BPA Day-Ahead Market Participation Benefits Study

PREPARED BY
John Tsoukalis
Kai Van Horn
Johannes Pfeifenberger
Evan Bennett
Son Phan
Jack Kalinski
Ellery Curtis

PREPARED FOR
GRIDLAB
NIPPC
NW ENERGY COALITION
PNGC POWER
RENEWABLE NORTHWEST

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Brattle

Timeline of the Brattle Team's Western Markets Studies

The nodal WECC model we used for this study includes system-specific data from more than 10 utilities in the WECC, giving us a detailed view of the western system, including:

- Long-term transmission rights, contracted resources (and transmission encumbrances), generation additions, transmission additions, renewable diversity and forecast errors, and market design detail/implementation
- **Study participants have helped refine our model by performing full reviews** of relevant modeling assumptions, including transmission rights, transmission costs, load forecasts, fuel prices, generation mix and costs, etc.
  - Study participants include **the Balancing Authority of Northern California, El Paso Electric, Idaho Power, LA Department of Power and Water, NV Energy, Portland General Electric, PacifiCorp, Public Service Company of New Mexico, Sacramento Municipal Utility District,** and other utilities, transmission owners and independent power producers
  - Several of these reviewers were able to provide **details relevant to BPA's system**, including Portland, PacifiCorp, and others

1 Pre-2022 Studies

Western Market Studies
- EDAM Feasibility Study
- SPP RTO Expansion Study
- CAISO EIM GHG Structure Study
- Xcel Colorado WEIS/WEIM Study
- WEIS and SPP Integration Study
- Mountain West RTO Study
- CA SB350 Study

2 2022 EDAM Study

2022 EDAM Benefits Study

We produced an updated assessment of EDAM benefits for five study participants, building on the work done for the 2019 EDAM feasibility study:
- BANC, Idaho Power, LADWP, PacifiCorp, SMUD

3 2023-24 EDAM-M+ Studies

Comparative EDAM-M+ Studies

We further refined our 2022 EDAM benefits study model with input from study participants and the Markets+ design documents to conduct benefits studies for several additional utilities , including:
- Portland General Electric, NV Energy, Public Service New Mexico, El Paso Electric, and others

4 This Study

BPA EDAM-M+ Benefits Study

We leveraged our work and modeling enhancements from all prior studies, and further refined our modeling of hydro using data provided by the Northwest Power and Conservation Council, to assess the comparative benefits to BPA of participating in EDAM vs Markets+.

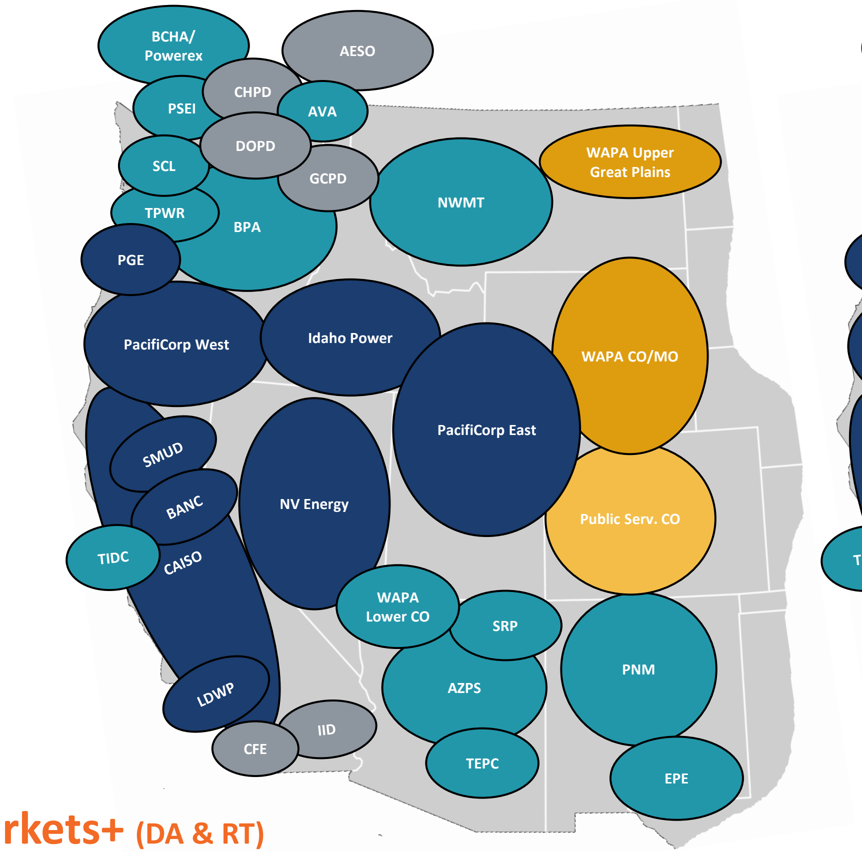
Key Model Features

We conducted all study simulations using a **nodal production cost model of the WECC** with added markets, transmission rights, and contract-path trading functionality

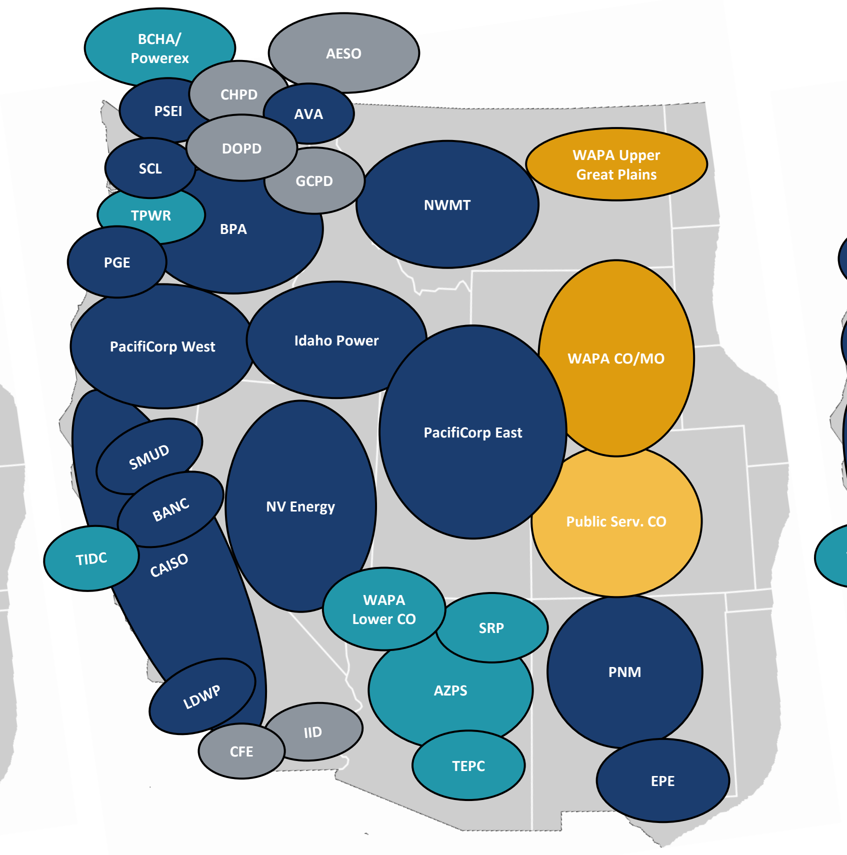
- Model developed in PSO/Enelytix, which contains state-of-the-art features
  - Simultaneously optimizes contract path and physical constraints
  - Models bilateral, day-ahead, and real-time markets (including uncertainty) sequentially through multiple solution cycles
  - Co-optimizes storage resources with other resources in unit-commitment and dispatch
  - Detailed ancillary service and operating reserve modeling (including reserve sharing) and co-optimization of ancillary services with energy
- **The study year is 2032**, which aims to reflect the first decade of markets operations, representing an intermediate year that captures known changes in resource mix and transmission infrastructure
- We modeled a **Business as Usual (BAU) Case** that reflects current and known market participation decisions, and **two market participation cases:** 1) almost all non-committed entities, including BPA, join Markets+, and 2) current WEIM members join EDAM (including BPA) or stay in WEIM *(see next slide)*
- **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, including gas price volatility beyond typical weather-normalized values to reflect the increased strain on the system and the ability of markets for addressing such strain
  - Capturing non-weather-normal impacts is becoming increasingly important due to the increasing frequency of severe weather events
- **Detailed modeling of EDAM and Markets+ specific GHG rules** which helps capture transfers into GHG pricing states
  - This includes the limits each market will place on sales to balancing authorities that price GHG emissions and the unit-type GHG cost representations instead of generic GHG charges
  - **We also model BPA's status as an asset-controlling supplier** for CA and WA, reflecting their lower cost to sell power into those zones

Overview of the Market Scenarios Studied

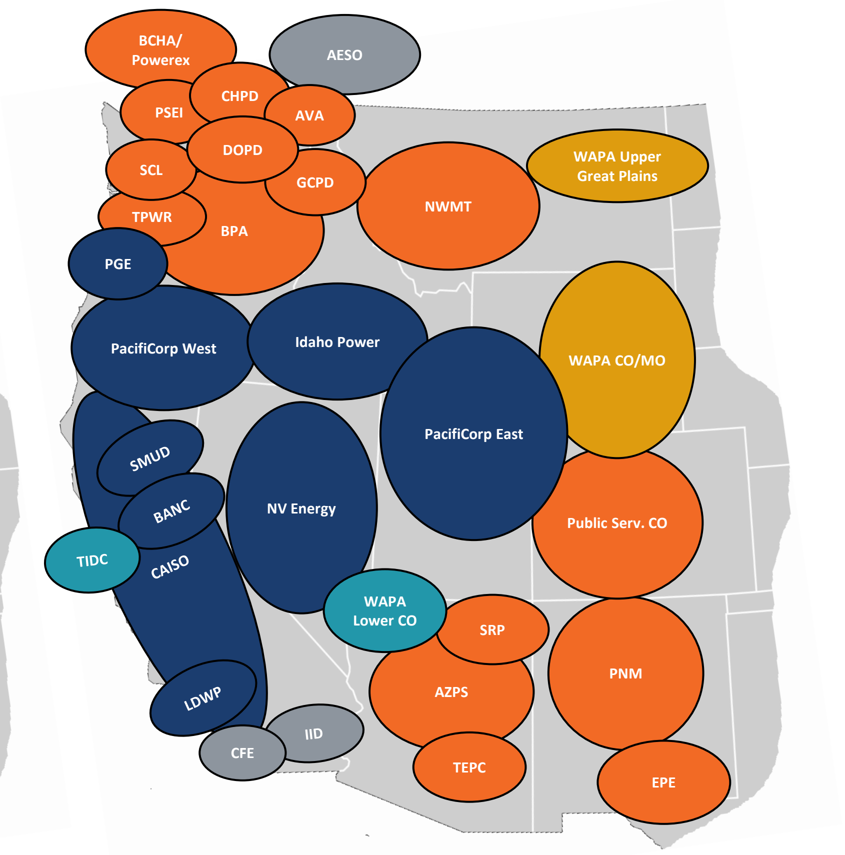
Business As Usual (BAU) Case
BPA in WEIM



EDAM Case
BPA in EDAM



Markets+ Case
BPA in Markets+



Markets+ (DA & RT)
EDAM (also in WEIM)
SPP RTO West *(co-optimizes with Markets+)*
WEIS
WEIM

Multi-Functional Simulation of WECC

Markets/RTO Functions & Configurations

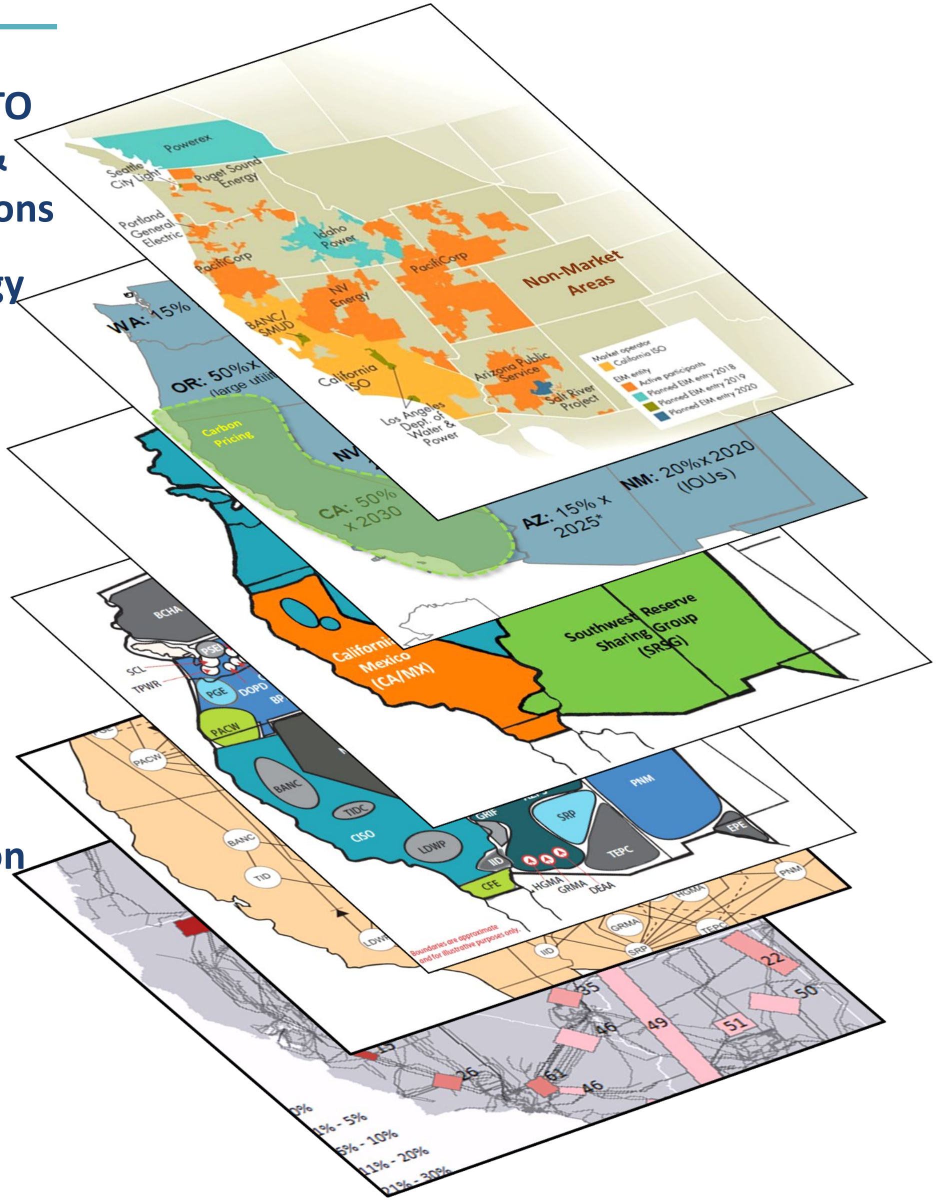
Clean Energy Policies

Reserve Sharing

BAA Functions

Bilateral Contract Paths and Transmission Rights

Physical Flows and Constraints



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

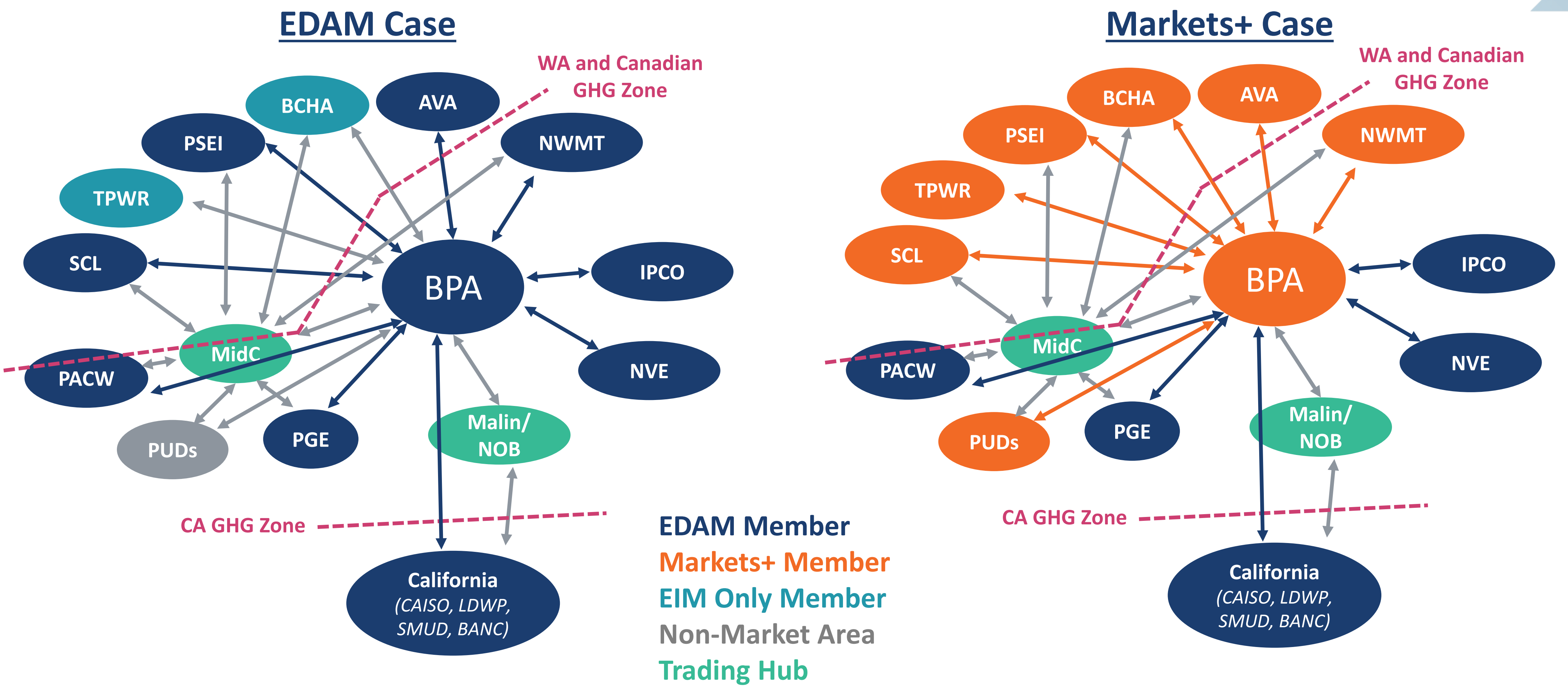
- Physical grid with ~20k buses, ~25k lines and ~5k generators represented as DC power flow
- 38 Balancing Authority Areas (BAAs) and contract paths
- WECC reserve sharing groups
- Diverse state clean energy policies
- Major trading hubs (e.g., Mid-C, Malin, PV, FC)
- Bilateral (long-term) transmission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

Transmission Assumptions Overview

Our study includes a **detailed view of the physical transmission system and long-term (contractual) transmission rights.** Key modeling features include:

- **Multiple trade type options between BAAs**, including:
  - Hourly bilateral trades and block trades at major trading hubs
    - Block trading is modeled as more liquid (i.e., lower friction) than hourly bilateral trades due to availability of exchange-traded peak and off-peak strip products
  - Trades on existing transmission contracts allow entities to trade without paying short-term wheeling fees
  - DA and RT market trades and seam trades between markets
- **GHG unit-type-specific trading structure** which closely mimics the unit-specific GHG import tracking and charge structures in the EDAM and Markets+ designs
- **We assume participating BAAs make all of their transmission available to the market, except where specific carve outs are identified by study participants**
  - The treatment of each BAA's transmission is the same in EDAM and M+
  - We encumber TTCs with the import of contracted resources outside of a BAA, based on information provided by study participants.

BPA's Modeled Contract-Path Transmission Connectivity

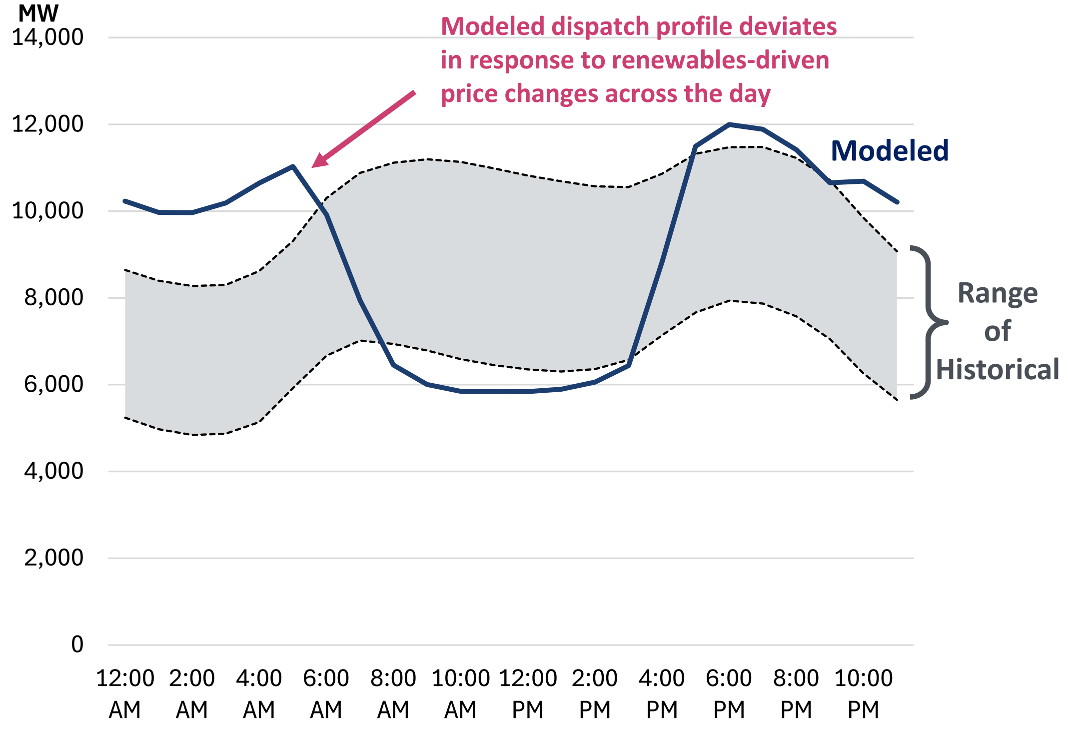


BPA Hydro Assumptions Overview

We worked with the Northwest Power and Conservation Council (NWPCC) to fine-tune our hydro flexibility modeling for BPA's generation resources

- The NWPCC provided **daily energy generation and minimum and maximum dispatch levels for BPA's hydro** from their detailed hydro dispatch modeling for three climate scenarios and ten hydrological years per scenario
  - We selected data from a single scenario/hydrological year from the NWPCC data that represented most closely an average historical hydro year
- **We modeled ~17 GW of BPA's ~22 GW of hydro capacity as being responsive to market prices within constraints derived from the NWPCC data**
  - These constraints included daily energy budgets and daily minimum and maximum dispatch levels
  - The data used to define constraints reflects plant limitations and environmental constraints, such as spill for fish, seasonal water limits, and recreational use
- **We assume BPA's ability to flexibly dispatch its hydro fleet is <u>the same across market scenarios</u>,** though dispatch may differ based on price patterns in each market

Average BPA Hydro Dispatch by Hour of Day
Modeled Data vs Historical 2007 – 2023 Range

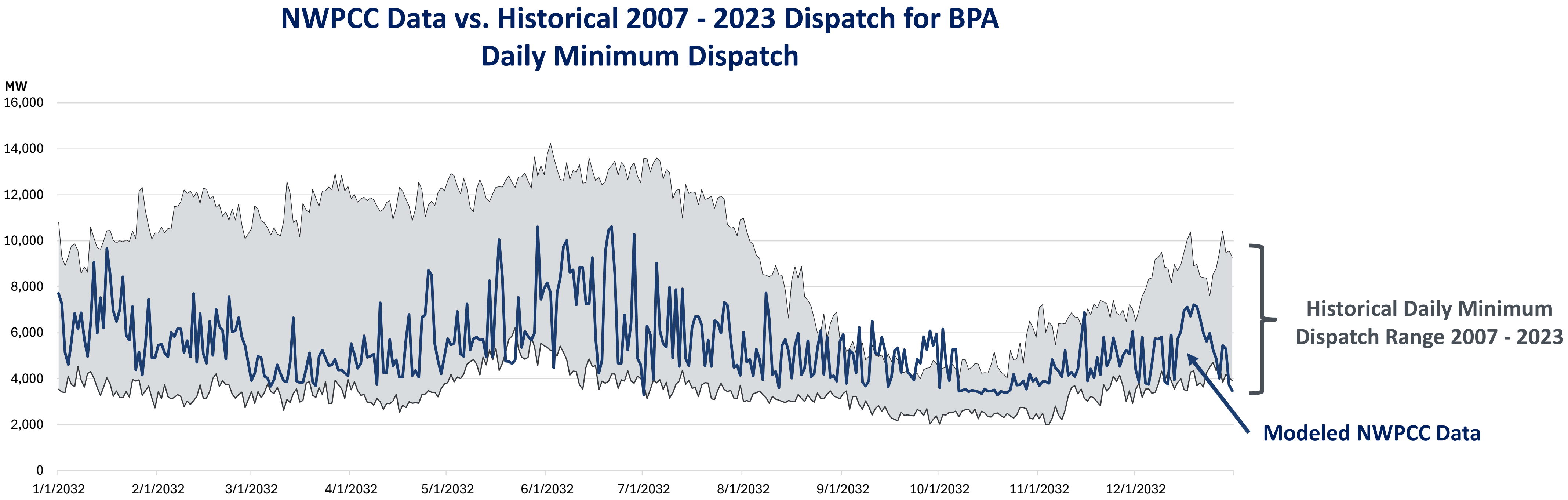


Sources: historical hourly hydro data drawn from BPA's EIA 930 reporting

BPA Hydro Assumptions Overview: Daily Minimum Dispatch

We compared the NWPCC data used in our simulations to historical 2007 - 2023 BPA hydro dispatch levels, looking at total generation, daily minimum, and daily maximum dispatch levels

- The NWPCC data is within BPA's historical daily average minimum dispatch for the vast majority of days, indicating that we are reasonably capturing non-power-related real-world hydro dispatch considerations and constraints on dams, such as for environmental, fish, and seasonal conditions



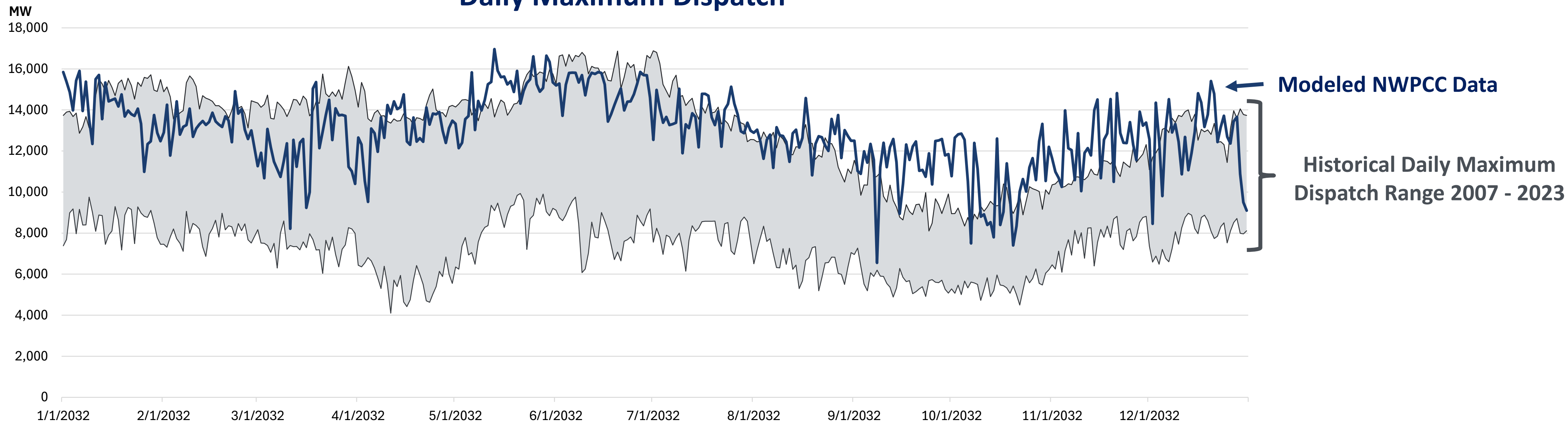
Sources: historical hourly hydro data drawn from BPA's EIA 930 reporting

BPA Hydro Assumptions Overview: Daily Maximum Dispatch

Daily maximum dispatch levels in our simulations similarly match historical 2007 – 2023 dispatch levels, with small adjustments for the changing resource mix and climate by the 2030s

- Modeled daily maximum dispatch levels exceed historical levels in the fall due to shifting seasonality in hydro generation by the 2030s, based on the NWPCC data
  - The NWPCC data incorporates climate change impacts on the seasonal and monthly timing of precipitation, increasing generation in the fall and early winter

NWPCC Data vs. Historical 2007 - 2023 Dispatch for BPA
Daily Maximum Dispatch



Sources: historical hourly hydro data drawn from BPA's EIA 930 reporting

Market Benefits Study Results

Summary of **BPA** Benefits

We estimate that the BPA's net system cost *decreases* by $65 million from joining EDAM while their net system cost *increases by* $83 million from joining Markets+

- **BPA sells significantly more power than it purchases, making its benefits responsive to small shifts in prices in each market**
- **The saving in EDAM** are driven by:
  - A reduction in APC of $43 million, due to higher sales revenues in EDAM due to slightly higher prices in hours when BPA sells power
  - Congestion revenues of $166 million, driven by the amount of transmission BPA brings to the market, its advantageous position in the EDAM footprint, and price deltas between CA and the PNW.
  - Benefits are offset by a loss of $37 million in short-term wheeling revenues and $114 million in bilateral trading revenues
- **The cost increases in Markets+** are driven by:
  - An increase of $72 million in APC, due to slightly lower prices in hours when BPA sells power compared to the BAU case *(see next slide)*
  - A reduction in bilateral trading revenue of $87 million, due to several bilateral trading partners joining Markets+ with BPA
  - Markets+ congestion revenues add $88 million of revenue
  - Markets+ does not reduce BPA's short-term wheeling revenues

Bonneville Balancing Authority Total Modeled System Cost by Case ($ Millions)

Benefit Metric	Metric	BAU	EDAM	Markets+
Adjusted Production Cost	*Cost*	-$650.1	-$693.2	-$578.5
Short-term Wheeling Revenue	*Revenue*	$39.2	$2.0	$38.9
EDAM Congestion Revenue	*Revenue*		$166.4	
EIM Congestion Revenue	*Revenue*	$11.9	$18.3	
Markets+ DA Congestion Revenue	*Revenue*			$81.2
Markets+ RT Congestion Revenue	*Revenue*			$6.5
Bilateral Trading Revenue [1]	*Revenue*	$198.4	$84.9	$111.2
APC Net of Revenues [2]		**-$899.6**	**-$964.8**	**-$816.3**
Net Benefits			**$65.2**	**-$83.3**

Notes:

[1] Bilateral trading values of exports and imports with non-market member neighboring systems, potentially including trades by third party marketers.

[2] Total system cost is adjusted production cost minus all the revenues

Sales Revenue to BPA

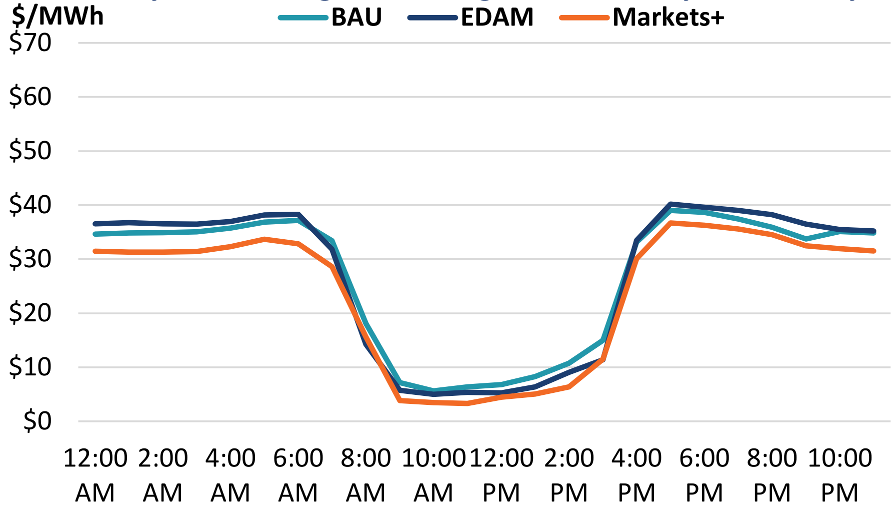
The results show prices in BPA's BAA falling slightly in Markets+ compared to the BAU and EDAM cases, reducing BPA's sales revenue and is the largest driver in the reduction in benefits under Markets+.

- The impact on prices is mostly in overnight hours, driven by the higher opportunity for increased thermal resource dispatch efficiency during these hours in the Markets+ footprint relative to the EDAM or BAU cases, which is driven by higher gas prices in the Pacific Northwest compared to the Southwest and Rocky Mountain regions.
- These opportunities are unavailable in BAU due to the trading hurdles between entities in the Pacific Northwest, Rockies, and Southwest that are in a different or no centralized market in the BAU.
- The increased thermal dispatch efficiency and lower prices in the Markets+ footprint benefit net buyers in the PNW through reduced purchase costs but reduces sale revenues to the detriment of net sellers in the PNW such as BPA.

BPA Day-Ahead Sales Revenues and Volumes by Season

Season	Volume of Sales (GWh)			Value of Sales ($ Millions)			Value of Sales ($ / MWh)		
	BAU	EDAM	Markets+	BAU	EDAM	Markets+	BAU	EDAM	Markets+
Winter	6,617	6,876	6,501	$362	$368	$311	$55	$53	$48
Spring	7,529	7,811	7,550	$139	$169	$138	$18	$22	$18
Summer	11,568	11,770	11,589	$303	$327	$291	$26	$28	$25
Fall	6,671	6,762	6,643	$299	$311	$266	$45	$46	$40
Total	**32,385**	**33,220**	**32,283**	**$1,103**	**$1,175**	**$1,006**	**$34**	**$35**	**$31**

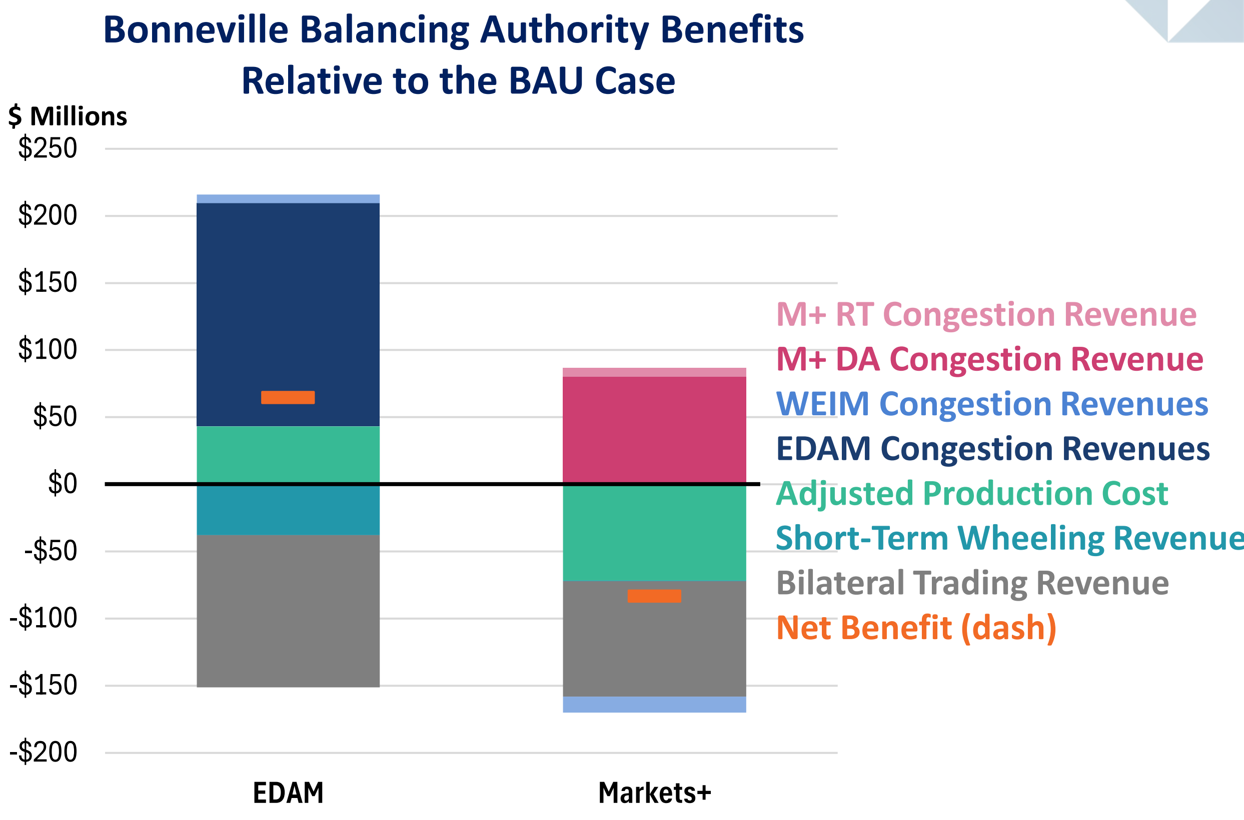
BPA Day-Ahead Weighted Average Sales Price by Hour of Day



Changes in Net Benefits by Components

Market congestion, bilateral trading revenues, short-term wheeling revenues, and APC savings are the key differentiators of BPA's net benefits between EDAM and Markets+

- BPA sees a net **APC benefit** in EDAM but not Markets+
- BPA sees more than double the day-ahead congestion revenue in **EDAM** than **Markets+**
  - The average value of congestion is about the same in each market ($4/MWh), but there is more volume of trading in EDAM
  - Real-time congestion revenues are a relatively small portion of the change in benefits
- BPA's **short-term wheeling revenue** declines in EDAM, as due to the reduction in bilateral trading relative to the BAU case, and remain about the same in Markets+ relative to the BAU
- **Bilateral trading revenue** falls more in EDAM as almost all of BPA's trading partners are in the EDAM



Summary of **Pacific Northwest** Benefits

We estimate that the PNW's net system cost *decreases* by $430 million in the EDAM case and *increases by* $18 million in the Markets+ case

- **PNW includes BPA, PACW, PGE, the PUDs, AVA, TPWR, PSEI, and SCL**
- **The savings in EDAM** are driven by:
  - A reduction in APC of $171 million, driven mainly by higher sales revenues in EDAM for the region
  - EDAM congestion revenues of $651 million
  - Benefits are offset by a loss of $66 million in short-term wheeling revenues and $283 million in bilateral trading revenues
- **The small cost increase in Markets+** is driven by:
  - Lower sales revenues, as discussed on previous slides, implies that the APC is relatively unchanged from the BAU ($24 million lower)
  - The large loss in the bilateral trading ($205 million) is offset by congestion revenue of $241 million *(including $125m of EDAM/WEIM congestion revenue for PACW/PGE)*

Pacific Northwest Total Modeled System Cost by Case ($ Millions)

Benefit Metric	Metric	BAU	EDAM	Markets+
Adjusted Production Cost	*Cost*	$1,323	$1,153	$1,299
Short-term Wheeling Revenue	*Revenue*	$78	$12	$43
EDAM Congestion Revenue	*Revenue*	$228	$605	$117
EIM Congestion Revenue	*Revenue*	$42	$46	$8
Markets+ DA Congestion Revenue	*Revenue*	$0	$0	$224
Markets+ RT Congestion Revenue	*Revenue*	$0	$0	$17
Bilateral Trading Revenue [1]	*Revenue*	$504	$222	$299
APC Net of Revenues [2]		**$699**	**$268**	**$717**
Net Benefits			**$430**	**-$18**

Notes:

[1] Bilateral trading values of exports and imports with non-market member neighboring systems, potentially including trades by third party marketers.

[2] Total system cost is adjusted production cost minus all the revenues

APC Tables: BAU vs. EDAM

BPA sees a net APC benefit of $43.1 million in EDAM, driven by:

- **(1) An increase in generation** of about 400 GWh, mostly gas, **increases production costs by $10 million**
- **(2) An increase in day-ahead and real-time purchases** of about 600 GWh each, **increases costs by $45 million**
- **(3) An increase in sales revenues of $98 million**, driven by both an $1-2/MWh increased average sales prices in day-ahead and real-time, and an 830 GWh increase in volumes sold in day-ahead plus ~600 GWh in real-time
  - Average sales prices increase mostly due to changes in the timing of BPA sales, shifting more of its hydro dispatch to the evening and morning hours when EDAM prices are higher (mostly driven by demand in California)

Adjusted Production Cost for BPA

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**BAU**	**EDAM**	**Difference**	**BAU**	**EDAM**	**Difference**	**BAU**	**EDAM**	**Difference**	
Production Cost	(+)	[1]	95,230	95,664	**434**	$3.57	$3.66	**$0.09**	340,084	350,008	**$9,924**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	2,593	3,014	**421**	$39.76	$41.49	**$1.73**	103,095	125,026	**$21,931**	**(2)**
Real-Time Market		[5]	1,570	2,134	**564**	$38.47	$39.01	**$0.54**	60,379	83,241	**$22,861**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	32,385	33,220	**835**	$34.07	$35.37	**$1.30**	1,103,431	1,174,916	**$71,486**	**(3)**
Real-Time Market		[8]	1,420	2,004	**584**	$35.37	$38.20	**$2.84**	50,219	76,550	**$26,331**	
Total Cost *(Negative Difference = Benefit)*		[9]	65,587	65,587	**0**	**-$9.91**	**-$10.57**	**-$0.66**	-650,092	-693,192	**-$43,100**	
% Change in APC											***6.6%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.

APC Tables: BAU vs. Markets+

BPA sees a net APC loss of $71.6 million in Markets+, driven by:

- **(1) A decrease in generation** of about 300 GWh, **reduces production costs by $14.6 million**
- **(2) A $7/MWh decrease in average purchase prices in day-ahead and $1/MWh in real-time, reduces purchase costs by $22 million** despite higher purchase volumes
- **(3) A decrease in average sales prices by about $3/MWh**, **reduces sales revenue by $108 million**
  - As shown on earlier slides, this is driven by a displacement of gas for hydro resources in the PNW and more efficient gas from the Southwest during overnight hours

Adjusted Production Cost for BPA

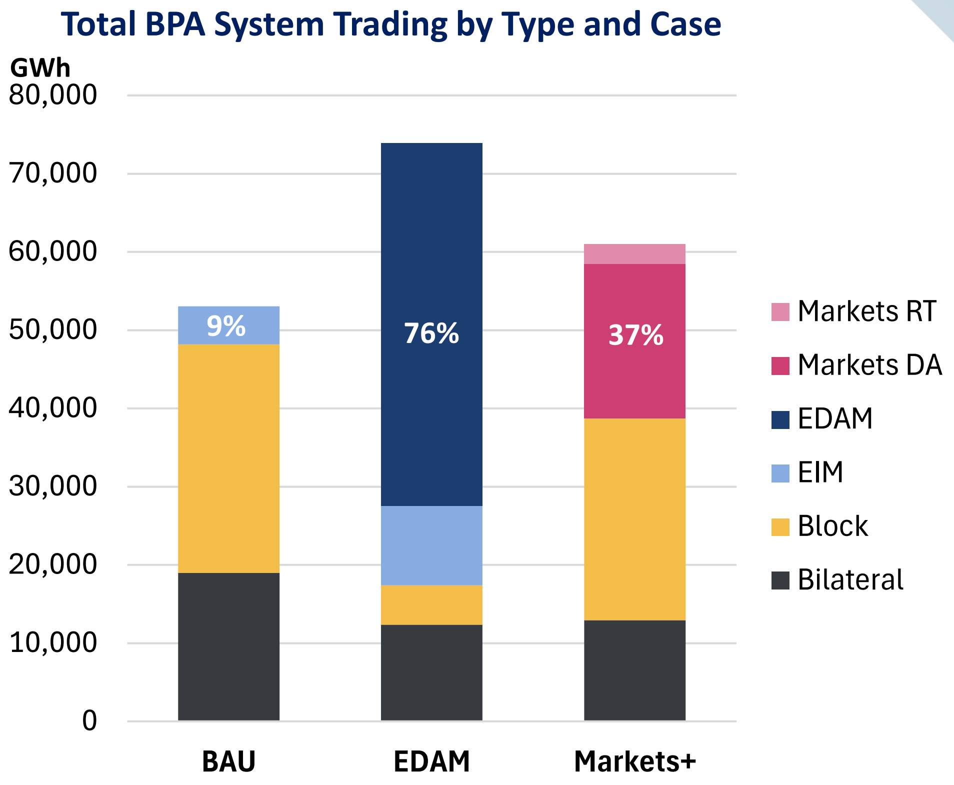
Cost Components			GWh BAU	GWh Markets+	GWh Difference	$/MWh BAU	$/MWh Markets+	$/MWh Difference	Total ($1000s/Year) BAU	Total ($1000s/Year) Markets+	Total ($1000s/Year) Difference	
Production Cost	(+)	[1]	95,230	94,929	**-301**	$3.57	$3.43	**-$0.14**	340,084	325,499	**-$14,584**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	2,593	2,871	**278**	$39.76	$32.50	**-$7.26**	103,095	93,317	**-$9,778**	**(2)**
Real-Time Market		[5]	1,570	1,292	**-278**	$38.47	$37.13	**-$1.34**	60,379	47,971	**-$12,409**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	32,385	32,283	**-102**	$34.07	$31.15	**-$2.92**	1,103,431	1,005,624	**-$97,807**	**(3)**
Real-Time Market		[8]	1,420	1,222	**-198**	$35.37	$32.45	**-$2.92**	50,219	39,653	**-$10,566**	
Total Cost *(Negative Difference = Benefit)*		[9]	65,587	65,587	**0**	**-$9.91**	**-$8.82**	**$1.09**	-650,092	-578,489	**$71,602**	
% Change in APC											***-11.0%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.

Summary of BPA Trading

In the EDAM case, BPA's trading is dominated by EDAM and EIM transactions, while the Markets+ case has significant block and bilateral volumes

- BAU total BPA trade volumes are 54 TWh
  - WEIM volumes are 9% of total trades
- EDAM total BPA trade volumes are 75 TWh
  - EDAM and EIM volumes are 76% of total trades
- Markets+ total BPA trade volumes are 63 TWh
  - Markets+ DA and RT volumes are 37% of total trades
- **BPA's block trading in Markets+ is driven by seam transactions with EDAM entities at MidC**
  - Block trades are mainly to PACW and PGE, with similar total volumes as in the BAU case
  - MidC is also used for some internal Markets+ trading, which is included in the red bars for Markets+ DA and RT volumes



BPA Trading in EDAM

BPA's trading increases with almost all other EDAM entities, including the rest of the PNW, California, the Rocky Mountain region; decreases at MidC

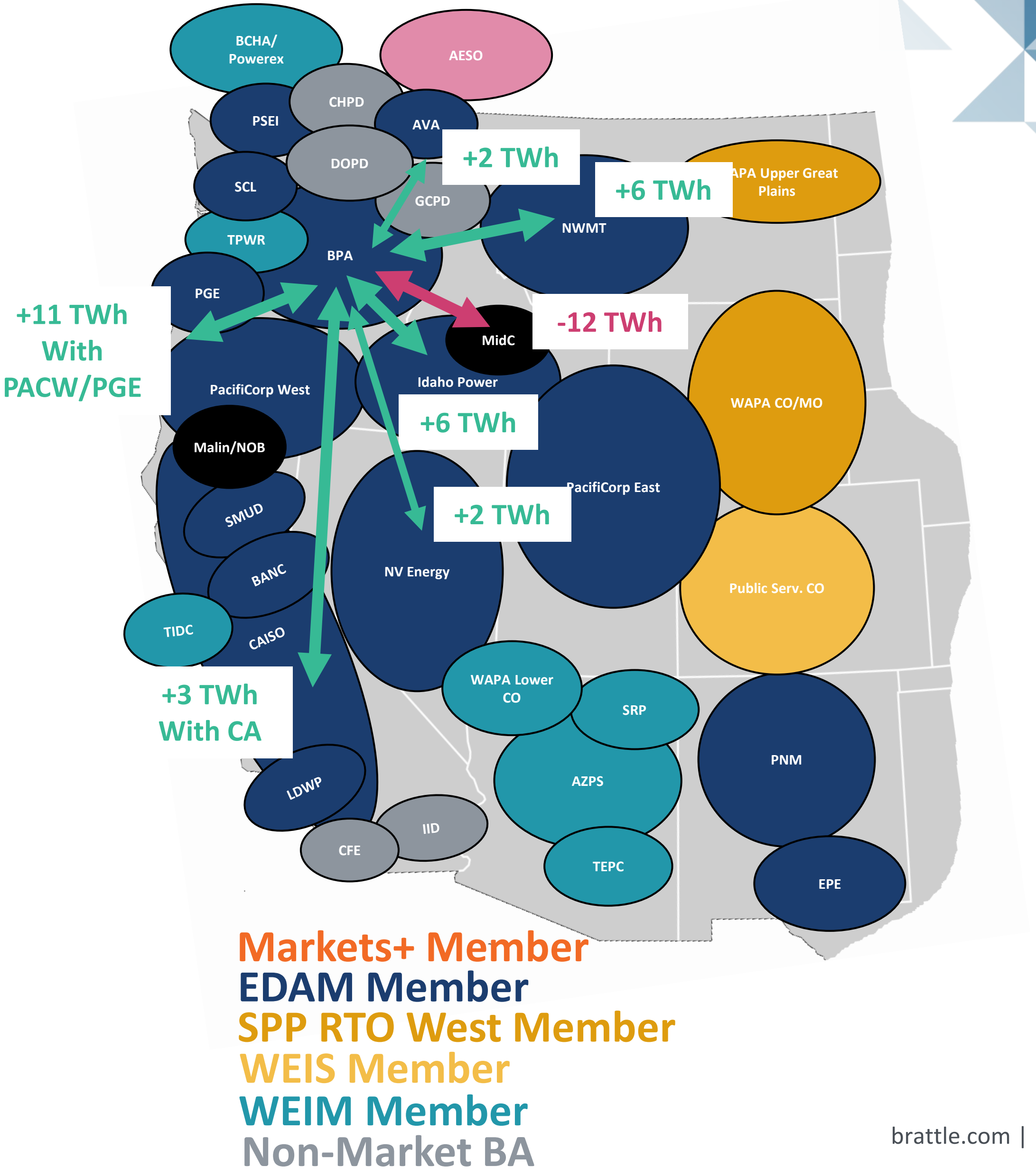
- Total BPA trading increases over 20 TWh in EDAM compared to the BAU Case

Total BPA System Trading by Type and Case
Blue denotes an EDAM Member, Orange a Markets+ Member

Partner	BAU			EDAM		
	Export	Import	Total	Export	Import	Total
AVA	152	53	**205**	2,270	56	**2,326**
IPCO	1,242	947	**2,189**	4,479	3,539	**8,018**
LDWP	120	738	**859**	4,473	582	**5,055**
NWMT	1,533	251	**1,784**	5,942	2,190	**8,132**
PACW	173	531	**704**	5,392	1,558	**6,950**
PGE	808	945	**1,753**	4,837	1,610	**6,447**
PSEI	222	154	**376**	728	284	**1,012**
Rest of BANC	194	685	**879**	1,455	153	**1,608**
SCL	4,447	307	**4,754**	4,983	2,983	**7,966**
NV Energy	156	178	**334**	930	1,411	**2,341**
EDAM Total	9,047	4,790	**13,838**	35,488	14,367	**49,855**
Malin	3,262	716	**3,978**	2,362	2,243	**4,605**
MidC	13,897	1,547	**15,445**	2,789	450	**3,239**
NOB	9,073	8	**9,081**	4,324	1,761	**6,086**
Hub Total	26,233	2,271	**28,504**	9,476	4,455	**13,930**
BCHA	5,941	3	**5,944**	6,196	349	**6,545**
TPWR	451	3,194	**3,646**	213	2,099	**2,312**
PUDs	2,579	100	**2,678**	2,463	97	**2,560**
Other Total	8,971	3,297	**9,589**	8,871	2,546	**8,857**
Total	**44,251**	**10,359**	**54,610**	**53,835**	**21,367**	**75,202**

Note: PUDs trading includes DOPD, CHPD, and GCPD

EDAM Case



BPA Trading in Markets+

Compared to the BAU Case, BPA's trading in Markets+ increases with the PNW and is relatively unchanged at the trading hubs and with the EDAM

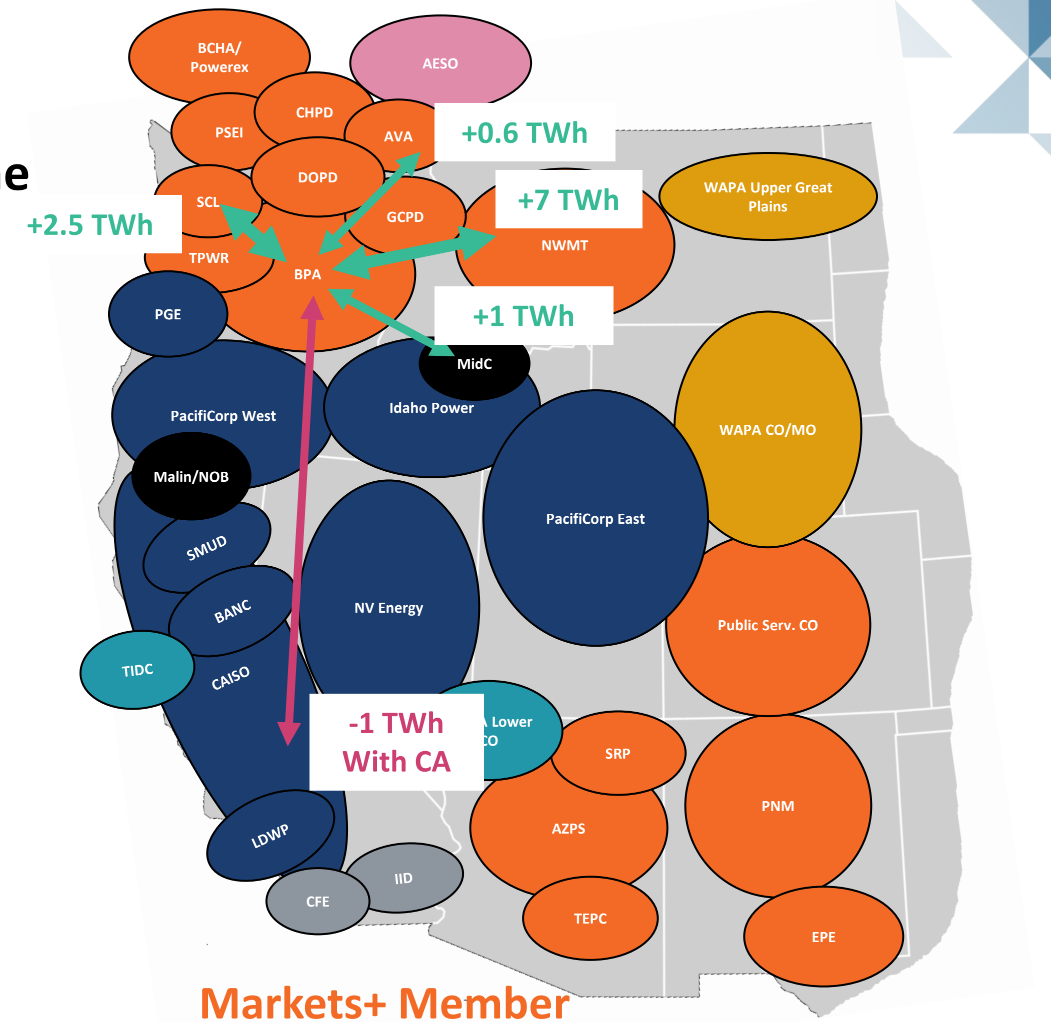
- Increased trading with NWMT includes exchanges with SPP West and BAAs in Markets+ in the SW

Total BPA System Trading by Type and Case
Blue denotes an EDAM Member, Orange a Markets+ Member

Partner	BAU			Markets+		
	Export	Import	Total	Export	Import	Total
AVA	152	53	**205**	780	39	**819**
BCHA	5,941	3	**5,944**	5,760	144	**5,904**
NWMT	1,533	251	**1,784**	5,471	3,296	**8,767**
PSEI	222	154	**376**	201	196	**397**
PUDs	2,579	100	**2,678**	2,535	99	**2,634**
TPWR	451	3,194	**3,646**	271	1,586	**1,857**
SCL	4,447	307	**4,754**	4,360	2,938	**7,298**
Mkt+ Total	15,325	4,062	**19,387**	19,378	8,297	**27,675**
Malin	3,262	716	**3,978**	3,682	55	**3,736**
MidC	13,897	1,547	**15,445**	13,433	3,181	**16,614**
NOB	9,073	8	**9,081**	7,913	52	**7,965**
Hub Total	26,233	2,271	**28,504**	25,028	3,287	**28,315**
IPCO	1,242	947	**2,189**	1,302	366	**1,668**
LDWP	120	738	**859**	739	113	**852**
PACW	173	531	**704**	387	308	**695**
PGE	808	945	**1,753**	613	1,119	**1,732**
Rest_of_BANC	194	685	**879**	219	885	**1,104**
NV Energy	156	178	**334**	315	168	**483**
EDAM Total	2,693	4,025	**6,718**	3,575	2,959	**6,534**
Total	**44,251**	**10,359**	**54,610**	**47,981**	**14,543**	**62,524**

Note: PUDs trading includes DOPD, CHPD, and GCPD

Markets+ Case



Summary of BPA Trading

BPA's trading volumes increase most in EDAM, as the majority of their trading partners are in the same market

- **EDAM trade volumes grow mostly with:**
  - PACW (increasing 6.2 TWh)
  - NorthWestern Energy (increasing 6.3 TWh)
  - Idaho Power (increasing 5.8 TWh)
  - Portland General Electric (increasing 4.7 TWh)
  - LADWP (increasing 4.2 TWh)
  - Trades fall mostly with MidC (decreasing 12.2 TWh) as most MidC entities directly connect with each other in EDAM
- **Markets+ trade volumes grow mostly with**
  - NorthWestern Energy (increasing 7 TWh)
  - Seattle City Light (increasing 2.5 TWh)
  - Avista (increasing 0.6 TWh)
  - Trades fall mostly with TPWR (decreasing 1.8 TWh) and NOB (decreasing 1.1 TWh), and remain similar for most other BAAs

Total BPA System Trading by Type and Case
Blue denotes an EDAM Member, Orange a Markets+ Member

Partner	BAU			EDAM			Markets+		
	Export	Import	Total	Export	Import	Total	Export	Import	Total
EDAM Partners									
IPCO	1,242	947	**2,189**	4,479	3,539	**8,018**	1,302	366	**1,668**
LDWP	120	738	**859**	4,473	582	**5,055**	739	113	**852**
PACW	173	531	**704**	5,392	1,558	**6,950**	387	308	**695**
PGE	808	945	**1,753**	4,837	1,610	**6,447**	613	1,119	**1,732**
Rest of BANC	194	685	**879**	1,455	153	**1,608**	219	885	**1,104**
NV Energy	156	178	**334**	930	1,411	**2,341**	315	168	**483**
Partners Switching Markets									
AVA	152	53	**205**	2,270	56	**2,326**	780	39	**819**
NWMT	1,533	251	**1,784**	5,942	2,190	**8,132**	5,471	3,296	**8,767**
PSEI	222	154	**376**	728	284	**1,012**	201	196	**397**
SCL	4,447	307	**4,754**	4,983	2,983	**7,966**	4,360	2,938	**7,298**
Markets+ Partners									
BCHA	5,941	3	**5,944**	6,196	349	**6,545**	5,760	144	**5,904**
PUDs	2,579	100	**2,678**	2,463	97	**2,560**	2,535	99	**2,634**
TPWR	451	3,194	**3,646**	213	2,099	**2,312**	271	1,586	**1,857**
Trading Hubs									
Malin	3,262	716	**3,978**	2,362	2,243	**4,605**	3,682	55	**3,736**
MidC	13,897	1,547	**15,445**	2,789	450	**3,239**	13,433	3,181	**16,614**
NOB	9,073	8	**9,081**	4,324	1,761	**6,086**	7,913	52	**7,965**
PNW	28,670	6,835	**32,827**	29,870	9,487	**36,798**	28,339	9,610	**35,315**
California	12,650	2,147	**14,797**	12,614	4,740	**17,354**	12,553	1,104	**13,657**
Other	2,931	1,376	**4,307**	11,351	7,140	**18,491**	7,089	3,829	**10,918**
Total	**44,251**	**10,359**	**54,610**	**53,835**	**21,367**	**75,202**	**47,981**	**14,543**	**62,524**

Note: PUDs trading includes DOPD, CHPD, and GCPD

Trading Volume and Value Shifts

- The **average value of trades** remains similar in each case, at about $3 - $4/MWh
- BPA experiences higher overall trading volume in EDAM with almost all other BAAs
- BPA's Markets+ trading volume and value increase with PNW entities; little changed with other entities

Total BPA System Trading (GWh)

Partner	BAU		EDAM		Markets+	
	Export	Import	Export	Import	Export	Import
EDAM Partners						
IPCO	1,242	947	4,479	3,539	1,302	366
LDWP	120	738	4,473	582	739	113
PACW	173	531	5,392	1,558	387	308
PGE	808	945	4,837	1,610	613	1,119
Rest of BANC	194	685	1,455	153	219	885
NV Energy	156	178	930	1,411	315	168
Partners Switching Markets						
AVA	152	53	2,270	56	780	39
NWMT	1,533	251	5,942	2,190	5,471	3,296
PSEI	222	154	728	284	201	196
SCL	4,447	307	4,983	2,983	4,360	2,938
Markets+ Partners						
BCHA	5,941	3	6,196	349	5,760	144
PUDs	2,579	100	2,463	97	2,535	99
TPWR	451	3,194	213	2,099	271	1,586
Trading Hubs						
Malin	3,262	716	2,362	2,243	3,682	55
MidC	13,897	1,547	2,789	450	13,433	3,181
NOB	9,073	8	4,324	1,761	7,913	52
Total	**44,251**	**10,359**	**53,835**	**21,367**	**47,981**	**14,543**

Note: PUDs trading includes DOPD, CHPD, and GCPD

Total BPA System Value ($ Millions)

Partner	BAU		EDAM		Markets+	
	Export	Import	Export	Import	Export	Import
EDAM Partners						
IPCO	$6	$8	$6	$16	$6	$4
LDWP	$1	$6	$49	$6	$6	$2
PACW	$0	$2	$6	$3	$1	$1
PGE	$2	$3	$3	$1	$2	$3
Rest of BANC	$2	$6	$18	$0	$2	$5
NV Energy	$0	$4	$0	$14	$1	$3
Partners Switching Markets						
AVA	$0	$0	$4	$0	$1	$0
NWMT	$4	$2	$2	$13	$2	$19
PSEI	$1	$0	$16	$0	$1	$0
SCL	$0	$1	$6	$8	$0	$15
Markets+ Partners						
BCHA	$56	$0	$58	$0	$44	$0
PUDs	$3	$0	$4	$0	$1	$0
TPWR	$1	$10	$1	$6	$1	$1
Trading Hubs						
Malin	$17	$3	$7	$4	$15	$0
MidC	$29	$1	$2	$0	$29	$0
NOB	$41	$0	$11	$7	$33	$0
Total	**$164**	**$46**	**$192**	**$78**	**$146**	**$53**

Note: PUDs trading includes DOPD, CHPD, and GCPD

Total BPA System Value ($/MWh)

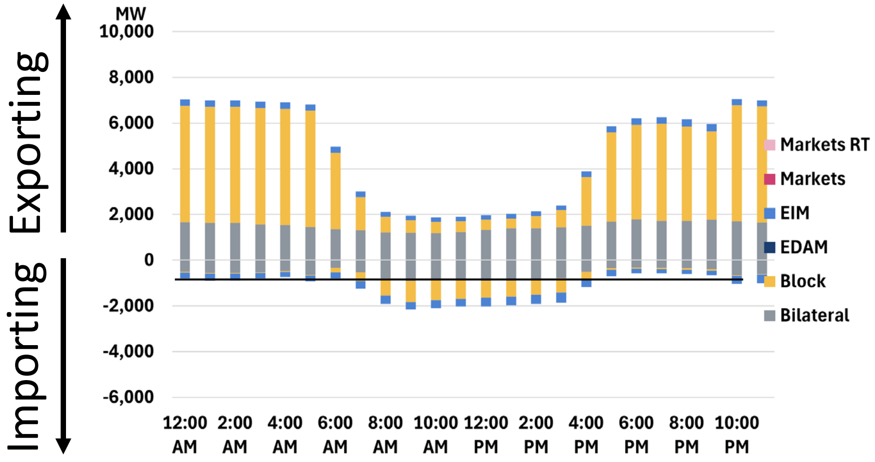
Partner	BAU		EDAM		Markets+	
	Export	Import	Export	Import	Export	Import
EDAM Partners						
IPCO	$5	$9	$1	$4	$5	$10
LDWP	$8	$9	$11	$10	$8	$14
PACW	$2	$4	$1	$2	$2	$3
PGE	$2	$3	$1	$1	$3	$3
Rest of BANC	$10	$9	$12	$3	$10	$6
NV Energy	$3	$20	$0	$10	$3	$16
Partners Switching Markets						
AVA	$1	$2	$2	$1	$2	$1
NWMT	$3	$6	$0	$6	$0	$6
PSEI	$5	$1	$21	$0	$4	$0
SCL	$0	$4	$1	$3	$0	$5
Markets+ Partners						
BCHA	$9	$5	$9	$1	$8	$0
PUDs	$0	$0	$1	$0	$0	$0
TPWR	$2	$3	$3	$3	$4	$1
Trading Hubs						
Malin	$5	$4	$3	$2	$4	$1
MidC	$2	$1	$1	$0	$2	$0
NOB	$5	$6	$3	$4	$4	$3
Total	**$4**	**$4**	**$4**	**$4**	**$3**	**$4**

Note: PUDs trading includes DOPD, CHPD, and GCPD

Time-of-Day Trading Shift Due to Market Participation

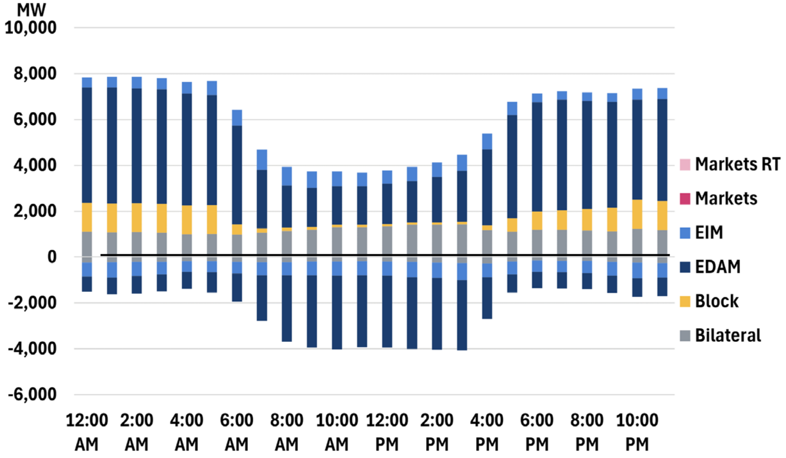
BPA see increase imports through EDAM in midday hours, driven by low-cost California solar, which allows for higher off-system sales in other hours of the day.

Average Trading for BPA By Transaction Type and Hour of Day in BAU Case

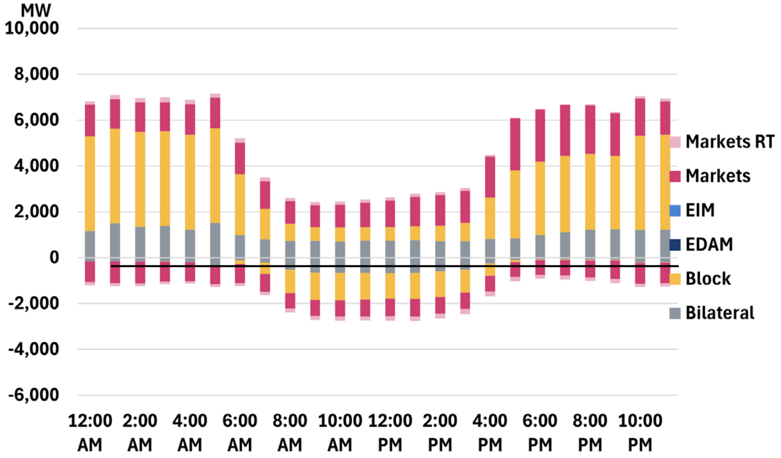


Note: Hourly trade numbers include PUD trading embedded in BPA trading volumes.

Average Trading for BPA By Transaction Type and Hour of Day in EDAM Case



Average Trading for BPA By Transaction Type and Hour of Day in Markets+ Case

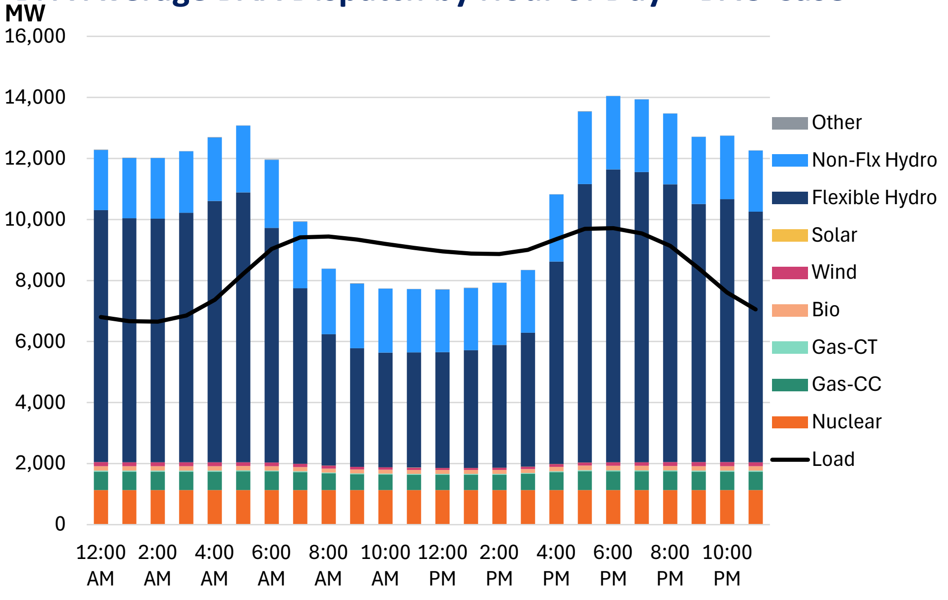


Summary of BPA Dispatch

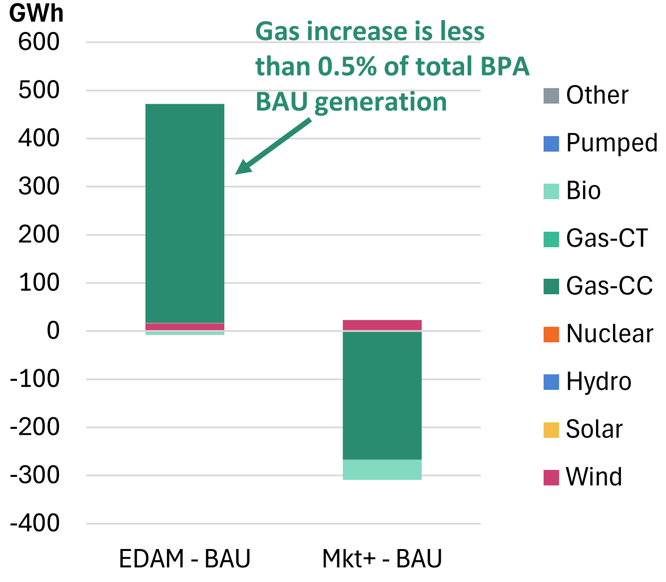
Bonneville's total generation changes very little between the market cases

- **In EDAM**, BPA increases gas dispatch ~400 GWh and shifts some of the time-of-day dispatch of its hydro fleet
- **In Markets+**, BPA dispatch falls slightly, with gas dispatch dropping ~300 GWh
- **BPA's hydro fleet is running near minimum generation levels midday most of the year**, as by 2032 solar is in significant excess midday in the WECC

BPA Average BAA Dispatch by Hour of Day – BAU Case



Market Case BPA Generation – BAU Case

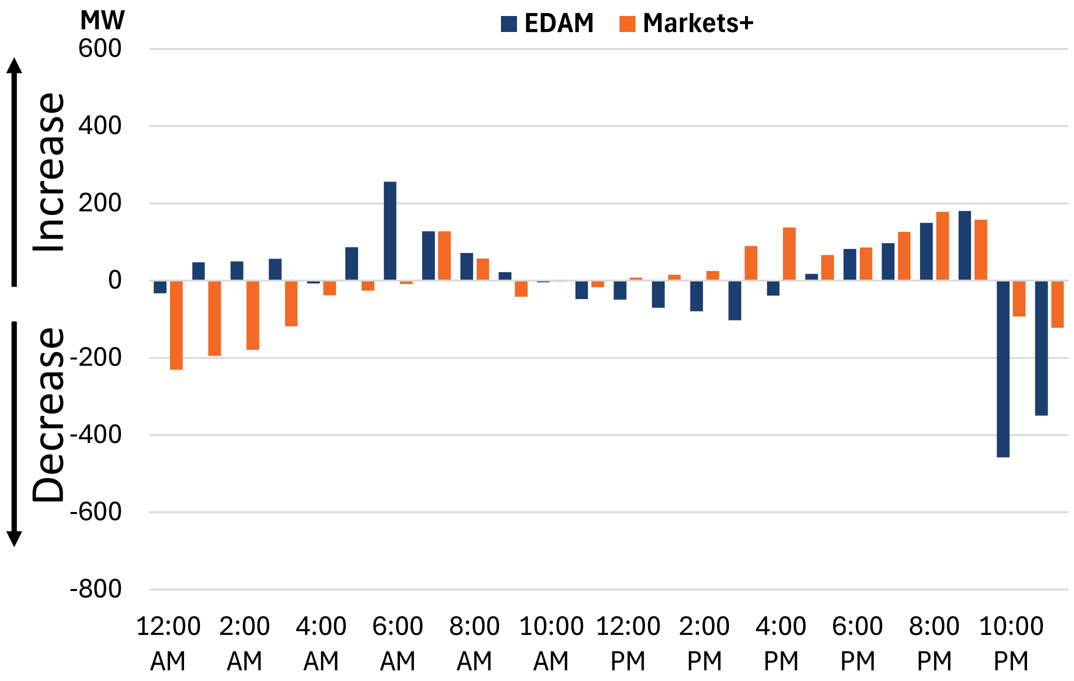


Summary of BPA Hydro Dispatch

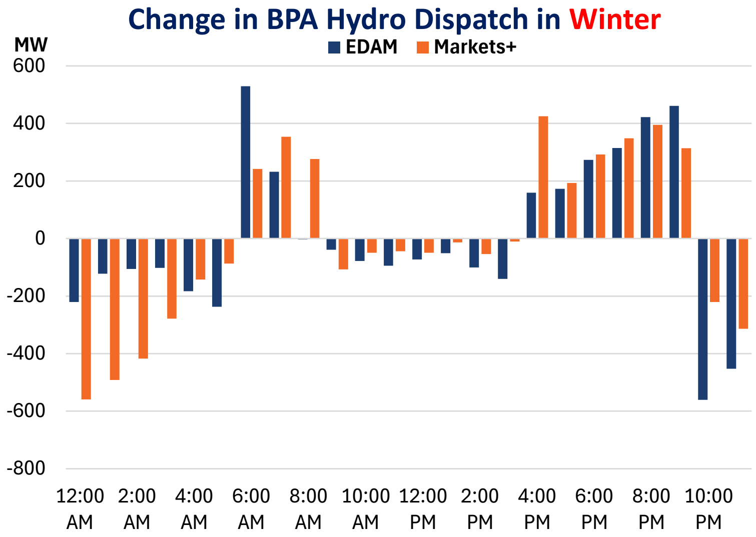
Bonneville's hydro fleet is dispatching slightly differently in the two market cases, reacting to changing prices

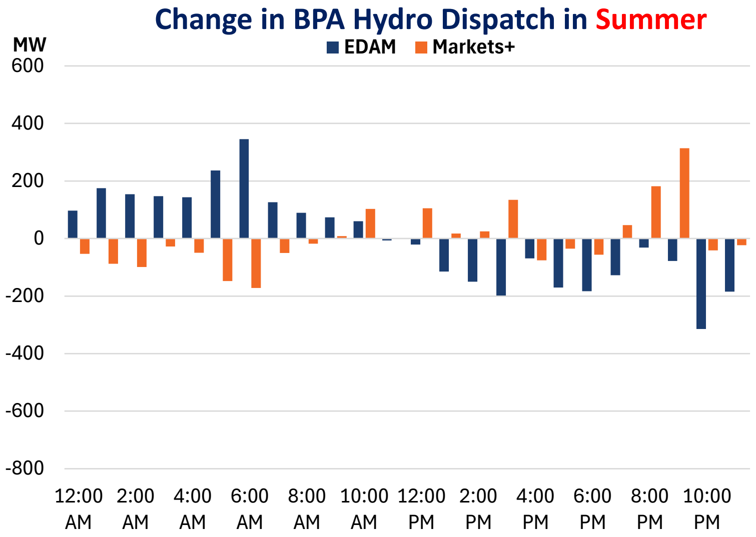
- **In EDAM** the fleet dispatches more in the evening and early morning, earning higher revenues when EDAM is short on renewables
  - While EDAM has significant excess solar generation midday, the hydro units **have mostly already flexed to their minimum generation levels in the BAU case**, leaving little room for shifts in EDAM
- **In Markets+** the fleet dispatches more in the morning and later evening
- BPA's entire hydro fleet is ~22 GW, so **these changes represent a small shift in the overall hydro dispatch of the system**

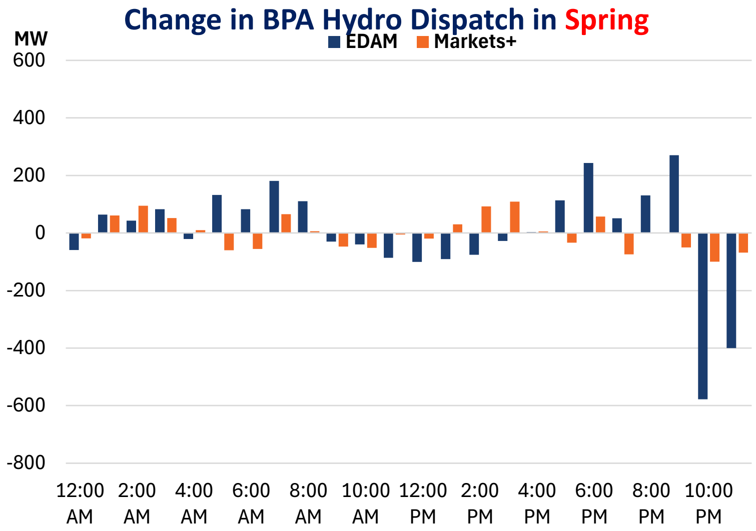
Change in BPA Hydro Dispatch, Day-Ahead Market Cases – BAU Average by Hour of Day

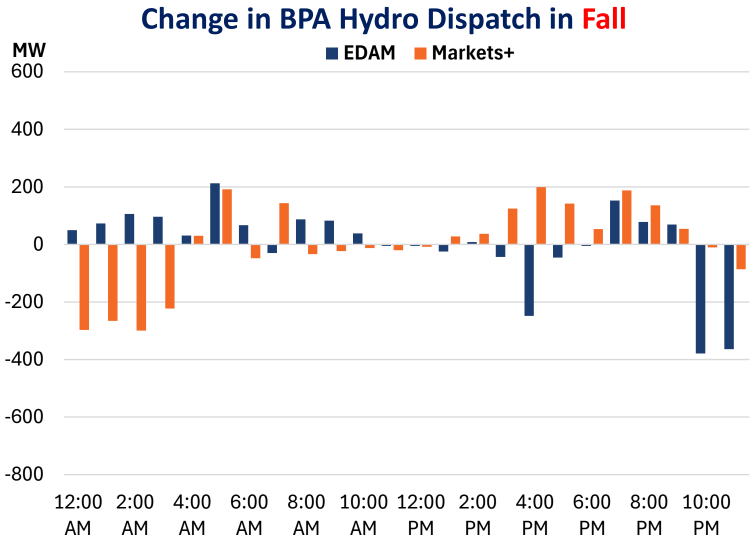


Change in BPA Hydro Dispatch by Season







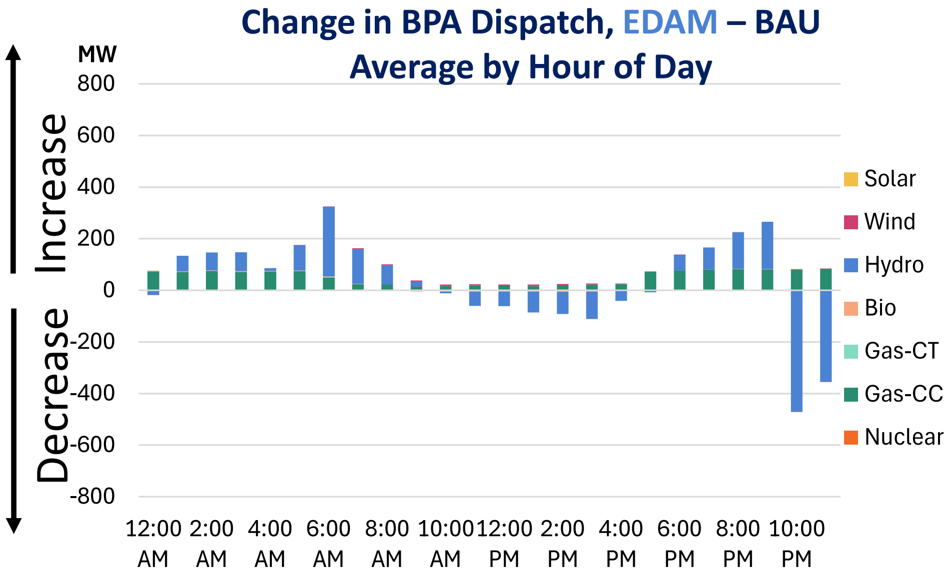


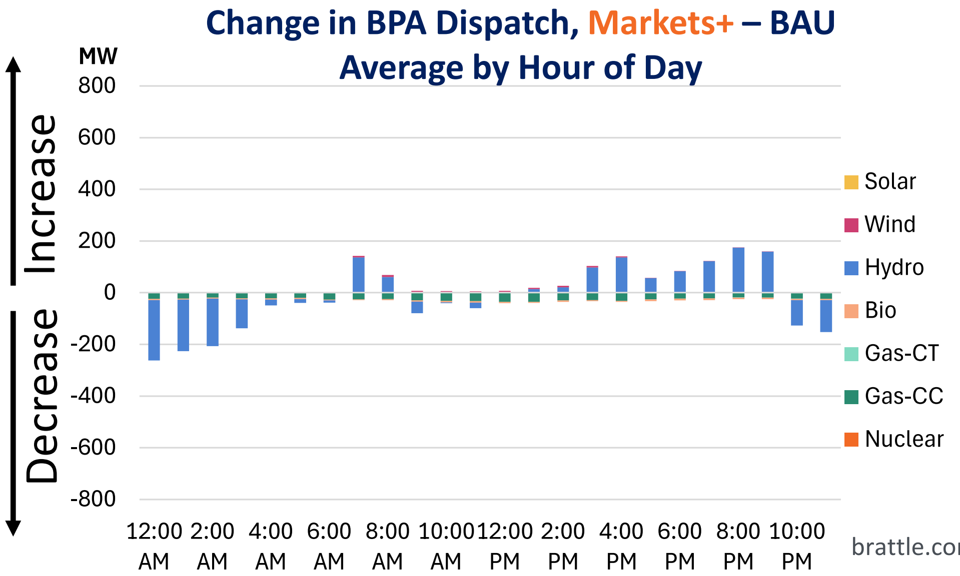
Note: All results shown are the market case’s average hydro dispatch in that hour of day ***minus*** the BAU case’s average dispatch in *the same hour of day*

Summary of BPA Overall Dispatch Behavior

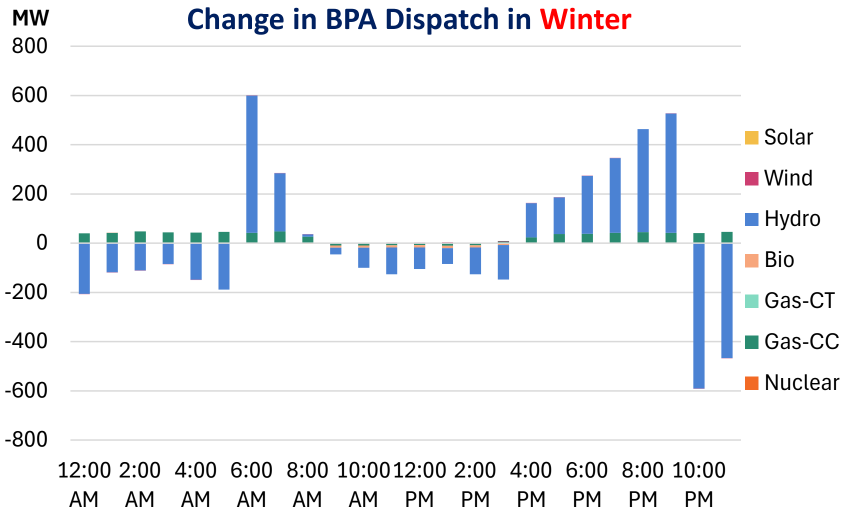
BPA's dispatch is mostly changing from movements in hydro, though the gas generation in the BPA BAA is dispatched differently in the two markets

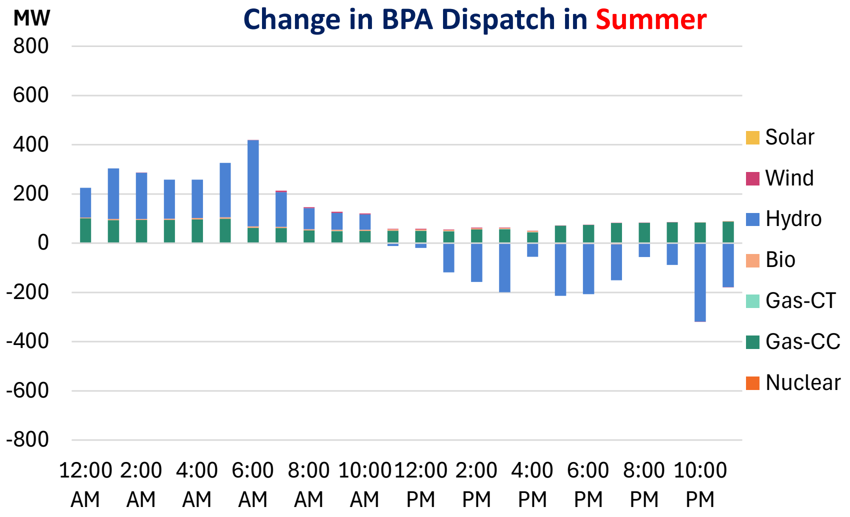
- **In EDAM** gas dispatch increases in the morning and evening, mostly in winter, spring, and summer
  - The few gas units in the BPA BAA are comparatively cheap and help serve demand during the periods with low renewable output
- **In Markets+** gas dispatches less as prices are lower in the PNW due to reduced hydro exports
  - This decrease is more concentrated in the winter than other seasons
  - BPA also sees a small decline in wind curtailment, totaling less than 10 GWh

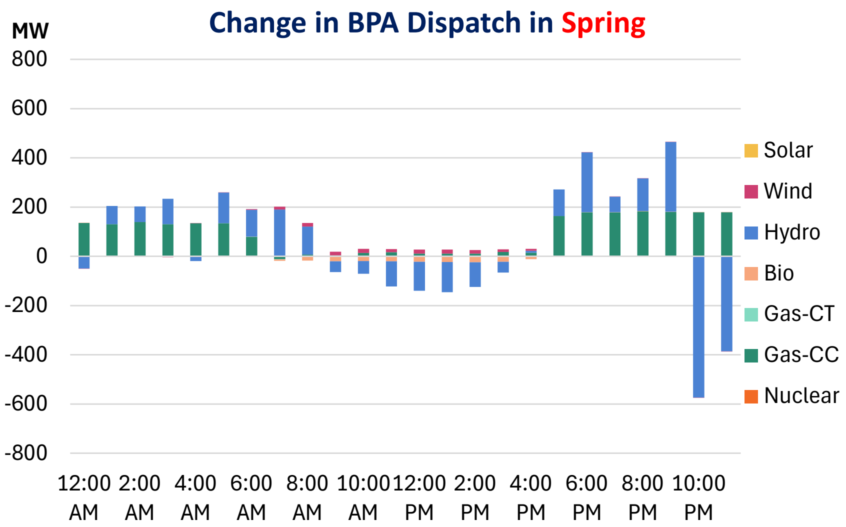


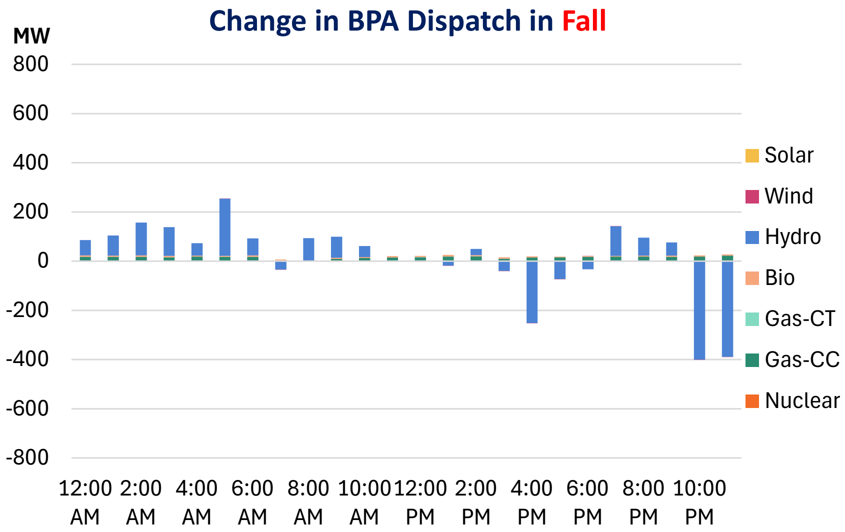


Change in BPA Dispatch by Season, EDAM *minus* BAU



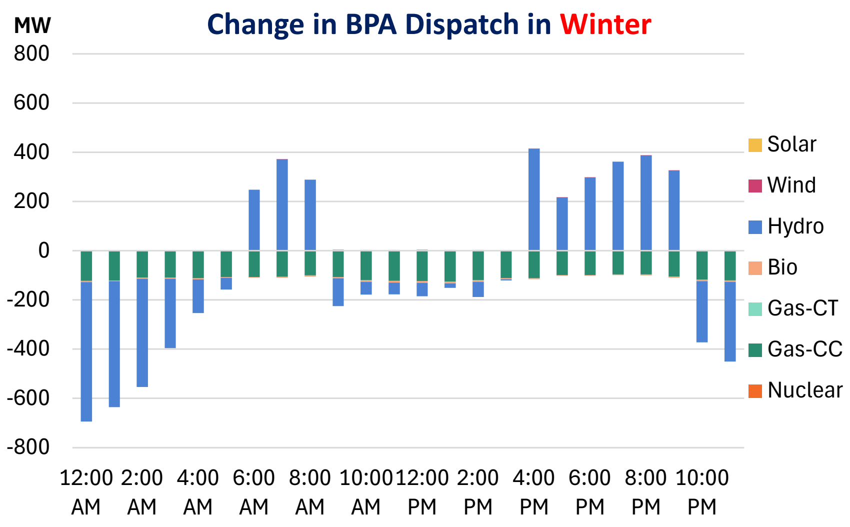


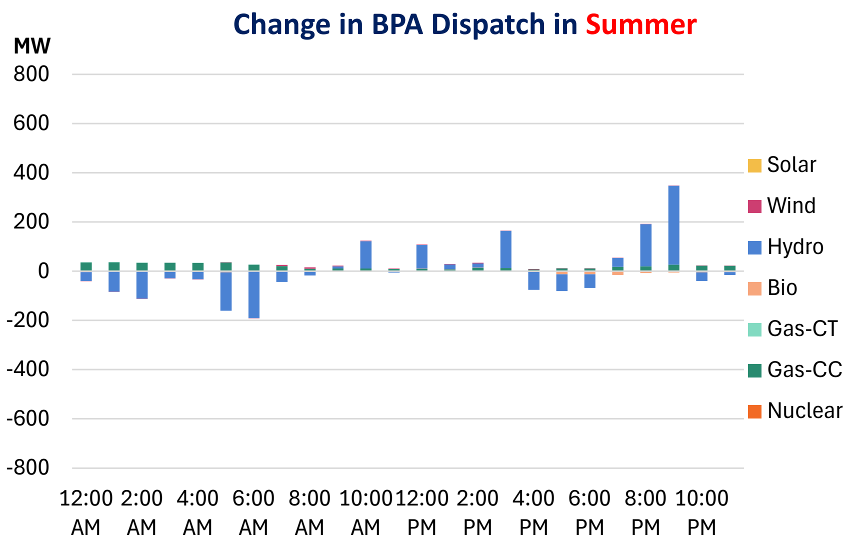


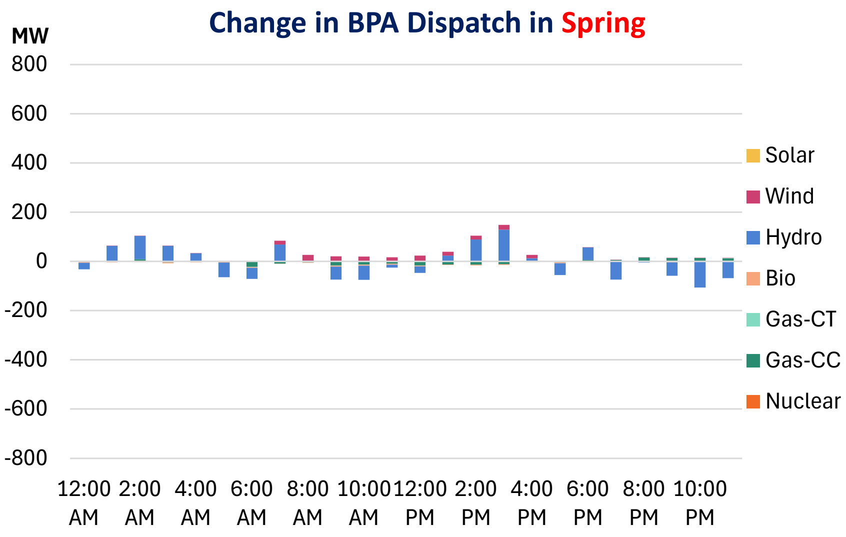


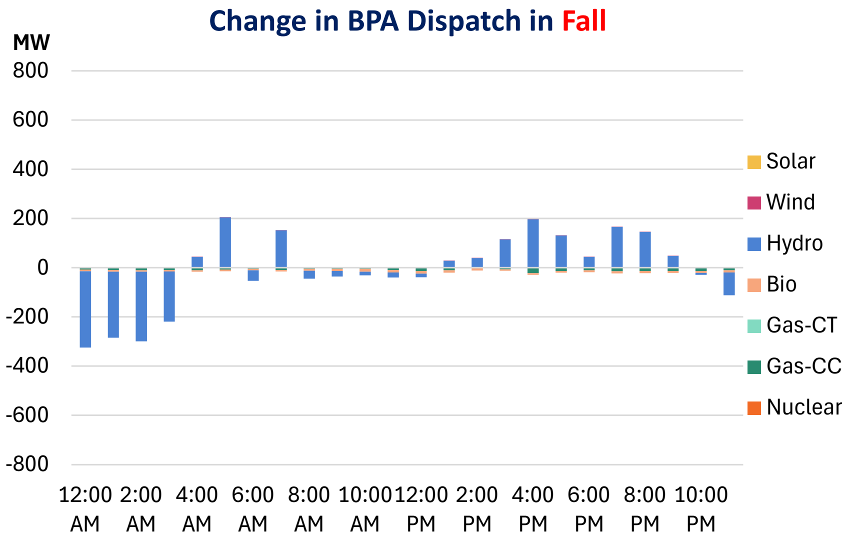
Note: All results shown are the market case average dispatch in that hour of day ***minus*** the BAU case average dispatch in *the same hour of day*

Change in BPA Dispatch by Season, Markets+ *minus* BAU









Note: All results shown are the market case's average dispatch in that hour of day ***minus*** the BAU case's average dispatch in *the same hour of day*

Summary of BPA Hydro Value by Case

BPA's hydro capacity earns higher revenues in the BAU and EDAM cases

- Hydro dispatch is most valuable in winter when renewable generation is lowest
- **Average BAU hydro revenue is $37.4/MWh**
- **Average EDAM is $37.7/MWh**, increasing slightly from the BAU case
  - Revenues remain about the same as BAU, but fall from solar producing hours 8am – 4pm by ~$2/MWh
- **Average Markets+ is $33.3/MWh**, as prices are lower in the PNW Markets+ footprint
  - Revenues fall more during midday hours, but decline in all hours across the day

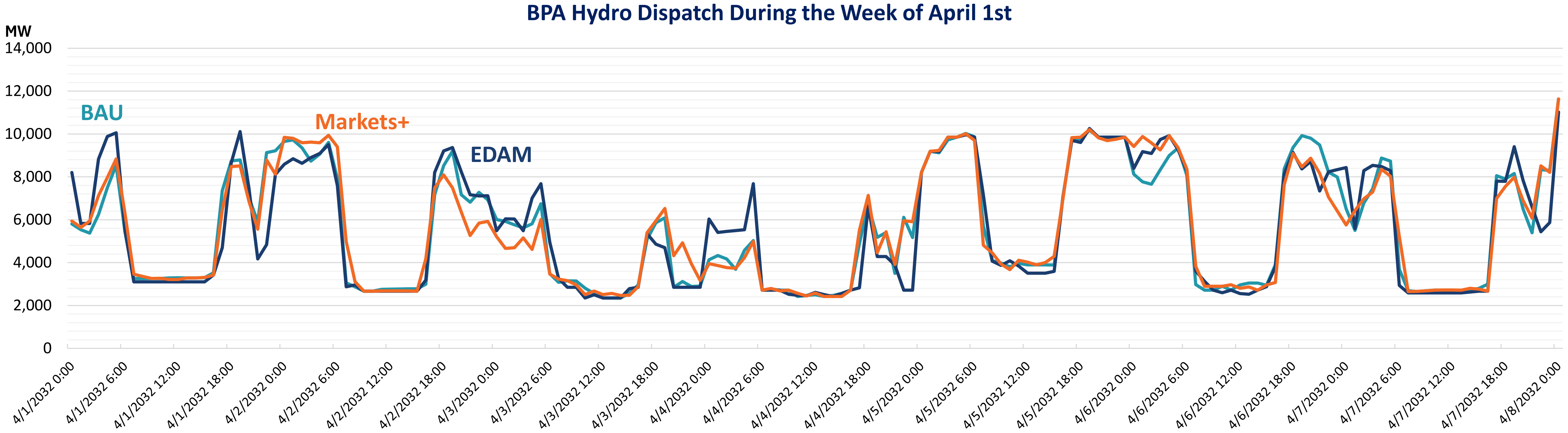
Generation Weighted Average Revenue of BPA's Flexible Hydro Units

	BAU		EDAM		Markets+	
Season	Revenue	Avg. Price	Revenue	Avg. Price	Revenue	Avg. Price
	$M	*$/MWh*	*$M*	*$/MWh*	*$M*	*$/MWh*
Winter	$923	$57	$886	$55	$798	$49
Spring	$256	$19	$287	$21	$232	$17
Summer	$484	$28	$501	$29	$454	$26
Fall	$587	$45	$593	$46	$519	$40
Total	**$2,249**	**$37.4**	**$2,267**	**$37.7**	**$2,004**	**$33.3**

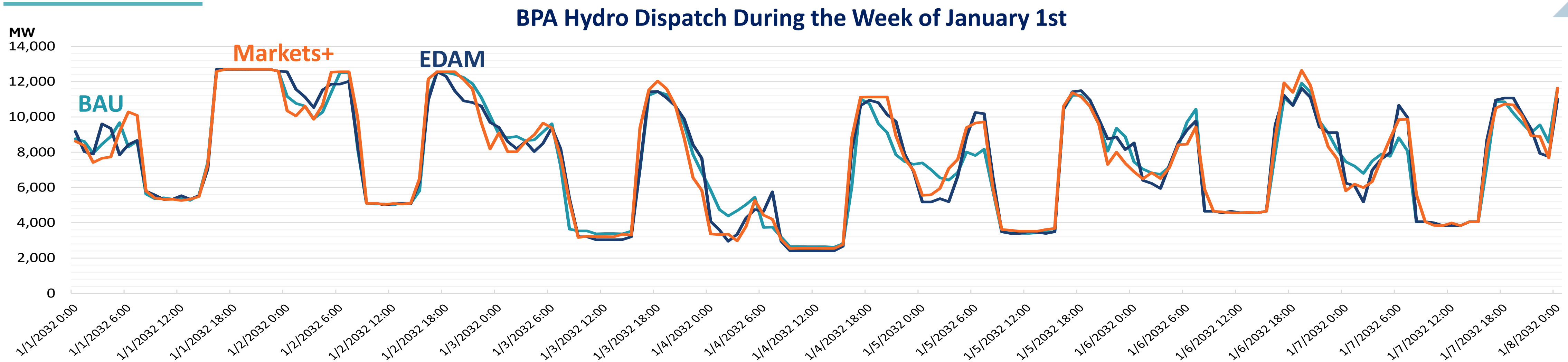
Example BPA Hydro Dispatch Hourly

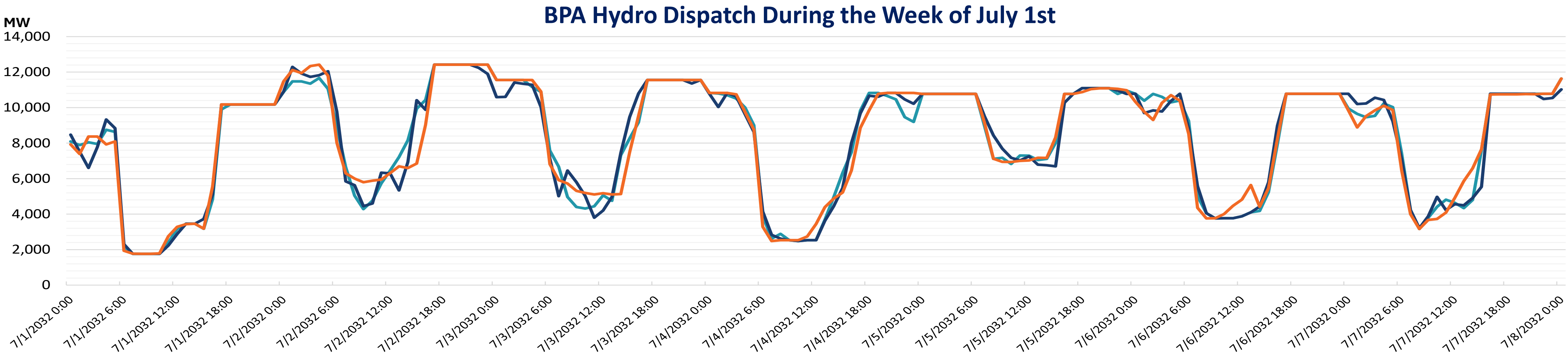
BPA's hydro dispatch changes in each case to take advantage of differing market prices

- The first week of April during the spring run-off period is shown here to show how the hydro dispatch is changing hourly for a single week as an example

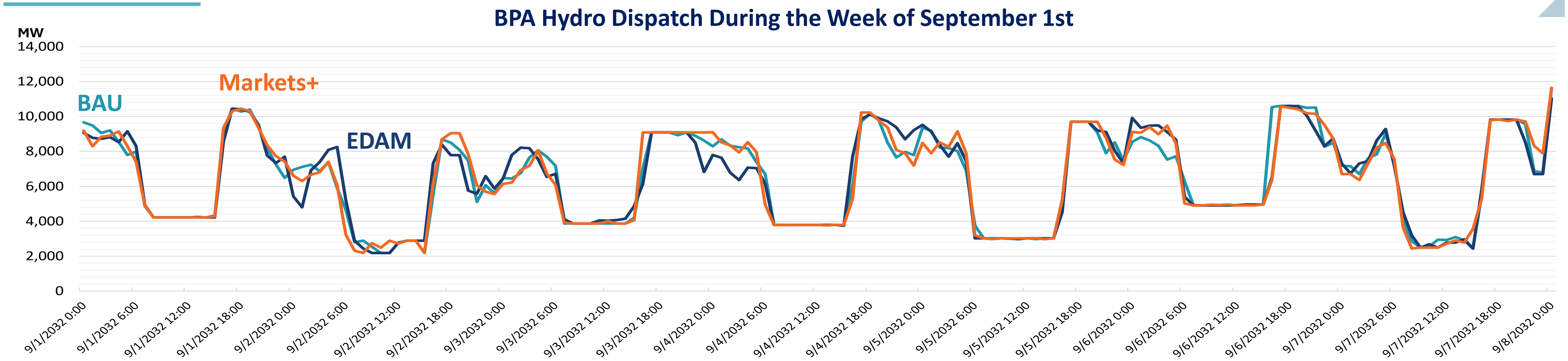


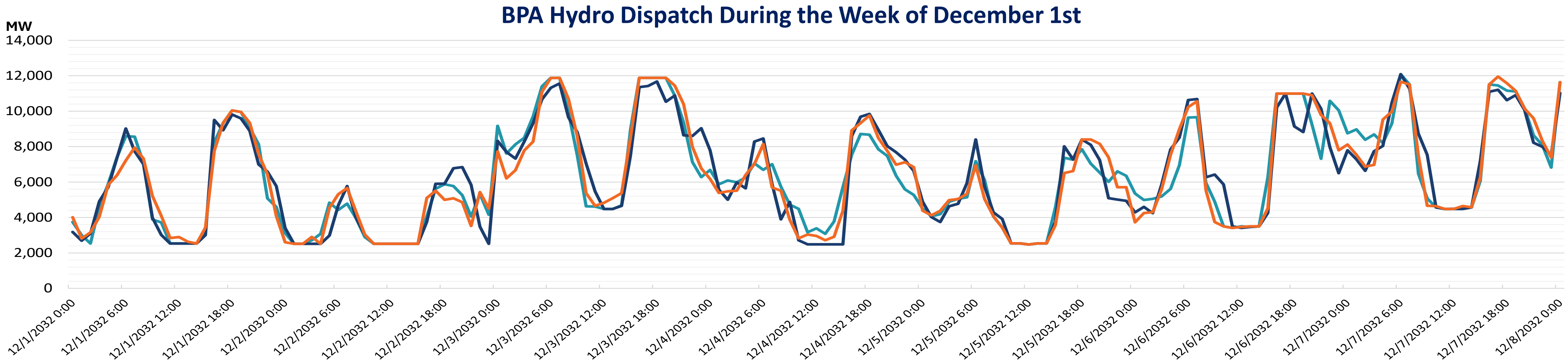
Examples of BPA Hydro Dispatch Hourly - Continued





Examples of BPA Hydro Dispatch Hourly - Continued





Emissions Impacts of Market Participation

Neither market formation changes GHG emissions significantly

- BPA BAA's total emissions are similar across all three cases, slightly lower in the Markets+, due to reduced gas generation
- In Markets+ WECC-wide emissions increase slightly due to gas-to-coal switching in the non-GHG pricing states
  - ~7,400 GWh increase in coal, ~6,400 GWh less gas
- In EDAM, there is a small amount of gas-to-coal switching relative to Markets+
  - ~1,600 GWh increase in coal WECC-wide, ~2,800 GWh less gas

Modeled CO_2 Emissions in Million Metric Tons

	BAU	EDAM		Markets+	
	Emissions	Emissions	EDAM less BAU	Emissions	Markets+ less BAU
BPA	2.99	3.13	0.14	2.84	-0.15
WECC	155.64	156.11	0.47	159.77	4.13

Benefits Comparison to WMEG

The WMEG study results illustrate similar market dynamics as shown in our study results, differing mostly on congestion and wheeling revenues

- The WMEG study found higher BPA costs in both markets, with a smaller increase in EDAM vs. Markets+
- **WMEG also found a similar lower price dynamic in the PNW in the Markets+ (Main Split) case as our Markets+ case**
- **Wheeling revenues are significantly higher in the WMEG study BAU than ours ($251m vs. $40m)**
  - We model significant long-term transmission contracts between BPA and its neighbors, reducing the wheeling revenues in the BAU case
  - Similarly, we show significantly more bilateral trading revenue, which may be explained by the modeling of long-term transmission contracts and the major trading hubs in the PNW, which both enable bilateral trading
- **The WMEG study found lower congestion revenues, likely due to the use of a zonal model of the WECC instead of nodal**
  - Our model more directly captures physical congestion through the nodal structure and both markets' congestion allocation rules, including transfer revenues in EDAM based on the tie line prices between BAAs

Bonneville Balancing Authority Total Modeled System Cost by Case ($ Millions)

		Brattle 2032			WMEG 2026		
Benefit Metric	**Metric**	**BAU**	**EDAM**	**Markets+**	**BAU**	**Bookend EDAM**	**Main Split**
Adjusted Production Cost	*Cost*	-$650.1	-$693.2	-$578.5	-$290.1	-$414.3	-$315.4
Short-term Wheeling Revenue	*Revenue*	$39.2	$2.0	$38.9	$251.4	$5.5	$31.8
EDAM Congestion Revenue	*Revenue*		$166.4				
EIM Congestion Revenue	*Revenue*	$11.9	$18.3				
Markets+ DA Congestion Revenue	*Revenue*			$81.2			
Markets+ RT Congestion Revenue	*Revenue*			$6.5			
Bilateral Trading Revenue [1]	*Revenue*	$198.4	$84.9	$111.2			
All Trading/Congestion Revenues	*Revenue*				*$49.9*	*$60.2*	*$53.5*
APC Net of Revenues [2]		**-$899.6**	**-$964.8**	**-$816.3**	**-$591.4**	**-$480.0**	**-$400.7**
Net Benefits			**$65.2**	**-$83.3**		**-$111.4**	**-$190.7**

Notes:
[1] Bilateral trading values of exports and imports from the BAs of EDAM members, includes impacts on trades by third party marketers.
[2] Total system cost is adjusted production cost minus all the revenues

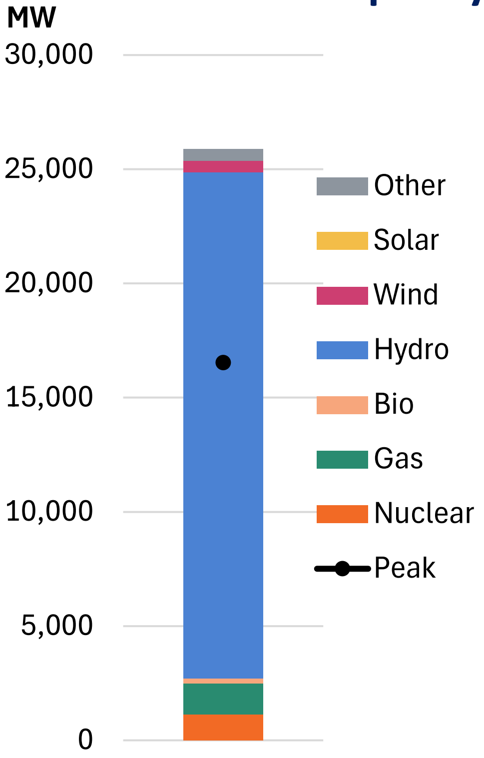
Appendix:
Modeling Inputs and Assumptions

BPA Modeled Capacity Mix

Bonneville's capacity mix is dominated by hydro in 2032, but also has some wind and gas

- BPA's mix includes resources **not necessarily owned by BPA, but that are in their BAA** or modeled in their BAA
  - This includes gas power plants like Grays Harbor and River Road

BPA Capacity Mix in 2032

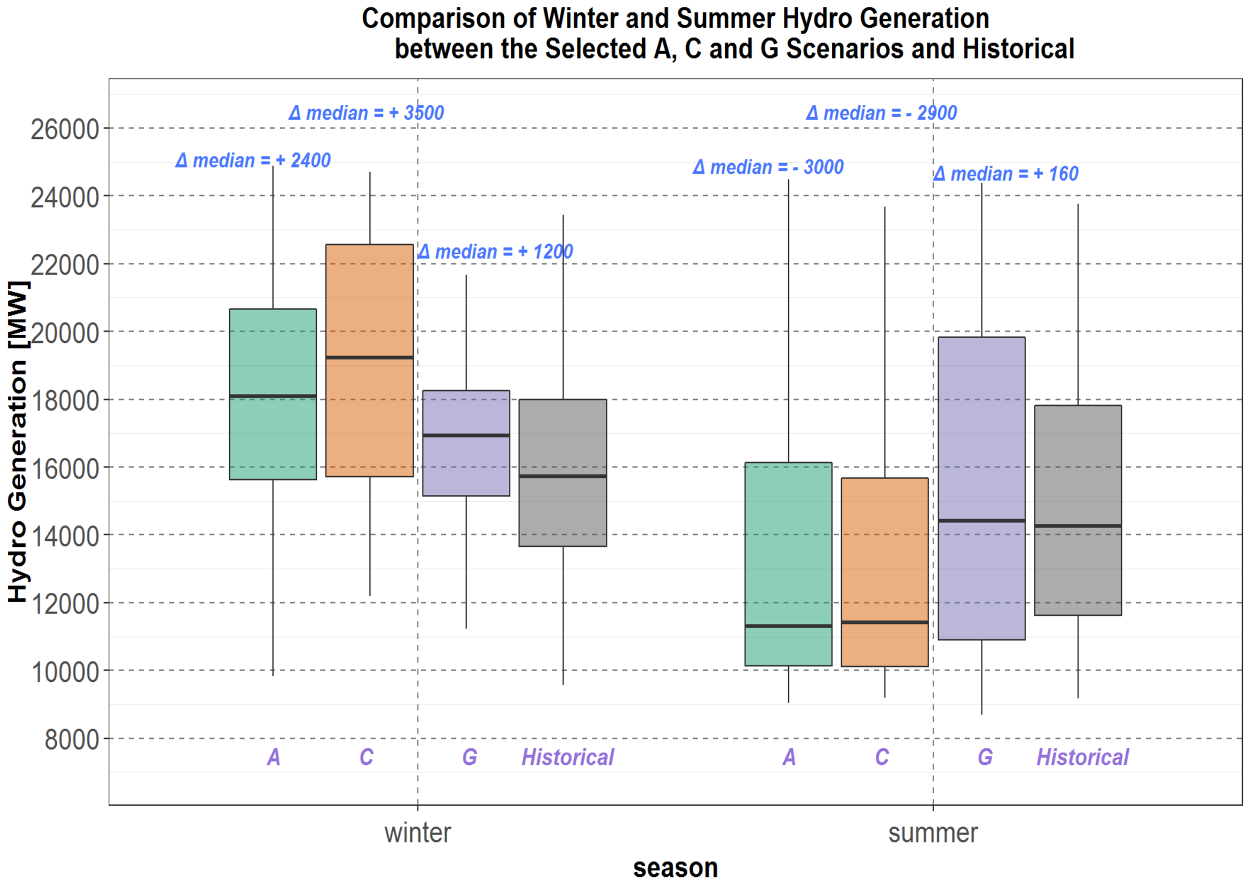


Type	BPA Capacity (MW)
Nuclear	1,130
Gas	1,359
Bio	223
Hydro	22,160
Wind	503
Solar	1
Other	509
Total	**25,886**

NWPCC Hydro Modeling Climate Scenarios

The NWPCC provided us hourly hydro data for three future climate scenarios with 10 hydro dispatch scenarios within each *(for 30 total potential hydro dispatch scenarios)*

- The climate scenarios A, C, and G represent different future "levels" of climate change effects on Pacific Northwest hydro generation
- **We selected scenario G for use in this study, for which the median and range of hydrological years is most similar to historical**
  - Prior to our refinements for this study, we assumed an "average hydro year" using the 2009 WECC hydro conditions



Source: NWPCC Climate Change Scenario Selection Process accessed here.

Other Model Data Sources

On top of data provided by utilities and the NWPCC, we have a variety of other data sources used in our WECC model

- The model's primary data source is the WECC 2032 Anchor Data set, which has been refined and improved from utility and other input
- Fuel prices have been updated in consultation with WECC utilities and using natural gas price forwards from S&P Global
- Renewable profiles and forecast errors have been developed and sourced from NREL data and we have developed forecast errors using both NREL and EIA hourly data *(for load forecast errors where utilities did not provide data)*
- Resource mix and loads have been updated via each utility's most recent IRPs, when not updated from the utility directly

NWPCC Climate Scenario G Hydro Year Data

From climate scenario G, we selected hydro year 3 to refine our BPA hydro flexibility constraints

Scenario G Hydro Year Budgets

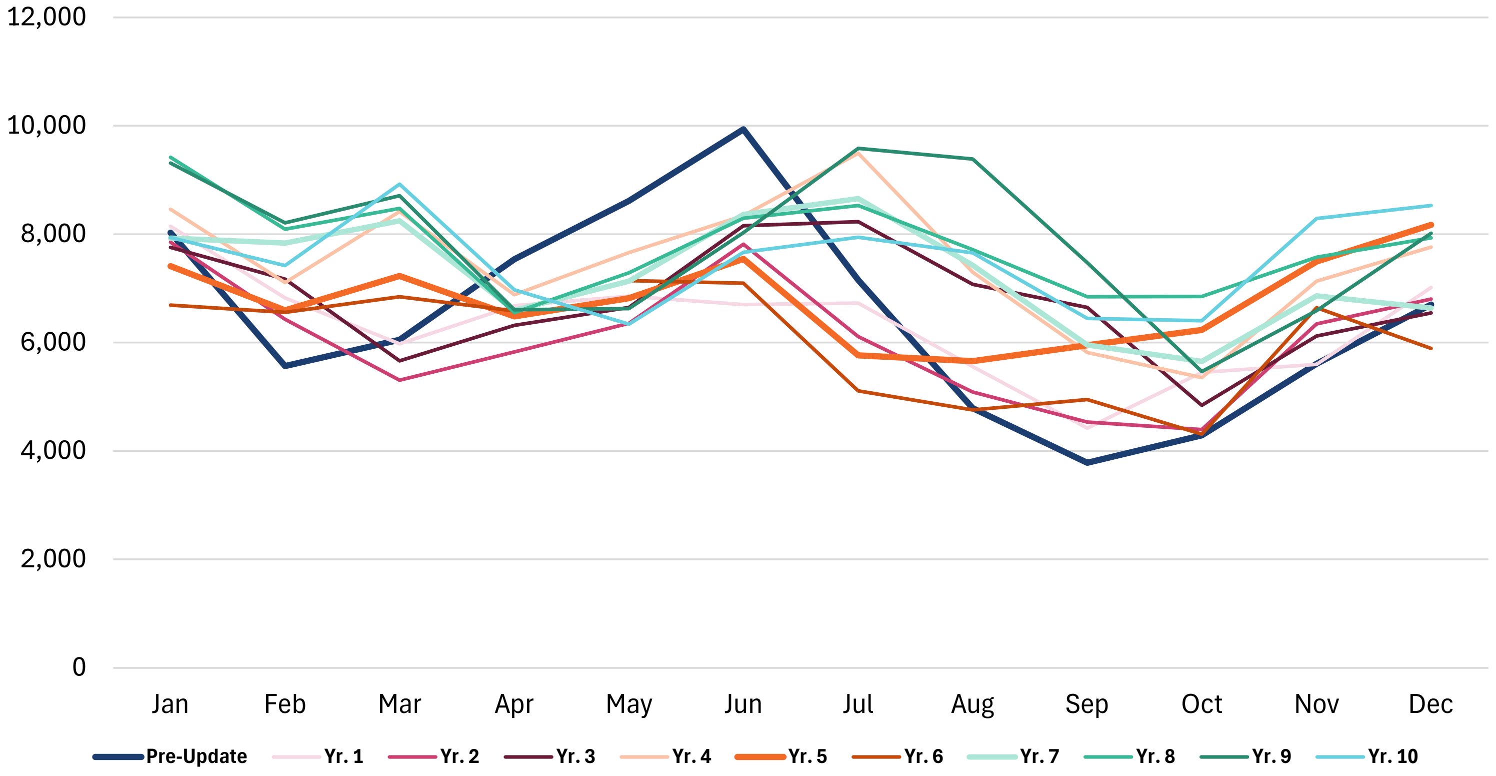
GWh

Hydro Year	Total BPA
Hydro Year 1	65,454
Hydro Year 2	62,650
Hydro Year 3	69,972
Hydro Year 4	76,962
Hydro Year 5	69,621
Hydro Year 6	62,277
Hydro Year 7	75,084
Hydro Year 8	80,611
Hydro Year 9	80,540
Hydro Year 10	77,822
Pre-Update Budget	**68,738**
Avg NWPCC Budget	**72,099**
Lowest NWPCC Budget	**62,277**
Highest NWPCC Budget	**80,611**

Note: Budgets do not include the BPA hydro units with no flexibility

Scenario G Hydro Year Monthly Hydro Budgets

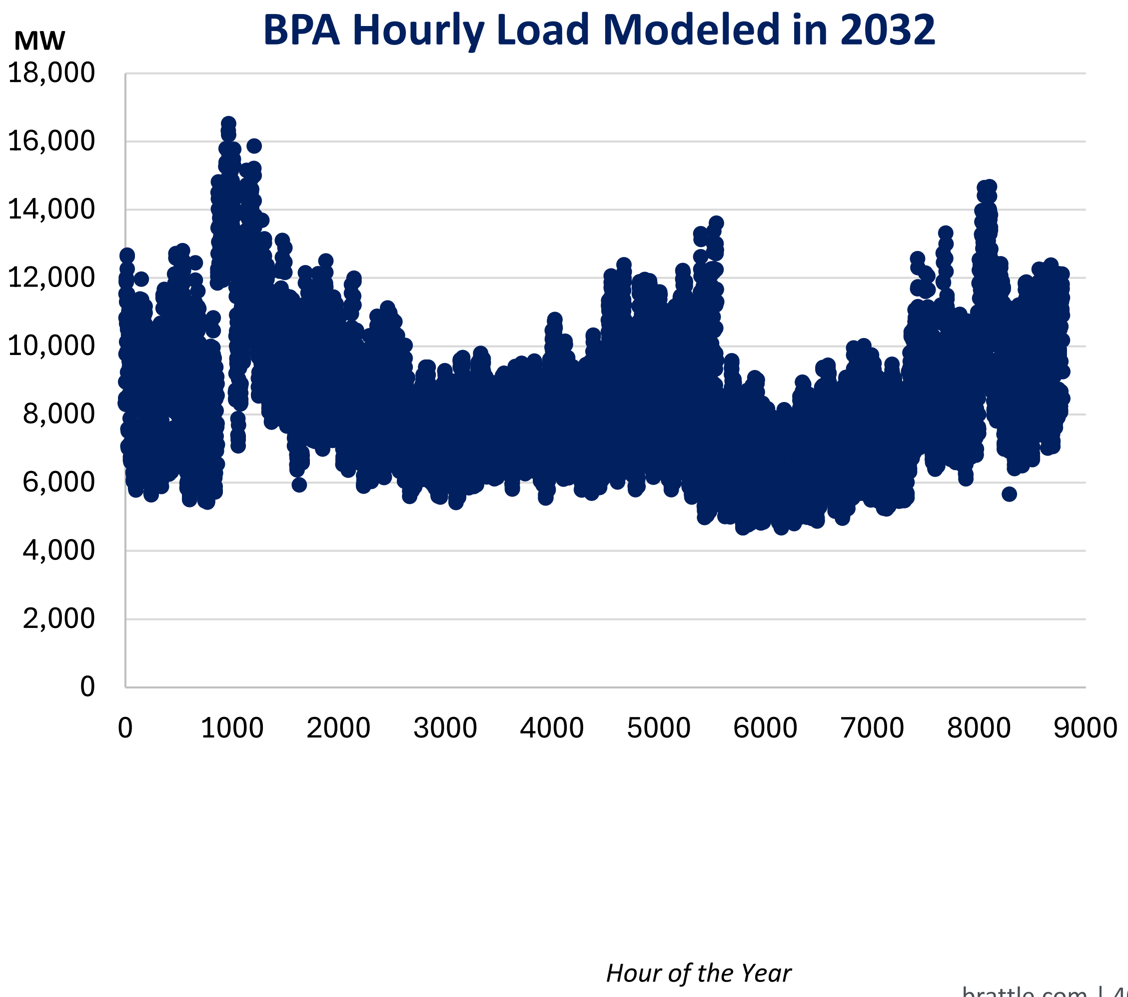
GWh



BPA Modeled Load

Bonneville's modeled load in 2032 is based on the 2032 WECC ADS data set

- The cold and hot extreme weeks increase load for BPA for those periods of time and are the causes of the spikes in load in February and August
- Modeled 2032 load is 74.8 TWh with a system peak of 16.5 GW that occurs during the cold snap in February



Hurdle Rate Assumptions

Markets+ and EDAM are modeled with separate bilateral trading frictions at the seam, as Markets+ automatically enables intertie bidding

- Bilateral transactions pay a $6/MWh friction charge for trades between two non-market entities
  - Bilateral transactions at the Markets+ seam pay $3/MWh, $1.5/MWh at an RTO seam, and $6/MWh at the EDAM seam (plus GHG and transmission service fees, if applicable).
- Exports across the market seams into a GHG zone are charged an unspecified resource GHG cost (equivalent to the emissions charge for a generic gas-CC unit, about $28/MWh)

Modeled Trading Friction Charges ($/MWh)

Transaction Type	Friction Charge	Transaction Pays OATT?
	$/MWh	***Yes/No***
Bilateral Transactions	$6	Yes*
Block Transactions	$1.5	Yes*
EDAM and WEIM Transactions	*None*	No
Markets+ DA / RT Transactions	*None*	No
RTO Intertie Transactions	$1.5	Yes*
Markets+ Seam Transactions	$3	Yes*
EDAM Seam Transactions	$6**	Yes*

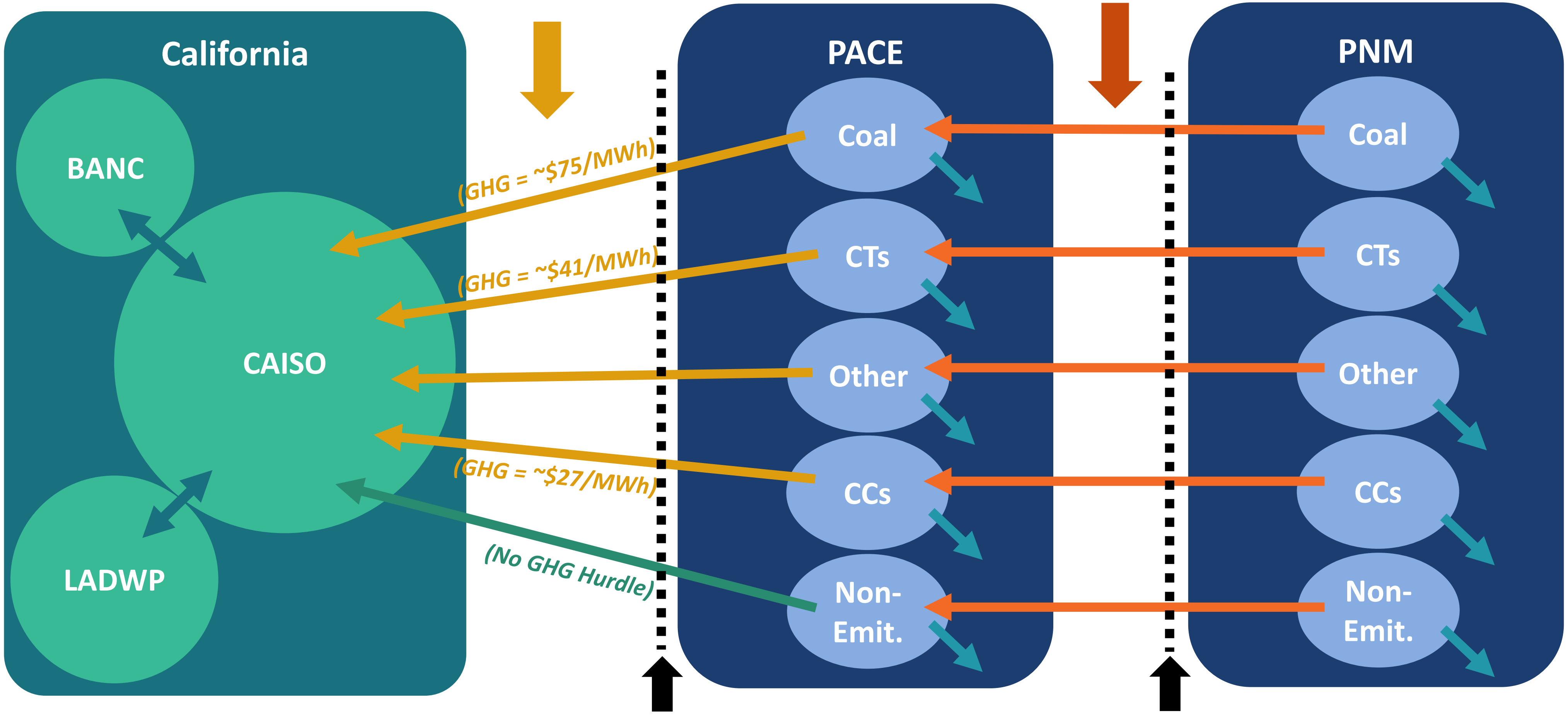
Note: *Trades across long-term transmission rights pay a friction charge, but no hourly OATT rate.
**EDAM seams with Markets+ pay the $3/MWh Markets+ friction.

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 <= min{BAA Total Export Limit - BAA Hourly Net Exports in reference pass, BAA Total Export Limit}**

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

Markets+ GHG Pricing Structure

Based on our review of the tariff language and the task force materials, we assume the Market+ GHG pricing structure will use the following approach:

- GHG surplus identification can 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.
  - We assume the Merit Order approach will apply to all resources in the market, and we calculate BAA hourly surplus capacity available for transfer to GHG pricing states outside of the model using the load data and a merit order constructed from modeled operating cost and capacity assumptions.
  - We apply resource 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 resources

Load Following Reserves

We calculate load following requirements for each market based on net load variability, and found that Markets+ results in marginally lower requirements for BPA

In both markets we calculate load following reserves (known as Imbalance Reserves in EDAM) both in the up and down directions to meet the 97.5 percentile of each BAA's historical net load variability.

- In the two market cases, participants' requirements are 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.
- Higher requirement in EDAM is driven by more renewable resources in the market footprint than Markets+.

Resource Sufficiency & Transmission

EDAM Resource Sufficiency Test

- EDAM will apply the Resource Sufficiency Test to each member before day-ahead market operations
  - In the 2019 EDAM Feasibility Study, E3 conducted an hourly analysis of Resource Sufficiency for each proposed EDAM member and found that failure was extremely rare.
  - For this study, conducted ex-post check and confirmed that 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, including existing long-term transmission contracts (ETCs)
  - Bucket 2: “Donated” Transmission Contracts, which are ETCs made available (“donated”) to the EDAM by participants
  - Bucket 3: Unsold Firm Transmission (no study participant informed us that they plan to hold back any transmission)
- 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

Markets+ Transmission

- All transmission with other Markets+ members is modeled as available in the market without wheeling charges
- No participants identified any transmission that should be carved out for WRAP or other resource adequacy purchases.

Congestion Rent Allocation

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

- We apply the Markets+ proposed approach to allocate congestion based on the portion of rights each market participant owns on the constraint where congestion is collected for market transactions between members.
- Congestion on transactions internal to a member's system (to serve native load) is assumed to apply to transmission owned or controlled by the local TSP and all internal congestion is allocated to the local TSP.
- This differs from the EDAM where tie points were used between BAs to determine the allocation of revenue, splitting revenue into internal congestion revenue within a BA (kept by that BAA), and transfer revenue between two BAs (split 50/50 between the BAAs).

Appendix:
Benefit 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 market cases to determine the market related reductions 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")

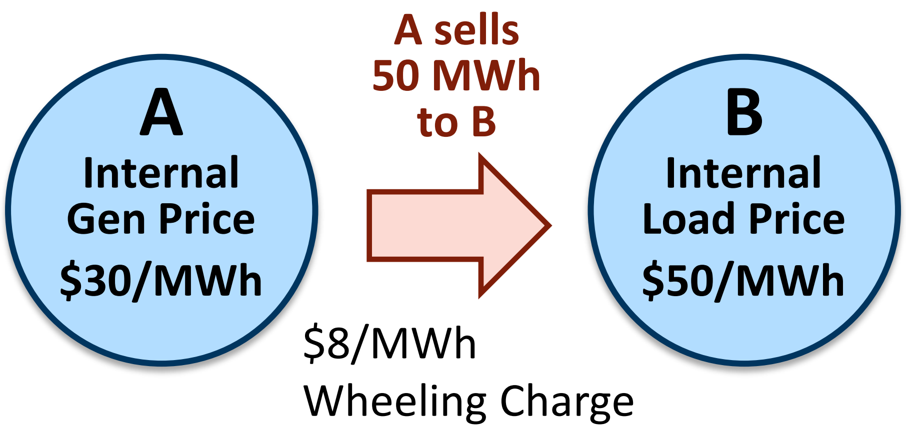
(−) Revenues from bilateral and market sales valued at the BAA's generation-weighted energy price ("Gen LMP")

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:

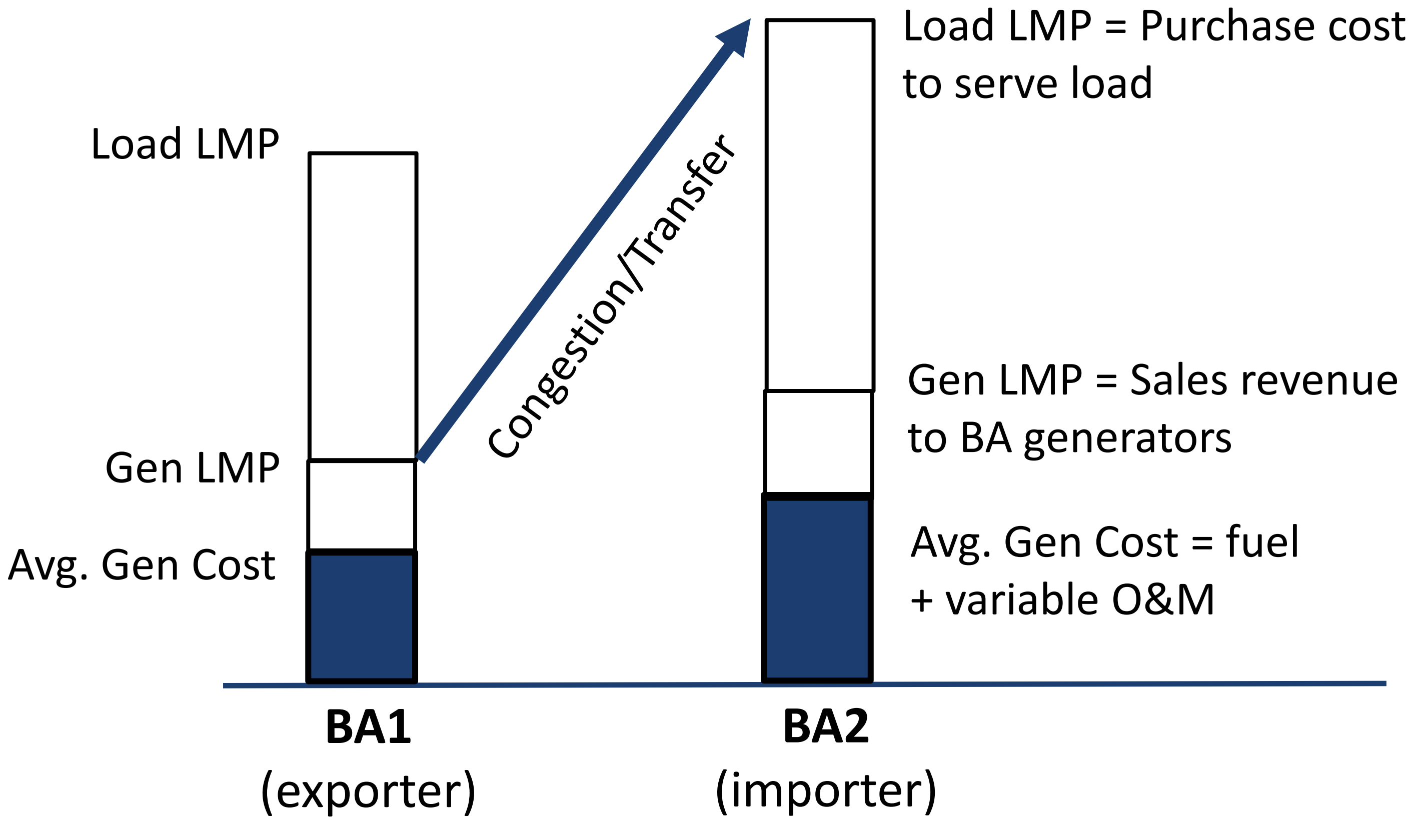
- A receives $30×50MWh=$1,500 in APC sales revenues
- B pays $50×50MWh=$2,500 in APC purchase costs

➔ $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

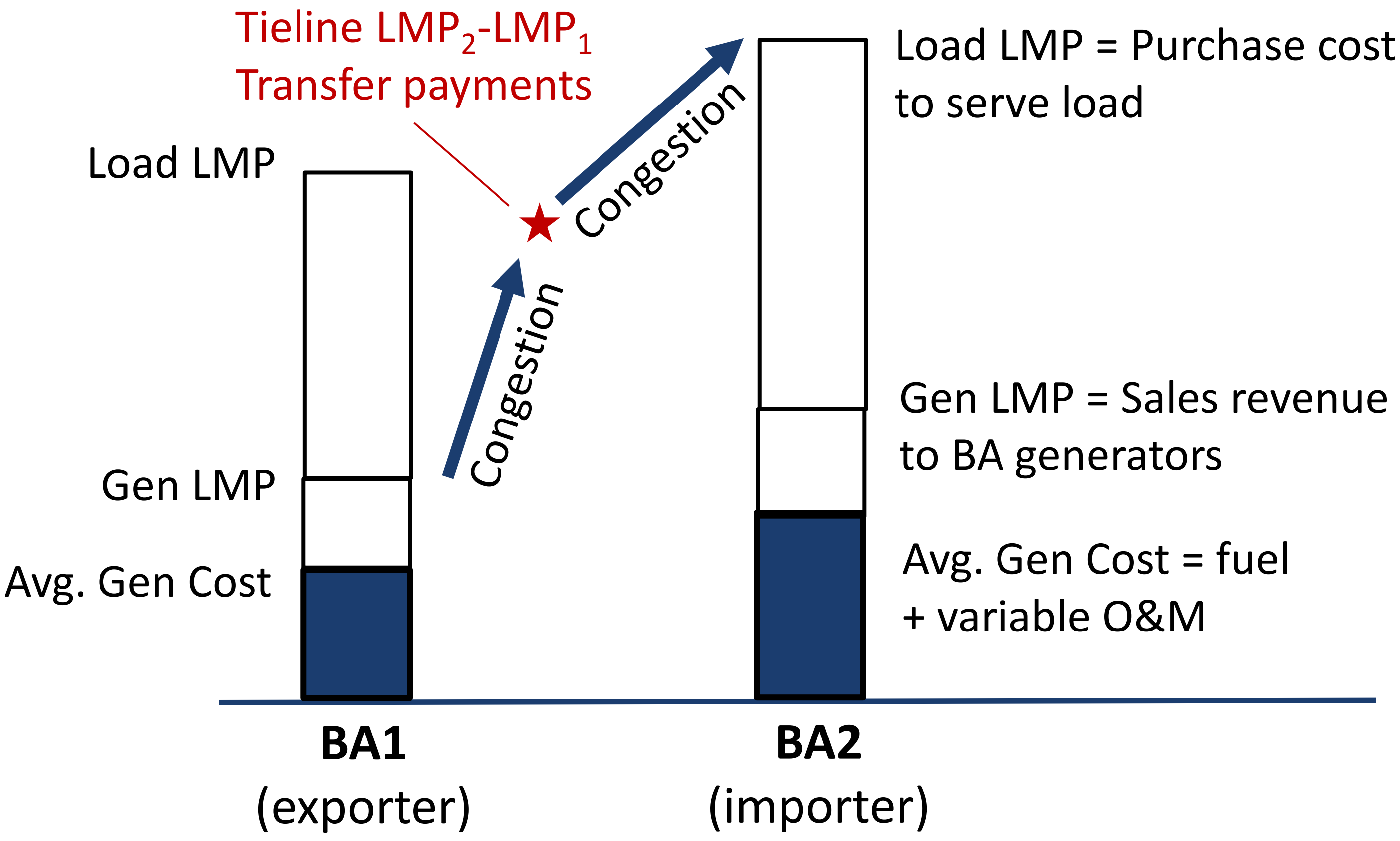
Illustration of Markets+ Congestion Revenues



Markets+ congestion revenues are rolled together and estimated based on BA load and gen LMPs:

- The BAA is assumed to own all rights on congested paths within their BAA, unless we have information on third-party contracts.
- Similarly, unless we have information on third-party contracts, we assume congestion between market members is owned 50/50 by the two BAAs
- Congestion/Transfer Revenue Payment (split 50/50) = MW x (Load LMP_2 – Gen LMP_1)

Illustration of EDAM Congestion and Transfer Revenues



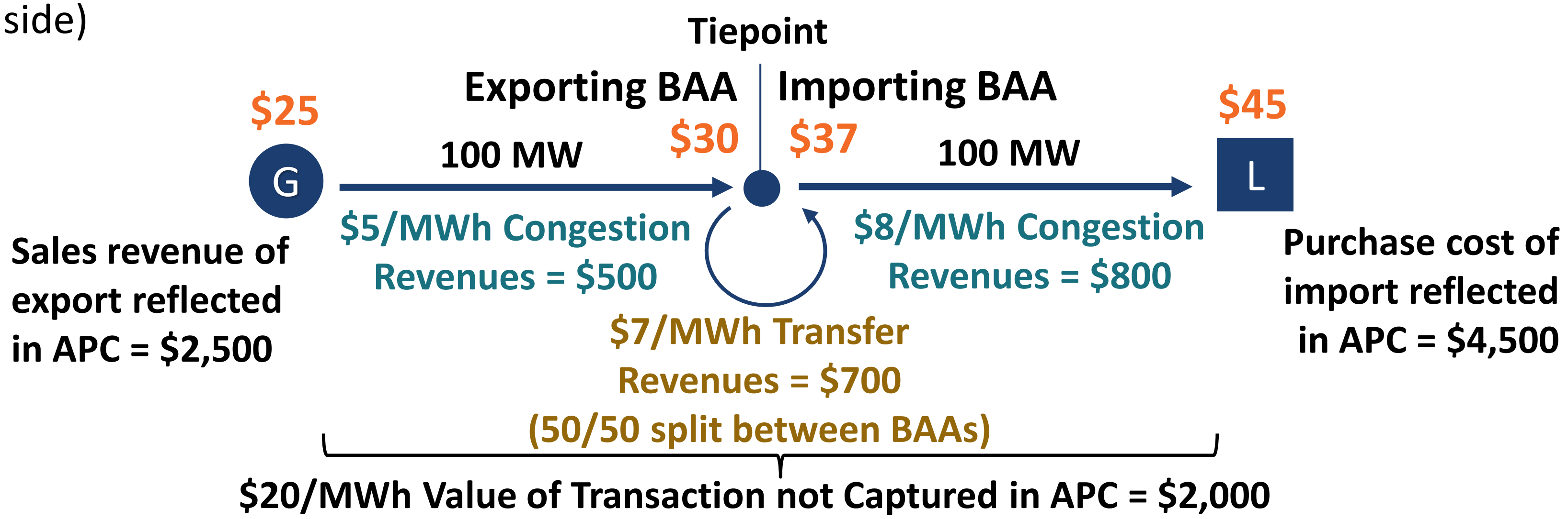
EDAM congestion and transfer revenues estimated based on individual tieline LMPs:

- **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 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)



Appendix:
Overview of Power System Optimizer (PSO)

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 flows and contract paths)
- 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

Independent Simulation of Multiple Time Horizons

PSO simulates multiple independent decision cycles to capture day-ahead vs. real-time unit commitment and dispatch

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)** • WEIM/WEIS/RTO trading of economic energy • Remaining Tx released for WEIM/WEIS • RT balancing in BAAs

Independent real-time decision cycle used to simulation EIM functions

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

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

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

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 simulates 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.

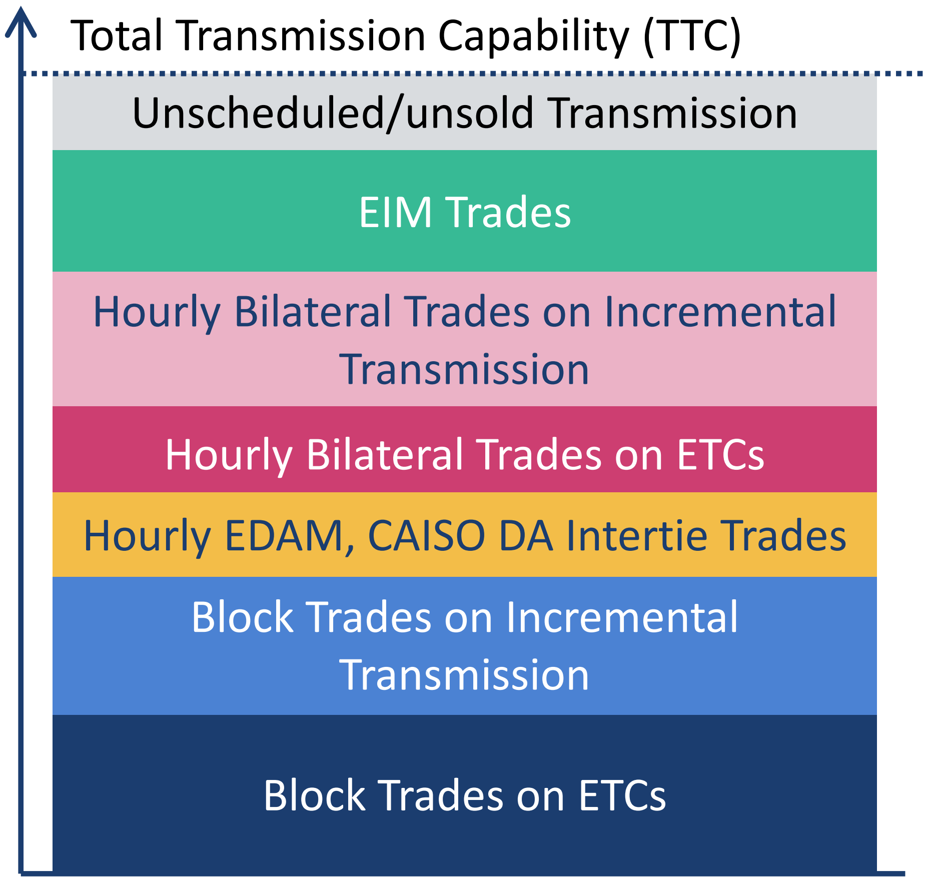
These cycles can take on different assumptions, depending on market structure. In a bilateral setting, all are set up to analyze utility-specific unit commitment and dispatch decisions, with each of them including hurdle rates and transmission fees that limit the amount of economic transactions that 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.

Types of Trades and Transmission Reservations Modelled

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

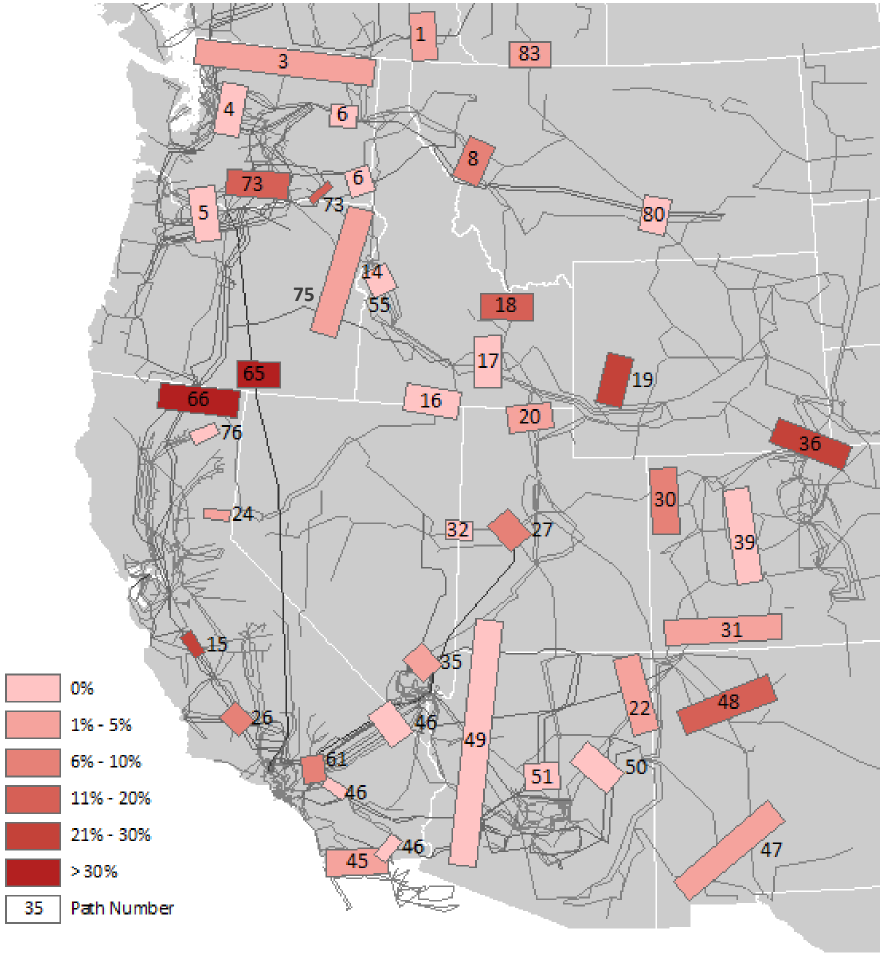
- Existing long-term transmission contracts (ETCs) and incrementally purchased transmission
- Total reservations on each contract path is limited by the total transfer capability (TTC)
- Trades are structured as blocks or hourly
- Bilateral trades between BAAs, at major hubs, or across CAISO interties
- 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.