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Updated Day-Ahead Market Impact Study

SENSITIVITY CASE RESULTS

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STATE OF CALIFORNIA ENERGY COMMISSION

June 5, 2025

Brattle

Overview of the Study and Drivers of Benefits

EDAM is scheduled to launch with several utilities in CA and neighboring states committed to participation, while other utilities in the western U.S. are exploring a different day-ahead market (Markets+) that will not include CA.

- Regional markets deliver cost savings to customers due to efficiency gains, environmental benefits through lower emissions, and reliability benefits by making it easier to manage the grid during extreme weather events
- This study calculates the benefits to CA customers if additional utilities across the western U.S. participate in EDAM
- We study 2032 as a proxy for the first decade of market operations
  - We use resource assumptions from utility IRPs and the CAISO's TPP
  - We build off the modeling efforts conducted for over a dozen utilities in the last two years

The benefits of EDAM will depend on the size and diversity of members that join. A larger and more diverse EDAM footprint will deliver more benefits to customers in California.

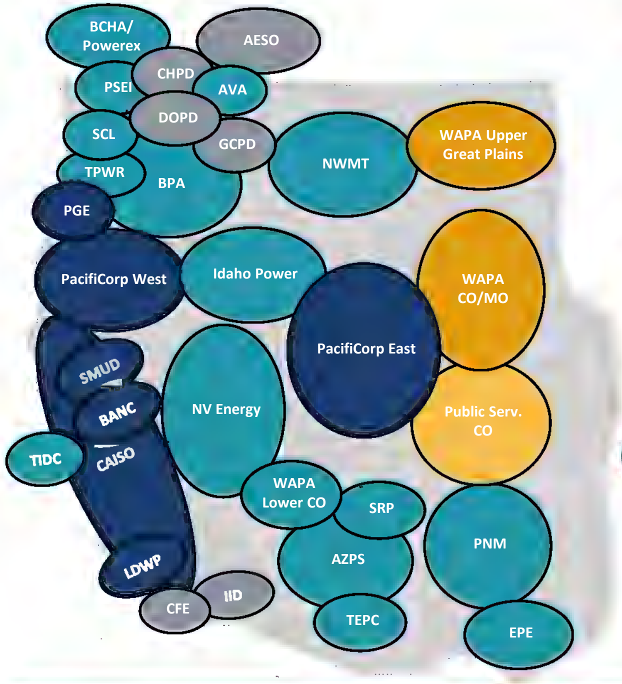
REVIEW OF INITIAL ANALYSIS

Simulated Market Footprints in Initial Analysis

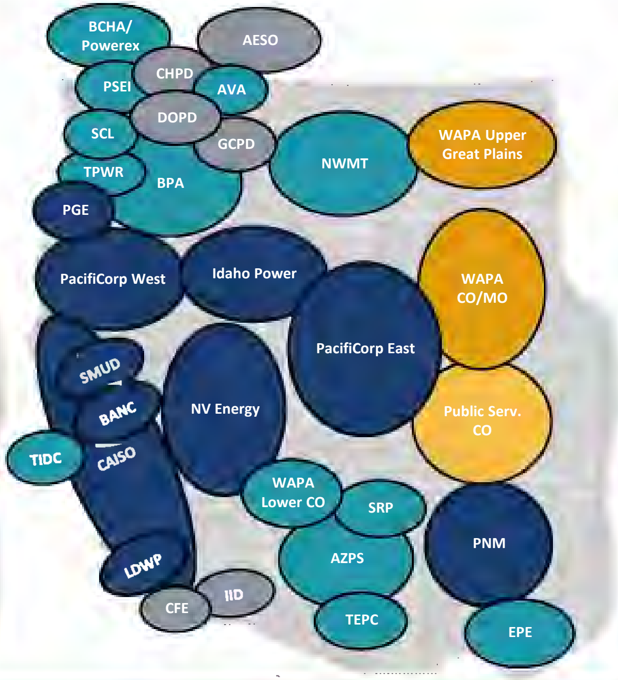
Markets+ (DA & RT)
EDAM (also in WEIM)
SPP RTO West *(co-optimizes w/ M+)*
WEIS
WEIM
Bilateral Markets Only

We initially analyzed the impacts for California DA market participation benefits under four market footprint scenarios and presented the results of that analysis at the January 2025 IEPR workshop

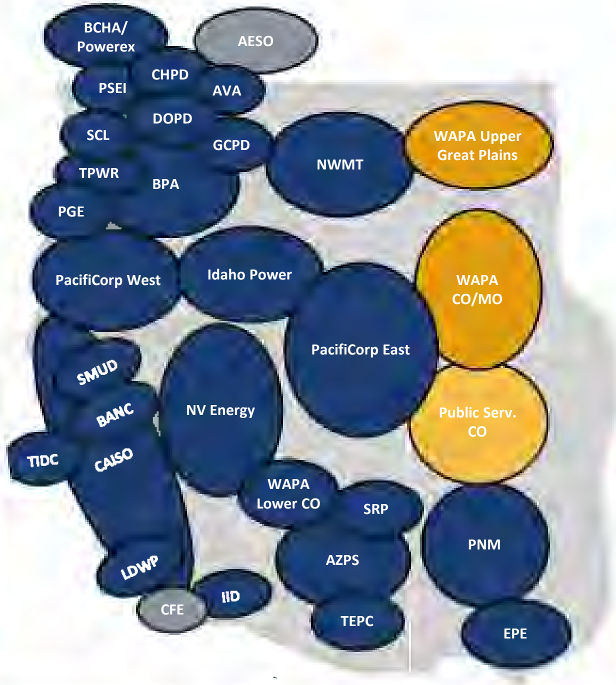
Baseline Case
(EDAM in 2026/2027)



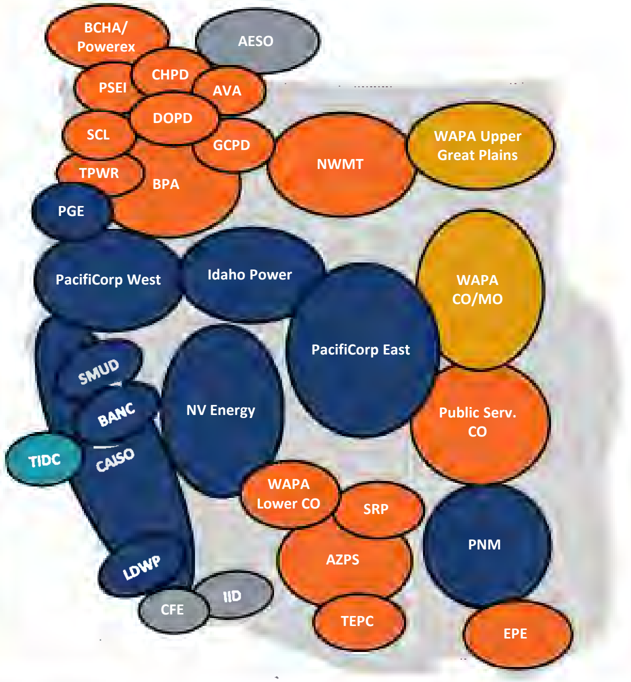
Baseline+ Case
(Likely EDAM Commitments)



Expanded EDAM Case
(Maximum EDAM Potential)



Split Market Case
(Likely EDAM Entities w/ Markets+)



Initial EDAM footprint and potential near-term outcome

Potential longer-term market footprint outcomes

Key Study Takeaways from Initial Analysis

Economic Benefits to California Customers are Largest in the Expanded EDAM Case

- California customers experience ~$790 million/year in net benefits in the Expanded EDAM case compared to the Baseline case
- California customer benefits are ~$500 million/year higher in the Expanded EDAM case than in the Split Market case

Expanding EDAM Impact on CO_2 Emissions & Renewables Curtailment

- The improved investment environment for renewables due to the larger EDAM footprint may accelerate the trend towards lower emissions in the WECC; GHG emissions are predicted to fall by more than 30% in the WECC between 2024 and 2032.
- An Expanded EDAM reduces curtailment of CA wind and solar by 10% compared to other market footprints

A Larger EDAM give CA Customers Greater Reliability During Scarcity Conditions

- The Expanded EDAM footprint contains about 25,000 MW of additional surplus capacity compared to the EDAM in the Split Market case, which can be used to serve CA customers during emergency events.
- The larger EDAM footprint can leverage the diversity of load and renewables across the WECC to enhance reliability for CA customers.

Sensitivity Analyses Motivation

To delve deeper into our findings from the four scenarios presented at the January 2025 IEPR workshop and address questions raised at that workshop, we conducted three sensitivity analyses:

- **Status Quo Case**
  - Create a more comprehensive picture of CA benefits from EDAM participation by illustrating the economic benefit of EDAM ***formation*** to CA customers, in addition to the benefit of EDAM ***expansion*** we had calculated from the previous cases
  - Determine the emissions impact due to EDAM ***formation*** compared to the impact due to EDAM ***expansion***
- **Lower Natural Gas Prices**
  - Test the robustness of the economic benefits of EDAM expansion under a lower fuel price scenario.
  - Understand the impact of natural gas prices on emissions outcomes under the market footprint scenarios
- **Market Revenue Analysis for CA Solar**
  - Analyze the change in market revenues for CA solar resources due to EDAM expansion, and the potential ramifications for renewables development more generally and the longer-term CA & WECC-wide resource mix

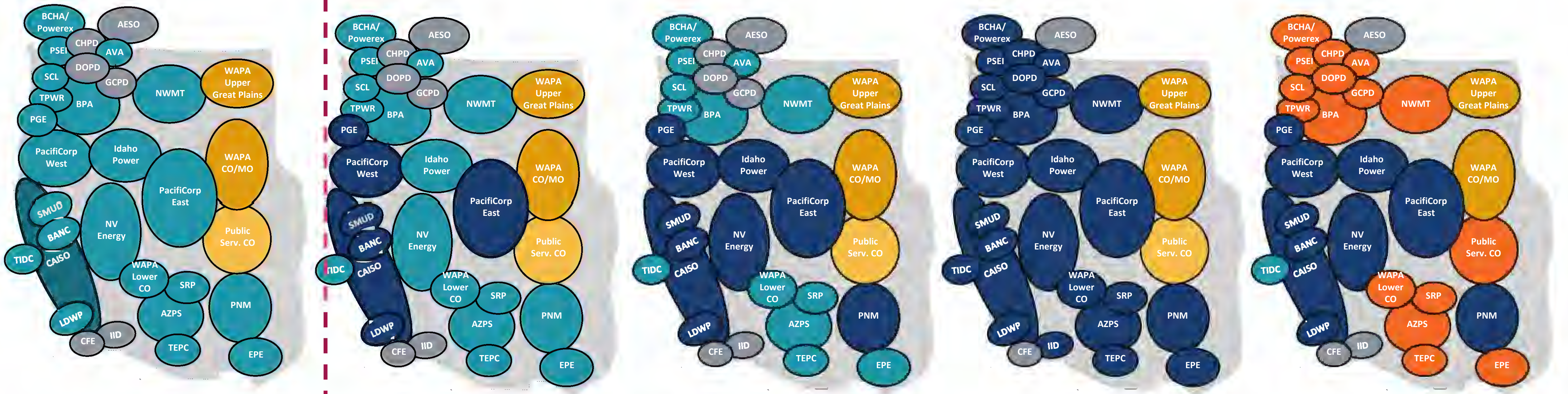
Status Quo Case

Status Quo Case Footprint and Motivation

Markets+ (DA & RT)
EDAM (also in WEIM)
SPP RTO West *(co-optimizes w/ M+)*
WEIS
CAISO & WEIM
Bilateral Markets Only

The Status Quo footprint allows us to measure the impact of EDAM formation and show a more comprehensive picture of market benefits

Status Quo *(No EDAM or Markets+ Footprints)* | **Baseline Case** *(EDAM in 2026/2027)* | **Baseline+ Case** *(Likely EDAM Commitments)* | **Expanded EDAM Case** *(Maximum EDAM Potential)* | **Split Market Case** *(Likely EDAM Entities w/ Markets+)*



Markets Today | Initial EDAM footprint and potential near-term outcome | Potential longer-term market footprint outcomes

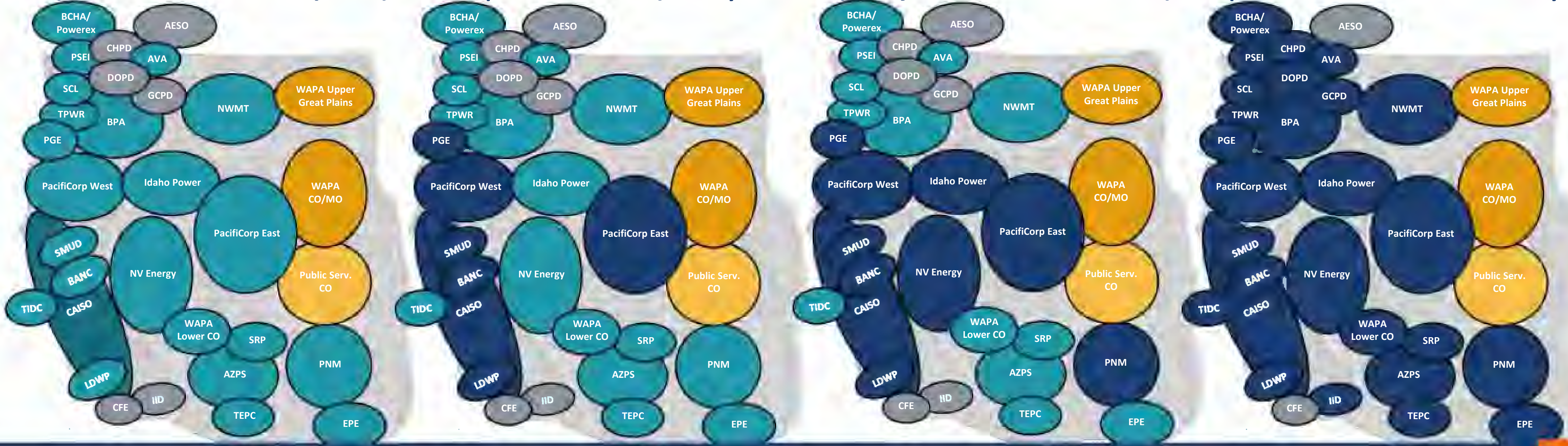
STATUS QUO CASE

Our Initial Study Focused on the Benefits of EDAM *Expansion*

EDAM (also in WEIM)
SPP RTO West
WEIS
CAISO & WEIM
Bilateral Markets Only

EDAM *formation* accounts for an additional $200-$300 million per year in market benefits for CA

Status Quo *(No EDAM or M+ Footprints)*	Baseline Case *(EDAM in 2026/2027)*	Baseline+ Case *(Likely EDAM Commitments)*	Expanded EDAM Case *(Maximum EDAM Potential)*



	Status Quo	Baseline Case	Baseline+ Case	Expanded EDAM Case
CA Total System Cost ($million per year)	$4,798	$4,511	$4,399	$3,721
Δ to Status Quo		$287	$399	$1,077
Δ to Baseline			$112	$790
Δ to Baseline+				$678

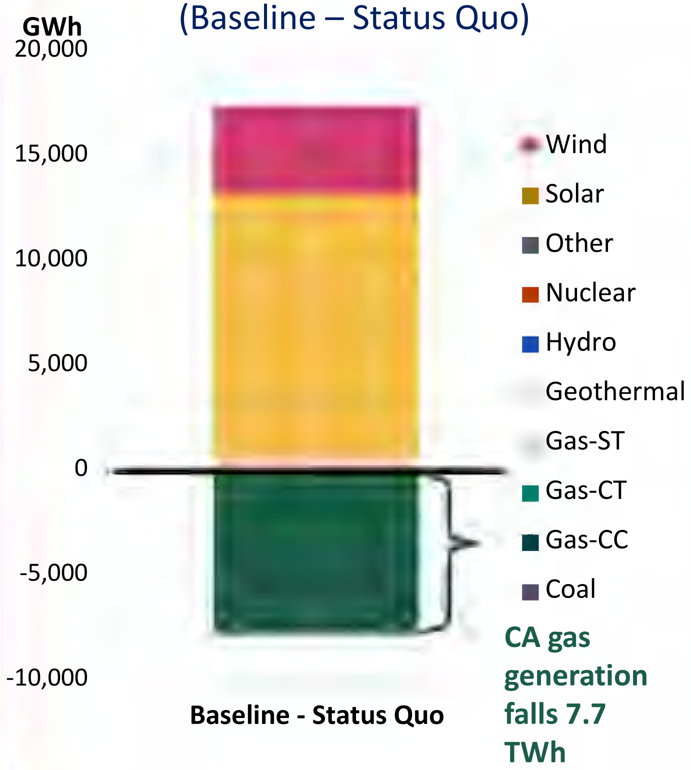
For Split Market benefits details relative to Status Quo, see Appx. A

Impacts on California Generation

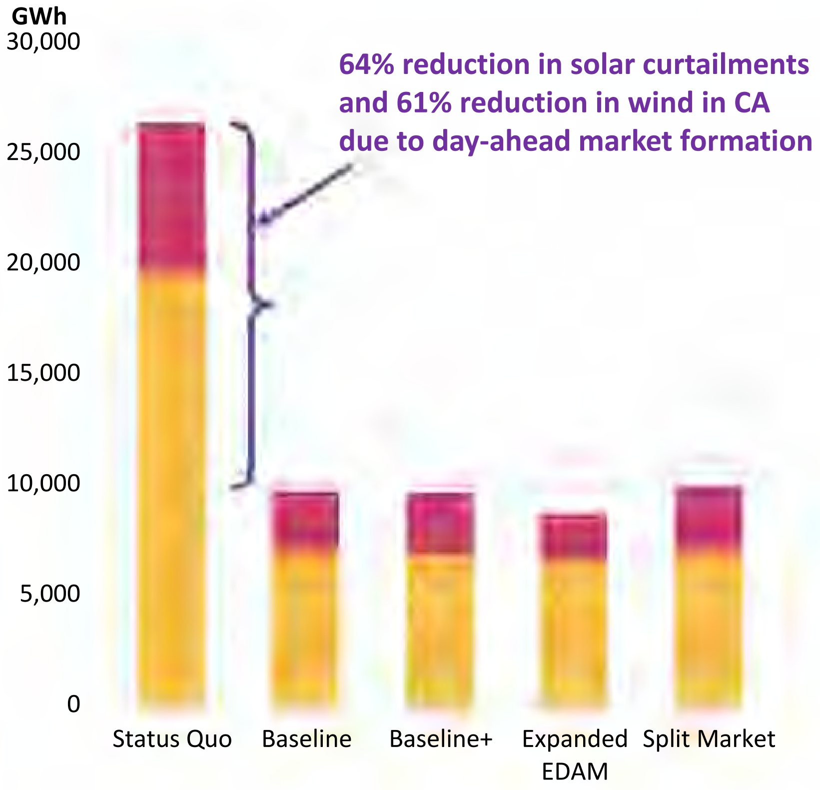
EDAM formation reduces California solar curtailments by more than 10 TWh

- Previously curtailed renewables unlocked by the formation and expansion of markets displace gas generation in CA and thermal generation throughout the WECC
- Lower curtailments may allow fewer resources to be built to meet renewables targets in the state
- Reduced curtailments additionally increase market revenues for renewables (discussed on later slide), which tends to accelerate development of such resources

California-Wide Generation
(Baseline – Status Quo)



Total California Curtailments by Case

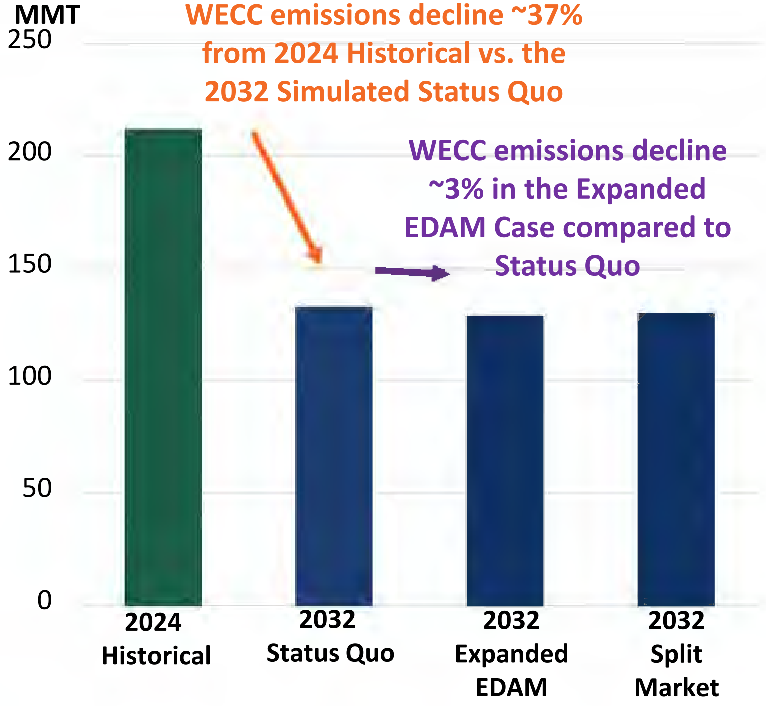


GHG Emissions Impacts Across All Cases

In the modeled footprints with WECC-wide day-ahead markets, Expanded EDAM and Split Market, both WECC and California emissions decline compared to the Status Quo

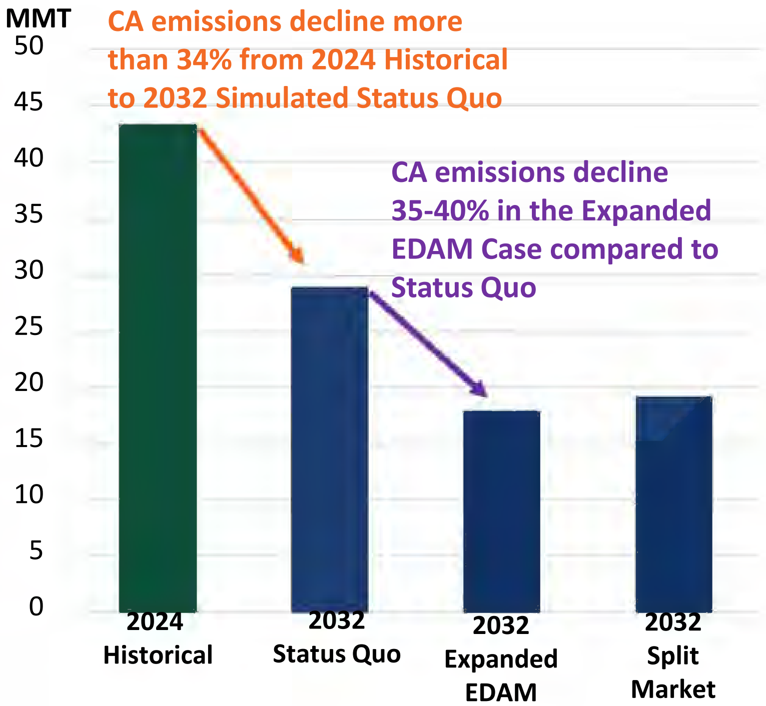
- The majority of WECC and California emissions savings compared to 2024 historical emissions come from the increasing penetration of new renewables making the incremental shifts from market participation, especially WECC wide, minimal
- We find that expanding the EDAM reduces emissions by ~3% WECC-wide compared to the Status Quo

Total WECC Emissions by Case



WECC-wide	Δ to 2024 (MMT)
Status Quo	-78
Expanded EDAM	-82
Split Markets	-81

Total California Emissions by Case



CA	Δ to 2024 (MMT)
Status Quo	-14
Expanded EDAM	-25
Split Markets	-24

Note: Historical emissions come from the EIA's AEO 2025. WECC emissions only includes the U.S. WECC in all numbers.

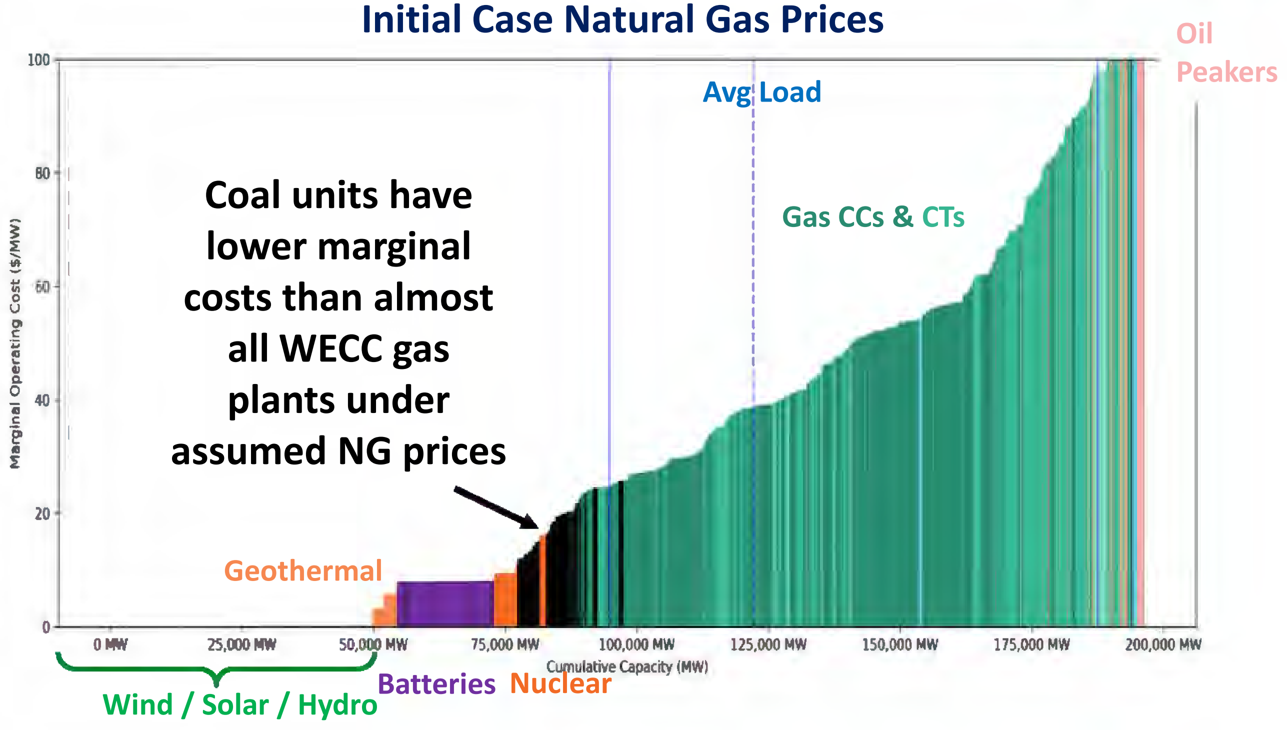
Low Natural Gas Price Sensitivity Cases

Low Natural Gas Price Sensitivity Motivation

The natural gas price outlook in our initial scenarios placed gas plants above coal in the supply stack in almost all cases

- Natural gas prices are a strong driver of market prices and influencer of market benefits
- Lower gas prices create more competition between gas and coal plants, especially in the expanded markets with fewer barriers to trade
- With these cases we sought to understand:
  - The impact of lower fuel prices on simulated market benefits and the relative benefits between the simulated footprint cases
  - The impact on emissions outcomes of increased competition between gas and coal

Simulated Average WECC Supply Curve with Initial Case Natural Gas Prices

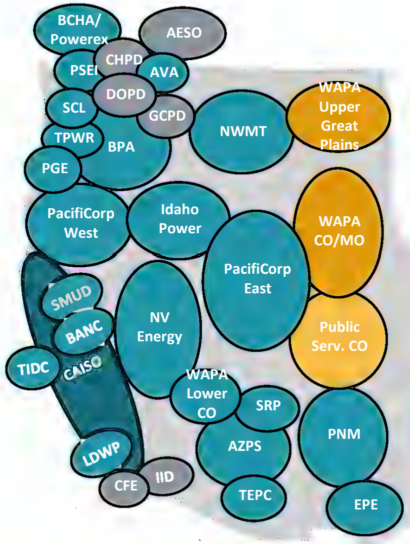


Markets+ (DA & RT)
EDAM (also in WEIM)
SPP RTO West (co-optimizes w/ M+
WEIS
CAISO & WEIM
Bilateral Markets Only

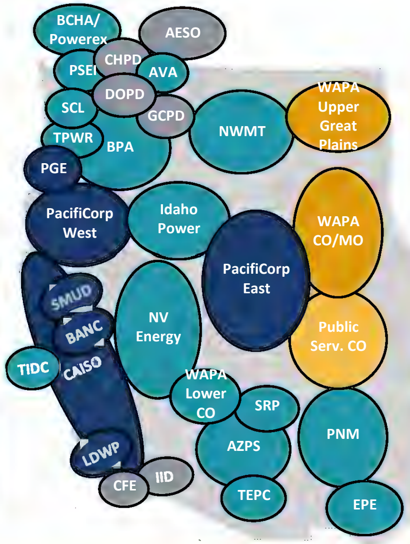
CA Market Benefits Remain Significant with Low Natural Gas Prices

CA benefits range from $244 to $897 million/year in EDAM cases and $600 million/year in Split Market case

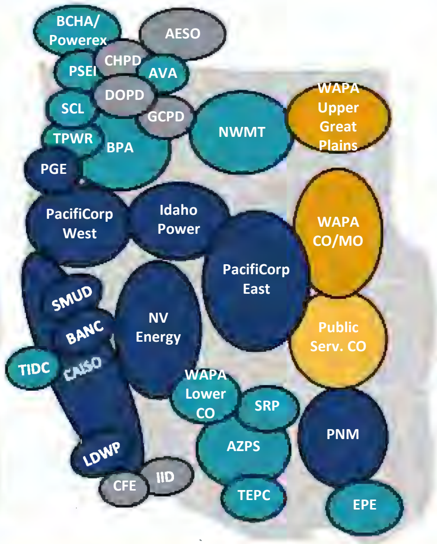
Status Quo
(No EDAM or Markets+ Footprints)



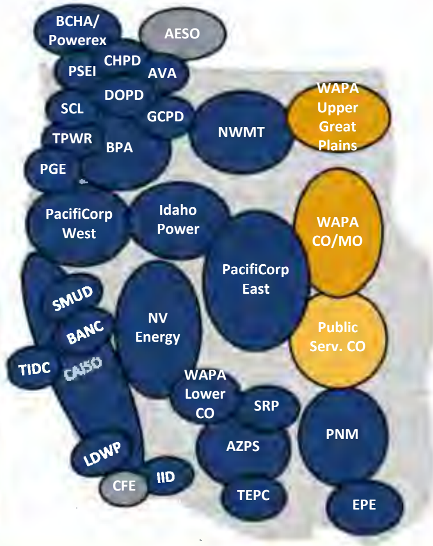
Baseline Case
(EDAM in 2026/2027)



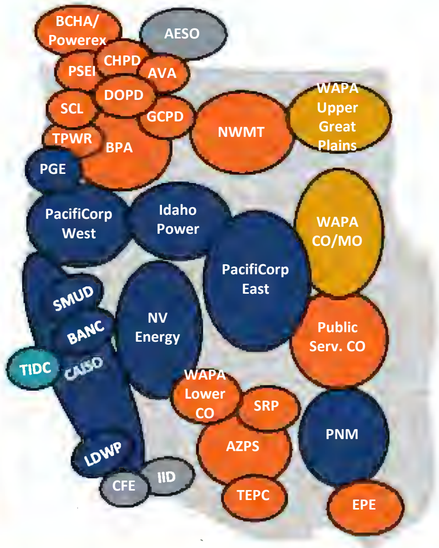
Baseline+ Case
(Likely EDAM Commitments)



Expanded EDAM Case
(Maximum EDAM Potential)



Split Market Case
(Likely EDAM Entities w/ Markets+)



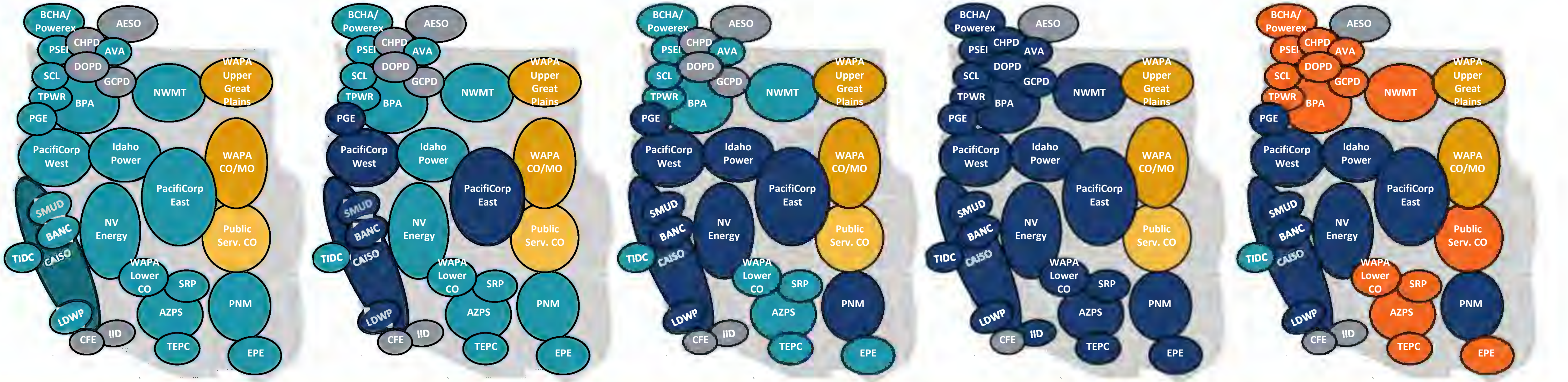
	Status Quo	Baseline Case	Baseline+ Case	Expanded EDAM Case	Split Market Case
CA Total System Cost ($million per year)	$4,418	$4,173	$4,012	$3,521	$3,819
Δ to Status Quo		$244	$405	$897	$599
Δ to Baseline			$161	$653	$354
Δ to Baseline+				$492	$194

CA Market Benefits with Lower Natural Gas Prices are Similar to the Benefits in Initial Cases after Accounting for Lower Underlying Costs

Markets+ (DA & RT)
EDAM (also in WEIM)
SPP RTO West (*co-optimizes w/ M+*
WEIS
CAISO & WEIM
Bilateral Markets Only

CA benefits range from 6 – 20% of the Status Quo cost in low natural gas price cases vs. 6 – 22% in initial cases

Status Quo	Baseline Case	Baseline+ Case	Expanded EDAM Case	Split Market Case
(No EDAM or Markets+ Footprints)	*(EDAM in 2026/2027)*	*(Likely EDAM Commitments)*	*(Maximum EDAM Potential)*	*(Likely EDAM Entities w/ Markets+)*



	Status Quo	Baseline Case	Baseline+ Case	Expanded EDAM Case	Split Market Case
CA Total System Cost ($million per year)	*$4,798* → **$4,418** (initial) (low ng price)	*$4,511* → **$4,173**	*$4,399* → **$4,012**	*$3,721* → **$3,521**	*$4,217* → **$3,819**
Δ to Status Quo		*$287* → **$244**	*$399* → **$405**	*$1,077* → **$897**	*$581* → **$599**

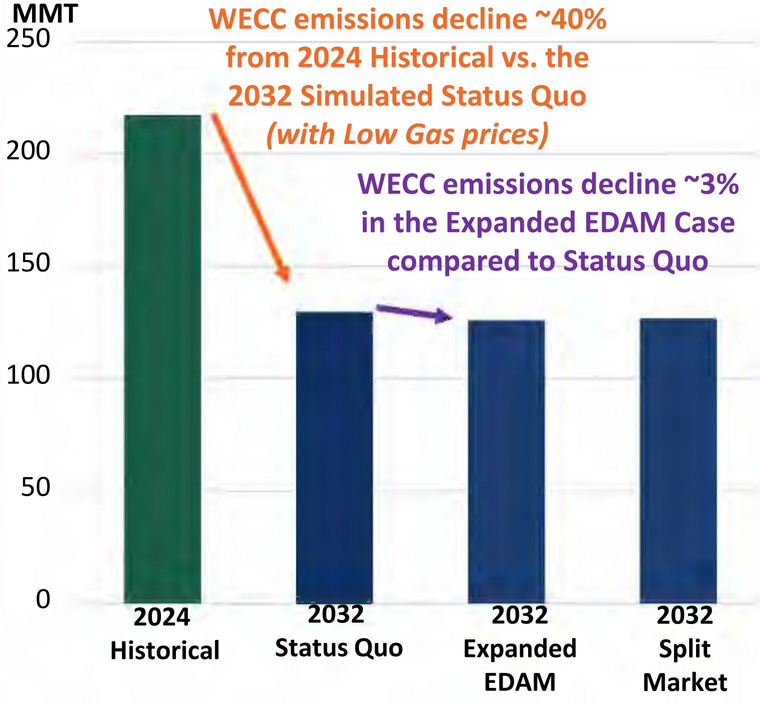
Benefits drivers in the low natural gas price cases remain similar to the initial cases

GHG Emissions Impacts Across the Low Gas Sensitivities

The low natural gas price sensitivity cases show similar emissions shifts as in the initial cases, just with reduced emissions in all cases due to lower coal dispatch

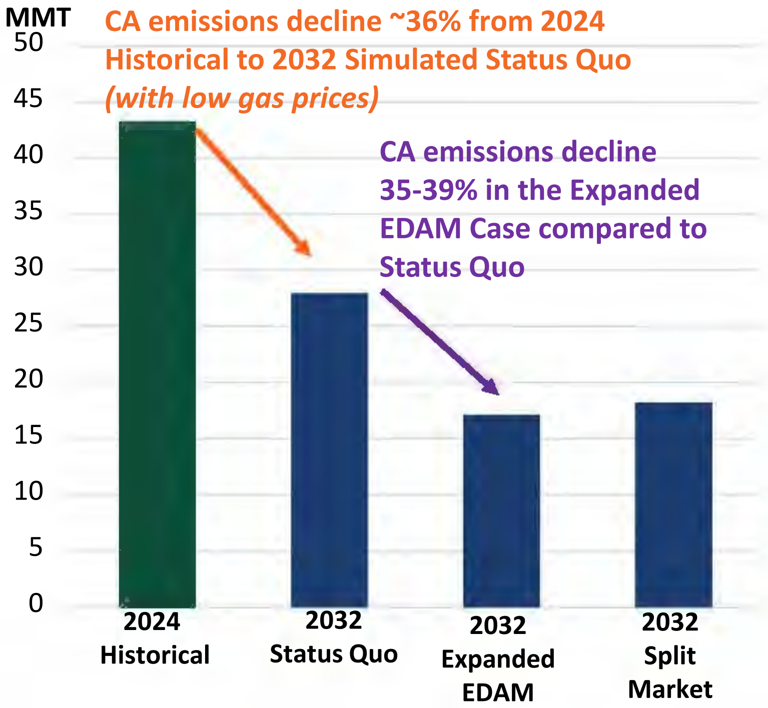
- WECC wide emissions in the Status Quo case start about 3 MMT lower than in the original cases with the lower natural gas prices due shifts from coal generation to gas
- In these sensitivity cases the Expanded EDAM footprint is still reducing emissions about 3% WECC wide and more than 35% in California

Total WECC Emissions by Case



WECC-wide	Δ to 2024 (MMT)
Status Quo	-82
Expanded EDAM	-86
Split Markets	-85

Total California Emissions by Case



CA	Δ to 2024 (MMT)
Status Quo	-15
Expanded EDAM	-26
Split Markets	-25

Note: Historical emissions come from the EIA's AEO 2025. WECC emissions only includes the U.S. WECC in all numbers.

Market Revenue Analysis for CA Solar

A Broader Market Footprint Increases the Value of Renewables

A broader market footprint enhances the value of renewables through greater load and resource diversity, lower aggregate forecast imbalances, and more opportunities to sell excess output

CA solar is a key resource for meeting clean energy targets in the state and shows the benefits of market formation/expansion for renewables

- Market revenues for CA solar increase from -$3/MWh in the Status Quo to $11/MWh in the Expanded EDAM case.
- Improved market conditions for solar are mostly driven by higher midday prices in CA, due to an increased ability to export excess solar in the EDAM.
- Increased market revenues for CA solar resources flow through to customers in the form of lower PPA costs.
- Higher market revenues reenforce trend towards solar by improving long-term investment environment for clean energy.

Average Revenue Earned by Solar Plants

$/MWh (Generation Weighted)

Area	Capacity (GW)	Average Case Revenue: Status Quo	Average Case Revenue: Baseline+	Average Case Revenue: Expanded EDAM
CAISO	70	-$5	$7	$10
All of California	73	-$3	$8	$11
CAISO Delta to Status Quo		-	$12	$15
All of California Delta to Status Quo		-	$11	$13
CAISO Delta to Baseline+		-	-	$3
All of California Delta to Baseline+		-	-	$3

CA solar value increase of market *forming*

CA solar value increase of market *expanding*

Appendix A: Modeling Assumptions and Detailed Results from Sensitivity Analyses

California-Wide Day-Ahead Market Expansion Benefits

The EDAM yields $287-$1,077 million per year in benefits to California customers relative to a Status Quo without the EDAM.

- **Adjusted production cost increases $441 million per year** compared to the Baseline case as California-wide gas generation increases 7.7 TWh and California sees a decline in sales revenue of more than $500 million per year
- **California's sales revenues decline** due to a 16.6 TWh increase in curtailments and reduced ability to export solar midday to the rest of the WECC
- **Bilateral trading revenues increase $338 million per year** offsetting about $190 million per year in EIM and EDAM trading revenue losses
- **Benefits in the Expanded EDAM case increase to $1.1 billion per year when compared to the Status Quo case**
- **Benefits in the Split Market case increase to $581 million per year when compared to the Status Quo case**

Summary of California-Wide System Costs & Revenues by Case ($ Million per year)

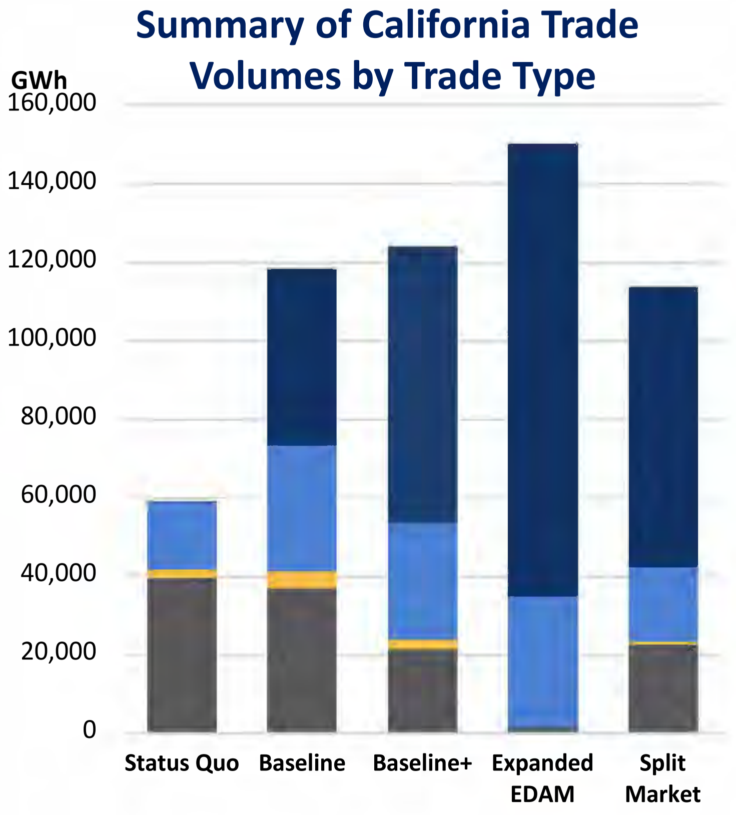
	Status Quo	Baseline	Baseline+	Expanded EDAM	Split Market
Adjusted Production Cost	$5,613	$5,172	$4,952	$4,585	$4,752
Production Cost	*$2,217*	*$1,744*	*$1,440*	*$1,258*	*$1,370*
Purchases Cost	*$3,130*	*$3,674*	*$3,907*	*$3,968*	*$3,805*
Sales Revenue (subtracted from costs)	*-$266*	*$246*	*$395*	*$640*	*$423*
Short-Term Wheeling Revenues	$228	$227	$108	$25	$84
Bilateral Trading Revenues	$537	$199	$157	$23	$106
WEIM Congestion Revenues	$50	$66	$73	$55	$42
EDAM Congestion and Transfer Revenues	$0	$170	$204	$538	$292
EDAM Transfer Revenue	*$0*	*$85*	*$105*	*$255*	*$112*
EDAM Congestion Revenue	*$0*	*$84*	*$99*	*$283*	*$179*
Net TRR Settlement	$0	$0	$6	$112	$6
Total System Production Cost and Market Revenues	**$4,798**	**$4,511**	**$4,399**	**$3,721**	**$4,217**
Benefit Relative to Status Quo		**$287**	**$399**	**$1,077**	**$581**
Benefit % of Status Quo Production Cost and Market Revenues		***6%***	***8%***	***22%***	***12%***
Benefit Relative to Baseline			**$112**	**$790**	**$294**
Benefit % of Baseline Production Cost and Market Revenues			***2%***	***18%***	***7%***
Benefit Relative to Baseline+				**$678**	**$182**
Benefit % of Baseline+ Production Cost and Market Revenues				***15%***	***4%***

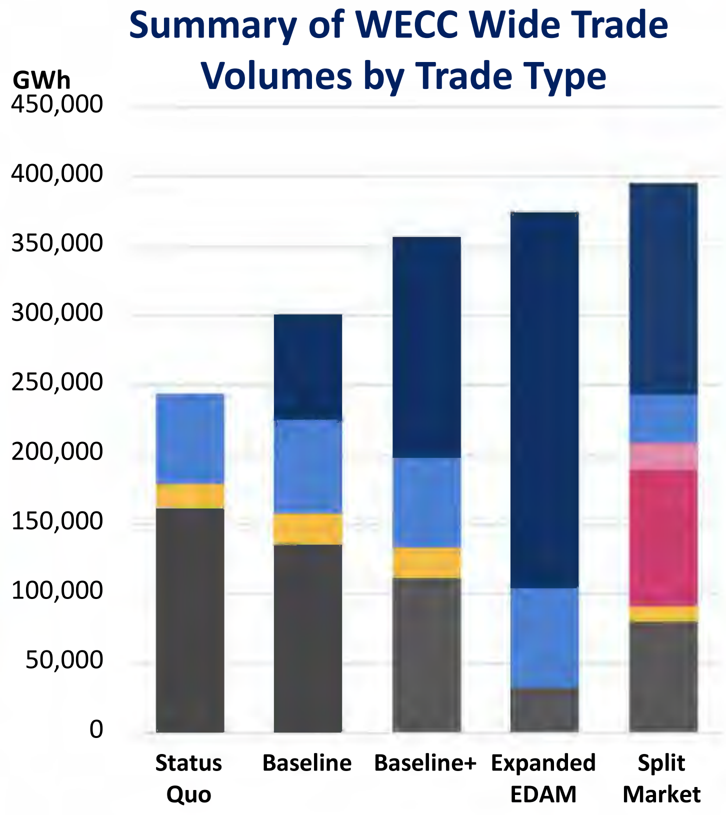
Note: Bilateral trading revenues refers to short-term bilateral trading of energy.

Trading Dynamics Impacts

The Baseline case sees California trading more than double from the Status Quo as EDAM market allows for more coordination and fewer constraints on CA exports

- **WECC-wide trading increases about 60 TWh or nearly 20% compared to Status Quo**
  - **EIM trading is lower in the Status Quo case due to restrictions on CAISO exports** considerably reducing midday solar exports from California
  - Bilateral and block trading remains about the same in both Status Quo and Baseline
  - Bilateral trading relatively similar between the Status Quo and Baseline cases due to our modeled CAISO export limit and CAISO's high WAC charge
- **California trading also increases about 60 TWh compared to Status Quo, all from EDAM and EIM trading**
- **We assume CAISO cannot export more than 7 GW in a single hour in the Status Quo case** which is consistent with prior Brattle studies
  - This assumption reflects that without a day-ahead market, other balancing authorities will not rely as heavily on CAISO exports from bilateral trades





CAISO Adjusted Production Cost in the Status Quo Case

CAISO's APC decreases $443 million in the Baseline case from the Status Quo case, driven by:

- **(1) $450 million/yr decrease in production cost** due to renewable curtailments decreasing over 16 TWh and displacing 7.7 TWh of gas generation
- **(2) $566 million/yr increase in purchase cost** as CAISO uses EDAM to import more and reduce internal generation
- **(3) $557 million/yr increase in sales revenue** as lower renewable curtailments allow to CAISO significantly increases midday sales and amplifies average sales prices

CAISO Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			Status Quo	Baseline	Difference	Status Quo	Baseline	Difference	Status Quo	Baseline	Difference	
Production Cost	(+)	[1]	288,038	299,918	**11,880**	$6.78	$5.01	**-$1.77**	1,951,596	1,501,096	**-$450,500**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	38,459	47,166	**8,706**	$56.13	$57.33	**$1.20**	2,158,640	2,703,855	**$545,215**	**(2)**
Real-Time Market		[5]	7,815	7,606	**-209**	$40.27	$44.06	**$3.79**	314,730	335,096	**$20,366**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	53,959	70,341	**16,382**	-$13.23	-$1.78	**$11.45**	-713,765	-125,112	**$588,653**	**(3)**
Real-Time Market		[8]	3,918	7,914	**3,996**	$13.88	$2.92	**-$10.96**	54,367	23,087	**-$31,280**	
***Total Cost** (Negative Difference = Benefit)*		[9]	**276,435**	**276,435**	**0**	**$18.39**	**$16.79**	**-$1.60**	5,084,364	4,642,072	**-$442,292**	
% Change in APC											***-8.7%***	

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. Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

Sensitivity Case Assumptions

To analyze how simulated benefits might shift with different future natural gas prices, we updated our gas prices to use April 2024 forward prices for the low natural gas price sensitivity cases

- **Updated forwards lowered the average modeled gas price WECC wide by about $1.1/MMBtu *(~26%)***
  - The average modeled gas price across the WECC declines from ~$4.2/MMBtu to ~$3.1/MMBtu (*in $2022*)
- **We updated the price for the El Paso San Juan hub and held the existing modeled basis differentials from other hubs to El Paso**
  - *This keeps regional supply stacks relatively consistent between the original cases and this sensitivity, measuring only a broad decline in average gas prices across the WECC, not the effects of shifting prices in specific regions only*

Average Hub Gas Price Pre and Post-Update to El Paso April 2024 Forward Prices ($2022)

Month	El Paso San Juan		PGA&E		Idaho	
	Pre-Update	Post-Update	Pre-Update	Post-Update	Pre-Update	Post-Update
January	$5.4	$4.3	$6.3	$5.3	$4.3	$3.3
February	$5.1	$4.0	$6.3	$5.2	$4.6	$3.5
March	$4.4	$2.8	$5.6	$3.9	$4.0	$2.4
April	$3.0	$1.5	$4.3	$2.8	$2.7	$1.2
May	$3.0	$1.8	$4.3	$3.1	$2.7	$1.5
June	$3.2	$2.0	$4.4	$3.2	$2.8	$1.6
July	$3.4	$2.6	$4.5	$3.8	$2.9	$2.1
August	$3.5	$2.7	$4.6	$3.8	$2.8	$2.0
September	$3.5	$2.6	$4.7	$3.9	$2.8	$2.0
October	$3.5	$2.6	$4.8	$4.0	$2.9	$2.1
November	$4.3	$3.0	$5.6	$4.3	$3.7	$2.4
December	$4.7	$4.0	$5.6	$4.9	$4.0	$3.3
Average	**$3.9**	**$2.8**	**$5.1**	**$4.0**	**$3.4**	**$2.3**

California-Wide Day-Ahead Market Expansion Benefits

The EDAM yields $244-$897 million per year in benefits to California customers relative to Status Quo in the low natural gas price sensitivity cases

- **Across all cases the sensitivity results show similar benefits to California in percentage terms to the original cases**
  - California benefits range from 6 – 22% of the Status Quo cost in the original cases vs. 6 – 20% in the low natural gas price sensitivity
- **The benefits of the EDAM have the same drivers in the sensitivity cases:**
  - **Adjusted production cost benefits** to California in the Expanded EDAM case (*compared to Status Quo*) go from $1,028 million in the original cases to $1,026 million in the sensitivity and are also about the same in the Split Market case
  - **Wheeling revenues decline** about the same as well, falling $203 million in Expanded EDAM in the original cases and $197 million in the Expanded EDAM low gas price sensitivity
  - **Total trading revenues increases are lower in the market cases due to lower prices across the model** with EDAM revenues only increasing $380 million in Expanded EDAM compared to Status Quo in the sensitivity, compared to a $538 million increase in the original cases

Summary of California-Wide System Costs & Revenues by Case ($ Million per year)

	Status Quo	Baseline	Baseline+	Expanded EDAM	Split Market
Adjusted Production Cost	$5,128	$4,797	$4,494	$4,103	$4,289
Production Cost	*$1,946*	*$1,499*	*$1,238*	*$1,110*	*$1,193*
Purchases Cost	*$2,711*	*$3,226*	*$3,312*	*$3,299*	*$3,205*
Sales Revenue (subtracted from costs)	*-$472*	*-$72*	*$56*	*$306*	*$109*
Short-Term Wheeling Revenues	$221	$216	$107	$24	$81
Bilateral Trading Revenues	$436	$178	$133	$19	$86
WEIM Congestion Revenues	$54	$62	$69	$48	$35
EDAM Congestion and Transfer Revenues	$0	$167	$167	$380	$262
EDAM Transfer Revenue	*$0*	*$95*	*$88*	*$148*	*$111*
EDAM Congestion Revenue	*$0*	*$71*	*$79*	*$232*	*$151*
Net TRR Settlement	$0	$0	$6	$112	$6
Total System Production Cost and Market Revenues	**$4,418**	**$4,173**	**$4,012**	**$3,521**	**$3,819**
Benefit Relative to Status Quo		***$244***	***$405***	***$897***	***$599***
Benefit % of Status Quo Production Cost and Market Revenues		***6%***	***9%***	***20%***	***14%***
Benefit Relative to Baseline			***$161***	***$653***	***$354***
Benefit % of Baseline Production Cost and Market Revenues			***4%***	***16%***	***8%***
Benefit Relative to Baseline+				***$492***	***$194***
Benefit % of Baseline+ Production Cost and Market Revenues				***12%***	***5%***

Note: Bilateral trading revenues refers to short-term bilateral trading of energy.
The Net TRR settlement was not adjusted for the Low Natural Gas Price Sensitivity, as we did not run a Baseline case with a more limited EDAM footprint to compare to.

Appendix B: Modeling Assumptions and Detailed Results from January 24th 2025 Workshop Slides

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 a dozen 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 for their systems, including transmission rights & costs, load forecasts, fuel prices, generation mix & 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 the CA system**, including input from CAISO 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

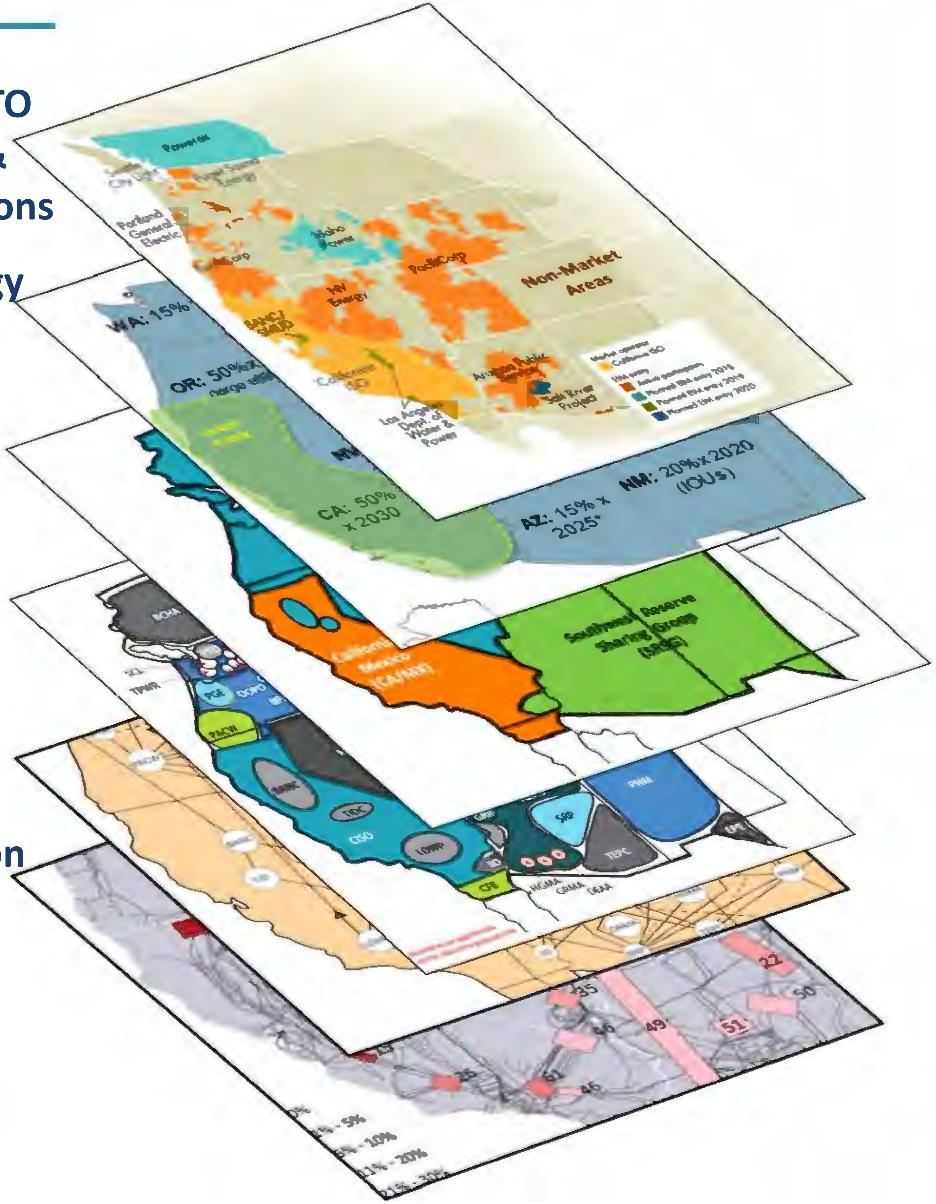
4 This Study

CEC Pathways Study

We leveraged our work and modeling enhancements from all prior studies to assess the value of a nearly-WECC-wide day-ahead market (i.e., an EDAM with a large footprint) compared to an outcome with two competing day-ahead markets in the WECC (i.e., split between EDAM and Markets+).

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

Key Model Features

We conduct 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
- **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

California-Wide Day-Ahead Market Expansion Benefits

California benefits from day-ahead market expansion under all four scenarios, but the incremental benefits of a nearly WECC-wide EDAM are ~3x those of a Split Market scenario

- **Under our Expanded EDAM scenario, California benefits from the wider market footprint to expand trading and reduce internal generation, resulting in $678 million lower net total system costs compared to the Baseline+ case:**
  - **Adjusted production cost savings of $366 million** from 3,200 GWh of reduced gas generation, lower purchase costs, and increased sales prices
  - **Total trading and congestion revenues increase $182 million**
  - **Short-term wheeling revenues decline of $82 million** as almost all of California's trading partners join EDAM
- **Under our Split Market scenario, California similarly reduces internal generation and increases trading, but to a lesser extent, resulting in $182 million in lower net total system costs compared to the Baseline+ case:**
  - **Adjusted production cost savings of $200 million** from 1,200 GWh of reduced gas generation and slightly increased average sales prices
  - **Relatively static trading gains and congestion revenues** as trading modestly shifts between bilateral and EDAM trading.
  - **Short-term wheeling revenues decline $23 million** as some bilateral trading dries up with the creation of Markets+

Summary of California-Wide System Costs & Revenues by Case ($ Million per year)

	Baseline	Baseline+	Expanded EDAM	Split Market
Adjusted Production Cost	$5,172	$4,952	$4,585	$4,752
Production Cost	*$1,744*	*$1,440*	*$1,258*	*$1,370*
Purchases Cost	*$3,674*	*$3,907*	*$3,968*	*$3,805*
Sales Revenue (subtracted from costs)	*$246*	*$395*	*$640*	*$423*
Short-Term Wheeling Revenues	$227	$108	$25	$84
Bilateral Trading Revenues	$199	$157	$23	$106
EIM Trading Revenues	$66	$73	$55	$42
EDAM Trading Revenues	$170	$204	$538	$292
EDAM Transfer Revenue	*$85*	*$105*	*$255*	*$112*
EDAM Congestion Revenue	*$84*	*$99*	*$283*	*$179*
Net TRR Settlement	$0	$6	$112	$6
Total System Cost	**$4,511**	**$4,399**	**$3,721**	**$4,217**
Benefit Relative to Baseline		**$112**	**$790**	**$294**
Benefit % of Baseline System Cost		***2%***	***18%***	***7%***
Benefit Relative to Baseline+			**$678**	**$182**
Benefit % of Baseline+ System Cost			***15%***	***4%***

Note: Bilateral trading revenues refers to short-term bilateral trading of energy.

Interpretation of Benefits in CAISO

Non-vertically integrated regions, such as CAISO, may have a more complex accounting of benefits to identify the portion of benefits that flows back to customers

Metric	
Adjusted Production Cost (APC)	We anticipate the large majority of APC benefits would flow to customers: • Flow through provisions in PPAs would see benefits passed through to customers. • Over the longer-term this could happen through the renegotiation of PPAs. • Reduced curtailments will impact future renewable PPAs. • Our study does not estimate any feedback effects this may have on RA prices.
Short-term wheeling revenue	Most of the impact flows through to customers, since changes in these revenues will impact transmission access charges.
Market congestion revenues	A large share of benefit flow to customers: • EDAM Transfer Revenues are allocated to measured demand, which is mostly load. • EDAM Congestion Revenues are placed in the CRR Balancing Account. The portion that flows to customers will depend on the efficiency of CRR auctions.
Bilateral trading revenues	Customers would benefit from revenues on trades executed by load-serving entities, but potentially not from those executed by third-parties or generators.
Emissions	Emissions reductions generally benefit all CA residents, but there may be distributional impacts depending on the geography of emitting generation changes.
Supply cushion	Reliability benefits flows to customers and CA residents.

California Adjusted Production Cost in the EDAM Case

California's APCs fall $366 million per year in the EDAM case, driven by:

- **(1) $182 million/yr reduction in production costs** as California generation declines on the net by ~1,700 GWh (~3,200 GWh lower gas generation offset by ~1,500 GWh more renewables and other generation)
- **(2) $61 million/yr increase in purchase costs** as California purchases about 4,000 GWh more in the day-ahead to substitute for lower internal gas generation, offset by lower real-time purchases
- **(3) $245 million/yr increase in sales revenue** as California sells about 2,500 GWh more in the day-ahead and does so at an average price about $2.5/MWh higher than in Baseline+

California-Wide Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	
Production Cost	(+)	[1]	344,267	342,584	**-1,683**	$4.18	$3.67	**-$0.51**	1,439,851	1,257,800	**-$182,051**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	66,003	69,998	**3,995**	$53.81	$52.15	**-$1.66**	3,551,652	3,650,703	**$99,051**	**(2)**
Real-Time Market		[5]	9,085	8,472	**-613**	$39.08	$37.43	**-$1.65**	355,030	317,101	**-$37,928**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	80,650	83,113	**2,463**	$2.26	$4.82	**$2.56**	182,145	400,738	**$218,593**	**(3)**
Real-Time Market		[8]	9,867	9,104	**-763**	$21.57	$26.33	**$4.76**	212,791	239,689	**$26,898**	
***Total Cost** (Negative Difference = Benefit)*		[9]	**328,837**	**328,837**	**0**	**$15.06**	**$13.94**	**-$1.11**	4,951,597	4,585,177	**-$366,419**	
% Change in APC											***-7.4%***	

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.

California Adjusted Production Cost in the Split Market Case

California's APCs fall $200 million per year in the Split Market case, driven by:

- **(1) $70 million/yr reduction in production cost** as California gas generation falls ~1,200 GWh (non-gas generation falls also, with renewable curtailments increasing ~200 GWh)
- **(2) $100 million/yr reduction in purchase costs** despite modestly higher overall purchase volumes due to lower purchase prices in day ahead and lower real-time purchases and prices
- **(3) $28 million/yr in increased sales revenue** due to higher day-ahead sales prices and higher real-time sales prices offsetting lower real-time volumes, drive in part by the breakup of the WEIM

California Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	
Production Cost	(+)	[1]	344,267	342,887	**-1,379**	$4.18	$4.00	**-$0.19**	1,439,851	1,370,114	**-$69,737**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	66,003	67,264	**1,261**	$53.81	$52.02	**-$1.79**	3,551,652	3,499,355	**-$52,297**	**(2)**
Real-Time Market		[5]	9,085	7,984	**-1,100**	$39.08	$38.29	**-$0.79**	355,030	305,747	**-$49,283**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	80,650	80,751	**100**	$2.26	$2.67	**$0.41**	182,145	215,481	**$33,336**	**(3)**
Real-Time Market		[8]	9,867	8,549	**-1,319**	$21.57	$24.29	**$2.72**	212,791	207,646	**-$5,145**	
Total Cost *(Negative Difference = Benefit)*		[9]	**328,837**	**328,837**	**0**	**$15.06**	**$14.45**	**-$0.61**	4,951,597	4,752,089	**-$199,507**	
% Change in APC											***-4.0%***	

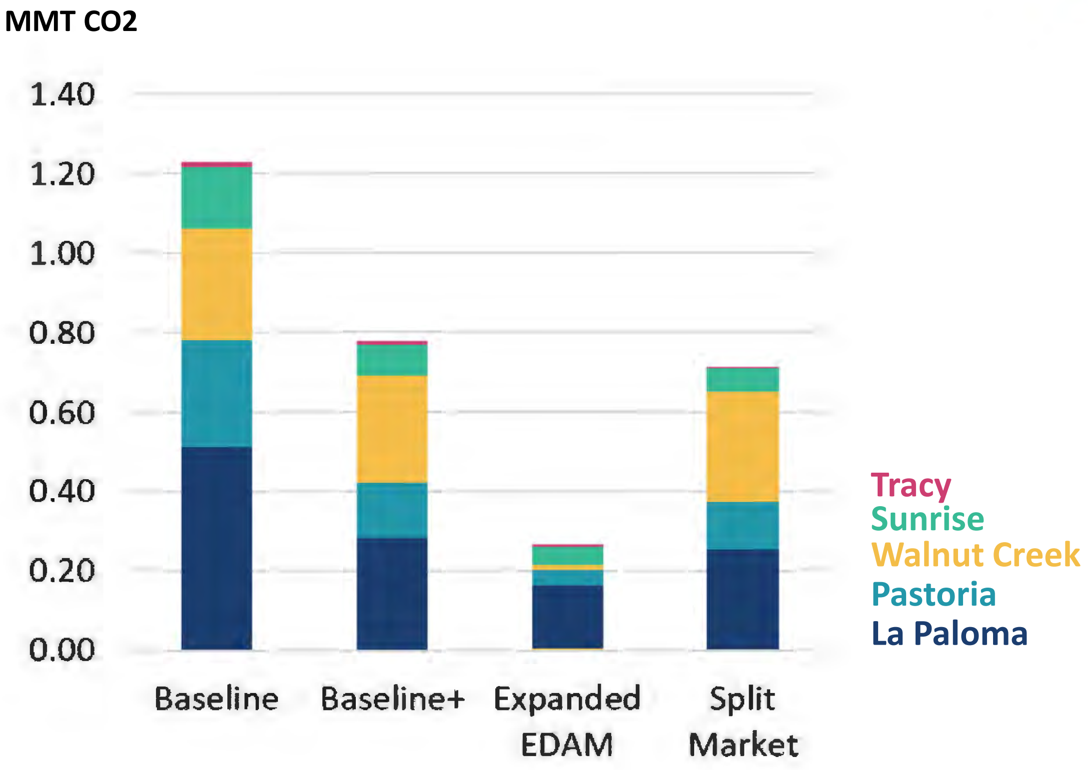
Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.

Gas Generation in California

In the Expanded EDAM case, gas generation in California declines by 31% relative to the Baseline+ Case.

- Emissions from some of the larger gas plants in California fall across the board, but dramatically more in the Expanded EDAM case.
- The decline in gas generation in the Expanded EDAM case is broadly consistent across all areas of California.

Select Plant-Specific CO_2 Emissions by Case

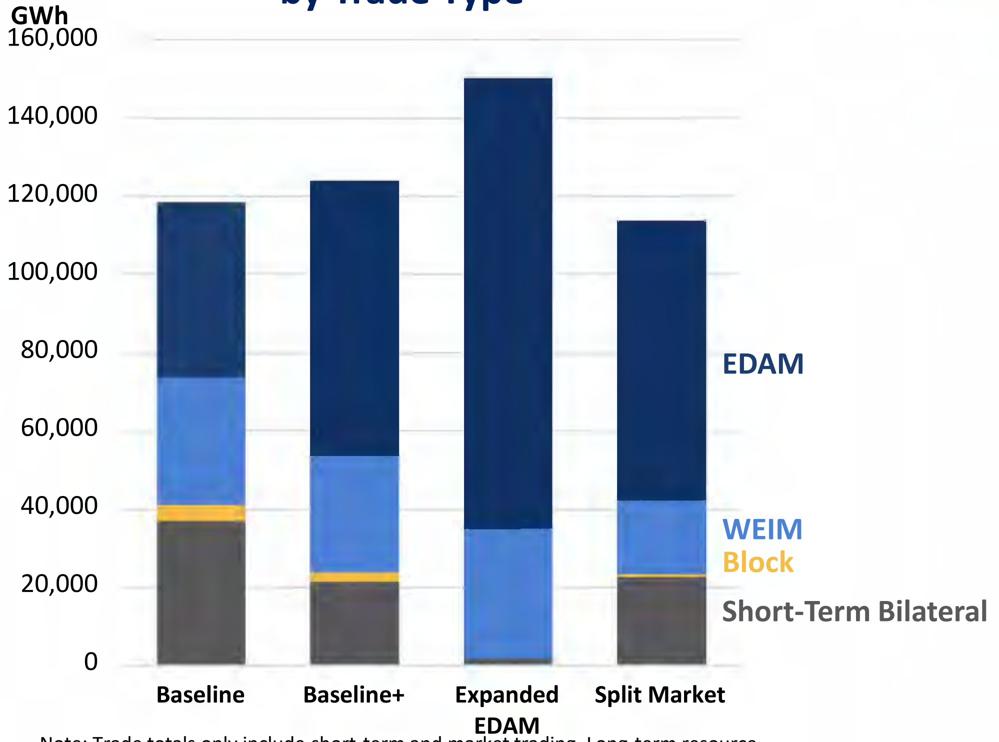


California Trading Volume by Case

California trade volumes are highest in the Expanded EDAM case, driven by increased opportunity in the broader market footprint

- **Total trade volumes increase 26 GWh (21%) for California from Baseline+ to the Expanded EDAM case**
- **Market transactions (EDAM + WEIM) make up 81% of all California trading in Baseline+ and 99% in the Expanded EDAM case**
  - Remaining bilateral transactions are with CFE in Mexico
  - Baseline market transactions are 65% of California trades
  - Split market case market transactions are 79% of California trade, as some seam trading returns with the PNW and Desert SW
- **From Baseline+ to the Expanded EDAM case, California is mainly increasing trading with the Desert Southwest and Pacific Northwest**

Total California Trading by Trade Type

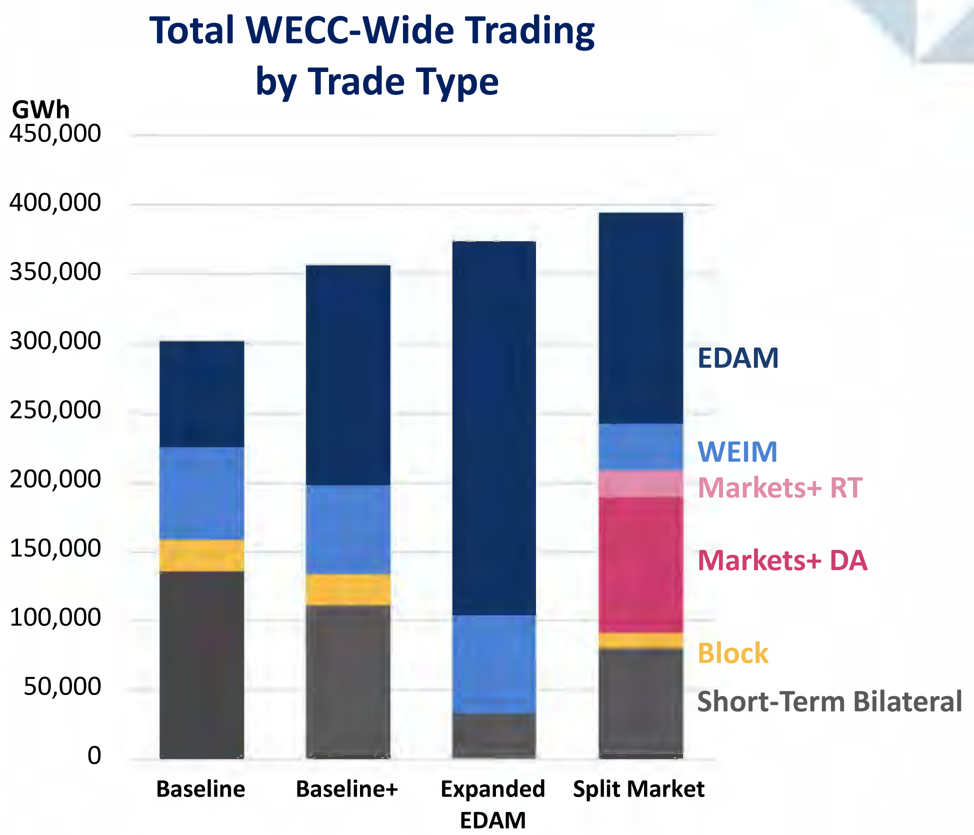


Note: Trade totals only include short-term and market trading. Long-term resource contracts are not included in these totals. Short-term bilateral trades include EDAM-Markets+ seam trades.

WECC-Wide Trading Volume by Case

WECC-wide trade volumes are highest in the Split Market case, due in part to transfers between the PNW and SW portions of Markets+

- **Markets+ transactions between the Southwest and PNW require trading across several entities compared to more direct connections in a WECC-wide market like the Expanded EDAM case**
  - For example, a trade from AZPS to BPAT in the Markets+ footprint requires power transacting several times across the M+ and RTO West entities in the Rocky Mountains
  - In the Expanded EDAM case, AZPS could trade more directly via Nevada or California into the PNW
- **Market transactions (EDAM or Markets+) are the highest share of trades in the Expanded EDAM case (93% of all WECC trading vs. 77% in the Split Market case)**
  - Remaining hourly and block trades between the markets (i.e., seam transactions) account for the majority of non-market trades

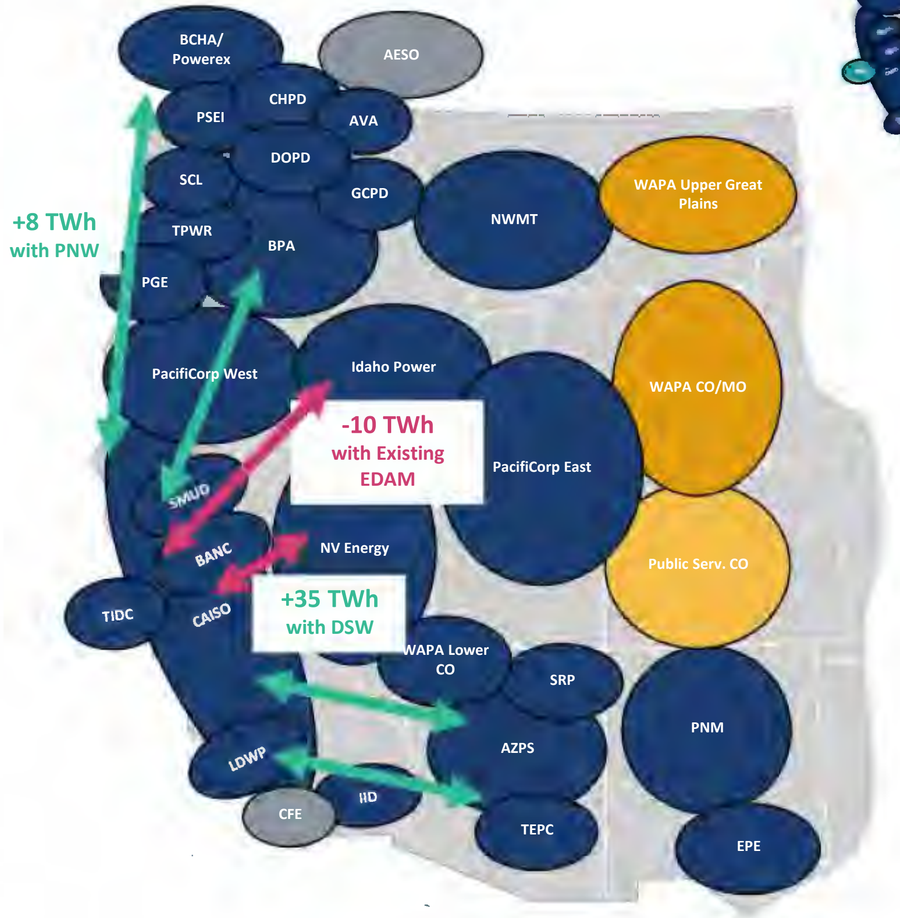


Note: Trade totals only include short-term and market trading. Long-term resource contracts are not included in these totals. Short-term bilateral trades include EDAM-Markets+ seam trades.

California Trading Changes: Baseline+ to Expanded EDAM

In the Expanded EDAM case, California trading increases with the new EDAM participants in the Desert Southwest and Pacific Northwest

- Hydro entities in the Pacific Northwest export 7 TWh more to California, mostly in the morning and evening
- California exports 20 TWh more to the Desert Southwest and imports 15 TWh more, exchanging renewables and efficient gas
- Trading with existing EDAM entities in the center of the WECC declines about 10 TWh
  - Idaho Power, NV Energy, and PacifiCorp increase direct trades with entities in the Pacific Northwest, Rocky Mountains, and Desert Southwest at the same time trades decease with California



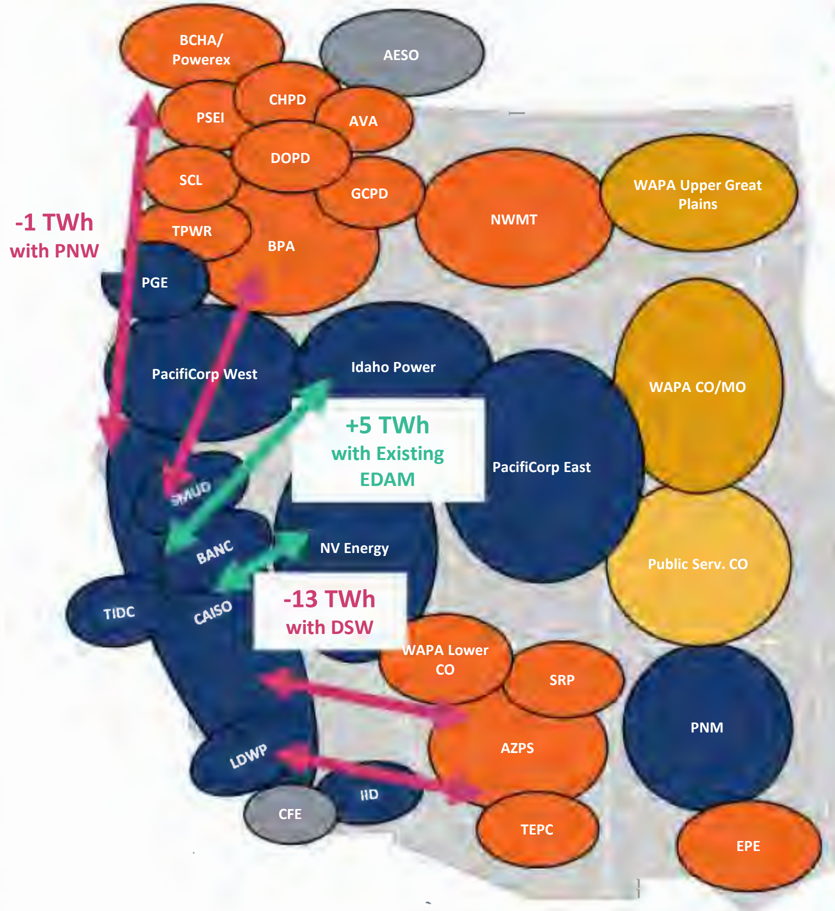
California Trading Changes: Baseline+ to Split Market

In the Split Market case, California trading increases with existing EDAM members, but falls with the Pacific Northwest and Southwest as those regions shift to trading within the Markets+ footprint

- Hydro entities in the Pacific Northwest export about the same to California, but California exports about 1.5 TWh less to the PNW
- California exports 6 TWh less to the Desert Southwest and imports 7 TWh less, reducing trading in both directions
- Trading with existing EDAM entities in the center of the WECC increases about 5 TWh
- Trading between EDAM entities within California also increases about 3 TWh

Split Market Case

(Likely EDAM Entities w/ Markets+)



Baseline+

Appendix C:
Description of 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 cases 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")

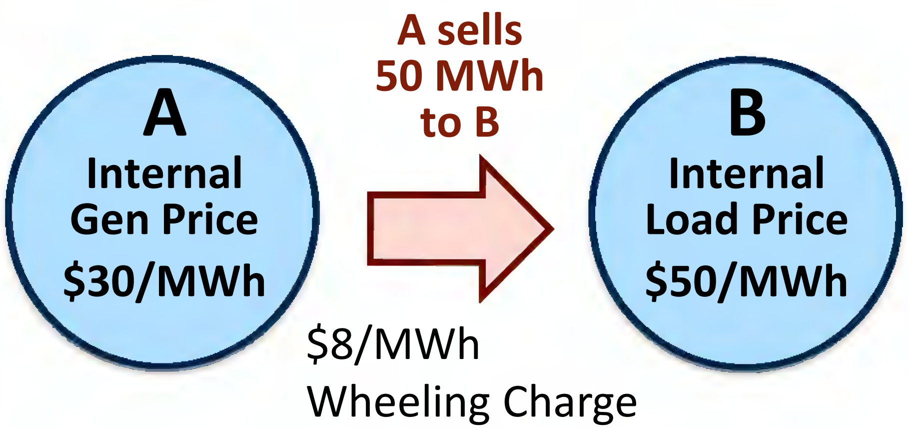
(−) Revenues from bilateral and market sales valued at the BAA's generation-weighted energy price ("Gen LMP")

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:

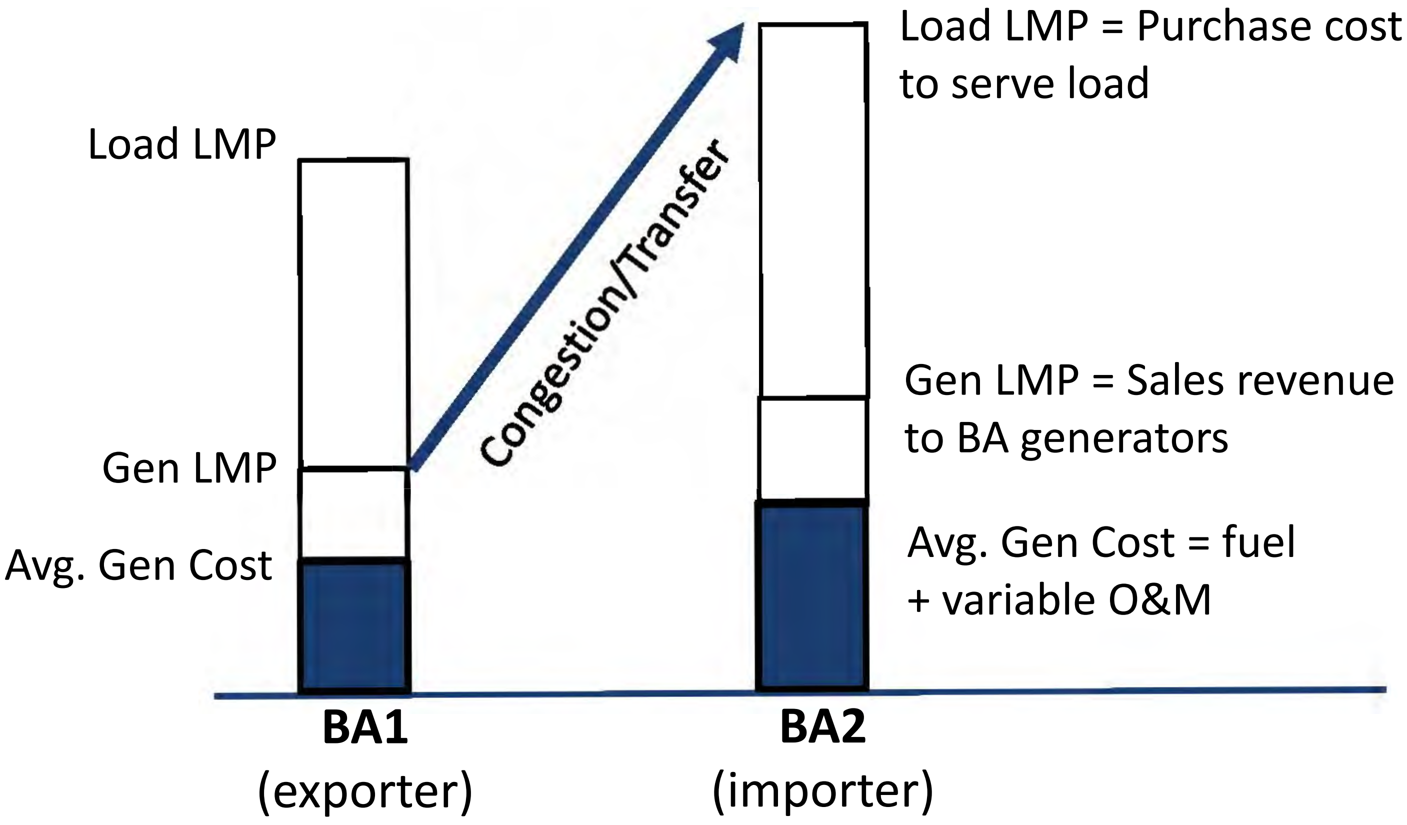
- A receives $30×50MWh=$1,500 in APC sales revenues
- B pays $50×50MWh=$2,500 in APC purchase costs

➔ $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

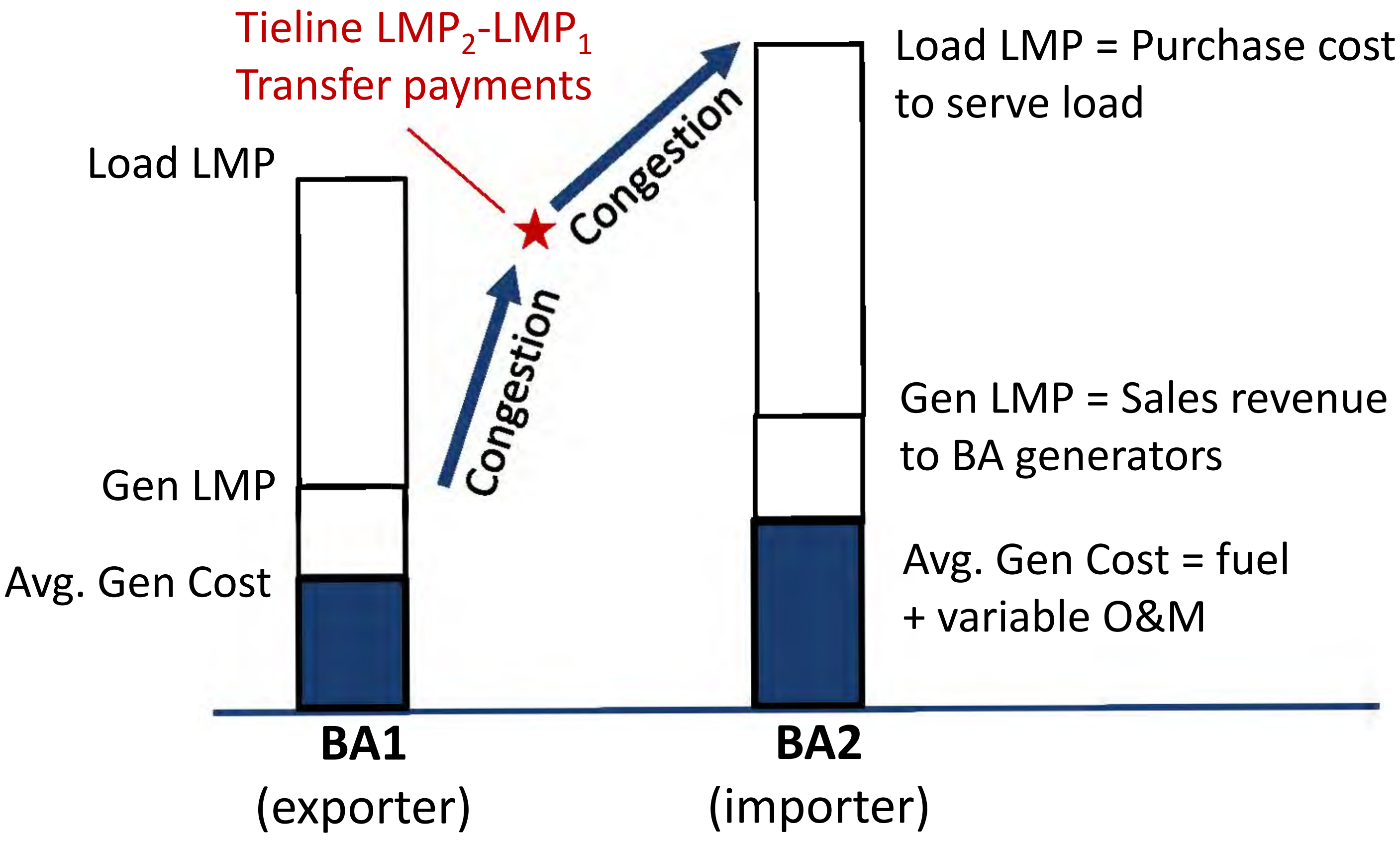
Illustration of Markets+ Congestion Revenues



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



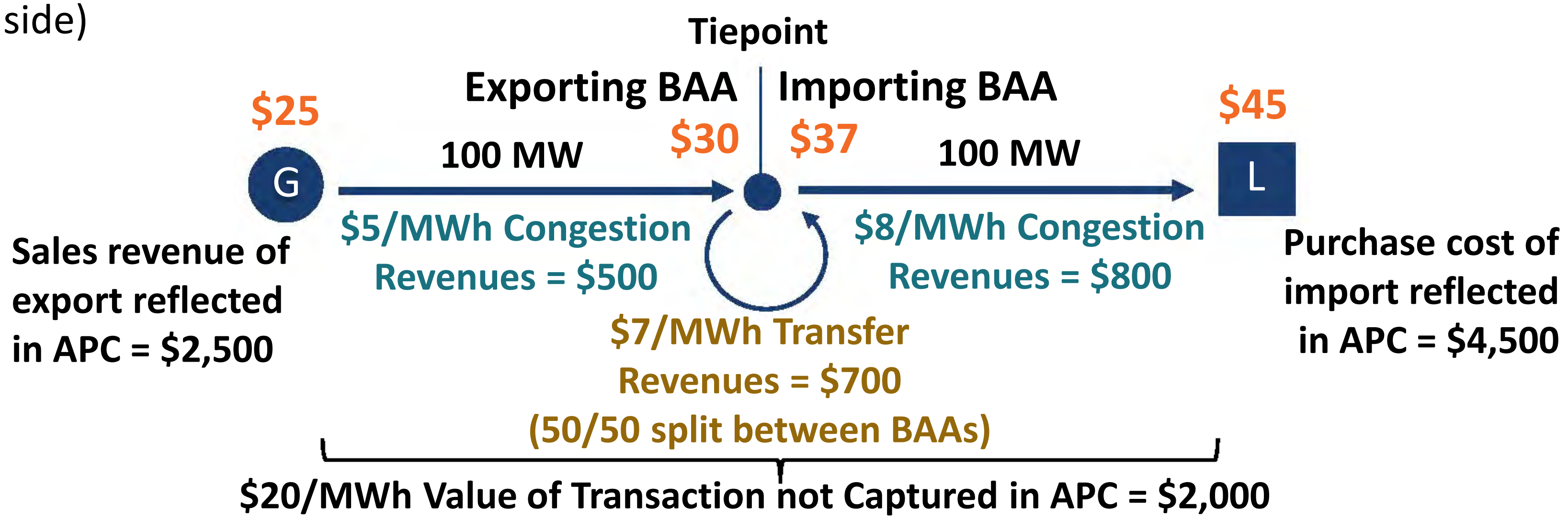
EDAM congestion and transfer revenues estimated based on individual tieline LMPs:

- **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 D:
Overview of Power System Optimizer (PSO)

Key Modeling Assumption Sources

Modeling assumptions based on public sources and refined with input from study participants

Assumption Category	California	Rest of WECC
Resource Mix	• CAISO resource mix assumptions reflect the 2023-2024 CAISO TPP portfolio • LADWP and BANC/SMUD provided resource mix assumptions directly during the 2022	• Participant updates for El Paso Electric, Idaho Power, NV Energy, Portland General Electric, PacifiCorp, Public Service Company of New Mexico • Recent IRP updates for Arizona Public Service, Tucson Electric Power, Avista, and Puget Sound Energy
Load	• CAISO load assumptions are based on the 2022 IEPR mid baseline load forecast • LADWP and BANC/SMUD provided resource mix assumptions	
GHG Prices	• GHG prices are based on the CEC's 2022 mid case, with the modeled CA & WA price in 2032 at ~$64/metric ton • We assume the WA and CA carbon markets are linked by 2032	
Natural Gas Prices	• Gas prices were provided by the study participants in prior iterations of EDAM/Markets+ studies.	
Transmission	• Participant updates for specific projects, and addition of interregional projects anticipated to be online by 2032, including SunZia, SWIP-N, TransWest Express, Cross-Tie, Greenlink North & West, B2H, Gateway Projects • Enforced physical limits include WECC-rated paths and specific constraints identified by paritcipants • Contract path limits based on public data and participant input and enforced for all BA-to-BA connections	

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

ENELYTIX®
powered by PSO

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	**Day-Ahead Market**	**Intra-Day Markets**	**EIM (RT Balancing)**
• DA block trades on long-term transmission rights and incremental transmission	• CAISO, EDAM, and RTO market clearing • Hourly intertie trading • Hourly trading with long-term transmission rights	• Hourly bilateral trades on remaining transmission	• 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.

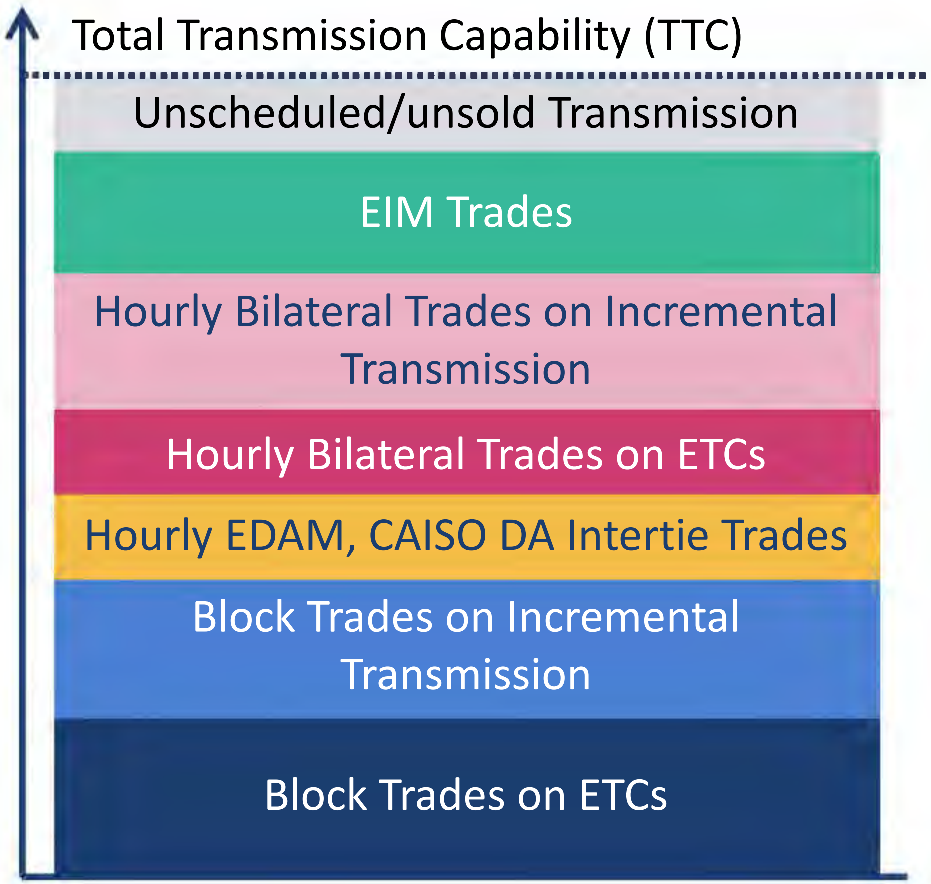
These cycles can take on different assumptions, depending on market structure. In a bilateral setting, all are set up to analyze utility-specific unit commitment and dispatch decisions, with each of them including hurdle rates and transmission fees that limit the amount of economic transactions that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

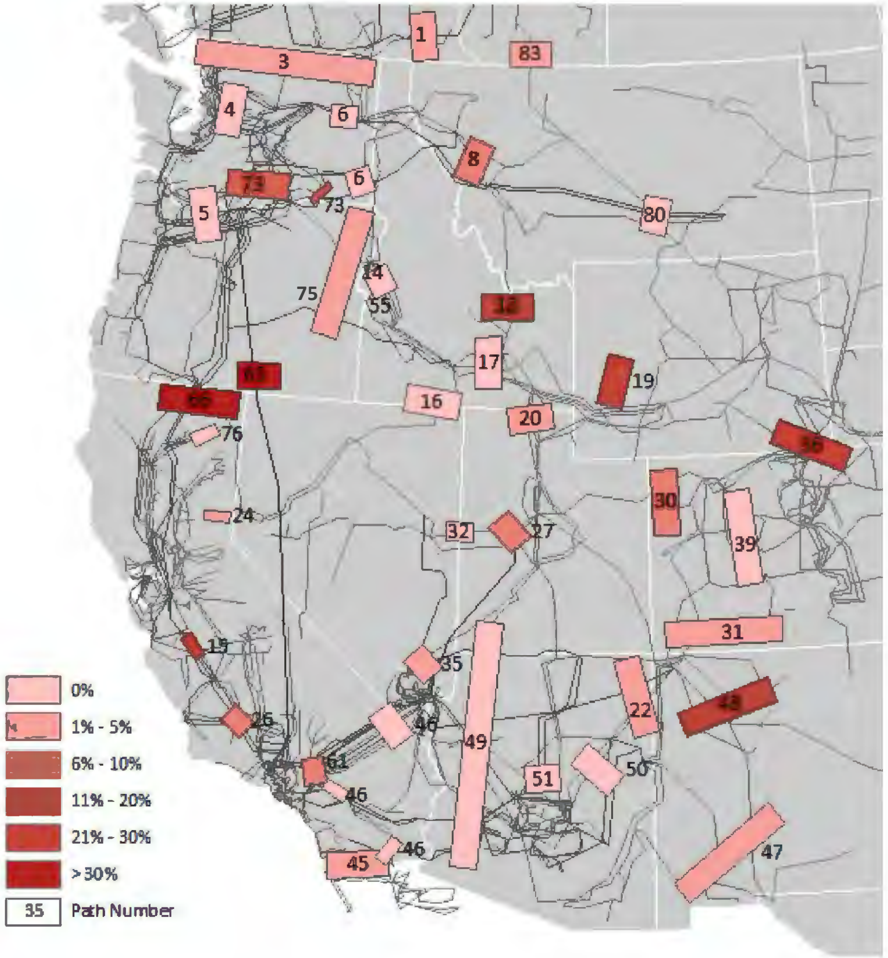
- Existing long-term transmission contracts (ETCs) and incrementally purchased transmission
- Total reservations on each contract path is limited by the total transfer capability (TTC)
- Trades are structured as blocks or hourly
- Bilateral trades between BAAs, at major hubs, or across CAISO interties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

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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.