached to this report in Appendix A. PGE also performed a qualitative analysis which evaluated both market designs

[1] For example, PGE has Chaired the WEIM Regional Issues Forum, and is co-chair of the West-wide Governance Pathways Initiative.
[2] While PGE's preference is for the WRAP to become operationally and financially binding in the first available season, Summer 2026, PGE cannot make this choice unilaterally. The WRAP participants have until May 2024 to finalize their decision to maintain Summer 2026 as the first binding season.
[3] The FERC rejected an element of the EDAM regarding the transmission revenue recovery proposal without prejudice. This element will not substantially impact PGE's participation.

according to the following six participation priorities detailed in Section 4: customer benefit, market footprint diversity, congestion revenue allocation, market implementation, decarbonization target alignment, and market governance.

Based on the evaluation, PGE will receive greater benefit from the CAISO's EDAM as PGE's energy market choice based on the following key findings:

- PGE expects to see a customer benefit of $6.1-17.5 million[4] in the EDAM compared to $8.3-8.7 million in Markets+. These benefits derive from direct connectivity to California's solar resources and broad footprint diversity.
- PGE estimated payments to the market operator for start-up costs demonstrates lower EDAM costs of $0.6-1.2 million compared with $4.9-8.1 million for Markets+.
- Over 50% of the load in the Western Interconnection has committed to the EDAM; therefore, the EDAM has sufficient load, generation, and transmission to realize expected market and reliability benefits.
- The EDAM congestion revenue allocation at the Balancing Authority-level with sub-allocation to transmission customers will provide an appropriate hedge for load against congestion cost.
- Since PGE already participates in the WEIM, adding the EDAM incrementally builds on PGE's existing systems and connectivity to the CAISO.
- The joint authority governance model of the CAISO strikes a fair balance between California and Western interests regarding energy markets.

In addition, the results from Energy Strategies' State-Led Market Study and E3's Western Market Exploratory Group ("WMEG") study both support PGE's decision to participate in a day-ahead market footprint that includes California. These studies are discussed in Section 5.

Overall, PGE finds the expected benefits, ease of entry, and alignment with PGE's strategy indicate that the EDAM is the better choice. PGE will continue to monitor western market developments and may reevaluate market opportunities once both markets are operational and mature.

[4] Lower range value represents reduction in benefit if current participants leave the WEIM, offset by higher sales in the day-ahead market.

3 Overview of the EDAM and Markets+

The success of the WEIM has propelled regional interest in extending participation into a day-ahead market. The CAISO's EDAM and the SPP's Markets+ approach market design individually, creating unique market proposals. PGE evaluated each markets' participation framework, resource sufficiency, transmission availability, greenhouse gas ("GHG") accounting, and congestion revenue allocation as key market design elements against the six participation priorities. PGE also reviewed both governance structures to ensure balanced representation regarding changes in market policy as the market design evolves. These design features are summarized in Table 1, below, and described in more detail in the following sections.

Table 1 - EDAM and Markets+ Market Design Overview

Features	CAISO's EDAM	SPP's Markets+
Participation Framework	Voluntary incremental market participation. Must participate in the WEIM and can elect to also participate in the EDAM. Generation and all load in an EDAM BAA must participate.	Voluntary but all participants in the footprint must take all incremental market services including both the stand-alone day-ahead and real-time markets and be a WRAP participant.
Resource Sufficiency	Requires participants to demonstrate sufficient energy, capacity, flexibility, and transmission on a day-ahead basis consistent with forecasted demand. VERs are fully credited at day-ahead forecast but are not required to bid at this level.	Uses Balancing Authority operating reserves, Flexibility Reserve Products, and WRAP forward showing requirement. VERs are credited 100% of day-ahead forecast and required to offer a minimum amount.
Transmission Framework	Transmission is available to be optimized through three pathways, with the ability to carve out consistent with the EDAM Entity tariff.	Transmission is available to be optimized unless otherwise carved out.
GHG Accounting	Uses a resource-specific method to account for imports into GHG regulation areas (i.e., California or Washington). Capped state solution to be addressed through open stakeholder process.	Uses a resource-specific method and unspecified pathways to account for imports into GHG regulation areas (i.e., Washington). Capped state solution to be addressed in Phase Two.
Congestion Revenue Allocation	Revenue will be allocated to the Balancing Authority where the congestion occurs, and the Balancing Authority will sub-allocate to individual customers consistent with the OATT.	Revenues will be allocated directly to the transmission rights holder based on long-term (monthly or greater) rights.
Governance Framework	Expands on joint authority model, between the WEIM Governing Body and the CAISO Board of Governors. Governing Body members are nominated by Western stakeholders while the California Governor nominates the Board.	The MIP has highest authority over Markets+ and are nominated by Markets+ members. The MIP has delegated authority from the SPP Board of Directors who are elected by SPP members.

3.1 CAISO's EDAM Design

The EDAM leverages the CAISO's existing day-ahead market, building on the successful WEIM platform. The EDAM optimizes all supply and demand across the market footprint while respecting transmission limitations to produce optimized day-ahead schedules. All generation and load within a participating EDAM Balancing Authority Area ("BAA") must either bid or self-schedule in the market. These transactions are then re-optimized in the WEIM sub-hourly 15- and 5-minute markets. The EDAM requires participants to demonstrate sufficient energy, capacity, flexibility, and transmission on a day-ahead basis, consistent with forecasted demand. Variable energy resources ("VERs") are credited at 100% of day-ahead forecast, but are not required to bid at this level. All load, generation, and transmission will participate under the Transmission Service Provider's tariff. An EDAM Entity can terminate participation with a six-month notice and no exit fee.

Each BAA has an initial $300,000 implementation fee with potential additional payments to cover actual costs with an expected total implementation cost of $0.6-2 million.[5] Unused funds will be returned. The CAISO will include transitional protective measures in the EDAM, similar to those in the WEIM, to insulate participants from adverse reliability or market outcomes during the implementation process. Implementation of the EDAM solution is anticipated to expand on existing business processes and utilize established software and modeling tools.

The EDAM transmission framework is designed to maximize transmission availability while respecting the Open Access Transmission Tariff ("OATT") rights and legacy contracts of participants. While the WEIM relies on transmission that is unused within the hour, the EDAM will commit transmission in the pre-schedule day. Notably, existing transmission rights and designated legacy transmission contracts are given a higher priority than other schedules. This includes transmission utilized in the WRAP forward showing, enabling compatibility with the WRAP. This priority allows the transmission customer to self-schedule in the day-ahead market, or prior to the close of the real-time market, to avoid exposure to congestion charges. The CAISO will model exchanges between participating EDAM Balancing Authorities based on the Total Transfer Capability at each intertie location.

[5] Based on the CAISO estimates as of March 2024. Actual cost will vary depending on complexity of the EDAM Entity's system.

Like the WEIM today, the CAISO will model transmission limitations or constraints and seek an optimized solution. Congestion rent is the difference between the incremental cost to serve demand in separate locations based on nodal pricing. The day-ahead congestion rents are allocated 100% to the Balancing Authority where the congestion occurs. Congestion on transmission paths between EDAM Balancing Authorities will be shared 50/50. The Balancing Authority then sub-allocates congestion revenue to transmission customers based on the EDAM Entity's OATT.

The current design accounts for the costs arising from state GHG accounting and reduction policies that price GHG. The CAISO is engaged in a regional stakeholder process to modify the GHG framework to account for a non-priced GHG-capped state policy.

The governance structure for the EDAM continues to evolve towards greater independence. The EDAM has adopted a joint authority model that provides equal weight to both the WEIM/EDAM Governing Body and the CAISO Board of Governors for proposals that "apply to" WEIM/EDAM participants. The stakeholder and western regulator led West-wide Governance Pathways Initiative ("Pathways Initiative")[6] is exploring options to create a fully independent regional operator with sole rights over the market tariff. The EDAM governance model includes oversight roles for the Body of State Regulators and the Regional Issues Forum. The CAISO relies on a staff-facilitated stakeholder process for new market policy enhancements with direct solution input and advocacy from stakeholders.

For more information on the CAISO's EDAM, please visit the CAISO website.[7]

3.2 SPP's Markets+ Design

The SPP's Markets+[8] is a new, stand-alone market design being developed to serve as both a day-ahead and real-time balancing market. Like the EDAM, Markets+ optimizes all supply and demand across the footprint to produce optimized day-

[6] The Pathways Initiative was initiated by regulators in Oregon, Washington, California, Arizona and New Mexico. More information is available at: westernenergyboard.org/wwgpi/

[7] California Independent System Operator. Initiative: Extended Day-Ahead Market. CAISO, 2024, stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market.

[8] PGE is basing its analysis on the Markets+ Tariff Version 1 as approved by the MIP on March 1, 2024, and published to the SPP website on February 24, 2024. Available at: spp.org/documents/71214/markets%20plus%20tariff_v1.pdf

ahead schedules. These transactions are then re-optimized in the sub-hourly 5-minute market. Markets+ also includes a day-ahead flexibility reserve product.

WRAP participation is a requirement for Markets+ and participants are assumed to be resource sufficient after passing the WRAP forward-showing requirement. There is a Markets+ must-offer obligation that requires the participant to submit supply offers equal to or greater than the sum of their load, flex obligation, WRAP adjustment (holdback sale or purchase),[9] and net position (forward purchases minus forward sales). VER minimum and maximum bids are set by the Markets+ tariff and the SPP's VER forecast. A market participant can terminate their agreement with the SPP with a minimum 90-calendar day notice and no exit fee.

The Markets+ design process includes the development of tariff language (Phase One) and a subsequent system implementation process (Phase Two). The total estimated budget for Markets+ is $130 million +/-25% that is split among load serving participants based on load-ratio share. There is also a separate fixed fee structure for participants that do not serve load. The annual administrative fee for participation is estimated at $60 million +/-25% split on a per MWh basis.[10] Payments for Markets+ Phase One are credited towards the participant's total obligation. Joining Markets+ requires participants to operationally implement the real-time and day-ahead market simultaneously.

The Markets+ transmission utilization framework is intended to maximize the availability of transmission in the Markets+ footprint while accommodating existing bilateral contracts and participant self-scheduling. Transmission paths are considered fully available unless participant constraints are communicated before the close of the day-ahead market. A Markets+ Transmission Service Provider must make unsubscribed transmission available for Markets+ use, but a transmission rights holder can opt-out specific transmission rights. Markets+ will economically dispatch energy across the footprint using flow-based transmission capability excluding any capacity specifically carved out.

[9] The WRAP operations program assesses each load serving entity's forecasted load and generation on a rolling seven-day basis and assigns a "holdback obligation" to participants that have forecasted surplus in the pre-schedule day. Participants with a forecasted deficit have an opportunity to purchase the holdback obligation or execute a bilateral transaction.
[10] Southwest Power Pool. "Markets+ Development Update." Southwest Power Pool. 16 November 2022. Slide 14. spp.org/documents/68264/du%20in%20person%20denver%2020221116.pdf

Markets+ proposes to calculate congestion rent based on the long-term rights from a Point of Receipt and Point of Delivery pair across constrained paths. Markets+ will allocate a pro rata share of the congestion on a specific constraint to the transmission rights holders who procured at least monthly long-term firm or conditional firm on that path. Redirects of firm transmission will not be eligible for congestion revenue. Network Integrated Transmission Service customers will receive congestion revenue based on a merit order dispatch from each Designated Network Resource to its network load from lowest cost to highest cost supply. In addition, Markets+ is designing a GHG framework that includes priced GHG compliance zones. Phase Two intends to investigate a tracking and reporting mechanism for non-priced GHG states.

The proposed governance structure for Markets+ combines sector-based voting and a Markets+ Independent Panel (“MIP”) that has delegated authority from the independent SPP Board of Directors, elected by SPP members. Actions taken by the MIP will be placed on the Board of Directors consent agenda and submitted to the FERC unless appealed or reviewed by the Board of Directors. Market participants from various sectors are afforded the opportunity to nominate candidates for the MIP.

The MIP is also advised by the Markets+ Participant Executive Committee (“MPEC”) and the Markets+ State Committee. Each market participant/stakeholder can appoint one representative to the MPEC. The MPEC is split into three membership sectors: Investor-Owned Utilities (“IOUs”), Public Power, and Independent. IOUs and Public Power votes are weighted on a load-share ratio basis within the sector. Independent sector grants one vote per entity. MPEC members must pay an annual fee of $5,000 unless the entity is an eligible nonprofit organization. An action approved by the MPEC needs to pass with approval from at least two of the three sectors. The Markets+ State Committee is comprised of one representative from each state in which a Markets+ participant has generation or load and is appointed by the Public Utility Commission of that respective state.

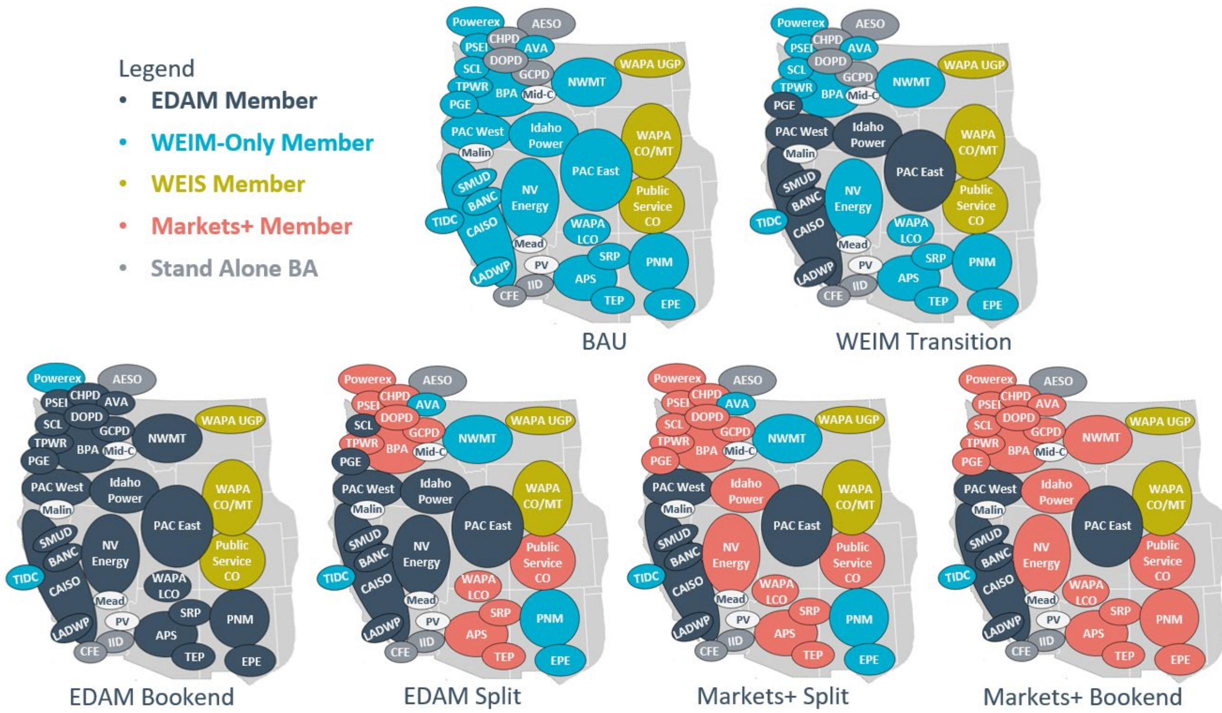
4 Market Comparative Analysis

This section documents PGE's qualitative and quantitative evaluation of the EDAM and Markets+ designs against six participation priorities deemed central to gauging the market's ability to deliver sustained value for PGE's customers. The following are PGE's day-ahead market participation priorities that are central to delivering value to customers:

- **Customer Benefit:** The market provides equal or improved reliability and net economic benefits.
- **Market Footprint Diversity:** The market has sufficient regional counterparties to support PGE's wholesale market needs, including non-coincident peak load events, deliverability, and market liquidity.
- **Congestion Revenue Allocation:** The allocation appropriately insulates load from congestion costs associated with long-term investments, compensates the transmission rights holder and signals efficient resource dispatch.
- **Market Implementation:** Implementing the market is timely, efficient, and is interoperable with other PGE commitments (e.g., a resource adequacy program). Implementation costs do not outweigh the forecasted benefits.
- **Decarbonization Target Alignment:** The market supports PGE's ability to meet Oregon's GHG reduction targets.
- **Market Governance:** The governance structure for the market appropriately balances interests of all market participants to enhance market stability and efficiency.

PGE engaged Brattle to simulate the specific EDAM and Markets+ designs for likely regional footprints based on participation. Figure 1, below, shows the six cases modeled by Brattle with varying market footprints.

Figure 1 - Brattle's Market Sensitivity Cases Modeled



In all cases, the market participants that have announced a commitment to a market (e.g., EDAM or the WEIS and RTO West) are modeled in that market's footprint. Both bookend cases assume most uncommitted Western Electricity Coordinating Council ("WECC") Balancing Authorities are participating in that respective market. The EDAM and Markets+ split cases look at specific footprints with varying market participation by PGE, Idaho Power Corporation ("IPC"), Nevada Energy ("NVE"), and Seattle City Light ("SCL"). Finally, PGE commissioned a WEIM transition case to evaluate an interim footprint where the WEIM is still largely intact.

In conjunction with the Brattle Study, PGE evaluated the EDAM and Markets+ designs against the six participation priorities to determine whether each market was aligned, neutral or unaligned. The results of this evaluation are summarized in Table 2 and provided in more detail below.

Table 2 – PGE's Day-Ahead Market Participation Priority Comparison

	CAISO's EDAM	SPP's Markets+
Aligned	• Customer Benefit • Market Footprint Diversity • Congestion Revenue Allocation • Market Implementation	• Customer Benefit
Neutral	• Decarbonization Target Alignment • Market Governance	• Market Footprint Diversity • Decarbonization Target Alignment • Market Governance
Unaligned		• Congestion Revenue Allocation • Market Implementation

4.1 Participation Priority 1: Customer Benefit

The primary driver of any market decision must be customer benefit. The two benefits evaluated here are: energy market savings for customers and reliability enhancements.

4.1.1 Objective 1: The market must provide energy market benefits

PGE's customers see a benefit in joining both market options; however, the highest benefit scenario was the Bookend EDAM based on the Brattle study results.

To estimate market benefits, Brattle modeled five scenarios compared to a business-as-usual ("BAU") case:

- **WEIM Transition**: PGE, IPC, and other announced entities join the EDAM. All other entities remain as they are in the BAU case. The WEIM transition case represents the most likely scenario for EDAM go live.
- **Bookend EDAM**: Assumes all WECC entities contemplating joining a day-ahead market, who are not already in RTO West or WEIS, join the EDAM. The exception is Powerex, who remains in the WEIM.[11]
- **EDAM Split**: Assumes PGE, IPC, NVE, SCL, and other announced entities join the EDAM. The other Phase One Funders join Markets+. All other entities remain as they are in the BAU case.

[11] Although Powerex has committed to Markets+, PGE made the simplifying assumption that Powerex would remain in the WEIM in the Bookend EDAM case.

- **Markets+ Split**: Assumes PGE, the Phase One Funders, and IPC join Markets+. All other entities remain as they are in the BAU case.
- **Bookend Markets+**: Assumes the entities that have announced joining the EDAM go to the EDAM, PGE goes to Markets+ with the remaining WECC BAAs, and other entities remain as they are in the BAU case.

Brattle used the following metrics to forecast net benefits of market participation:

1. Adjusted Production Cost ("APC"),
2. Impact on wheeling revenue,
3. Loss of bilateral trading profits, and
4. Congestion and transfer revenues.

Brattle used a nodal production cost model of the WECC with added market functionality, such as contract-path transmission, to generate results.

Based on the Brattle bookend footprint simulations compared to the BAU case, PGE's EDAM maximum net benefit is $17.5 million compared to a Markets+ maximum net benefit of $8.7 million. Table 3, below, summarizes PGE's net benefits compared to the BAU case for each scenario.

Table 3 - Brattle's Net Benefit Summary for PGE ($Million)

Market Membership	WEIM Transition	Bookend EDAM	EDAM Split	Markets+ Split	Bookend Markets+
Delta APC to BAU	(5.30)	(3.60)	7.70	(13.20)	(13.90)
Delta Revenues to BAU					
Wheeling Revenues	(1.60)	(1.70)	(1.60)	(1.40)	(1.40)
Bilateral Revenues	2.92	(1.62)	2.08	1.04	(0.89)
WEIM Revenues	(7.14)	(4.4)	(10.3)	(15.71)	(15.71)
WEIS Revenues	-	-	-	4.34	4.12
EDAM Revenues	11.06	21.66	23.55	-	-
Markets+ Revenues	-	-	-	7.16	6.48
Total Net Benefit	**$10.54**	**$17.54**	**$6.03**	**$8.63**	**$8.28**

Brattle's modeling did not include costs to implement and/or start-up the market. Section 4.4 discusses the market implementation costs.

Additionally, PGE requested that Brattle evaluate the modeled benefits from EDAM or Markets+ participation compared to the Multi-area Optimization Network Energy Transaction ("MONET") model that PGE uses to develop the Company's net variable power costs ("NVPC") forecast. Brattle concluded that the benefits modeled in their study are not incremental to what is currently reflected in the NVPC forecast.[12]

Since Brattle's study builds upon the model previously developed for PacifiCorp ("PAC"), IPC, Balancing Authority of Northern California ("BANC"), Los Angeles Department of Water and Power ("LADWP"), and NVE, PGE has limited ability to adjust modeling assumptions to reflect PGE's specific regulatory environment. This approach ensures that study assumptions and results reported by regional entities are comparable.

Participation in either the CAISO's EDAM or the SPP's Markets+ will reduce operational friction, resulting in market price formation transparency. Additionally, opting into the EDAM convergence bidding framework supports price convergence between day-ahead and real-time trading windows. As part of an organized day-ahead market, PGE's resource portfolio will be submitted, modeled, and optimized in an expanded regional resource portfolio and geographic footprint through the independent day-ahead market operator. Because the day-ahead market will optimize the regional portfolio, value streams that are currently captured through bilateral trading or market arbitrage activities will be realized through the day-ahead market-optimized portfolio dispatch and settlement. This means portfolio cost reduction actions realized by PGE through bilateral transactions and trading activities, such as transmission resales or arbitrage trading at the California-Oregon Border, will be replaced with day-ahead market optimization and settlement mechanisms. Since the MONET model already captures PGE's system operations and trading consistent with assumed day-ahead optimization, PGE sees a day-ahead market as an automation tool to capture the optimization already assumed in the NVPC forecast.

While both markets provide increased opportunities to capture the regional optimization in the MONET model, the EDAM offers additional price convergence 00tools. Overall, the EDAM provides greater customer benefit when compared to Markets+.

4.1.2 Objective 2: The market must have equal or enhanced reliability

For PGE to participate in a day-ahead market, it must have equal or improved reliability. While energy markets do not provide capacity reduction savings, they offer enhanced reliability through regional coordination, diversity benefits, and the ability

[12] *See* Appendix A, slides 34-38.

to manage transmission congestion through redispatch instead of curtailment. Additionally, markets must ensure participants do not inappropriately lean on the market.

The EDAM will utilize the existing WEIM Resource Sufficiency Evaluation ("RSE") to ensure that market participants bring enough generation, transmission, and flexibility to cover their forecasted load obligations for the market horizon. While the RSE tests whether a market participant has sufficient resources to meet its load, resource adequacy ensures a Balancing Authority has adequate resources to meet expected obligations on a planning horizon. The EDAM is compatible with both the WRAP and the California's Resource Adequacy program.

In addition, the CAISO's day-ahead market will introduce two new market products: imbalance reserves and reliability capacity. The imbalance reserve product will address ramping needs between intervals and the uncertainty that can occur between the day-ahead and real-time markets. This can reduce each EDAM entity's overall daily sufficiency requirement. The imbalance reserve product will play a critical role in supporting EDAM transfers when uncertainty materializes between day ahead and real time, increasing the degree of confidence that these transfers can serve load reliably. Because both supply and demand bids in the day-ahead market is voluntary, reliability capacity is a market mechanism that ensures that enough supply is committed in the day-ahead market to meet forecasted demand.

Markets+ utilizes the WRAP's forward showing program to prevent leaning on the market. The integration of the WRAP could produce an opportunity to capture both energy and capacity savings through an integrated approach. This benefit will need to be demonstrated through a sufficiently broad footprint to achieve diversity savings and lower capacity reserve margins.

Overall, EDAM provides appropriate tools to enhance reliability through the RSE and day-ahead market products.

4.2 Participation Priority 2: Market Footprint Diversity

To maximize financial, reliability, and decarbonization benefits from the day-ahead market, the footprint must provide geographic diversity for both load and generation, as well as sufficient transmission to enable energy exchange. PGE will evaluate the following objectives on an integrated basis:

1. Sufficient depth and size of regional counterparties to provide a liquid wholesale energy market that will result in benefits for customers;

2. Load and resource diversity; and
3. Transmission deliverability.

4.2.1 Objective 1: Sufficient depth and size of regional counterparties

A footprint that has sufficient depth and size of regional counterparties to provide a liquid wholesale energy market that will result in benefits for customers is a requirement for participation. Diverse load and generation directly contribute to enhanced reliability and customer value as the footprint's markets are better able to both withstand peak load events and absorb low-cost generation. A geographically diverse footprint decreases the likelihood that the entire footprint will experience extreme weather simultaneously, enabling energy transfers into areas experiencing extreme weather events.

For the EDAM, the current market footprint consists of BANC, LADWP, and PAC. PGE has direct connectivity to the CAISO through the California-Oregon Intertie and is interconnected with PAC's western BAA. The Brattle study shows that PGE's main trading partners in the EDAM are PAC and California participants via Malin.

For Markets+, the committed market footprint consists of Powerex. For purposes of this evaluation, PGE evaluated multiple scenarios with Markets+ Phase One Funders to make a range of assumptions about impacts of a possible final market footprint. In the Markets+ footprint cases, the Bonneville Power Administration ("BPA") would be PGE's major trade partner.[13]

Brattle's study results show greater trade volume benefits to PGE in the EDAM cases compared to Markets+.

4.2.2 Objective 2: Load and resource diversity

Geographic diversity of generation provides for a greater likelihood of a diverse supply of low or zero carbon generating resources with offset production times. This non-coincident generating pattern allows greater access to low cost and low carbon supply to meet load while minimizing the potential curtailment of renewable generation. For example, the Desert Southwest's ("DSW's") greatest solar production occurs during midday, while wind generation in the Columbia River Gorge is primarily produced overnight. Having a wide geographic footprint with diverse load

[13] *See* Appendix A, slide 16.

peaks can also reduce curtailments of renewable resources, supporting decarbonization while lowering costs for customers.

In the EDAM, PGE is directly connected to diverse resources, including California solar. The WEIM covers 80% of load in the WECC, offering a broad footprint at EDAM startup.

Markets+ Phase One Funders represent a diverse resource footprint, including Pacific Northwest ("PNW") hydro and DSW solar. The large number of hydro owners in the Markets+ Phase One Funding Group offer a valuable benefit of participating in this footprint.

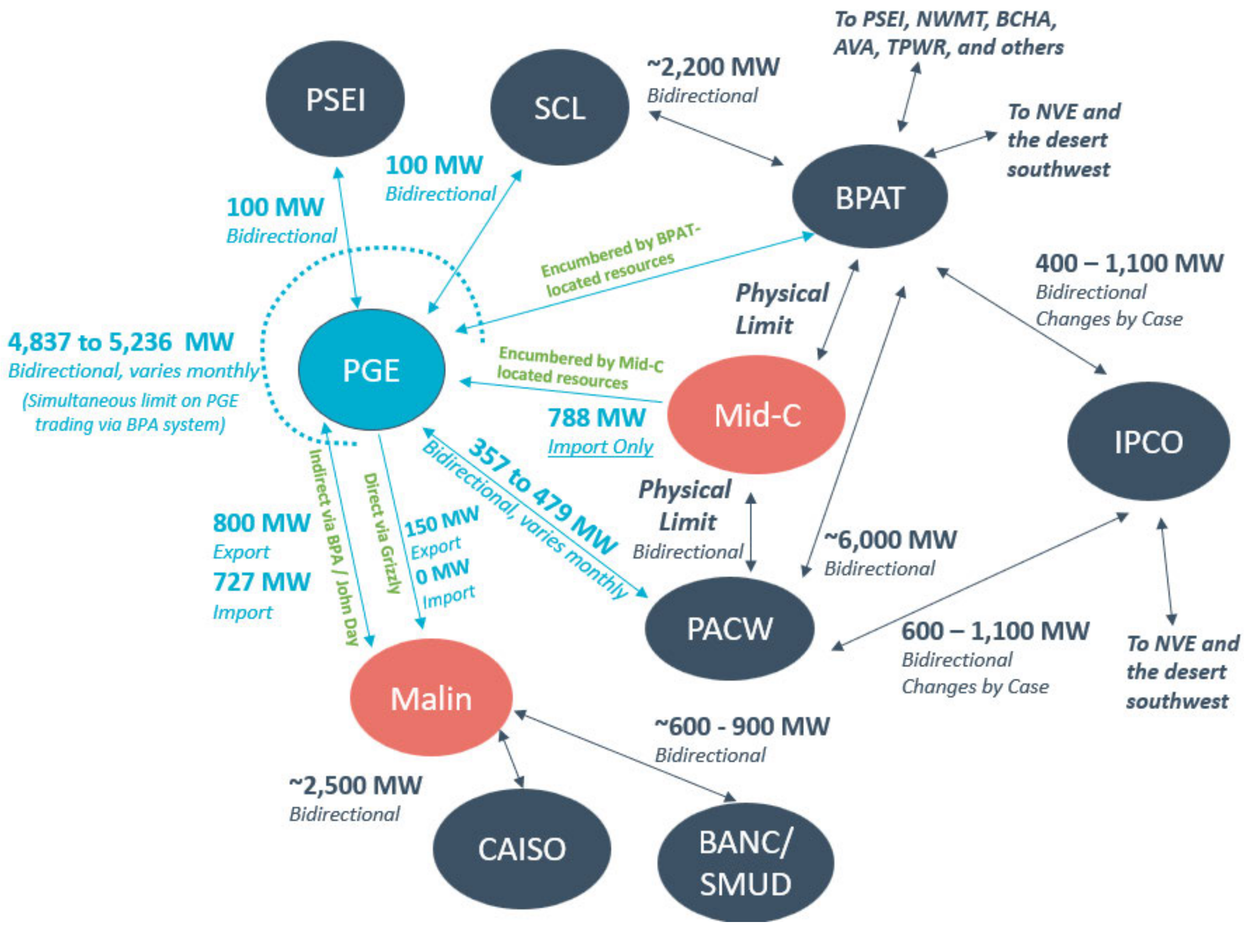
4.2.3 Objective 3: Transmission Deliverability

Transmission deliverability is critical to unlocking the load and resource diversity benefits discussed above if the market footprint becomes limited. Transmission can be limited in a variety of ways, including the physical capacity of the line, the electrical location of load and generation, or the transfer capacity between market participants. A market seam location also impacts energy transfers by introducing hurdle rates. In addition, grid conditions, such as weather or outages, can limit flows and create market congestion. Finally, the transmission availability framework of the market can affect deliverability if it allows for carveouts of either or both transmission rights and generation resources.

Figure 2, below, shows that in the EDAM, PGE has direct access to California through the California-Oregon Intertie and to PAC West.[14] In the Markets+ footprint, PGE's largest direct transmission connection is with the BPA.

[14] *See* Appendix A, slides 10 and 16.

Figure 2 - Figure Simplified PGE Connectivity Map



Overall, while both the EDAM and Markets+ offer diverse footprints, when considering all three aspects of market footprint diversity together, the utilities currently committed to the EDAM represent a diverse footprint that will provide greater benefits to PGE's customers. The Brattle Study results show that the EDAM footprint allows PGE to reduce gas generation due to the greater surplus of midday solar in the footprint.[15]

PGE's Brattle Study results show that participation in Markets+ produces solar curtailments in PGE's footprint due to limited connectivity in the Markets+ footprint, especially between the PNW and the DSW.[16] While the PGE-BPA transmission interface represents the most direct connectivity between PGE and any market participant in either the EDAM or Markets+, that connectivity does not extend beyond

[15] *See* Appendix A, slide 12.
[16] *See* Appendix A, slide 12.

the PNW geographic border. The lack of transmission to access resource diversity across the footprint reduces the value of participation in Markets+.

4.3 Participation Priority 3: Congestion Revenue Allocation

Congestion revenue allocation is one of the most important market design elements in determining market participation value for PGE's customers. The EDAM and Markets+ take different approaches to congestion revenue allocation. Congestion revenue allocation must balance the interests of load and generation. PGE's priority in assessing a congestion revenue framework is whether it provides sufficient protection for load while appropriately compensating generation that is able to provide congestion relief through redispatch.

While Markets+ proposes a unique approach for congestion revenue allocation that may prove to be accurate and equitable, at this time this methodology has not been assessed in any organized market. At this time, PGE is unable to forecast the impact to customers from the application of this methodology to PGE's unique market position.[17] Many of PGE's resources are remote to PGE's Balancing Authority and are delivered to PGE's border on long-term firm Point-to-Point transmission rights. They are then delivered to load via Network Integration Transmission Service. This would create an internal congestion "seam" at the PGE-BPA border that could increase costs to customers. If PGE redirects this transmission, it is no longer considered long-term firm. In this case, PGE would not receive congestion revenue, exposing customers to high congestion costs. While PGE recognizes that these concerns are speculative, congestion allocation is sufficiently complex that PGE would prefer to see the application of this approach in an operational market before making a commitment to participate.

Overall, PGE finds that the EDAM approach of allocating congestion revenue to the Balancing Authority for sub allocation to transmission customers, including load, to be an equitable approach that protects load and compensates generation. PGE has seven years of experience with this allocation methodology through the WEIM and finds that it has produced consistent, equitable allocation of congestion revenue.

[17] The Brattle Study was completed before the congestion revenue allocation was approved by the MIP.

4.4 Participation Priority 4: Market Implementation

While the first three participation priorities review the benefits of market participation, the Market Implementation priority enables PGE to evaluate the costs and risks to integrate into either market option in a timely, efficient, and obtainable manner. The market also needs to be interoperable with PGE's other commitments, including PGE's participation in the WRAP. Lastly, implementation costs cannot outweigh the forecasted benefits.

As the WEIM builds on existing systems and capability, the cost to join the EDAM is incremental. As noted above, PGE estimates that the payment to CAISO for implementation will range from $0.6-1.2 million. PGE will be able to operate in the WEIM until the cutover to the EDAM, preserving existing benefits. Preliminary analysis indicates that EDAM implementation will primarily impact PGE's power operations, market settlement, risk management, and transmission pre-schedule process. Leveraging the current systems integration and modeling with the CAISO will allow for a more efficient implementation that will minimize costs for PGE customers.

Markets+ is a unique market that was designed specifically to address western market design priorities. Migrating from the WEIM to the new Markets+ platform will require PGE to essentially re-implement the real-time market as well as add the day-ahead functionality. Migrating to Markets+ will incur the following costs:

- Funding Markets+ development is estimated at $130 million +/-$32.5 million. Assuming that PGE is approximately 5% of the share, PGE's estimated payment to the SPP for market development and implementation is $4.9-8.1 million.
- Transitioning from the CAISO Reliability Coordinator to the SPP Reliability Coordinator.
- Discontinue WEIM participation during Markets+ parallel operations for 60-120 days, losing WEIM revenue and increasing operational costs.
- Transfer existing network model from the CAISO to the SPP.
- PGE staff training to adopt new terminology, processes, and resource models.
- Maintain CAISO settlement system for three years after cutover to comply with the CAISO and PGE tariffs (operate two settlement systems in parallel).
- Software integration with the SPP systems.

Migration to the Markets+ model would require a duplication of both people and process. Due to PGE's participation in the WEIM, a transition to the EDAM is more timely, efficient, and obtainable from a personnel and systems execution standpoint.

4.5 Participation Priority 5: Decarbonization Target Alignment

Access to robust regional energy markets is a core component of PGE's decarbonization strategy; the market PGE joins must be designed to support those efforts.

The EDAM design enhances the operational WEIM GHG framework to accommodate the priced GHG policies of Washington and California. The CAISO is collaborating with stakeholders on additional GHG enhancements, including PGE's top two GHG concerns: 1) more detailed GHG emissions data for WEIM and EDAM imports, and 2) addressing the attribution of clean power to market participants in states where there is no GHG emissions price (e.g., Oregon). The CAISO has addressed the working group's request for more detailed data reflecting the WEIM footprint's emissions rate while continuing to evaluate the stakeholder process solutions.

The Markets+ GHG task force has developed a framework for Washington's cap and trade program to be included in the Markets+ tariff filing. Similar to the CAISO, Markets+ is utilizing a stakeholder-driven process to evaluate GHG policy options for states with capped GHG compliance programs, including Oregon, New Mexico, and Colorado. Markets+ intends to continue the GHG task force to lead discussions in Phase Two.

Oregon Department of Environmental Quality ("DEQ") and Public Utility Commission of Oregon Staff participate in both the CAISO and Markets+ stakeholder GHG processes. Overall, both market operators are seeking solutions for non-GHG capped states.

4.6 Participation Priority 6: Market Governance

Equitable and transparent market governance is critical to establish trust in the market solution. Market governance must appropriately balance the interests of all market participants and support the stability of the market design.

Under the EDAM, the EDAM Governing Body will have joint authority with the CAISO Board of Governors on tariff changes that apply to the EDAM and WEIM markets. As a member of the Governance Review Committee, PGE finds that this approach provides an appropriate balance between the EDAM Governing Body and the CAISO Board. While this balance is appropriate from PGE's perspective, PGE recognizes that additional autonomy for the EDAM Governing Body is a precondition for many Western market participants.

Since the CAISO Board of Governors is appointed by the Governor of California and confirmed by the California State Senate, there are ongoing concerns with market expansion that goes beyond the EDAM design. To address these concerns, Western regulators have launched the Pathways Initiative to address barriers to additional market integration. As co-chair of the Pathways Initiative, PGE sees a clear path to achieving the primary authority governing model that is preferred by other market participants. There is diverse support from both California and Western stakeholders for solutions that provide fully independent governance over the market function. While PGE finds that joint authority is an equitable and appropriate model for the EDAM market, full independence is a necessary precondition for any incremental market services beyond energy market optimization.

With regards to the role of the stakeholder, the CAISO's EDAM has an open, stakeholder-driven workshop process followed by a staff-facilitated policy development process. PGE finds that this is an open and transparent opportunity to enable all stakeholders to have a voice in the market evolution. This open stakeholder process enables a diverse array of stakeholders, including consumer advocates and non-governmental organizations, to have an active role in shaping the market elements that matter to their respective organizations, providing an open forum to discuss all stakeholder concerns in the same venue.

For Markets+, the SPP Board of Directors has similarly delegated authority to the MIP. The primary difference between the EDAM and Markets+ delegation of authority is that the SPP Board of Directors is elected by SPP market services members, not the Governor of a single state, ensuring the SPP governance process is fully independent from any single-market participant or state. While this is a critically important distinction for many market participants, PGE remains concerned about the complete severance between the Markets+ footprint and the SPP Regional Transmission Organization ("RTO") footprint. Without co-optimization, the two markets will not have a shared interest. PGE sees an absence of a shared interest across all governing boards as a potential source of conflict when allocating staffing resources.

The Markets+ tariff changes are stakeholder driven. The MPEC is responsible, through its designated working groups, for developing and recommending policies and procedures related to the technical operations of Markets+. If PGE were to join Markets+, PGE would have approximately 5% of the IOU sector vote in the MPEC. There is concern about PGE's ability to have Oregon issues (e.g., a GHG cap) addressed in a footprint that requires a majority vote to undertake a stakeholder initiative. This could leave PGE without an opportunity to integrate new state policy priorities into the market design.

Additionally, PGE finds that the MPEC approach to voting rights creates an approach where some key stakeholder voices may be excluded. For example, non-governmental organizations may not pay the fees or complete the waiver to participate directly, instead choosing to resolve in other forums. Additionally, market participants may extend their influence into other sectors through participation in multiple trade associations.

PGE finds both the EDAM and Markets+ governance frameworks to be neutral in the Company's analysis.

5 Other Studies on Western Regionalization

In addition to evaluating the various published Brattle Study results,[18, 19] PGE also considered the results of the Energy Strategies' State-Led Market Study and E3's WMEG study.

Energy Strategies' State-Led Market Study (2021) was funded by a grant from the US Department of Energy. The study was led by state regulators to focus on state-level and regional benefits of various market configurations in 2020 and 2030 periods. Figure 3, below, shows the various footprints evaluated in the study. The results indicate that a single day-ahead market with California generates $24 million more in benefit than a day-ahead market footprint without California.[20]

The WMEG operated from 2022-2023 to further explore the implications of various western organized markets. E3 was retained to study the potential change in variable production cost over a variety of footprints and market functionality cases in the 2023, 2030, and 2035 periods. WMEG members had individual results and were given discretion to share publicly. The WMEG production cost study is provided as Appendix B. PGE's results show the greatest benefit when participating in the EDAM footprint.[21] In addition, although PGE did not fund alternative scenarios, BPA shared its results publicly and found their largest benefits with an EDAM footprint that includes BPA, IPC, PAC, and PGE.[22]

The results from the State-Led Market Study and the WMEG both support PGE's decision to participate in a day-ahead market footprint that includes California as it provides the greatest potential benefit to PGE's customers.

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[18] Bennet, Evan, Hannes Pfeifenberger, and John Tsoukalis. "Brattle EDAM Simulations: PacifiCorp Results." The Brattle Group. April 2023. brattle.com/wp-content/uploads/2023/04/Brattle-EDAM-Simulations-PacifiCorp-Results.pdf

[19] NVE published their results, indicating a significantly higher benefit for EDAM over Markets+. NEVP OASIS. "Western Market Development." OATI webSmartOASIS. 2024. oasis.oati.com/NEVP/

[20] Energy Strategies. The State-Led Market Study. Energy Strategies. 30 July 2021. static1.squarespace.com/static/59b97b188fd4d2645224448b/t/6148a012aa210300cbc4b863/1632149526416/Final+Roadmap+-+Technical+Report+210730.pdf

[21] *See* PGE's OASIS website for PGE's WMEG Results, tab "Cost Benefit (2026)".

[22] Hayes, Matt, Libby Kirby, Russ Mantifel, and Andy Meyers. "E3 WMEG Benefits Study." Bonneville Power Administration Day-Ahead Market Workshop. 23 October 2023. Portland, Oregon. bpa.gov/learn-and-participate/projects/day-ahead-market.

6 Conclusion & Next Steps

Based on the results of the comparative analysis, PGE's energy market choice is the CAISO's EDAM based on the following key findings:

- PGE expects to see a customer benefit of $6.1-17.5 million in the EDAM compared to $8.3-8.7 million in Markets+. These benefits derive from direct connectivity to California's solar resources and broad footprint diversity.
- PGE estimated payments to the market operator for start-up costs demonstrates lower EDAM costs of $0.6-1.2 million compared with $4.9-8.1 million for Markets+.
- Over 50% of the load in the Western Interconnection has committed to the EDAM; therefore, the EDAM has sufficient load, generation, and transmission to realize expected market and reliability benefits.
- The EDAM congestion revenue allocation at the Balancing Authority-level with sub-allocation to transmission customers will provide an appropriate hedge for load against congestion cost.
- Since PGE already participates in the WEIM, adding the EDAM incrementally builds on PGE's existing systems and connectivity to the CAISO.
- The joint authority governance model of the CAISO strikes a fair balance between California and Western interests regarding energy markets.

Overall, PGE finds the expected benefits, ease of entry, and alignment with PGE's strategy to indicate that the EDAM is the better choice before PGE. Therefore, PGE is committing to the CAISO's EDAM as its day-ahead market option. PGE will work with the Public Utility Commission of Oregon on next steps for evolving PGE's wholesale regulatory framework to enable EDAM participation. PGE will continue to monitor western market developments and may reevaluate market opportunities once both markets are operational and mature.

7 Appendix

Appendix A: Brattle Market Participation Sensitivity Results for PGE

Portland General Electric Day-Ahead Market Benefits Studies

COMPARATIVE BENEFITS FOR PGE OF JOINING EDAM VS MARKETS+

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MARCH 2024

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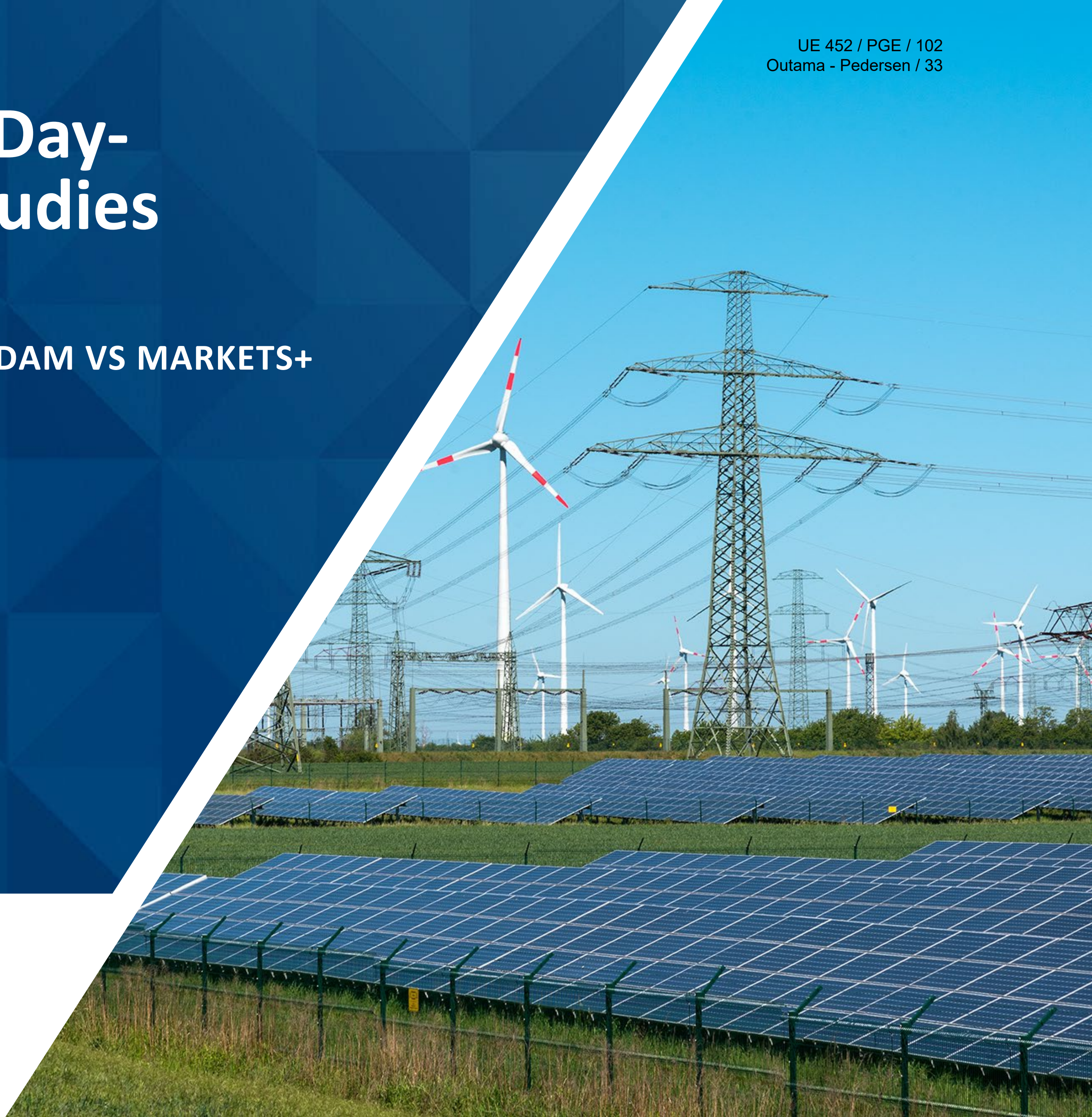


PGE Day-Ahead Market Participation Benefits Summary

PGE's benefits from joining EDAM or Markets+ markets are primarily driven by:

- Production cost savings
  - PGE replaces internal gas generation with lower cost market purchases across cases, especially during high solar periods
  - Production cost savings tend to be higher in M+ vs EDAM, with lower sales attenuating these savings in EDAM
- Market trading revenues
  - Increased net trading revenue when PGE joins EDAM
  - Decreased net trading revenue when PGE joins Markets+ principally due to lower RT trading revenues in M+ vs WEIM

Portland General Electric System Cost by Case ($ Millions)

		BAU	WEIM Transition	Bookend EDAM	EDAM Split	Markets+ Split	Bookend Markets+
Market Membership	**Metric**	**EIM Only**	**EDAM**	**EDAM**	**EDAM**	**Markets+**	**Markets+**
Adjusted Production Cost	Cost	$332.3	$327.0	$328.7	$340.0	$319.1	$318.4
Wheeling Revenues	Revenue	$1.7	$0.1	$0.0	$0.1	$0.3	$0.3
Trading Revenues:							
Bilateral	Revenue	$2.41	$5.33	$0.79	$4.49	$3.45	$3.30
WEIM	Revenue	$15.71	$8.57	$11.31	$5.41	-	-
Mkt+ RT/WEIS	Revenue	-	-	-	-	$4.34	$4.12
EDAM	Revenue	-	$11.06	$21.66	$23.55	-	-
Markets	Revenue	-	-	-	-	$7.16	$6.48
Total System Cost		**$312.5**	**$301.9**	**$295.0**	**$306.4**	**$303.8**	**$304.1**
Benefit to BAU			**$10.6**	**$17.5**	**$6.1**	**$8.7**	**$8.3**

WECC-Wide Benefits Summary

The implementation of M+ and/or EDAM produces significant WECC-wide customer benefits, with **benefits ranging from $639-$1,051 million per year** across the scenarios considered

- A single market covering most of the WECC (bookend EDAM in this case) produces the highest benefits
- Two-market EDAM/M+ scenarios produce ~$110-120 million/year fewer benefits than the single market
- WEIM transition, with a limited EDAM footprint and no Markets+, produces the lowest benefits

WECC-Wide Benefits ($ Millions)

	BAU	WEIM Transition	Bookend EDAM	EDAM Split	Markets+ Split	Bookend Markets+
WECC-Wide						
Adjusted Production Cost	$10,313	$9,704	$9,010	$9,894	$9,956	$9,919
Wheeling Revenue	$447	$374	$129	$372	$481	$425
Trading Revenues:						
Bilateral	$1,294	$856	$483	$485	$483	$344
WEIM	$330	$307	$260	$233	$183	$99
WEIS/Mk+ RT Market	$27	$30	$31	$88	$127	$130
EDAM	-	$562	$945	$982	$681	$680
Markets+	-	$0	-	$450	$728	$954
Total System Cost	**$8,214**	**$7,575**	**$7,163**	**$7,284**	**$7,273**	**$7,287**
Benefit Compared to BAU		**$639**	**$1,051**	**$930**	**$941**	**$927**

The Bookend EDAM produces the lowest WECC-wide APC, indicating the most efficient system dispatch

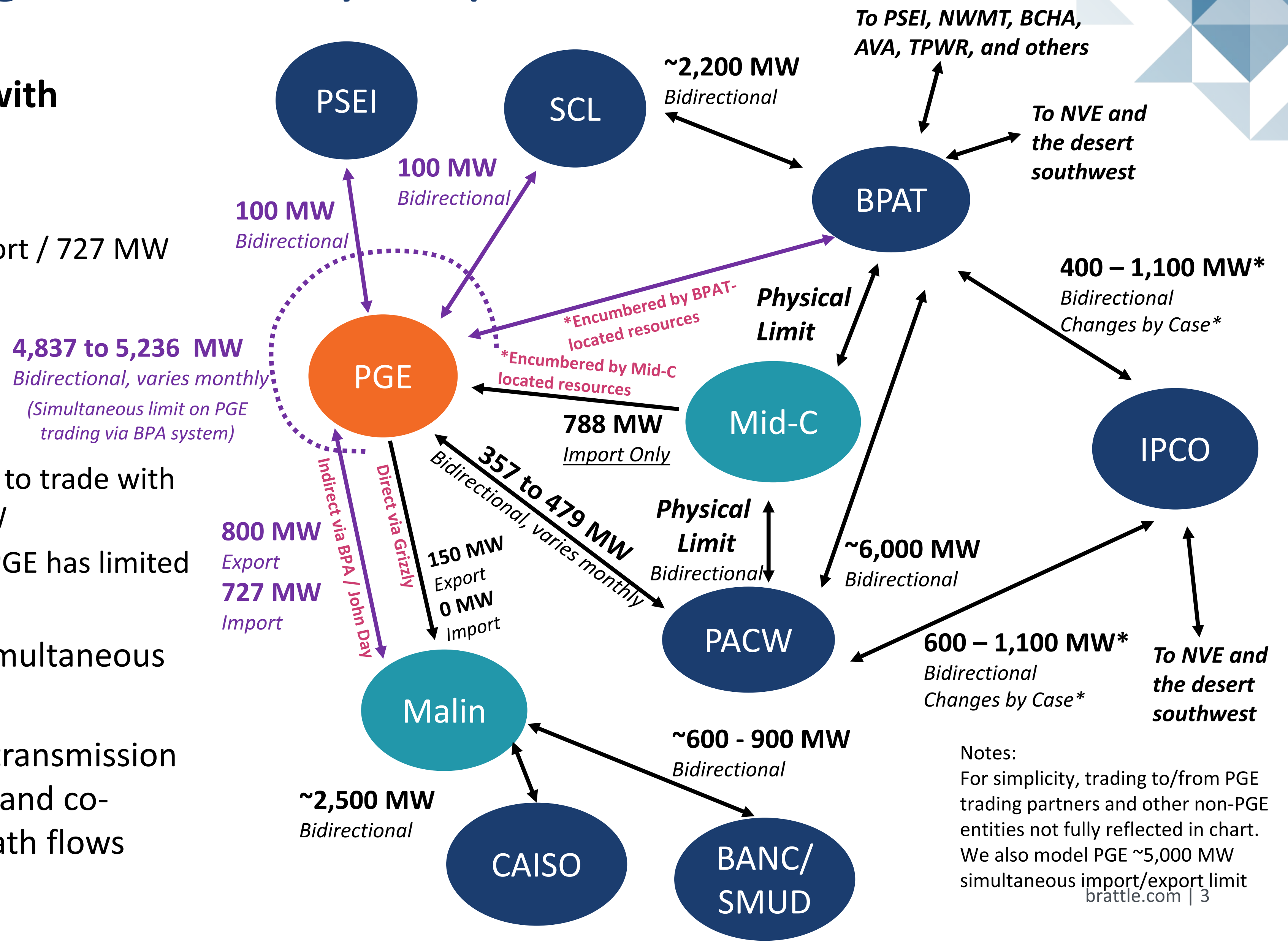
However, wheeling revenues, bilateral trading gains and market congestion may be higher in some split cases

All market participation scenarios show benefits relative to BAU

PGE Modeled Trading Connectivity Map

PGE's biggest trading paths are with California, PAC, and BPA

- **California & PAC**
  - California (via Malin): 950 MW export / 727 MW import to CAISO and BANC/SMUD
  - PAC: ~500 MW PACW
- **BPA & Mid-C**
  - BPA: over 4,800 MW of TTC
  - Mid-C: 788 MW net import for PGE to trade with other PNW entities, including PACW
  - Without IPCO & NVE in Markets+, PGE has limited access to solar in the M+ footprint
- We modeled PGE's ~5,000 MW simultaneous export/import limit
- Our model also includes physical transmission limits, such as WECC-rated paths, and co-optimizes physical and contract path flows



Notes:
For simplicity, trading to/from PGE trading partners and other non-PGE entities not fully reflected in chart. We also model PGE ~5,000 MW simultaneous import/export limit

BAU Case

BAU case assumes the day-ahead market will remain a bilateral market outside of the SPP RTO west, and that current WEIM and WEIS members remain in those markets

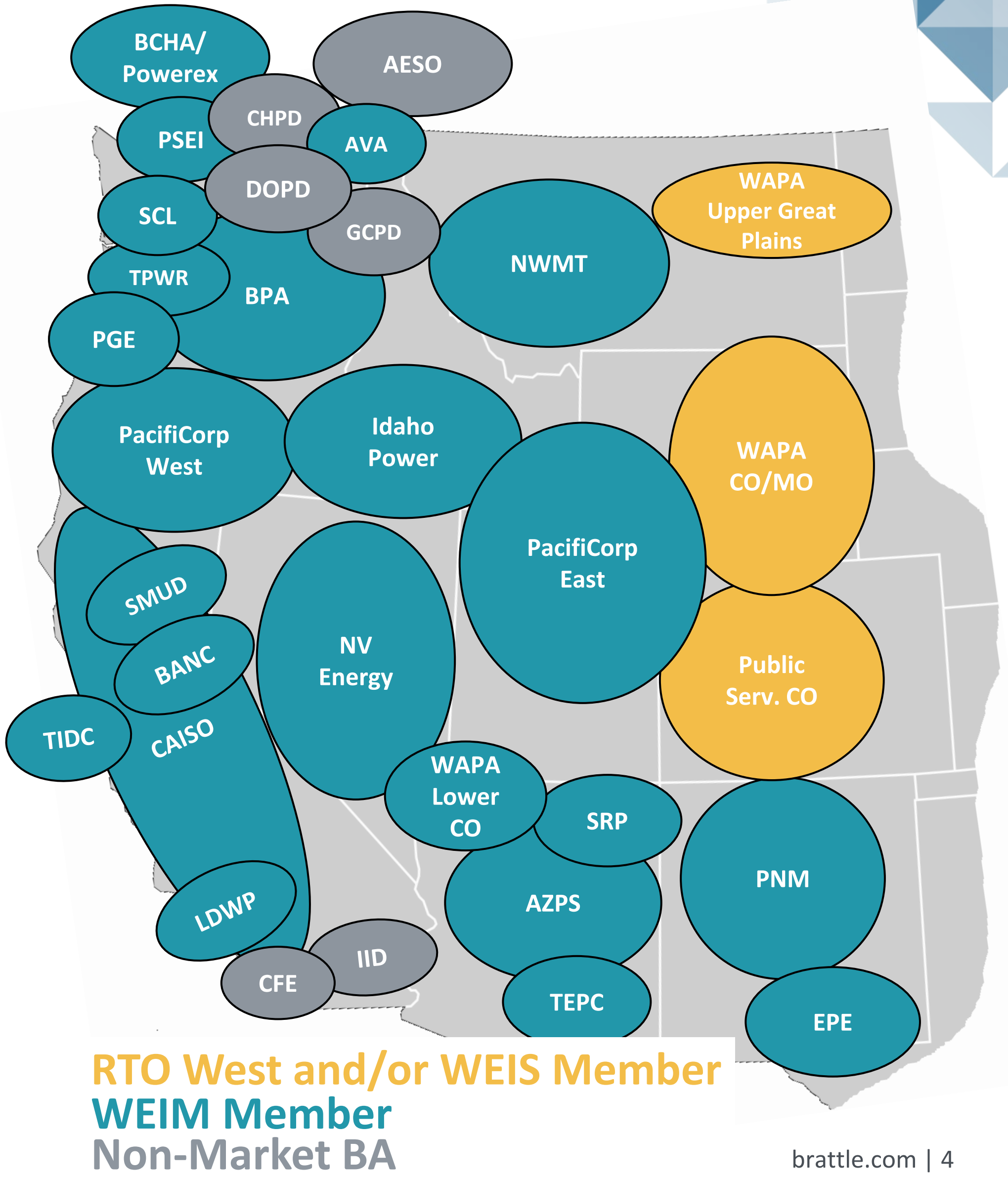
PGE trading dynamics in BAU

- California: PGE imports 3,000 GWh from California, mostly midday solar
  - *PGE also exports 800 GWh to CAISO in WEIM (direct CAISO trades reflect WEIM transfers)*
- Mid-C Trading Hub: PGE imports 3,500 GWh and exports 1,650 GWh
  - *Largest sellers to Mid-C are BCHA and BPAT hydro, largest buyers are BPAT, NWMT, PACW*
- PACW and BPAT: both 1,000 – 2,000 GWh of flows

Portland General Electric Total Trading All Types - GWh

Partner	BAU	
	Exports	Imports
BPAT	714	447
PACW	459	746
PAWA	486	27
SCL	211	22
PSEI	421	275
MidC	1,650	3,417
Malin	827	2,977
Total	**4,769**	**7,912**

BAU Market Footprints



WEIM Transition Case

WEIM Transition case assumes PGE joins EDAM with entities have announced to join EDAM and IPCO, and other entities remain as they are in the BAU case

- Entities that join EDAM assumed to remain in WEIM

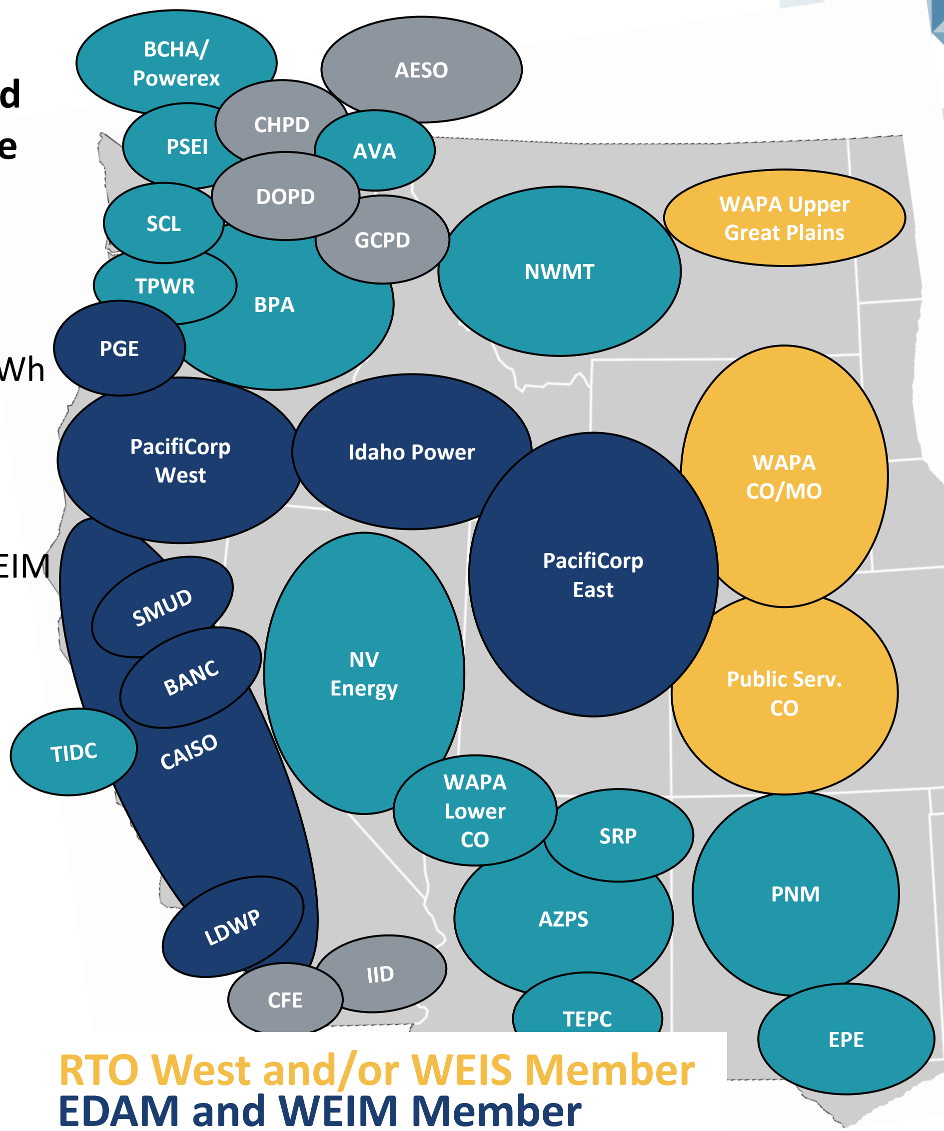
PGE trading & benefits dynamics relative to BAU

- PGE trades increase in EDAM by ~2,100 GWh with California (via Malin) and ~2,300 GWh with PACW and PAWA, and PGE facilitates EDAM market exports via Mid-C
  - *PACW trades through PGE out to BPA and NWMT account for majority of Mid-C trade increase*
- PGE EDAM benefits of $10.6 million/yr driven largely by EDAM transfer revenues and savings from displacing internal generation with market purchases, offset by lower WEIM revenues

Portland General Electric Total Trading (All Types - GWh)

Partner	BAU		WEIM Transition	
	Exports	Imports	Exports	Imports
BPAT	714	447	962	432
PACW	459	746	1,114	1,033
PAWA	486	27	838	1,087
SCL	211	22	133	36
PSEI	421	275	314	345
MidC	1,650	3,417	4,912	7,904
Malin	827	2,977	2,434	3,478
Total	**4,769**	**7,912**	**10,709**	**14,315**

WEIM Transition Market Footprints



RTO West and/or WEIS Member
EDAM and WEIM Member
WEIM-Only Member
Non-Market BA

Bookend EDAM Case

Bookend EDAM case assumes all WECC entities contemplating joining a day-ahead market and not in RTO West or WEIS join EDAM, except for BCHA and TIDC which remain only in WEIM

- Entities that join EDAM assumed to join or remain in WEIM

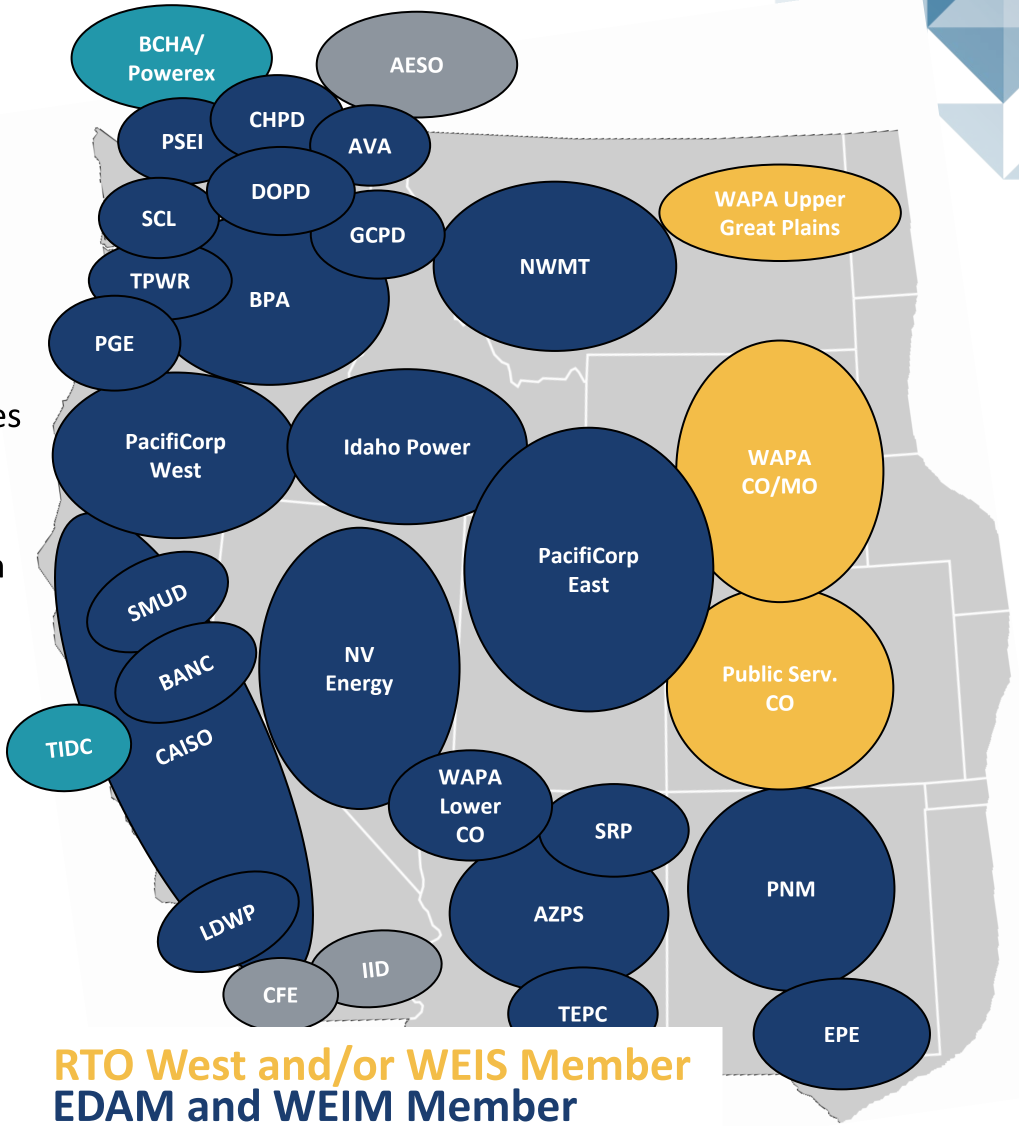
PGE trading & benefits dynamics relative to BAU

- PGE trading picks up in relative to BAU as all partners join EDAM, with biggest increases coming in PNW, esp. BPA, with direct market trades displacing trades through Mid-C
- PGE EDAM benefits of $17.5 million/yr driven largely by EDAM transfer revenues and savings from displacing internal generation with market purchases, offset by decline in WEIM revenues

Portland General Electric Total Trading (All Types - GWh)

Partner	BAU		Bookend EDAM	
	Exports	Imports	Exports	Imports
BPAT	714	447	1,114	3,264
PACW	459	746	527	1,087
PAWA	486	27	1,155	728
SCL	211	22	541	560
PSEI	421	275	755	329
MidC	1,650	3,417	0	588
Malin	827	2,977	1,492	2,642
Total	**4,769**	**7,912**	**5,585**	**9,199**

Bookend EDAM Market Footprints



RTO West and/or WEIS Member
EDAM and WEIM Member
WEIM-Only Member
Non-Market BA

EDAM Split Case

EDAM Split assumes PGE, IPCO, NVE, and SCL join EDAM with the entities that have announced they are joining EDAM, the Phase 1 Funders not in EDAM join Markets+, and other entities remain as they are in the BAU case

- Entities that join EDAM assumed to remain in WEIM
- Entities that join Markets+ assumed to join a Markets+ RT market

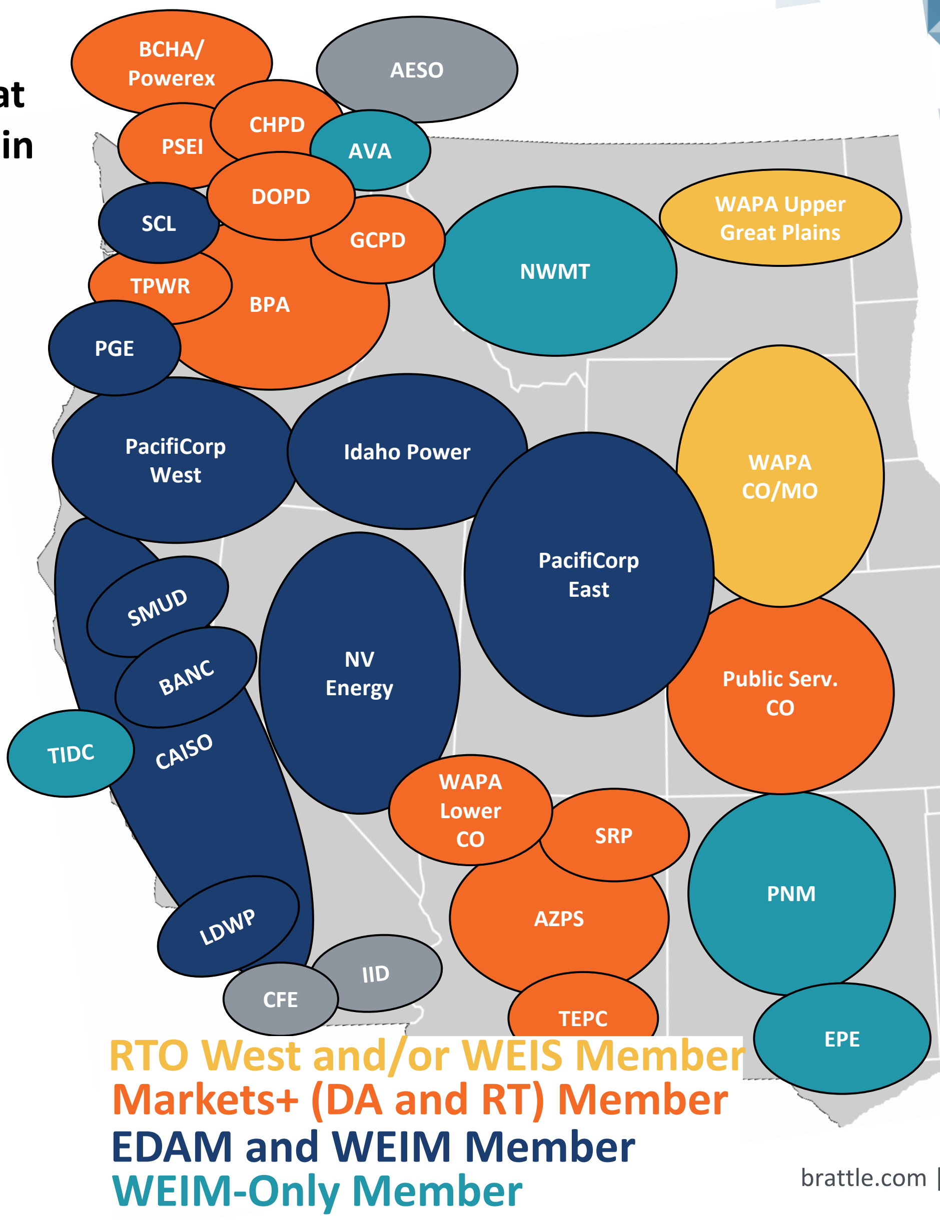
PGE trading & benefits dynamics relative to BAU

- PGE trades increase in EDAM by ~2,900 GWh with PACW/PAWA and 1,500 GWh with California, importing solar midday and exporting hydro and other resources overnight
  - *PGE facilitates trades out of EDAM footprint, accounting for increased volumes at Mid-C*
- PGE EDAM benefits of $6.6 million/yr driven largely by EDAM transfer revenues and offset by lower sales and sales revenues in the market & lower WEIM revenues

Portland General Electric Total Trading (All Types - GWh)

Partner	BAU		EDAM Split	
	Exports	Imports	Exports	Imports
BPAT	714	447	95	520
PACW	459	746	710	2,259
PAWA	486	27	1,321	337
SCL	211	22	235	254
PSEI	421	275	30	14
MidC	1,650	3,417	2,731	6,461
Malin	827	2,977	2,907	2,570
Total	**4,769**	**7,912**	**8,028**	**12,416**

EDAM Split Market Footprints



Markets+ Split Case

Markets+ Split assumes PGE and the Phase 1 Funders plus IPCO join Markets+, and other entities remain as they are in the BAU case

- Entities that join EDAM assumed to remain in WEIM
- Entities that join Markets+ assumed to join or shift to a Markets+ RT market

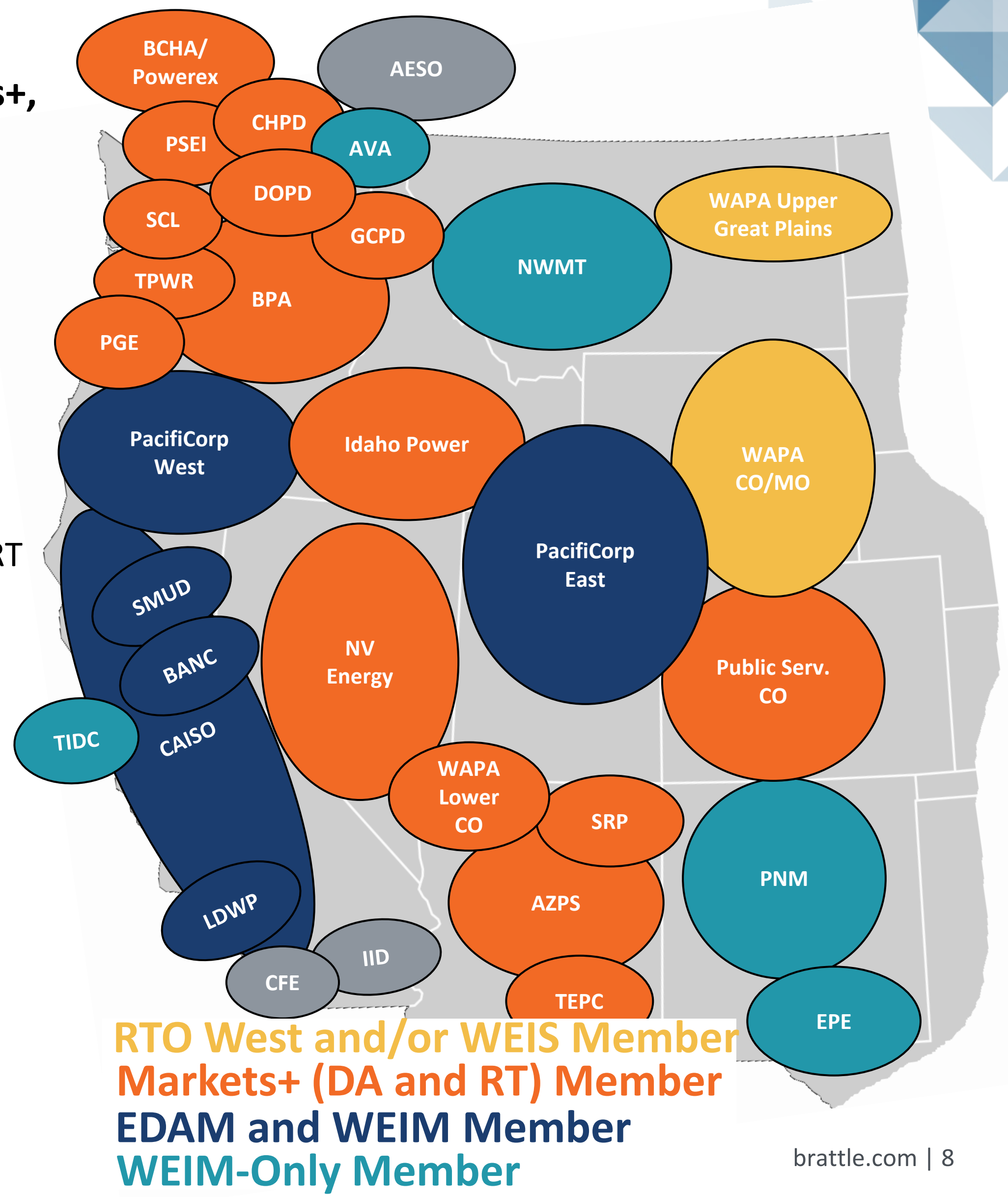
PGE trading & benefits dynamics relative to BAU

- PGE trading increases in Markets+ especially with BPAT (~6,900 GWh) displacing bilateral & WEIM trades with CAISO and PACW/PAWA
- PGE M+ benefits of $8.7 million/yr driven largely by savings from displacing internal generation with market purchases & M+ transfer revenues, offset by loss of ~75% of RT revenue from shifting out of the WEIM into Markets+ RT

Portland General Electric Total Trading (All Types - GWh)

Partner	BAU		Markets+ Split	
	Exports	Imports	Exports	Imports
BPAT	714	447	3,604	4,464
PACW	459	746	335	158
PAWA	486	27	0	24
SCL	211	22	15	118
PSEI	421	275	235	206
MidC	1,650	3,417	1,508	3,446
Malin	827	2,977	0	1,131
Total	**4,769**	**7,912**	**5,698**	**9,546**

Markets+ Split Market Footprints



Bookend Markets+ Case

Bookend Markets+ assumes the entities that have announced they are joining EDAM go to EDAM, PGE goes to Markets+ with most of the remaining WECC BAs, and other entities remain as they are in the BAU case

- Entities that join EDAM assumed to remain in WEIM
- Entities that join Markets+ assumed to join or shift to a Markets+ RT market

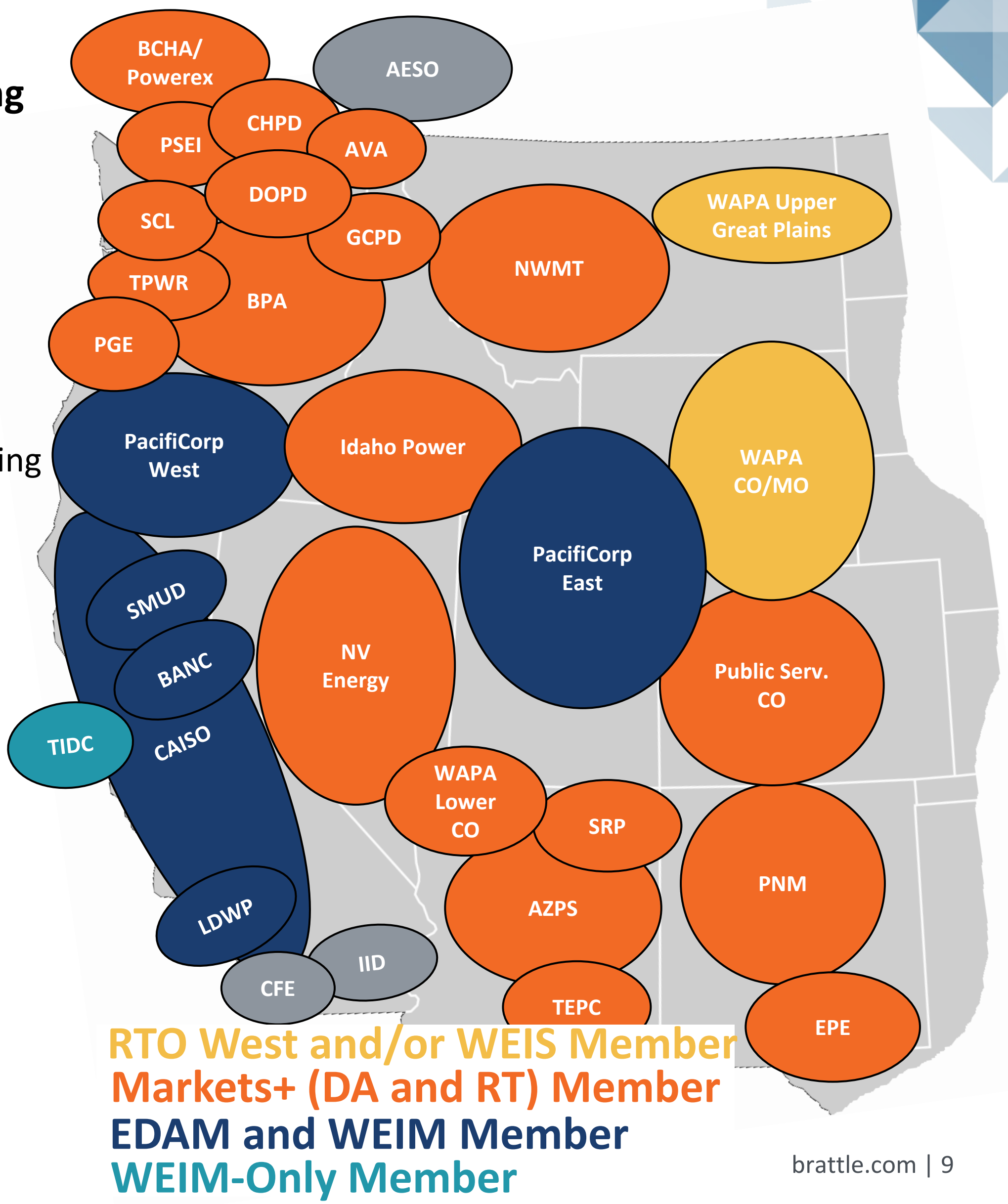
PGE trading & benefits dynamics relative to BAU

- PGE trading increases in Markets+ especially with BPAT (~5,400 GWh increase) displacing bilateral & WEIM trades with CAISO and PACW/PAWA
- PGE M+ benefits of $8.3 million/yr driven largely by savings from displacing internal generation with market purchases, increased sales revenue, & M+ transfer revenue, offset by loss of ~75% of RT revenue from shifting out of the WEIM into Markets+ RT

Portland General Electric Total Trading (All Types - GWh)

Partner	BAU		Bookend Markets+	
	Exports	Imports	Exports	Imports
BPAT	714	447	3,241	3,294
PACW	459	746	329	220
PAWA	486	27	0	34
SCL	211	22	16	158
PSEI	421	275	180	223
MidC	1,650	3,417	1,061	3,350
Malin	827	2,977	0	1,194
Total	**4,769**	**7,912**	**4,827**	**8,474**

Bookend Markets+ Market Footprints



PGE Trading Volumes Summary

PGE trading volumes similar in Bookend Cases, but tend to be higher in EDAM in other cases

- Markets+ trading volumes highest with BPA, with which PGE has the most trading capability in that market
- PGE's largest trading partners in EDAM tend to be PAC and CAISO / BANC via Malin
  - When EDAM footprint is limited, PGE facilitates trades out of the market footprint via Mid-C
  - When footprint is broad (e.g., EDAM Bookend), PGE trades favor direct paths with neighbors in the market, rather than trades through Mid-C

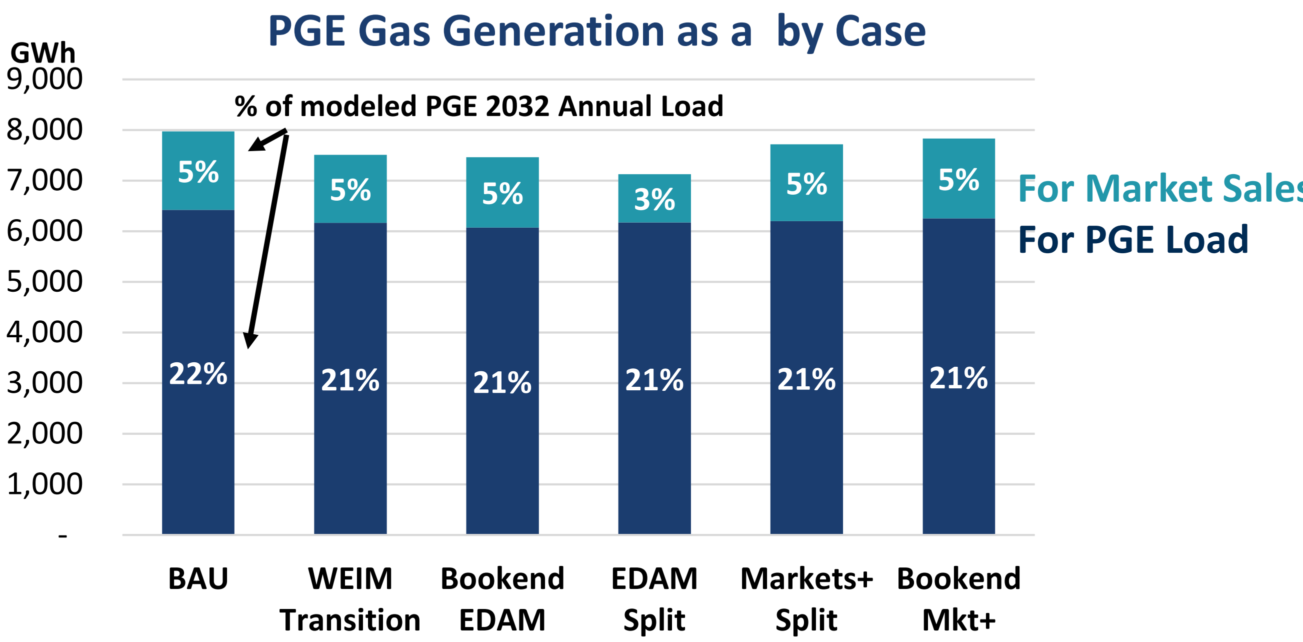
Portland General Electric Total Trading (All Types - GWh)

Partner	BAU		WEIM Transition		Bookend EDAM		EDAM Split		Markets+ Split		Bookend Markets+	
	Exports	Imports	Exports	Imports	Exports	Imports	Exports	Imports	Exports	Imports	Exports	Imports
BPAT	714	447	962	432	1,114	3,264	95	520	3,604	4,464	3,241	3,294
PACW	459	746	1,114	1,033	527	1,087	710	2,259	335	158	329	220
PAWA	486	27	838	1,087	1,155	728	1,321	337	0	24	0	34
SCL	211	22	133	36	541	560	235	254	15	118	16	158
PSEI	421	275	314	345	755	329	30	14	235	206	180	223
MidC	1,650	3,417	4,912	7,904	0	588	2,731	6,461	1,508	3,446	1,061	3,350
Malin	827	2,977	2,434	3,478	1,492	2,642	2,907	2,570	0	1,131	0	1,194
Total	**4,769**	**7,912**	**10,709**	**14,315**	**5,585**	**9,199**	**8,028**	**12,416**	**5,698**	**9,546**	**4,827**	**8,474**

PGE Gas Generation Impacts

PGE's gas fleet annual generation relatively consistent across scenarios

- We modeled PGE's unit costs and fuel limitations, but not direct generation or emissions limits
- PGE gas generation attributable to PGE load exceeds ~20% of load in all cases, though by a small margin
- Market sales of gas generation tend to be more valuable in Markets+, which has a more thermal-heavy footprint-wide supply mix



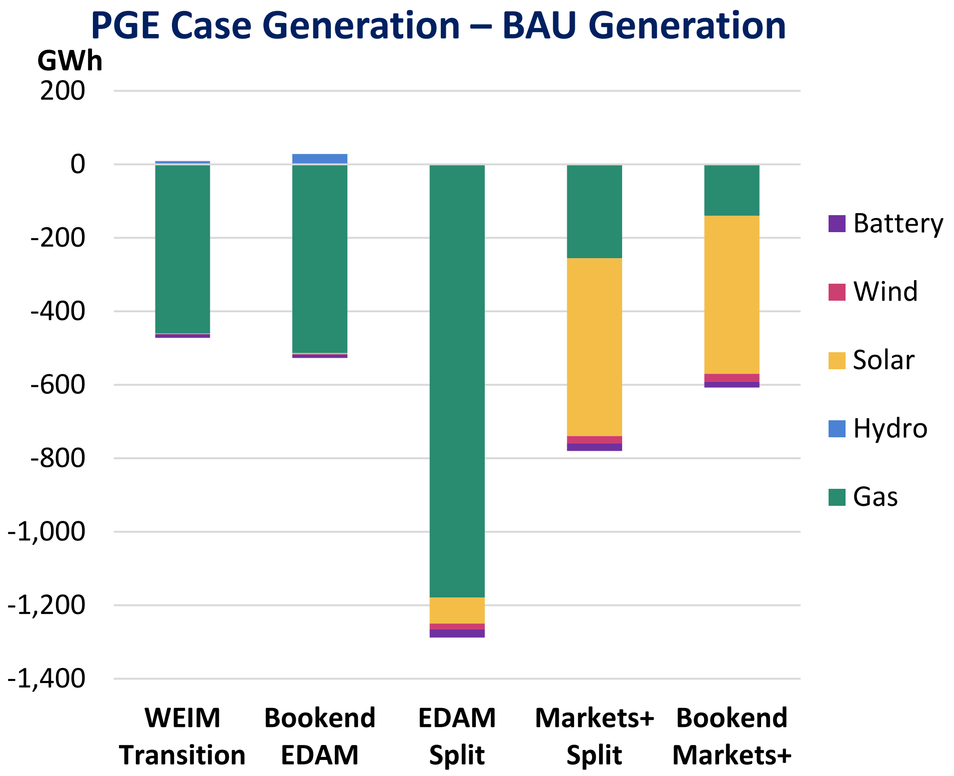
PGE Generation Mix Impacts

EDAM cases show largest reduction in gas generation

- Access to markets allows PGE to reduce gas generation and purchase cheaper largely renewable power from the market
- Gas generation ramps down more in EDAM than Markets+ cases as due to the greater surplus of midday solar in the footprint

Markets+ cases show largest solar curtailment

- Markets+ produces solar curtailments in PGE's footprint due to limited connectivity in the Markets+ footprint, especially between the PNW and Southwest
  - As Markets+ footprint grows solar curtailments in PGE decline but exceed the renewable curtailments for the cases in which PGE is in EDAM
    - 501 GWh solar curtailment in Markets+ Split
    - 447 GWh solar curtailment in the Markets+ Bookend case



Additional Results

Hurdle Rate Assumptions

Hurdle rates vary by trade type, decision timeframe, and whether trade involves GHG transfers

- Hourly bilateral trading friction $6 in the dispatch cycle, $16 in unit commitment cycle
  - $10/MWh adder in commitment vs dispatch prevents over-optimization of commitment
- Block trading at hubs and intertie transactions charged lower trading friction due to greater ease of execution for such trades vs hourly bilateral trades
- Bilateral or intertie trades into GHG regions charge unspecified resources rate of ~$28/MWh
- Within the EDAM, EIM, and Markets+ (DA and RT) footprints, trades into GHG region charged resource-type-specific GHG charges

Cost of Transactions by Type ($/MWh)

Trade Type		Decision Timeframe	Trading Friction	GHG Pricing	OATT Charge	Total Charge
Block Trades	With ETC Rights	Day-Ahead	$1.50	Generic Import Cost **$28/MWh** *(Based on CA Rule)*	$0	$1.5 + *GHG*
	With<u>out</u> ETC Rights	Day-Ahead	$1.50		$1.03	$2.53 + *GHG*
Hourly BA-BA Trades	With ETC Rights	Day-Ahead	$16 Commitment, $6 Day-Ahead		$0	$6 - $16 + *GHG*
	With<u>out</u> ETC Rights	Day-Ahead	$16 Commitment, $6 Day-Ahead		$1.03	$7.03 - $17.03 + *GHG*
CAISO Intertie Trade	With ETC Rights	Day-Ahead	$1.50		$0	$1.5 + *GHG*
	With<u>out</u> ETC Rights	Day-Ahead	$1.50		$1.03	$2.53 + *GHG*
EDAM	EDAM Trades	Day-Ahead	$0.00	Resource-Type Specific Cost	$0	$0 + *GHG*
Markets+	Markets+ Trades	Day-Ahead	$0.00		$0	$0 + *GHG*
EIM Market	EIM Trades	Real-Time	$0.00		$0	$0 + *GHG*
WEIS Market	WEIS Trades	Real-Time	$0.00		$0	$0 + *GHG*

Notes: "Commitment" refers to the stage of the model that makes unit commitment decisions right before running day-ahead dispatch results.

Transmission Utilization Rates

PGE's trading path utilization tends to be higher in EDAM

- PGE imports from PACW and Malin are generally highest in the EDAM Split, in which the EDAM footprint is more limited
  - While Malin>PGE utilization is 55% in this case, but with flow almost entirely midday
  - Spring utilization midday averages 70-90%
- Even with BPAT>PGE TTCs encumbered by BPA-located PGE generation coming home, significant trading headroom remains available on the path

Average Path TTC Utilization for PGE

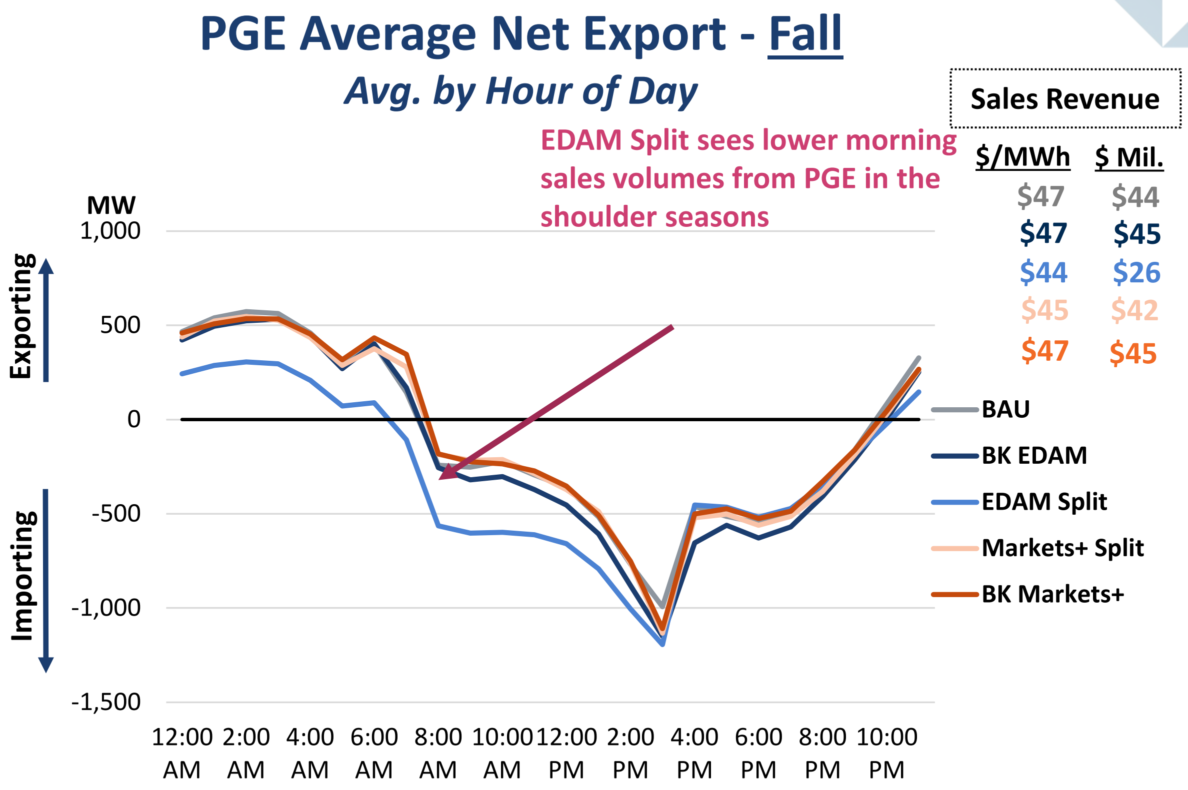
		BAU	WEIM Transition	Bookend EDAM	EDAM Split	Markets+ Split	Bookend Markets+
Export Paths							
PGE	PACW	12%	32%	30%	48%	8%	8%
PGE	BPAT	2%	6%	4%	5%	7%	6%
PGE	PSEI	48%	36%	86%	3%	27%	21%
PGE	SCL	67%	62%	78%	75%	71%	70%
PGE	Malin	10%	31%	19%	37%	0%	0%
Import Paths							
PACW	PGE	4%	42%	31%	62%	5%	7%
BPAT	PGE	53%	50%	57%	50%	57%	55%
PSEI	PGE	31%	39%	37%	2%	24%	37%
SCL	PGE	44%	61%	57%	72%	63%	62%
MidC	PGE	29%	43%	8%	54%	24%	30%
Malin	PGE	54%	63%	48%	47%	21%	22%

Notes:
1: BPAT imports to PGE includes PGE owned generation in BPAT's territory that encumbers TTC.
2: Malin to PGE and vice-versa includes the CAISO EIM transfers.

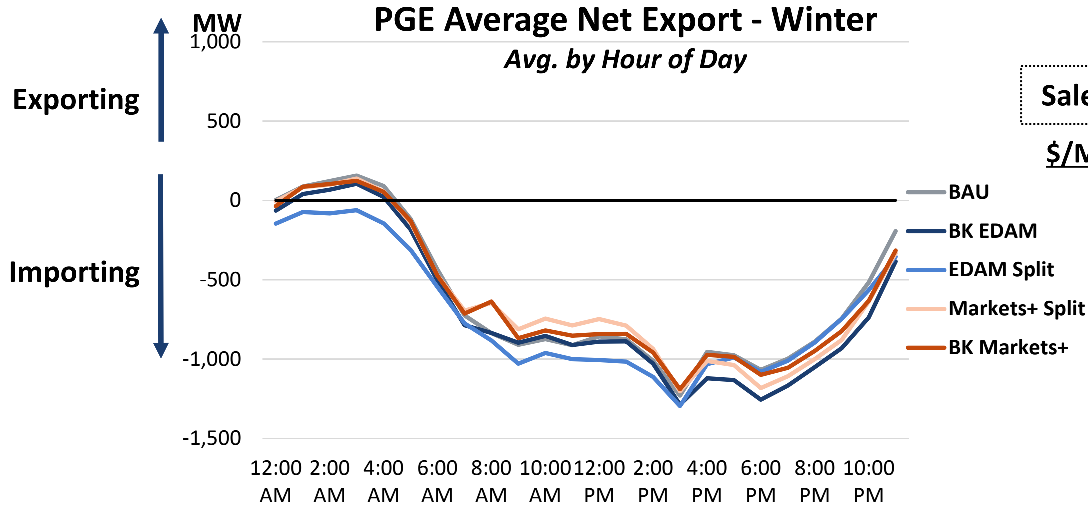
PGE Net Exports and Sales Revenue (Fall Example)

PGE consistently selling at night, seeking opportunities to displace less efficient gas generation in the market footprints

- EDAM Split seeing lowest PGE sales contributing to the reduced PGE adjusted production cost benefit in that case
  - These reduced sales comes mainly in Aug-Oct and Feb-March, periods in which the more limited EDAM footprint in this case has higher supply of renewables / hydro, and thus lower need for gas generation
  - For example, the Markets+ Split footprint in September is 36% gas and coal generation, whereas the EDAM Split footprint is just 10% gas and coal

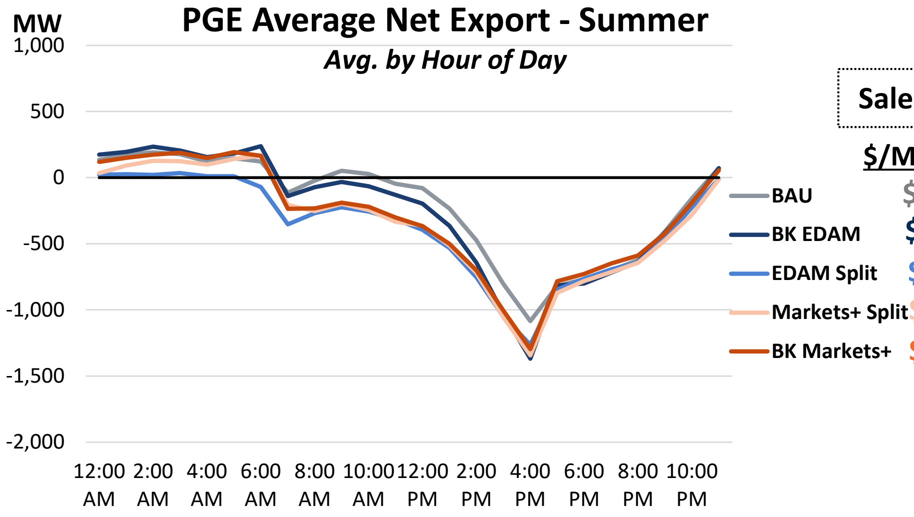


PGE Net Exports and Sales Revenue (All Seasons)



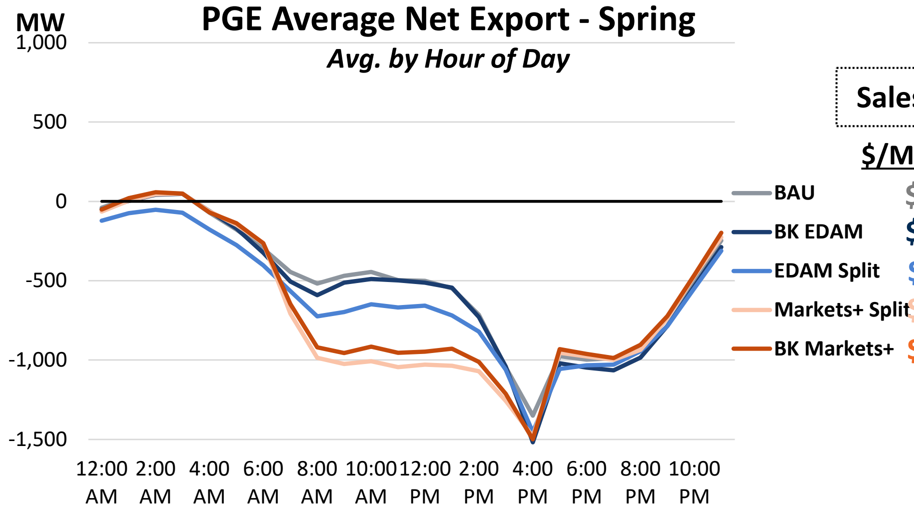
Sales Revenue

	$/MWh	$ Mil.
BAU	$48	$27
BK EDAM	$46	$28
EDAM Split	$45	$19
Markets+ Split	$47	$29
BK Markets+	$48	$29



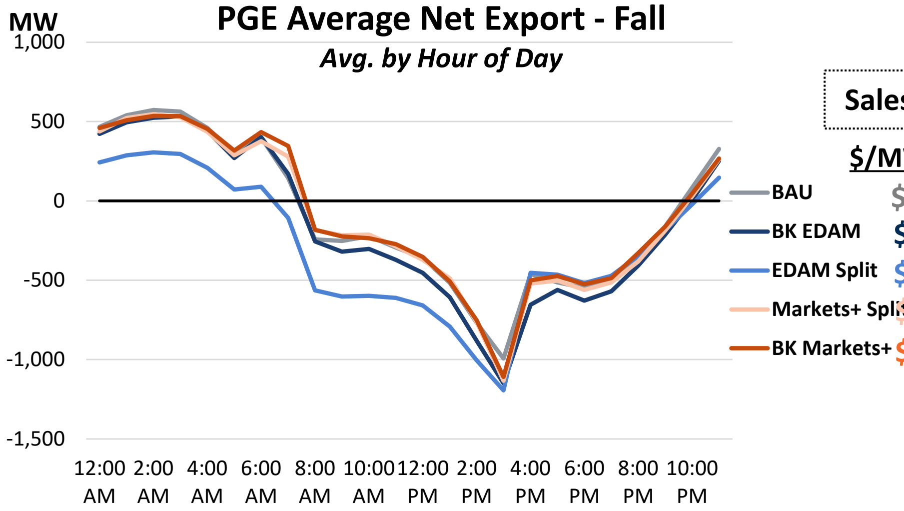
Sales Revenue

	$/MWh	$ Mil.
BAU	$35	$31
BK EDAM	$35	$30
EDAM Split	$31	$20
Markets+ Split	$36	$29
BK Markets+	$36	$30



Sales Revenue

	$/MWh	$ Mil.
BAU	$7	$5
BK EDAM	$3	$2
EDAM Split	$4	$2
Markets+ Split	$11	$7
BK Markets+	$12	$8



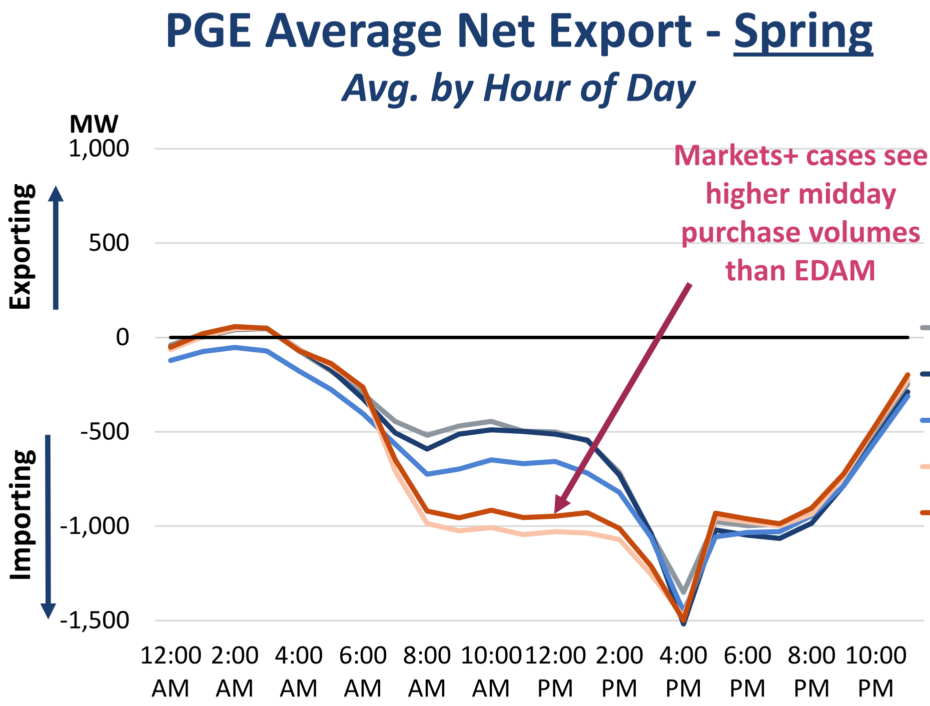
Sales Revenue

	$/MWh	$ Mil.
BAU	$47	$44
BK EDAM	$47	$45
EDAM Split	$44	$26
Markets+ Split	$45	$42
BK Markets+	$47	$45

PGE Net Exports and Purchase Costs (Spring Example)

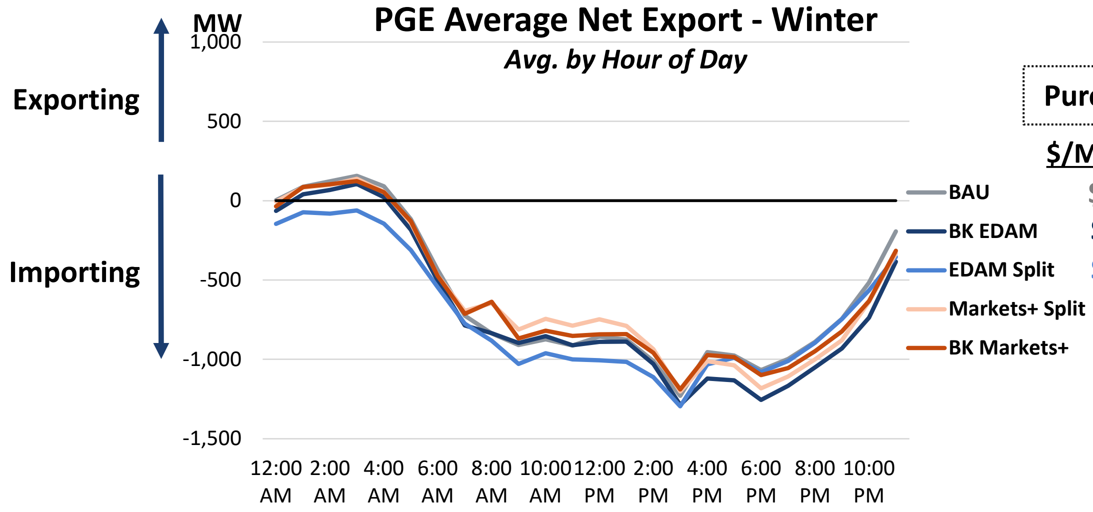
PGE consistently buys during the day and evening

- Markets+ generation mix in the spring is about as clean as EDAM's at about 90-92% zero-cost generation
  - This is because of strong hydro generation and Nevada/AZPS being large solar producers
  - PGE's high TTC with BPAT allows it in Markets+ to buy excess hydro and solar over the amount it can buy in EDAM
- In EDAM Split, PGE's imports from CAISO and PAC are somewhat transfer limited
  - TTC from Malin has an average utilization of 70-90% during solar hours, and its import path from PACW an average utilization 60-70%



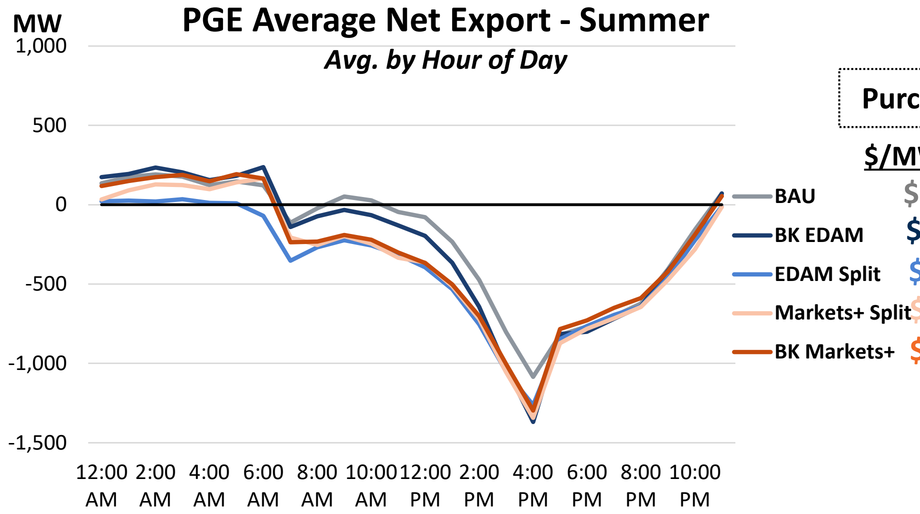
Purchase Cost	
$/MWh	$ Mil.
$-3	$-5
$-3	$-5
$-3	$-5
$-7	$-15
$-6	$-11

PGE Net Exports and Purchase Costs (All Seasons)



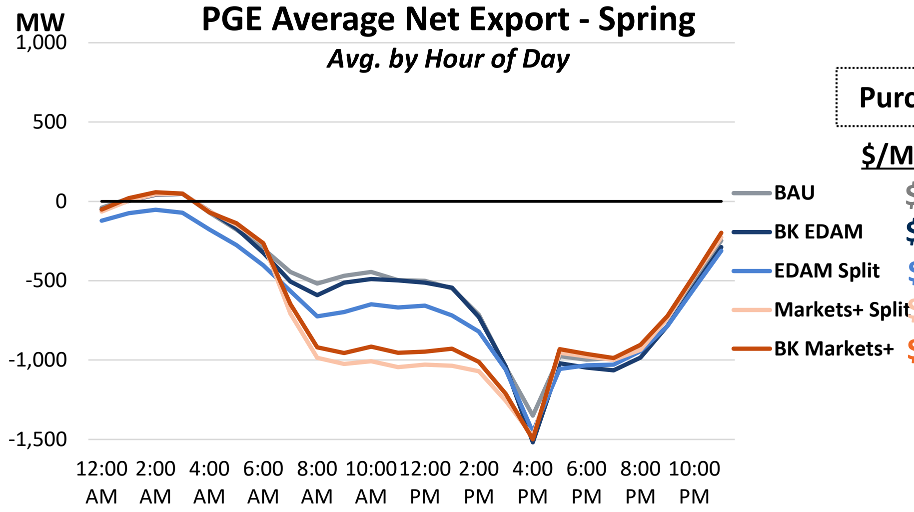
Purchase Cost

	$/MWh	$ Mil.
BAU	$55	$103
BK EDAM	$52	$110
EDAM Split	$55	$108
Markets+ Split	$54	$106
BK Markets+	$55	$107



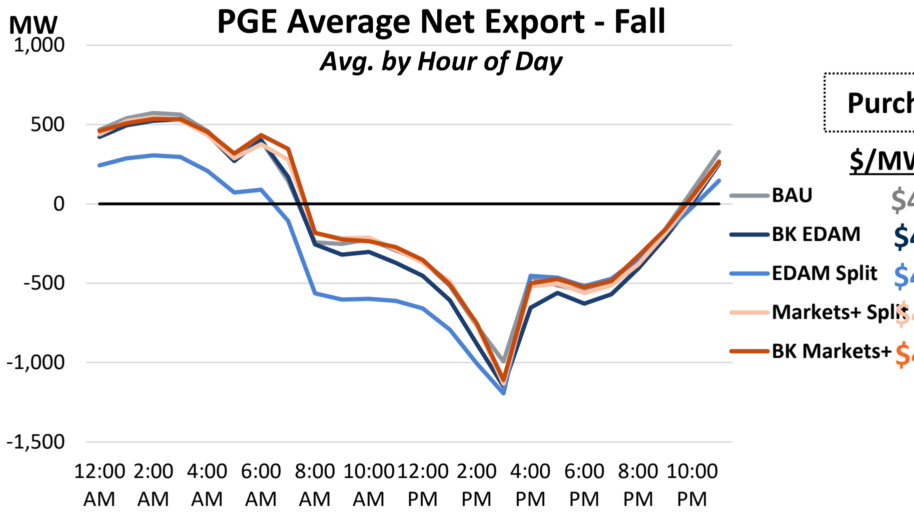
Purchase Cost

	$/MWh	$ Mil.
BAU	$11	$15
BK EDAM	$16	$22
EDAM Split	$13	$19
Markets+ Split	$10	$15
BK Markets+	$9	$14



Purchase Cost

	$/MWh	$ Mil.
BAU	$-3	$-5
BK EDAM	$-3	$-5
EDAM Split	$-3	$-5
Markets+ Split	$-7	$-15
BK Markets+	$-6	$-11

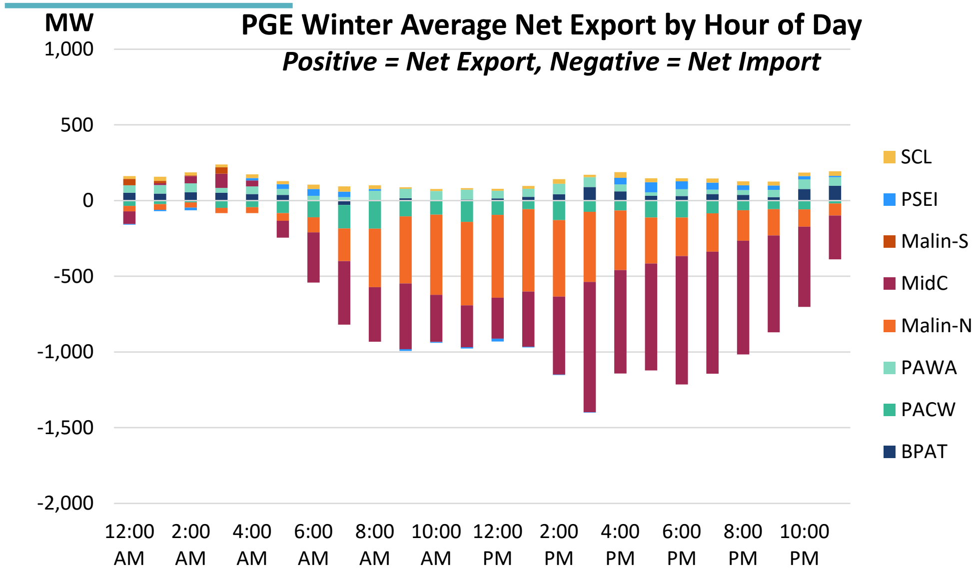


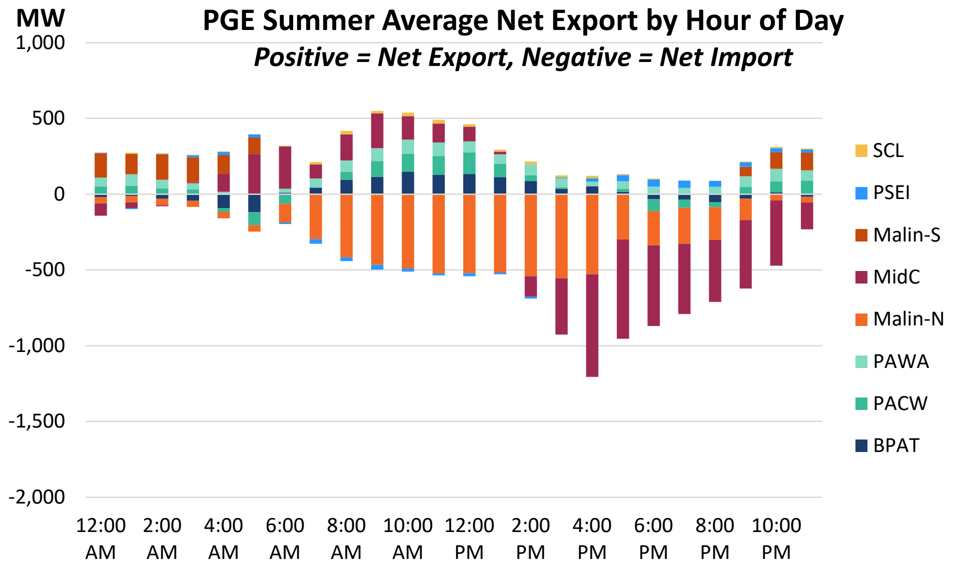
Purchase Cost

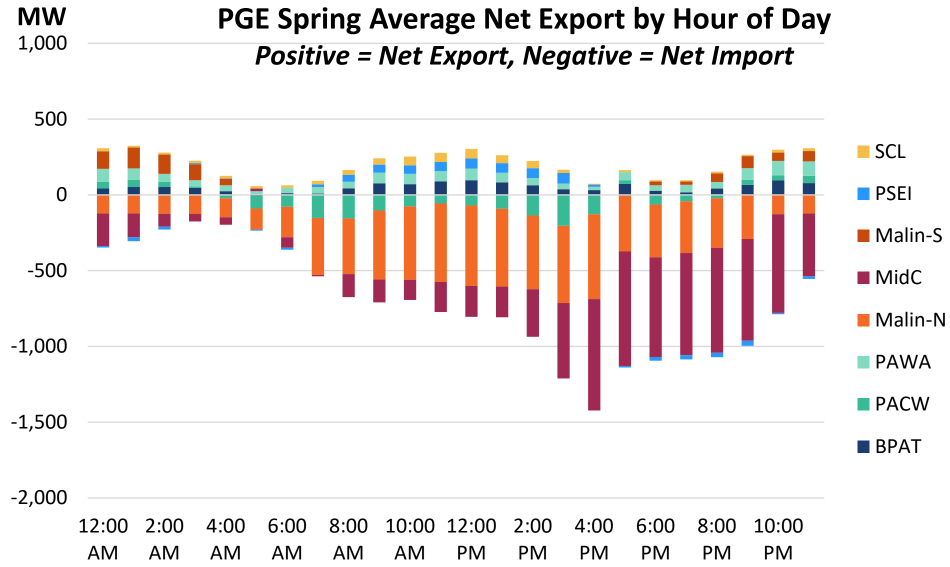
	$/MWh	$ Mil.
BAU	$44	$50
BK EDAM	$42	$55
EDAM Split	$41	$50
Markets+ Split	$43	$51
BK Markets+	$45	$52

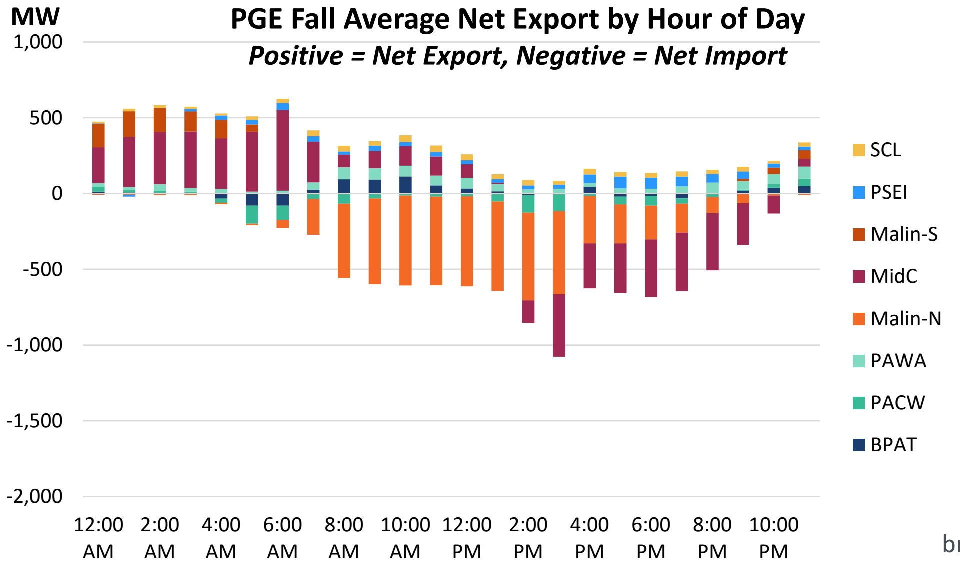
PGE Seasonal Trading Charts

BAU Case Trading (Seasonal)

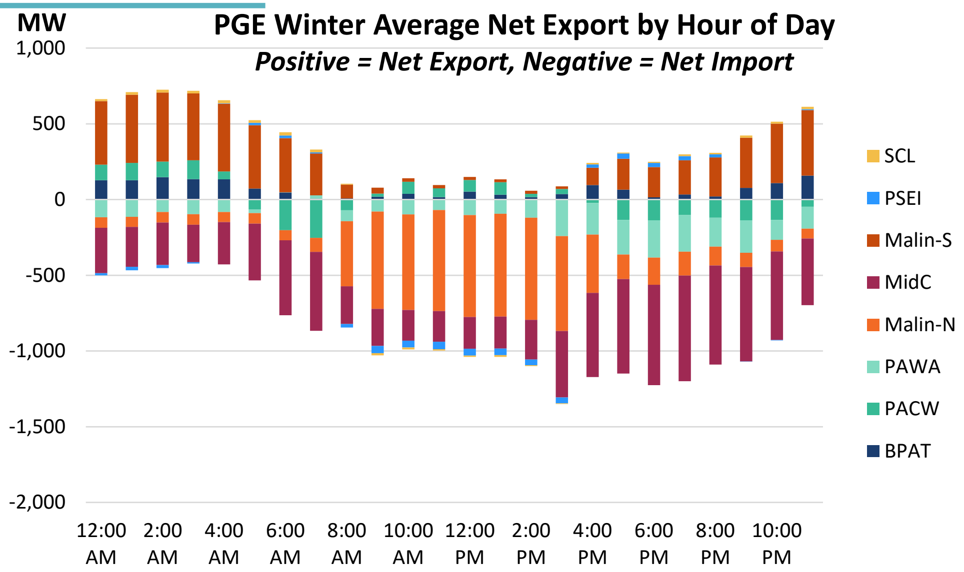


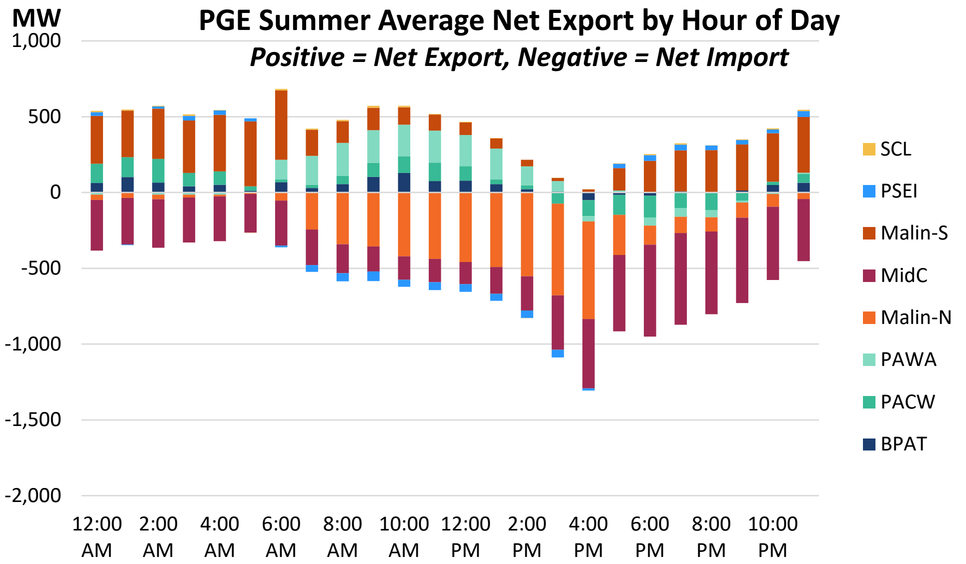


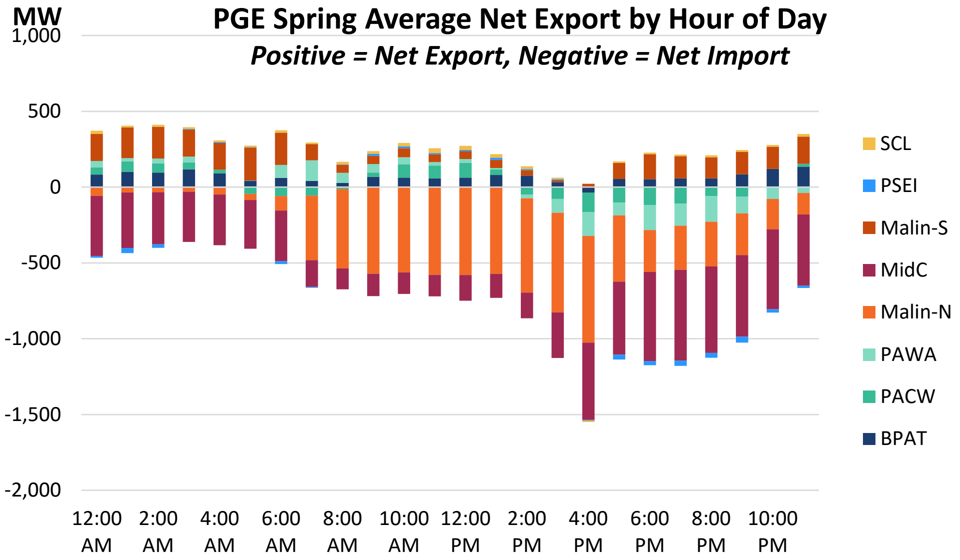


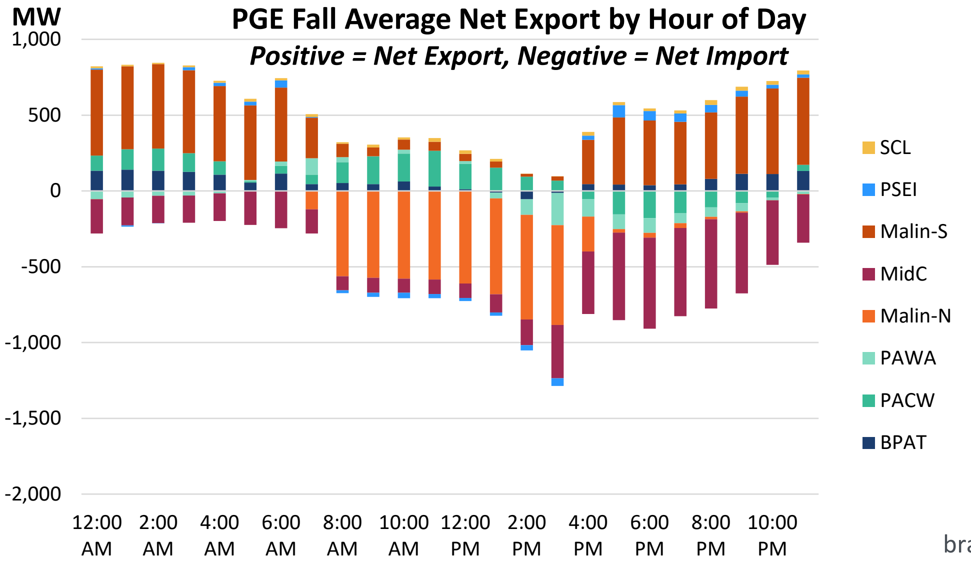


WEIM Transition Case Trading (Seasonal)

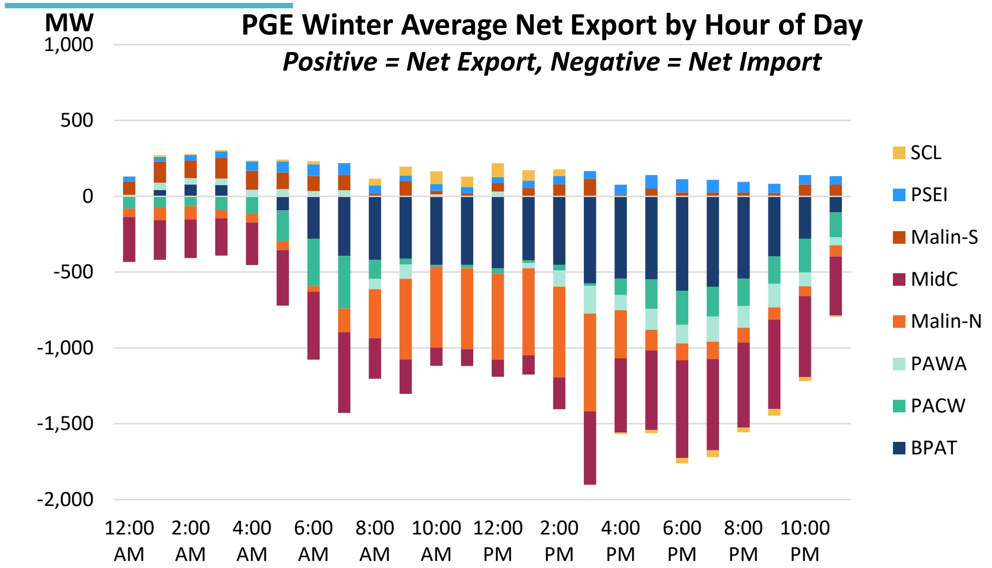


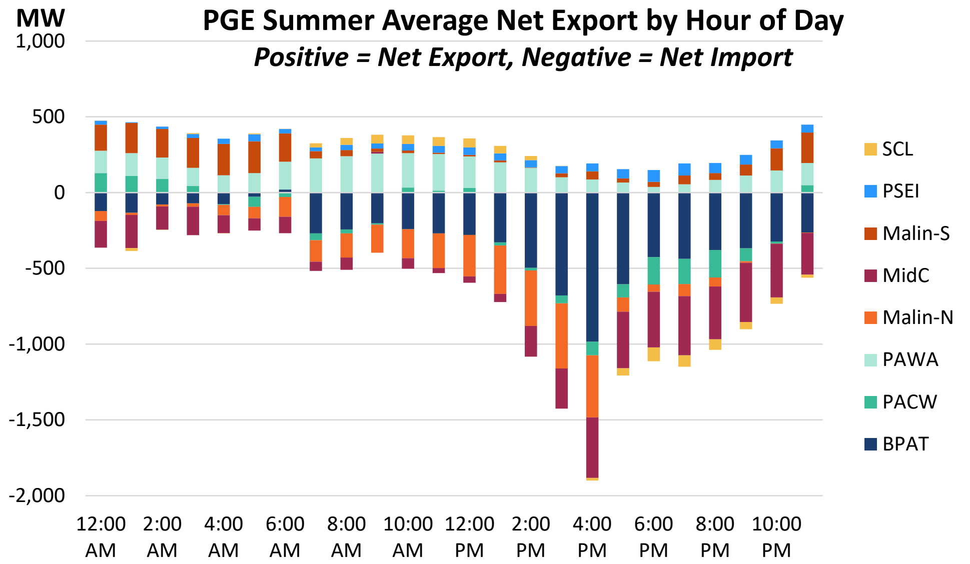


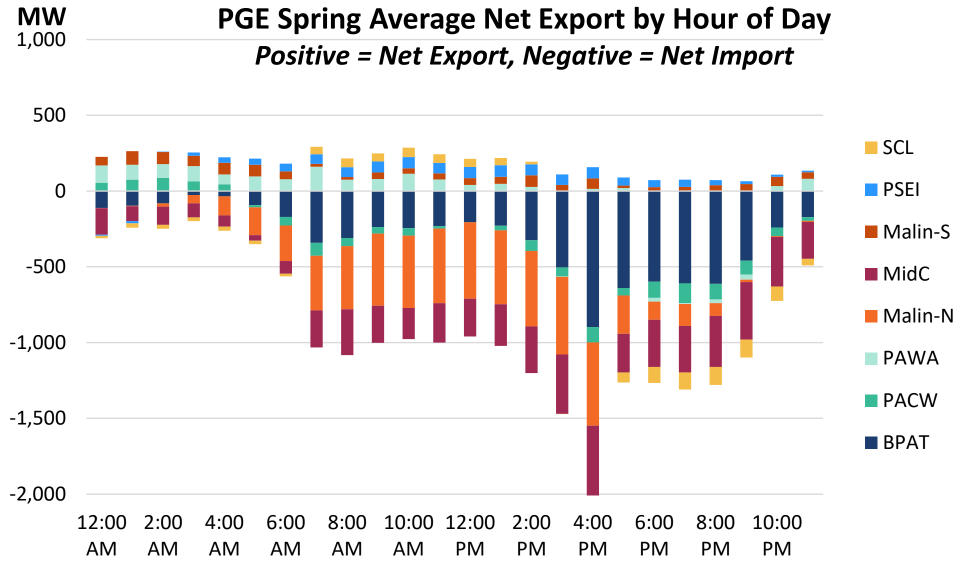


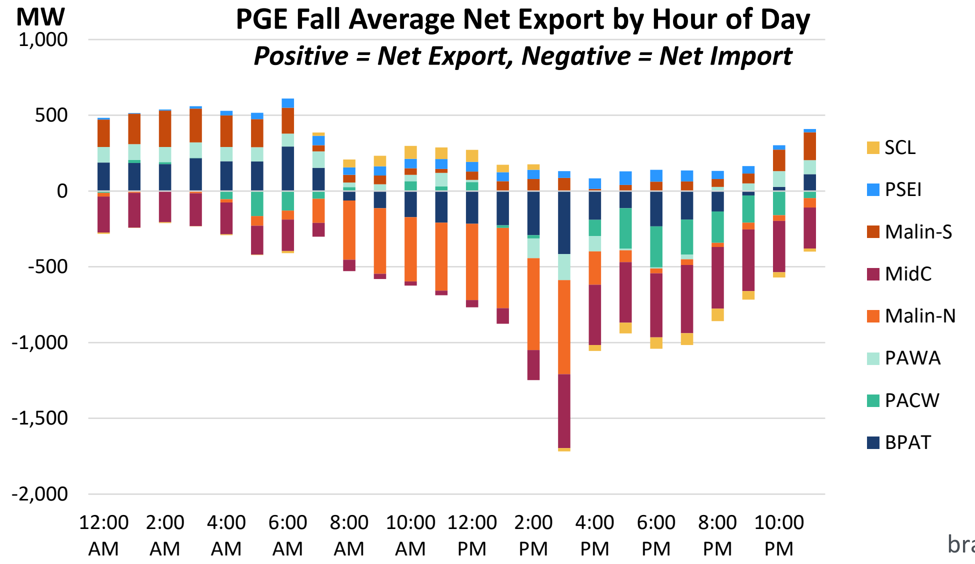


Bookend EDAM Case Trading (Seasonal)

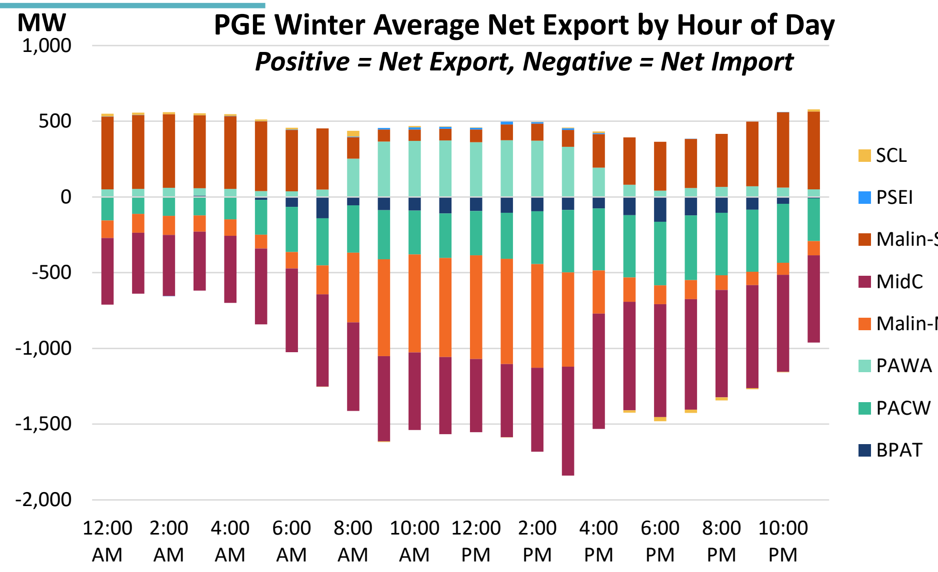


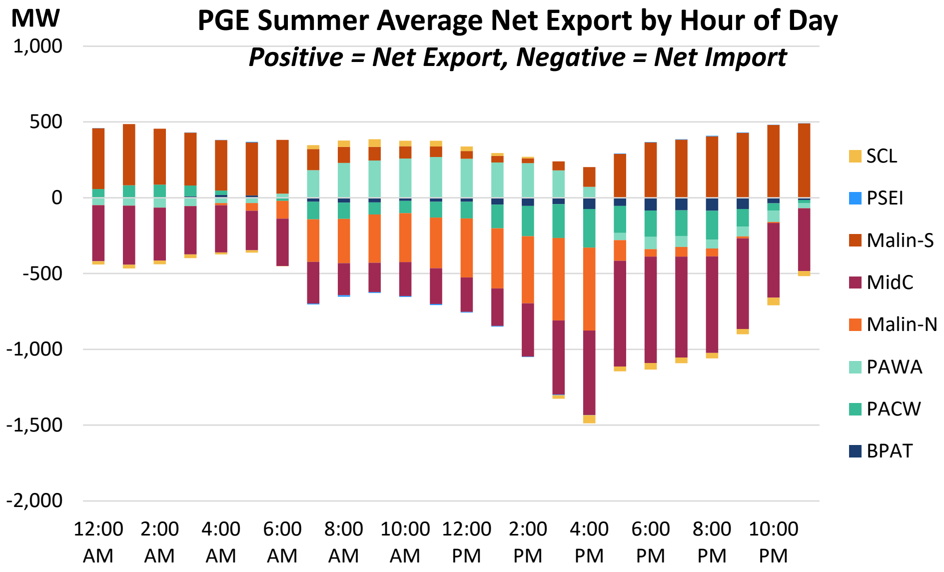


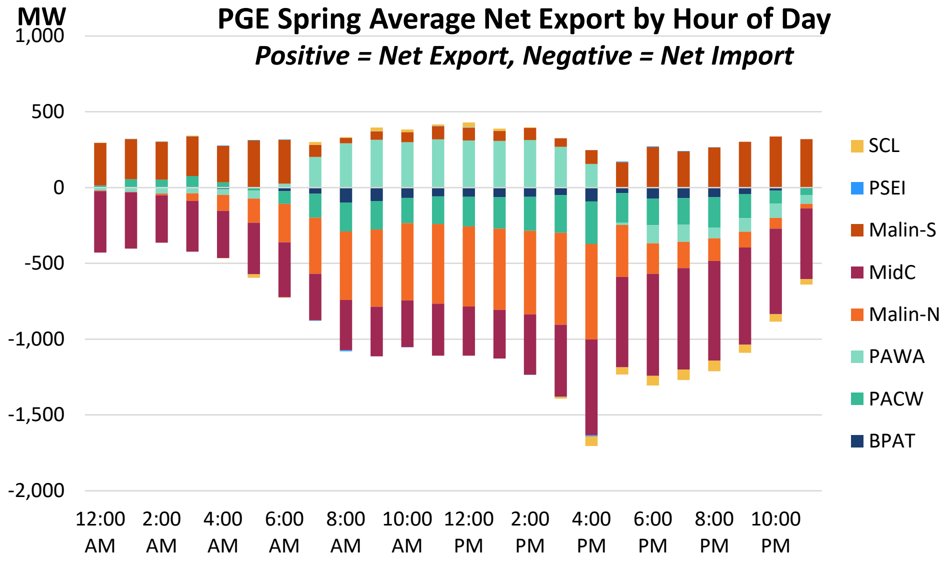


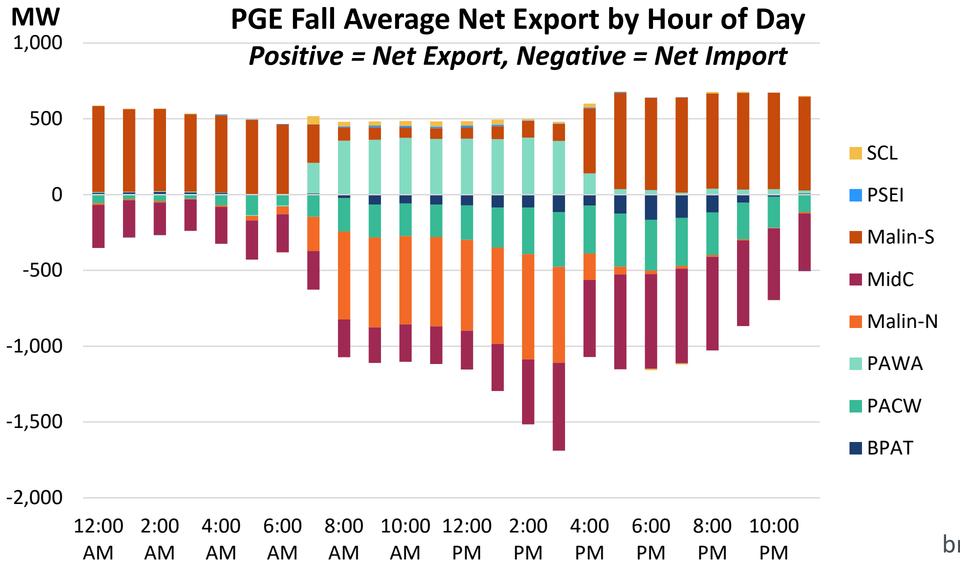


EDAM Split Case Trading (Seasonal)

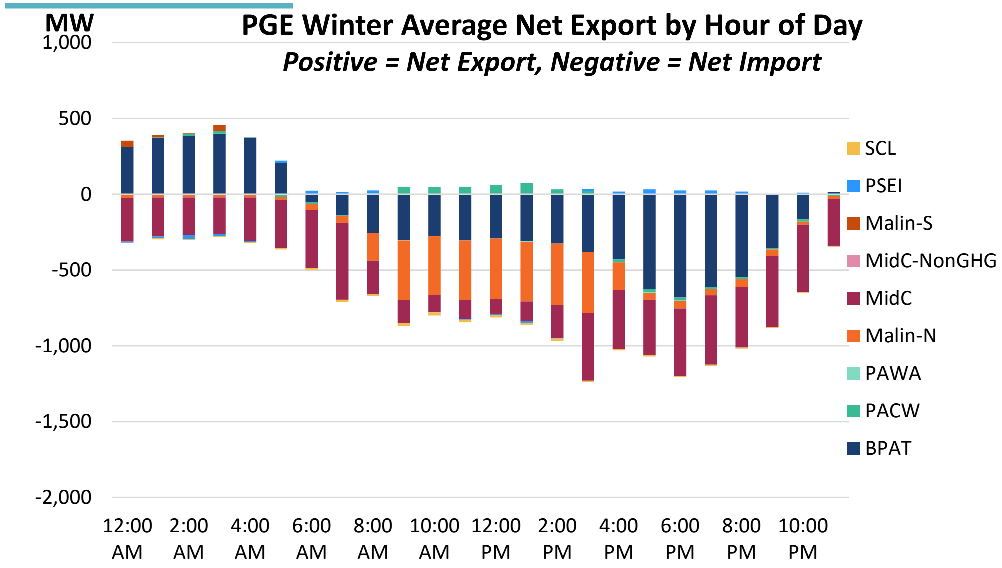


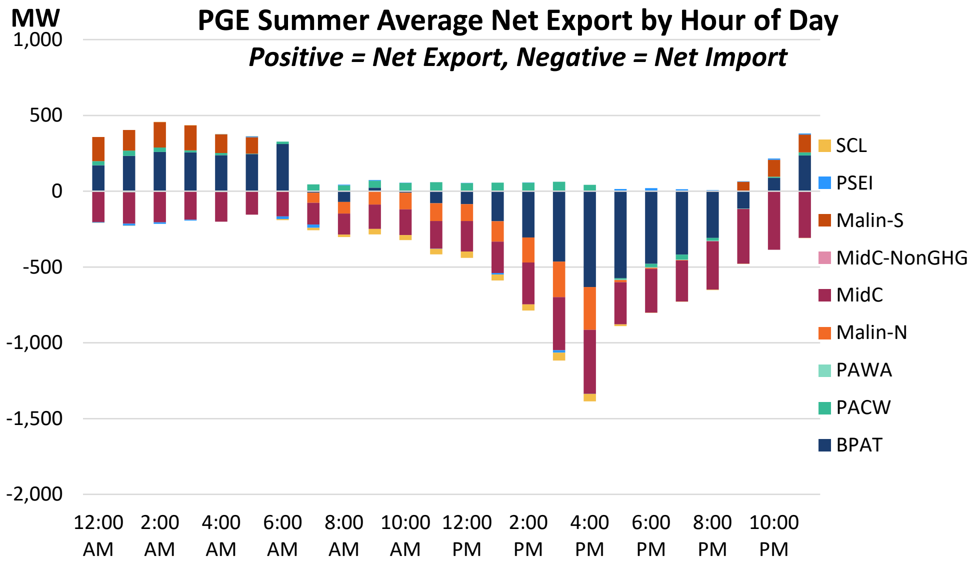


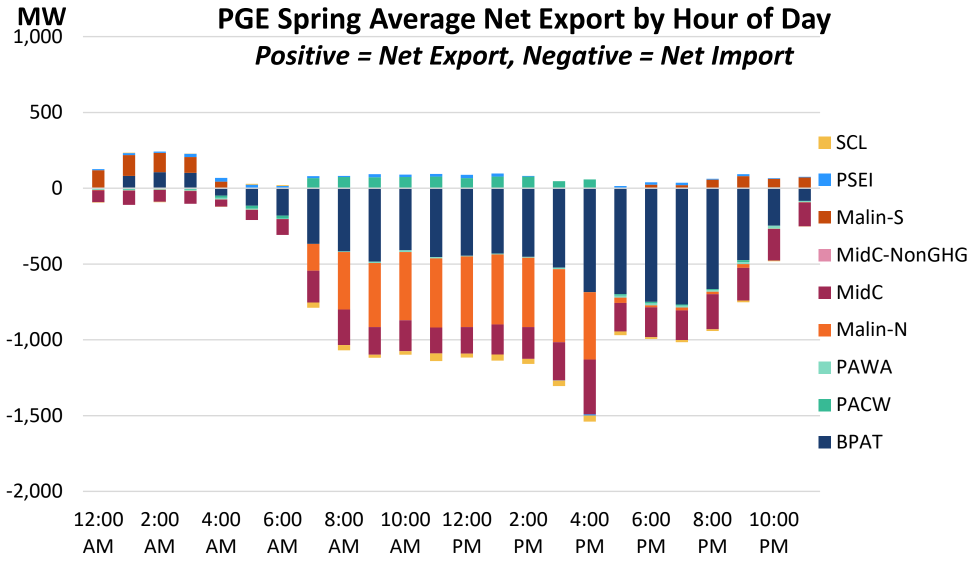


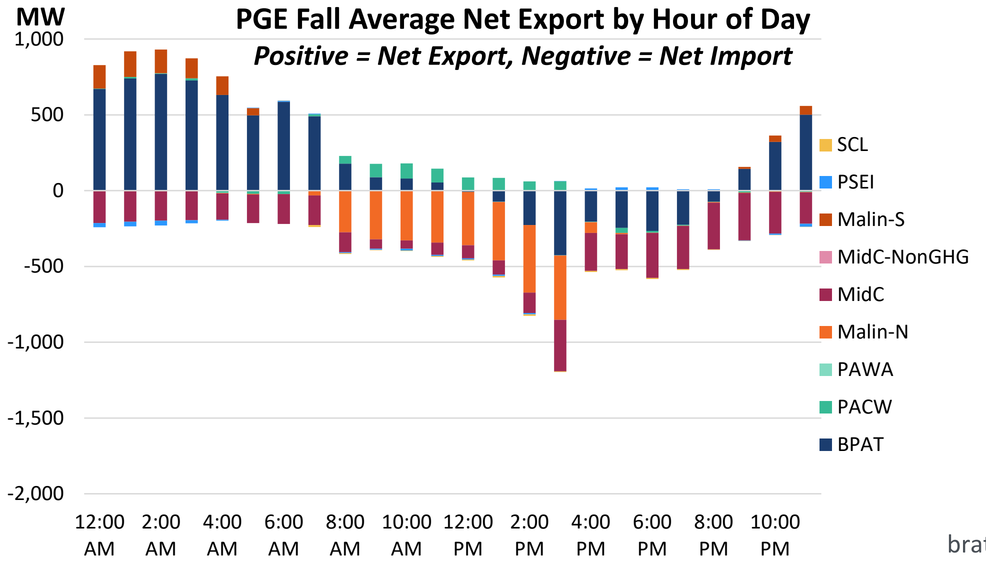


Markets+ Split Case Trading (Seasonal)

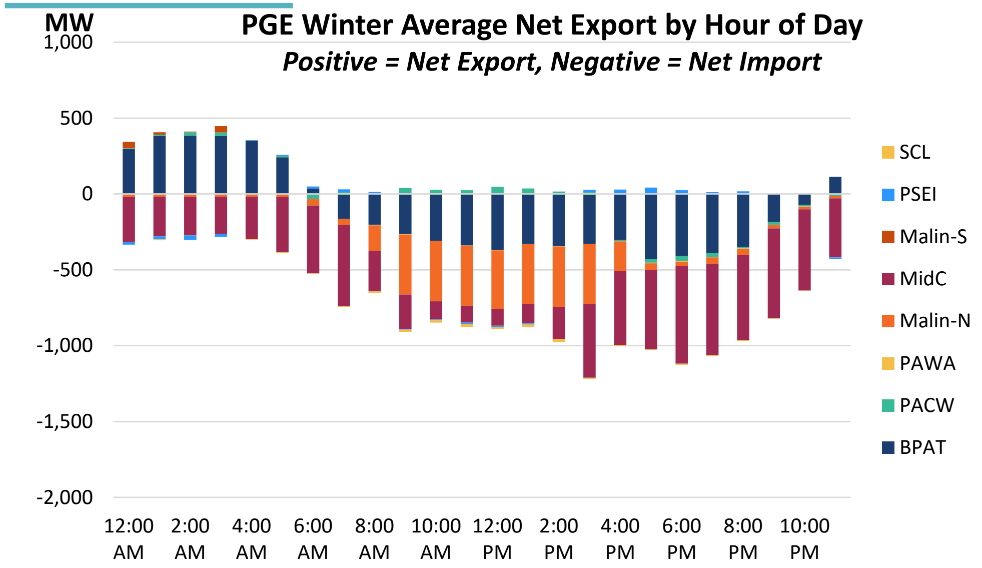


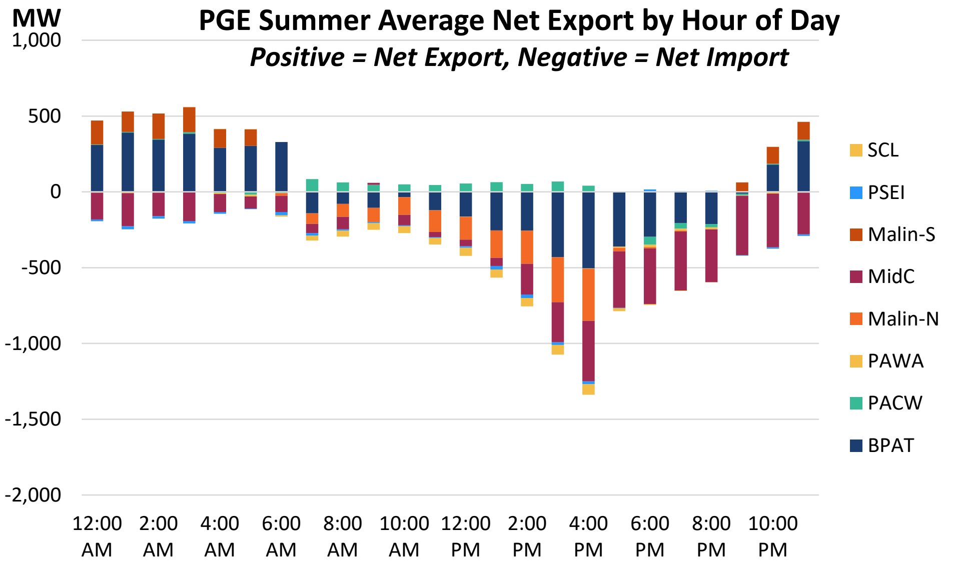


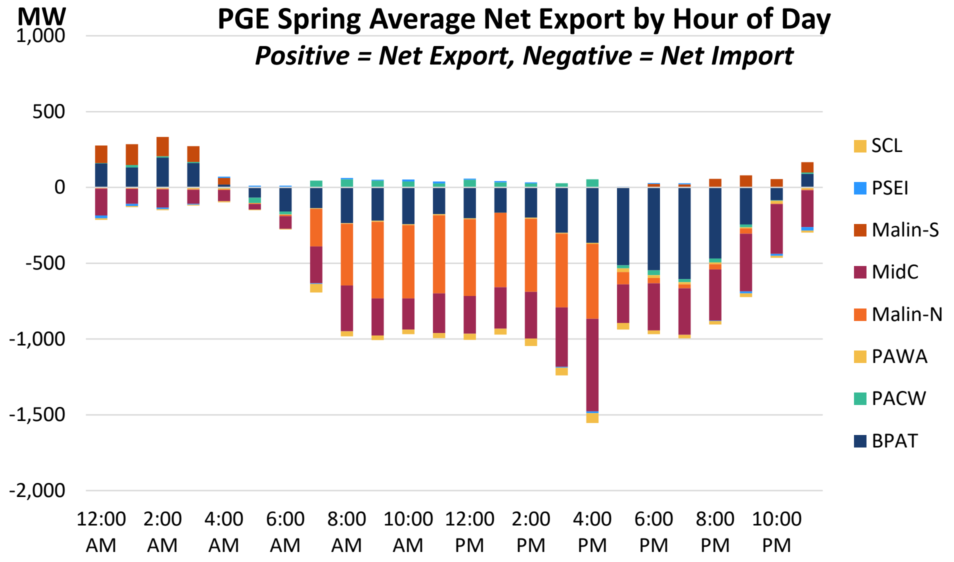


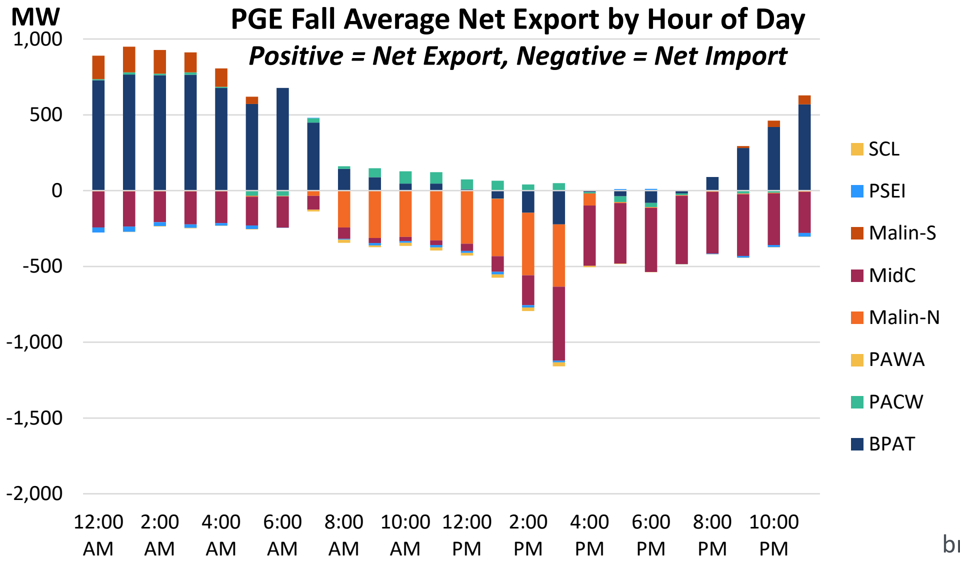


Bookend Markets+ Case Trading (Seasonal)







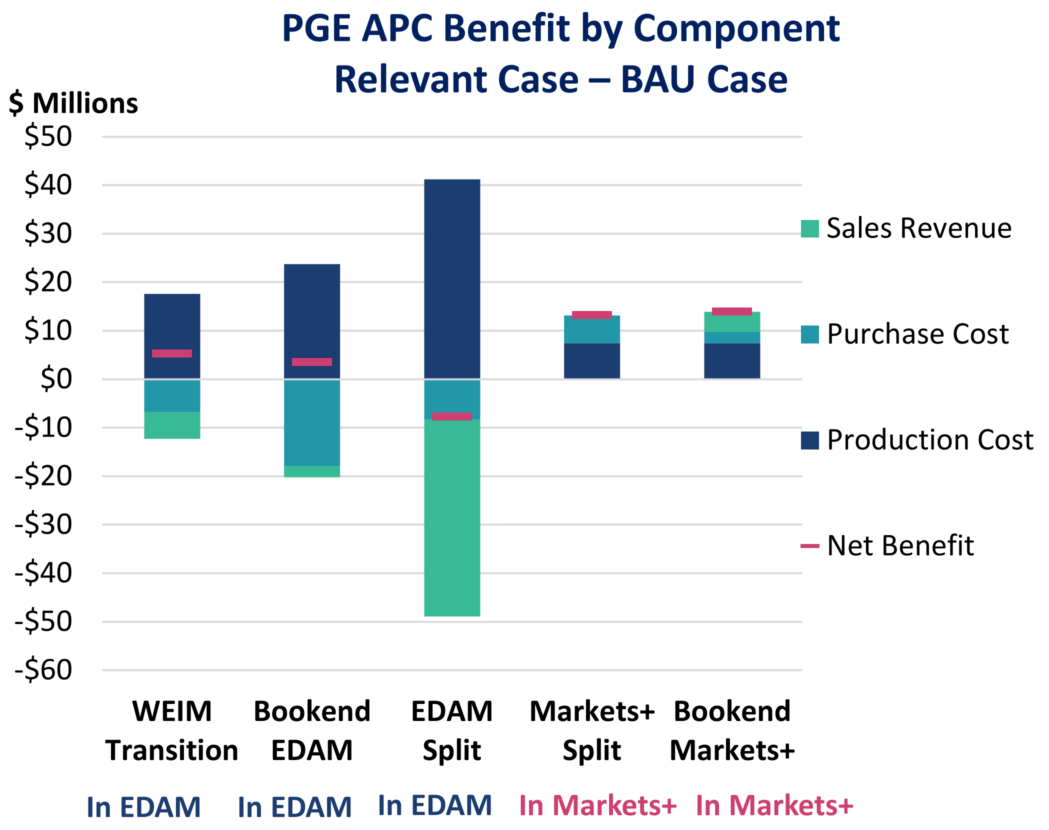


PGE Detailed APC Results

PGE Adjusted Production Cost Benefits

PGE's APC benefits are generally higher in Markets+ than in EDAM

- Though PGE tends to make more market purchases in Markets+ then EDAM, it does so at lower prices, which nets to a benefit
- PGE generally sees lower reductions in sales in Markets+ relative to BAU as well as higher sales prices, retaining most sales revenues despite the lower sales
- While EDAM sees higher displacement of production costs from internal generation compared to Markets+, due to a higher reduction in gas generation, declines in sales and average sales prices and increased purchases at average prices similar to BAU result in lower net APC benefits



PGE APCs – EDAM Bookend

PGE is seeing a net APC benefit of $3.6 million, driven by:

- **(1) Reduced generation** saving $23.8 million from 500 GWh of reduced generation, almost all of which is gas
- **(2) Benefits are offset by increased purchase costs** with average cost of purchasing increasing slightly in day ahead and purchase volumes increasing 516 GWh, resulting in a net cost of about $18 million
- **(3) Benefits are also offset by reduced sales revenues** as day-ahead average sales prices fall $2/MWh and real time sales volumes decline, a net cost about $2 million

Adjusted Production Cost Comparison for PGE

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Status Quo**	**Bookend EDAM**	**Difference**	**Status Quo**	**Bookend EDAM**	**Difference**	**Status Quo**	**Bookend EDAM**	**Difference**	
Production Cost	(+)	[1]	26,022	25,524	**-498**	$10.58	$9.85	**-$0.72**	275,234	251,476	**-$23,757**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	5,013	5,529	**516**	$26.40	$27.07	**$0.67**	132,329	149,636	**$17,307**	**(2)**
Real-Time Market		[5]	1,239	1,196	**-43**	$25.33	$26.75	**$1.42**	31,393	31,991	**$598**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	1,465	1,450	**-15**	$43.49	$41.40	**-$2.10**	63,730	60,021	**-$3,709**	**(3)**
Real-Time Market		[8]	1,635	1,625	**-10**	$26.26	$27.29	**$1.03**	42,934	44,343	**$1,409**	
***Total Cost** (Negative Difference = Benefit)*		[9]	**29,174**	**29,174**	**0**	**$11.39**	**$11.27**	**-$0.12**	332,292	328,740	**-$3,553**	
% Change in APC											***-1.1%***	

PGE APCs – WEIM Transition

PGE is seeing a net APC benefit of $5.4 million, driven by:

- **(1) Reduced generation** saving $17.6 million from about 500 GWh of reduced generation, almost all of which is gas
- **(2) Benefits are offset by increased purchase costs** with average cost of purchasing declining in day ahead, but purchase volumes increasing 501 GWh, resulting in a net cost of about $10 million
- **(3) Benefits are also offset by reduced sales revenues** as day-ahead average sales prices increase $1/MWh in day ahead but sales volumes decline about 200 GWh

Adjusted Production Cost Comparison for PGE

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Status Quo**	**WEIM Transition**	**Difference**	**Status Quo**	**WEIM Transition**	**Difference**	**Status Quo**	**WEIM Transition**	**Difference**	
Production Cost	(+)	[1]	26,022	25,558	**-464**	$10.58	$10.08	**-$0.50**	275,234	257,613	**-$17,621**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	5,013	5,513	**501**	$26.40	$25.79	**-$0.61**	132,329	142,171	**$9,842**	**(2)**
Real-Time Market		[5]	1,239	1,077	**-162**	$25.33	$26.25	**$0.92**	31,393	28,274	**-$3,120**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	1,465	1,275	**-190**	$43.49	$44.60	**$1.11**	63,730	56,881	**-$6,849**	**(3)**
Real-Time Market		[8]	1,635	1,699	**64**	$26.26	$26.02	**-$0.23**	42,934	44,226	**$1,292**	
Total Cost *(Negative Difference = Benefit)*		[9]	**29,174**	**29,174**	**0**	**$11.39**	**$11.21**	**-$0.18**	332,292	326,951	**-$5,342**	
% Change in APC											***-1.6%***	

PGE APCs – EDAM Split

PGE is seeing a net APC loss of $7.7 million, driven by:

- **(1) Reduced generation** saving $41.2 million from 1,200 GWh of reduced generation, 1,100 GWh of which is gas
- **(2) Slight increase in purchase costs** with average cost of purchasing staying roughly the same in day ahead, but purchase volumes increase 457 GWh, resulting in a net cost of about $12 million
- **(3) Benefits are offset by reduced sales revenues** as day-ahead average sales prices fall $5 in day-ahead and $2 in real time, with volumes declining about 400-500 GWh in both, costing about $40 million
  – Prices decline considerably as PGE enters the solar-heavy EDAM market footprint in this case, but doesn't have the same export partners in bookend EDAM like BPAT

Adjusted Production Cost Comparison for PGE

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Status Quo**	**EDAM Split**	**Difference**	**Status Quo**	**EDAM Split**	**Difference**	**Status Quo**	**EDAM Split**	**Difference**	
Production Cost	(+)	[1]	26,022	24,786	**-1,236**	$10.58	$9.44	**-$1.14**	275,234	234,012	**-$41,222**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	5,013	5,469	**457**	$26.40	$26.38	**-$0.02**	132,329	144,302	**$11,974**	**(2)**
Real-Time Market		[5]	1,239	1,056	**-184**	$25.33	$26.30	**$0.97**	31,393	27,768	**-$3,626**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	1,465	1,005	**-460**	$43.49	$38.12	**-$5.38**	63,730	38,327	**-$25,403**	**(3)**
Real-Time Market		[8]	1,635	1,132	**-503**	$26.26	$24.53	**-$1.72**	42,934	27,766	**-$15,168**	
***Total Cost** (Negative Difference = Benefit)*		[9]	**29,174**	**29,174**	**0**	**$11.39**	**$11.65**	**$0.26**	332,292	339,989	**$7,696**	
% Change in APC											***2.3%***	

PGE APCs – Markets+ Split

PGE is seeing a net APC benefit of $13.2 million, driven by:

- **(1) Reduced generation** saving $7 million from 700 GWh of reduced generation, about 300 GWh of which is gas
- **(2) Reduced purchase costs** with day-ahead purchase volumes increasing 800 GWh but prices also declining almost $5/MWh as PGE buys mainly from BPA, resulting in a net cost reduction of ~$5 million
- **(3) About equal sales revenues** with day-ahead sales revenues increasing due to higher average sales prices and real-time sales revenues decreasing due to lower volumes sold

Adjusted Production Cost Comparison for PGE

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			Status Quo	Markets+ Split	Difference	Status Quo	Markets+ Split	Difference	Status Quo	Markets+ Split	Difference	
Production Cost	(+)	[1]	26,022	25,324	-698	$10.58	$10.58	$0.00	275,234	267,808	-$7,426	(1)
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	5,013	5,835	822	$26.40	$21.79	-$4.61	132,329	127,166	-$5,163	(2)
Real-Time Market		[5]	1,239	967	-273	$25.33	$32.00	$6.67	31,393	30,929	-$464	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	1,465	1,475	10	$43.49	$45.65	$2.16	63,730	67,338	$3,608	(3)
Real-Time Market		[8]	1,635	1,477	-158	$26.26	$26.71	$0.45	42,934	39,456	-$3,478	
***Total Cost** (Negative Difference = Benefit)*		[9]	29,174	29,174	0	$11.39	$10.94	-$0.45	332,292	319,110	-$13,182	
% Change in APC											-4.0%	

PGE APCs – Markets+ Bookend

PGE is seeing a net APC benefit of $14 million, driven by:

- **(1) Reduced generation** saving $7.5 million from 500 GWh of reduced generation, about 200 GWh of which is gas
- **(2) Reduced purchase costs in the day-ahead** where average cost of purchasing declines about $3/MWh from BAU offsetting cost increases due to 613 GWh of increased sales volume, resulting in a net cost reduction of ~$2 million
- **(3) Increased day-ahead sales revenues** as average sales price increases about $2.5/MWh, which is offset by reduced real-time sales revenues of $2.8 million due to declining sales volumes

Adjusted Production Cost Comparison for PGE

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			Status Quo	Bookend Mkt+	Difference	Status Quo	Bookend Mkt+	Difference	Status Quo	Bookend Mkt+	Difference	
Production Cost	(+)	[1]	26,022	25,527	**-495**	$10.58	$10.49	**-$0.09**	275,234	267,788	**-$7,446**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	5,013	5,626	**613**	$26.40	$23.19	**-$3.21**	132,329	130,441	**-$1,888**	**(2)**
Real-Time Market		[5]	1,239	1,011	**-229**	$25.33	$30.68	**$5.35**	31,393	31,007	**-$386**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	1,465	1,536	**70**	$43.49	$46.06	**$2.57**	63,730	70,738	**$7,008**	**(3)**
Real-Time Market		[8]	1,635	1,454	**-181**	$26.26	$27.59	**$1.34**	42,934	40,122	**-$2,812**	
***Total Cost** (Negative Difference = Benefit)*		[9]	**29,174**	**29,174**	**0**	**$11.39**	**$10.91**	**-$0.48**	332,292	318,376	**-$13,916**	
% Change in APC											***-4.2%***	

Comparing EDAM Results Against MONET Modeled Trading

Context

As a part of our PGE EDAM benefits study, we analyzed the MONET modeling assumptions to assess if and how our simulated EDAM results can be compared with the MONET's simulated trading

Based on our review of the MONET assumptions, we have concluded that **MONET modeling captures PGE system operations and trading in a manner consistent with participation in EDAM.**

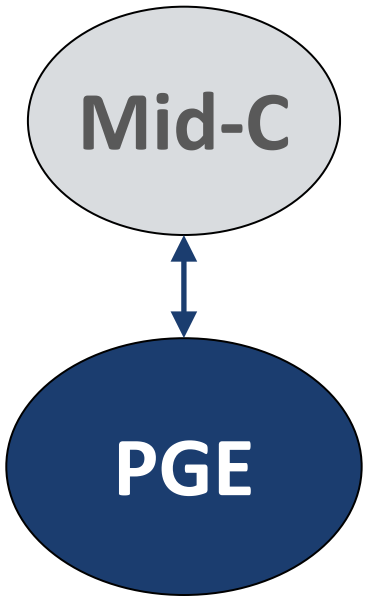
- In contrast to our modeling for the EDAM benefits study, the MONET model uses a simplified set of assumptions about PGE's system and its capability to trade with other BAAs in the WECC.
- However, those assumptions generally align with how the EDAM will function once implemented, therefore we conclude estimates of PGE's trading volumes using MONET are likely to more closely approximate PGE's trading volumes in EDAM than in the current bilateral market in the WECC.

The following slides summarize the key assumptions across MONET and our EDAM Benefits Study model and highlights the ways in which MONET models PGE in a similar manner as we model it in EDAM.

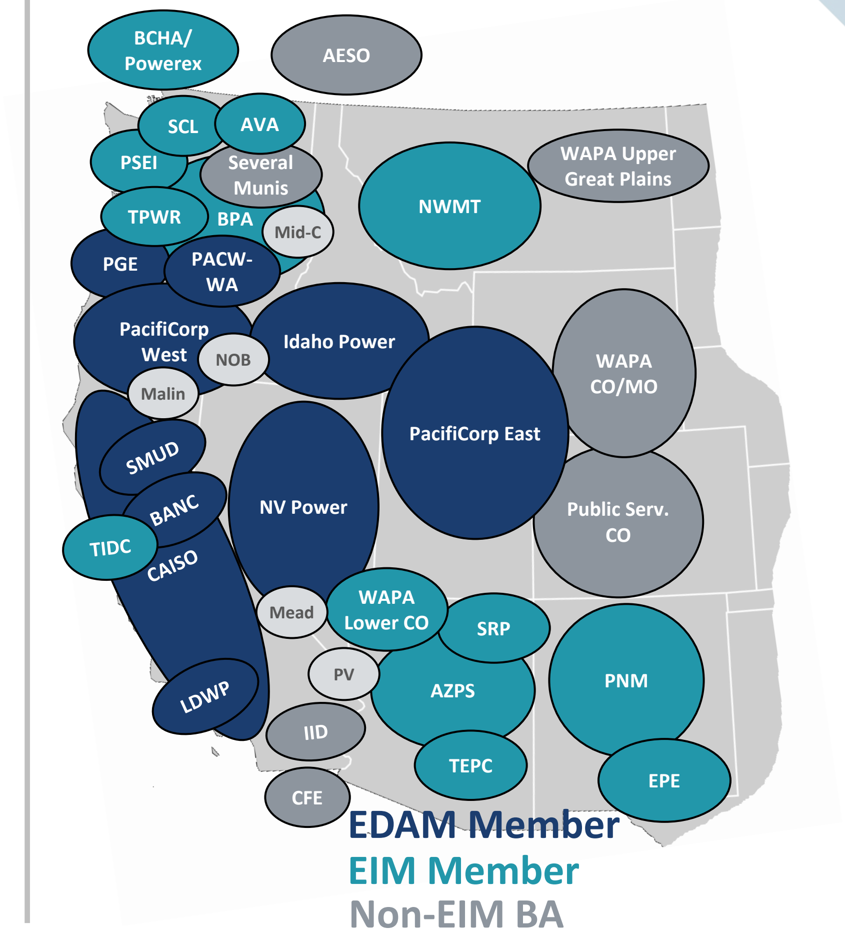
MONET vs EDAM Benefits Modeling Framework

Assumption Area	MONET Model	Brattle EDAM Model
Optimization scope	PGE system dispatch and trades to/from Mid-C	WECC-wide unit commitment and dispatch
Decision cycles	One dispatch decision cycle	Multiple cycles for DA UC, DA ED, & RT
Trading limits	Unrestricted	contractual limitations between BAAs (TTC, ETC, EIM)
Trading types	Hourly	Block & hourly bilateral, **hourly EDAM & EIM**
Wheeling fees and hurdles on trades	None	OATT rates + friction on incremental, **None for EIM / EDAM trades**
Purchase/sale prices	Monthly forwards from PGE trading, shaped to hourly by MONET team	Endogenous to model, **explicitly captures hub pricing including Mid-C**
Network constraints	None	WECC paths

PGE MONET Model Topology



EDAM Benefits Model Topology



Note: this comparison does not capture all of the details modeled in the EDAM benefits study, rather focuses on the assumptions that are relevant for assessing trading / market benefits

MONET reflects the key elements of trading in EDAM

Assumption Area	MONET Model	Brattle EDAM Model
Optimization scope	PGE system dispatch and trades to/from Mid-C	WECC-wide unit commitment and dispatch
Decision cycles	One dispatch decision cycle	Multiple cycles for DA UC, DA ED, & RT
Trading limits	Unrestricted	contractual limitations between BAAs (TTC, ETC, EIM)
Trading types	Hourly	Block & hourly bilateral, **hourly EDAM & EIM**
Wheeling fees and hurdles on trades	None	OATT rates + friction on incremental, **None for EIM / EDAM trades**
Purchase/sale prices	Monthly forwards from PGE trading, shaped to hourly by MONET team	Endogenous to model, **explicitly captures hub pricing including Mid-C**
Network constraints	None	WECC paths

Although our model is more detailed, MONET align treats purchases and sales largely how they would be treated in the EDAM, specifically:

- **Hurdle-free trading** between PGE and the market/Mid-C is consistent between MONET and EDAM
- **Hourly market transactions** allow for granular trading
- **Deep liquidity** in both EDAM and MONET
- **Exposure to market prices**
  - Though prices used in MONET today reflect bilateral market, that could updated when EDAM goes live
- **Capability for large trading volumes**
  - Trading volumes and network constraints are completely unrestricted in MONET, while EDAM trades will be limited to contributed transmission and system congestion. Implying that MONET *overstates* the trading volumes that will occur in EDAM

MONET's Trading Results are Likely Consistent with EDAM, but it Fails to Capture Certain EDAM Revenues

MONET's modeling framework likely captures much of PGE's benefits from EDAM participation, and may actually overstate the benefits

- The trading volumes estimated by MONET, would be reflected in our EDAM model and captured in our Adjusted Production Cost (APC) metric.

However, MONET's simplified representation of the system leaves out some revenues PGE will collects as an EDAM member

- **Congestion revenues**: MONET does not have any transmission/trading limitations and so does not capture congestion and congestion revenues that would accrue to PGE in EDAM
- **EDAM transfer revenues & wheeling revenue impacts**: MONET captures total trade value (bilateral + EDAM) and so does not allow EDAM trade revenues and loss of wheeling revenue on bilateral trades to be directly calculated

Portland General Electric Day-Ahead Market Benefits Studies

MODELING APPROACH

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FEBRUARY 2024

Brattle

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Model Overview

Scope of Studies

Scope: to simulate the specific EDAM/M+ designs for realistic market footprints, not a simplified representation of a wholesale market across the entire WECC

- **Calculate a multiple benefit metrics:** (1) Adjusted Production Cost (APC), (2) impact on wheeling revenue, (3) loss of bilateral trading profits, and (4) EDAM/M+ congestion and transfer revenues
- **Model the EDAM and/or M+ GHG structure:** as specified in the design or contemplated design
  - EDAM: simulated the "GHG Reference Pass" to set limits on transfers into the GHG region (CA and WA).
  - M+: simulated "Resource Owner, Merit Order w/ Enhanced Floating Surplus" approach to setting transfer limits into GHG regions
  - Modeled resource-type-specific GHG costs
- **Simulate existing & prospective real-time markets:** WEIM in parallel with the EDAM, formation of a day-ahead and real-time market with M+, nodal representation of entire WECC
  - Estimated the impact on existing WEIM and new EDAM or Markets+ trades and congestion revenues
- **Capture value of coupled day-ahead and real-time markets to manage unexpected imbalance:** modeled renewable and load forecast uncertainty between DA and RT
- **Realistically represent bilateral markets:** captured existing contract-path transmission rights, major trading hubs, block trading, CAISO intertie trades, hourly BA-to-BA trades, and wheeling charges where applicable

Key Model Features

We conducted all study simulations using a **nodal production cost model of the WECC** with added market functionality, such as contract-path transmission.

- Model developed in PSO/Enelytix, which contains state-of-the-art features
  - Simultaneously optimizes contract path and physical constraints
  - Models bilateral, day-ahead, and real-time markets sequentially through multiple solution cycles
  - Co-optimizes storage resources with other resources in unit-commitment and dispatch
  - Detailed ancillary service and operating reserve modeling and co-optimization of ancillary services with energy
- **The study year is 2032**, which aims to reflect the first decade of markets operations, representing both an intermediate year in the near-future and a year with reasonably high renewable penetration in the WECC
- **Model includes two extreme weather events** based on a historic cold snap and a historic heat wave
  - These events are modeled as single weeks in which we increase modeled loads (peak and energy) and gas prices beyond the typical weather-normalized values to reflect the increased strain on the system and the ramifications of markets for addressing such strain.
  - Capturing non-weather-normal impacts is becoming increasingly important due to the increasing frequency of severe weather events
- **Modeled hydro represents average hydro year in the WECC,** using data from 2009 for hydro generation
- **Study base cases include the existing WEIM and WEIS markets**, meaning all noted cost and benefit metrics already include an entity's benefit coming from WEIM and WEIS (and thus all results show incremental loss or gain in WEIM and WEIS benefits as a day-ahead market is formed)

See Appendix for additional model and assumptions detail, including detail related to EDAM and M+ design modeling

Estimated EDAM & M+ Benefits are Conservatively Low

The estimated benefits are likely understated due to several factors:

- **Overstated base-case efficiency:** our simulation of the BAU is more efficient than reality
  - The Base Case assumes that balancing authorities have optimal security-constrained unit-commitment and dispatch (SCUC and SCED) in both DA and RT, making the simulated dispatch more optimal than in reality.
  - Inefficient utilization of transmission by bilateral trades is not fully modeled, understating the extent EDAM and M+ will be able to make better use of all physically and contractually available transmission.
  - Transmission outages are not modeled, which would magnify the benefit of SCED-based congestion management in EDAM and M+ compared to the BAU
- **Normalized loads and fuel prices:** the model uses weather-normalized loads and averaged monthly natural gas prices without daily volatility
  - Challenging market conditions (beyond the included heat wave and cold snap), such during as the 2022 gas price spikes, will magnify EDAM/M+ benefits. Illustrated by the WEIM experience of much higher benefits in 3Q of 2021 and 3Q-4Q of 2022
  - The Base Case does not reflect the limited liquidity of bilateral market during challenging market conditions
- **No capacity benefits quantified:** we have not quantified the extent to which EDAM and M+ may reduce investment costs associated with lower operating reserve requirements

Model Details

Overview of Modeling Approach

We utilize the WECC ADS nodal production cost model as a starting point imported into Power System Optimizer (PSO), as refined during the EDAM feasibility study and follow-on engagements

Utilized the Polaris Power System Optimizer (PSO), an advanced market simulation model

- Nodal mixed-integer model representing each load and generator bus in the WECC
- Licensed through Enelytix
- Detailed operating reserve and ancillary service product definition
- Detailed representation of the transmission system (both physical power flow
- Sub-hourly granularity (but used hourly simulations due to limited data availability)
- Designed for multiple commitment and dispatch cycles (e.g., DA and RT) with different levels of foresight
- EDAM feasibility study assumptions updated to reflect the most recent utility resource plans and forecasts of system conditions and costs

PSO is uniquely suited to simulate bilateral trading, joint dispatch, imbalance markets, and RTOs, reflecting multiple stages of system operator decision making

Multi-Functional Simulation of WECC

Markets/RTO Functions & Configurations

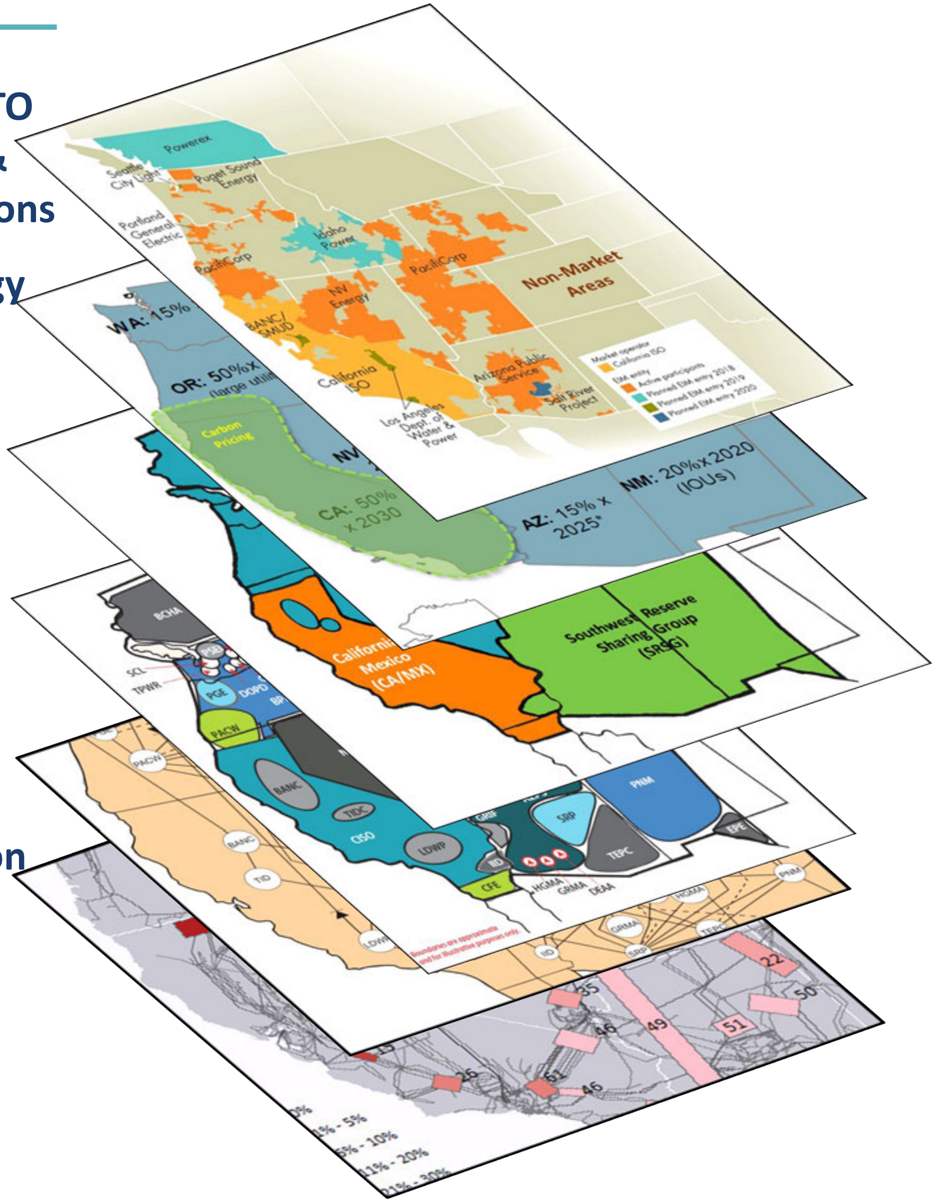
Clean Energy Policies

Reserve Sharing

BAA Functions

Bilateral Contract Paths and Transmission Rights

Physical Flows and Constraints



We employ a multi-layer simulations to represent the various physical, policy, and operational facets of the WECC

- Physical grid with ~20k buses, ~25k lines and ~5k generators represented as DC power flow
- 38 Balancing Authority Areas (BAAs) and contract paths
- The WECC reserve sharing groups
- Diverse state clean energy policies
- Major trading hubs (e.g., Mid-C, Malin, PV)
- Bilateral transmission rights
- Renewable diversity, day-ahead forecast uncertainty, real-time operations
- CAISO, RTO West, M+, EDAM, WEIM, & WEIS footprints

Independent Simulation of Multiple Time Horizons

We simulate multiple independent decision cycles to capture day-ahead vs. real-time unit commitment and dispatch and uncertainty

D-1 (am)	D-1 (~noon)	D-1 (pm-D)	D
DA Bilateral Markets • DA block trades on long-term transmission rights and incremental transmission	**Day-Ahead Market** • CAISO, EDAM, and RTO market clearing • Hourly intertie trading • Hourly trading with long-term transmission rights	**Intra-Day Markets** • Hourly bilateral trades on remaining transmission	**EIM (RT Balancing)** • EIM/CAISO trading of economic energy • Transmission released for EIM • RT balancing in BAAs

Independent real-time decision cycle used to simulate EIM functions

DA Unit Commitment Cycle → DA Economic Dispatch Cycle → Real Time Cycle

Decision cycles capture bilateral trading, market clearing, BAA functions in DA and RT, and market cycles (incl. EDAM "GHG reference" pass, EDAM market, and EIM)

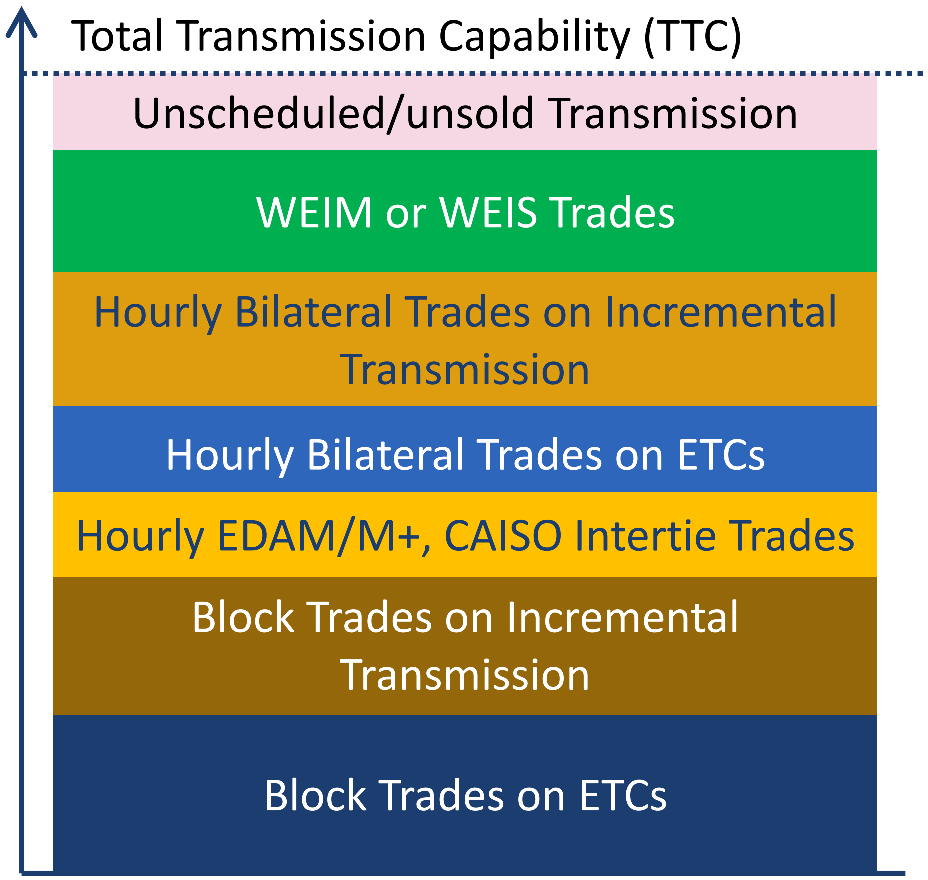
Independent real-time decision cycle used to simulate DA vs. RT, including <u>forecast errors</u> for wind and solar

Types of Trades and Transmission Reservations Modelled

Our model simulates the use of different types of contract-path transmission reservations for bilateral trading across DA and RT

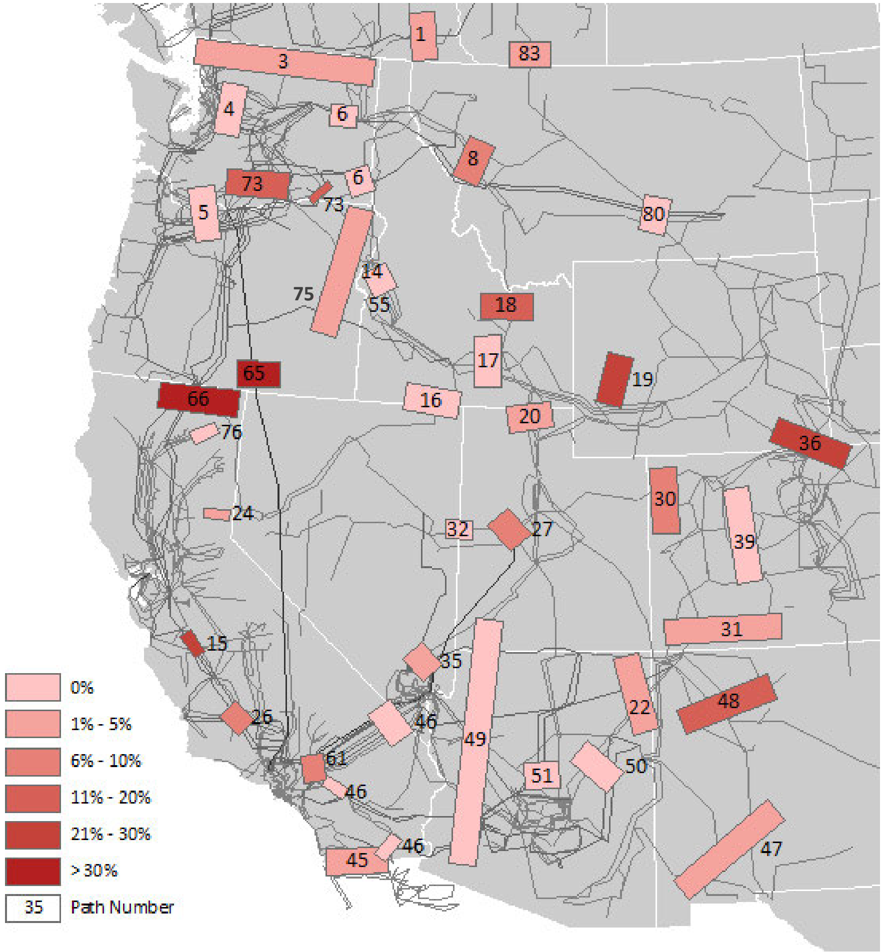
- Existing long-term transmission contracts (ETCs) and incrementally purchased transmission
- Total reservations on each contract path is limited by the total transfer capability (TTC)
- Trades are structured as blocks or hourly
- Bilateral trades between BAs, at major hubs, or across CAISO or RTO West interties
- Account for renewable diversity and day-ahead forecast uncertainty vs. real-time operations
- Unscheduled transfer capability released for EIM trades in real-time

Types of Trades Modeled



Nodal Simulations Based on Physical Transmission

WECC-Defined Paths Modeled



Limits on the physical transmission system include all the paths defined in WECC Path Rating Catalogue

- Additional transmission paths to represent congestion internal to each BA
- Limits on all paths and constraints reflect updates provided by the study participants

ENELYTIX®
powered by PSO

Power System Optimizer (PSO), developed by Polaris Systems Optimization, Inc. is a state-of-the-art market and production cost modeling tool that simulates least-cost security-constrained unit commitment and economic dispatch with a full nodal representation of the transmission system, similar to actual RTO and ISO market operations. Such nodal market modeling is a commonly used method for assessing the operational benefits of wholesale market reforms (e.g., JDAs, EIMs, RTOs).

PSO can be used to test system operations under varying assumptions, including but not limited to: generation and transmission additions or retirements, de-pancaked transmission and scheduling charges, changes in fuel costs, novel environmental and clean energy regulations, alternative reliability criteria, and jointly-optimized generating unit commitment and dispatch. PSO can report hourly or sub-hourly energy prices at every bus, generation output for each unit, flows over all transmission facilities, and regional ancillary service prices, among other results. Comparing these results among multiple modeled scenarios reveals the impacts of the study assumptions on the relevant operational metrics (e.g. power production, emissions, fuel consumption, or production costs). Results can be aggregated on a unit, state, utility, or regional level.

PSO has important advantages over traditional production cost models, which are designed primarily to model dispatchable thermal generation and to focus on wholesale energy markets only. The model can capture the effects of increasing system variability due to large penetrations of non-dispatchable, intermittent renewable resources on thermal unit commitment, dispatch, and deployment of operating reserves. PSO simultaneously optimizes energy and multiple ancillary services markets on an hourly or sub-hourly timeframe.

Like other production cost models, PSO is designed to mimic ISO operations: it commits and dispatches individual generating units to meet load and other system requirements, subject to various operational and transmission constraints. The model is a mixed-integer program minimizing system-wide operating costs given a set of assumptions on system conditions (e.g., load, fuel prices, transmission availability, etc.). Unlike some production cost models, PSO simulates trading between balancing areas based on contract-path transmission rights to create a more realistic and accurate representation of actual trading opportunities and transactions costs. This feature is especially important for modeling non-RTO regions.

One of PSO's distinguishing features is its ability to evaluate system operations at different decision points, represented as "cycles," which occur at different times ahead of the operating hour and with different amounts of information about system conditions available. Under this sequential decision-making structure, PSO can simulate initial cycles to optimize unit commitment, calculate losses, and solve for day-ahead unit dispatch targets. Subsequent cycles can refine unit commitment decisions for fast-start resources and re-optimize unit dispatch based on the parameters of real-time energy imbalance markets. The market structure can be built into sequential cycles in the model to represent actual system operation for utilities that conduct utility-specific unit commitment in the day-ahead period but participate in real-time energy imbalance markets that allow for re-optimization of dispatch and some limited re-optimization of unit commitment. For example, PSO can simulate an initial cycle that determines day-ahead unit commitment decisions that reflects the constraints faced by, and decisions made by, individual utilities when committing their resources in the day-ahead timeframe. The initial day-ahead commitment cycle is followed by cycles that simulate day-ahead economic dispatch, including bilateral trading of power, and a real-time economic dispatch, reflecting trades in real time (whether bilateral or optimized through an EIM or RTO). Explicit commitment and dispatch cycle modeling allows more accurate representation of individual utility preference to commit local resources for reliability, but share the provision of energy around a given commitment.

Simulating Several Wholesale Market Cycles in PSO

The model setup for wholesale market simulation effort contains several cycles to simulate unit commitment and dispatch decisions in three different timeframes and within different market structures. For example, cycles simulated can include are:

- **Day-Ahead Unit Commitment Cycle:** the model optimizes unit commitment decisions, 24 hours at a time (with 48-hour look ahead), for long-lead time resources such as coal and nuclear plants, based on their relative economics and operating characteristics (e.g., minimum run time, maintenance schedules, etc.), transmission constraints, and trading frictions. The model ensures that enough resources are committed to serve forecasted load, accounting for average transmission losses and the need for ancillary services. Separate regions' commitment decisions are segregated through higher hurdle rates on imports and exports. Trading within a single balancing area, like the various RTO sub-zones, is not subject to any hurdles.
- **Day-Ahead Economic Dispatch Cycle:** the model solves for the optimal level of hourly day-ahead dispatch and trading in 24-hour forward-looking optimization cycles, with 48-hour look ahead periods. Dispatch across the study footprint is optimized based on resource economics. In this cycle, the model also co-optimizes ancillary service procurement for each area. The high hurdle rates for unit commitment are lowered to enable more bilateral trading between balancing areas.
- **Intra-day trading:** the model simulates market activity through one-hour optimization horizons. Trading is assumed to utilize unused transmission, represented as the difference between their day-ahead trading volume and the total contract path limits. No unit re-commitment is allowed due to the non-firm nature of the transactions. Changes to generation availability, such as forced outages, which were not "visible" during the day-ahead cycle become visible during this cycle.
- **Real-Time Cycle:** this cycle simulated the operation of the real-time imbalance markets, such as through EIM transactions. In this cycle, the model can re-optimize dispatch levels and unit commitment decisions for fast-start thermal resources (based on the assumption that the real-time market design allows for unit re-commitment). Deviations from day-ahead forecasts (due to uncertainty) need to be balanced in real-time.

These cycles can take on different assumptions, depending on market structure. In a bilateral setting, all are set up to analyze utility-specific unit commitment and dispatch decisions, with each of them including hurdle rates and transmission fees that limit the amount of economic transactions that can take place between the utilities. In EIM and EDAM+EIM scenarios, all of the cycles are set up to simulate market-wide optimization of unit commitment and dispatch, including the EDAM "reference pass" cycle. In the EDAM case, there would be no hurdle rates between EDAM participants in any of the cycles, allowing the model to optimize both unit commitment and dispatch in the market footprint on both a day-ahead and real-time basis.

Benefits Metrics

Benefit Metric: Adjusted Production Cost

Adjusted Production Cost (APC) is a standard metric used to capture the direct variable energy-related costs from a customer impact perspective

The APC is calculated for the BAU Case and the RTO case to determine the RTO-related reduction in APC

- By using the generation price of the exporter and load price of the importer for sales revenues and purchase costs, the APC metric does not capture wheeling revenues and the remaining portion of the value of the trade to the counterparties (see next slide)

The APC is the sum of production costs and purchased power less off-system sales revenue:

(+) Production costs (fuel, startup, variable O&M, emissions costs) for generation owned or contracted by the load-serving entities

(+) Cost of bilateral and market purchases valued at the BAA's load-weighted energy price ("Load LMP")

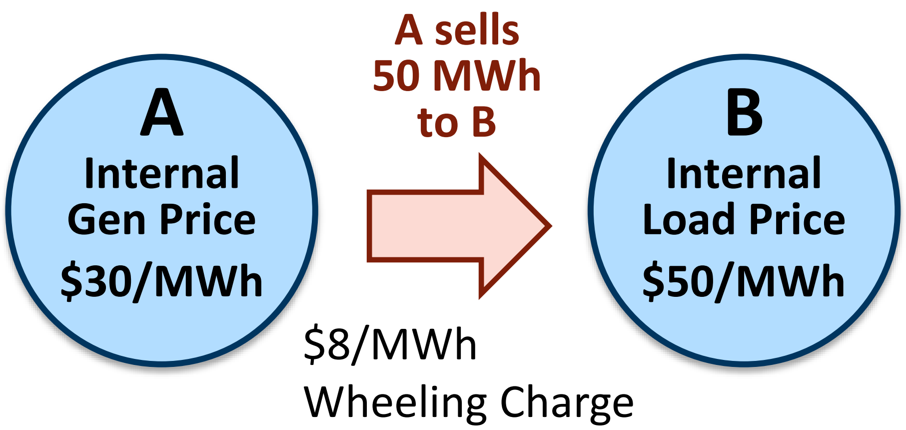
(−) Revenues from bilateral and market sales valued at the BAA's generation-weighted energy price ("Gen LMP")

Benefit Metrics: Wheeling Revenues, Trading Gains

Based on the simulation results, we also estimate several additional impacts from increased trading facilitated by the market reforms, which is not fully captured in APC.

- **Wheeling Revenues:** collected by the exporting BAAs based on OATT rates
- **Trading Gains:** buyer and seller split 50/50 the trading margin (and congestion revenues in EIM/EDAM)

EXAMPLE: Bilateral Trade



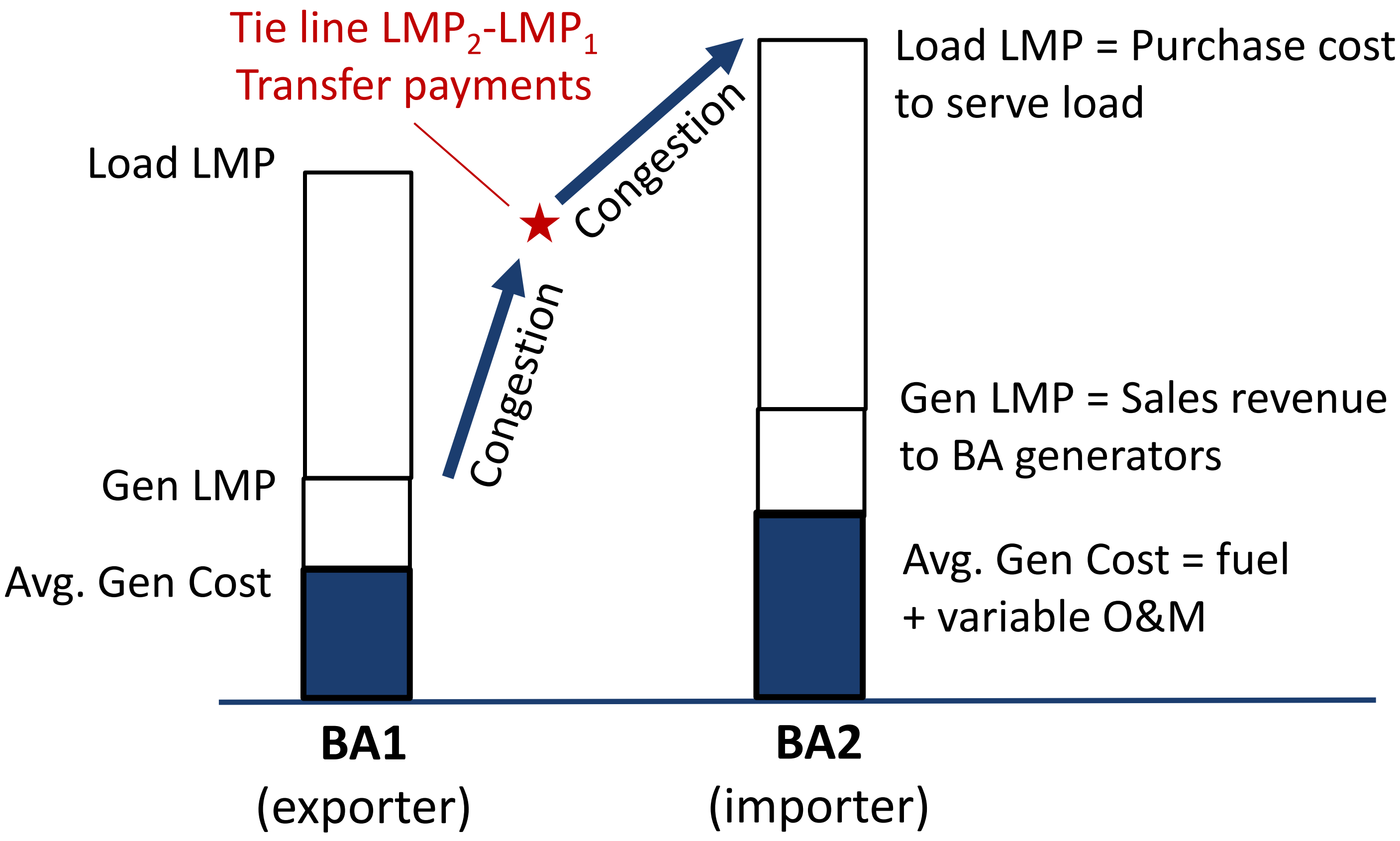
The APC metric only uses area-internal prices for purchase cost and sales revenues, which does not capture part of the value:

- A receives $30×50MWh=$1,500 in APC sales revenues
- B pays $50×50MWh=$2,500 in APC purchase costs
- ➔ $1,000 of trading value not captured in APC metric

Trading value = $20/MWh Δprice x 50 MWh = $1000

- Exporter A receives wheeling revenues: $8/MWh x 50MWh = $400
- Remaining $600 trading gain split 50/50: both A and B receive $300

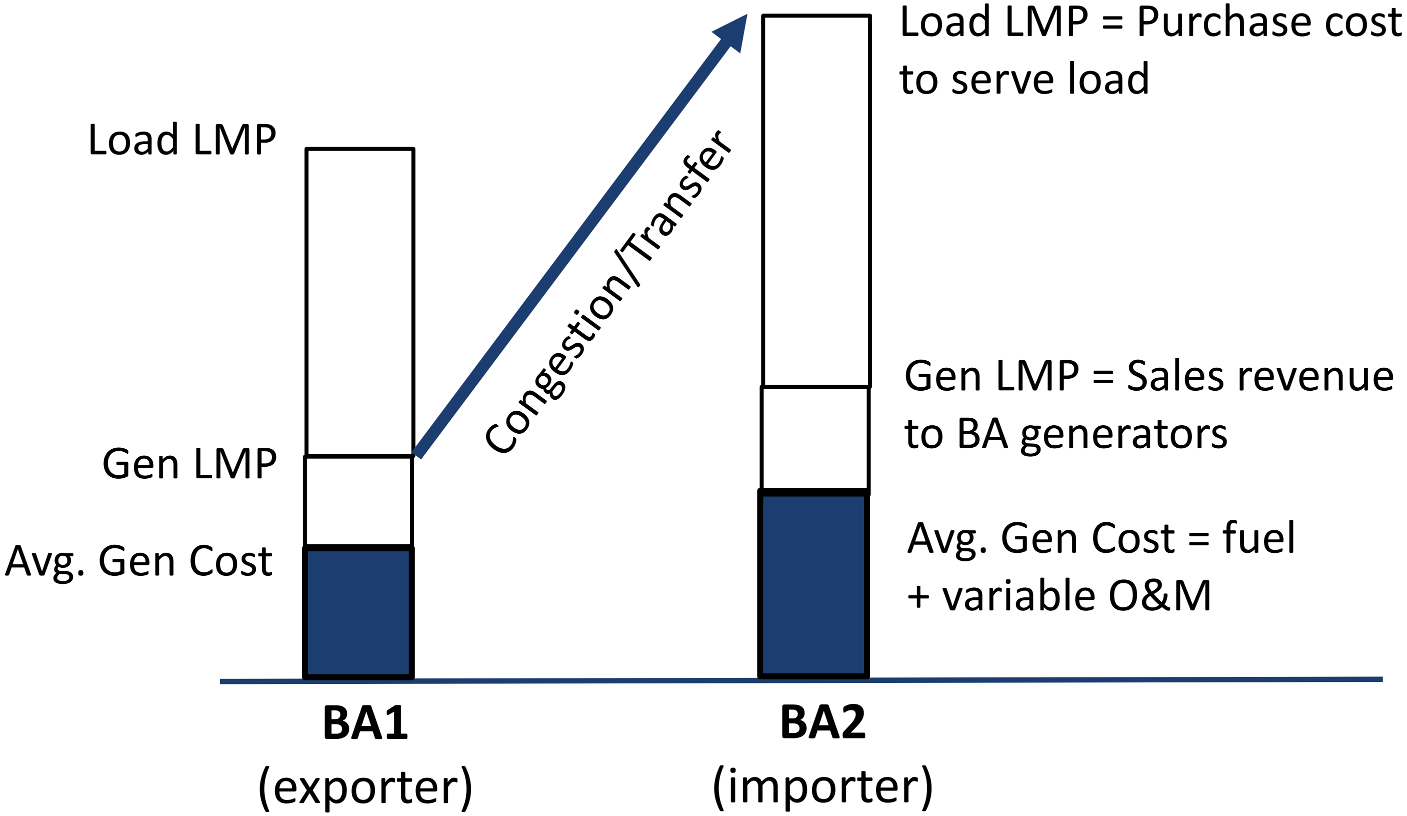
Illustration of EDAM Congestion and Transfer Revenues



EDAM congestion and transfer revenues estimated based on individual tie line LMPs:

- **Congestion Payment (to exporter) = MW x (Tie LMP_1 – Gen LMP_1)**
- **Congestion Payment (to importer) = MW x (Load LMP_2 – Tie LMP_2)**
- **Transfer Payment (split 50/50) = MW x (Tie LMP_2 – Tie LMP_1)**

Illustration of M+ Congestion/Transfer Revenues



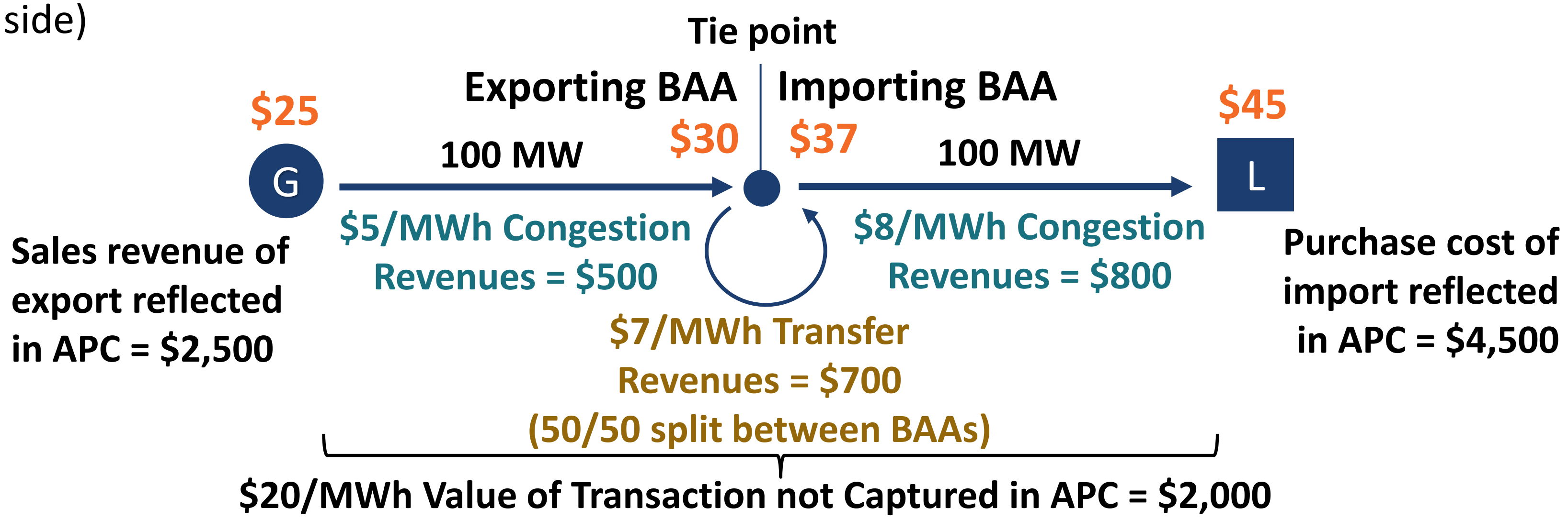
M+ congestion/transfer revenues rolled together and estimated based on BA load and gen LMPs:

- **Congestion/Transfer Revenue Payment (split 50/50) = MW x (Load LMP_2 – Gen LMP_1)**

Illustration of Congestion/Transfer Revenues vs. APC

Generators and loads get paid/pay the prices within their BAAs

- Therefore, congestion on internal transfers (between a member's own gen and load) is captured in the APC metric.
- However, congestion/transfer revenue on external transactions (to neighboring members) is not captured in APC.
- In the example below, for an external market transaction, the selling BAA has a price of $25 and the purchasing BAA has a price of $45.
  - The $20 difference between the seller and buyer is the congestion and transfer revenue.
  - **$5/MWh of congestion revenue** is allocated to the seller ($30 on their side of the intertie less $25 internal gen price)
  - **$8/MWh of congestion revenue** is allocated to the buyer ($45 internal load price less $37 on their side of the intertie)
  - **$7/MWh of transfer revenue** is split 50/50 between the buyer and seller ($37 on the buyer side of the intertie less $30 on the seller side)



EDAM Modeling Assumptions

Resource Sufficiency & Transmission

Resource Sufficiency Test

- The EDAM design applies the Resource Sufficiency Test to each EDAM member the day prior to real-time, before day-ahead market operations
  - In the 2019 EDAM Feasibility Study, E3 conducted an hourly analysis of Resource Sufficiency for each proposed EDAM member at that time
    - In that analysis, failure of the test was extremely rare
    - In fact, all current study participants (BANC, CAISO, IPCO, LADWP, SMUD, and PAC) previously passed the resource sufficiency test in all hours
  - For this study, conducted ex-post check and confirmed that all assumed EDAM members are resource sufficient in all hours

EDAM Transmission

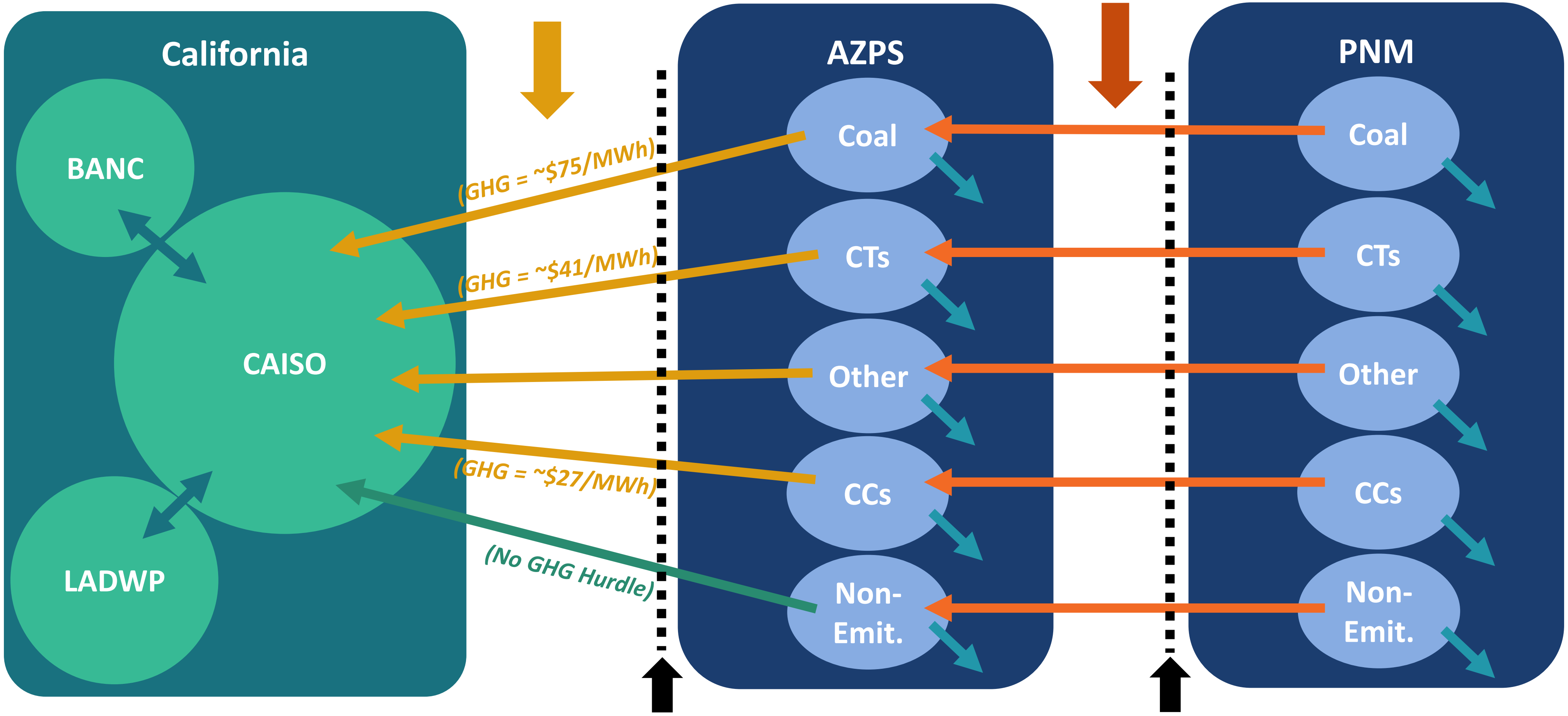
- All three buckets of EDAM transmission are modeled and assumed to be hurdle-free:
  - Bucket 1: Transmission to Support Resource Sufficiency
    - Includes existing long-term transmission contracts (“ETCs”) for energy used for sufficiency accounting purposes
  - Bucket 2: “Donated” Transmission Contracts
    - Existing transmission contracts (ETCs) made available (“donated”) to the EDAM by participants
  - Bucket 3: Unsold Firm Transmission
    - Remaining transmission made available for EDAM (participants might hold back from transmission for block trading)
- Simulated Bucket 1 and 2 EDAM transmission equals total ETC capacity; Bucket 3 transmission equals the remaining transfer capability (i.e., TTC less ETC) between the assumed EDAM members

GHG Structure Illustration

Sales incur unit GHG cost, relevant hurdles, and are limited by attributions from the GHG Reference Pass

Resources can sell into neighboring BAAs by paying applicable fees:

- Bilateral market: OATT fee, trading margin
- EIM: no hurdle on available transmission
- EDAM: no hurdle on Buckets 1,2, & 3



Resources serve load in their own BAA with no hurdle

Flows restricted to BAA export limit + BAA Net Export GHG Attribution Limit

A nomogram restricting total BAA-to-BAA flows to export limit, which varies by market type – bilateral, EIM, and EDAM

EDAM GHG Structure: "Reference Cycle"

Our GHG modeling structure accounts for two constraints specified in the EDAM design for GHG attributions relative to a baseline from EDAM's "reference pass" cycle, which we simulate as well

1. **Resource Specific GHG Attribution (resource-type attribution under proposed approach) =**

   max{0, min{GHG Bid, UEL – Reference Pass, Optimal Dispatch}}

   - **GHG Bid:** Simulations assume resources bid all their capacity into the GHG Region
   - **UEL – Reference Pass:** Calculated using results of our GHG Reference Pass run
   - **Optimal Dispatch:** GHG attribution cannot exceed final dispatch of resource

2. **BAA Total GHG Attribution <= (Net TTC Difference - BAA Net Exports hourly in reference pass)**

These reference pass results set **hourly export limits** that are enforced in the actual EDAM case for EIM and EDAM members for sales to GHG balancing authorities

Imbalance Reserve Requirement

EDAM reserve requirement estimated to fall about 2-4.2 GWh in the EDAM Case (relative to Base Case) due to the diversity benefit achieved by the EDAM footprint

Imbalance Reserve is a new reserve product being implemented by the CAISO as part of their DA Market Enhancements (DAME) initiative, and will apply to EDAM

- The Imbalance Reserve requirement (up and down) will be set to meet the 97.5 percentile of each BAAs historical net load variability
- In EDAM, participants' Imbalance Reserve Requirement will be reduced by the diversity benefit created by pooling commitment and dispatch across the regional footprint
- Does not impact other operating reserve types – regulation, contingency, etc.
- **Brattle Assumption:** we calculated each EDAM participants Imbalance Reserve Requirement and the EDAM diversity benefit to reduce each member's requirement

Markets+ Assumptions

Transmission Usage in the Market

Modeling Assumption: All transmission with other Markets+ entities was modeled as available for market transaction without any wheeling charges

- Brattle modeled BPAT consistent with their participation in WEIM, with limited transmission made available to the market
- We asked all study participants if you want to identify some transmission to set aside for WRAP, third party ownership, or other reasons.
  - *No study participants identified any WRAP transmission to be withheld from the market optimization*

M+ GHG Structure

Based on our review of the draft tariff language and the task force materials posted online, we assume for the purposes of these studies that M+ will use the following approach:

- Only energy identified as GHG surplus will be available to transfer to the GHG zone
- GHG surplus identification will happen through the Resource Operator and Merit Order approach
  - Rules from state agencies may restrict what resources can be identified as surplus energy by the resource operator
  - Resource operators make all resources available for transfer to the GHG zone
  - BA-level hourly surplus capacity available for transfer to the GHG transfer is calculated outside of the model using modeled load and a merit order constructed from modeled cost and capacity assumptions
  - We apply type-specific GHG costs to surplus transfers to the GHG zone
- We assume the market optimization will use the "Enhanced Floating Surplus" approach
  - This allows transfer of type-specific surpluses from anywhere in the dispatch range of eligible resource

Seams Management

Modeling Assumption: Brattle modeled the Markets+ seam consistent with the description from the Seams Task Force

- Exports into or imports out of Markets+ were charged a small bilateral friction charge plus the exporting entity's wheeling rate
- This is consistent with how we model the CAISO seam in the BAU Case
- Exports across the Markets+ seam into a GHG zone are charged an unspecified resource GHG cost (equivalent to the emissions charge for a generic gas-CC unit)
  - This makes Markets+ exports to CAISO and other GHG entities fairly expensive, as the GHG cost alone will be around $30/MWh

Modeled Trading Friction Charges ($/MWh)

Transaction Type	BAU Case	Markets+ Case	Pays OATT?
EIM & WEIS Transactions	$0	$0	No
Bilateral Transactions	$6	$6	Yes
ETC Transactions	$6	$6	No
RTO Intertie Transactions	$1.5	$1.5	Yes*
Block Transactions	$1.5	$1.5	Yes*
EDAM Transactions	$0	$0	No
Markets+ Transactions	$0	$0	No

*Note: *Block and RTO transactions won't pay an OATT rate if the transaction occurs over long-term ETC rights, just like ETC transactions broadly. The friction charge is the same regardless.*

Markets+ imports & exports pay either the bilateral or RTO intertie friction costs *(RTO for trades with CAISO or SPP West, who connects to PACE)*

Real Time Market

Brattle modeled Markets+ with a real-time market that operates like SPP's Western Energy Imbalance Service (WEIS)

- At the time the study was conducted, the Markets+ Task Forces had not discussed how the real-time market would function, but it is expected that Markets+ would include a RT market
- This also provides an apples-to-apples comparison with EDAM/WEIM

Real-time transactions at the Markets+ seam pay a small hurdle rate to capture bilateral friction + the exporting BAA's wheeling free + applicable GHG costs

- Transactions in real time across GHG zones and between markets (e.g., from EDAM to Markets+ or from Markets+ to CAISO/EDAM are charged the unspecified GHG rate)
  - For example, exports from **CAISO to Markets+** are charged the CAISO TAC + hurdle rate
  - Exports from **Markets+ to CAISO** are charged the GHG rate + exporter's OATT rate + hurdle rate

Congestion Rent Allocation

Congestion revenues are allocated back to market participants consistent with proposed constraint-level approach

- The Markets+ proposed approach is to allocate congestion based on the portion of rights each market participant owns on the constraint where congestion is collected
- *This differs from the EDAM model where tie points were used between BAs to determine the allocation of revenue between two BAs, splitting revenue into internal congestion revenue within a BA (kept by that BA), and transfer revenue between two BAs (split 50/50 between the BAs)*

Market Transmission Use Settlement

Assumption: Brattle calculated the MTU settlement consistent with the proposed approach

- Brattle used 2032 modeled wheeling revenues in the BAU Case as a proxy for future lost transmission revenue that goes into the settlement calculation
- This differs from some of the original EDAM cases which used historic wheeling revenues provided by the clients as the basis for the EDAM TRR settlement

Appendix B: E3 WMEG: Western Day Ahead Market Production Cost Impact Study

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

Prepared by Energy and Environmental Economics (E3)

June 2023

Energy+Environmental Economics

 Energy & Environmental Economics, Inc.

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1 Study Context and Key Questions

The Western Markets Exploratory Group (WMEG) is a group of 25 utilities and public power entities across the Western Interconnection. The WMEG is examining ways to develop more integrated electric power markets in the West, including emerging day-ahead market opportunities, and ways to further integrate markets services over the long term, up to and including a regional transmission organization (RTO).

The West is at a critical juncture of regionalization within the power industry, as it seeks to extend regional markets from real-time operations to the day-ahead level. Organized electricity markets have long been shown to provide various benefits to participant members including a more optimal system dispatch. The Western Energy Imbalance Market (EIM or WEIM) is the first organized market outside of the California ISO (CAISO) to bring these benefits to multiple Balancing Authority Areas (BAAs) in the Western Interconnection. The WEIM is a real-time wholesale energy market with participants across the WECC footprint. Over the past decade, it has provided millions of dollars of annual savings for members. In 2021, SPP launched a similar real-time imbalance market in the West: the Western Energy Imbalance Services (WEIS).

Recently, California ISO (CAISO) proposed plans to form a day-ahead market option for the West titled the **Extended Day- Ahead Market** (EDAM). The Southwest Power Pool (SPP) released a separate plan to offer Western entities a day-ahead market service titled **Markets+**. Both market options will augment existing functionality for real-time markets in different parts of the Western Interconnection through CAISO's Western Energy Imbalance Market (WEIM or EIM) and SPP's Western Energy Imbalance Service (WEIS or EIS) offering.

Colorado[1] and Nevada[2] have passed laws that require transmission utilities to join RTOs by 2030. PacifiCorp recently announced it will join EDAM[3] and Powerex Corp. has announced it will join Markets+[4]. Amid the rollout of these new markets and moves towards regionalization, it is important for Western utilities to understand the impacts of these markets to help make informed decisions on their next steps.

The WMEG, through its consultant Utilicast, engaged Energy & Environmental Economics, Inc. (E3) to perform a Cost Benefit Study ("CBS" or "the study") examining the economic impact that joining either the EDAM or the Markets+ option would have for each WMEG entity and for the WECC overall. The study explores the impact that each market could have along two dimensions: (1) based on different **footprints** of which entities join either market, and (2) on the currently proposed design **features** of each market. In the CBS, E3 studies a Business as Usual (BAU) Case and three different market footprint options each comprised of different Western entities joining EDAM or Markets+ respectively by the 2026 study year.

[1] Colorado SB21-072, https://leg.colorado.gov/sites/default/files/2021a_072_signed.pdf

[2] Nevada SB 448, https://www.leg.state.nv.us/App/NELIS/REL/81st2021/Bill/8201/Text#

[3] PacifiCorp, "PacifiCorp to build on success of real-time energy market innovation as first to sign on to new Western day-ahead market", https://www.pacificorp.com/about/newsroom/news-releases/EDAM-innovative-efforts.html

[4] Powerex, "Powerex Commits to Markets+", https://Powerex.com/sites/default/files/2022-11/Powerex%20Commits%20to%20Markets%2B.pdf

Additionally, for the 2030 and 2035 study years, the CBS also examines the impact that increasing levels of market integration over a longer-term period could have for WMEG members.

Study impact focus: The WMEG guided E3 to focus the CBS only on the impact to variable generation and power purchase costs for each entity – that is, changes to the costs each entity incurs for fuel, variable O&M, and startup costs to generate electric power, as well the cost and/or revenue from power market purchases and sales. The E3 study does not estimate the cost of joining either market in terms of labor, software, or participation fees; savings in this study can be seen as gross of the cost of participation.

Additionally, this study does not consider a range of other benefits generally found to result from formation of a regional market, such as:

a) generation investment savings due to programmatic sharing of load and resource diversity for participating entities – for example, through the proposed Western Resource Adequacy Program (WRAP),
b) procurement savings by market enabling entities to contract with resources from across a larger market footprint (supported by a transparent locational market price and frictionless transmission access) rather than restrictions to procuring resources in one's own local area or with direct transmission schedules to reserve transfer capability to a local area,
c) coordinated regional transmission planning and investment, or
d) reliability improvement during extreme weather or challenging operational conditions.

The WMEG chose to focus the CBS on variable generation and purchase cost impacts as a directly quantifiable outcome of market formation but recognizes that these other benefit components may provide significant additional long-term savings. For example, the State Led Study Market Studies found that a two-market day-ahead option relative to a BAU case with only real-time markets could yield $85 million in adjusted production cost savings and $416 million in capacity savings.[5] Also, the 2016 Senate Bill 350 Study on the impact to California of a regional CAISO-led Western power market identified $104 to $523 million in adjusted production cost savings, $680 to $800 million in annual capital cost investment savings related to renewable procurement, and $120 million in annual capacity savings due to load diversity.[6] Additionally, for an example in the Eastern Interconnection, MISO's 2022 Value proposition estimates that the MISO market facilitates $890 to $923 million in Energy and Ancillary Services savings, $1,942 to $2,866 million in Resource Capacity Sharing, and $409 to $479 million in Renewable Resource Optimization, which is procurement related.[7] It is important to recognize that the savings estimates calculated in this study are conservative because they do not include these other types of potential savings.

[5] https://www.energystrat.com/s/Final-Roadmap-Technical-Report-210730.pdf
[6] https://www.caiso.com/documents/sb350study_aggregatedreport.pdf
[7] https://cdn.misoenergy.org/2022%20Value%20Proposition%20Annual%20View%20-%20Detailed%20Report628393.pdf

2 Study Approach

Study methodology overview: To conduct this study, E3 created a multi-stage simulation of the Western Interconnection using the PLEXOS production cost model developed by Energy Exemplar. Energy Exemplar worked closely with E3 to enhance E3's efficiency running over 4,000 cases in a Cloud-based environment, as well as customizing PLEXOS to directly address WMEG questions and represent the EDAM and Markets+ offerings in detail. In PLEXOS, E3 modeled the dispatch of all major power plants in the Western Interconnection on an hourly basis for each study year and study scenario.

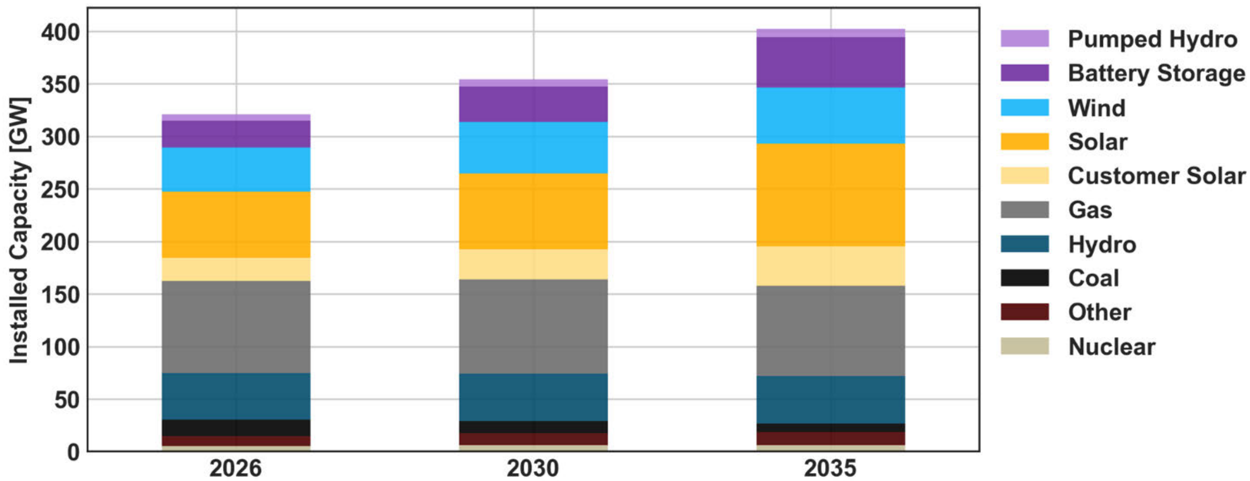
E3 modeled each of these cases first on a day ahead (DA) stage to identify commitment of long-start generation and calculate day ahead transactions, and then on a Real Time (RT) stage for actual dispatch in the operating day. E3 modeled the DA stage with load, wind, and solar forecast error in DA relative to the actual load, wind, and solar values that occur in the RT stage. To manage this forecast error, the model held flexibility on generators in the form of DA forecast error reserves to respond to changes in load or variable energy resources (VERs) between the DA and RT stages.

This section provides a summary of the study data and key assumptions. Appendix A to this report contains more extensive detail on each of these assumptions.

Study data: 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.[8] The CBS benefited significantly from contributions by staff from each WMEG member in providing input data – including load growth projections, updated generator additions and retirement information, as well as generator operational parameters, costs, and percentage shares that are owned and or contracted to different WMEG entities, which is necessary for calculating the adjusted production cost impact of different market participation plans for each entity. The 2026 study cases and those for subsequent years include significant generation additions, particularly of solar, wind, and storage resources based on the data developed by WECC and updated by WMEG members. The regionwide resource mix for each year is summarized in the table below.

[8] The 25 WMEG members represented are AEPCO, APS, Avista, Balancing Authority of Northern California (BANC), Black Hills Energy, BPA, Chelan County PUD, El Paso Electric (EPE), Grant County PUD, Idaho Power Company, Los Angeles Department of Water & Power (LADWP), NV Energy, PacifiCorp, Public Service of new Mexico (PNM), Platte River power Authority, Public Service of Colorado (PSCO), Puget Sound Energy (PSE), Salt River Project (SRP), Tacoma Power, Tucson Electric Power (TEP), Tri-State Generation and Transmission Authority (TSGT), and Western Area Power Administration (WAPA), which was modeled in 5 separate areas (SNR, CRCM, LAP, WALC/DSW, and WAUW). The rest of the WECC was represented as non-WMEG.

Figure 2-1 Total U.S. WECC Installed Capacity[9]



The CBS uses a zonal transmission topology based on Total Transfer Capability (TTC) between entities. The zonal option enables the study to avoid the additional complexity and significant run-time considerations of modeling a nodal topology, allowing both more cases to be run and more accurate modeling of ancillary services as well as the specific proposed market features of EDAM and Markets+. To ensure accurate modeling of transmission limitations, the study model incorporated a number of market trading hubs (or "tie zones") that connect multiple entities in today's actual operations. E3 developed the topology for these tie zones with the support of the WMEG transmission task force and staff at many WMEG entities. E3 also worked with WMEG Task Force members to develop assumptions for gas price forecasts, as well as greenhouse gas (GHG) prices, which were applied on in-state generation as well as imports into California, Washington, and Colorado. For non-WMEG areas, E3 supplemented data in the WECC ADS case with additional information gathered on resources and transmission.

Study Scenarios: The table below shows four scenarios with alternative market participation footprints that WMEG directed E3 to model for the 2026 study year.[10] In the BAU case, E3 models wheeling and trading friction at the border of individual BAAs. Within each market footprint (EDAM or Markets+), transactions do not face wheeling or frictional costs, but these charges are applied to trades on the border or seams between markets. Additionally, the market footprint determines the region over which DA forecast error reserves can be held on resources.

These cases were developed by the WMEG using a collaborative process intended to explore key impacts of (a) having a single market spanning all of the US WECC (in the EDAM Bookend case) versus (b) having two Western markets, with separate market footprints that reflect intentions already announced by

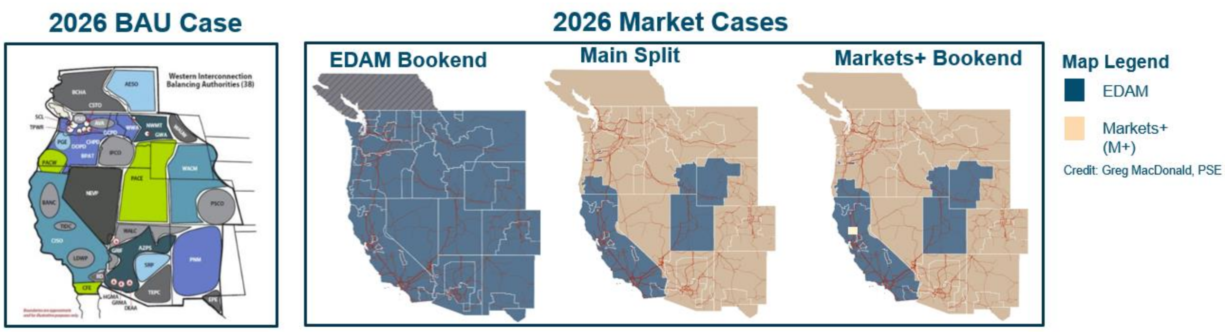
[9] Total WECC capacity does not include AESO resources as this was implemented as a price stream within the CBS. BC resources and loads (as well as trades with Alberta) were modeled as an integrated pumped hydro facility based on the anticipated quantity of energy to be imported from or exported to the US, based on data provided by Powerex. This BC capacity is included with pumped storage in the chart.

[10] For a subset of WMEG members who requested further exploration, E3 modeled four other alternative market footprints in 2026.

certain entities to join the EDAM or Markets+ as well as one potential set of assumed participation choices by the remaining Western entities that have not yet announced market decisions (in Main Split and Markets+ Bookend). These footprints do not represent the only potential maps for two Western Markets, as there are a wide range of potential combinations that could lead to different market footprints. A subset of WMEG members chose to fund additional footprint sensitivity cases, which are provided separately from this report.

The detailed participation of each entity in different markets for these scenarios is provided in Appendix B to this report.

Figure 2-2 2026 Core Study Cases

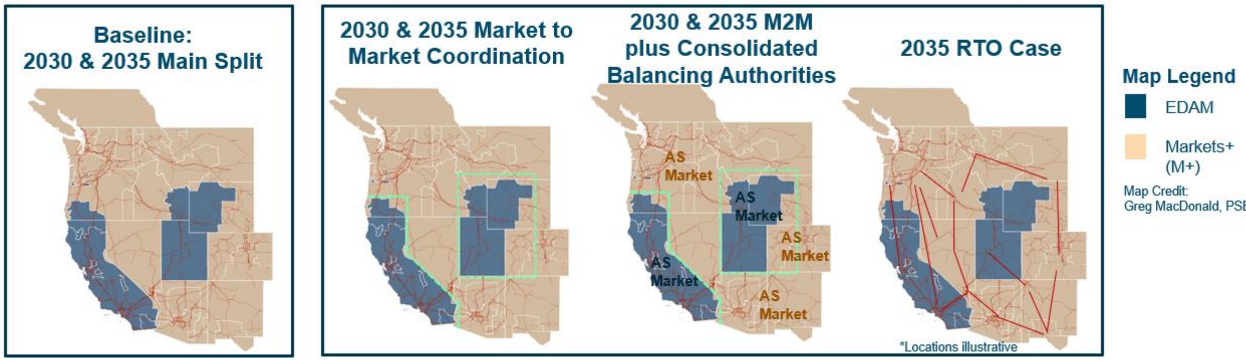


Note: The Markets+ Bookend footprint matches that of the Main Split Case, except for WAPA SNR region which was represented in Markets+ in the Markets+ Bookend and in EDAM in the Main Split Case

- The **2026 BAU Case** models a day-ahead (DA) stage with bilateral trading but no organized market. In the real-time (RT) stage, the BAU case represents wheeling and friction-free trading within the existing WEIM and WEIS footprints.
- The **EDAM Bookend** case models a single DA and RT market that covers the entire U.S. portion of the Western Interconnection, excluding Alberta, British Columbia (BC), and CFE in Baja Mexico. Trades inside the Market reflect the currently proposed EDAM design and are simulated with no wheeling costs or transactional friction.
- The **Main Split** case models two separate DA and RT footprints: (a) an EDAM comprised of PacifiCorp, and the state of California (CAISO, LADWP, BANC, LADWP, TIDC, and IID), and (b) a Markets+ region consisting of the rest of the US WECC, plus BC which is modeled as a pumped hydro generator with net purchases and sales at the US-Canadian border.. Alberta and CFE are modeled as external zones not participating in either the EDAM or Markets+.
- Finally, the **Markets+ Bookend** case models market footprints similar to the Main Split, except that WAPA Sierra Nevada Region (SNR), a sub-BA of the Balancing Authority of Northern California (BANC) is modeled in Markets+ rather than EDAM.

For the 2030 and 2035 study years, the Core CBS simulates additional cases shown in the figure below. WMEG selected these cases to explore ways in which the WECC region could pursue additional integration beyond a day-ahead and real-time energy market. Each case adds an extra feature of further integration to the previous simulation. Additional detail to these scenarios is provided in Appendix B to this report.

Figure 2-3 2030 and 2035 Core Study Cases



- E3 modeled **2030 & 2035 Main Split** cases with the same market footprint as the 2026 Main Split case, but with load growth, generation retirement additions, and updated fuel and GHG prices reflected.
- The **2030 and 2035 Market to Market (M2M) Coordination** cases use the 2030 and 2035 Main Split footprint for EDAM and Markets+ but reduces the hurdle rates that are charged on trades over the seams between the two markets footprints to represent transactional friction.
- 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 and adds significant transmission to evaluate each market's performance with additional transmission from coordinated planning, enabling greater trading across the footprint.

Market Features: the most distinct modeling difference between the EDAM and Markets+ footprints was that E3 represented **Fast Start Pricing (FSP)** in the Markets+ portion of the WECC footprint, but not in zones that are placed in EDAM. FSP is an adjustment to settlements currently used in the SPP market in the Eastern Interconnection and proposed for Markets+. Typically, generators provide multi-part bids including (a) start costs and costs to run at minimum output, and (b) the incremental cost to dispatch at a higher level. However, the locational marginal prices (LMPs) calculated by PLEXOS and used to settle energy transactions for all loads and generators do not include the start costs. Historically in LMP-based markets, an ex-post calculation determined whether generator start costs were fully recovered through infra-marginal rents during hours when the generator operated. Any start costs that were not fully recovered were charged to all loads via an "uplift" charge. Recently, certain North American markets have incorporated FSP, which converts generator start cost and minimum load costs into a marginal cost adder and then reruns the market process to generate new, higher market clearing prices. This higher price is then used to settle generator awards and load payments.

For this study, E3 created a custom modeling process in the PLEXOS simulation to follow the same approach used by SPP for FSP and applied the resulting prices to Day-Ahead transactions in areas within the Markets+ footprint of each scenario. This resulted in higher prices in some hours in the Markets+ zones (by up to $10/MWh in a limited number of hours and approximately $1/MWh on average). Notably, however, the FSP price adders may not propagate to the entire market footprint when transmission congestion occurs. For example, if there is congestion between the Pacific Northwest and

Desert Southwest during a time when fast-starting pricing is triggered in the Desert Southwest, the price increases from fast start pricing do not apply to zones in the Pacific Northwest. This dynamic is observed in many hours of the simulations.

The other major market feature modeled differently between the markets was GHG revenue allocation for the EDAM Market.[11] The current EDAM market design proposal includes a mechanism to allocate revenue associated with imports into GHG regulated zones (California and Washington for the study; this approach was not applied for Colorado) from other EDAM locations that do not have GHG pricing. E3 created a separate "GHG Reference Case" run in PLEXOS that excluded any imports into the GHG regulated zones and then used a detailed post-processing approach to identify EDAM member zones that send incremental energy to the GHG regulated areas (when compared to the GHG Reference Case), and then to identify generators that produce incremental energy. In situations in which the identified generator with incremental dispatch to California has a lower GHG emission factor than the market clearing emissions rate, E3's modeling allocates net revenue to the generator reflecting additional margin beyond the cost the generator would face for GHG permits on the imported energy. The Markets+ design proposal does not currently have a defined GHG allocation approach so costs for GHG are assumed to be returned to the regulating state. The state regulatory agencies can then determine whether to allocate a portion of this revenue among energy entities (or to allocate this revenue elsewhere). For this modeling study, we do not allocate GHG revenue for markets where the mechanism for allocation has not been defined at the time of this study. More detail on GHG modeling is described in Appendix A to this report, and more detail on allocation of GHG revenue is provided in Appendix C.

Individual WMEG Entity Benefit Calculations: E3 developed a comprehensive settlement process code that takes in output data from the various market model runs and generates ex-post settlement details down to the generator level for each WMEG entity over the study year. The code then aggregates these results to an entity level for each WMEG member. For each entity and each scenario, E3 calculate an entity-specific "**Net Variable Cost**" using the following formula:

Net Variable Cost = Load Cost + Generation Cost + Reserve Cost – Reserve Revenue – Generation Revenue – Wheeling Revenue – Congestion Revenue – Wheeling Revenue

Each of these components is discussed below.

- **Load Cost:** Entities incur a cost to serve load based on (a) the hourly quantity of load (in MWh) that the entity is obligated to serve in each zone of the model times (b) the hourly zonal energy price.
- **Generation Cost:** The model reports variable production costs for each generating unit as the sum of fuel costs, startup costs, and variable O&M cost for that resource. Generation Costs are attributed to each entity as (a) the total variable production cost of the unit times (b) the percentage share of that unit that is owned or contracted to the entity.

[11] For a subset of WMEG members who requested further exploration, E3 modeled additional market scenarios for 2026 in which transmission capability in the EDAM footprint and on market seams (as well as in the BAU) was reduced by 10%. Markets+ transmission capability was maintained at the same full TTC level to represent the potential impact of Markets+ utilizing a Mod 30 transmission rating approach.

- **Reserve Cost & Reserve Revenue:** In the BAU Case, E3 enforces ancillary service reserve requirements at the BAA level but does not settle these products at a market clearing price. For all the market cases, day ahead forecast error reserves are enforced at the level of a subregion within each market (e.g. the Northwest portion of Markets+), and each entity is assigned a Reserve Cost responsibility based on of (a) the hourly quantity of reserves that entity needs times (b) the hourly market price for reserves within that market sub-region. ; each entity is also awarded Reserve Revenue from the market based on (a) the quantity of reserves that are contributed by generators owned or contracted by the entity times (b) the hourly market price for reserves within that market subregion. In the 2030 and 2035 CBA cases, Reserve Costs and Reserve Revenues are calculated separately for each reserve product (spinning reserves, non-spinning reserves, and regulating reserves, as well as day ahead forecast error reserves).
- **Generation Revenue:** Generation Revenue is first calculated for each resource based on (a) the hourly energy produced by the generator, times (b) the hourly price at the generator's zone. This Generation Revenue is then attributed to each entity based on the percentage share of each resource that is owned or contracted to the entity.
- **Wheeling Revenue:** Wheeling revenue is revenue that transmission providers earn by selling transmission service. In the BAU Case, total Wheeling Revenue is calculated in the model for each entity based on the product of (a) the amount of energy exported over transmission lines connected to that entity, times (b) the OATT rate or market wheeling rate applicable that BAA or transmission entity, plus an additional $/MWh charge for bilateral day ahead market friction. In the RT stage of the BAU Case, wheeling is not charged for transactions between entities in the WEIM or WEIS market. In the DA markets cases, total wheeling revenue is first determined at a market-footprint level based on the (a) amount of energy flowing exported over transmission lines connected to each market footprint times (b) the load-weighted average of OATT rates of zones participating in that market, plus an additional $/MWh charge for transactional friction on seams between the markets. This total market wheeling revenue is then distributed among market participants based on each participant's percentage share of total load in the market (load-ratio share basis).[12]
- **Congestion Revenue:** Price differentials between zones due to transmission constraints creates congestion between entities, resulting in loads paying higher prices than remote generators receive on the other side of congested interface. The value of this difference is assigned back to the entities in the BAU case and for lines within each market footprint. Congestion on the border of each market is allocated among all participants in that market on a load ratio share basis.
- **GHG Revenue:** For established GHG revenue allocation methodologies (CAISO/EDAM) individual generators are awarded GHG revenues per the applicable allocation methodology. However, for Markets+, which does not have an established allocation methodology fully defined yet so in the model GHG revenue on imports are assigned the regulating states, which would have

[12] Separate proposals for market elements in EDAM and Markets+ that seek to provide some compensation to entities that lose current short-term firm or non-firm point to point revenues were not represented in this analysis due to the definitions of those mechanisms not being fully defined at the time when study assumptions for this analysis were finalized. Revenue from such mechanisms (or charges to derive this revenue) would be additional to any individual benefits represented in this study.

responsibility for determining any allocations of this revenue under currently proposed Markets+ rules.

For each entity, E3 then calculated the **Net Variable Cost Savings** from market participation (or the **Net Variable Cost Increase** due to market participation) as the difference between the Net Variable Costs for that entity in a market case (e.g., EDAM Bookend) compared to that entity's Net Variable Cost in the BAU case.

The sum of Net Variable Cost for all entities in the region (including WMEG members and non-WMEG entities) is equal to the regionwide Adjusted Production Cost. Therefore, the sum of Net Variable Cost Savings (or Net Variable Cost Increases) compared to the BAU for all entities in the region equals the total regionwide Adjusted Production Cost savings (or Adjusted Production Cost Increase).[13]

E3's settlement process is performed for both the Day-Ahead and Real-time market. Real-Time market settlement is typically performed as incremental to the Day-Ahead settlements – for example incremental Real-time generation dispatched at a level higher than the Day-Ahead schedule from the DA run will be valued based on RT stage prices and used for RT settlements. Similar approaches are used for Load costs and other individual benefit components. All pricing for the Day-Ahead settlement includes Fast Start Pricing for any zones included in the Markets+ footprint.

[13] This regionwide equation is due to the fact that most of the components of Net Variable Cost represent "transfers" or payments from one entity in the region to another entity in the region, which leads the net effect of revenues and costs from these transfers to cancel or offset each other at the regionwide level. The exception to this (components that are net transfers) are (a) Generator Costs, which are payments for fuel, operations, and maintenance for the generators, (b) revenues for sales or cost for purchases from entities outside the region (in Alberta or the Eastern Interconnection), and (c) GHG compliance costs that are paid to the GHG regulating states (if GHG revenue for imports are in excess of the GHG compliance cost, then those are captured as transfers to the exporting entity as well).

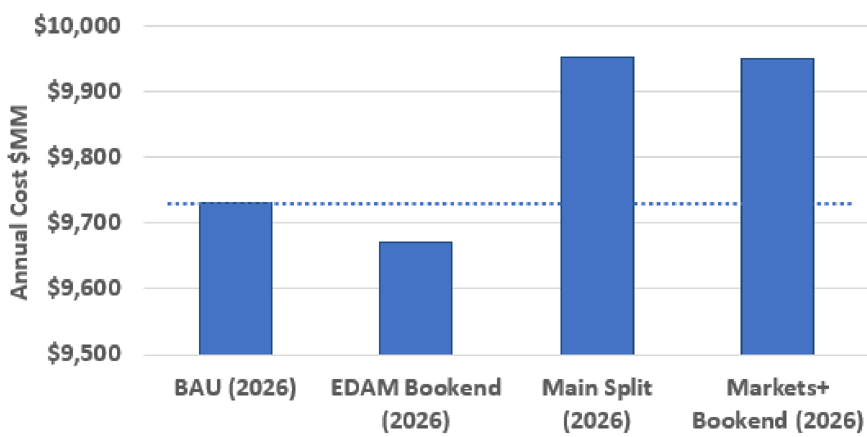
3 Study Results and Key Findings

The simulation cases that E3 modeled each produced hourly dispatch and dispatch cost for each generator, hourly reserves held on each unit, as well as hourly zonal transmission flows, and market prices. E3 used these outputs to create a set of adjusted production costs for each case on a regionwide basis, as well as a summary of the Net Variable Cost impact for each WMEG member (as well as for the non-WMEG entities, comprised of and for the rest of WECC loads and resources not associated with any WMEG member). Each case produced many results, so it is valuable to look across cases to highlight their important impacts and to explore their implications for the WMEG members and the Western Interconnection more broadly. This section describes the results of these cases, as well as key implications of their results.

3.1 Regionwide Impact

Under the BAU Case, the regionwide Adjusted production Cost is $9,732 million in 2026. Compared to BAU case, the regionwide Adjusted Production Cost is $60 million lower in the EDAM Bookend Case, $221 million higher in the Main Split Case, and $218 million higher in the Markets+ Bookend. As the next section describes, the impact for individual entities varies widely for each case, and the majority of the increase in Adjusted production Cost in the Main Split and Markets+ Bookend accrues as a Net Variable Cost increase for non-WMEG members.

Figure 3-1 Annual Regionwide Adjusted Production Cost by 2026 Study Case



Note: Y-axis in chart does not start at $0.

The magnitude of the regionwide impact for market cases ranges from 0.6% to -2.3% as a percentage of BAU case costs. This impact is small relative to total production costs because the BAU Case includes existing real-time markets (the WEIM and WEIS), and the market cases change the footprint of these real-time markets while also adding day-ahead markets. In addition, compared to today's system, the 2026 study year has fewer long-start resources (due to retirement of existing coal generators) and more flexible storage and quick-start thermal resources. These changes in the regional resource mix enable greater optimization in the real-time stage of operations (modeled here as hourly) relative to today's system.

The increase in regionwide production costs in the cases with two markets (Markets+ Bookend and Main Split) is due to reducing the size of the WEIM's geographic footprint. The increase in production costs due to a smaller WEIM footprint outweighs the savings that accrue from the addition of two day-ahead markets for the EDAM and Markets+ footprints.

In addition to the cases above, E3 modeled a separate BAU sensitivity case that assumed less optimized WEIM and WEIS markets. The purpose of this sensitivity is to recognize the uncertainty around how efficient and flexible RT markets (alone) could become by 2026, and to develop a bookend value that represents an optimistic case for the additional value created by DA markets. This sensitivity case constrains RT flows over each line between zones to the day ahead scheduled flow ± 15% of the line's total transfer capability. For example, if a 1000 MW line had 500 MW scheduled to flow in the DA stage for a given hour, the RT stage flows were constrained to range between 350 MW and 650 MW for that hour (500 ± 15% x 1000). This case results in regionwide annual production costs that are $70 million higher than the BAU case for this study. Comparing the DA market cases to this BAU sensitivity results in regionwide production cost savings in the EDAM Bookend growing from $60 million to $130 million, and the regionwide Adjusted Production Cost increases in the Main Split case shrinking from $221 million to $151 million.

Implication of small regionwide energy cost impact: It is important to carefully assess the other sources of potential impact of a DA market or greater integration, such as compatibility with a resource adequacy market that can enable generation investment savings, coordinated transmission planning, reduced curtailment of energy production that meets state clean and renewable energy standards, and more optimal resource procurement over a geographic wider area. Because dispatch-related benefits are relatively modest, it is more likely that other benefit types are key determinants in whether one or the other market options available to WMEG members is more beneficial overall.

Analyzing these other sources of benefits was not in the scope of this CBS, but other regional market studies have shown these benefits sources to be considerable – ranging from two to ten times the DA energy cost impact from DA trading alone.[14] Because this study has shown that DA energy benefits are likely relatively small, it is even more likely that other benefit types are key determinants in whether one or the other market options available to WMEG members is more beneficial overall.

3.2 Net Cost Impact for individual entities

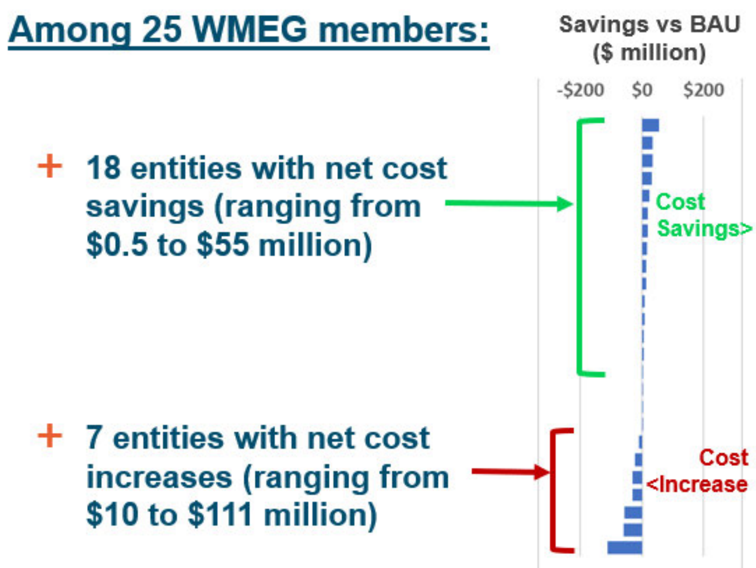
The Net Cost Impact for each individual entity was provided confidentially to each WMEG member funding this study, and the WMEG members chose to keep those results confidential. While Net Variable Cost for individual entities are not included in this summary report, this section discusses the key dynamics observed in results across different entities. The impacts on individual entities vary widely depending on the scenario.

[14] See discussion of other studies in Section **Error! Reference source not found.**.

3.2.1 EDAM Bookend Case Individual Results

In the figure below, each blue bar represents the Net Variable Cost savings or increases in the EDAM Bookend versus the 2026 BAU for one of the 25 WMEG member entities.[15]

Figure 3-2 EDAM Bookend Case – Net Cost Impacts among WMEG members



Overall, in the EDAM Bookend case compared to the BAU, the majority of WMEG members experience Net Variable Cost savings, ranging from $0.5 to $55 million per year. Other WMEG members, however, show increases in Net Variable Cost, ranging from $10 million up to $111 million, in the EDAM Bookend case. **For all 25 WMEG members summed together, Net Variable Cost increases by $20 million in the EDAM Bookend**. Higher Net Variable Cost for individual entities is largely due to two factors:

1. Reduced wheeling revenue compared to the BAU case since wheeling is not collected in intra-market transactions and the EDAM spans nearly the full West in this scenario. There is notable variation in wheeling revenues among study participants. The study approach did not attempt to capture existing transmission contracts in the BAU case, which may impact how these revenues would actually be distributed. Some entities may choose to discount the impact of wheeling revenues when analyzing their individual results. To facilitate this, wheeling revenues have been segregated from other benefit streams when requested. <u>If the reduced wheeling revenue were omitted from Net Variable Costs, WMEG members would together see savings of $369 million in the EDAM Bookend case</u> compared to the BAU; and
2. An increase in the price of market purchases for certain entities: in the BAU case, some entities purchase energy from their immediate neighbors at a low price because those neighbors would have faced pancaked wheeling charges to sell their energy to entities farther away, but the

[15] The impact for five WAPA regions is represented as a single total bar for WAPA as a one WMEG member, though individual results were provided to WAPA by sub-region. These individual impacts include reduced wheeling costs which have a significant impact on Net Variable Costs for members.

EDAM Bookend reduces the cost to transact throughout the wider EDAM footprint, which increases competition for purchases and increases market prices in in some instances.

Non-WMEG entities experience a Net Variable Cost savings of **$80 million versus the BAU case**. Non-WMEG entities include loads in the Western Interconnection that are not represented by the WMEG members as well as resources not owned or contracted to WMEG members. A significant majority of non-WMEG entities, representing 73% of non-WMEG load and 66% of non-WMEG generation capacity in the model, is based in California.[16]

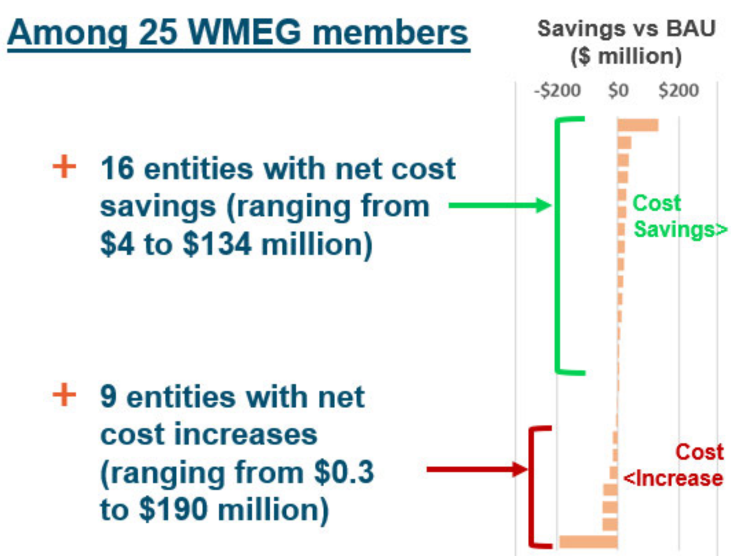
The production cost savings and individual member impacts in the EDAM Bookend relative to the BAU case are due to the day-ahead optimization over a large market footprint.

The market features simulated here for EDAM are largely similar to that of Markets+, with the exception of Fast Start Pricing (FSP) and allocation of GHG revenue for imports, which affect allocation of benefits but not regionwide savings. Therefore, if footprint identical to the EDAM Bookend market had been represented in a Markets+ scenario, the model would have produced similar regionwide result as for the EDAM Bookend, though with some differences in the allocation of participant-specific benefits.

3.2.2 Main Split & Markets+ Bookend Case Individual Results

In the figure below, each orange bar represents the net savings (or net cost increase) in the Main Split Case versus the 2026 BAU for an individual WMEG member.

Figure 3-3: 2026 Main Split Case – Individual Net Cost Impact among WMEG members



[16] California based non-WMEG entities include loads and resources in CAISO, IID, and Turlock Irrigation District. Non-WMEG entities outside California include CFE, BC, Douglas PUD, Grid Force, Avangrid, and Basin Electric, as well as generation in the model that was located throughout the WECC but not identified as being owned or contracted to WMEG entities so treated as merchant generation for the purposes of summarizing cost impacts.

Similar to the EDAM bookend, the majority of WMEG members experience net cost savings in the Main Split Case though some of the members experience cost increases. **For all 25 WMEG members summed together, Total Net Costs decline by $26 million**. The size of this cost decline reflects the net impact of reduced wheeling revenues modeled for WMEG entities compared to the BAU case. As previously noted, wheeling revenues vary significantly among study participants, and this study did not attempt to capture the impact of existing transmission contracts on wheeling revenue distribution. <u>If the impact on the model of reduced wheeling revenue were omitted from Net Variable Costs, WMEG members would together have a $266 million Net Variable Cost reduction in the Main Split case compared to the BAU.</u> Individual WMEG entities that experience lower net Variable Net Costs in the EDAM Bookend do not all experience lower Total Net Variable Costs in the Main Split Case.

The **Main Split case also showed a $247 million Total Net Cost increase for the non-WMEG entities**. The driver of this cost increase for non-WMEG members is that the Main Split Case introduces a larger cost of wheeling over the market seams.

The Non-WMEG entities, who are primarily located in California and are part of the EDAM in this case, import significant amounts of energy in the BAU case, though these entities also have significant net sales (exports) in other hours, primarily solar heavy periods.

In the Main Split case, many of the entities that export power to serve non-WMEG loads join Markets+, which causes those exports to EDAM to face a significant wheeling cost and market friction. To reduce exposure to these higher import costs, the non-WMEG entities increase dispatch of local gas generation – with a 6.7 TWh increase in non-WMEG gas dispatch overall compared to the BAU case.

Many gas units have higher fuel costs in the non-WMEG areas (compared to WMEG areas) due to pipeline transportation costs. Additionally, the implied heat rates of gas units in non-WMEG zones are also elevated during early evening ramping hours. Together, these factors result in a higher cost for the incremental local gas generation dispatched in the Main Split Case compared to the cost of market purchases in the BAU Case.

Moreover, the non-WMEG areas also face a higher cost for exporting generation, so the non-WMEG entities must curtail more solar generation when prices outside the EDAM are not high enough to justify the export cost. Batteries and pumped storage are also run more heavily in the non-WMEG areas, incurring round trip efficiency losses.

Regionwide GHG total emissions change moderately in this case, but the location of their source shifts – with California and other GHG-regulated areas facing more GHG emissions from local generation in non-WMEG areas, rather than from imports. It is possible that this local gas generation impact may have different impacts on local air quality, but E3 did not explore these changes in this study. Additionally, more gas dispatch in California could potentially have an impact on local gas prices due to higher in-state fuel use in certain hours compared to a BAU case, though these impacts were not considered in the current study.

Among WMEG entities, the impact of the Main Split Case varies widely due to three separate factors:

First, these entities overall **reduce local gas dispatch** (due to lower exports to non-WMEG areas), **resulting in lower Generator Costs but also less Generation Revenue**.

Additionally, many WMEG entities in the Main Split Case **lose wheeling revenue compared to the BAU** Case since wheeling revenue **(based on the transmission tariff and buy-sell spreads from transactional friction)** is not collected in intra-market transactions in this case. Some entities in Markets+ footprint, however, **receive increased Wheeling Revenue** due to the allocated share of wheeling charges applied on transactions over market seams when selling to the EDAM footprint. The EDAM participants also receive a share of Wheeling Revenue from EDAM exports to the Markets+ footprint.

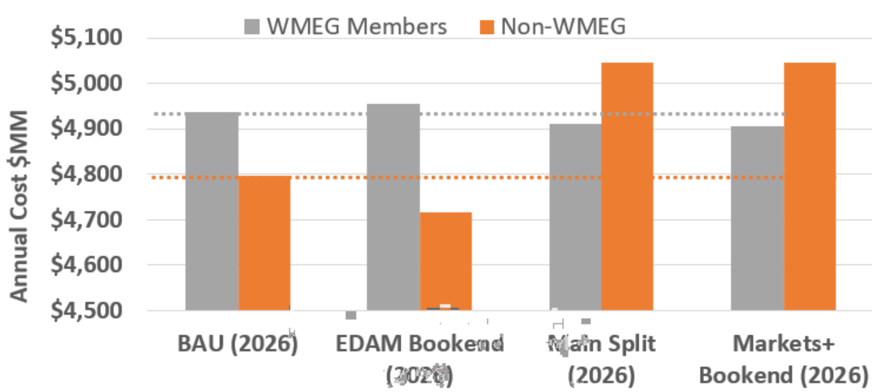
Finally, **the market footprint (and cost to transact over market seams) greatly impacts day-ahead market prices, which have a significant effect on the Load Cost and Generation Revenue for many individual WMEG entities.** Fewer exports to the EDAM area (comprised of primarily non-WMEG members) result in lower prices in the Main Split Case for the Markets+ footprint in some hours. WMEG entities that are net purchasers of energy during these hours make their purchases at a lower price than in the BAU Case (or in the EDAM case) resulting in savings. The converse is also true –net sellers in the BAU Case tend to have more negative results in the Main Split Case when prices are lower.

Fewer exports from the EDAM area during heavy solar, low load periods do lead to higher prices in the Markets+ region at certain times. The impact of these lower solar-hour prices varies, however, by entity, as some Southwest entities with significant local solar generation received more revenue for the solar generation they own or have contracted; additionally, the load levels in these hours tend to be smaller so price reductions are less impactful on total net costs.

In the Desert Southwest, there are hours with Fast Start Pricing (FSP) applied in the Main Split Case, which boosts Markets+ prices during those hours, partially offsetting the downward price impact from fewer exports to the EDAM region. Fast start pricing, however, has less of an impact in the Pacific Northwest portion of the Markets+ footprint, due to transmission constraints getting from the Northwest to the Southwest or Rockies area while avoiding transmission through the EDAM (California and PacifiCorp). The next section discusses these effects in more detail.

The table below summarizes the net cost to WMEG and non-WMEG members across different cases for 2026, highlighting the greater variation in results for non-WMEG entities vs. the sum of impact for WMEG members across cases.

Figure 3-4: Sum of Total Net Variable Cost for WMEG Members and Non-WMEG Entities



Note: Y-axis in chart does not start at $0.

Implication of wide variation in individual entity benefits: The individual entity results discussed here have two key implications:

- Among WMEG entities: it is important to closely consider the individual entity impact. These impacts do not always have the same sign as regionwide production cost impacts, nor the sum of Total Net Costs to all WMEG members. Overall, the two factors that most affect individual entity Total Net Costs are (a) whether the entity is a net purchaser or seller and whether the market footprint increases or decreases market prices, and (b) the allocation of wheeling and congestion revenues—particularly on market seams. The market rules for these allocations are still being defined but could affect the individual benefits of many entities in the West.
- For non-WMEG entities: it is important to consider that non-WMEG entities likely receive a sizable amount of the Net Variable Cost reduction in a single market footprint (as reflected in the EDAM footprint). They would also accrue a significant share of the cost increase that results from dividing the Western interconnection into two separate market footprints. While individual WMEG entity impacts vary, the sum of changes in the Total Net Cost to all WMEG members together remains relatively stable over the cases. Non-WMEG results, by contrast, show wider differences between different market cases or different footprints. Recognizing this difference in impact, it may be useful for non-WMEG members to seek other attributes of a single market (outside of Net Variable Cost) that could provide additional encouragement for wider participation. Alternatively, it may be useful to seek opportunities for improving market-to-market coordination (discussed later in this report) that could lead to results that are more like those of a single market.

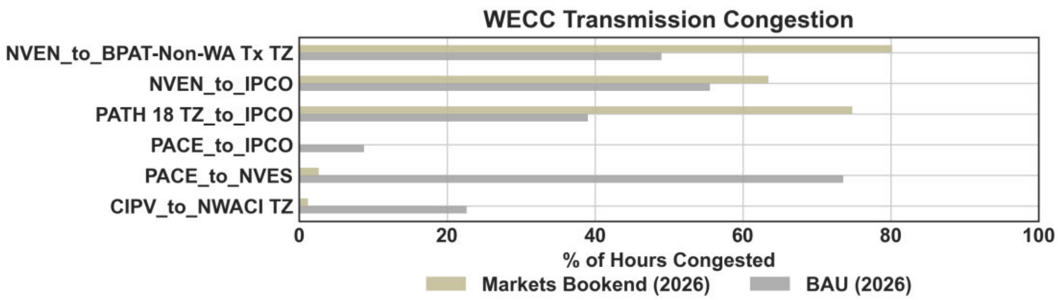
3.3 Importance of Transmission between Pacific Northwest and Desert Southwest

In the Main Split and Markets+ Bookend Case, transactions within the Markets+ Footprint between the Pacific Northwest and Desert Southwest (as well as to the Rockies) depend heavily on key paths through the states of Idaho, Nevada, and Montana. These transmission ties, which are already frequently utilized in the BAU Case, increase in importance in the Main Split Case because California and PacifiCorp are represented in a separate market (EDAM). Sending power from one part of the Markets+ footprint to California areas or PacifiCorp incurs significant wheeling charges and transactional friction on the market seam. Moreover, passing through the EDAM footprint to get to another sub-region of the Markets+ footprint would require also incurring wheeling costs a second time to get out of the EDAM, resulting in an additional “pancaked” transmission cost.[17]

[17] Powerex, which was represented in Markets+ for all scenarios, identified additional transmission contracts it holds on paths connecting the Northwest to the Southwest. This contracted transmission is modeled as part of the Markets+ region to facilitate more trades between the Northwest and Southwest. The total demand for Northwest to Southwest transactions, however, was still greater than the transmission available when transactions over paths connecting through zones participating in EDAM are subject to wheeling charges and friction on market seams.

As a result, in the Main Split case, the model indicates a large shift of transmission flow. There is a reduction of flow and congestion on paths that cross the market seams, including the Northwest AC Intertie (NWACI) to the PG&E Valley zone in Northern California (CIPV), as well as on lines between PacifiCorp East (PACE) and NV Energy (NVES). Instead, transmission flows in this case shift to lines that connect the Northwest to other portions of the Markets+, including from BPA to Nevada, BPA to Idaho Power, and Idaho Power to Montana (via Path 18). The chart below identifies the percentage of hours in which these links are congested in the model in the BAU case as well as the Main Split case which results in a significant increase in intra-Markets+ flow.

Figure 3-5: Frequency of Transmission Congestion on Key Northwest-Southwest Paths

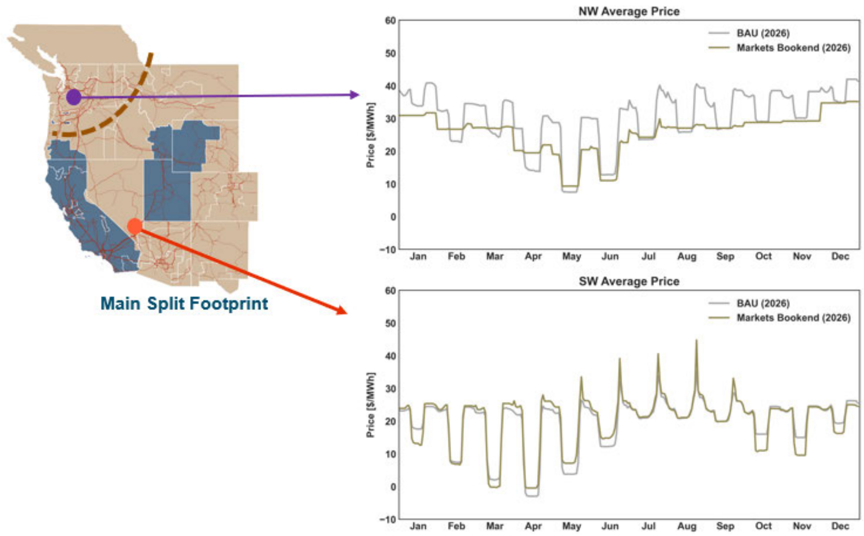


The congestion on these lines has a significant impact on market pricing in the sub-regions of the Markets+ footprint. The figure below compares Pacific Northwest (NW) and Desert Southwest (SW) prices in the BAU case versus the Markets+ bookend on a month-hour basis. For example, the average price for all January days at 1:00 AM is shown as the first data point in each table. The Northwest prices are higher on average due to GHG pricing applied in the State of Washington, but in the BAU Case the patterns of prices between the Northwest zones are quite similar to the pattern of the Southwest, because the BAU case does not have a high cost market seam (as there is in the Main Split Case) that limits the economic transmission flow through California zones or the PacifiCorp system.

In the Markets Bookend Case, however, as well as in the Main Split Case, prices in the Northwest become much flatter than in the Southwest. The Northwest has significant quantities of flexible hydro generation that can be used to balance local loads and renewables. This flexibility is also used to make hourly exports to other zones outside of the Northwest. With the significant hurdle rate and wheeling cost now imposed on transmission to California (or through PacifiCorp), there are many evening hours with higher market prices in the Southwest. In these hours, the Northwest cannot get as much of its flexible generation directly over to the Southwest due to transmission congestion. As a result, Southwest prices spike upward (and even more so due to fast-start pricing) but Northwest prices stay flat as there is sufficient local hydro to balance out and meet local demand across most days.

In the Southwest, there are hours with Fast Start Pricing (FSP) applied in the Main Split Case, which boosts Markets+ prices during those hours, but fast start pricing has less of an impact in the Pacific Northwest portion of the Markets+ footprint, due to the transmission constraints between the Northwest and Southwest.

Figure 3-6: Month-Hour Average Market Prices in Northwest versus Southwest



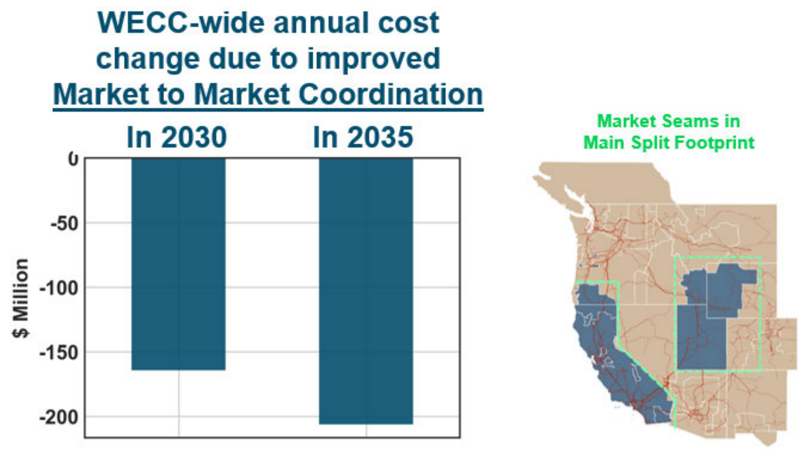
Implication of Northwest-Southwest transmission congestion within Markets+ zones: These congested lines indicate that there is value from Northwest hydro flexibility that is not being fully utilized for maximizing efficiency across the Markets+ zone. This results in higher dispatch costs and higher load prices for Southwest entities in Markets+ compared to a situation in which these lines were not congested. This dynamic also reduces revenue for Northwest entities that could export more energy at high value times if there were more transmission available within the Markets+ region.

This result implies that if the Western U.S. ends up forming two separate markets with a footprint similar to Main Split or Markets+ Bookend, it will be valuable to explore opportunities to contract for or potentially construct additional transmission to more robustly connect the Northwest and Southwest portions of Markets+.

3.4 Impact of Market-to-Market Coordination

For both 2030 and 2035, the study also modeled a Main Split with improved Market to Market (M2M) Coordination. This case was implemented by reducing the assumed cost of transactional friction in both directions on market seams between the Markets+ and EDAM footprints. For 2030, this reduction in market seams friction reduces regionwide Adjusted Production Cost by $162 million compared to the 2030 Main Split case with no M2M coordination, and in 2035, the reduction in seams friction created a $206 million reduction in Adjusted Production Cost compared to the 2035 Main Split Case with no M2M coordination. These results are highlighted in the figure below together with a map illustrating the approximate vicinity of the market seams between cases. The largest portion of this reduction in cost due to M2M coordination accrued as Net Variable Cost reduction for non-WMEG entities.

Figure 3-7: Regionwide Adjusted Production Cost Impact due to Improved Market to Market Coordination



Market to Market coordination could benefit WMEG members in Markets+ (reducing the Net Variable Cost for many WMEG members) by facilitating more sales to the EDAM footprint, as well as purchases from EDAM when those transactions are economic in a scenario with Market to Market Coordination but may not be economic in the absence of M2M coordination due to the high cost of transactional friction on market seams. M2M could also create opportunities to transact more between different portions of the Markets+ footprint if transactions through EDAM transmission (which may otherwise be underutilized) can be used for Markets+ to EDAM to other Markets+ areas as a result of potentially lower seams cost in M2M cases in certain period.

For EDAM participants, the Net Variable Cost savings that accrue from improved M2M coordination could also be significant. EDAM participants benefit from an improved opportunity to purchase economic imports from the Markets+ footprint at costs lower than that of local generation, as well as the opportunity to export more solar generation (with lower seams cost) during midday hours.

Key implications of M2M results: In practice, M2M coordination can involve a wide range of different processes. A separate report for WMEG, led by Utilicast, summarized existing M2M practices and experiences from other jurisdictions, highlighting some of the more valuable opportunities.

There is a large degree of uncertainty regarding the transactional friction that might occur between the EDAM and Markets+ footprints, because they are each new instances of day-ahead markets options that are not full RTOs, and because the experiences of market-to-market transactions depends significantly on details of the resources and practices of neighboring regions.

Therefore, the magnitude of transaction friction modeled on market seams the 2030 Main Split Case ($10/MWh in Day ahead and Real time) and the reduced level in the M2M case ($6/MWh in Day ahead and $3/MWh in real time) carry some degree of uncertainty.[18] Nevertheless, the results provide a strong indication of the positive directional impact on potential savings that pursuing M2M coordination could

[18] Additional detail on hurdle rates in each scenario are provided in Appendix A to this report.

carry. The results of these cases highlight the value of prioritizing further exploration of improving M2M coordination through the process of designing either market.

When exploring M2M coordination, this study points toward the particular value of coordination in real time or near real time. Coordination during the RT stage may be more challenging than day ahead due to faster speed at which RT transactions need to be executed, but if there are two separate Western markets with both DA and RT stages, it may be useful to explore mechanisms for facilitating more liquid transactions between the markets after the DA stage but ahead of the RT stage. For example, at a period of three to four hours ahead of the operation hour (either through market mechanisms or in an improved bilateral trading format), the level of certainty for wind, solar, and load has greatly improved compared to the prior day, and there may still be time to bring additional thermal generation online if economic to do so. Therefore, better coordination in this period a few hours before real-time (either through the markets or in an improved bilateral format) is worth exploring for its potential to obtain a portion of the savings and efficiency of a single market.

3.5 Impact of Consolidated Balancing Areas

For the 2030 and 2035 simulation years, the study also modeled Consolidated Balancing Areas (CBAs) for zones within each market footprint, with footprints consistent with the Main Split Case. The model represented a CBA by aggregating the Spinning Reserve, Non-Spinning Reserve, and Regulating Reserve requirements for each BAA to a level of a sub-region of each market footprint allowing zones to purchase reserves from their neighboring zones in the same market.

The CBA case does not reduce the total quantity of reserve requirements needed within each sub-region. By setting the Spinning and Non-Spinning Reserves requirements in the BAU Case each at 3% of zonal load, the BAU case already reflects savings enabled from existing contingency reserve sharing pools in the West. It is possible that the quantity of Regulating Reserves could be reduced through BA consolidation but calculating potential changes in these needs would require intensive sub-hourly data analysis. Since this study focused on an hourly time step, Regulating Reserves quantities were not changed in this case, so potential quantity reductions represent an additional potential opportunity for savings not examined here. The CBA case also did not model any potential increase in path ratings due to BA consolidation, which if feasible would represent additional potential benefits beyond the savings included here.

This change resulted in a $10 million annual reduction in regionwide Adjusted Production Cost compared to the Main Split M2M case for both the 2030 and 2035 study years. The size of this incremental savings change is modest, which is likely driven by the fact that the model already has significant flexible storage resources making it relatively easy to meet operational reserve requirements in most hours of the year. Since the overall cost of carrying operational reserve requirements is relatively low during these future years, the savings are also relatively small from carrying them in a more geographically flexible manner in the CBA scenarios.

It is important to note that the study covers only the operational-related cost savings from a CBA – which is largely related to more efficient commitment of less or less expensive thermal generation. The study did not seek to account for potential capacity-related savings that a CBA might provide if it enabled fewer or more optimal investments in new resources for serving load and meeting reserve needs. Investment savings, if any, would be additional to those modeled in this study.

3.6 Impact of RTO

The 2035 Main Split RTO case modifies the 2035 M2M+CBA Case, by adding significant additional transmission facilities throughout the region to reflect coordinated transmission planning for an RTO. Additional detail on the transmission additions in Appendix B to this report. The 2035 main Split RTO case produced a $387 million reduction in incremental regionwide Adjusted Production Cost compared to the 2035 Main Split M2M + CBA case. These savings accrued in similar levels between the non-WMEG entities and the WMEG members, though the impact to individual WMEG members varies based both on how the new lines affect market prices and on each WMEG members' net positions as sellers or purchasers.

This case was particularly important in creating more integrated pricing between the Northwest and Southwest regions by reducing transmission congestion on paths connecting these areas relative to the other cases that did not add transmission capability in those corridors. This result indicates that more transmission capability would provide value in either market footprint for improving dispatch efficiency and reducing Adjusted Production Costs on a regionwide basis, as well as improving the Net Variable costs to individual entities.

For the Core CBS Study, the RTO Case is only modeled for the Main Split Scenario, though a sub-set of WMEG members also funded additional footprint sensitivities cases for the RTO case. The CBS did not model a WECC-wide RTO scenario, but similar levels of regionwide Adjusted production Costs savings would likely accrue in a WECC-wide RTO footprint, which may not require as much additional transmission to realize these savings due to the absence of market seams.

The results of the RTO case reflect do not reflect the capital cost of constructing new transmission, nor any generation investment savings due to programmatic sharing of load and resource diversity for participating entities, or from more optimized regional resource procurement. Therefore, these results indicate that more transmission capability would provide value in either market footprint for improving dispatch efficiency and reducing Net Variable Cost, but do not represent a full assessment of benefits of any individual line to compare to the line's full costs.

3.7 Summary of key results and implications

The table below summarizes the key results of this study, along with the drivers that lead to these results, and the implication of these results for further market development and actions.

Table 3-1: Summary of Key Study Results, Drivers, and Implications

Key Result	Key Drivers of Results	Implication of Results
1. Market Cases have a relatively small impact on regionwide variable cost	The BAU case includes WEIM and WEIS real-time markets, which already provide significant savings, leaving less room for improvement.	Other benefit categories (such as generation investment savings for serving peak load, and optimized procurement over the market footprint,

(0.6 to 2.3% change vs. total BAU costs).		and coordinated transmission) may have a larger impact than Adjusted production Cost at a regionwide level or individual entity net variable costs, and therefore are important for further assessment.
2. Impacts on individual WMEG members vary widely within market cases.	(a) Entities that are net purchasers benefit from reduced prices in market cases, while sellers see lower sales revenues. (b) Additionally, some entities receive less wheeling revenue from exports or wheel-through transactions in the market cases than in the BAU case because the market cases do not charge wheeling on intra-market transactions.	When an entity evaluating the Net Variable Cost impact of different market options, it is important to consider: (a) the entity's anticipated net sales position and also how wheeling revenues on market seams are allocated in final design, and (b) how much wheeling revenue the entity would receive in a BAU (no market) scenario, and whether the entity expects transmission customers will continue contracting for transmission in a market scenario (e.g., for greater certainty or to receive congestion revenue) or will reduce payments for transmission contracts
3. Significant savings in EDAM Bookend accrues to non-WMEG members (primarily California) while the Main Split and Markets+ Bookend Cases create cost increases primarily in non-WMEG areas (again – primarily in California).	In the non-WMEG areas, gas generation goes down in EDAM Bookend but up significantly in the Main Split Case because higher costs of wheeling friction over market seams prevent optimal trading.	Non-WMEG members should recognize the variable cost savings that accrue to them in a situation with one Western market versus two markets and look for ways that other benefit categories may help encourage this direction.
4. If there are two Western markets (such as in the Main Split Case), transmission between the Northwest and Southwest is important for Markets+ transactions.	Results in the Main Split case show a significant amount of flexibility in the Northwest with limited transmission to reach the Southwest via Idaho and Nevada as well as through Montana to the Rockies.	If pursuing two markets in the West, it is important to seek options to contract for or build additional transmission capability in Markets+ between the Northwest and Southwest.
5. If there are two Western markets, Market to Market coordination can be valuable for achieving improved efficiency.	Market to market coordination in the 2030 M2M case reduced regionwide costs by over $150 million due to the reduction in the transactional friction applied on market seams.	Market to Market coordination may be challenging to implement but important to investigate, particularly in the real-time market stage. Potentially, improved trading in hours leading up to real-time could help facilitate improved efficiency.

Appendix A. CBS Modeling Approach

A.1. Modeling Framework and Assumptions

The modeling framework behind the analysis focused on the key differences between the proposed EDAM and Markets+ products and how those would translate to different costs or benefits relative to one another. The study was done using Energy Exemplar's PLEXOS production simulation model, and E3's machine learning-based RESERVE tool provided reserve requirements based on load and renewable forecast error. E3 also developed renewable generation forecasts at the plant level and load forecasts for WMEG members. Lastly, E3 developed a settlements algorithm using Python that conducted hourly settlement of both EDAM and Markets+ across market participants to provide entity-specific system costs for any scenario.

EDAM and Markets+ Features

E3 incorporated differences and similarities between EDAM and Markets+ in the production cost modeling and settlement calculations. E3 used industry knowledge, conducted research, and worked extensively with Utilicast and WMEG members through multiple task forces to identify important market features including:

- Fast Start Pricing
- Transmission Availability
- GHG Revenue Allocation
- Market Seams
- Imbalance Reserves
- Transmission Congestion Rent
- Wheeling Revenue
- Resource Sufficiency Test
- 3rd Party Transmission revenue

E3 then worked with Utilicast and WMEG task forces to understand the key differences and similarities between EDAM and Markets+. For this study, a resource sufficiency test was discussed with the WMEG but was not included in the modeling. Thus, these results assume that all market participants are considered resource sufficient for each hour, but the model did not explicitly assess this compliance. Any potential resource insufficiency penalties should be assessed by the individual WMEG members. Third Party transmission revenue was not calculated within this analysis as this revenue may change in the future. E3 instead provided full transmission congestion and wheeling revenue on each line to members who could allocate a portion to 3rd parties as a post-processing step outside of the core analysis. E3, Utilicast, and WMEG discussed the remaining market features extensively and developed the key aspects of remaining contrast and comparability.

Given that some EDAM and Markets+ rules have not been fully developed, it was challenging to know if there were indeed similarities or differences in some of the market features. For the purposes of this study, it was assumed that if a market feature has not been distinctly defined for Markets+ or EDAM, then it was treated similarly to the other market that had defined this area. This treatment is consistent with the observation that in the long run, mature markets tend to be aligned and resemble one another. The table below identifies how E3 modeled the key market features for EDAM and Markets+ within the analysis with particular attention to Fast Start Pricing and GHG revenue allocation. Transmission availability appeared to differ between the two markets, however the differences were not clear enough to be considered part of the core study and were instead changed as part of a sensitivity study (APP #3).

Table A-1 Market Feature Comparison in EDAM vs. Markets+

Feature	EDAM	Markets+
Features modeled in different ways for each market*:		
Fast Start Pricing	No	Yes
GHG Revenue Allocation	GHG Revenue allocated to out of state generators in EDAM sending incremental power to CA & WA (compared to a "GHG Reference Case")	Distribution of revenue for GHG imports not yet specified in market design; assumed to be determined by the states; for this study was not explicitly allocated to electric power entities represented in the study
Transmission Availability	Modeled based on Zone-to-zone Total Transfer Capability (TTC) with tie zones. **Sensitivity case (APP3)**: Reduce transmission availability in EDAM relative to M+ capability based on flow based.	
Features modeled similarly for each market:		
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 needed in each zone (or sub-region) calculated based on percentile of each zone's DA forecast net load forecast error (reduced for EDAM or M+ footprint diversity)	
Transmissions Congestion Rents	Congestion rent allocation based on ownership share of lines/paths between zones (Markets+ allocation design not yet fully defined so assumed to follow same format as EDAM)	

This Appendix section contains additional details on each of these market features as well as other modeling assumptions detail.

While not a direct feature of the market per se, Powerex provided guidance to model its system and transactions with the U.S. A consistent assumption across all modelling scenarios is that Powerex is participating in Markets+. Powerex has publicly committed to joining Markets+ and is working with SPP to enable implementation of Markets+ real-time in 2024. The full Markets+ Day Ahead /Real-time platform is expected to go live in 2026.

For each WMEG scenario, Powerex provided information about its projected market activity in two key categories:

1. The portion of its market activity that is likely to occur in fixed 24/16/8-hour blocks; and
2. The portion of its market activity that is likely to occur on an hourly optimized basis.

Under the modelling scenarios in which BPA and other NW entities join EDAM, Powerex expects that its most attractive market opportunities would be forward sales in 24/16/8-hour blocks to utilities and large commercial and industrial customers seeking reliable firm capacity for resource adequacy purposes and/or deliveries of carbon-free energy (often on a 24/7 basis).

To supplement these block transactions, Powerex also expects that it would generally make approximately 1,000 MW of hourly flexibility available for hourly optimized transactions in Markets+, including enabling intertie bidding at the BC/US Border for transactions to and from the EDAM footprint. These assumptions are generally consistent with the present, in which Powerex's WEIM activity has been limited (to much less than 1,000MW on average), as a result of:

1. Powerex viewing price formation in the bilateral markets as more attractive; and
2. Powerex choosing not to make sales of carbon-free energy in the WEIM, due to its concerns about the CAISO's GHG algorithm inaccurately deeming Powerex's carbon-free supply as being delivered to California, with an assumed simultaneous backfilling of unspecified energy to BC.

Under the modelling scenarios in which BPA and other NW entities join Markets+ (enabling strong transmission connectivity within the NW), Powerex expects that its most attractive market opportunities will be hourly optimized transactions through Markets+ (instead of continuing to make forward transactions in fixed blocks for resource adequacy and carbon-free supply purposes).

Accordingly, Powerex indicated that it expects to make its full hourly flexibility available to a well-connected Markets+ footprint (limited only by minimum and maximum generation and transmission limits). Consequently, the modelling scenarios in which BPA (and other NW entities) join Markets+ have much more Powerex hourly flexibility available for dispatch. E3 estimates that the incremental regionwide cost reduction attributable to Powerex's increased hourly flexibility in these scenarios is approximately $7 million.

A.2. Market Modeling

The analysis uses Energy Exemplar's PLEXOS production cost simulation software to model the current Business-as-Usual (BAU) WECC market interactions as well as the proposed EDAM and Markets+ markets.

E3 used CAISO's modified 2032 Anchor Data Set WECC-wide model as the base model for this study, which includes CAISO's resource updates for California.

Model Topology

E3 worked with WMEG members and Utilicast to develop an updated model topology that reflects the geographical locations of BAAs while also capturing key transmission constraints and trading hubs throughout the West. The topology goes a level deeper than the usual hub and spoke representation of WECC.

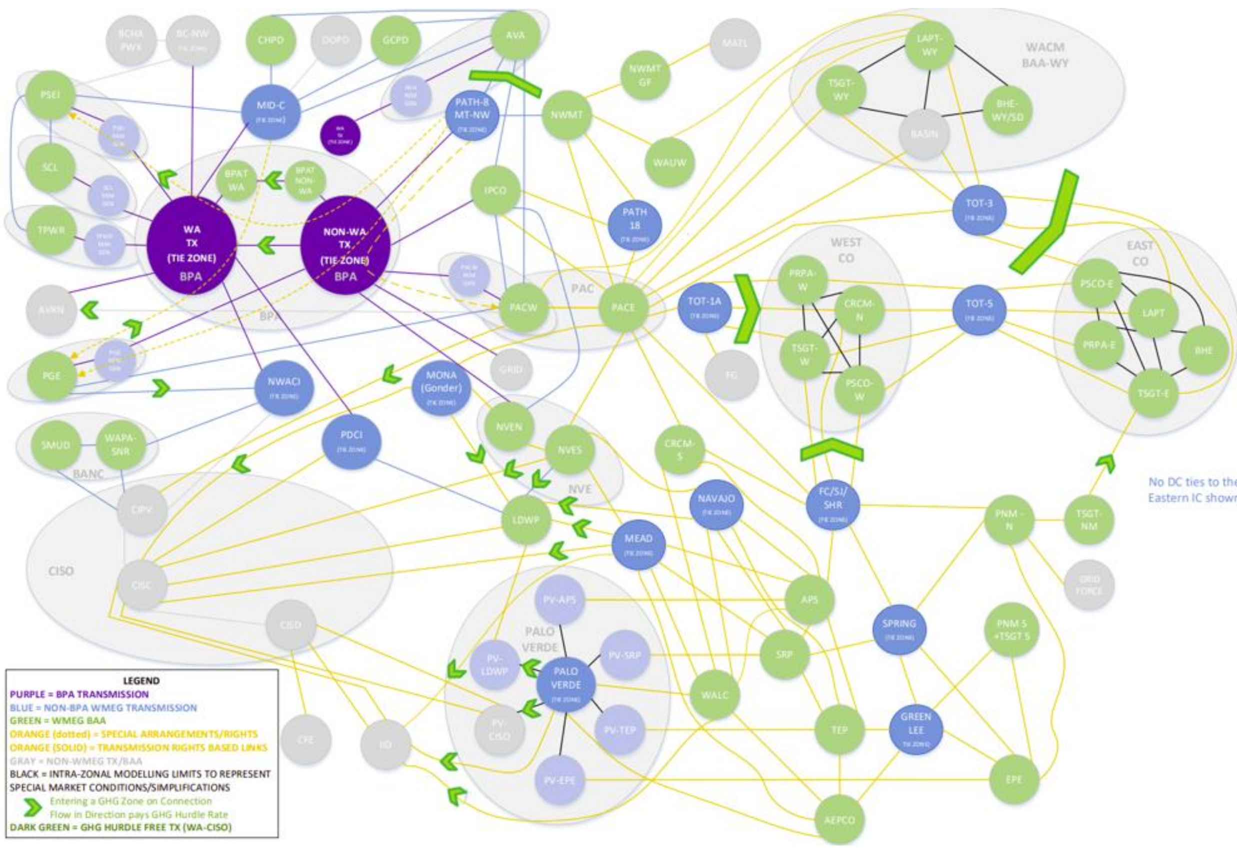
In addition to incorporating major trading hubs in the West such as Mid-C, Palo Verde, and Mead, E3 models other areas where multiple entities can transact with one another. These junctions are defined as "Tie Zones" within the model and allow transmission paths to be broken out and allocated among WECC entities to track transactions into and out of individual zones. This is particularly an issue in the Southwest where entities can transact with each other at multiple seams across the region, and the Northwest where most entities use BPA transmission to some extent. This level of granularity allows individual members to highlight transmission constraints either within their BAA or within their region while also maintaining a more detailed accounting of transmission capacity, wheeling, and congestion revenues.

The Tie zones in the model are shown in the figure below and include the following locations:

- In the Pacific Northwest: Washington Transmission (WA TX) Tie Zone and Non-WA Transmission Tie zone in BPA, Mid-C, Path-8 (Montana-Northwest), and Path 18, as well as the NWACI, PDCI, and Mona connections to California
- In the Rockies region: Tot-3 Tot-1A, and Tot-5, and
- In the Desert Southwest: Palo Verde, Mead, Navajo, Four Corners/San Juan/Shiprock, Springerville, and Greenlee tie zones.

Each of these zones connects multiple entities that can transact with each other up to a given level of transmission capability to the tie zone and/or downstream from the tie zone to another entity.

Figure A-1 Modified Zonal Model Topology



As shown by the green chevrons in Figure A-1, E3 included a greenhouse gas (GHG) import hurdle rate on lines that flow into Washington, California, and Colorado. These are used to help calculate GHG revenue across different scenarios. The WECC system is also connected to the Eastern Interconnect via multiple DC tie lines, which are not shown on Figure A-1. The Eastern Interconnect is defined by an hourly price stream based on historical data for SPP North and South hubs and adjusted for projected future changes to gas prices for 2026, 2030, and 2035.

Canada was modeled differently from the rest of the Western interconnection. With the help and guidance of Powerex, the BC Hydro system load and generation was simplified to be represented as a single integrated pumped hydro facility. Separately, Alberta was modeled as an external market with a fixed hourly price to which the WECC could make sales or purchases.

Model Input Assumptions

E3 worked with WMEG members and Utilicast to update and add data to the base model. The model simulates all major WECC generators (except for Canadian resources, as discussed above) and optimizes a full year of operations at an hourly granularity. Based on member feedback, E3 added new and subtracted resources from the base model for the CBS study years 2026, 2030, and 2035, and modified detailed generator operational data.

The base model used 2018 weather year data for hourly renewable profiles. E3 used the large library of existing solar and wind profiles within the database as the profiles in the CBS. WMEG members provided data to E3 to help update load forecasts at the BAA level for 2026, 2030, and 2035. To model coincident weather-driven load and renewable conditions, E3 and WMEG members matched future load profiles to 2018 weather/load conditions on a daily basis. Hydro data was collected from all members that wanted to provide updated data. Though 2018 was the selected weather year for the study, members could also provide updated hydro data to reflect future weather conditions. E3 used ADS fuel prices that were either sourced from the CEC's IEPR forecasts or EIA data.

Given the modified zonal model topology, members provided Total Transfer Capability (TTC) values for each line in the forward and backward direction for 2026 and provided any TTC changes in 2030 and 2035.

All members also provided long term point-to-point Open Access Transmission Tariff (OATT) rates which were converted to $/MWh in the day-ahead stage Business as Usual (DA BAU) case, these wheeling rates for each BAA were added to $2/MWh of assumed friction-based hurdle rate to represent the total wheeling or "hurdle rates" applied. In the real-time (RT BAU) case, these values were set to zero within the WEIM and WEIS footprint but are still used on market seams for exports from each real-time market footprint.

The OATT-based wheeling rates for each entity were also used to develop EDAM and Markets+ wheeling rates for transactions on market seams (for exports that are delivered outside of each market footprint). The exit rate of each market was assumed to be calculated as the load-weighted average of the wheeling rate of the entities participating in that market, together with additional frictional wheeling charges discussed by scenario the table below.

Table A-2 Hurdle Rate Assumptions

BAU Hurdle Rate	Market Hurdle Rate
OATT Rate + Friction on exports from zone or collection of zones that represent one entity	**Weighted Average OATT Rate of Market + Friction + Congestion Risk** for exports from a zone that is in Market A to a zone that is in Market B

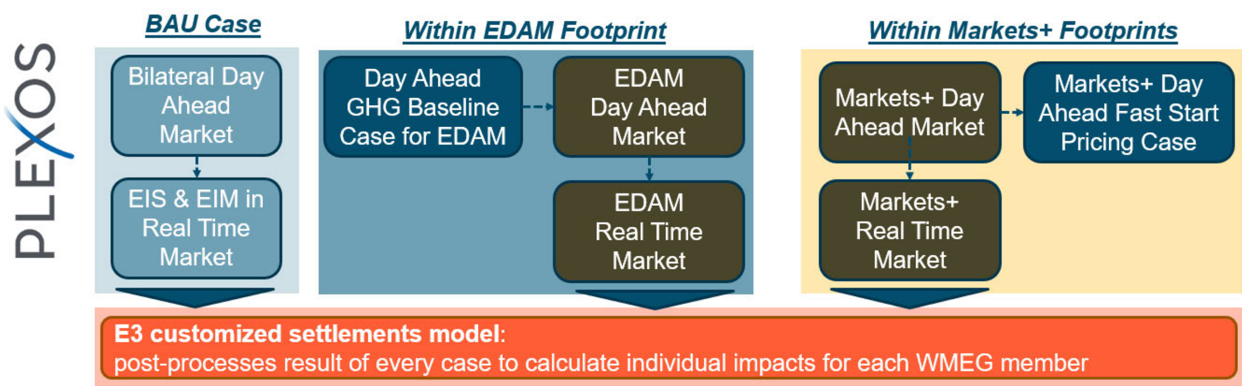
All CBS assumptions on hurdle rates are discussed in more detail later in Appendix A.

PLEXOS Model Structure

The PLEXOS model uses a multi-stage process to capture Day-Ahead and Real-Time market transactions as well as other unique market characteristics. For the BAU case, the Day-Ahead stage is a bilateral market run that creates an optimal dispatch subject to transmission based on BAA load forecasts and renewable forecasts. In this bilateral trading stage, long-start unit commitment decisions (gas and coal steam, combined cycle) are made in the context of economic dispatch. These commitment decisions are held through the Real-Time stage. In the Real-Time stage, WEIM and WEIS participants can trade with each other at no cost while non-market participants can transact bilaterally subject to OATT rates.

The market cases (representing both EDAM and Markets+) use the same two stage process as the BAU, however, the Day-Ahead stage now represents an EDAM or Markets+ footprint. Similar to the BAU cases, for the market cases during the Real-time modeling stage, commitment of longer start units are held fixed or "locked in" to their DA schedule. In the market cases, there are additional dispatch runs to capture unique characteristics of each of the various markets: (a) a GHG Baseline run and (b) a Fast Start pricing run.

Figure A-2: PLEXOS case structure and E3 settlements model



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

Day Ahead Dispatch Period

The WMEG members determined which units are available for the model to use in the day ahead dispatch period. Each of the economic dispatch solutions honor availability and generator restrictions leading into the DA run and carry these restrictions (and day-ahead commitment for longer-start units) forward into the RT dispatch period.

The CBS does not reflect Virtual Bids or Offers in any market footprint – CAISO, EDAM or Markets+. While these products may be in all the Market designs by 2026, at the time of the CBS, WMEG does not yet have a basis for how these Virtual Transaction might be strategically used by financial participants. To the extent that WMEG wants to account for some effect, it would be more practical to assume some percentage of the benefits accrue to financial players.

There is no Residual Unit Commitment (RUC) represented process in the PLEXOS model for the CBS. It is assumed that reliability has been checked via resource adequacy programs or reserve requirements that have been calculated as inputs to the DA dispatch run.

Real-Time Market Period

The Real-Time Market for this simulation is run at an hourly granularity. This simplifying assumption may understate the benefits of the WEIM, which solves at 15-minute granularity for unit commitments and then optimizes the dispatch at 5-minute intervals and WEIS market which optimizes the dispatch at 5-minute intervals, but these real-time subhourly benefits may be similar in the BAU case and market Cases due to the presence of RT markets in the BAU.

The PLEXOS Real-Time Market stage does allow additional resource commitments of certain units. The CAISO WEIM market has a Short-Term Unit Commitment (STUC) and Real-Time Unit Commitment (RTUC) process. For the CBS, CT resources are allowed to re-commit for the RT Market.
The WEIS Market does not currently have a RT Resource commitment process, but for the CBS, CT resources in that footprint were allowed to re-commit. SPP's Integrated Marketplace does have a Real-Time RUC process which commits additional resources as necessary every few hours.

GHG Baseline stage overview

The GHG Baseline run is used to mimic the GHG revenue allocation methodology in EDAM and potentially Markets+. This dispatch run is optimized by assuming no imports into the Washington and California areas[19] to provide a reference dispatch against which the actual EDAM and Markets+ dispatches will be compared. In the EDAM and Markets+ Day Ahead runs these import constraints are lifted, which enables quantification of GHG imports and associated GHG revenue. As part of the EDAM benefit calculation, the settlement calculations award GHG revenue to resources. Since Markets+ GHG accounting rules have not been finalized, GHG revenue was not calculated by resource for any of the California- or Washington-based zones that are represented in Markets+ for a particular case. Instead imports into those Markets+ GHG regulated zones are represented as a total dollar amount that could be assigned to the state for determination of how to allocate. Additional detail on GHG modeling is provided later in this appendix.

Fast Start Pricing stage overview

Costs incurred as a function of generator commitment, such as start and no-load costs, have traditionally been recovered via uplift charges because these costs are not included in the marginal price of energy. As part of Markets+, units that can start quickly ("fast start" units) can potentially recover some of these costs by increasing energy prices during intervals in which they have started. To do so, first a Day-Ahead economic dispatch run is performed to establish the unit commitment of all units. Subsequently, a Fast Start Pricing run is performed, which holds unit commitment decisions constant from the initial Markets+ Day-Ahead run but adds an incremental fast start cost ($/MWh) to units that can start quickly. This cost is added only to intervals in which the units started in the initial Day-Ahead run. Markets+ defines the fast start adder as the sum of no-load cost and start cost amortized over the minimum run time of the unit. This fast start pricing run re-optimizes the economic dispatch of the system, producing the final market clearing prices within the Markets+ footprint. Additional detail on modeling of Fast Start Pricing is provided in the next section of this Appendix.

[19] The WMEG group also considered Colorado a GHG area in this study that was subject to carbon prices, however, unlike CA and WA, the WMEG group recommended that GHG revenue not be explicitly allocated to generators exporting to Colorado; instead GHG revenue associated with wheeling energy into Colorado was tracked as a total dollar figure that would then be allocated by the state. This is the same procedure that was used for addressing GHG revenue in Markets+.

A.3. Fast Start Pricing Detail

Fast Start Pricing is a market feature exclusively for Markets+. The SPP Integrated Marketplace has updated the approach to LMP determination to include an adjustment for Fast Start Resources (FSRs). This is described in the Protocols Section 3.1.1. In essence, for FSRs, the scheduling run performs normally according to the three-part offers (startup, no-load and incremental energy). When an FSR is committed in the scheduling run, SPP will "amortize" the startup and no-load costs over the Resource max and the minimum market run time based on the relevant market interval definition (rounded up). These additional costs are then added to the energy offer to create a "composite" offer for the pricing run (subject to mitigation). It appears that this could significantly increase the market clearing price when FSRs are committed. The approach applies in both DA and RT in Integrated Marketplace. It is not known whether this will be included in Markets+.
SPP defines an FSR for Marketplace as a Resource which offers in DA or RT: a Start-Up Time of 10 min or less and Minimum Run Time offer of 60 minutes or less.

Based on discussions with SPP, E3 developed a Day-Ahead Fast Start Pricing run to mimic Markets+ operations. The Day-Ahead run produces market outputs and generator schedules based on marginal cost offers. The Fast Start Pricing run fixes unit commitments from the Day-Ahead market schedule. All CTs and ICE resources are assumed to be fast start eligible and are taken as FSRs in the Past Start Pricing run. In the pricing run, FSRs are allowed to dispatch down to 0MW and have "fast start adder" on their marginal cost bid that represented the addition costs to make the composite offer discussed above. The CBS production cost model did not incorporate no-load costs for resources therefore in this study only the start-up cost is assumed to be included in the Fast Start price offer.

The Fast Start Pricing run is then run again to generate updated Markets+ prices within its footprint which are subsequently used within the settlement calculation process. The Fast Start Pricing run was only implemented as part of the Day-Ahead market run and not the Real-Time market run. The assumption here is that most transactions occur in the Day-Ahead stage so having Fast Start Pricing in that run would capture almost all of its effect.

A.4. Wheeling Rates & Transactional Friction in Model

The following assumptions are used to model interactions between footprints of a given Market Operator by model Stage.

DA BAU enables bilateral trading between WECC entities and does not assume any market operator except the existing CAISO. In DA BAU, apart from CAISO, all BAAs will charge a hurdle rate exiting their area equivalent to their long-term point-to-point OATT rate in Q4 of 2022. CAISO has no wheeling between zones in its footprint as it is an organized market. In DA stages that include EDAM or Markets+, once EDAM is modeled in a scenario it becomes part of CAISO by removing any hurdle rate between EDAM zones and CAISO zones and they are treated as one larger market footprint. The same applies to Markets+ zones, hurdle rates between participants in DA are reduced to $0/MWh.

Between EDAM and Markets+ footprints the hurdle rate will be large to mimic reluctance to trade across different DA markets. The assumption for these rates contains three major pieces. The first is the load weighted average of the long-term point-to-point OATT rates of the entities within the EDAM or Markets+

footprint to mimic an access charge much like CAISO has today. The second is an assumed market friction adder in DA that quantifies the opportunity cost of trading across markets. The third is a congestion risk adder.

The market wheeling rates and hurdle rates adders for each scenario included in the CBS are summarized in the table below. Appendix B provides additional detail describing each Scenario including market participation of each entity.

Table A-3 Market Wheeling rates and Sub

	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	**Within Market: $0**	**Within Market: $0**
	Seam: Weighted 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	**Seam: Weighted Avg OATT Rate of Markets+ $2 Friction + $8 Congestion Risk** for exports from a Zone that is in Market A to a Zone that is in Market B	**Seam: Weighted Avg OATT Rate of Markets+ $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	**Within Market:** $0
		Seam: Weighted 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	**Seam: Weighted 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	Within Market: $0
		Seam: Weighted 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	**Seam: Weighted 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

The weighted-average market wheeling rates for each footprint are represented in the table below for each market scenario and each study year.

Table A-4 Market Wheeling Rates

Weighted Average OATT of Market* ($/MWh)

** Friction, congestion risk, and GHG adders not included in the values below*

Main Split Scenario

Market	EDAM	Markets+
2026	$ 9.53	$ 4.21
2030	$ 9.56	$ 4.22
2035	$ 9.57	$ 4.25

EDAM Bookend Scenario

Market	EDAM	Markets+
2026	$ 6.43	$ 7.76
2030	$ 6.45	$ 7.76
2035	$ 6.50	$ 7.76

Markets+ Bookend Scenario

Market	EDAM	Markets+
2026	$ 9.66	$ 4.19
2030	$ 9.68	$ 4.20
2035	$ 9.69	$ 4.23

In RT BAU, entities that are not part of WEIM or WEIS may continue to bilaterally trade close to real-time for any last-minute balancing subject to BAA wheeling rates. There is a Market Operator assumption for entities in WEIM or WEIS in the BAU scenario that brings the hurdle rate to $0/MWh between zones within the same market footprint. This also applies to all other RT market scenarios for EDAM and Markets+.

For 2030 and 2035 scenarios, cross market hurdle rates are reduced in the market-to-market (M2M) change cases. The DA case will reduce its congestion risk hurdle adder from $8/MWh to $4/MWh. In RT the congestion risk adder will reduce further from $4/MWh in DA to $1/MWh. These reductions in hurdle rates between markets represent increased coordination between markets and reduced barriers to cross-market trading that may occur with market maturity.

A.5. Reserve Modeling & Forecasting

E3 developed Day-Ahead load and renewable forecasts that are used in the Day-Ahead market stage. E3 also developed Real-Time load profiles for the study years with input from WMEG members. E3 used these forecasts as well as additional assumptions to create reserve requirements across all cases in the CBS.

Load and Renewable Forecasting

Day-Ahead forecasts for load and renewables were developed as part of the multi-stage market analysis. Decisions in the Day-Ahead market stage and market schedule outcomes are based off these forecasts.

E3 worked with WMEG members to develop real-time future year load profiles either using member specific forecasts or E3's forecast methodology. E3 wanted to maintain load and renewable correlation by modeling the same weather year within the CBS. The PLEXOS model was pre-seeded with WECC Anchor Data Set (ADS) profiles based on a 2018 weather year. Those were kept in the CBS model as the real-time renewable resource profiles. Each member forecast load for the RT stage followed observed 2018 weather patterns to ensure that weather-dependent load is realistically correlated across the study region, and overall load levels were scaled to approximate a median or 1-in-2 forecast level. E3 worked with WMEG members to obtain the real-time load profiles for the 2026, 2030, and 2035 study years.

For the Day-ahead stage, E3 then perturbed those profiles using historical day-ahead forecast error data to create load profiles that represent day-ahead forecasts of the future year profile. E3 developed a computable methodology to generate hundreds of renewable forecast profiles. These day-ahead renewable forecasts were developed by E3 based on a weighted combination of the actual real-time for matching hours from the prior day, together with month-hour average values. E3 then blended these values with the actual real-time to match data E3 previously obtained for day ahead forecast error mean average percentage error (MAPE) statistics to more accurately account for relative forecast quality. The advantage of this relatively simple forecast methodology is that unlike forecasts developed using randomized forecast error for each resource, it produces an error that captures correct correlations of errors across different projects locations. This feature allows the forecast to account correctly for geographic diversity both within individual BAAs, as well as when the forecast errors for multiple BAAs are combined into a broader market region.

Creation of load profiles directly involved WMEG members as part of a load forecasting task force. WMEG members provided hourly demand projections for E3 to use in the CBS study. Demand profiles for 2026, 2030, and 2035 were provided based on each WMEG member's latest or most applicable demand forecasts. E3 used a day matching approach to synchronize the member-submitted load forecasts with the 2018 weather year of the wind and solar profiles. The rank order of days within seasonal windows were calculated for both the member-submitted forecasts and a reference load forecast from the ADS that was based on 2018 weather conditions. Each day from the member-submitted forecast was re-arranged to correspond to the rank order of daily load values in the reference ADS load forecast. Member-submitted forecasts were used in the real-time model stage.

To develop day-ahead load forecasts consistent with member-submitted load profiles, E3 developed an hourly time series of forecast error percentage using historical data. To do so, day-ahead forecast and real-time demand data for each balancing area in WECC was collected from the Energy Information Administration's Hourly Electric Grid Monitor. The percentage difference between the day-ahead and real-time demand was calculated for each hour of a single year (either 2018 or 2019, depending on balancing area). Forecast error percentages were capped at 30% in any single hour to address data quality issues and were adjusted upward or downward to set the annual mean forecast error to zero. The resulting hourly time series of percentage error values were multiplied by the member-submitted forecasts, resulting in a synthetic day-ahead load forecast for each balancing authority area (BAA).

Reserves overview

Five ancillary service products are represented in the production cost model: Spinning Reserves, Non-Spinning Reserves, Regulation Up, Regulation Down, and Imbalance Up. Except for Imbalance Up reserves, the reserve requirements are calculated as a percentage of load: Spinning (3%), Non-Spinning (3%), Regulation Up (1%), and Regulation Down (1%).

Imbalance reserve requirements ensure system reliability by reserving capacity to account for forecast error associated with renewables and load. Imbalance reserves are part of proposed EDAM and Markets+ Day-Ahead market designs. For the CBS, imbalance reserve requirements were calculated using E3's in-house RESERVE model, which calculates imbalance reserve requirements given forecast errors of load, wind, and solar. Imbalance Up reserve requirements were created using RESERVE's prediction of the 97.5th percentile of net load forecast error, and as such the Day-Ahead production cost model stage is prepared to address all but 2.5th percentile of net load under-forecast events. Imbalance Down reserves were not modeled in the CBS due to the expected abundance of resources that could provide this product in the day-ahead timeframe, including the ability to de-commit thermal units, charge storage resources, or curtail renewable generators.

Depending on the CBS scenario, reserve requirements were either modeled as BA-specific or pooled as part of a market at a regional level via the subregion breakout in Figure A-3. Pooling reserve requirements across a larger area provides diversity benefits compared to a BA-specific requirement and is one of the numerous benefits of an organized wholesale market. Specifically, the imbalance or day ahead forecast error reserves were calculated in pooled cases based on the aggregated net load forecast error of sub-regions of each market footprint (for example the Pacific Northwest sub-area of Markets+). The aggregation of net load across multiple zones results in a lower reserve level needed to cover the 97.5th percentile of forecast error, so these pooled cases enable cost savings and reduced reserve needs due to geographic diversity.

Figure A-3 Market Reserve Subregions[20]

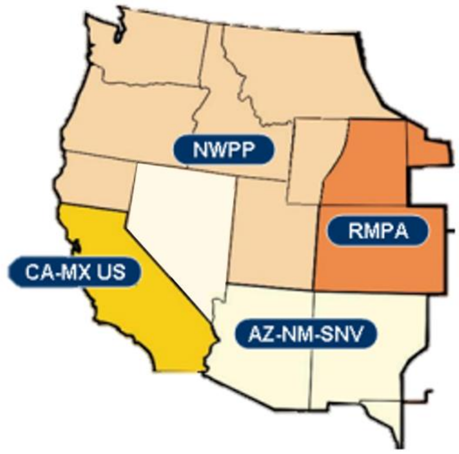


Table A-5 Categorization of Western Zones for Reserve Subgroups

California	Northwest	Southwest	Rockies
CAISO	PacifiCorp	NVE	BH
BANC	ID	AEPCO	PRPA
LADWP	NWMT	APS	PSCo
Turlock	Avangrid	EPE	TSGT
IID	Avista	PNM	BASIN
WAPA SNR	BPA	SRP	WAPA CRSP
	Chelan	TEP	WAPA LAP
	Douglas	WAPA DSW	
	Grant		
	PGE		
	PSE		
	SCL		
	Tacoma		
	WAPA UGP		
	BC/Powerex		

E3's RESERVE tool was used to provide both BA-specific and regional imbalance reserve requirements that were used for different scenarios within the CBS. The details of E3's RESERVE tool and its application to the CBS are discussed in more detail in the next section. **Error! Reference source not found.** includes more d etails on how each reserve was modeled. CBS modeling does not include capacity held and subsequently released in real-time via flexible ramping product (for the WEIM) or a similar reserve in the WEIS market.

Currently most WECC BAAs self-provide ancillary services. There are a few sales here and there, especially as it relates to some entities which do not have the ability to really provide these services reliably on their own (e.g., Avangrid, NaturEner), but there are not large volumes of transactions. As part of this study,

[20] NERC, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/EPA_Scenario_Final_v2.pdf

ancillary service requirements were set for each BAA in the BAU case and then at the subregional level within the market scenarios with ancillary service markets. For most of the market scenarios, the Spinning, Non-Spinning and Regulating reserve requirements were maintained at the individual BAA level with values that were the same as in the BAU Case. In the 2030 and 2035 M2M+CBA scenarios however, these reserve requirements were pooled within each market on a sub-regional basis. The same quantity of total reserves in these categories, however, is maintained, such that the CBA market cases' total reserves for each sub-region are equal to sum of the individual BAA level requirements from the BAU case for the zones in that sub-region. By contrast, Imbalance Up reserve requirements were calculated at the BAA level for the BAU case and at the subregional level in all market cases. E3 used its RESERVE tool, described in the next section of appendix, to calculate hourly requirements for Imbalance Up reserves.

Imbalance reserves are held to prepare for forecast errors between day-ahead and real-time market timeframes. Because the timeframe of required response is relatively long for imbalance reserves, thermal resources that can start quickly are able to provide the required response, even when offline. As a result, combustion turbines and reciprocating engines were modeled as contributing to Imbalance Up reserves when offline. These resources were also modeled as contributing to Imbalance Up reserves when online. Longer-start thermal resources such as gas and coal steam turbines and gas combined cycles are modeled as only contributing to Imbalance Up reserves when online because these resources may not be able to start up in time to correct for forecast errors between day-ahead and real-time markets.

We ensured that system operators would be prepared for contingency events by requiring contingency reserve headroom to be held in both the Day-Ahead and Real-Time stages. However, the model did not change the schedule of generator outages between the Day-Ahead and Real-Time, and as a result we did not model contingency reserve deployment in Real-Time.

Dispatchable hydro, thermal, and storage resources were modeled as able to contribute to all reserve products. The contribution of these resources to each reserve was limited via their ramp rates (**Error! Reference source not found.**). To address state of charge concerns, storage resources were required to keep an adequate amount of energy in storage to be able to provide the required service for one hour continuously. For upward reserves, this means that providing reserves requires energy to be stored in the battery; for downward reserves this requires the battery to have a state of charge that is less than full.

We do not model wind and solar resources as contributing to reserves in the CBS, though the exclusion of Imbalance Down reserves from the modeling is in part because renewable resources could supply downward imbalance reserve capacity by turning down (curtailing) output in real-time. Storage, online thermal, and dispatchable hydro resources are also expected to provide ample Imbalance Down capacity, thereby minimizing the impact that including this reserve would have on modeling results.

As is standard in production cost modeling, the CBS model's co-optimization of energy and reserves results in resources providing reserves at their opportunity cost; no additional cost or bid to provide reserves was added above a resource's opportunity cost when determining reserve commitments.

Table A-6 Reserve products modeled in the CBS

	Imbalance Up	Spinning	Non-Spinning	Regulation Up	Regulation Down
Purpose	Prepare for forecast errors between day-ahead and real-time market timeframes	Quickly replace capacity lost from a contingency event	Replace spinning reserve capacity	BAA ACE management outside of market signals	BAA ACE management outside of market signals
Direction	Headroom	Headroom	Headroom	Headroom	Footroom
How is the requirement calculated?	97.5% percentile of day ahead forecast error, as calculated by E3's RESERVE model	3% of load	3% of load	1% of load	1% of load
Held in Day-Ahead Stage?	Yes	Yes	Yes	Yes	Yes
Held in Real-Time Stage?	No (capacity released for dispatch)	Yes	Yes	Yes	Yes
Offline quick-start thermal capacity can contribute?	Yes	No	Yes	No	No
Timeframe (limits online resource contribution via ramp rates)	10 minutes	15 minutes	30 minutes	10 minutes	10 minutes

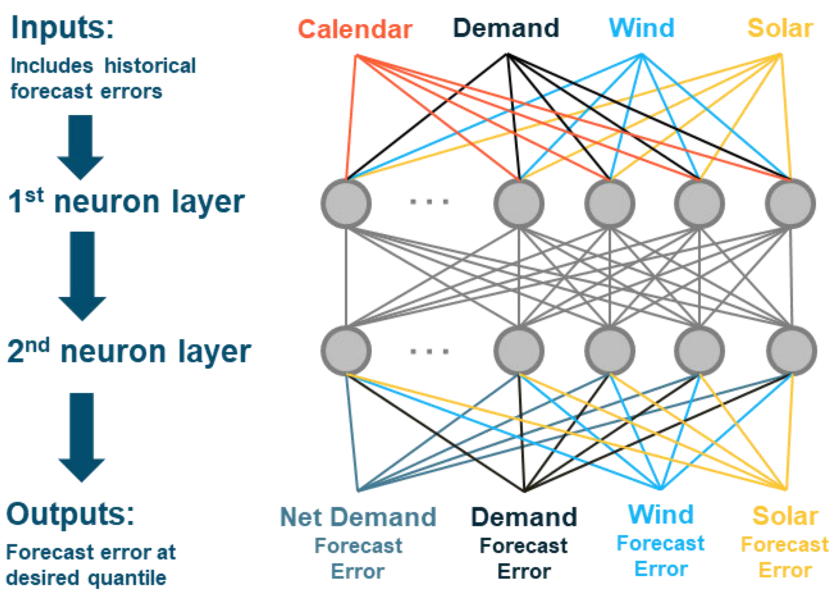
A.6. E3 RESERVE Tool Description

We use the RESERVE model[21] to quantify the likelihood of extreme forecast error events. Extreme forecast error events are inherently infrequent and can therefore be challenging to quantify in a statistically rigorous manner. Furthermore, forecast errors can be driven not only by weather conditions themselves, but also by non-linearities in the response of load, wind output, and solar output to changes in weather conditions. As an example, the relationship between cloudiness and solar output is non-linear. With no clouds or fully overcast sky, the variability of solar output stays minimal as the solar output stays minimal, whereas in partly overcast weather we see the highest amount of uncertainty.

[21] See Sun, Yuchi, James H. Nelson, John C. Stevens, Adrian H. Au, Vignesh Venugopal, Charles Gulian, Saamrat Kasina, Patrick O'Neill, Mengyao Yuan, and Arne Olson. "Machine learning derived dynamic operating reserve requirements in high-renewable power systems." Journal of Renewable and Sustainable Energy 14, no. 3 (2022): 036303. https://doi.org/10.1063/5.0087144

The RESERVE model employs the multi-layer perceptron method (MLP), commonly known as artificial neural network (ANN). ANNs can model highly non-linear relationships between inputs and outputs by choosing a non-linear activation for each neuron and allowing the neurons to interact and superimpose their non-linearity. RESERVE employs a pinball loss function.

Figure A-4 Illustrative diagram of the RESERVE neural network



One of the primary data sources that RESERVE uses to make forecast error predictions is renewable and load forecast and actual (real-time) data. RESERVE combines this forecast error data with calendar data such as the earth's revolution and rotation angle, as well as the solar azimuth and elevation angle. The calendar data allows the model to capture dynamics that depend on the hour of day, time of year, or position of the sun in the sky. RESERVE's neural network uses the input data to make forecast error predictions that are individually tailored to each hour of the year.

RESERVE can simultaneously produce multiple probabilistic outputs, including predictions of net load forecast error as well as the forecast error of individual net load components (load, wind, and solar). In this study we focused on net load forecast error as it directly sets the imbalance reserve requirements. The individual net load component forecast errors were used in the quality control process.

The RESERVE model can characterize reserve requirements for any user-defined percentile of forecast error. Following the EDAM Final Proposal,[22] in this study RESERVE was used to calculate an Imbalance Up reserve requirement that is set at the 97.5% percentile of net load forecast error in each hour. Put another way, the day ahead net load forecast plus the imbalance reserve requirement will be higher than the realized real-time net load in all but 2.5% of hours.

[22] http://www.caiso.com/InitiativeDocuments/FinalProposal-Day-AheadMarketEnhancements.pdf, p.28-29

A.7. Non-WMEG Entity Modeling

There are 14 Balancing Areas in the WECC which are not participants of WMEG. **Error! Reference source not found.** contains the modeling assumptions for these entities.

Figure A-5 Non-WMEG Modeling Assumptions

BAA	Description	Type	Approach
CISO	California ISO	CAISO	EDAM Transactions as CAISO
AESO	Alberta	Non-US	Assumed to be independently optimized relative to their own unique organized market. Modeled as a price stream within the WMEG model
BCHA	BC Hydro	Non-US	Described in detail below
CFE	Mexico	Non-US	Bilateral Only
SPP	SPP Marketplace	Non-WECC	Assumed to be independently optimized relative to their own unique organized market. Modeled as a price stream within the WMEG model
DEAA	Arlington Valley	IPP	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios
GRIF	Griffith	IPP	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios
GWA	NaturEner Glacier	IPP	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios
HGMA	Harquahala	IPP	Bilateral or as Contracted to WMEG; Assumed in a market in market scenarios
WWA	NaturEner Wind Watch	IPP	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios
DOPD	Douglas PUD	Muni	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios
IID	Imperial Irrigation District	Muni	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios
TID	Turlock Irrigation District	Muni	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios; WEIM in BAU
GRID	Grid Force	Multiple Clients	Bilateral or as Contracted to WMEG; Assumed it a market in market scenarios

BC Hydro was modeled uniquely with guidance from Powerex. The BC Hydro system was aggregated as a pumped-storage unit. The unit was given maximum and minimum daily energy budgets which were shaped to the WECC net load profile from the CBS study. As Powerex has committed itself to Markets+ the units flexibility was dependent on the footprint and the neighboring entities. In a single EDAM market case, Powerex is only allowed to trade in blocks and will withhold some of its generation from the market for other internal system usages. If other WECC entities are part of Markets+, BC Hydro will make its total capacity fully available and fully flexible for Markets+ interaction. The BC Hydro system can import and export to the rest of the West via its transmission into the Northwest and elsewhere.

A.8. Fuel, and Electric Market Price Modeling

Fuel Price Forecast

Fuel prices use forecasts are based on data from the CEC 2021 Integrated Energy Policy Report (IEPR) and the Energy Information Agency's (EIA) 2022 Annual Energy Outlook (AEO). The CEC IEPR forecasts originate from the North American Market Gas-trade (NAMGas) Model which considers some degree of natural gas pipeline capacity via a nodal model. All fuel prices, except natural gas, are constant over the year. Natural gas prices are developed on a monthly granularity. For 2026 and 2035, the data directly uses the forecast for Western hub locations from the CEC IEPR. That CEC forecast is based on projected Henry Hub prices of $2.98/MMBtu on average for 2026 and $3.26/MMBtu for 2030 (in 2022$). For 2035, the IEPR does not have a gas projection so the monthly CEC basis differentials from 2030 are added to the EIA AEO data for Henry Hub in 2035 ($3.74/MMBtu).

Gas prices do not vary between DA and RT stages as this may cause results to be skewed if different members provide individual views on gas price deviations at hubs or generators across WECC. The table below shows the resulting annual average of gas prices at selected Western Hub locations. Each price shown varies monthly.

Table A-7 Annual Average Gas Price for Selected Western Locations ($/MMBtu)

Study Year	SoCal Citigate	Sumas (Northwest)	Waha (West Texas)
2026	$4.68	$3.17	$2.72
2030	$5.12	$3.48	$3.06
2035	$5.60	$3.96	$3.55

Electric Market Price Forecasts (External regions)

E3 develops in-house price forecasts for locations across North America including the West, Canada, and SPP. For the CBS, E3 developed market prices for Alberta and SPP where WECC entities could interact with the separate organized markets. Within this model, SPP is represented via two different price streams - SPP North and SPP South - that vary between 2026, 2030, and 2035. Alberta is represented as a single price stream that connects to the model's Montana-Alberta Tie Line (MATL) zone. Hourly historical prices for SPP and AESO were selected in a year weather synchronized with WECC load and renewable data; E3 then scaled these prices to be consistent with gas price increases that E3 used for the projected study year of 2026, 2030 and 2035.

Market participants provided OATT based wheeling charge to be applied for imports and exports with Alberta (including MATL charges) and the Eastern Interconnection DC ties which.

A.9. Hydro Modeling

Several WMEG members have hydro fleets with sufficient storage to meaningfully shift generation between hours of the day, days of the week or, sometimes, on a seasonal basis. This ability to shift generation impacts the opportunity cost which will drive the Resource offer in the Day-Ahead and Real-Time Markets. These Resources also often have reservoir restrictions which do not match the generator characteristics (e.g., minimum elevation, maximum elevation, minimum flow, maximum draft).

Hydro resources are modeling two distinct ways within the production cost model:

1. Fixed Dispatch
2. Dispatchable

As a default assumption, the CBS uses 2018 hydro year, because it is representative for typical or average hydro conditions for many Western locations, and because it aligns with the wind and solar shapes used for the study; in particular cases, however, WMEG members provided alternative values if they believed that another year for their system was more representative of typical conditions than 2018.

Fixed Dispatch: resources were model with a fixed 8760 profile that was either provided by a WMEG member based on their hydro year or the original. These units were held at their fixed output with a $0/MWh generation cost.

Dispatchable: for these resources, WMEG members shaped their hydro based on their chosen hydro year into daily hydro budgets reflective of any inherent flow restrictions or minimum flow requirements. PLEXOS optimized the hydro dispatch over each day and does not consider longer hydro budget usage. For this, members provided daily energy budgets that were shaped based on a weekend/weekday schedule. The energy budgets were considered hard constraints by the model which meant that the entirety of the budget was to be utilized by the model over the day and PLEXOS would shift hydro generation around within the day to minimize system-wide production cost. Hydro dispatch was also restricted to member-defined hourly (8760) maximum MW output and Minimum MW output profiles. This enabled members to represent minimum flow requirements or any other unique flow requirements for individual hydro units. Much like the fixed dispatch hydro, dispatchable hydro units were dispatched without a marginal cost (at $0/MWh); the value of the energy and flexibility of dispatchable hydro is determined by the opportunity cost of the production simulation. Dispatchable units were able to contribute to all ancillary services, subject to the limits defined above.

Pumped storage represents an additional resource type that was modelled somewhat differently than hydro resources. Pumped storage units were modeled using head and tail reservoir volumes and pumping efficiencies from the WECC ADS. This was altered if members provided different data. Like other hydro units there was no offer cost. The marginal cost of these units ranged from $0 to $3/MWh to reflect variable O&M on certain units, in addition to pumping efficiency losses. Pumped storage units were modeled as able to provide reserves. WMEG members selectively updated pumped storage generator properties including pmax, pmin, max pump load, and pumping efficiency for certain units.

As part of the CBS, pumped storage and dispatchable hydro units were scheduled in the Day-Ahead market and were able to be re-optimized again in the Real-Time market. This may provide some additional flexibility in the model that may not be reflective of reality. Fixed profile resource outputs remained the same in Day-Ahead and Real-Time. Furthermore, hydro units within the production cost model were only allowed to bid their marginal cost, which is assumed to be $0/MWh. There were no offer prices included in any resources as this would indicate some sort of trading strategy among participants in the West. The purpose of this modeling was to estimate costs and benefits in a market where there are not additional bidding strategies other than bidding at cost. Market power mitigation assumptions are also discussed later.

A.10. Green House Gas Modeling

E3 worked with the Green House Gas Task Force to develop the modeling assumptions for GHG in the CBS. Based on discussion within the task force, a Clean Energy Policy matrix was developed that identifies state and corporate clean energy targets, the model created three **GHG areas** to effectively represent the overlap of these different policies as part of one regionwide production cost model. The GHG areas are **California**, **Washington**, and **Colorado**.

The GHG market feature has been developed in detail for EDAM, however Markets+ had not established a GHG methodology at the time of developing assumptions for the CBS. GHG prices were based on the California Energy Commission (CEC) 2021 IEPR mid forecast. In this analysis there was no distinction between specified and unspecified imports. All imports into GHG areas were subject to the same hurdle rate that is defined by a GHG price, which was set based on the default rate used for unspecified imports into California. These values are summarized in **Error! Reference source not found.**.

Table A-8 Carbon Price GHG Hurdle Rate for Imports to CA, WA, and CO

Study Year	Carbon Price ($/metric tonne)	Unspecified Rate on Imports (tonnes/MWh)	Implied GHG Hurdle Price ($/MWh)
2026	$39.33	0.437	$17.19
2030	$62.05	0.437	$27.12
2035	$109.74	0.437	$47.96

EDAM Approach

The CBS uses the following steps to represent EDAM's GHG approach in the model:

- Establish a GHG Baseline dispatch which would exist for each BAA. This is done with no transfers and all GHG bids being set to zero be not allowing any imports into GHG areas in the GHG Baseline run.
- Using E3's settlement script, generators are rewarded GHG revenue based on GHG price less compliance cost of each resource. GHG revenue allocation is described in more detail in Appendix C to this report.
- Each external resource "bids" a GHG price and MW based on compliance cost and emissions rate which is calculated on an annual basis from the Day-Ahead run (Total Emissions/Total Generation)
- Calculate the cost-based Bid for each Resource and eligible MW per Resource as the DA Award – Reference Run Award
- Calculate the BAA eligible GHG award per hour based on net exports in that hour.
- Calculate the Resource stack per BAA capped by the BAA net exports.
- Create the market resource stack based on each BAA's capped Resource stack.
- Determine the cleared resources up to the CA and WA imports.
- Calculate the potential margin per cleared Resource.
- Allocate the GHG revenue based on each unit's bid cost.

- A similar process is done for Real-Time except using the Day-Ahead Award as the baseline and the Real-Time dispatch would be incremental or decremental to that.

Markets+ Approach

For the purposes of the CBS, Markets+ uses a zonal approach for GHG with the following key steps:

- Each Resource has a GHG cost. There are three general types of resources. In-Zone, External-Specified and External-Unspecified. The Unspecified resources are assigned a proxy GHG cost.
- The market minimizes the combined cost of Energy and GHG.
- When there are imports to the GHG Zone, there is a shadow price for the marginal cost of GHG. The LMP reflects only the Energy Cost (and congestion and loss).
- Resources within the GHG zone have a compliance obligation. They receive GHG revenues in settlements. Like the EDAM approach, if the GHG shadow price is above their compliance cost, they will receive net payments.
- Specified External Resources have a compliance obligation. They receive GHG revenues in settlements. Like the EDAM approach, if the GHG shadow price is above their compliance cost, they will receive net payments.
- Unspecified External Resources do not have a compliance cost. The market operator collects that money and returns it to the state of the compliance region for further allocation, but this process has yet to be defined at the time of this study.

As part of the CBS, it is assumed that all external resources are unspecified and do not have a compliance cost and the money associated with imports into GHG areas is collected by the Markets+ operator and returned to the compliance entity, in this case the GHG area. The lump sum is provided to participants in a Markets+ in the CBS and at that point it is up to the GHG area to decide how that will be allocated among participants.

Additional Washington State Detail

For the purposes of the CBS, the California and Washington GHG market is considered linked for all cases. As a result, the study applies a GHG price at the generator level for each state but did not charge a separate GHG cost for energy that is wheeled between zones in these states.

Washington's Clean Energy Transformation Act's "No-Coal" provision excludes power purchases with a term of one-month or less.[23] The CBS has an hourly or daily transaction profile so there is no need to explicitly address this clause.

[23] See RCW 19.405.030.

A.11. Transmission Availability

E3 utilizes a hybrid nodal and zonal model that typically represents BAAs as individual zones. The model divides certain BAAs into more than one zone when needed to reflect impactful internal transmission constraints for WMEG members, or to represent cases where multiple different WMEG members operate as separate sub-BAAs or are otherwise important to distinguish in market operations. Some of these sub-zones are already reflected in the areas defined in the WECC Anchor Data set, and the CBS models a few additional sub-divisions. The CBS model typically does not charge wheeling or hurdle rates in the BAU case on transactions within each BAAs when a single entity responsible for most of the load and owning of the generation in both of the BAAs. With this approach, the CBS accurately represents the WECC system without utilizing a larger nodal model, which would have required significantly longer run time for each case, as well as additional decisions on the placement of new generators whose intended nodal points of injection have not yet been decided.

In addition to the tie-zones previously discussed, the BAAs that are modeled as more than one zone in the study include:

- California ISO, which the model divides into PG&E Bay Area (represented as CIPB in the model), PG&E Central Valley Area (CIPV), Southern California Edison (CISC) and San Diego Gas & Electric (CISC) to reflect internal transmission constraints.
- NV Energy, which the model divides into separate Northern (NVEN) and Southern (NVES) zones to reflect internal transmission constraints.
- PNM, which model divides into separate PNM North (PNM-N) and PNM South including Tri-State South (PNM-S + TSGT-S) and Tri-State Northern New Mexico (TSGT-NM) zones to reflect internal transmission constraints as well as distinct Tri-state operations.
- BPA, which the model divides into Washington (BPAT WA) and Non-Washington (BPAT Non-WA) zones to enable the Washington area to be represented with GHG pricing applied.
- NorthWestern Energy, which the model divides into the NorthWestern – Great Falls Area (NWMT-GF) and all other NorthWestern territory (NWMT) to reflect internal transmission constraints. The NWMT GF zone connects directly to the MATL line for transactions with Alberta.
- The PSCO BAA, which the model divides into separate PSCO-West (PSCO-W), PSCO-East (PSCO-E) and Black Hills Energy of Colorado (BHE) zones to reflect transmission path constraints, and distinct entity operations.
- The WAPA - Lower Colorado Region, for which the model represents distinct operations for the AEPCO sub-BAA and leaves the remainder of loads and resources WALC sub-zone.
- The WAPA – Colorado-Missouri Region (WACM), which the model divides into 12 separate zones to reflect transmission path constraints, distinct entity operations, and GHG regulations applicable in Colorado. These 12 zones are CRCM-North (CRCM-N), CRCM-South (CRCM-S), Loveland Area Project (LAPT), Loveland Area Project – Wyoming (LAPT-WY), Platte River Power Authority – West (PRPA-W), Platte River Power Authority – East (PRPA-W), Tri-State G&T – West (TSGT-W), Tri-State G&T – East (TSGT-E), Tri-State G&T – Wyoming (TSGT-WY), Black Hills Energy in Wyoming & South Dakota (BHE-WY/SD), Basin Electric (Basin), and Flaming Gorge (FG).
- The WAPA Sierra Nevada Region (SNR) is a member of the BANC BAA. However, for the CBS WAPA SNR requested to be studied independently from BANC for certain scenarios. BANC members other than SNR are modeled in EDAM for all scenarios. WAPA SNR, by contrast is modeled in Markets+ region the Markets+ Bookend Case (and EDAM for the EDAM Bookend

and Main Split Case). To implement this distinction, WAPA SNR is broken out of the BANC zone and assigned its own load and transmission connections to CAISO, SMUD, and the Northwest.

- Finally, for a number of entities, sub-zones were created to represent, remote generation located at a tie zone that is owned or contracted to a receiving entity who typically takes that output (e.g. over a dynamic schedule or pseudo-tie) and does not typically face incremental transmission charges or transactional friction for bringing the output of the generation into their area, but may face limits to the transmission capability that can constrain the sum of energy brought to load from energy produced by the generator and energy purchased at the tie zone.

Transmission availability was reflected within the model as total transmission capacity (TTC) between BAs and across any relevant WECC paths.

E3, Utilicast, and WMEG developed an added layer of transmission availability to the model which created the ability to define multi-party transfer limits. This concept was labeled by the group as "Seams" or "Tie-Zones" and is depicted in **Error! Reference source not found.**. Limits in and out of these l ocations are defined for multiple parties and enable multiple transactions to and from multiple entities across one path. Having Tie-Zone representations also allows for more accurate settlement calculations, particularly for wheeling and congestion, as all transactions can be tracked by individual entities. This concept was mainly for the Southwest and to some degree, the Northwest. For other regions, the Tie-Zone was used to represent entity-specific breakouts of WECC paths to again, keep track of individual wheeling and congestion.

Figure A-6 Tie-Zone Representation in Southwest

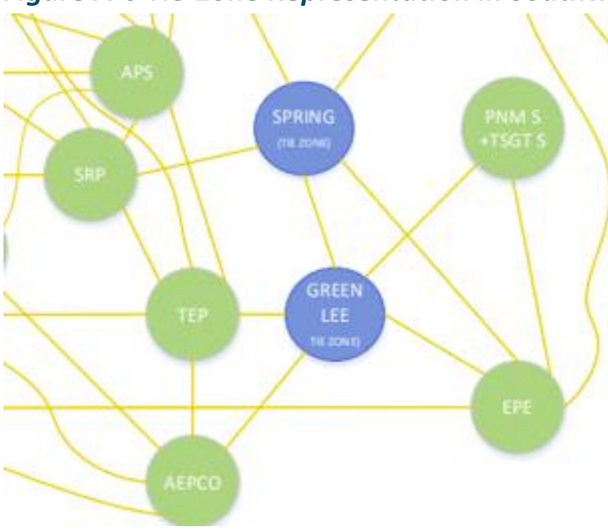
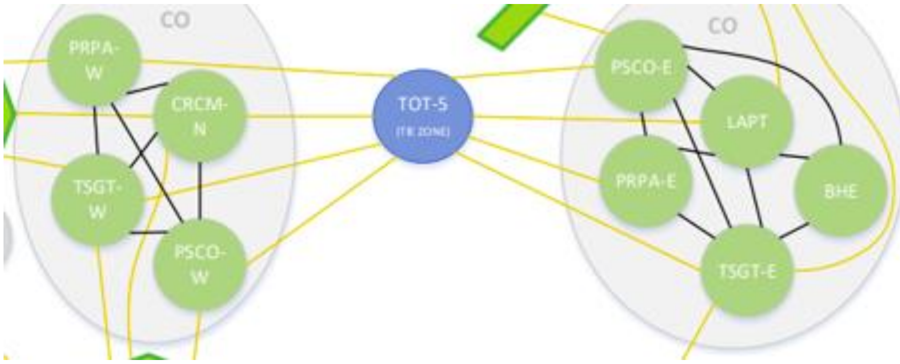


Figure A-7 Tie-Zone representation of WECC Path in Colorado



E3 incorporated an additional layer of transmission availability that included special transmission rights and special transfer obligations for WMEG members.

In the BAU case, 100% of transmission is made available for bilateral transactions within the Day-Ahead market. The Real-Time market also enables use of the full TTC which might be seen as being more flexible than reality.

To test the impact of this assumption, E3 modeled a separate BAU sensitivity case that assumed more limited efficiency in RT markets, to explore the uncertainty around how efficient and flexible RT markets (alone) could become by 2026. This sensitivity case constrained RT flows over each line between zones to the day ahead scheduled flow +/- 15% of the line's total transfer capability. For example, if a 1000 MW line had 500 MW scheduled to flow in the DA stage for a given hour, the RT stage flows were constrained to range between 350 MW and 650 MW for that hour. This case resulted in regionwide annual production costs that were $70 million higher than the BAU case for this study. If this BAU sensitivity were instead used as a point of comparison to the DA Market Cases, the resulting impact of forming a DA market would improve by $70 million for each of these cases, resulting in regionwide savings in the EDAM Bookend growing to $130 million, and the regionwide net cost increase in the Main Split case instead changing to $151 million.

According to the two different markets, there are slight differences in how they consider transmission. Though Markets+ claims to use a different transmission capacity within its market, in discussion with the WMEG it seemed like this market feature was not fully established and raised more questions than answers namely: how would each entity estimate their transmission capacity if all transactions today are done based on path ratings? Based on this, the transmission availability was not altered between an EDAM and Markets+ market. Within the CBS model each market used the available TTC between different zones.

A.12. Load Participation

The model cleared 100% of forecasted demand in the Day-Ahead run, which included day-ahead forecast error of load, wind and solar for each zone. The Real-Time run represented load and renewable "actual values", which differ from the Day-Ahead forecast values based on a simulated forecast error between the day-ahead and real-time timeframes. E3 did not model virtual bidding or other bidding behavior that would reflect less than 100% of forecasted Day-Ahead being cleared. E3 adopted this assumption for three main reasons:

Clearing less than 100% of forecasted load in the Day-Ahead regionwide model would have resulted in resource shortages in real-time dispatch because the day-ahead timeframe will be the last commitment timeframe for longer-start units. Without an adequate amount of capacity committed from longer start units, the headroom available on committed units and the fast start capacity available in real time would have likely been insufficient to meet load on certain days, especially days with very high loads or with large forecast error events. In actual practice, the residual unit commitment process can typically provide access to enough capacity to operate reliably on these days, however it is likely that both economic and reliability concerns would result in most demand being cleared day-ahead instead.

To give the CBS model the opportunity to clear less than 100% of forecasted demand, additional data would have been required to develop pricing for the opportunity to clear different levels of demand in the day-ahead timeframe. This pricing information would have required modeling tradeoffs not ideal for this study and would have been speculative to determine for the future study years.

This CBS sought to reflect the benefits for participants assuming no other bidding strategies were utilized other than bidding at cost, to minimize system cost while reliability serving hourly load. Holding a portion of generation back from the DA stage could have artificially depressed Day-Ahead prices and increased real-time prices, thereby potentially skewing benefits.

A.13. Market Power Mitigation

Market power mitigation was addressed in discussion with the WMEG; however, the model does not address MPM as the model inherently assumes all generators are bidding in a competitive manner. A central aspect of this modeling effort is to provide an estimate of benefits among all participating WMEG members in a market where participants are all acting within power market rules to minimize cost. Introducing uncompetitive bids into the analysis may skew results.

Exploration of non-cost-based bidding strategies in a future WECC power system with higher levels of renewables and storage is not feasible within the proposed timeline of the CBS.

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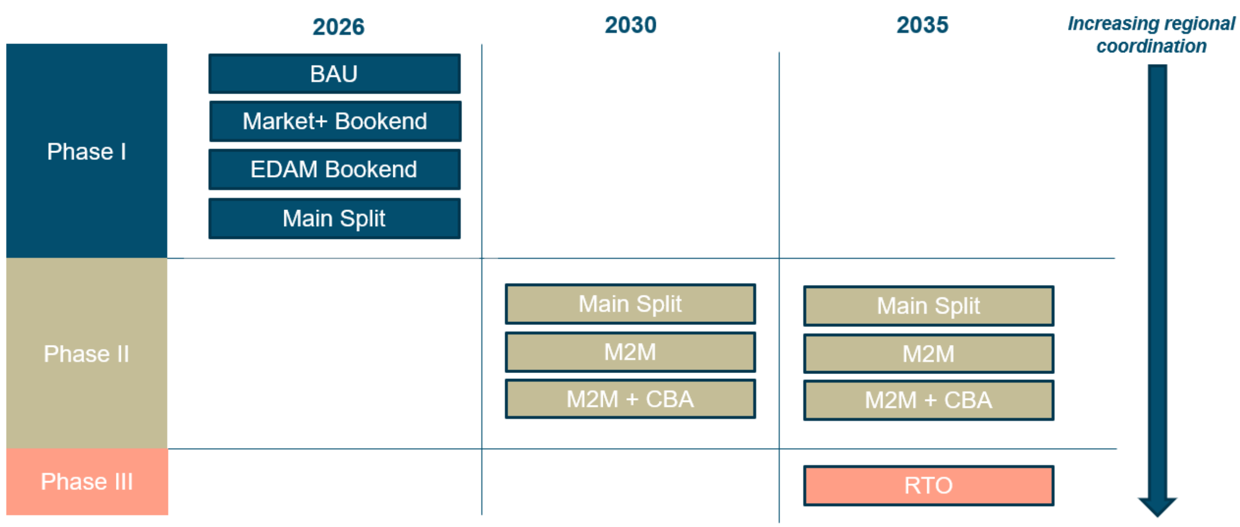
A.14. Resource Sufficiency Tests

Based on discussion with the broader WMEG members and Utilicast, E3 established that creating an additional resource sufficiency test as part of this study would require significant time to implement. Therefore, the resource sufficiency test was not conducted as part of the study, and it is assumed that all entities that participate in EDAM or Markets+ are resource sufficient in each interval of the production cost simulation as is often the case for the current WEIM.

Appendix B. Scenario Design

The scenarios within this study help address key questions surrounding the EDAM and Markets+ markets and how the different characteristics and footprints change production cost benefits. The core study has three phases of scenarios that build on one another from a BAU case to an RTO case by adding increasing regional coordination across case scenarios to provide insight to benefits of moving from a separate Day-Ahead and Real-Time market to a fully integrated RTO. Figure B-1 shows the various scenarios included in the core study and the subsequent sections of the report describe the scenarios in more detail.

Figure B-1 Study Scenario Summary



B.1. Phase I

Phase I looks at the 2026 timeframe and measures the effects of a Day-Ahead market relative to BAU.

2026 Business-as-Usual (BAU)

The BAU case sets a baseline to compare the subsequent 2026 market cases analyzed in the CBS. In the BAU case, there is no active Day-Ahead market outside of CAISO. Instead, there are scheduled bilateral transactions between zones and are subject to member long-term point-to-point OATT rate assumptions.

In the Real Time stage, the WEIM and WEIS markets are both active and additional transactions occur within their respective market footprints. WEIM and WEIS transactions are not subject to OATT rates.

Table B-1 WMEG Member Market Participation in BAU Scenario

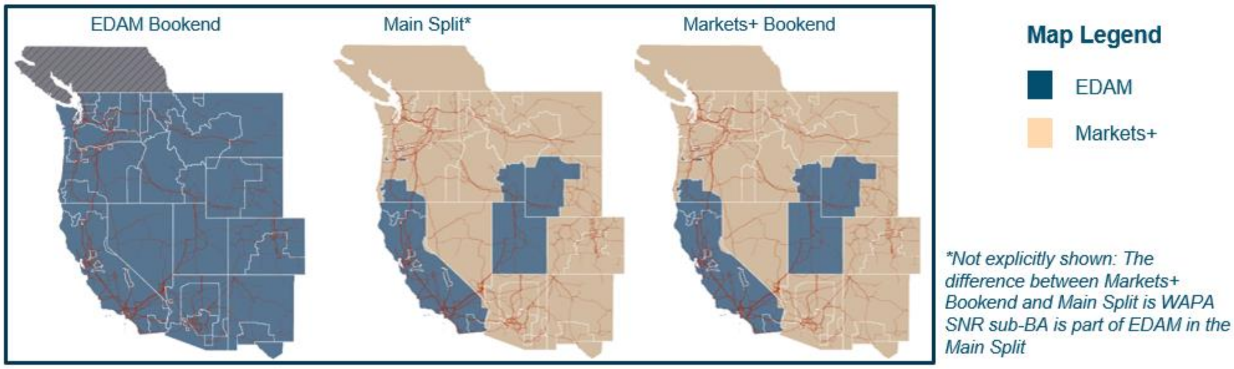
WMEG Member	Day-Ahead Market	WEIM	WEIS
AEPCO	×	✓	×

APS	✗	✓	✗
Avista	✗	✓	✗
BANC	✗	✓	✗
Black Hills	✗	✗	✓
BPA	✗	✓	✗
CHPD	✗	✗	✗
EPE	✗	✓	✗
GCPD	✗	✗	✗
IDP	✗	✓	✗
LADWP	✗	✓	✗
NWMT	✗	✓	✗
NVE	✗	✓	✗
PAC	✗	✓	✗
PGE	✗	✓	✗
PNM	✗	✓	✗
PRPA	✗	✗	✓
PSCo	✗	✗	✓
PSE	✗	✓	✗
SCL	✗	✓	✗
SRP	✗	✓	✗
Tacoma	✗	✓	✗
TEP	✗	✓	✗
TSGT	✗	✗	✓
WACM	✗	✗	✓
WALC	✗	✓	✗
WAUW	✗	✗	✓
WAPA SNR	✗	✓	✗

2026 Market Cases

Three different market footprints were analyzed as part of Phase I of the core CBS study: an EDAM Bookend, a Markets+ Bookend, and a Main Split. These are shown geographically in Figure B-2 2026 Market Scenario Footprints Within the different footprints, each WMEG member is considered part of either EDAM or Markets+ and is assumed to also be part of the corresponding Real-Time WEIM or WEIS market respectively.

Figure B-2 2026 Market Scenario Footprints



Since some WECC entities have already announced their intentions of joining either EDAM or Markets+, these were not changed across any footprints. There was also an additional assumption that all California Entities will remain in the EDAM across all cases except for WAPA Sierra Nevada Region (WAPA SNR), a BANC sub-BA.

Table B-2 Static WECC Market Participation Assumptions

	EDAM	Markets+
WECC Members	CAISO, BANC, TIDC, IID, LADWP, PAC	BC Hydro/Powerex

The rest of the WMEG members, including WAPA SNR, were put in EDAM in the EDAM Bookend, Markets+ in the Markets+ Bookend, and agreed on where to be placed in the Main Split scenario.

Table B-3 WMEG Member Market Assumptions for 2026 Market Scenarios

	EDAM Bookend		Markets+ Bookend		Main Split	
WMEG Member	**EDAM**	**Markets+**	**EDAM**	**Markets+**	**EDAM**	**Markets+**
AEPCO	✓	✗	✗	✓	✗	✓
APS	✓	✗	✗	✓	✗	✓
Avista	✓	✗	✗	✓	✗	✓
BANC	✓	✗	✓	✗	✓	✗
Black Hills	✓	✗	✗	✓	✗	✓
BPA	✓	✗	✗	✓	✗	✓
CHPD	✓	✗	✗	✓	✗	✓
EPE	✓	✗	✗	✓	✗	✓
GCPD	✓	✗	✗	✓	✗	✓
IDP	✓	✗	✗	✓	✗	✓
LADWP	✓	✗	✓	✗	✓	✗
NWMT	✓	✗	✗	✓	✗	✓
NVE	✓	✗	✗	✓	✗	✓
PAC	✓	✗	✓	✗	✓	✗
PGE	✓	✗	✗	✓	✗	✓

PNM	✓	✗	✗	✓	✗	✓
PRPA	✓	✗	✗	✓	✗	✓
PSCo	✓	✗	✗	✓	✗	✓
PSE	✓	✗	✗	✓	✗	✓
SCL	✓	✗	✗	✓	✗	✓
SRP	✓	✗	✗	✓	✗	✓
Tacoma	✓	✗	✗	✓	✗	✓
TEP	✓	✗	✗	✓	✗	✓
TSGT	✓	✗	✗	✓	✗	✓
WACM	✓	✗	✗	✓	✗	✓
WALC	✓	✗	✗	✓	✗	✓
WAUW	✓	✗	✗	✓	✗	✓
WAPA SNR	✓	✗	✗	✓	✓	✗

As part of the market scenario set up, Imbalance reserve requirements were calculated for WECC subregions. Aggregate reserve requirements across subregions in WECC create a noticeable diversity benefit relative to a BAU framework. For the Main Split Case, diversity-related reduction in imbalance reserve requirements range from 16% in the Rockies subregion to 43% in the Southwest sub-region with California and the Northwest in between these two values.

Table B-4: Subregional Imbalance Reserve Diversity Benefit*

Subregion**	California	Northwest	Northwest	Rockies	Southwest
Market	EDAM	EDAM	Markets+	Markets+	Markets+
Mean Reserve Requirement* (MW)	2,472	634	759	414	1,180
Sum of Mean Individual Entity BAU Reserves in Subregion (MW)	3,562	770	1,161	493	2,062
Diversity Benefit Reduction	31%	18%	35%	16%	43%

*Hourly Imbalance Reserve Requirements for each subregion in the market cases were calculated as percentile of the day ahead forecast error for load, wind, and solar for that sub-regional grouping of zones and reflects diversity in forecast error among the zones in each group. The mean reserve requirement takes the average of all hourly requirements across the year. More detail on reserve requirement calculations is provided in Appendix A.

**The zones comprising each subregions listed here are listed in Table A-5 of Appendix A.

B.2. Phase II

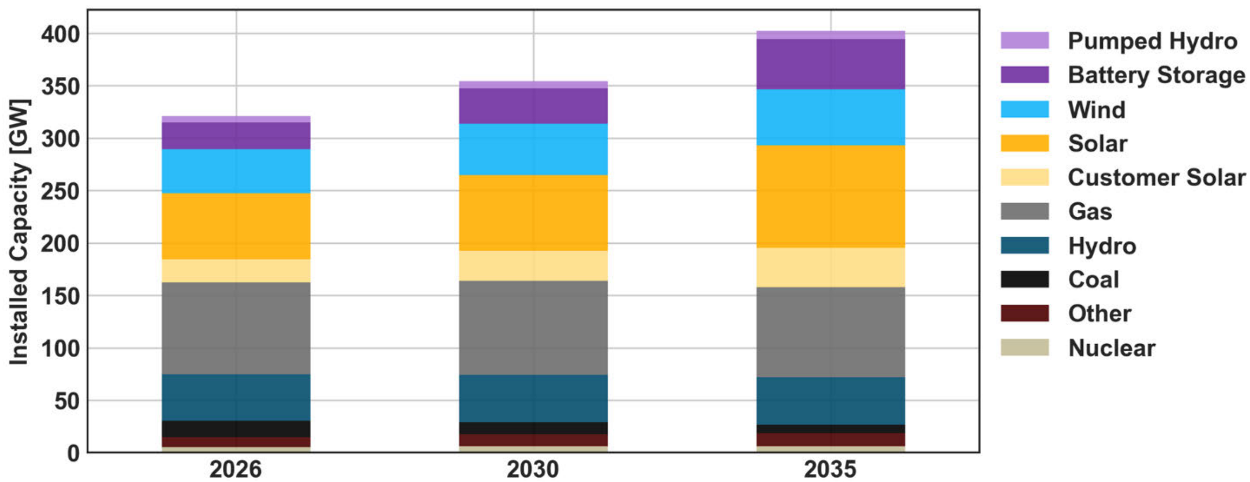
Phase II scenarios for the core CBS study involve analyzing the Main Split case for 2030 and 2035 under increasing intra- and inter-market coordination.

Main Split

The 2030 and 2035 Main Split cases account for increases in generation capacity across WECC according to WMEG member input data as well as some transmission upgrades that were considered important for individual entities. The remaining scenarios in Phase II build off each other starting with the 2030 and

2035 Main Split cases. WMEG members provided input into the resource additions and retirements for the 2030 and 2035 years. Total resource capacity across WECC shows a reduction in coal and gas capacity through 2035 while solar, wind, and storage see noticeable increases across that same timeframe.

Figure B-3 Total U.S. WECC Installed Capacity[24]



Market to Market (M2M) Coordination

The first sensitivity involves increased market-to-market (M2M) coordination. In the future, once EDAM and Markets+ have established themselves as functional Day-Ahead markets in the West, they will continue to mature and refine market rules to enhance liquidity and lower prices. Moreover, even without production cost savings, this kind of coordination could aid reliability if market to market trading opportunities can be an option near real-time. Either EDAM or Markets+ may look to enhance the efficiency of external transactions by developing clear cross-border trading procedures and minimizing the cost associated with this type of scheduling. This type of improved market to market coordination could result in a more liquid and robust trading between markets which may provide more cost-effective than strictly trading internally within either market separately.

Table B-5: 2030 & 2035 Main Split M2M Hurdle Rate Component Breakout

	Non-M2M Coordination Hurdle Rate	M2M Coordination Hurdle Rate
Within Market	$0	$0
Market Seam	**Weighted Average OATT Rate of Market**	**Weighted Average OATT Rate of Market**

[24] Total WECC capacity does not include AESO resources as this was implemented as a price stream within the CBS. BC resources and loads (as well as trades with Alberta) were modeled as an integrated pumped hydro facility based on the anticipated quantity of energy to be sent to the US for on an hourly or block schedule basis. This capacity is included with pumped storage in the chart.

	+ $2 Friction **+ $8 Congestion Risk** for exports from a Zone that is in Market A to a Zone that is in Market B	**+ $2 Friction** **+ $4 DA Congestion Risk (or $1 RT Congestion Risk)** for exports from Market A to a Zone that is in Market B

Market to Market & Consolidated Balancing Area (M2M + CBA)

The M2M + CBA case represents a future where not only have markets been able to encourage better inter-market trading, but they have also developed into a more consolidated balancing area. This includes optimal dispatch within the market footprint in addition to ancillary services markets within the footprint. Beyond an imbalance reserve sharing between entities in a Day-Ahead market construct, the consolidated balancing area would expand reserve sharing by including Spinning, Non-Spinning, and Regulation reserve market products. These reserve groupings are aggregated on a sub-regional basis within each market, instead of for the full market footprint, to account for transmission constraints within the West that may prevent reserves from being fully sourced from across the entire market footprint.

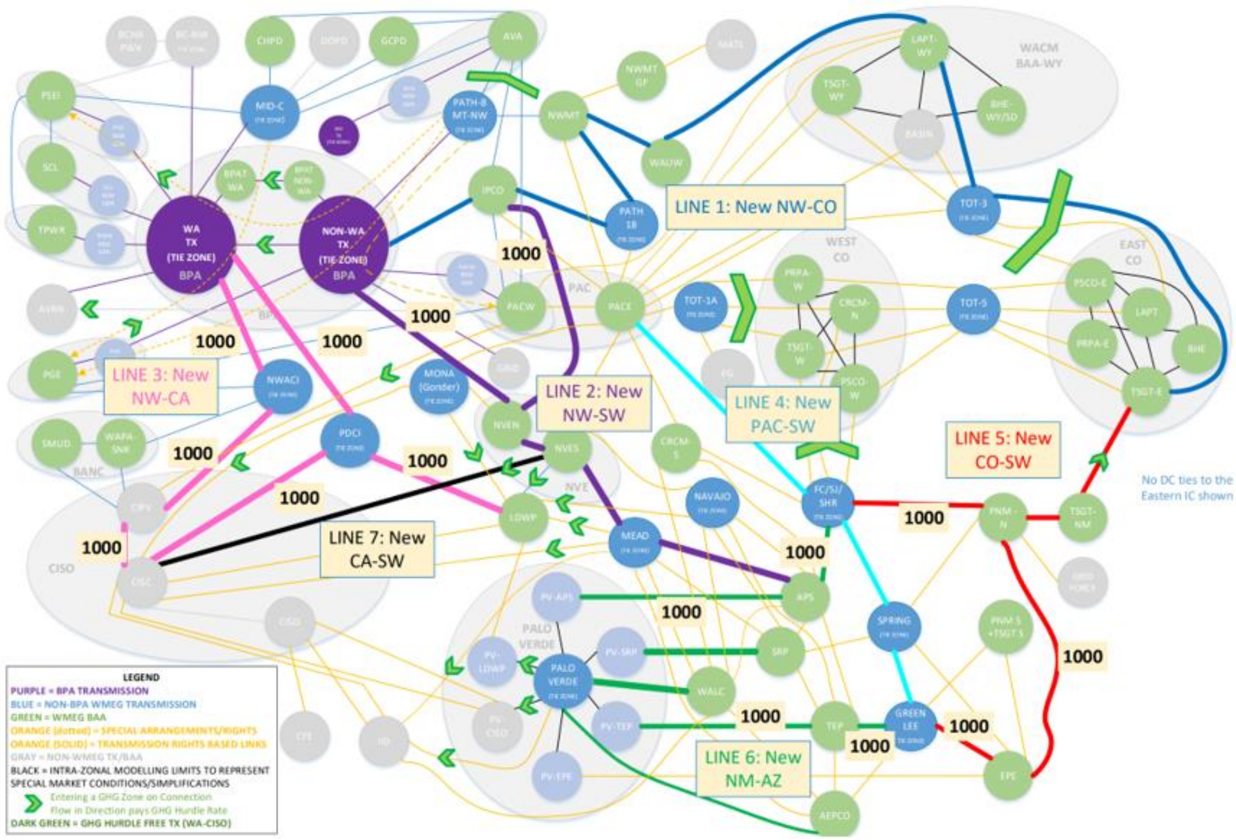
B.3. Phase III

2035 RTO Scenario

The 2035 RTO case uses the M2M + CBA case as the starting point and adds additional transmission capacity along seven major paths within the existing model topology as a representation of increased coordination of transmission development that may be facilitated through an RTO. The WMEG did not analyze individual transmission addition scenarios to determine the net cost or benefit of any individual line, nor were these linked to specific projects under development; rather, the scenario explores the aggregate impact that significant transmission additions could have for enhancing market benefits.

The map below indicates the major transmission upgrades highlighted in thicker bold coloring for the 2035 RTO Scenario, augmenting transmission links already in the existing case. The highlighted links in the figure that are marked with “1000” have added 1000 MW to the transmission capability between the linked zones compared to the transmission in the base model for 2035. The highlighted links without a number shown have added 2000 MW to transmission in the base model.

Figure B-4 RTO Case Transmission Capacity Additions



Appendix C. Settlement

E3 developed a comprehensive and detailed settlement process that takes output data from the various market model runs and generates ex-post settlement details down to the generator level for each WMEG entity over the study year. The components of settlement include the components listed below in this section.

The total **Net Variable Costs** for each entity are based on the sum of each of these components where costs are positive values and revenues are treated as negative (offsetting costs). For each entity, E3 then calculated the Net Variable Cost savings (or increase) from market participation as the difference between the Net Variable Costs for that entity from a market case (e.g., EDAM Bookend) compared to the net costs in the BAU case.

All pricing for the Day-ahead settlement includes Fast Start Pricing for any zones included in the Markets+ footprint. E3's settlement process conducts both a day-ahead market and a real-time market settlement down to the generator unit level across WECC.

C.1. Generation Cost

Generation cost for each member is the sum-product of each generator's production cost and the member's generator ownership share factor. Depending on the generator technology, its production cost could include fuel, VO&M, start/shutdown, and emission cost components (i.e., VO&M is the only relevant component for batteries). Generation costs are only incurred in real-time.

C.2. Generation Revenue

Generation revenue for each member is the sum-product of each generator's net-revenue and the member's generator ownership share factor. The net-revenue for each generator is the product of the nodal price and generation (net of any pump or charging load). DA generation revenue is calculated using DA prices and volumes, and then summed with the RT incremental volume (RT-DA) valued at the RT price. Finally, members that are off-taking hydro power from other members have those obligations (valued at the DA price at a supplying member node) added to their generation revenue (while the supplying member has it subtracted).

C.3. Loads Cost

Load cost for each member is the sum-product of nodal price, native-load,[25] and member load-ownership factor. The member load-ownership factors allocate balancing area load into member service load. DA load cost is calculated using DA prices and volumes, and then summed with RT incremental volume (RT-DA) valued at the RT price. RT native-load can be different from DA native-load due to load forecast error.

[25] Native load is the raw input load and does not include generator pumping/charging load that is accounted for in generation revenue.

C.4. Reserve Cost & Reserve Revenue

Reserve cost only includes the explicit costs for procuring market reserve products; non-market reserve cost can be considered embedded in generator net-revenues as opportunity cost. Reserve cost for each member is the sum-product of reserve price, reserve requirement, region-BAA requirement factors, native-load ratio factor, and member load-ownership factor. In cases that have region reserve markets for ancillaries, the region-BA requirement factors decompose the region-wide reserve requirement to balancing areas (defined by BA reserve requirements from the BAU 2026 case). The native-load ratio factors allocate the BA requirements to model nodes (which each represent BA or sub-BA) based on native-load. Finally, the load-ownership factors allocate cost to members. DA reserve cost is calculated using DA prices and volumes, and then summed with RT incremental volume (RT-DA) valued at the RT price. RT reserve requirement can be different from DA due to load forecast error.

Market reserve revenue for each member is the sum-product of generator reserve provision, reserve price, and generator ownership factor. Like reserve cost, DA and RT components were included.

C.5. GHG Revenue

Generator revenue for each member is the sum-product of generator GHG award, emission intensity factor and GHG price. GHG revenue can be allocated to generators outside of states with GHG programs (CA, WA, CO) when they help serve load in these localities. The hourly GHG demand is determined using the change in net imports over eligible lines[26] relative to a reference phase.[27] Generator supply caps vary for dispatchable vs non-dispatchable resources but are broadly based on differences between changes in generation and headroom between phases. After determination of the GHG demand and generator available supply caps, hourly GHG awards are allocated to generators in emission intensity merit-order. Only generators that are in BA's that are net-exporters are considered candidate resources for awards, and if there is not enough GHG supply to meet demand the remainder is allocated to a shortage resource (not owned by any member). The price that a generator receives for its GHG awards is a fraction of the GHG price proportional to its emission intensity relative to a cut-off emission intensity of 0.437 Tons/MWh. Consequently, zero-emission resources receive the full GHG price at the cut-off emissions intensity.

C.6. Wheeling Revenue

Transmission wheeling revenue is the product of line flow and the hurdle rate (constituted of OATT rate, market hurdle adder and friction adder). Broadly, when a market region is exporting power from a transmission line that crosses a market seam, the wheeling revenue is allocated to all the balancing on a native-load ratio share basis and then to members on a load-ownership share basis. Incremental RT revenue is included. The exact methodology for allocating wheeling revenue to members depends on

[26] GHG eligible lines are transmission connection connecting a non-GHG area to a GHG area. All flow entering the GHG area is subject to the designated GHG price and is represented as an additional hurdle rate.

[27] The reference phase for DA is the GHG phase (which prevented flow over GHG lines); for RT, the DA phase is used as a reference. RT demand for GHG is only considered when incrementally greater net-imports were made into GHG areas in RT than DA.

whether the line connects (1) two different markets (market-to-market), (2) a market region to a non-market region (market-to-nonmarket), or (3) an intra-market or intra-nonmarket line (non-market seam).

Wheeling revenue is distributed among entities in the BAU case based on to the amount of energy exported over transmission lines connected to their zones and their OATT rate or market wheeling rate; in the markets cases, wheeling revenue is determined based on the amount of energy flowing exported over transmission lines connected to each market footprint and then is distributed among market participants based on each participant's percentage share of total load in the market (load-ratio share basis).[28]

C.7. Congestion Revenue

Transmission congestion revenue is only incurred when (1) a line hits its flow limit, (2) the flow is in the direction of the price premium and (3) the premium exceeds any hurdle rate applicable to the line. Like wheeling revenue, the congestion revenue methodology depends on whether the line is (1) a market-to-market line, (2) a market-to-non-market line, or (3) a non-market seam line. Like wheeling revenue, when a market region is exporting power to a zone that is outside the market footprint, any congestion on the market seam is allocated to all members of that market on a load-ratio share basis. However, for other types of lines the BA exporting on the congested line is allocated all the congestion revenue and to members by load-ownership share. When the exporting node is a tie-zone, the BAAs or zones (connected via other lines) that are receiving energy from tie-zone serve the congested region divide the congestion revenue equally. This revenue would subsequently be allocated by each WMEG member to each of its transmission customers via load ratio share. RT congestion revenue is only included when the line is congested in RT and was not DA stage.

[28] Separate proposals for market elements in EDAM and Markets+ that seek to provide some compensation to entities that lose current short-term firm or non-firm point to point revenues were not represented in this analysis due to the definitions of those mechanisms not being fully defined at the time when study assumptions for this analysis were finalized. Revenue from such mechanisms (or charges to derive this revenue) would be additional to any individual benefits represented in this study.

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 452

PGE 2026 Annual Power Cost Update Tariff

PORTLAND GENERAL ELECTRIC

Direct Testimony
Pricing

Direct Testimony of:

Jaki Ferchland, PGE

Casey Manley, PGE

April 1, 2025

Table of Contents

I. Introduction and Summary

Q. Please state your names and positions.

A. My name is Jaki Ferchland. I am a Senior Manager in Rates and Regulatory Affairs for Portland General Electric Company (PGE).

My name is Casey Manley. I am a Senior Regulatory Analyst in the Pricing and Tariff Department. Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. Our testimony describes the following:

- The estimated base rate impacts from this filing anticipated to occur on January 1, 2026.
- The calculation of Schedule 125 prices and how this has changed to be consistent with the methodology established in Docket UE 435 (UE 435).
- The calculation of the changes in the applicable System usage and Distribution prices for individual rate schedules related to Special Conditions 1 and 2 of Schedule 129 and Schedule 139, Long-Term Transition Adjustments.

PGE will file the final Schedule 125 tariff prices that will incorporate the final updates to Net Variable Power Costs (NVPC) in November 2025. The changes in the other applicable base rate schedules will also be filed at that time.

Q. What are the base rate impacts of the proposed $50.6[1] million increase in Schedule 125 prices, inclusive of changes in system usage charges?

A. Table 1, below, summarizes the estimated 2026 cost of service (COS) base rate impacts for selected rate schedules. These estimates are preliminary and subject to changes in market electric and gas prices and forecasted loads, among other items.

Table 1
Estimated Base Rate Impacts

Schedule	Rate Impact
Sch 7 Residential	1.3 %
Sch 32 Small Non-residential 30 kW or less	1.2 %
Sch 83 Non-residential 31-200 kW	1.6 %
Sch 85 Secondary 201-4,000 kW	1.8 %
Sch 85 Primary 201-4,000 kW	2.4 %
Sch 89 Primary Over 4,000 kW	2.2 %
Sch 89 Subtransmission Over 4,000 kW	1.9 %
Schedule 90	2.4 %
COS Overall	1.6 %

Q. How did you calculate 2026 NVPC revenues at current rates?

A. Current NVPC revenues are primarily collected via Schedule 125[2] with a credit associated with Clearwater embedded in Schedule 122a[3] rates. To accurately assess the combined revenue at current prices for 2026 from both schedules, PGE isolated the NVPC benefit embedded in current Schedule 122a collections and developed segmented prices that reflect only the NVPC portion of the overall Schedule 122a revenue requirement. In 2026, the Clearwater NVPC benefit will flow exclusively through Schedule 125 which is reflected in proposed 2026 prices. This method for determining current revenues for 2026 results in an appropriate apples-to-apples comparison of current and proposed revenues for 2026 related to NVPC. The deferred portion of Schedule 122 was not considered as these are historic values that occurred in 2024.

Q. What is the total proposed NVPC to be collected in 2026 rates?

A. The total amount of proposed power costs forecasted to be collected through Schedule 125 in 2026 is $1,059.7 million.

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[1] The $50.6 million includes the change in 2026 NVPC of $48.9 million and the revenue sensitive cost of $1.7million.
[2] *In re Portland Gen. Elec. Co. Request for a Gen. Rate Revision,* UE 435, Order No. 24-454 (Dec. 20, 2024).
[3] The Annual Adjustment Clause (AAC) portion of Schedule 122.

Q. How are you treating the NVPC within the Automatic Adjustment Clause (AAC) portion of Schedule 122 in 2026?

A. The AAC portion of Schedule 122 reflects amounts for contemporaneous amortization associated with the renewable automatic adjustment clause. As in our calculation for 2025, to provide an accurate picture of NVPC, we have similarly updated the AAC portion of Schedule 122 to contain only the non-NVPC amounts. Beginning in 2026 the NVPC benefits currently returned to customers via the AAC portion of Schedule 122 will flow through Schedule 125 NVPC. Were we to leave the power costs benefits in Schedule 122 it would effectively be double counting the NVPC benefit to customers.

II. Calculation of Schedule 125 Prices

Q. Please describe how you calculated the Schedule 125 amount.

A. We determined the total 2026 revenue requirement, inclusive of revenue sensitive amounts, by calculating 2026 NVPC revenues at current rates (inclusive of Schedule 125 and the NVPC benefit portion of the Schedule 122 AAC) and subtracting from the total forecasted 2026 NVPC amount of $1,059.7 million. We then multiplied the delta by the revenue sensitive factor from UE 435 of 3.50% to determine the incremental revenue sensitive amount needed. This calculation is performed to appropriately update revenue sensitives in current base rates, to reflect the 2026 NVPC forecast. We added the incremental revenue sensitive amount to the 2026 NVPC target, which resulted in a total targeted revenue requirement for 2026 of $1,061.4 million. PGE Exhibit 201 provides a summary of the Schedule 125 amount of $1,061.4 million and how it is spread to the respective schedules. Also included on PGE Exhibit 201 are the proposed Schedule 125 prices.

Q. Does this methodology differ from prior Annual Update Tariff (AUT) calculations?

A. Yes, this methodology does differ from what was historically used. In prior years, Schedule 125 was calculated as the difference between the projected NVPC and the current NVPC with the addition of the revenue sensitive factor. In UE 435, PGE changed Schedule 125 to include all costs of NVPC whether PGE filed for a full rate revision or an AUT to more clearly demonstrate base price changes from NVPC price changes. The pricing is now done with the entire forecasted NVPC plus the revenue sensitive factor on the delta between current and proposed NVPC.

Q. Have any other changes been made to the pricing structure?

A. To remain consistent with the pricing structure approved in UE 435 for Schedule 125, on, mid, and off-peak pricing is now present in the pricing structure for Schedule 125. The pricing structure retains the differentials established in UE 435 and follows the same methodology for calculating the on, mid, and off-peak prices for Schedules 38, 83, 85, 89 and on and off-peak prices for Schedule 90.

Q. Please describe how you allocate the Schedule 125 amount to each rate schedule and how you calculate the Schedule 125 price.

A. We allocate NVPC consistent with Special Condition 1 of Schedule 125 which states:

Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

Once the allocations have been determined, prices are calculated using the forecasted annual usage for each customer and for Schedules 38, 83, 85, 89, and 90, and a differential, which was calculated in UE 435 is applied to determine the on, mid, and off-peak prices.

Q. Where is the calculation of the basis of the Schedule 125 allocations, the 2026 NVPC Revenues?

A. We present this calculation, which is simply the 2026 projected energy billing determinants multiplied by the tariff NVPC energy prices, including the 2025 Schedule 122 NVPC benefit in PGE Exhibit 202.

III. Calculation of System Usage and Distribution Prices

Q. Do you propose updating the System Usage and Distribution Prices for the various rate schedules?

A. Yes, consistent with Special Conditions 1 and 2 of Schedule 129 and Schedule 139 we are truing up the collection or credits related to prospective transition adjustment payments made by long-term direct access (LTDA) customers and new load long-term direct access (NLDA) customers.

Q. How do you allocate the Schedule 129 and Schedule 139 Transition Adjustment payments from LTDA and NLDA customers to the rate schedules?

A. We allocate the long term transition adjustment payments received from LTDA and NLDA customers to all customers on the basis of equal cents per kWh, as stated in Special Conditions 1 and 2. We then compare these allocations of 2026 long term transition adjustment payments to the amount that is currently embedded in the System Usage and Distribution prices determined in PGE's most recent rate revision filing, as of December 2024. For Schedules 85, 89, 90 and their direct access equivalent schedules, the System Usage Charges are expected to increase by 0.01 mills/kWh. For other schedules, the System Usage or Distribution Charges are also expected to increase by 0.01 mills/kWh. PGE Exhibit 203 provides detail regarding these calculations.

Q. In addition to truing-up the Schedule 129 and Schedule 139 Transition Adjustment payments, what other factors may cause changes to the System Usage or Distribution Charges?

A. Should additional enrollment in LTDA and NLDA occur in in the September 2025 LTDA enrollment window for service commencing in 2026, PGE will allocate the additional long term transition adjustments from that enrollment window consistent with Special Condition 1, and, additionally, allocate the incremental changes in fixed generation revenues consistent with Special Conditions 2 and 3.

Q. Does a potential change in the Distribution Charges for the Outdoor Lighting Schedules 15, 91, 95, 491, 495, 515, 591, and 595 mean that the Compliance Filing to this docket may include changes to the numerous fixture prices included in these schedules?

A. Yes. The true-up of long term transition adjustments may require changes in the fixture prices for those rate schedules with an energy price included as part of the fixture price.

Q. Does this conclude your testimony?

A. Yes.

IV. Qualification

Q. Ms. Ferchland, please state your educational background and qualifications.

A. I received a Bachelor of Science in Electrical Engineering and a Master of Business Administration both from the University of Denver and a Post-Baccalaureate in Accounting from Portland State University. I joined PGE in 2015 as an Investor Relations Analyst and transitioned to the Principal Treasury Analyst role in 2017 where I worked with PGE's revolving credit facility, debt issuances, and annual rating agency presentations. I became the Manager of Revenue Requirement within Rates and Regulatory Affairs in November 2019, and the Senior Manager of Pricing, Tariff and Power Cost Recovery in February 2025.

Q. Ms. Manley, please state your educational background and qualifications.

A. I received a Bachelor of Business Administration degree from University of Portland with a focus in Operations & Technology Management. I have been a Senior Regulatory Analyst since August of 2022. I joined PGE in 2016 as the Commercial Credit Card Analyst and became an analyst in Rates and Regulatory Affairs in 2018. Since joining Rates and Regulatory Affairs in 2018, my areas of focus have included revenue requirement, pricing of supplemental schedules, operational tariffs for our customer-facing products and programs, and other regulatory issues.

V. List of Exhibits

Exhibit	**Description**
201	Calculation of Schedule 125 Prices
202	Calculation of Adjusted NVPC Revenues
203	Calculation of System Usage and Distribution Prices

PORTLAND GENERAL ELECTRIC
Calculation of Schedule 125 Prices

Schedules	2026 Calendar COS Energy MWh	2026 On-Peak MWh	2026 Mid-Peak MWh	2026 Off-Peak MWh	2026 NVPC Revenues ($000)	NVPC Allocation	Sch 125 Allocation ($000)	2026 Sch 125 Flat Price mills/kWh	2026 Sch 125 On-Peak Price mills/kWh	2026 Sch 125 Mid-Peak Price mills/kWh	2026 Sch 125 Off-Peak Price mills/kWh	2026 Sch 125 Revenues	Cycle MWh	Cycle Revenues	Sch 125 and 122 NVPC Revenues at Current Price	Sch 125 and 122 NVPC Revenues at Updated Price	Sch 125 and 122 NVPC Revenue Change
Schedule 7	7,928,368				$436,140	43.1%	$457,986	57.77				$458,022	7,903,509	$456,586	$436,139,521	$ 458,021,816	$ 21,882,296
Schedule 15	12,236				$479	0.0%	$503	41.14				$503	12,236	$503	$479,406	$ 503,389	$ 23,983
Schedule 32	1,518,720				$73,567	7.3%	$77,252	50.87				$77,257	1,518,623	$77,252	$73,566,807	$ 77,257,297	$ 3,690,490
Schedule 38	26,913	5,641	12,393	8,880	$1,271	0.1%	$1,334		61.42	49.02	42.82	$1,334	26,910	$1,334	$1,270,616	$ 1,334,226	$ 63,610
Schedule 47	21,268				$1,238	0.1%	$1,300	61.13				$1,300	21,005	$1,284	$1,238,031	$ 1,300,135	$ 62,104
Schedule 49	58,680				$3,345	0.3%	$3,513	59.87				$3,513	58,943	$3,529	$3,345,349	$ 3,513,174	$ 167,825
Schedule 83	2,843,311	641,723	1,202,680	998,908	$135,865	13.4%	$142,670		61.72	50.27	42.64	$142,670	2,841,594	$142,583	$135,864,573	$ 142,669,625	$ 6,805,051
Schedule 85-S	2,024,385	427,542	871,630	725,214	$92,165	9.1%	$96,781		59.57	48.13	40.50	$96,788	2,021,528	$96,651	$92,164,708	$ 96,787,523	$ 4,622,815
Schedule 85-P	757,802	163,244	297,362	293,832	$34,145	3.4%	$35,856		59.46	48.02	40.39	$35,852	754,438	$35,852	$34,145,216	$ 35,852,309	$ 1,707,094
Schedule 89-S	0				$0	0.0%	$0						0	$0	$0	$ -	$ -
Schedule 89-P	1,441,302	307,439	527,142	606,721	$61,227	6.1%	$64,294		52.55	45.11	40.16	$64,301	1,437,172	$64,116	$61,226,991	$ 64,300,579	$ 3,073,588
Schedule 89-T/75	38,706	6,481	21,661	10,563	$1,639	0.2%	$1,721		52.01	44.57	39.62	$1,721	0	$1,717	$1,638,927	$ 1,721,075	$ 82,148
Schedule 90-P	3,975,424	2,278,719		1,696,705	$168,051	16.6%	$176,468		47.59		40.09	$176,465	3,958,840	$175,729	$168,050,765	$ 176,465,156	$ 8,414,391
Schedule 91/95	39,861				$1,562	0.2%	$1,640	41.15				$1,640	39,861	$1,640	$1,562,153	$ 1,640,280	$ 78,128
Schedule 92	2,760				$117	0.0%	$123	44.41				$123	2,760	$123	$116,720	$ 122,572	$ 5,851
TOTAL	20,689,736				$1,010,810	100.0%	$1,061,441					$1,061,489	20,597,420	$1,058,900	$1,010,809,784	$1,061,489,155	$50,679,371

2026 NVPC Revenue Requirement ($000)	$1,059,729
2026 NVPC Revenues at Current Prices ($000)	$1,010,810
Incremental 2026 NVPC Revenue Requirement ($000)	$48,919
Revenue Sensitive Adj. 3.50%	$1,712
Sch 125 Revenue Requirement	$1,061,441
Full Incremental 2026 NVPC Revenue Requirement ($000)	$50,631

PORTLAND GENERAL ELECTRIC
Calculation of NVPC Revenues

Schedule	2026 Calendar MWh	2025 NVPC Price (mills)	2026 NVPC Revenues (000s)	2025 Sch 122 NVPC Benefit Price (mills)	2026 Sch 122 NVPC Benefit Revenues (000s)	2026 Cycle MWh	2026 Cycle to Calendar Ratio
Sch 7							
Block 1	7,928,368	57.88	$458,894	(2.87)	($22,754)	7,903,509	0.9969
Block 2	0	57.88	$0	(2.87)	$0	0	0.9969
Sch 15	12,236	41.23	$504	(2.05)	($25)	12,236	1.0000
Sch 32	1,518,720	50.90	$77,303	(2.46)	($3,736)	1,518,623	0.9999
Sch 38							
On-peak	5,641	61.41	$346	(2.35)	($13)	5,640	0.9999
Mid-peak	12,393	49.01	$607	(2.35)	($29)	12,391	0.9999
Off-peak	8,880	42.81	$380	(2.35)	($21)	8,879	0.9999
Sch 47	21,268	60.78	$1,293	(2.57)	($55)	21,005	0.9876
Sch 49	58,680	59.51	$3,492	(2.50)	($147)	58,943	1.0045
Sch 83							
On-peak	641,723	61.73	$39,614	(2.40)	($1,540)	641,336	0.9994
Mid-peak	1,202,680	50.28	$60,472	(2.40)	($2,886)	1,201,953	0.9994
Off-peak	998,908	42.65	$42,602	(2.40)	($2,397)	998,305	0.9994
Generation Demand	8,516,756				$0	8,511,613	0.9994
Sch 85-S					$0		
On-peak	427,542	59.61	$25,486	(2.32)	($992)	426,938	0.9986
Mid-peak	871,630	48.16	$41,981	(2.32)	($2,022)	870,400	0.9986
Off-peak	725,214	40.53	$29,395	(2.32)	($1,682)	724,190	0.9986
Generation Demand	5,345,732				$0	5,338,188	0.9986
Sch 85-P					$0		
On-peak	163,972	59.09	$9,689	(2.09)	($343)	163,244	0.9956
Mid-peak	298,688	47.64	$14,231	(2.09)	($624)	297,362	0.9956
Off-peak	295,142	40.01	$11,809	(2.09)	($617)	293,832	0.9956
Generation Demand	1,473,720				$0	1,467,179	0.9956
Sch 89-S							
On-peak	0	53.00	$0	(2.09)	$0	0	0.9971
Mid-peak	0	45.56	$0	(2.09)	$0	0	0.9971
Off-peak	0	40.60	$0	(2.09)	$0	0	0.9971
Sch 89-P							
On-peak	307,439	52.51	$16,144	(2.09)	($643)	306,558	0.9971
Mid-peak	527,142	45.07	$23,759	(2.09)	($1,102)	525,632	0.9971
Off-peak	606,721	40.11	$24,337	(2.09)	($1,268)	604,982	0.9971
Sch 89-T							
On-peak	6,481	52.01	$337	(2.12)	($14)	6,466	0.9976
Mid-peak	21,661	44.57	$965	(2.12)	($46)	21,610	0.9976
Off-peak	10,563	39.61	$418	(2.12)	($22)	10,538	0.9976
Sch 90 (30 MWa - 250 MWa)							
On-peak	377,136	47.50	$17,914	(2.06)	($777)	375,442	0.9955
Off-peak	279,008	40.00	$11,160	(2.06)	($575)	277,755	0.9955
Sch 90 (GT 250 Mwa)							
On-peak	1,901,583	47.50	$90,325	(2.02)	($3,841)	1,893,770	0.9959
Off-peak	1,417,697	40.00	$56,708	(2.02)	($2,864)	1,411,873	0.9959
Sch 91/95	39,861	41.23	$1,643	(2.04)	($81)	39,861	1.0000
Sch 92	2,760	44.49	$123	(2.20)	($6)	2,760	1.0000
Totals	20,689,736	51.33	$1,061,933	(2.47)	($51,123)	20,636,033	0.9974

PORTLAND GENERAL ELECTRIC
CALCULATION OF SYSTEM USAGE AND DISTRIBUTION PRICES
Allocation of Schedule 129/139 Transition Adjustment
2026

ALLOCATION OF TRANSITION ADJUSTMENT

Schedules	Cycle Energy	Percent	Allocations ($000)	mills/kWh
Schedule 7	7,903,509	34.1%	$715	0.09
Schedule 15	12,236	0.1%	$1	0.09
Schedule 32	1,518,623	6.5%	$137	0.09
Schedule 38	26,910	0.1%	$2	0.09
Schedule 47	21,005	0.1%	$2	0.09
Schedule 49	58,943	0.3%	$5	0.09
Schedule 83	2,841,594	12.2%	$257	0.09
Schedule 85-S	2,453,260	10.6%	$222	0.09
Schedule 85-P	1,032,367	4.4%	$93	0.09
Schedule 89-S	0	0.0%	$0	0.09
Schedule 89-P	3,098,539	13.3%	$280	0.09
Schedule 89-T	242,617	1.0%	$22	0.09
Schedule 90-P 30-250 MWa	653,196	2.8%	$59	0.09
Schedule 90-P >250 MWa	3,305,643	14.2%	$299	0.09
Schedules 91/95	39,861	0.2%	$4	0.09
Schedule 92	2,760	0.0%	$0	0.09
TOTAL	23,211,065	100.00%	$2,101	0.09
		TARGET	$2,101	

Change in Schedule 129/139 Transfer Payment Amount 2026

Schedules	Current mills/kWh	2025 mills/kWh	Change mills/kWh	Tariff Category
Schedule 7	0.08	0.09	0.01	Distribution
Schedule 15	0.08	0.09	0.01	Distribution
Schedule 32	0.08	0.09	0.01	Distribution
Schedule 38	0.08	0.09	0.01	Distribution
Schedule 47	0.08	0.09	0.01	Distribution
Schedule 49	0.08	0.09	0.01	Distribution
Schedule 83	0.08	0.09	0.01	System Usage
Schedule 85-S	0.08	0.09	0.01	System Usage
Schedule 85-P	0.08	0.09	0.01	System Usage
Schedule 89-S	0.08	0.09	0.01	System Usage
Schedule 89-P	0.08	0.09	0.01	System Usage
Schedule 89-T	0.08	0.09	0.01	System Usage
Schedule 90-P 30-250 MWa	0.08	0.09	0.01	System Usage
Schedule 90-P >250 MWa	0.08	0.09	0.01	System Usage
Schedules 91/95	0.08	0.09	0.01	Distribution
Schedule 92	0.08	0.09	0.01	Distribution
TOTAL				

Total Change in Distribution/System Usage Charge 2026

Schedules	Sys. Usage Current mills/kWh	Sch 129/139 Change mills/kWh	2026 Sys. Usage mills/kWh	Category
Schedule 7	5.35	0.01	5.36	Distribution
Schedule 15	21.79	0.01	21.80	Distribution
Schedule 32	4.66	0.01	4.67	Distribution
Schedule 38	(7.39)	0.01	(7.38)	Distribution
Schedule 47	(7.75)	0.01	(7.74)	Distribution
Schedule 49	(7.67)	0.01	(7.66)	Distribution
Schedule 83	8.58	0.01	8.59	System Usage
Schedule 85-S	2.87	0.01	2.88	System Usage
Schedule 85-P	2.84	0.01	2.85	System Usage
Schedule 89-S	2.79	0.01	2.80	System Usage
Schedule 89-P	2.76	0.01	2.77	System Usage
Schedule 89-T	2.73	0.01	2.74	System Usage
Schedule 90-P 30-250 MWa	2.25	0.01	2.26	System Usage
Schedule 90-P >250 MWa	2.25	0.01	2.26	System Usage
Schedules 91/95	14.44	0.01	14.45	Distribution
Schedule 92	5.58	0.01	5.59	Distribution
Schedule 515	10.19	0.01	10.20	Distribution
Schedule 532	1.93	0.01	1.94	Distribution
Schedule 538	2.22	0.01	2.23	Distribution
Schedule 549	1.45	0.01	1.46	Distribution
Schedule 583	8.70	0.01	8.71	System Usage
Schedule 485/585-S	0.65	0.01	0.66	System Usage
Schedule 485/585-P	0.65	0.01	0.66	System Usage
Schedule 489/589-S	0.18	0.01	0.19	System Usage
Schedule 489/589/689-P	0.67	0.01	0.68	System Usage
Schedule 489/589-T	0.66	0.01	0.67	System Usage
Schedule 490/590	0.11	0.01	0.12	System Usage
Schedule 491/495/591/595	5.60	0.01	5.61	Distribution
Schedule 492/592	2.37	0.01	2.38	Distribution