Western market regionalization: APS Day-Ahead market benefits analysis

Full report

Environmental Defense Fund

October 14th, 2025

Agenda

Executive Summary

- This study aims to quantify the potential impacts on costs, generation mix, and emissions for the Arizona Public Service (APS) balancing authority (BA) under the following Western US market regionalization scenarios (1) APS participation in Markets+, (2) APS participation in EDAM, (3) APS, TEP, SRP, and WALC participation in EDAM (AZ EDAM incl. WALC), and (4) APS, TEP, and SRP participation in EDAM while WALC remains uncommitted (AZ EDAM, excl. WALC)
- The analysis employs Production Cost Modeling across the WECC balancing authorities to compare the market outcomes driven by APS's DAM choice. Modeling inputs at the BA level such as capacity mix and load growth follow proposed Integrated Resource Plans and remain constant across scenarios. DAM choice by BA is modeled based on announced commitments or intentions and is constant across scenarios for all BAs except when explicitly adjusted
- This study finds that APS's participation decision has the following impacts:
  - APS balancing authority can save **an average of $109.9 million/year from participation in EDAM over Markets+**, enabled/mitigated by:
    - **Higher production costs** from increased thermal generation to offset for decreased thermal imports from SRP
    - **Lower bilateral trading costs** from decreased overall import volumes and access to increased renewables from the wider EDAM footprint
    - **Higher congestion and wheeling revenue** due to higher utilization of transmission capacity from trade with PNM and PACE
  - In the AZ EDAM incl. WALC scenario, while APS sees higher system costs relative to the APS EDAM configuration, a larger EDAM footprint enables Arizona-wide BAs savings of $91 million/year on average
- **Conclusion:** This study finds that APS sees largest cost savings from participation in EDAM as compared to participation in Markets+, under the specific capacity mix, load, DAM configuration, and transmission capacity assumed for the scenarios modeled in this analysis

Sources: Aurora Energy Research

Average annual costs for APS are reduced by an average of $109.9 million/year when participating in EDAM as opposed to Markets+

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This analysis aims to identify the potential benefits or costs for Arizona Public Service (APS) under two Western US market regionalization scenarios: (1) APS participates in EDAM and (2) APS participates in Markets+, with all else remaining equal. Comparisons between scenarios include those of various cost categories, generation mix, and emissions outputs.

Average annual cost breakdown for APS EDAM vs APS Markets+, 2027-2040
$Million/year, real 2024

Metric	Day-Ahead Market cases		Average delta, EDAM – Markets+[1]
	APS EDAM	APS Markets+	
Production cost	1,110.7	1,101.4	9.3
Bilateral trading costs	356.6	427.5	(70.9)
Congestion revenue[2]	(100.0)	(52.2)	(47.8)
Wheeling revenue[2]	(13.9)	(13.5)	(0.5)
Annual average costs[3] (APS)	**1,353.5**	**1,463.3**	**(109.9)**

- APS sees an average $109.9mil/year benefit in total costs when participating in EDAM vs. Markets+
- **Production costs** - When in EDAM, reduced thermal imports from SRP drives greater peaking generation and production costs as a result
- **Bilateral trading costs** - A larger trading footprint under EDAM enables APS access to import more renewable generation and export more, driving its reduced bilateral trading cost compared to the Markets+ configuration
- **Congestion and wheeling revenue** – Under the EDAM scenario APS sees higher utilization of its transmission interconnection to facilitate trades, particularly with PNM and PACE[2]

1) A negative delta indicates lower costs when APS is modeled in EDAM compared to Markets+, demonstrating benefits to joining EDAM 2) Ownership assumed to be split 50-50 with connecting BA unless data on ownership is available. 3) Average annual costs after revenues.
Sources: Aurora Energy Research

The composition of each offering in the West is modeled based on confirmed and assumed commitments by balancing authority

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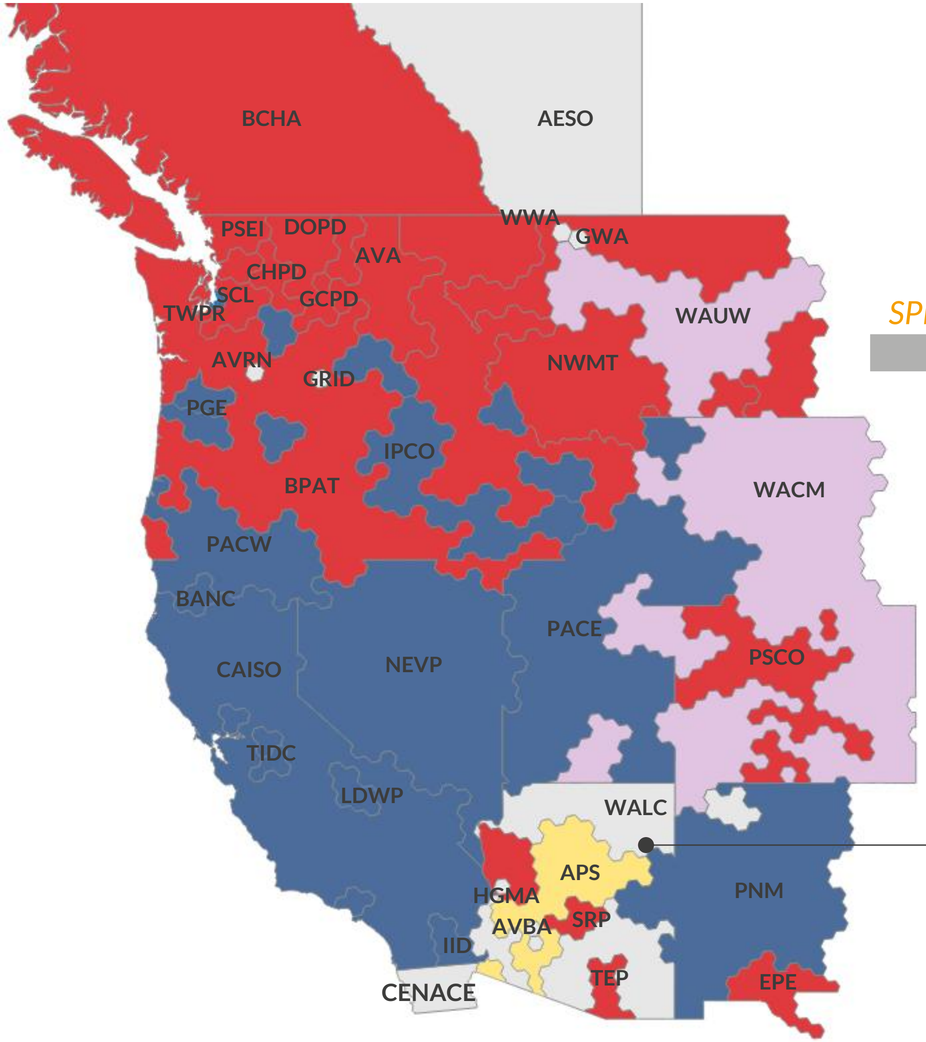
Map of modeled balancing authority (BA) market decisions



SPP continues to the east

Key[1,2]

- BA of focus (APS)
- Modeled in Markets+
- Modeled in EDAM
- Modeled in RTO West
- Modeled as Uncommitted

The Day-Ahead Market (DAM) commitment for APS was modeled under 2 scenarios to determine the comparative regionalization benefits:

1. APS participation in EDAM
2. APS participation in Markets+

1) BAs with announced commitments are modeled as participating in the respective offering. BAs that are undecided or have no public leaning are modeled as uncommitted and therefore do not participate in any offering 2) Some BAs are modeled to join a market after the initial markets go live. All DAM positions are finalized by 2030.

Sources: Aurora Energy Research, CAISO, SPP

Aurora modeled APS's capacity mix following APS's 2023 IRP Preferred Portfolio through to 2038

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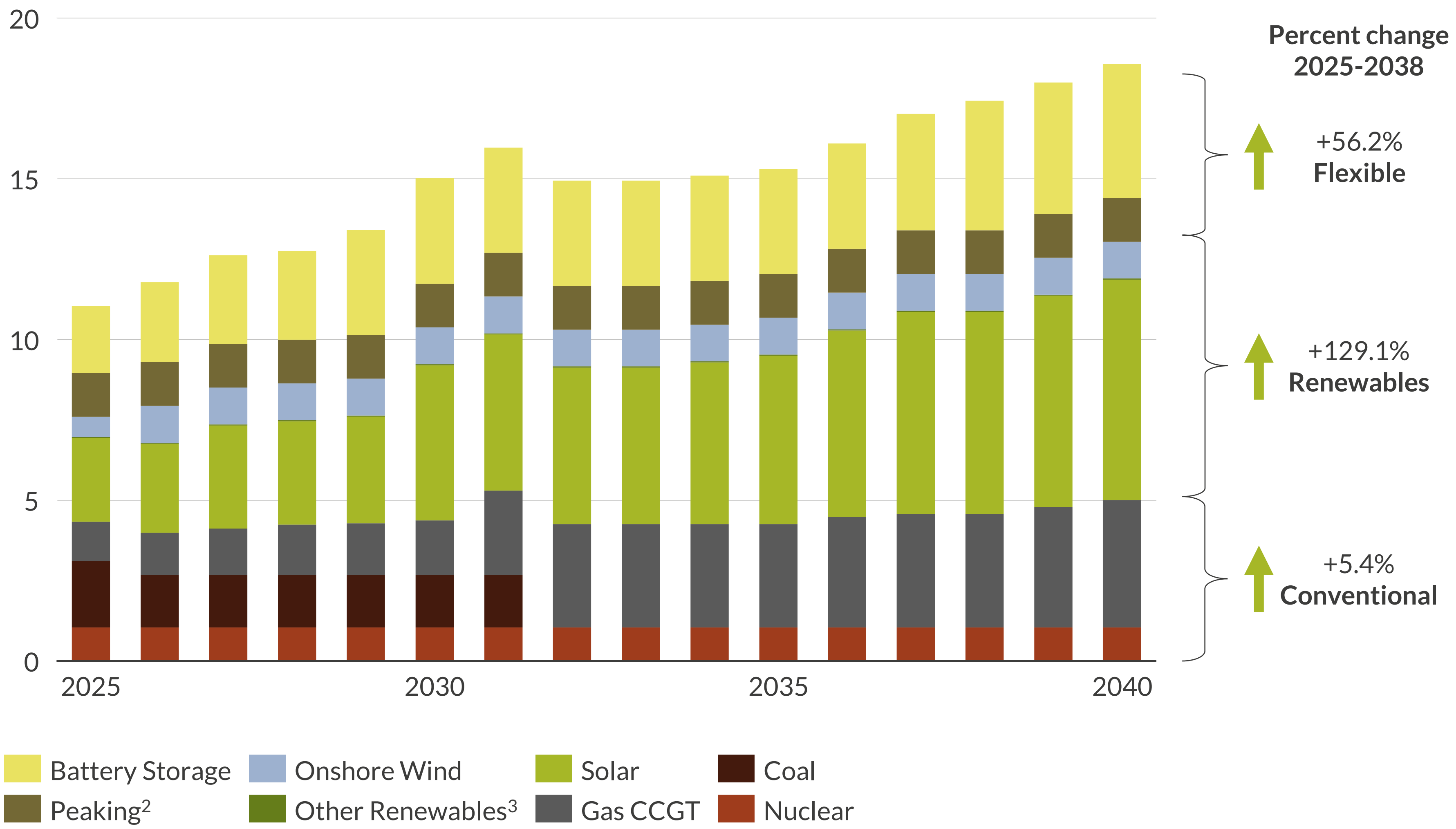
Installed capacity in APS[1]
GW



1) Capacity additions after 2038 use extrapolated growth rates during the IRP period. 2) Peaking includes OCGT, reciprocating engines. 3) Other Renewables includes biomass and geothermal.

Sources: Aurora Energy Research, APS

- Aurora modeled APS installed capacity based on existing installed capacity owned and contracted, with capacity growth through to 2038 following the APS Integrated Resource Plan (IRP) released in 2023
- Resource additions as detailed in the 2023 IRP are driven by thermal retirements, load growth, and voluntary clean energy goals for 100% carbon-free electricity by 2050
- The last coal plant in APS, Four Corners Steam Plant, is expected to retire in 2031, removing 1.6GW of baseload conventional capacity from the system

APS demand forecast is modeled to follow the IRP growth rates through 2038

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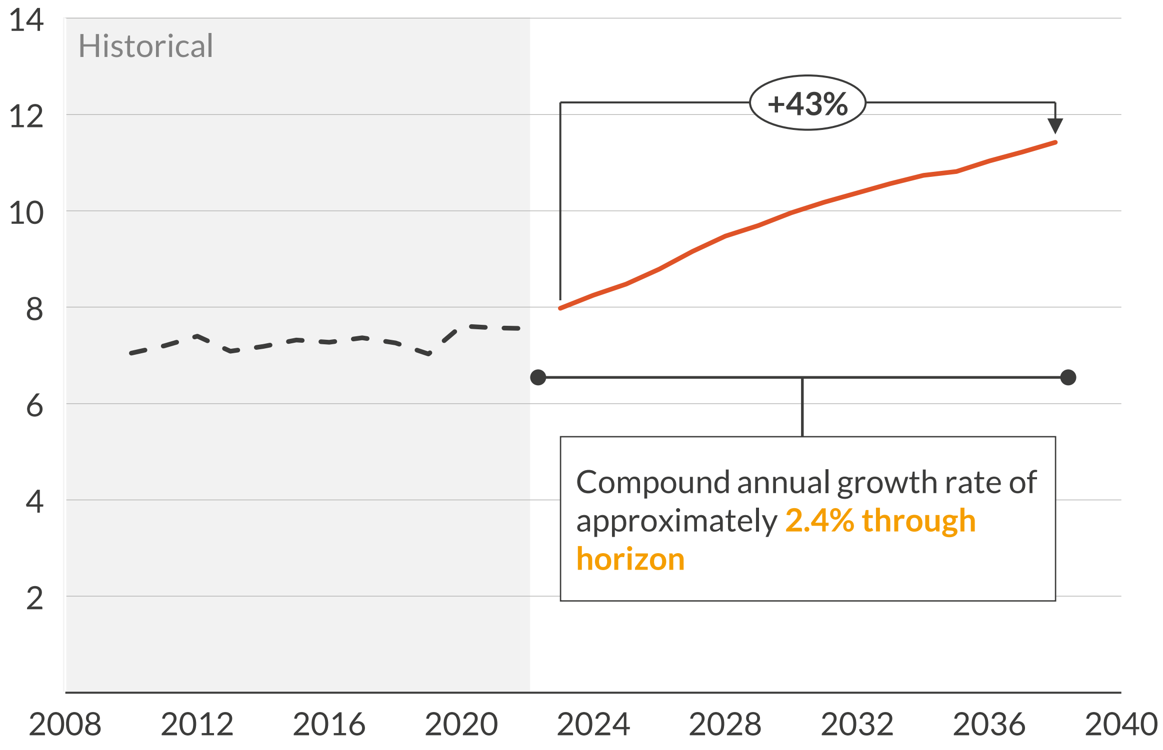
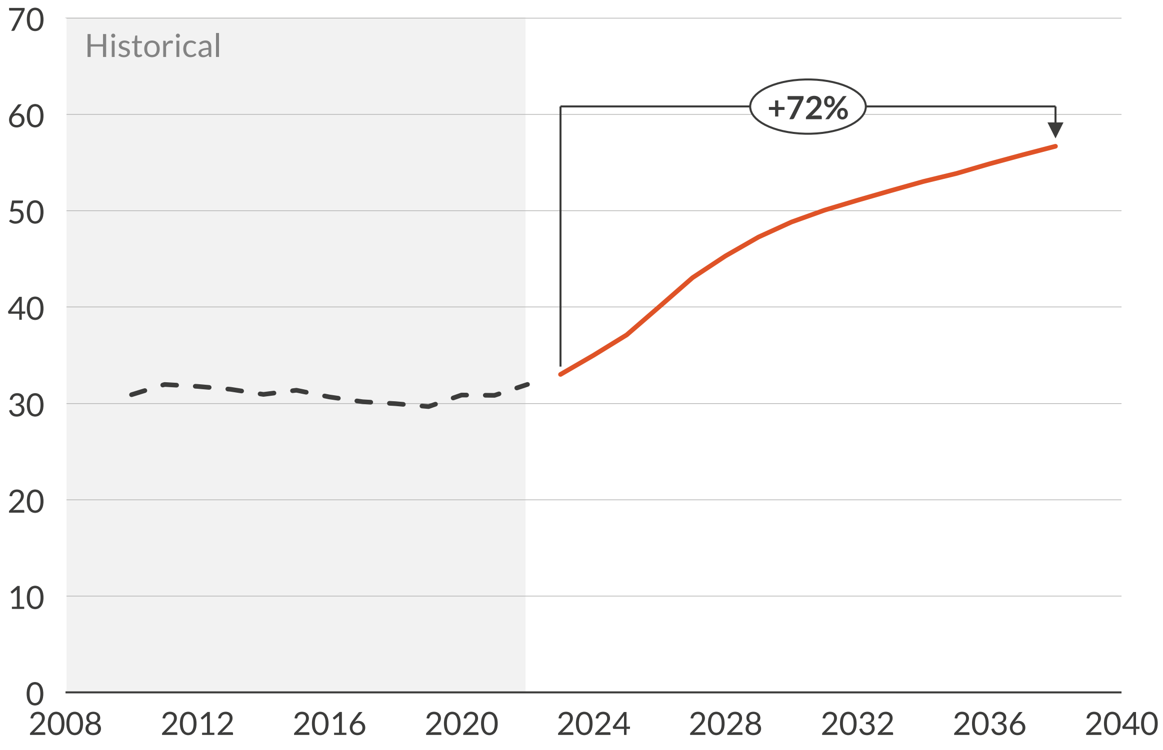
APS coincidental peak demand[1,2]
GW



APS annual system load[1,2]
TWh



- APS has significantly increased its peak and annual load forecasts in the latest IRP in response to increased data center and large industrial and manufacturing customer demand

- Electric vehicle adoption is also expected to drive load growth as APS forecasts the addition of over 1 million EVs during the planning period
- Total annual system load in 2030 increased by 21% between the 2020 and 2023 IRPs

Historical — 2023 IRP

1) Peak demand and forecasted annual system load is at generation, post-demand side management. 2) Historical peak demand and annual load data is net demand.

Sources: Aurora Energy Research, APS, WECC

Aurora models transfer limits between regions based on historical recorded interchanges when modeling the Western Interconnection

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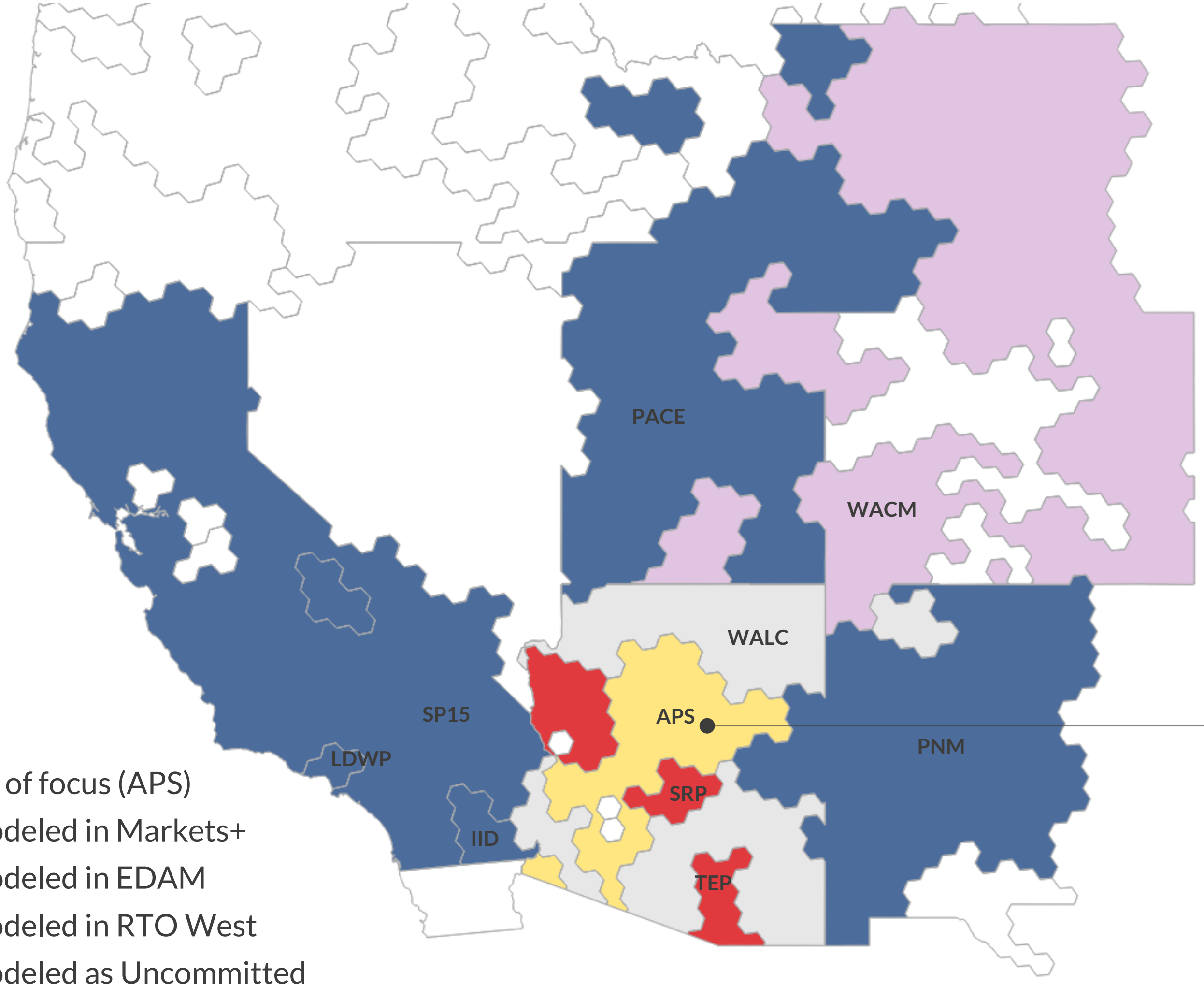
Map of balancing authorities with modeled interchange with APS



Key
- BA of focus (APS)
- Modeled in Markets+
- Modeled in EDAM
- Modeled in RTO West
- Modeled as Uncommitted

Modeled transfer limits from and to APS in 2032[1]

Balancing authority	Export[2] transfer limit (MW)	Import transfer limit (MW)
California[3]	1755	309
PACE	196	454
PNM	339	303
SRP	436	4263
TEP	24	111
WACM	321	208
WALC	1328	193

Transmission in APS is modeled after the APS Ten-Year Transmission Plan; planned network projects to facilitate increased transmission from trading hubs such as Palo Verde and Gila Bend are reflected in increasing transfer limits modeled

1) Transfer limits are modeled at the BA level. BAs identified here show all modeled interchange possibilities for PSCo with neighboring BAs. 2) Refers to exports from APS into listed balancing authorities. 3) 'California' includes SP15, LDWP, and IID.

Sources: Aurora Energy Research, WECC, EIA, APS

Agenda

Input assumptions for APS align with the 2023 IRP, with adjustments to market commitments and assumptions specific to each scenario

As in APS standard inputs unless stated otherwise		APS standard inputs[1]	APS DAM cases	AZ EDAM, including WALC	AZ EDAM, excluding WALC
Demand	Underlying demand	**Consistent with APS 2023 IRP** reported compound annual growth rate for the IRP Planning Period 2023-2038			
Commodities	Gas price	Henry Hub prices increase to $4.5/MMBtu in 2030 and $5.4/MMBtu in 2060			
	Coal price	Stable coal price across forecast horizon			
Technology	Renewables	**Consistent with the 2023 IRP Preferred Plan**, which adds +8GW renewables from 2023-2038			
	Thermal	**Consistent with 2023 IRP Preferred Plan** – thermal additions and exits as outlined			**Reflective of TEP July 2025 press release**, which converts Unit 2 of Springerville Generating Station to a natural gas plant
	Hydro	P60 hydro availability throughout the Western Interconnection			
Policy	Pollution standards	APS is not subject to any formalized environmental mandates			
	Renewables incentives	ITC and PTC consistent with the Inflation Reduction Act and extended at lower levels after IRA expires			
	Carbon price	No carbon price is applied to APS. Washington and California carbon markets link and prices increase to $101/ton by 2035 and level off at $140/ton			
Market	Day-Ahead	All BAs are modeled based on formalized commitment or assumption	APS is modeled to either join EDAM or Markets+. All other BAs are modeled based on formalized commitment or assumption	APS, WALC, TEP, and SRP are modeled to join EDAM. All other BAs are modeled based on formalized commitment or assumption	APS, TEP, and SRP are modeled to join EDAM. All other BAs are modeled based on formalized commitment or assumption

1) The input assumptions align with Arizona Public Service's (APS) 2023 IRP where available. These assumptions include demand, new build capacity, and retirements. IRP assumptions are available until 2038, after which inputs are extrapolated from pre-2038 data. Aurora standard input assumptions for modeling the West are used elsewhere unless specified

Sources: Aurora Energy Research

APS demand forecast is modeled to follow the IRP growth rates through 2038

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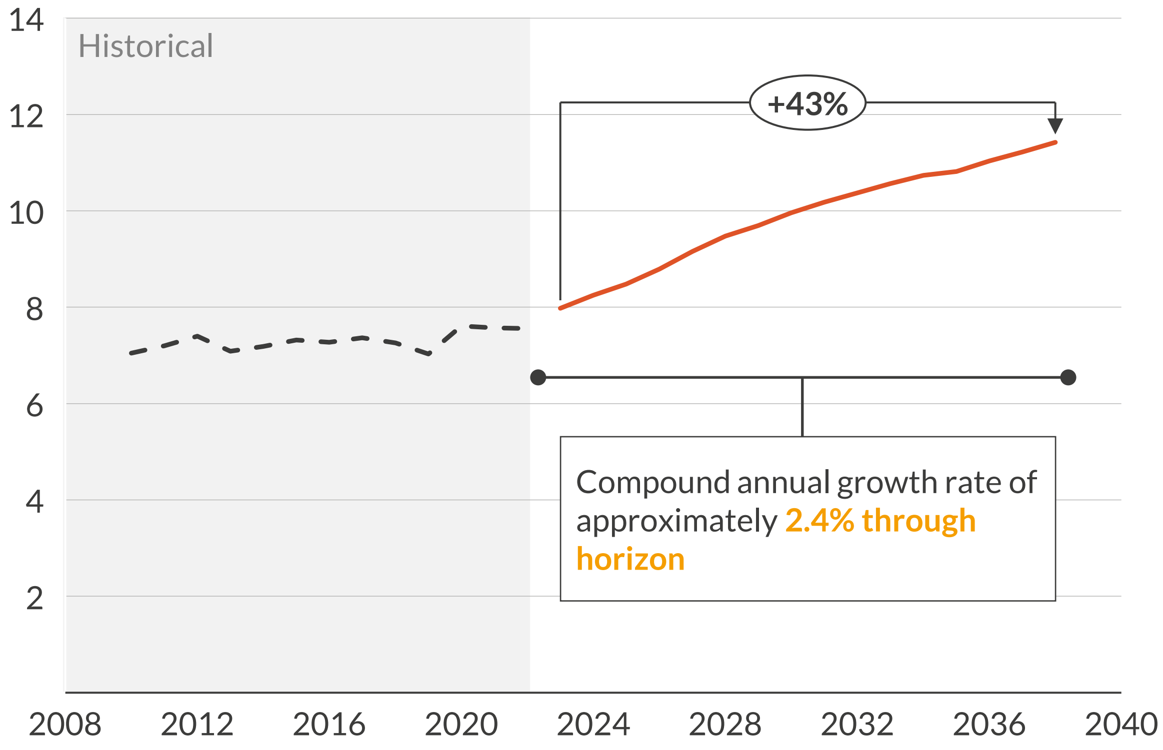
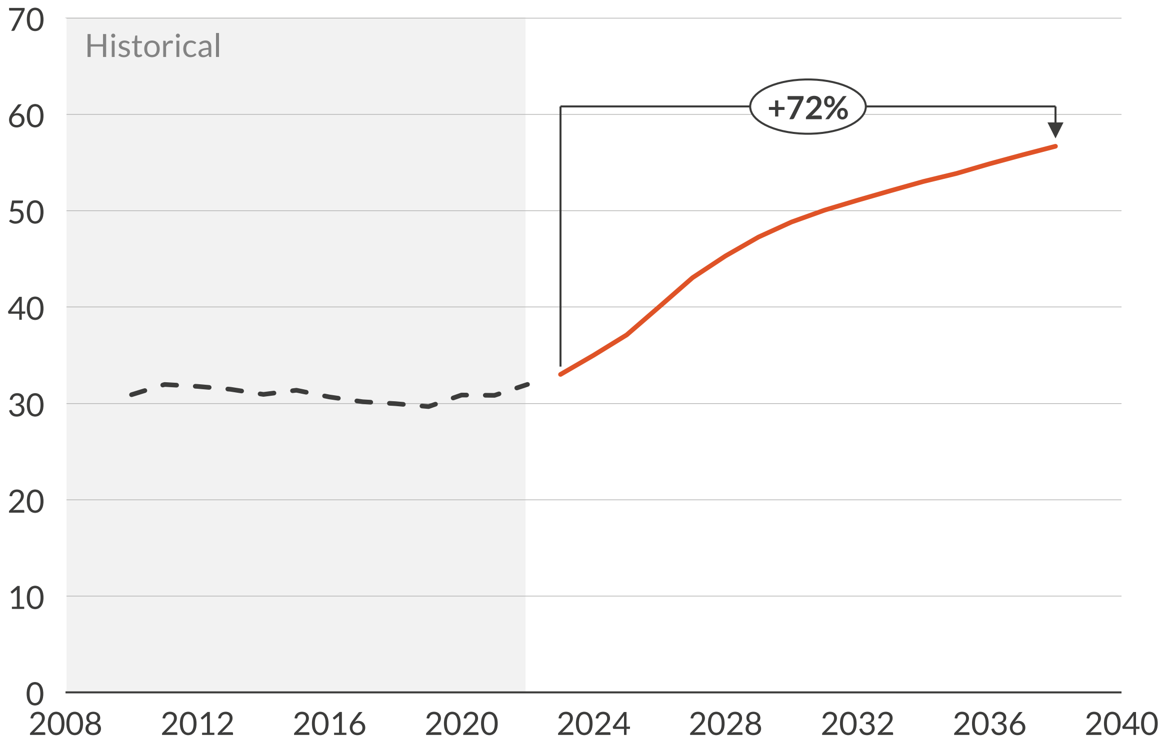
APS coincidental peak demand[1,2]
GW



APS annual system load[1,2]
TWh



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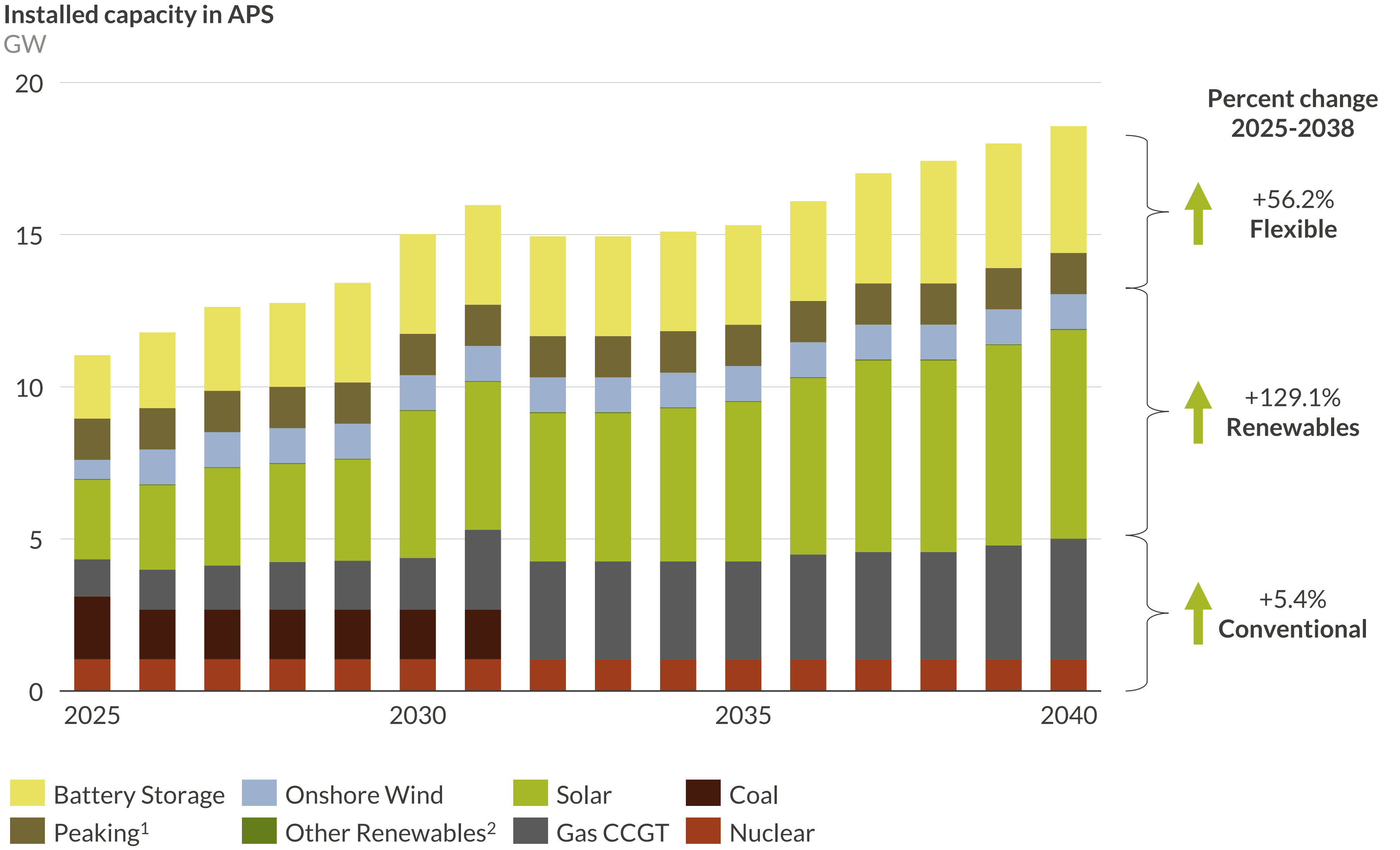

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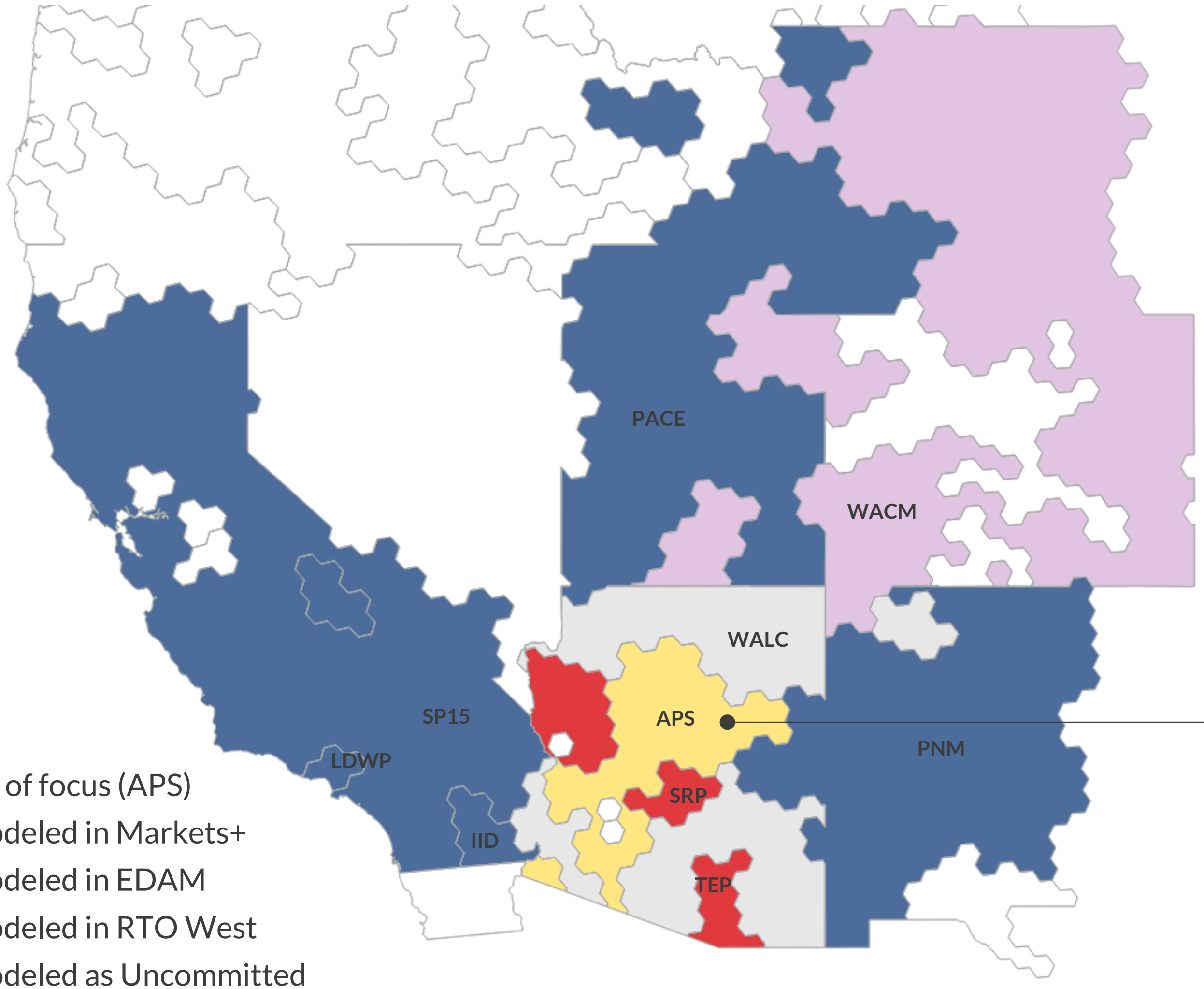

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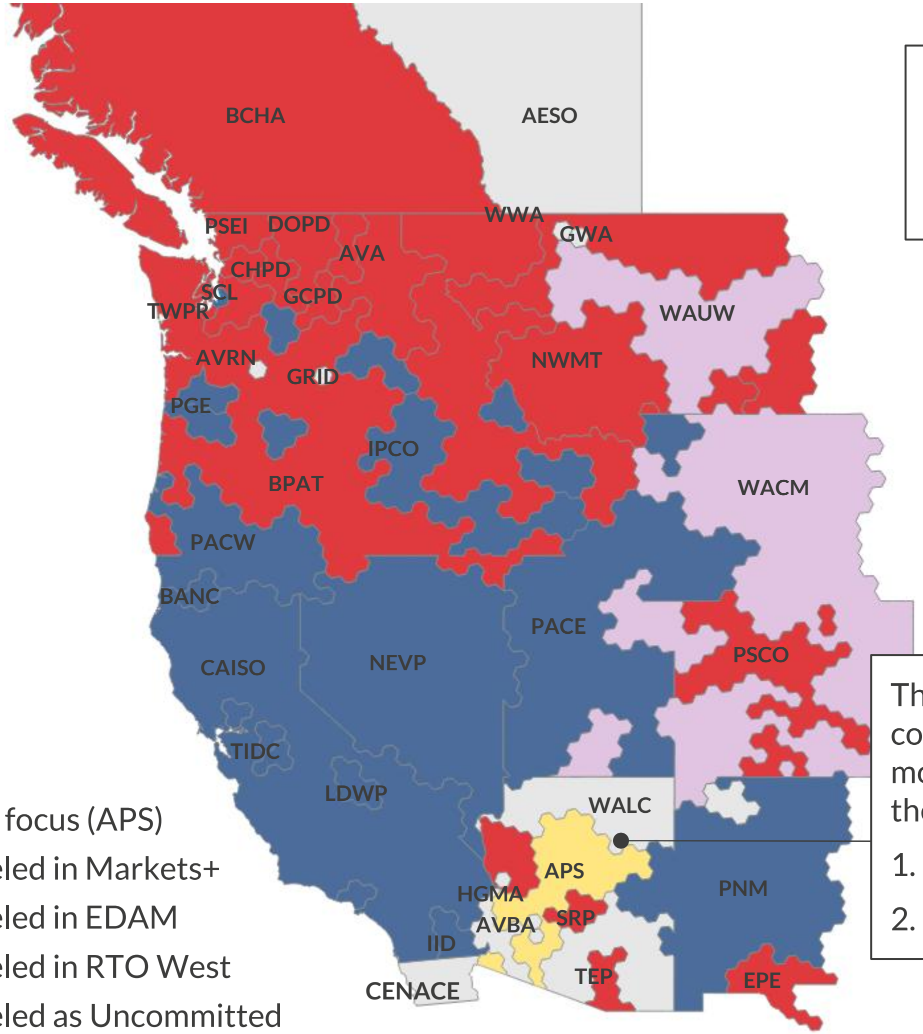
BAs are modeled to join DAMs based on confirmed or assumed commitments in the APS DAM cases, with variations across scenarios

AURORA

Map of modeled balancing authority (BA) market decisions – APS DAM cases



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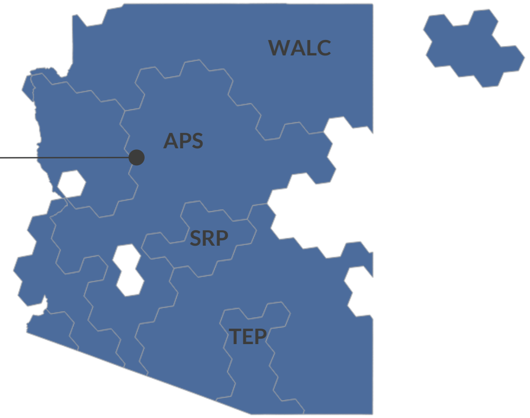
The Day-Ahead Market (DAM) commitment for APS was modeled under 2 scenarios in the APS DAM cases:

1. APS in EDAM
2. APS in Markets+

Modeled BA market decisions in Arizona – AZ EDAM incl. WALC

In the AZ EDAM incl. WALC scenario, Arizona BAs APS, TEP, SRP, and WALC are modeled to join EDAM



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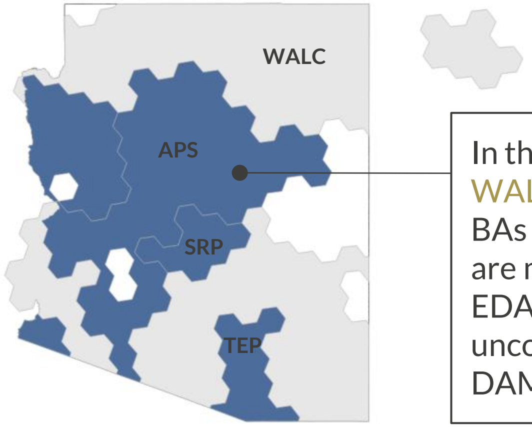

In the AZ EDAM excl. WALC scenario, Arizona BAs APS, TEP, and SRP are modeled to join EDAM. WALC remains uncommitted to either DAM

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Sources: Aurora Energy Research, CAISO, SPP

Transfers between markets, RTOs, or uncommitted BAs are expected to face friction charges due to differences in market optimization

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Transfers to Markets+		
Source BA	Sink BA	Friction charge[1]
Markets+	Markets+	$0/MWh
EDAM	Markets+	$3/MWh
RTO West	Markets+	$1.5/MWh
Uncommitted	Markets+	$3/MWh

Transfers to EDAM		
Source BA	Sink BA	Friction charge[1]
EDAM	EDAM	$0/MWh
Markets+	EDAM	$3/MWh
RTO West	EDAM	$3/MWh
Uncommitted	EDAM	$6/MWh

Transfers to RTO West		
Source BA	Sink BA	Friction charge[1]
RTO West	RTO West	$0/MWh
EDAM	RTO West	$1.5/MWh[2]
Markets+	RTO West	$0.75/MWh
Uncommitted	RTO West	$1.5/MWh

Transfers to uncommitted BAs		
Source BA	Sink BA	Friction charge[1]
Uncommitted	Uncommitted	$6/MWh
EDAM	Uncommitted	$6/MWh
Markets+	Uncommitted	$6/MWh
RTO West	Uncommitted	$6/MWh

1) Friction charges are additive to wheeling rates and carbon adders (imports to CA or WA). The full hurdle rate for trades between BAs is modeled as the sum of wheeling rates, friction charges, and carbon adders. Wheeling rates between BAs in the same DAM are reduced to $0/MWh 2) EDAM to CAISO transfers see a $0/MWh friction charge

Sources: Aurora Energy Research

Agenda

I. Executive summary

II. Scenario design methodology

III. APS Day-Ahead Market results

1. Cost savings
2. Emissions
3. WECC-wide impact

IV. Additional scenario results

V. Appendix: Overview of modeling approach

Average annual costs for APS are reduced by an average of $109.9 million/year when participating in EDAM as opposed to Markets+

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C Congestion revenue[2]	(100.0)	(52.2)	(47.8)
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Annual average costs[3] (APS)	**1,353.5**	**1,463.3**	**(109.9)**

X Deep dive to follow

- APS sees an average $109.9mil/year benefit in total costs when participating in EDAM vs. Markets+
- **Production costs** - When in EDAM, reduced thermal imports from SRP drives greater peaking generation and production costs as a result
- **Bilateral trading costs** - A larger trading footprint under EDAM enables APS access to import more renewable generation and export more, driving its reduced bilateral trading cost compared to the Markets+ configuration
- **Congestion and wheeling revenue** – Under the EDAM scenario APS sees higher utilization of its transmission interconnection to facilitate trades, particularly with PNM and PACE[2]

1) A negative delta indicates lower costs when APS is modeled in EDAM compared toMarkets+, demonstrating benefits to joining EDAM 2) Ownership assumed to be split 50-50 with connecting BA unless data on ownership is available. 3) Average annual costs after revenues.
Sources: Aurora Energy Research

Ⓐ Increased thermal generation in APS in the EDAM scenario drives up production costs, though the impact is <1% of annual total costs

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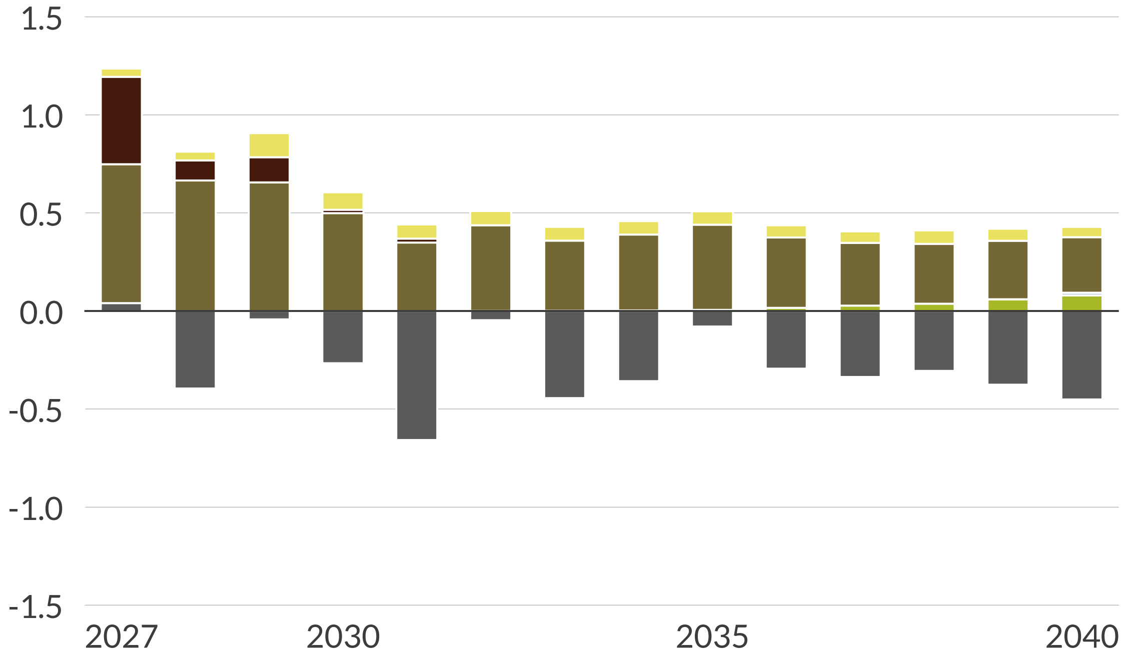
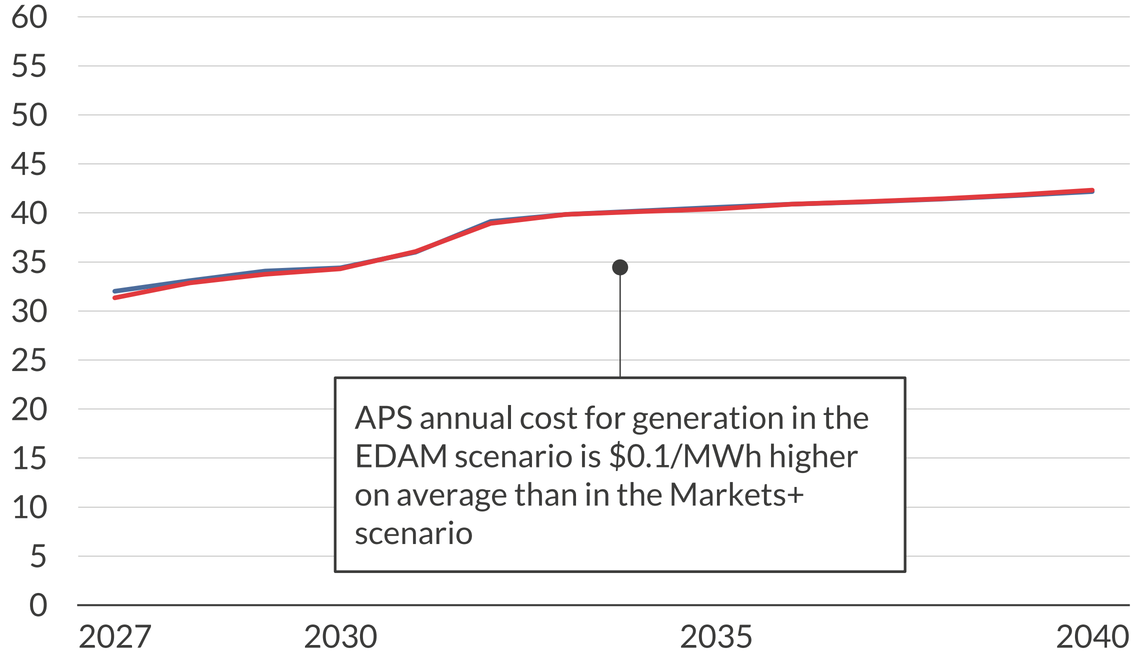
Yearly generation delta[1] in APS, 2027-2040
TWh



Average annual price of generation in APS
$/MWh, real 2024



- Through to the early 2040s, APS sees increased peaking generation in the EDAM scenario as it has reduced thermal imports from SRP due to higher hurdle rates. Instead, APS sources baseload thermal generation from PACE where no additional costs to trade are incurred as they are both trading under EDAM. This reduces domestic gas production in APS, driving the negative delta
  - As a result, there is minor difference in the average price for generation in APS

Battery storage[2] | Peaking[3] | Nuclear | Solar | Coal | Gas CCGT | Onshore wind

APS EDAM scenario | APS Markets+ scenario

1) Delta is calculated as EDAM scenario – Markets+ scenario. 2) APS reports a positive battery generation delta in the EDAM scenario throughout, which is driven by a net larger decrease in charging. 3) Peaking includes OCGTs and reciprocating engines.

Sources: Aurora Energy Research

B APS in EDAM incurs lower bilateral trading costs due to decreased reliance on thermal imports and increased export of renewables

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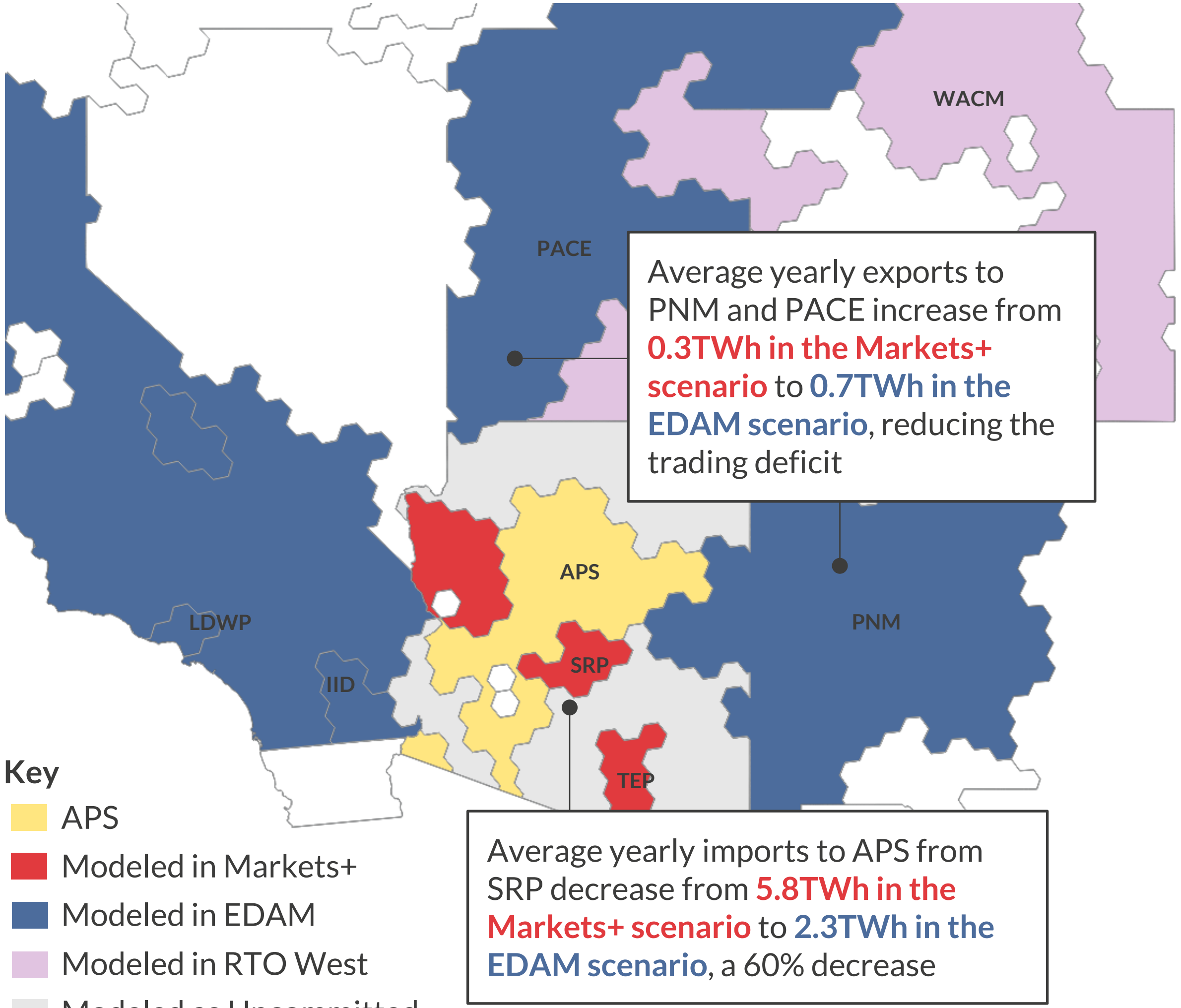
Map of APS and neighboring trading regions

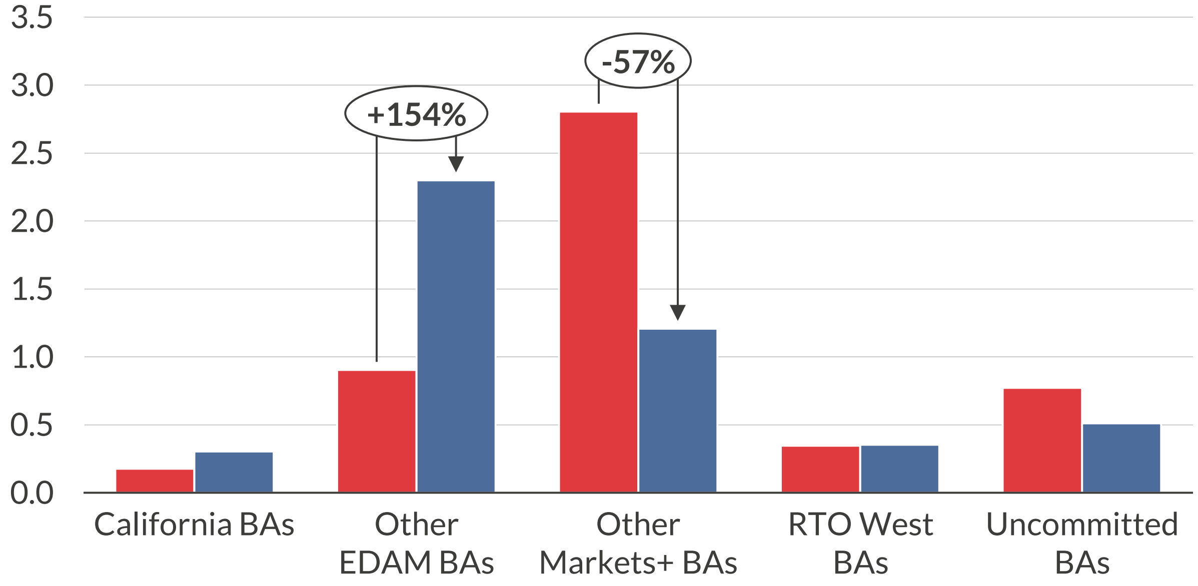


Key

- APS
- Modeled in Markets+
- Modeled in EDAM
- Modeled in RTO West
- Modeled as Uncommitted

Average annual APS net imports to neighboring regions[1], 2027-2040

TWh



- APS has historically been reliant on SRP thermal exports to meet baseload demand. Higher hurdle rates to trade with Markets+ BAs in the EDAM scenario shifts APS's baseload imports to PACE which incurs no additional cost
- As APS import trade capacity with SRP is significantly larger than with other BAs, APS sees reduced trade volumes overall in the EDAM scenario and instead increases domestic baseload generation
- Access to trade with PNM and PACE at no additional cost increases APS's export of renewables, further decreasing costs to trade in the EDAM scenario

APS Markets+ scenario | APS EDAM scenario

1) Net imports is calculated as imports minus exports.

Sources: Aurora Energy Research

C Utilization of transfer capacity to PNM and PACE significantly increases with APS in EDAM, driving a positive revenue delta

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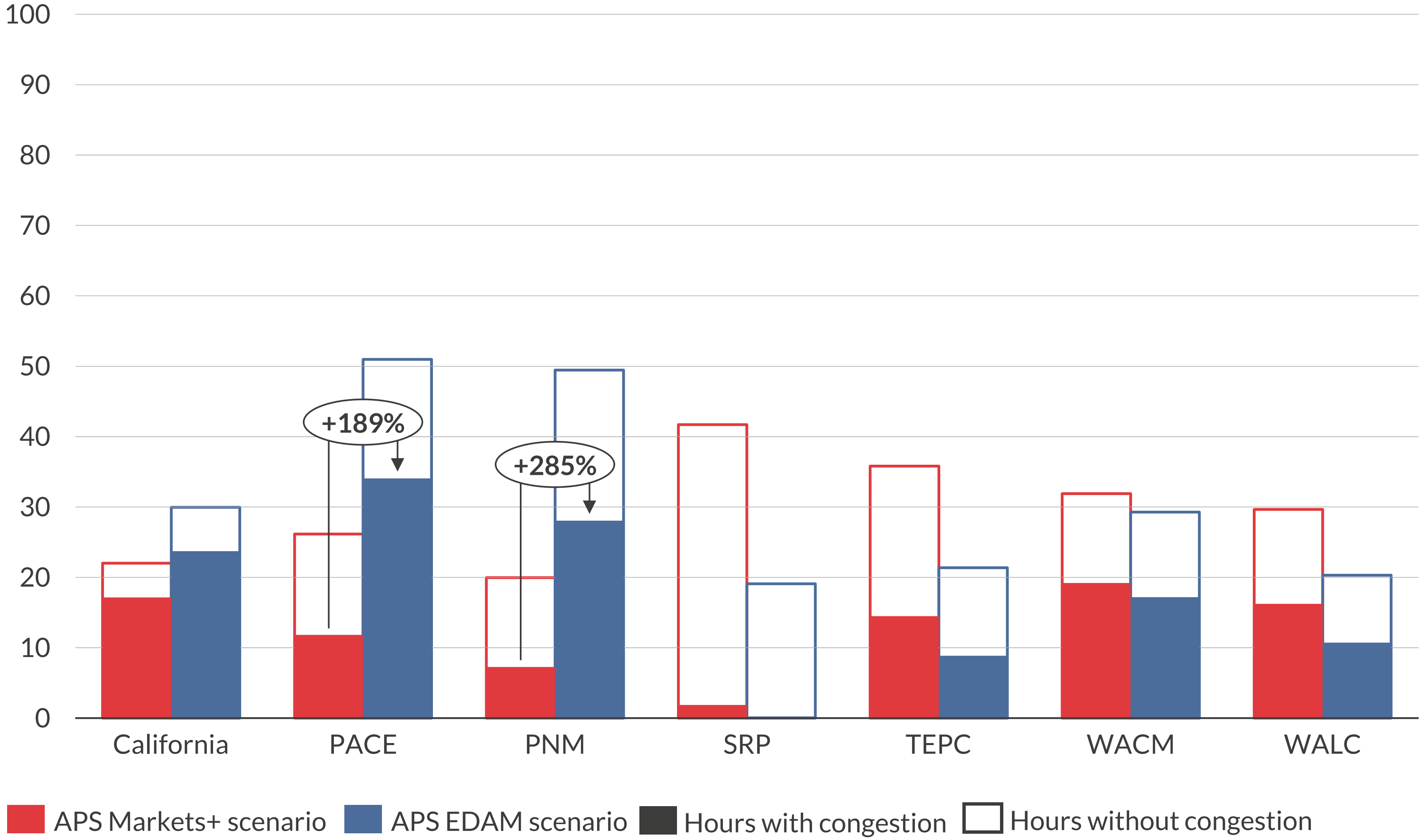
Average annual inter-BA congestion and wheeling trading hours with APS, 2027-2040
% of hours per year



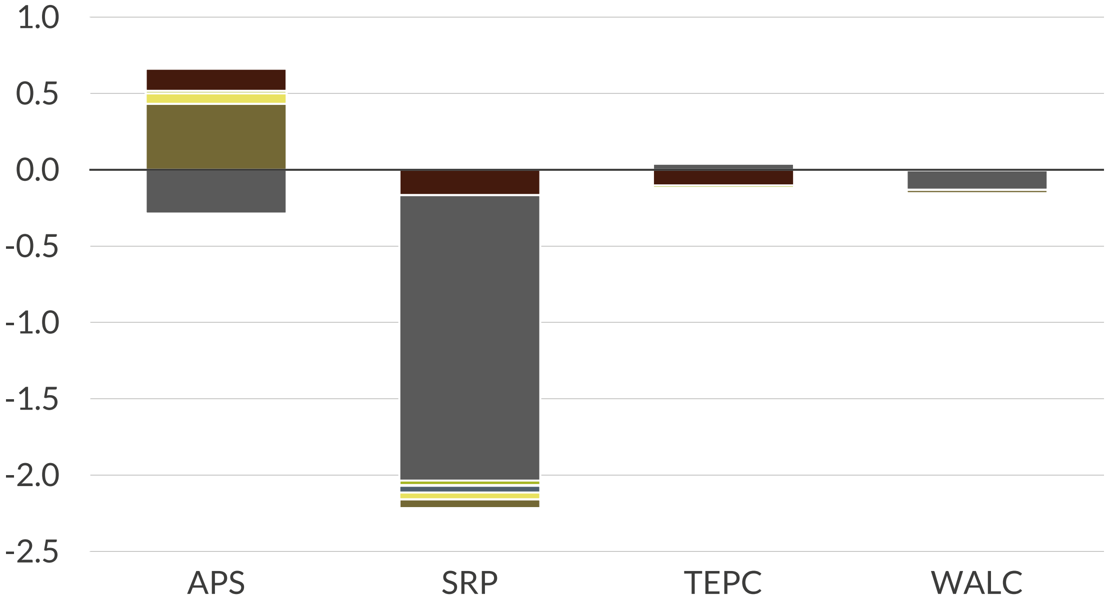
- In the EDAM scenario, APS has access to trade with PNM, PACE, and the wider California balancing authorities at lower hurdle rates
  - In particular, interconnection capacity to and from PACE and PNM are more highly utilized and increase the frequency of both congestion and wheeling revenue relative to the Markets+ scenario[1]
- In the Markets+ scenario, utilization of interconnection to SRP and associated congestion frequency increases. However, total congestion and associated revenues in the EDAM scenario still report a net positive delta relative to the Markets+ scenario as APS has access to trade with more BAs with reduced hurdle rates

1) Ownership of transmission assumed to be split 50-50 with connecting BA unless data on ownership is available.

Sources: Aurora Energy Research

Arizona sees lower emissions in the APS EDAM scenario, with SRP thermal generation reduction offsetting increased generation in APS

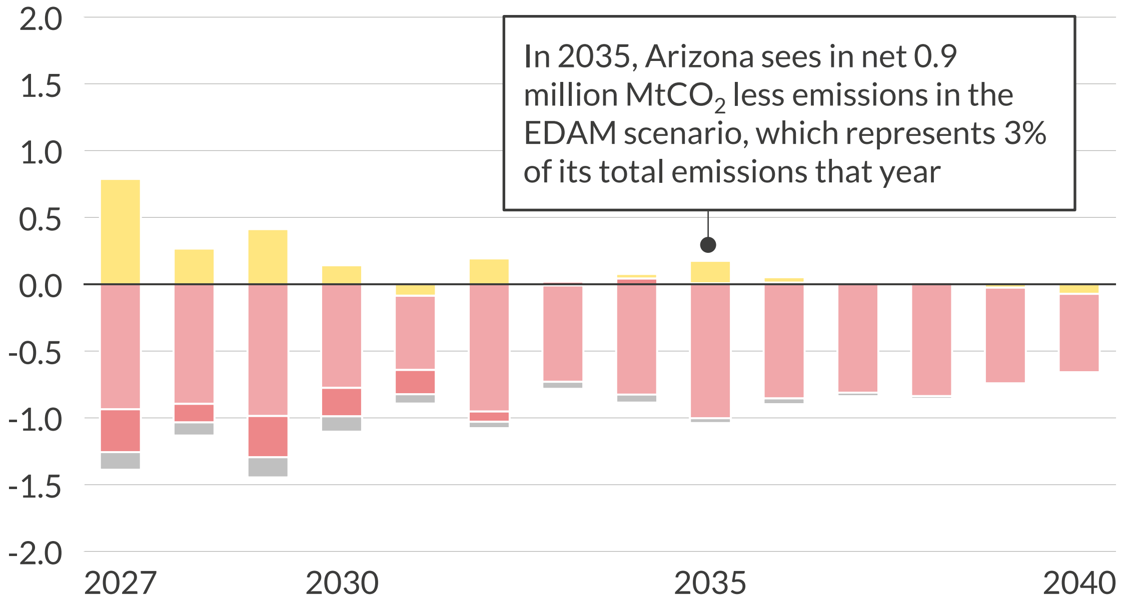
Average annual net electricity production delta[1], 2027-2040
TWh



- SRP has historically been a major net exporter to APS during peak net-load hours due to its large conventional baseload thermal capacity
- In the EDAM scenario, APS sees reduced friction to trade with the wider EDAM footprint, enabling access to cheaper renewables and baseload thermal generation at lower costs. As a result, APS is less reliant on SRP exports, driving SRP to generate on average 2.1TWh less conventional generation in the EDAM scenario annually

Coal, Solar, Onshore wind, Battery storage[3], Gas CCGT, Other RES[2], Pumped storage[3], Gas / oil peaker

Arizona annual emissions delta[1], 2027-2040
Million $MtCO_2$



- APS initially sees higher emissions in the EDAM scenario due to increased peaker and baseload thermal generation to offset its reduced shoulder hour trades with SRP
- On average, APS emits 0.1 million $MtCO_2$ more annually in the EDAM scenario, which represents 1.3% its average annual emissions

APS, TEPC, SRP, WALC

1) Delta is calculated as EDAM scenario – Markets+ scenario. 2) Other RES includes biomass and geothermal.3) Storage technologies report a net charging production; a positive delta indicates less net charging.

Sources: Aurora Energy Research, CAISO

Arizona BAs and APS trading partners see cost reductions when APS commits to EDAM, while WECC-wide results are similar

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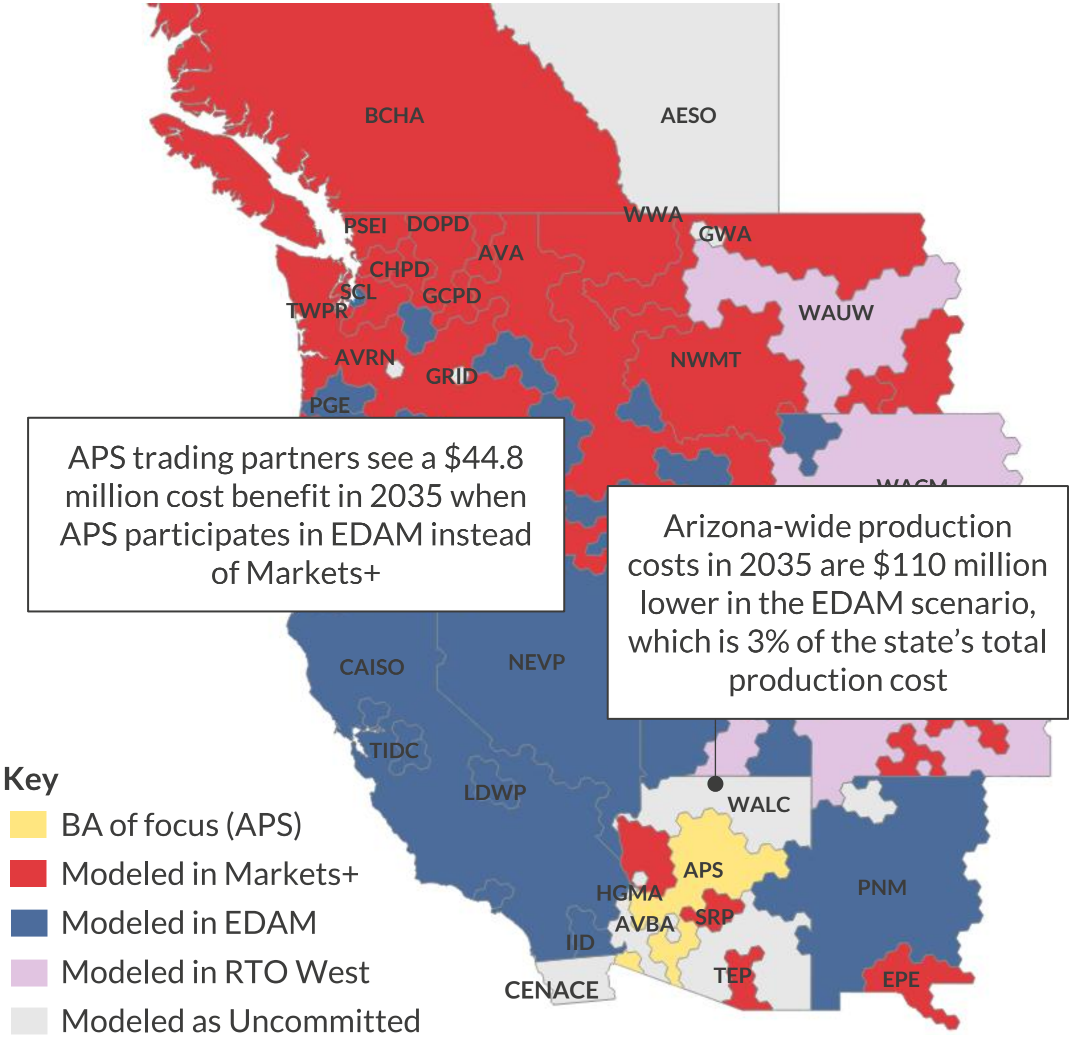
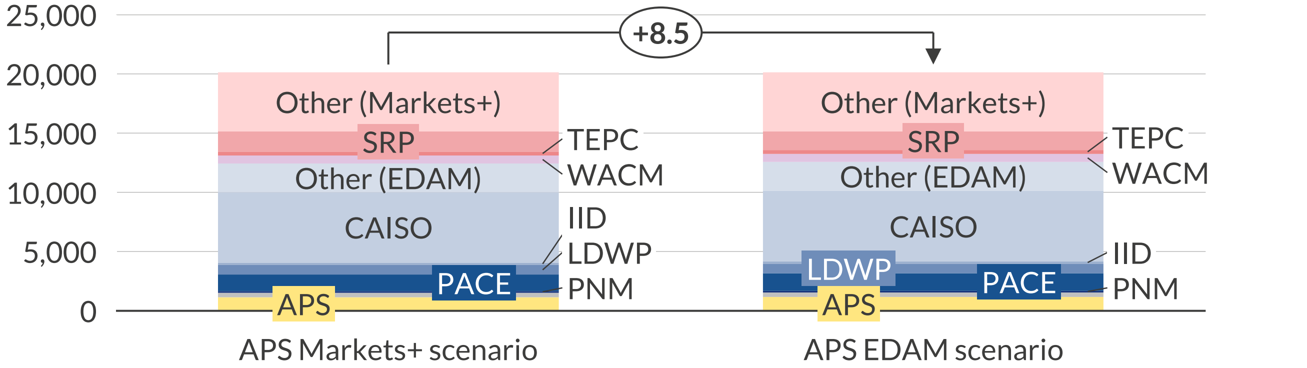
Map of modeled balancing authority (BA) market decisions



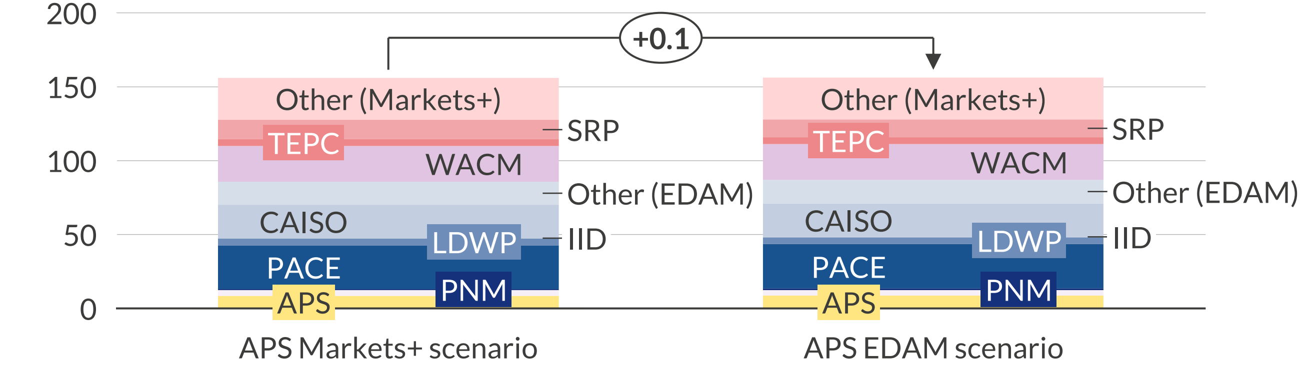
Total WECC-wide production costs in 2035[1]

$Million, real 2024



Total WECC-wide emissions, 2035[1]

Million Mt CO_2



- When APS joins EDAM, its trading partners and Arizona BAs see production cost reductions while WECC-wide costs are higher, although this just translates to a 0.04% increase
- It should be noted that production cost is a subcomponent of a system's total costs; higher production costs does not necessarily indicate a costlier system as it can result in increased export revenues and associated line congestion and wheeling revenues from trading

1) The "Other (Markets+)" category includes AVA, AVBA, AVRN, BCHA, CHPD, DOPD, GCPD, NWMT, TPWR, PSEI, and EPE. The "Other (EDAM)" category includes PACW, PGE, BANC, TIDC, NEVP, SCL, and IPCO.

Sources: Aurora Energy Research, CAISO, SPP

Agenda

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Input assumptions for APS align with the 2023 IRP, with adjustments to market commitments and assumptions specific to each scenario

AURORA

As in APS DAM cases unless stated otherwise		APS DAM cases[1]	AZ EDAM, including WALC	AZ EDAM, excluding WALC
Market	Day-Ahead	APS is modeled to either join EDAM or Markets+. All other BAs are modeled based on formalized commitment or assumption	APS, WALC, TEP, and SRP are modeled to join EDAM. All other BAs are modeled based on formalized commitment or assumption	APS, TEP, and SRP are modeled to join EDAM. All other BAs are modeled based on formalized commitment or assumption

1) The input assumptions align with Arizona Public Service's (APS) 2023 IRP where available. These assumptions include demand, new build capacity, and retirements. IRP assumptions are available until 2038, after which inputs are extrapolated from pre-2038 data. Aurora standard input assumptions for modeling the West are used elsewhere.

Sources: Aurora Energy Research

Annual average system costs are lowest for Arizona BAs when participating in EDAM as opposed to Markets+

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Average annual cost breakdown for APS across modeled scenarios, 2027-2040
$Million/year, real 2024

	APS DAM cases			AZ EDAM, incl. WALC		
Metric	APS EDAM	APS Markets+	**Delta[1]**	APS	**Delta to APS EDAM**	**Delta to APS Markets+**
Production cost	1,110.7	1,101.4	9.3	1,030.2	**(80.5)**	**(71.2)**
Bilateral trading costs	356.6	427.5	(70.9)	466.6	**110.0**	**39.1**
Congestion revenue[2]	(100.0)	(52.2)	(47.8)	(84.4)	**15.6**	**(32.2)**
Wheeling revenue[2]	(13.9)	(13.5)	(0.5)	(13.9)	**0.0**	**(0.4)**
Annual costs[3] (APS)	**1,353.5**	**1,463.3**	**(109.9)**	**1,398.5**	**45.1**	**(64.7)**
Annual costs[3] (AZ)	**3,333.3**	**3,381.7**	**(48.5)**	**3,266.8**	**(66.5)**	**(114.9)**

- In the AZ EDAM incl. WALC scenario, APS has access to import thermal and renewable generation from a wider footprint. As a result, APS sees a lower production cost and higher import costs driving a negative bilateral trading cost delta relative to the APS DAM cases
- AZ-wide costs are minimized when all BAs commit to EDAM as the region as a whole benefits significantly from access to a more comprehensive and interconnected footprint. Efficient resource sharing reduces AZ-wide costs by 2.0%-3.4% relative to the APS DAM cases

1) EDAM – Markets+. A negative delta indicates lower costs when the BA is modeled in EDAM compared to Markets+, demonstrating benefits to joining EDAM 2) Ownership assumed to be split 50-50 with connecting BA unless data on ownership is available. 3) Annual costs after revenues
Sources: Aurora Energy Research

The successive inclusion of Arizona BAs in EDAM drives lower total system costs as compared to when they participate in Markets+

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Average annual cost breakdown for APS and Arizona BAs across modeled scenarios, 2027-2040
$Million/year, real 2024

	APS in Markets+[3]	AZ EDAM, excl. WALC	AZ EDAM, incl. WALC
Metric			
Production cost	1,101.4	1,046.2	1,030.2
Bilateral trading costs	427.5	451.4	466.6
Congestion revenue[1]	(52.2)	(83.8)	(84.4)
Wheeling revenue[1]	(13.5)	(14.3)	(13.9)
Annual costs[2] (APS)	**1,463.3**	**1,399.5**	**1,398.5**
Annual costs[2] (AZ)	**3,381.7**	**3,342.2**	**3,266.8**

Highest AZ costs → *Lowest AZ costs*

System cost reduction (AZ)	(39.5)	(75.4)	

- APS sees incremental cost reductions as Arizona BAs commit to EDAM, with the largest cost benefit occurring when APS, TEP, SRP join EDAM, driving $63.8M/yr cost benefit
- Arizona-wide system costs are minimized when all BAs commit to EDAM, largely due to access to a more expanded footprint and lower trading costs, increasing resource sharing efficiency gains
- However, even when WALC remains uncommitted to a DAM, Arizona BAs see a $39.5M/yr cost benefit when APS, TEP, and SRP all commit to EDAM instead of Markets+. This is because participation in EDAM allows the Arizona BAs to access cheaper renewable generation and increase trade with the wider EDAM footprint surrounding Arizona

1) Ownership assumed to be split 50-50 with connecting BA unless data on ownership is available. 2) Annual costs after revenues. 3) This scenario is equivalent to an AZ Markets+, excl. WALC scenario where APS, SRP, and TEP join Markets+ and WALC remains uncommitted
Sources: Aurora Energy Research

The inclusion of WALC to EDAM drives minimal cost change for APS and significant savings at the state level from increased trading

Average annual cost breakdown for APS across modeled scenarios, 2027-2040
$Million/year, real 2024

	AZ EDAM incl. WALC	AZ EDAM, excl. WALC	Delta (AZ EDAM incl. WALC – AZ EDAM excl. WALC)
Metric			
Production cost	1,030.2	1,049.3	**(19.1)**
Bilateral trading costs	466.6	448.8	**17.8**
Congestion revenue[1]	(84.4)	(83.2)	**(1.2)**
Wheeling revenue[1]	(13.9)	(14.5)	**0.6**
Annual costs[2] (APS)	**1,398.5**	**1,400.4**	**(1.9)**
Annual costs[2] (AZ)	**3,266.8**	**3,401.5**	**(134.7)**

The AZ EDAM excl. WALC scenario reflects the TEP 2025 July Press Release, which converts the Springerville coal generator to natural gas, adding 400MW of gas to the system relative to the TEP's IRP. This increases TEP's baseload thermal capacity relative to scenario including WALC. As TEP and APS overlap across many trading partners, this depresses APS's export potential as TEP has additional capacity to export

1) Ownership assumed to be split 50-50 with connecting BA unless data on ownership is available. 2) Annual costs after revenues.

Sources: Aurora Energy Research

- APS sees an average $1.9mil/year additional cost when WALC joins EDAM alongside TEP, SRP, and APS.
- WALC sits on top of significant thermal capacity; when in EDAM, this increases the amount of baseload generation available for resource sharing. As a result, when WALC remains uncommitted to a DAM, APS sees higher production costs and increased export revenues which decrease its bilateral trading cost relative to the AZ EDAM incl. WALC scenario
- At the state level, AZ BAs see a $134.7mil/year cost benefit when WALC joins EDAM as APS, SRP, and TEP are able to access trade with WALC, particularly its thermal imports

AZ EDAM incl. WALC: An expanded EDAM footprint enables more resource sharing at lower costs, driving reductions in AZ system costs

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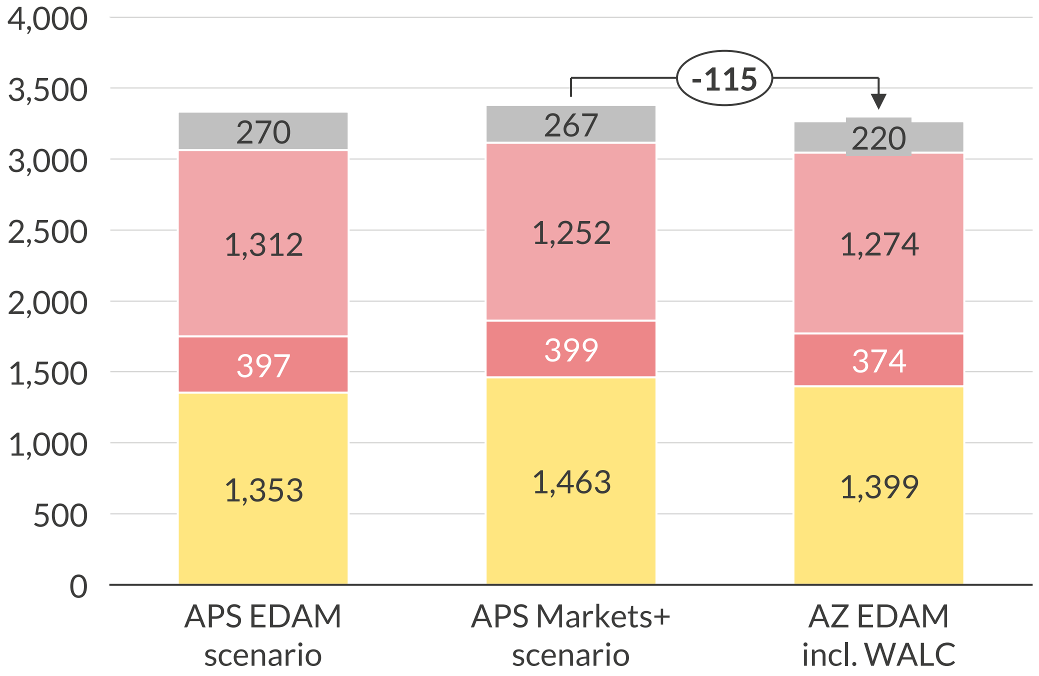
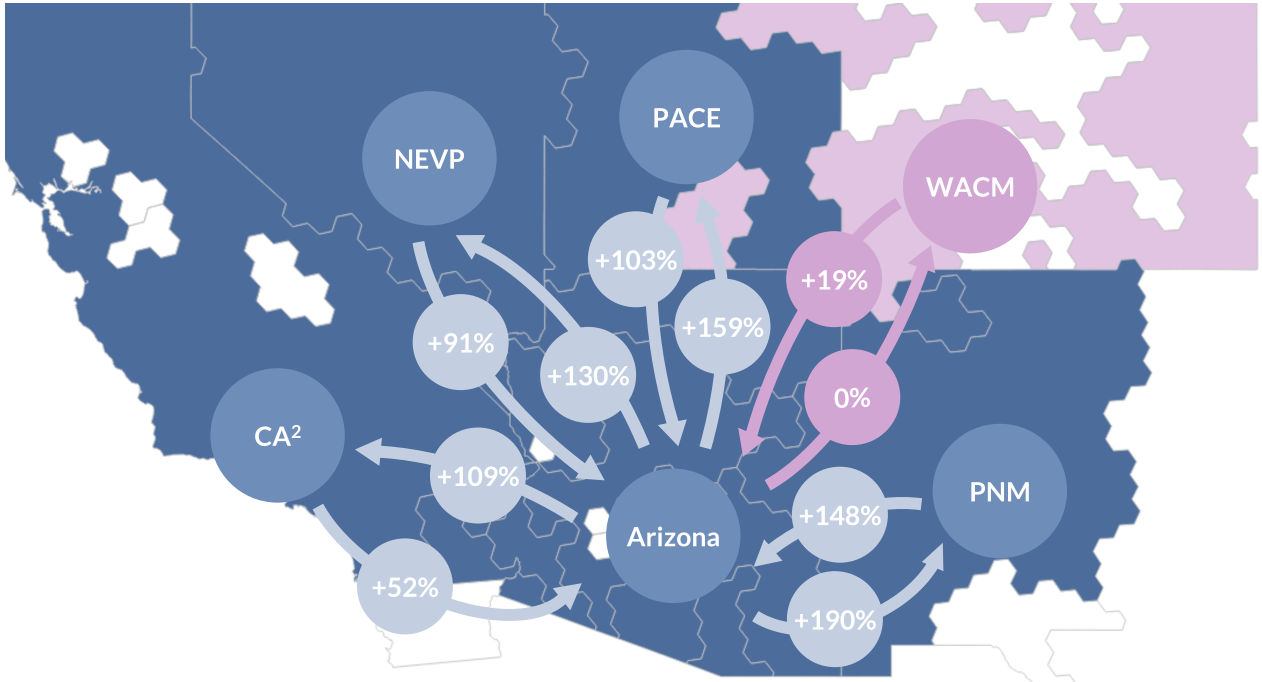
Arizona-wide[1] average annual total system cost, 2027-2040
$Million/year, real 2024



- Arizona BAs see a $67-115million/year reduction in total system costs in the AZ EDAM incl. WALC configuration compared to the APS EDAM and APS Markets+ scenarios
- Lower seams to trade incentivizes resource sharing across the Arizona BAs and outwards to neighboring EDAM regions, reducing domestic generation costs while increasing congestion revenues in particular

WALC SRP TEPC APS

Arizona[1] average annual trade delta to APS Markets+[3] scenario, 2027-2040
%



- A highly interconnected EDAM footprint and lower costs to trade significantly incentivizes trade with neighboring EDAM BA regions. Specifically, average annual imports into Arizona total 17.9TWh and exports from Arizona total at 7.8TWh, representing a 39.6% and 48.7% increase, respectively, from the APS Markets+ scenario

EDAM RTO West

1) Arizona comprises WALC, TEP, SRP, and APS. 2) California comprises the three BAs that APS engages in trade with: LDWP, SP15, and IID. 3) This scenario is equivalent to an AZ Markets+, excl. WALC scenario where APS, SRP, and TEP join Markets+ and WALC remains uncommitted

Sources: Aurora Energy Research

AZ EDAM excl. WALC: Exclusion of WALC drives higher production costs for other AZ BAs and lower congestion and wheeling revenues

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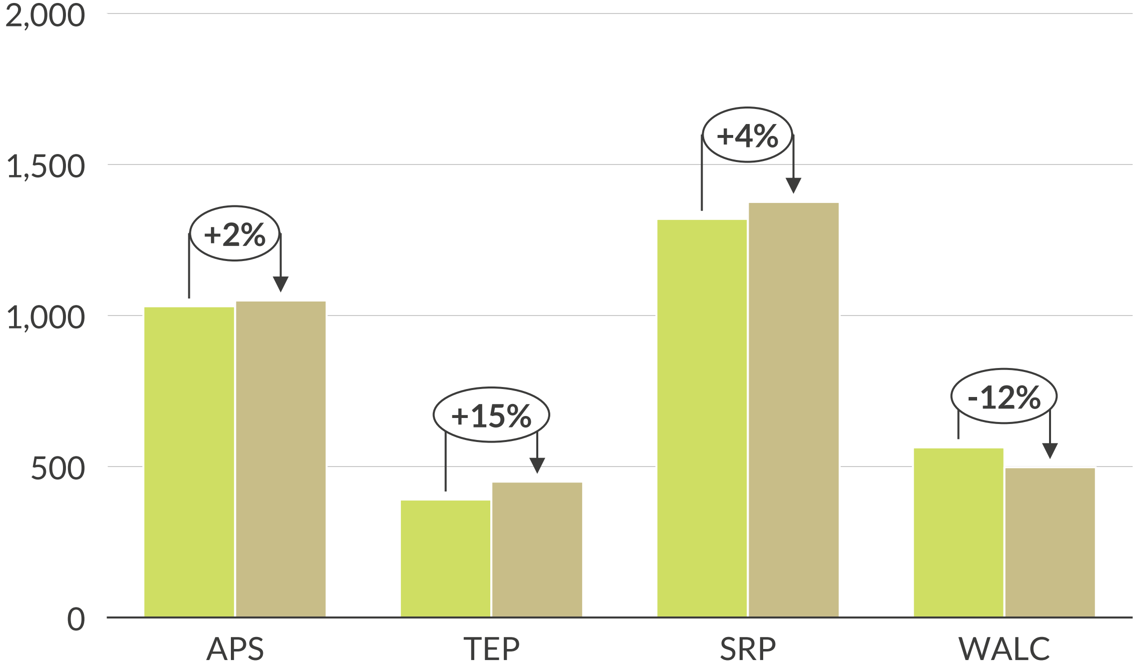
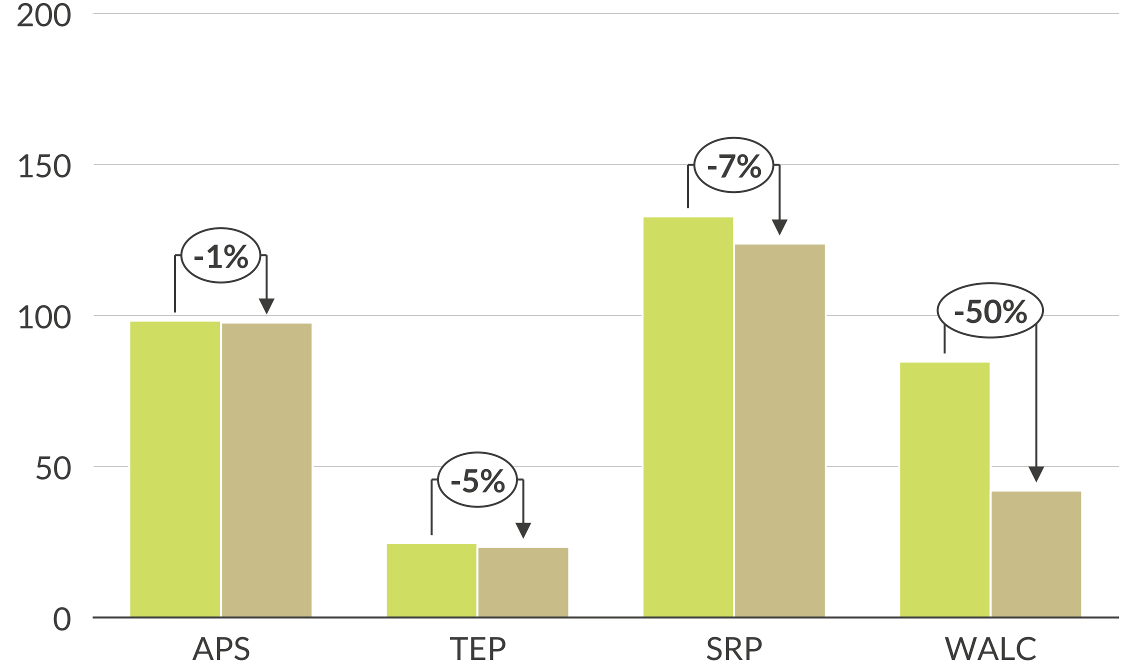
Average annual cost of generation
$Million/year, real 2024



- APS, TEP, and SRP see higher production costs in the scenario excluding WALC as higher seams to access WALC thermal exports incentivizes the BAs to ramp up their own thermal generation instead
- Reduced trade results in lower production costs for WALC; however, in net, increase in production costs across the other BAs exceeds WALC's production cost reduction

Average annual congestion and wheeling revenues
$Million/year, real 2024



- All Arizona BAs see reduced congestion and wheeling revenues associated with trading, with APS seeing a comparatively smaller percentage decrease as it has the most expansive access to the EDAM footprint outside of Arizona
- WALC sees the largest reduction in congestion and wheeling revenues when it remains uncommitted to a DAM as it faces higher seams to trade with the rest of Arizona

AZ EDAM incl. WALC scenario   AZ EDAM excl. WALC scenario

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Unique, proprietary, and integrated in-house modeling capabilities underpin Aurora's superior analysis

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5 Integrated Models

- Global Commodities (AER-GLO)
- Hydrogen (AER-HY)
- Gas (AER-GAS)
- Power markets (AER-ES)
- Nodal/network model (AER-EN)

INPUTS

- Technology
- Policy
- Demand
- Commodity prices[1]
- Weather patterns

Dispatch model

- ½ hourly or hourly
- Iterative modeling
- Dynamic dispatch of plant
- Endogenous interconnector flows

Continuous iteration until an equilibrium is reached

Investment decisions module

- Capacity market modeling
- Capacity build / exit / mothballing
- IRR / NPV driven
- Detailed technology assessments

OUTPUTS

- Capacity mix
- Generation mix
- Wholesale & imbalance prices
- Capacity market prices
- Profit / Loss and NPV
- Electric vehicle charging

ADDITIONAL INPUTS

- Network snapshot - existing & future
- Nodal load map
- Nodal generation map

OUTPUTS

- Power flows & losses
- Nodal prices / loss factors

Up to 70	c. 85k	~15k	80+	Quarterly updates
specifications modeled for each plant	investment hours on modeling capabilities	model runs per week	strength of modeling team globally	through subscription research

1) Gas, coal, oil and carbon prices fundamentally modeled in-house with fully integrated commodities and gas market model.

Sources: Aurora Energy Research

Demand, capacity, and technology assumptions reflect utility integrated resource plans and Aurora's long-term outlook

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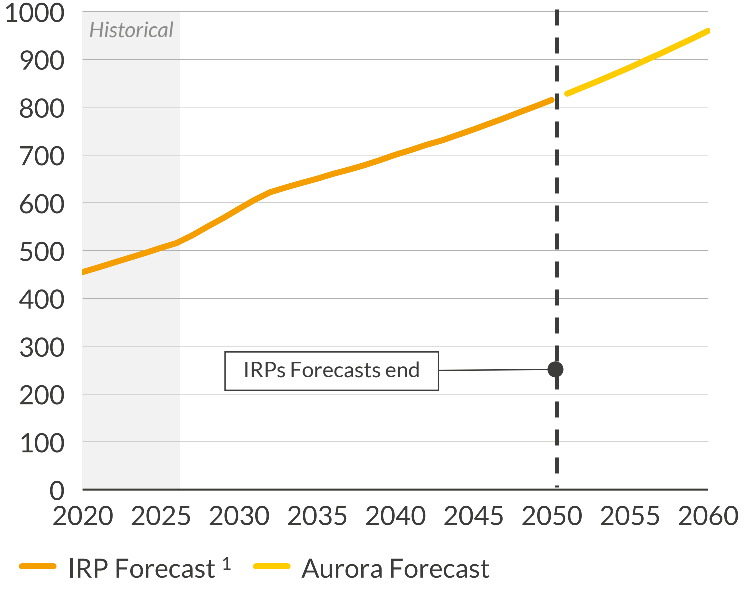
Demand assumptions

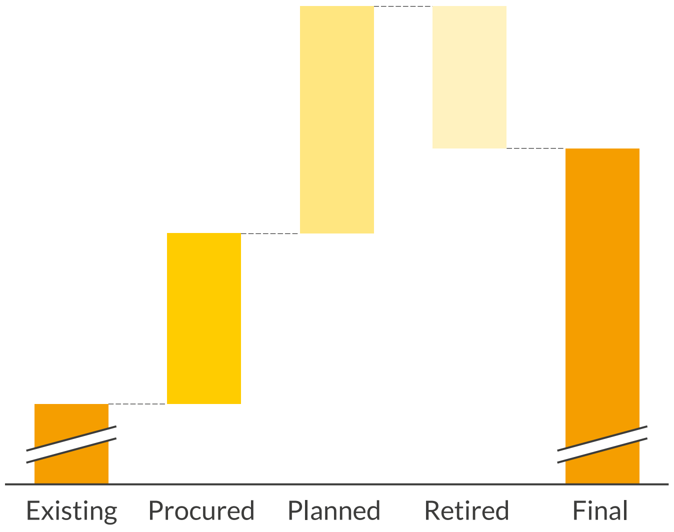
Annual electricity demand
TWh



- Utility IRPs are used through their forecast horizon and reflect their assumptions on EVs, data centers and other demand drivers.
- Beyond the IRP period, we extend demand using trend-based assumptions and expected long-term patterns.

Capacity assumptions

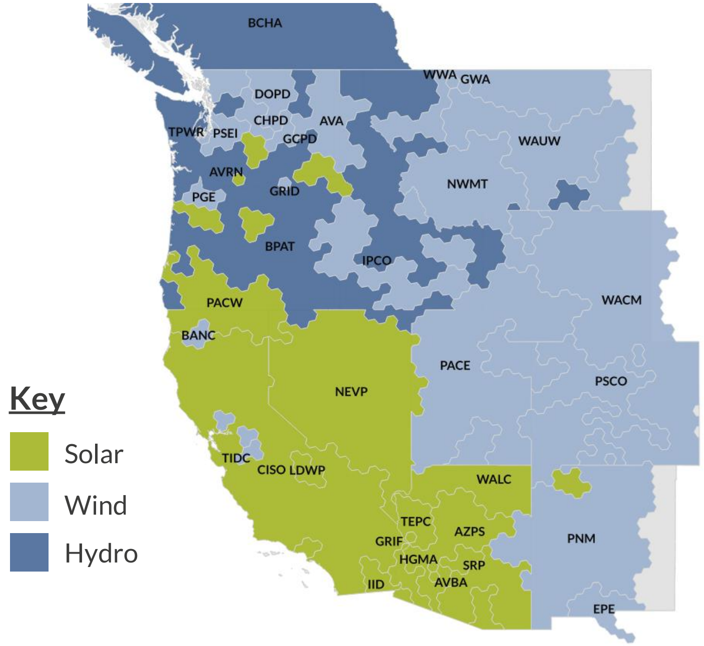
Capacity assumptions components
GW



- Capacity additions include resources procured through recent utility Requests For Proposals, and planned builds identified in IRPs.
- Retirements include units expected to come offline, as announced in IRPs or other public documents.

Technology assumptions

Technology with highest load factor by BA[2]



- Load factor assumptions are based on historical performance of renewables assets across BAs[2].
- Aurora also incorporates assumptions on thermal assets efficiency, availability, and ramping constraints using EIA[3] and EPA[4] data.

1) Integrated Resource Plans. 2) Balancing Authority. 3) Energy Information Administration. 4) Environmental Protection Agency.

Sources: Aurora Energy Research

Aurora anticipates that balancing authority commitments to different day-ahead markets will partition the Western Interconnection

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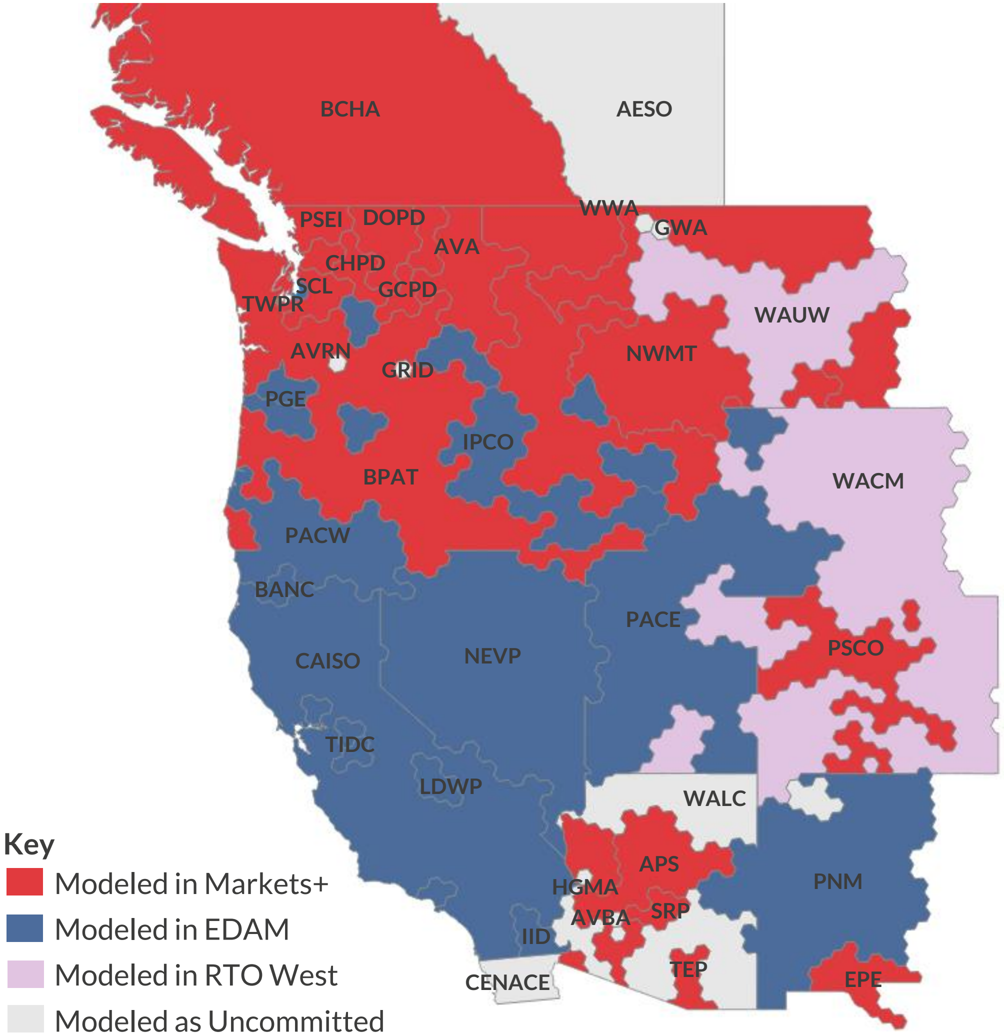
Central outlook on assumed day-ahead market participation[1]



Timeline of assumed day-ahead market participation[1]

EDAM LAUNCH | **2026** | RTO West LAUNCH

- EDAM: PACW, PACE, PGE
- RTO West: WACM, WAUW

2027 | MARKETS+ LAUNCH

- EDAM: BANC, LDWP, PNM, IID
- Markets+: BCHA, TWPR, SRP, TEPC
- EDAM: NEVP[2], IPCO[3]

2028

- Markets+: BPAT, EPE, PSCo
- EDAM: SCL[4], TIDC[5]
- Markets+: PSEI, AVA, GCPD, DOPD, CHPD, NWMT[6]

1) As of May 1, 2025. 2) Nevada Energy is a confirmed participant assumed to begin participation in 2027. 3) Idaho Power is a likely participant assumed to begin participation in 2027. 4) Seattle City Light has expressed interest in EDAM and is modeled as participating starting 2028. 5) Turlock Irrigation District confirmed its 2027 participation in EDAM after the conclusion of Aurora's ing in May 2025. 7) Some Pacific Northwest utilities indicated they would follow Bonneville Power's market decision.

Sources: Aurora Energy Research, WECC, PacifiCorp, PNM, Xcel, APS, PGE, PSE, NVE, SRP, IPCO, AVA, TEP, CAISO, SPP, EIA

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