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ENERGY RESEARCH

Western regionalization: Day-Ahead market benefits analysis for Arizona balancing authorities

CAISO presentation

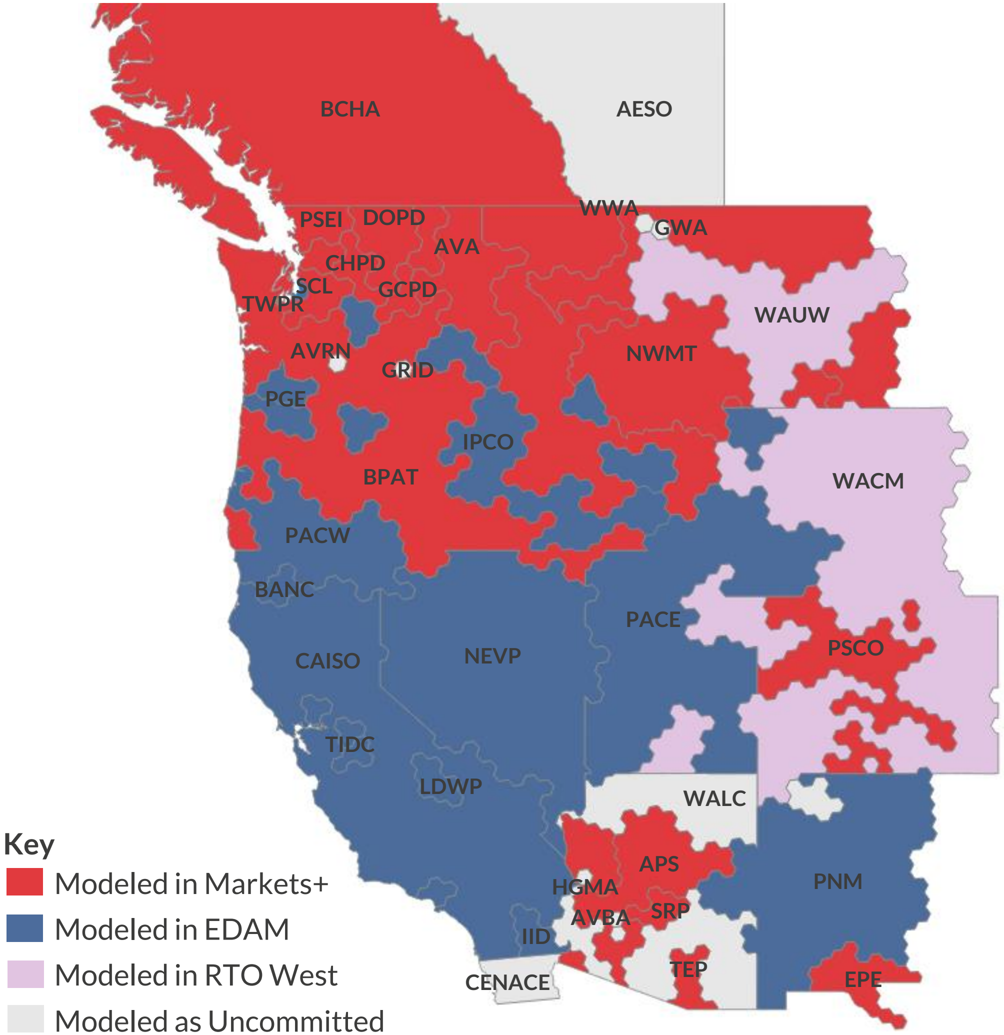
Environmental Defense Fund

February 9th, 2026

Agenda

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

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



Timeline of assumed day-ahead market participation[1]

2026 — EDAM LAUNCH | 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

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

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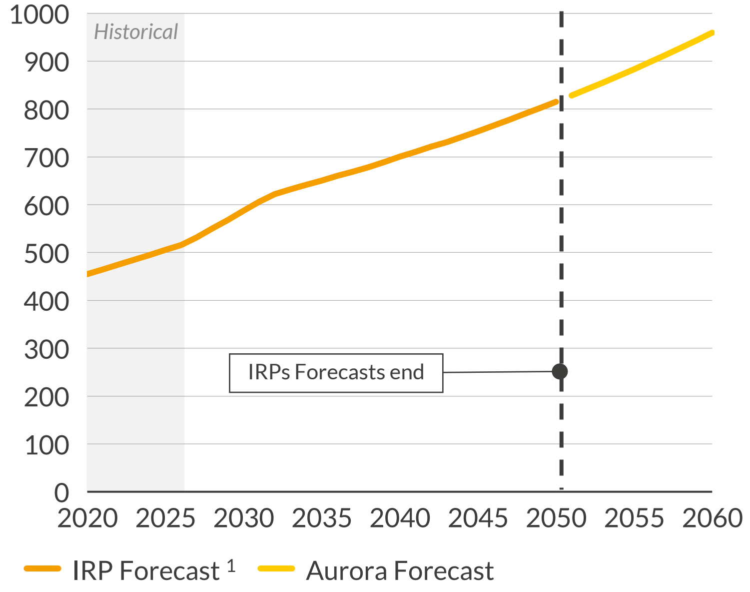
Demand assumptions

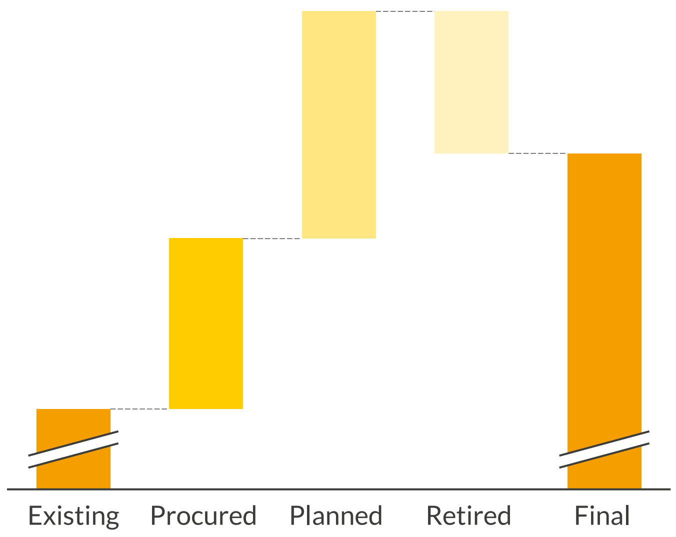
Annual electricity demand
TWh



- 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

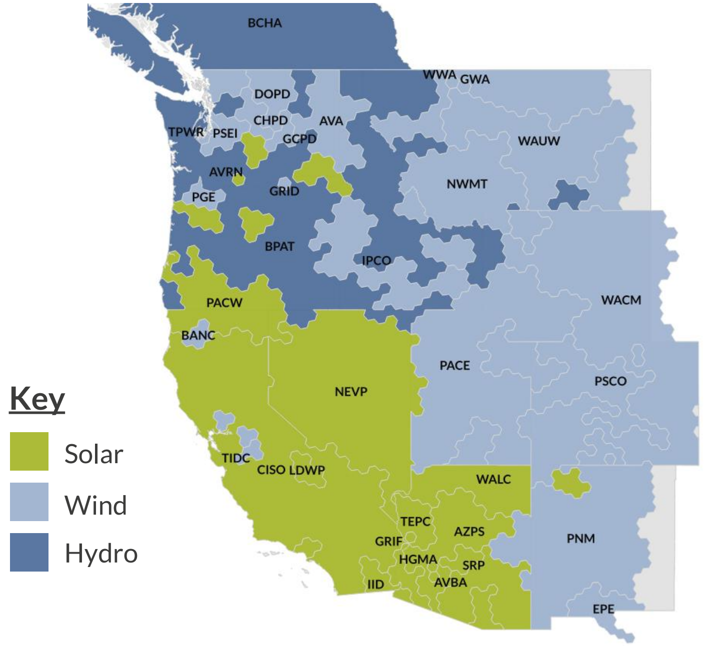
Capacity assumptions components
GW



- 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

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

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

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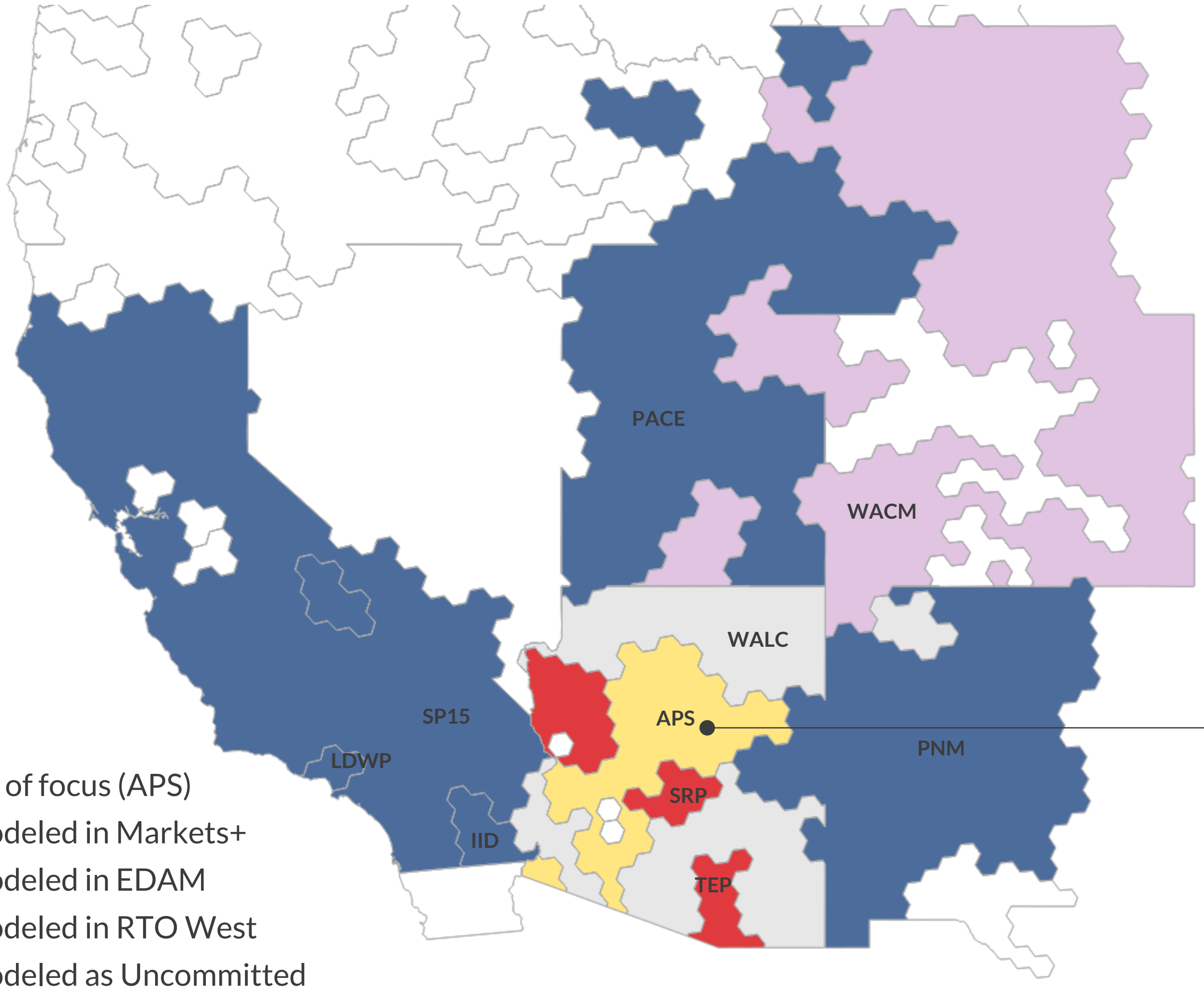
Map of balancing authorities with modeled interchange with APS



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

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
A 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)**

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 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

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

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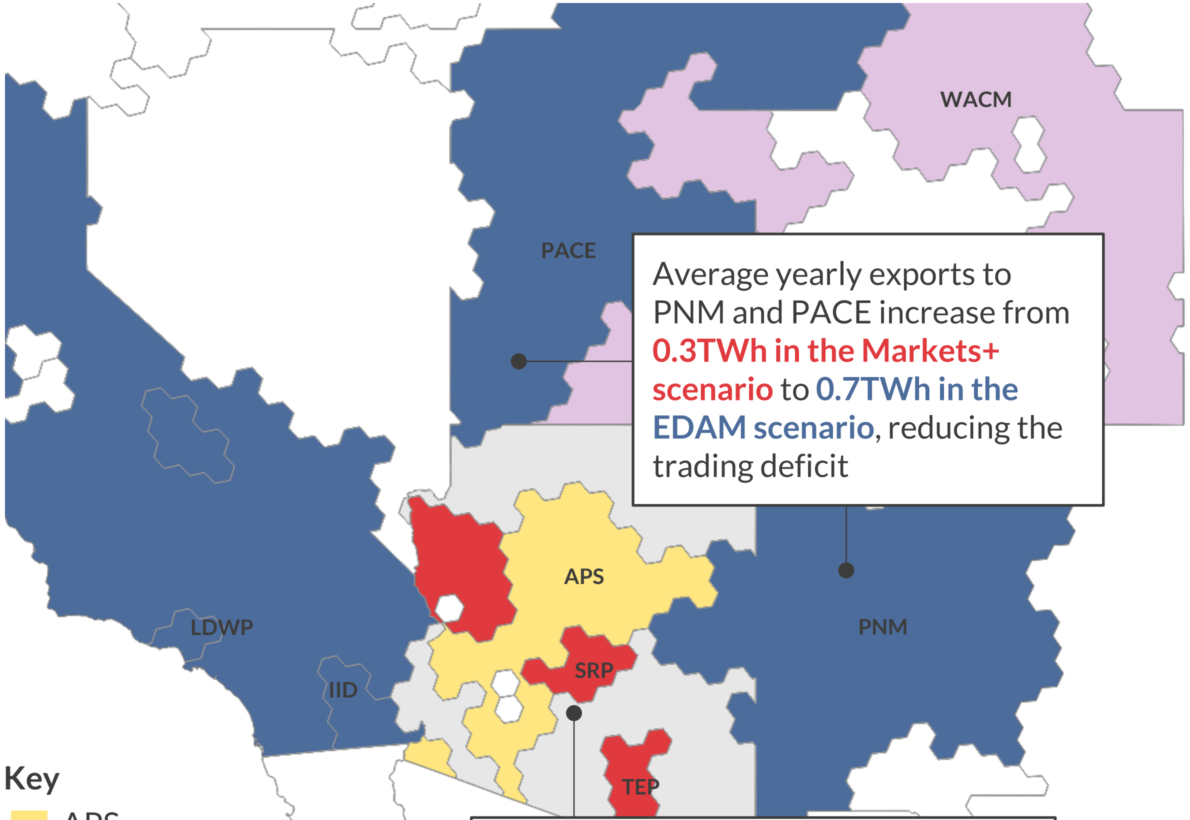
Map of APS and neighboring trading regions



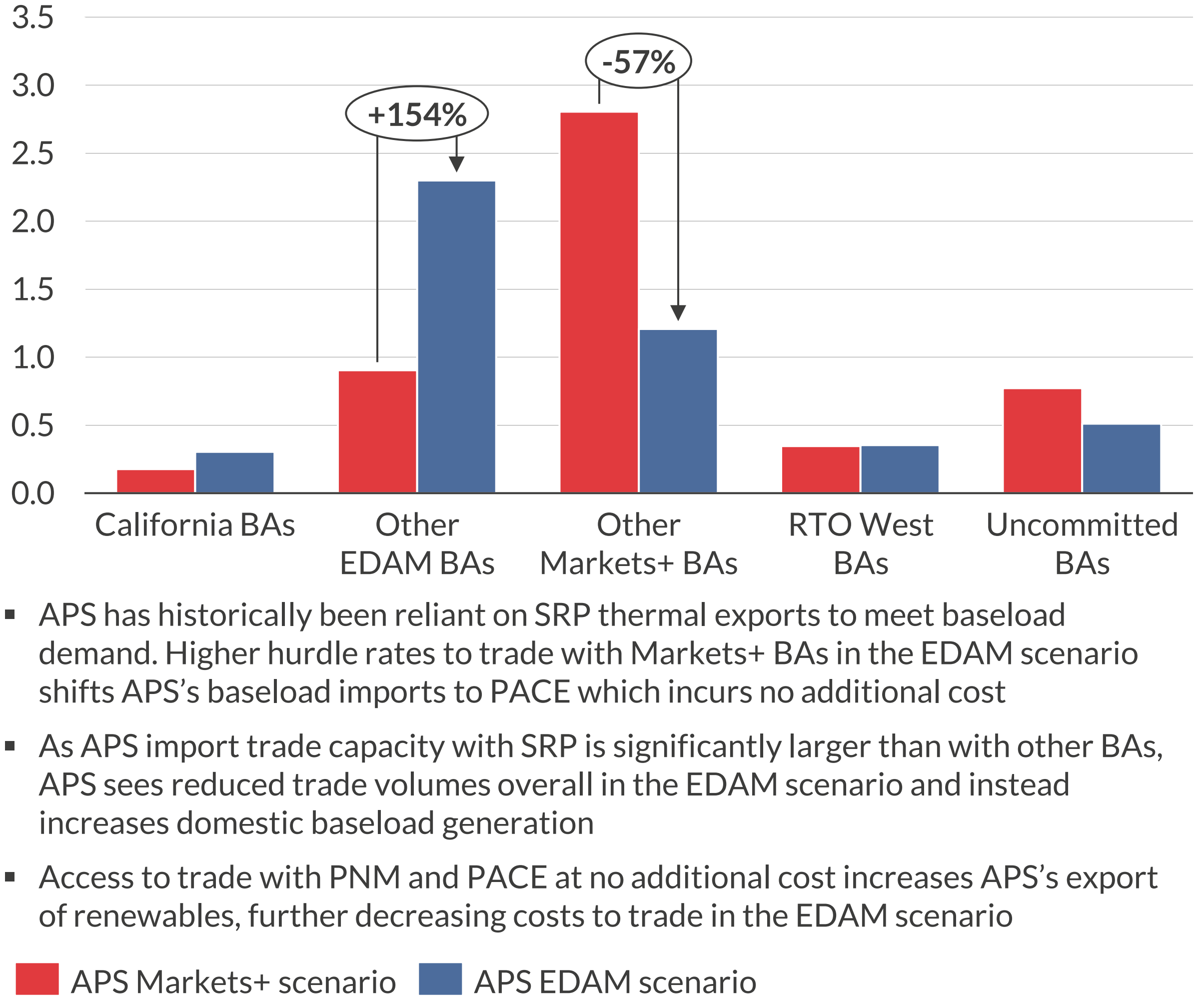
Average yearly exports to PNM and PACE increase from **0.3TWh in the Markets+ scenario** to **0.7TWh in the EDAM scenario**, reducing the trading deficit

Average yearly imports to APS from SRP decrease from **5.8TWh in the Markets+ scenario** to **2.3TWh in the EDAM scenario**, a 60% decrease

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

1) Net imports is calculated as imports minus exports.

Sources: Aurora Energy Research

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

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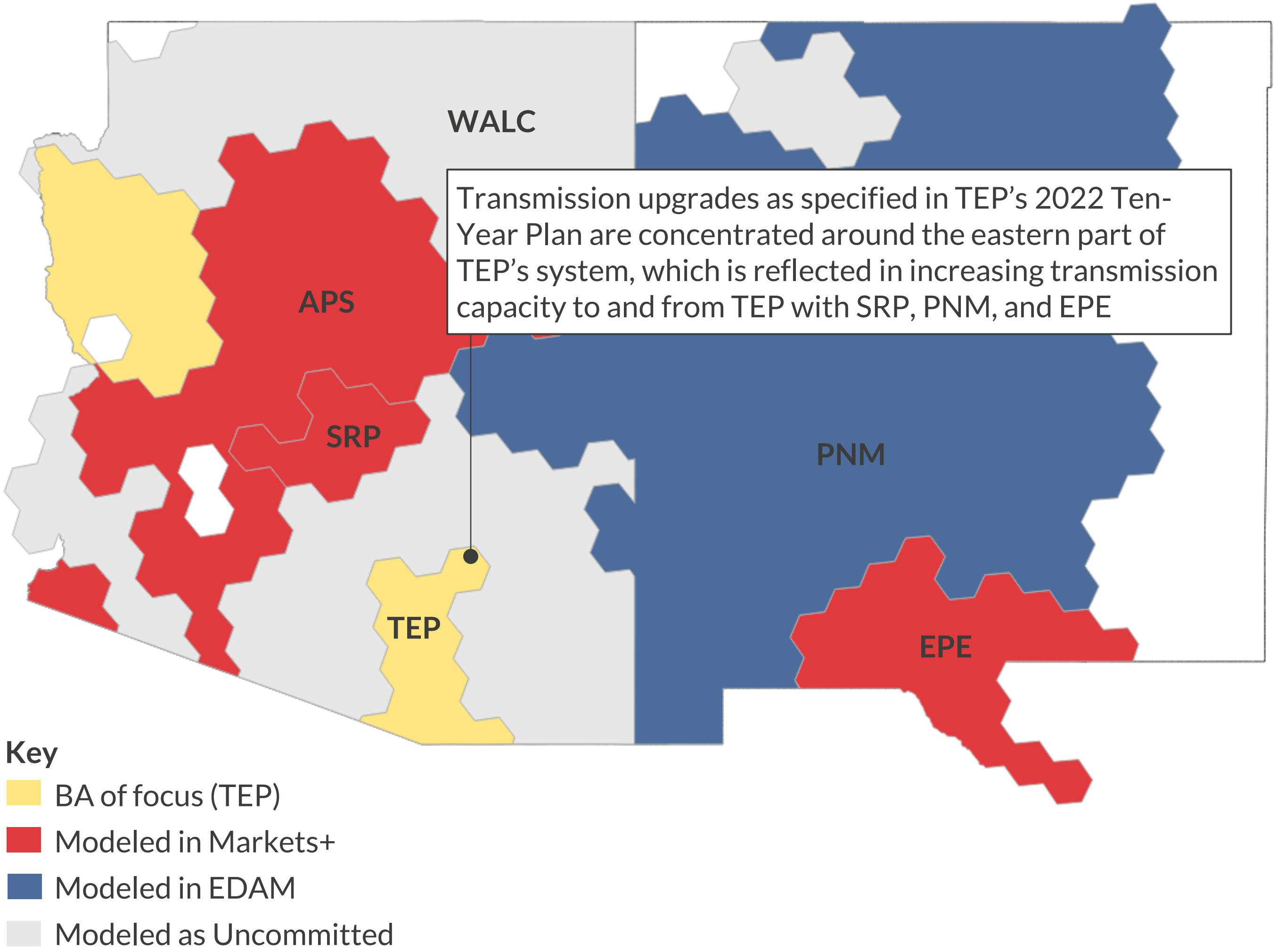
Map of balancing authorities with modeled interchange with TEP



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

Balancing authority	Export[2] transfer limit (MW)	Import transfer limit (MW)
PNM	197.0	216.7
EPE	442.2	106.1
SRP	369.0	708.5
APS	111.3	24.1
WALC	20.8	103.7

Overview of TEP's planned and proposed transmission projects[3]

Project Class	Upgrade Type	Details
500kV lines	New	2 projects
	Upgrade	0 projects
345kV lines	New	4 projects
	Upgrade	0 projects
230kV lines	New	2 projects
	Upgrade	0 projects
138kV lines	New	12 projects
	Upgrade	2 projects
Substations	New	15 projects
	Upgrade	5 projects

1) Transfer limits are modeled at the BA level. BAs identified here show all modeled interchange possibilities for TEP with neighboring BAs. 2) Refers to exports from TEP into listed balancing authorities. 3) Encompassing all projects in TEP's 2022 Ten-Year Transmission Plan.

Sources: Aurora Energy Research, WECC, EIA, TEP

TEP sees total costs reduced by an average of $8.1 million/year through 2040 when participating in EDAM as opposed to Markets+

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This analysis aims to identify the potential benefits or costs for Tucson Electric Power (TEP) under two Western US market regionalization scenarios: (1) TEP participates in EDAM and (2) TEP 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 TEP EDAM vs TEP Markets+, 2027-2040
$Million/year, real 2024

Metric	Day-Ahead Market cases		Average delta, EDAM – Markets+[1]
	TEP EDAM	TEP Markets+	
A Production cost	391.5	416.4	**(25.0)**
Bilateral trading costs	(7.1)	(18.0)	**10.9**
Congestion revenue[2]	(12.5)	(18.1)	**5.5**
Wheeling revenue[2]	(4.4)	(4.9)	**0.5**
Annual average costs[3] (TEP)	**367.4**	**375.5**	**(8.1)**

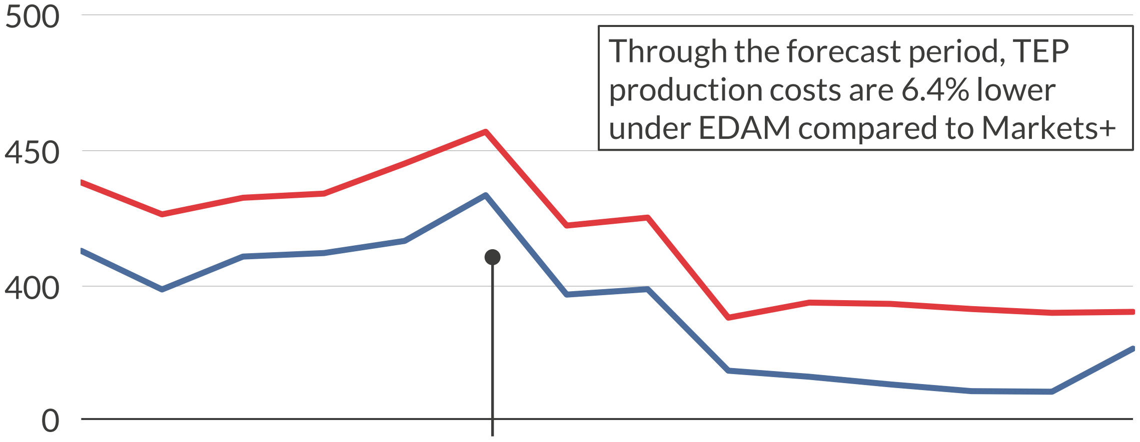
X Deep dive to follow

1) A negative delta indicates lower costs when TEP 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

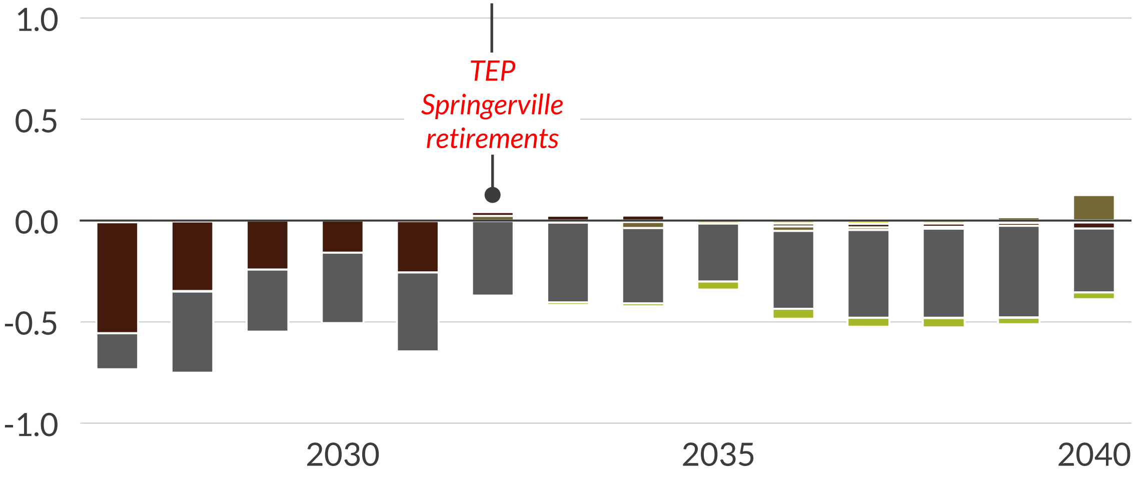
- TEP sees an average $8.1mil/year benefit in total costs when participating in EDAM vs Markets+
- **Production costs** – When in EDAM, TEP sees less baseload thermal generation from reduced exports to Markets+ BAs, resulting in a lower average production cost
- **Bilateral trading costs** – TEP engages in less trade under EDAM as it has access to a smaller trading footprint. In net, lower revenues from decreased exports outweighs the lower costs from decreased imports in the EDAM configuration
- **Congestion and wheeling revenue** – Under the EDAM scenario TEP sees less utilization of its transmission interconnection, particularly to and from SRP[2]

A Lower baseload thermal production in the EDAM scenario from reduced thermal exports drives lower production costs for TEP

Yearly TEP production cost, 2027-2040
$Million/year, real 2024



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



2027-2032:

- TEP is in a net exporting position, sitting on top of gas capacity and significant coal capacity from the Springerville Generating Station.
- In the Markets+ configuration, TEP ramps up generation to export lower cost thermal to neighboring Markets+ BAs, driving a higher production cost relative to the EDAM scenario

2033-2040:

- Following Springerville coal retirements, the TEP system becomes more resource-constrained. Under EDAM, TEP sources more PNM thermals to compensate for reduced domestic baseload.
- Under Markets+, access to lower cost baseload thermals from SRP allows TEP to continue exporting its domestic gas generation, which maintains its production cost delta to the EDAM scenario

1) Delta is calculated as EDAM scenario – Markets+ scenario. 2) Peaking includes OCGTs and reciprocating engines.

Sources: Aurora Energy Research

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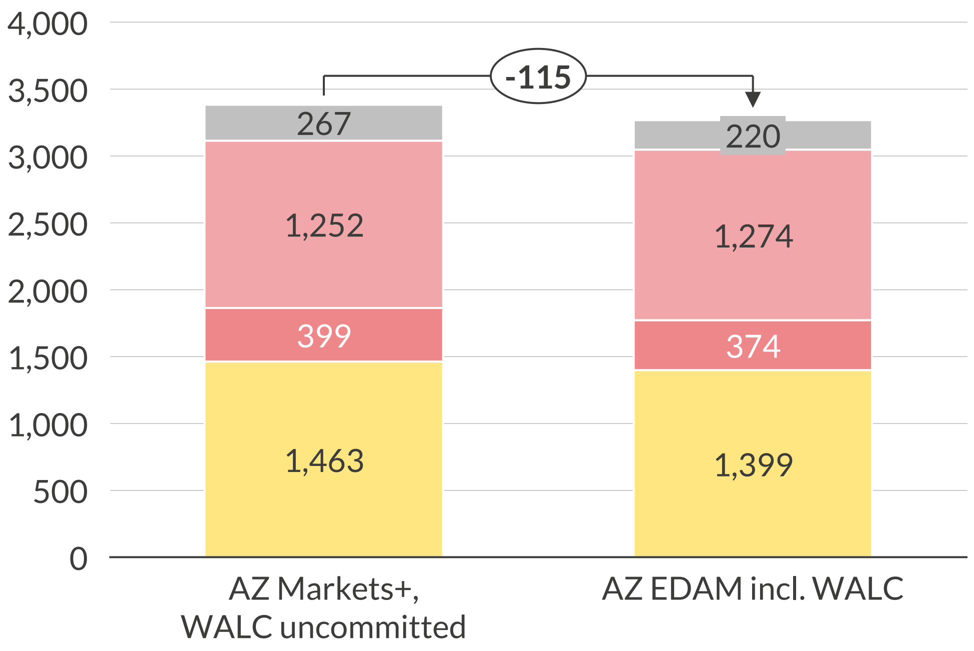
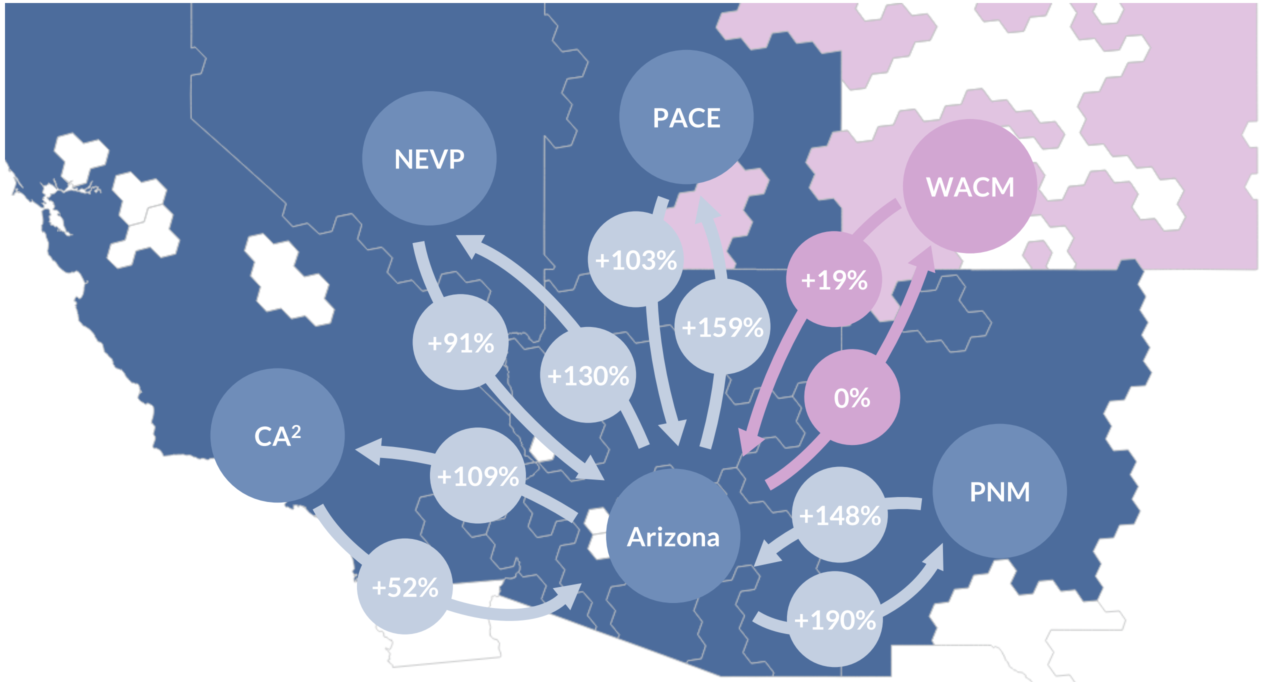
Arizona-wide[1] average annual total system cost, 2027-2040
$Million/year, real 2024



Arizona[1] average annual trade delta to AZ Markets+, WALC uncommitted scenario
%



- Arizona BAs see a 115million/year reduction in total system costs in the AZ EDAM incl. WALC configuration compared to the AZ Markets+, WALC uncommitted scenario
- 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

- 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 AZ Markets+, WALC uncommitted scenario

WALC SRP TEPC APS

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.

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

	AZ Markets+, WALC uncommitted	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.

Sources: Aurora Energy Research

Decreased thermal generation in SRP in the AZ EDAM scenarios drives lower production costs relative to the Markets+ scenario

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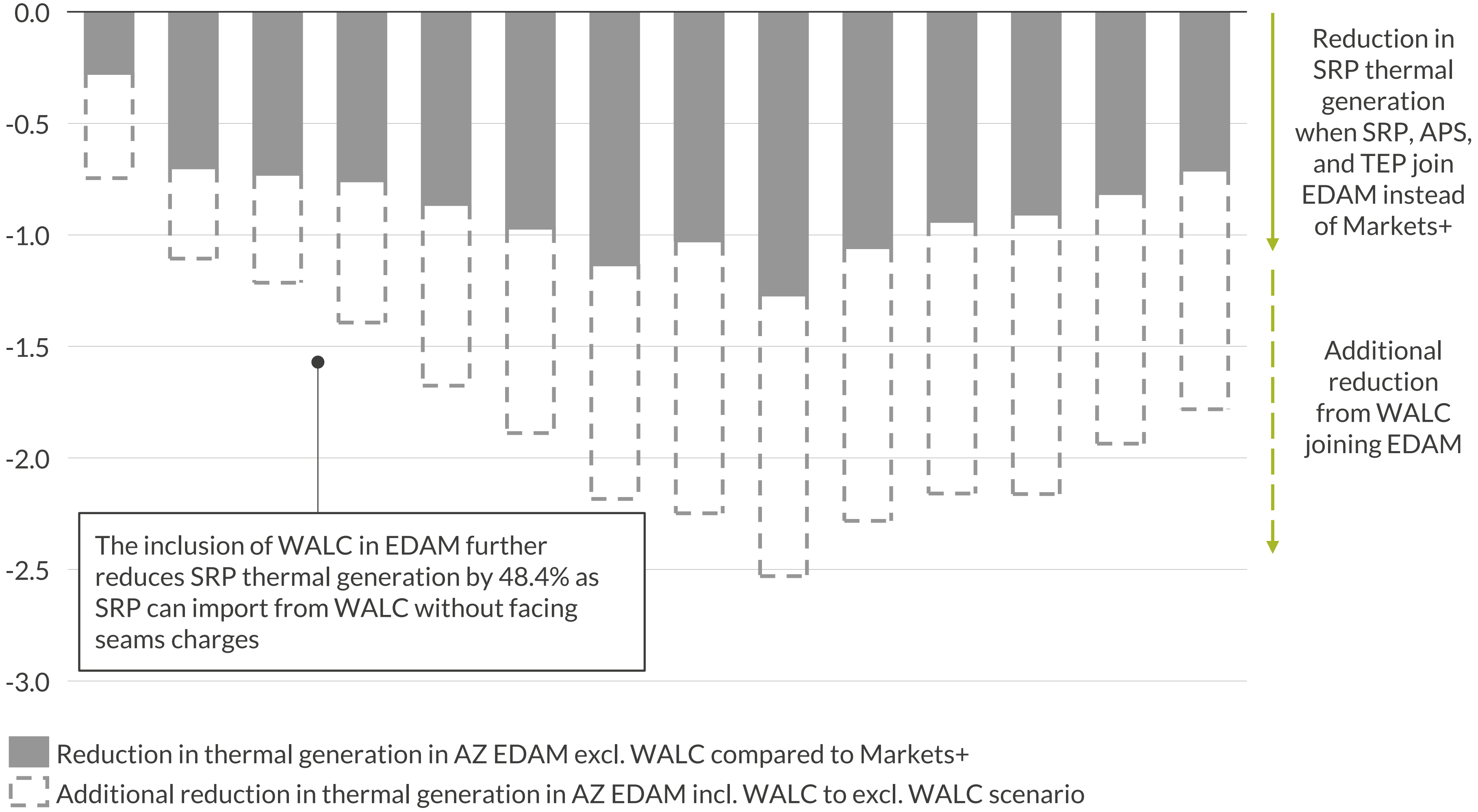
Yearly thermal generation delta in SRP, 2027 – 2040
TWh



- When Arizona participates in EDAM, SRP sees reduced export volumes, particularly to APS, and increased import volumes, particularly from SP15. The increase in net imports reduces domestic production and the associated production cost for SRP under AZ EDAM as opposed to SRP Markets+
- The reduced domestic thermal generation drives a 3.1-4%, or ~0.4MMtCO2, reduction in annual SRP emissions under the AZ EDAM scenarios compared to the Markets+ scenario
- While not quantified in the system cost metrics, there are benefits associated with reduced carbon emissions that can counteract some of the cost increases in the EDAM scenarios

Sources: Aurora Energy Research

SRP sees higher average system costs when Arizona BAs commit to EDAM over Markets+, although this translates to less than <2%

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This analysis aims to identify the potential benefits or costs for Salt River Project (SRP) under three Western US market regionalization scenarios: (1) SRP participates in Markets+, (2) SRP, APS, TEP participate in EDAM, and (3) SRP, APS, TEP, WALC participate in EDAM, with all else remaining equal. Comparisons between scenarios include those of various cost categories, generation mix, and emissions outputs.

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

	SRP in Markets+[3]	AZ EDAM, excl. WALC	AZ EDAM, incl. WALC
Metric			
Production cost	1,426.1	1,376.4	1,327.8
Bilateral trading costs	(35.7)	40.1	91.0
→ Export revenue	(420.0)	(379.2)	(382.2)
→ Import cost	384.2	419.3	473.2
Congestion revenue[1]	(94.1)	(102.7)	(112.0)
Wheeling revenue[1]	(22.5)	(21.2)	(20.6)
Annual costs[2] (SRP)	**1,273.8**	**1,292.6**	**1,286.2**
Annual costs[2] (AZ)	**3,381.7**	**3,342.2**	**3,266.8**

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 the AZ Markets+, WALC uncommitted scenario
Sources: Aurora Energy Research

- SRP experiences an average $12–19M/year cost increase under AZ EDAM configurations relative to Markets+, though total Arizona-wide costs are lower
- **Production costs:** EDAM increases renewable imports from SP15 and reduces thermal exports to APS, lowering SRP's thermal dispatch and production costs
- **Bilateral trading costs:** The EDAM footprint raises SRP's import volumes and costs, while reducing SRPs export volumes to APS as APS accesses a broader pool of generation. The combination of greater imports and lower exports increases SRP's bilateral trading costs
- **Congestion and wheeling revenue:** EDAM drives higher utilization of SRP's transmission interties, particularly for SP15 imports, increasing congestion and wheeling activity

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 $66.5 million/year relative to the APS EDAM scenario and $114.9 million/year relative to the APS Markets+ scenario
- **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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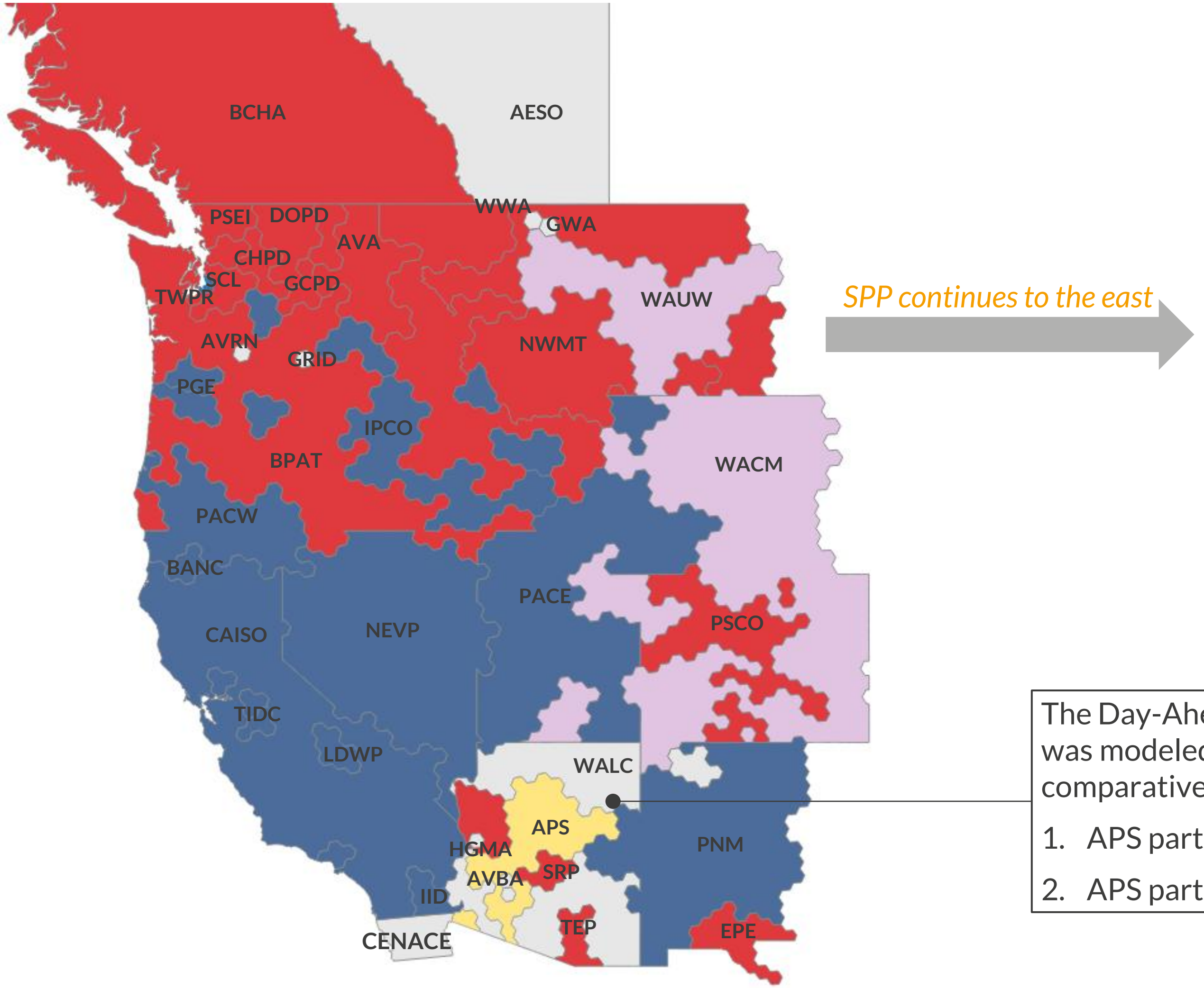
Map of modeled balancing authority (BA) market decisions



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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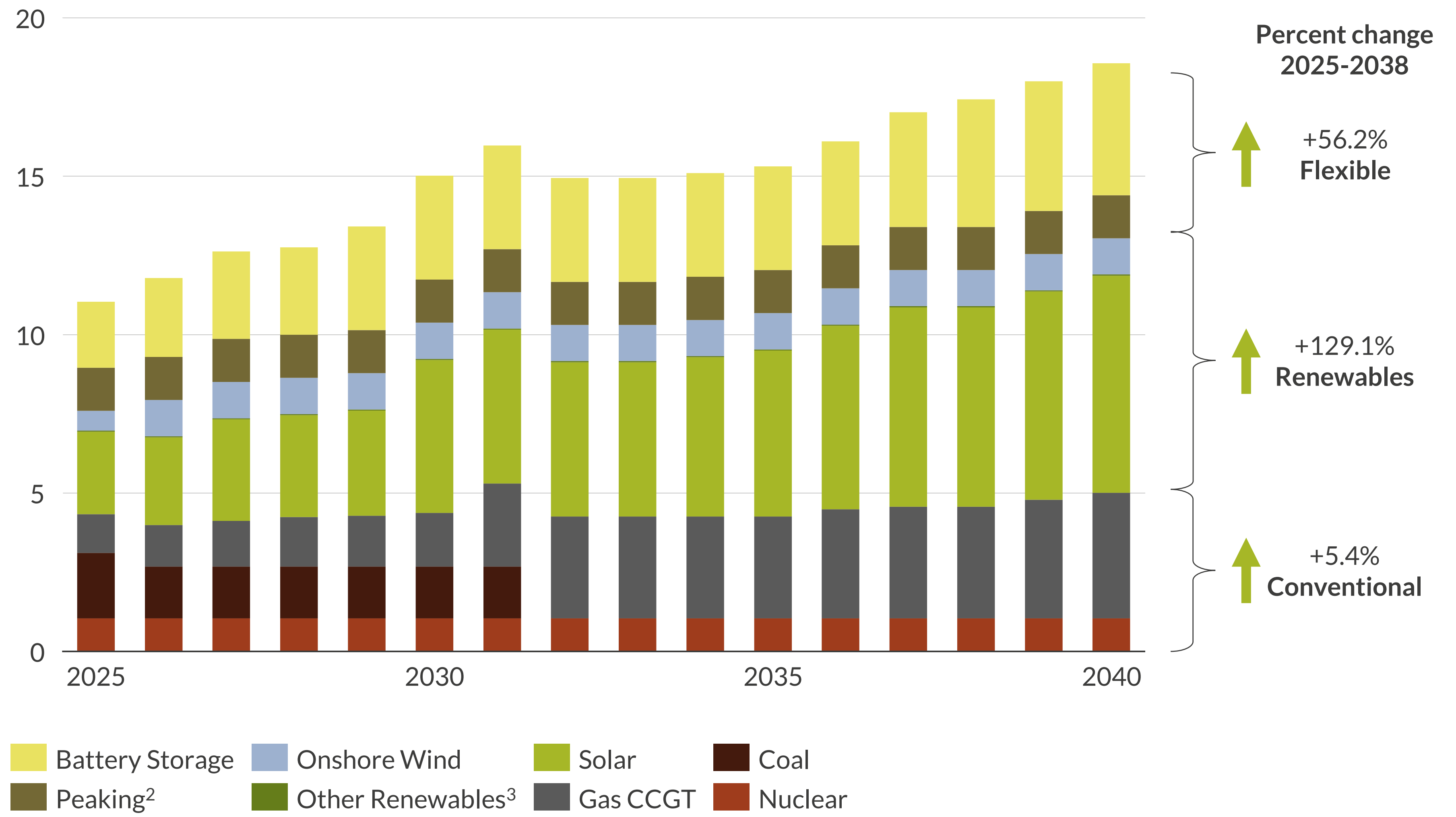
Installed capacity in APS[1]
GW



- 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

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

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

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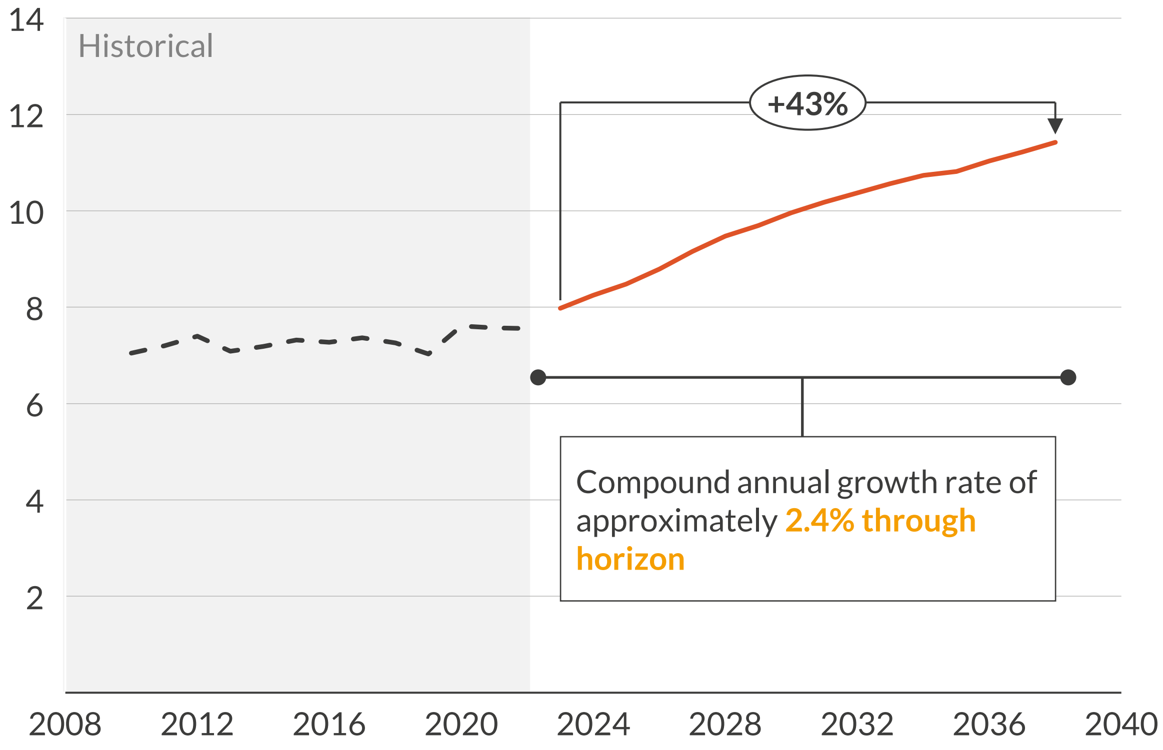
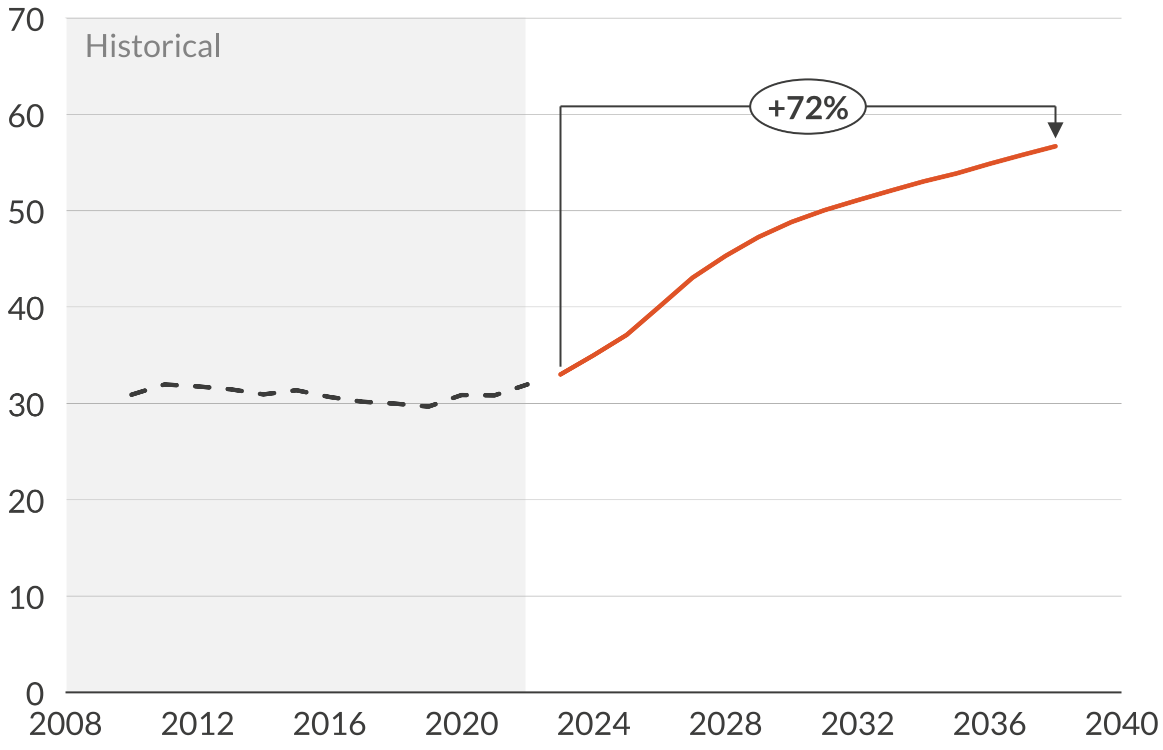
APS coincidental peak demand[1,2]
GW



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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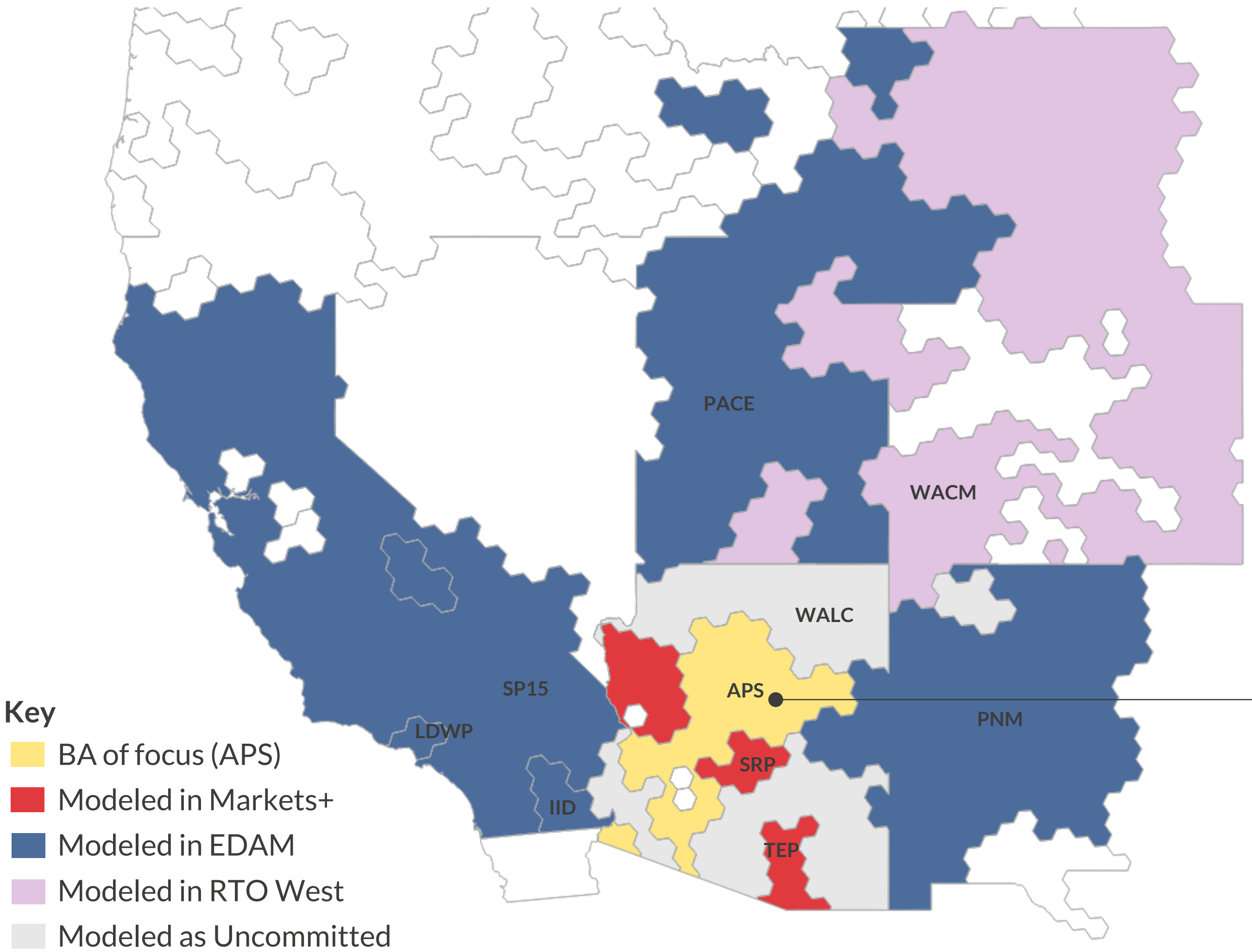
Map of balancing authorities with modeled interchange with APS



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

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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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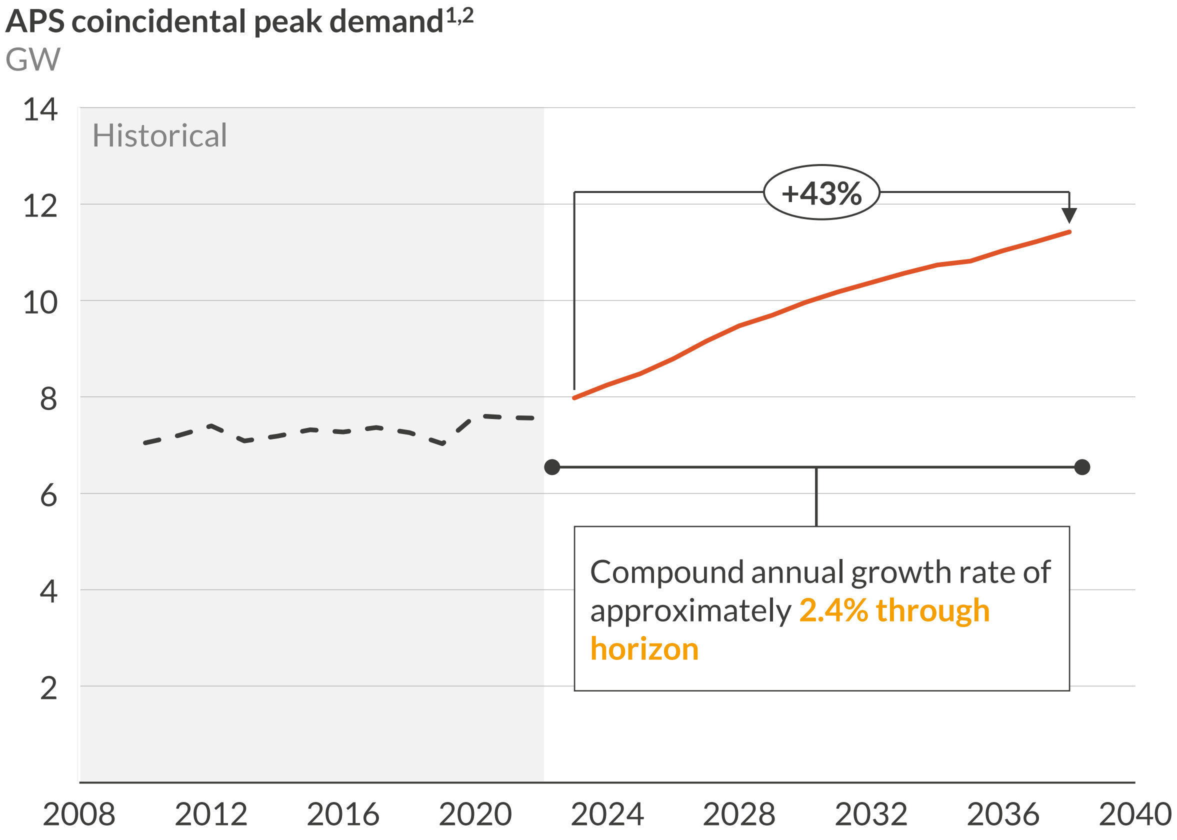

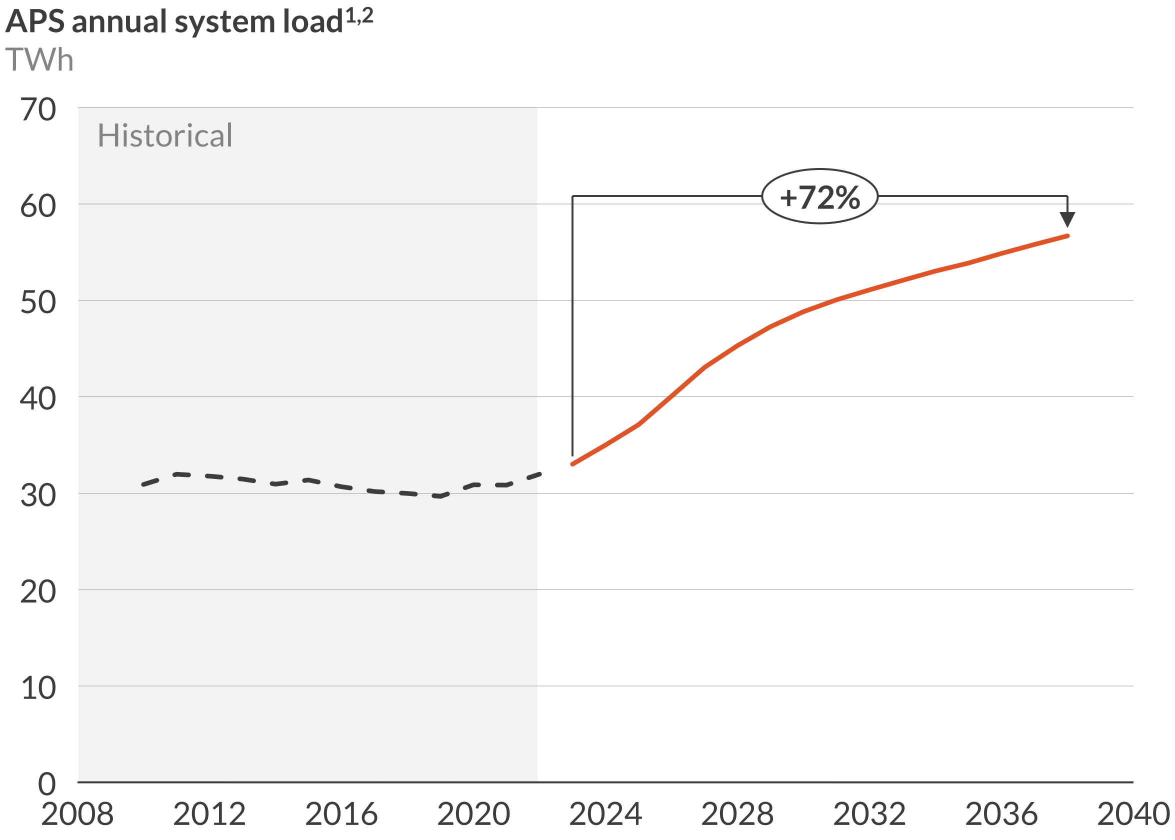

- APS has significantly increased its peak and annual load forecasts in the latest IRP in response to increased data center and large industrial and manufacturing customer demand

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

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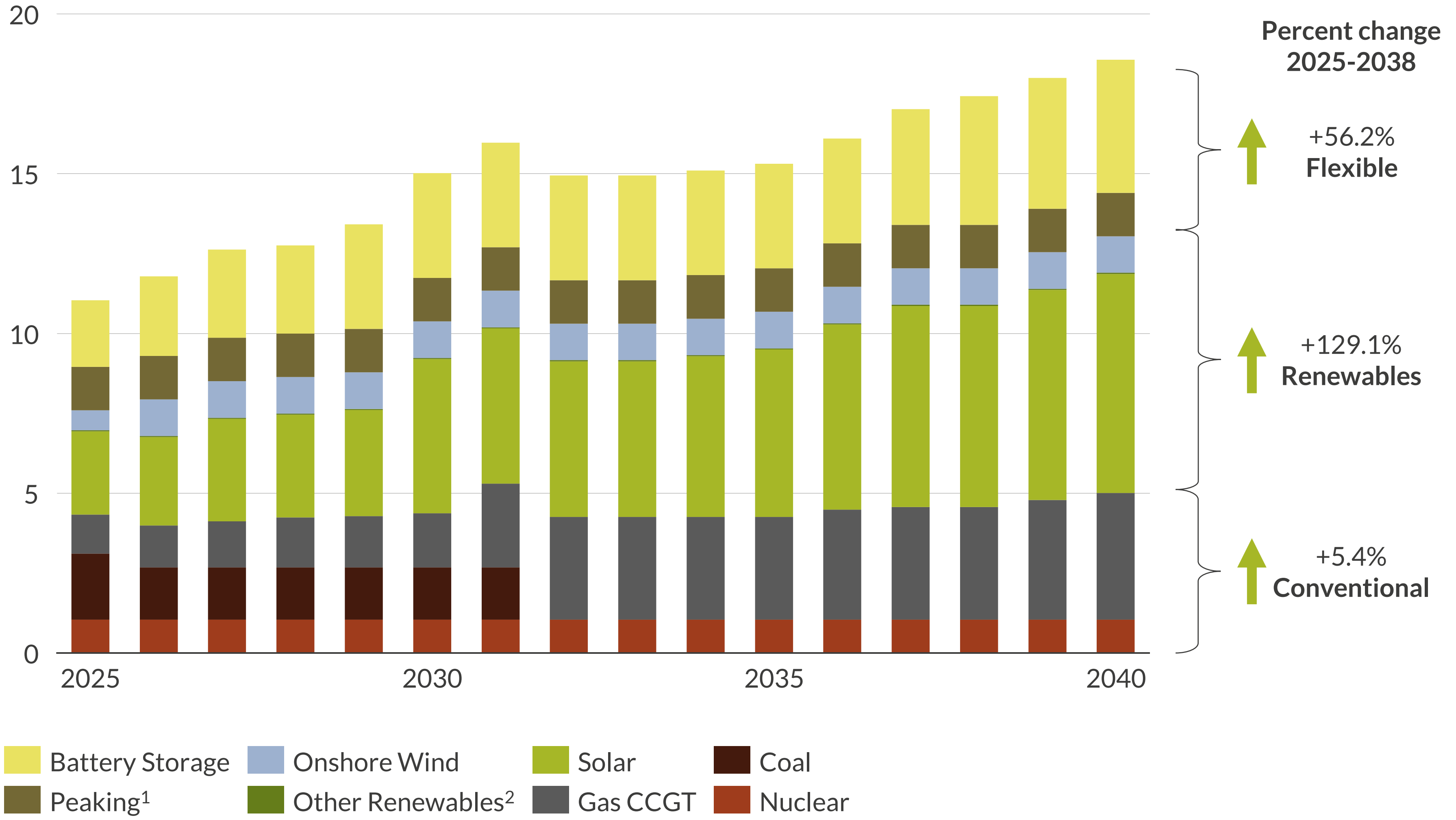
Installed capacity in APS
GW



1) Peaking includes OCGT, reciprocating engines. 2) 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

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

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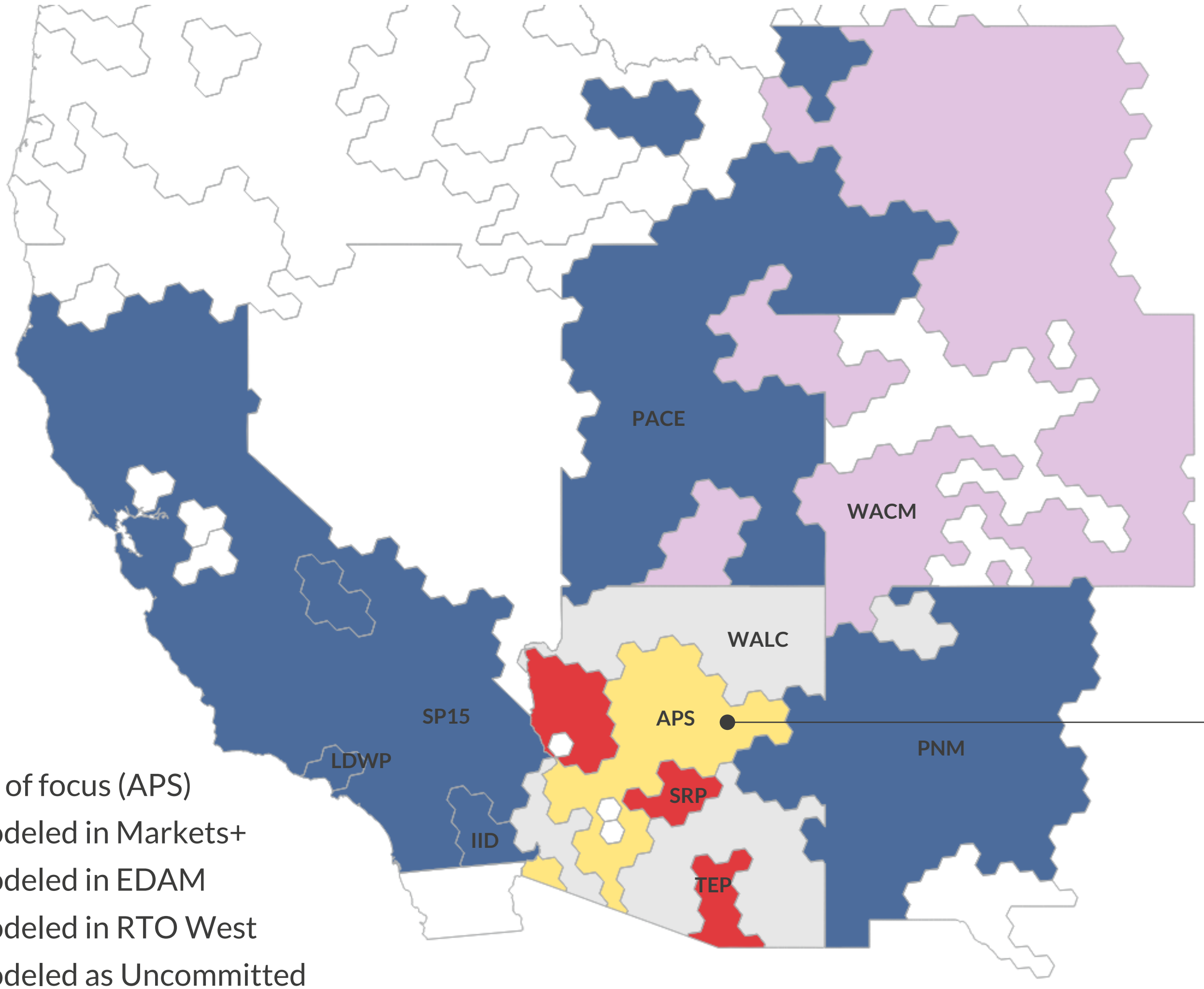
Map of balancing authorities with modeled interchange with APS



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
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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

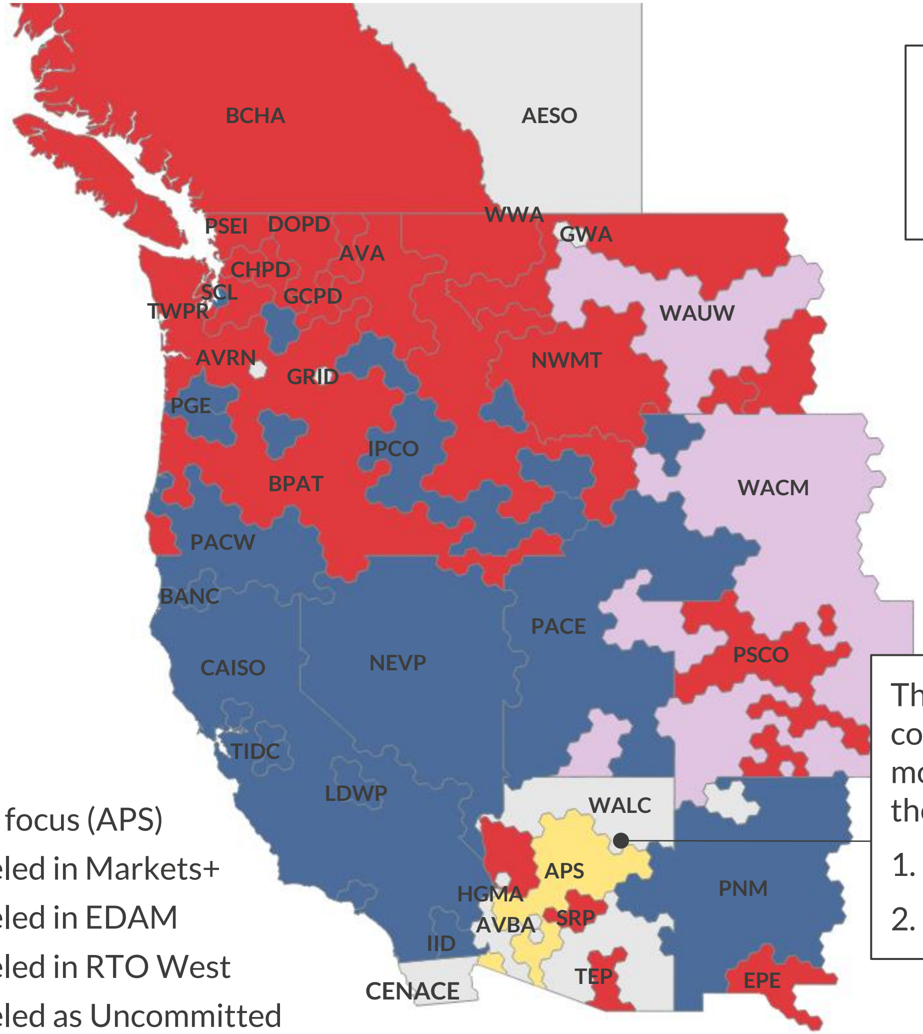
1) Transfer limits are modeled at the BA level. BAs identified here show all modeled interchange possibilities for PSCo with neighboring BAs. 2) Refers to exports from APS into listed balancing authorities. 3) 'California' includes SP15, LDWP, and IID.

Sources: Aurora Energy Research, WECC, EIA, APS

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



Key[1,2]

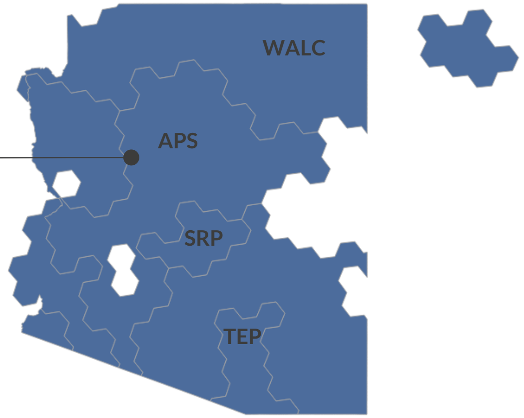
- BA of focus (APS)
- Modeled in Markets+
- Modeled in EDAM
- Modeled in RTO West
- Modeled as Uncommitted

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

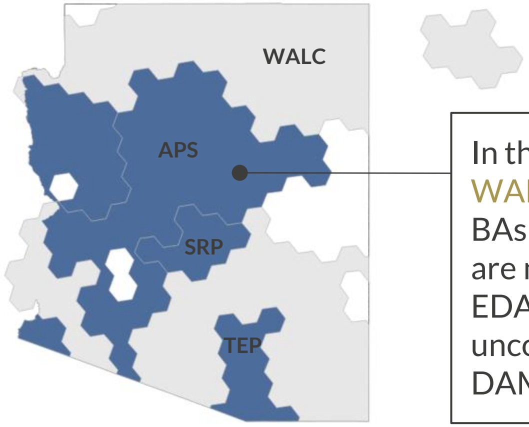
1. APS in EDAM
2. APS in Markets+

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



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



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

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

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

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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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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+	
A Production cost	1,110.7	1,101.4	9.3
B Bilateral trading costs	356.6	427.5	(70.9)
C Congestion revenue[2]	(100.0)	(52.2)	(47.8)
C Wheeling revenue[2]	(13.9)	(13.5)	(0.5)
Annual average costs[3] (APS)	**1,353.5**	**1,463.3**	**(109.9)**

X Deep dive to follow

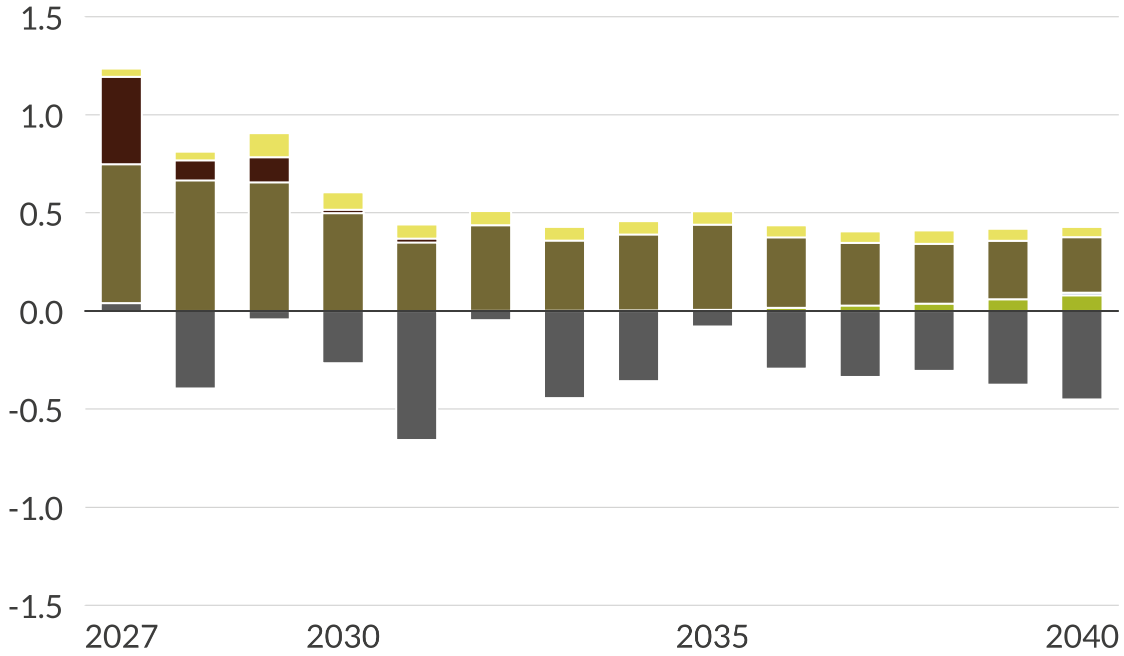
- APS sees an average $109.9mil/year benefit in total costs when participating in EDAM vs. Markets+
- **Production costs** - When in EDAM, reduced thermal imports from SRP drives greater peaking generation and production costs as a result
- **Bilateral trading costs** - A larger trading footprint under 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 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

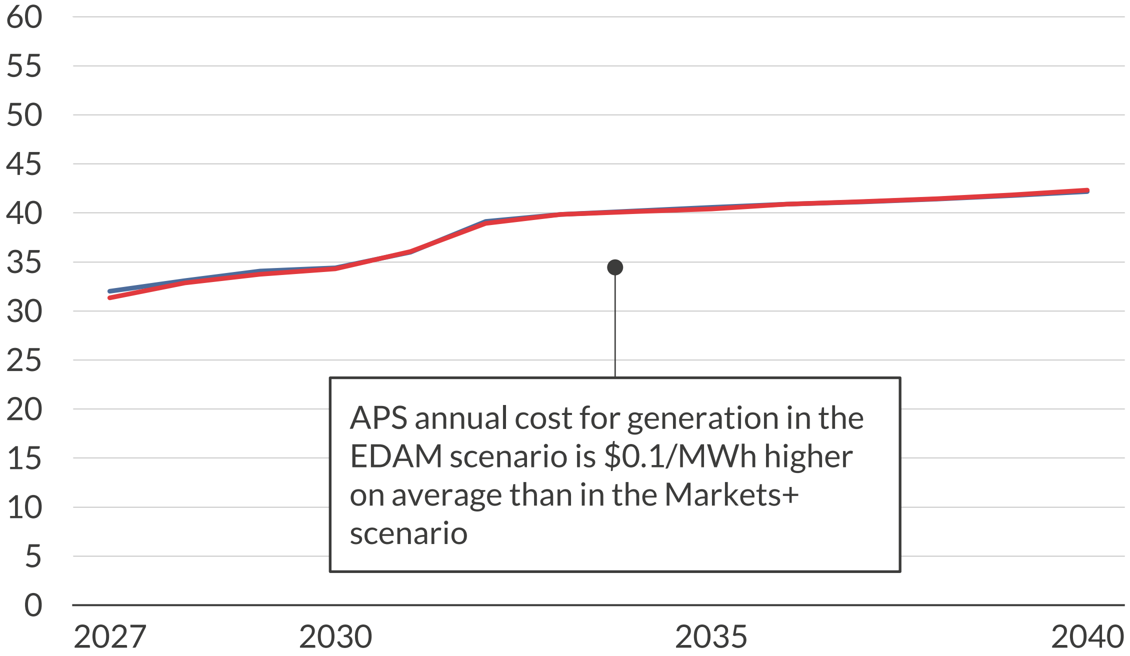
A Increased thermal generation in APS in the EDAM scenario drives up production costs, though the impact is <1% of annual total costs

AURORA

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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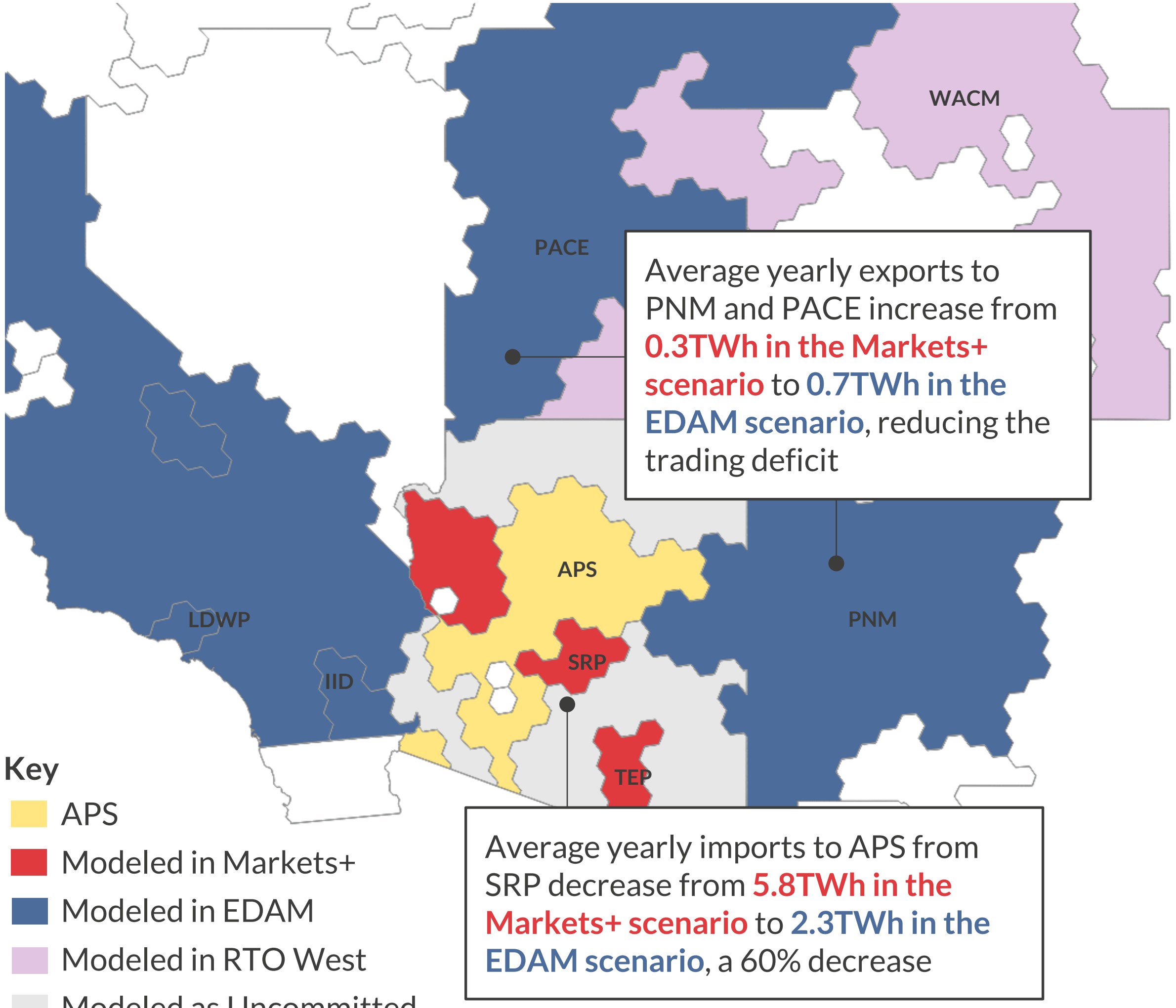
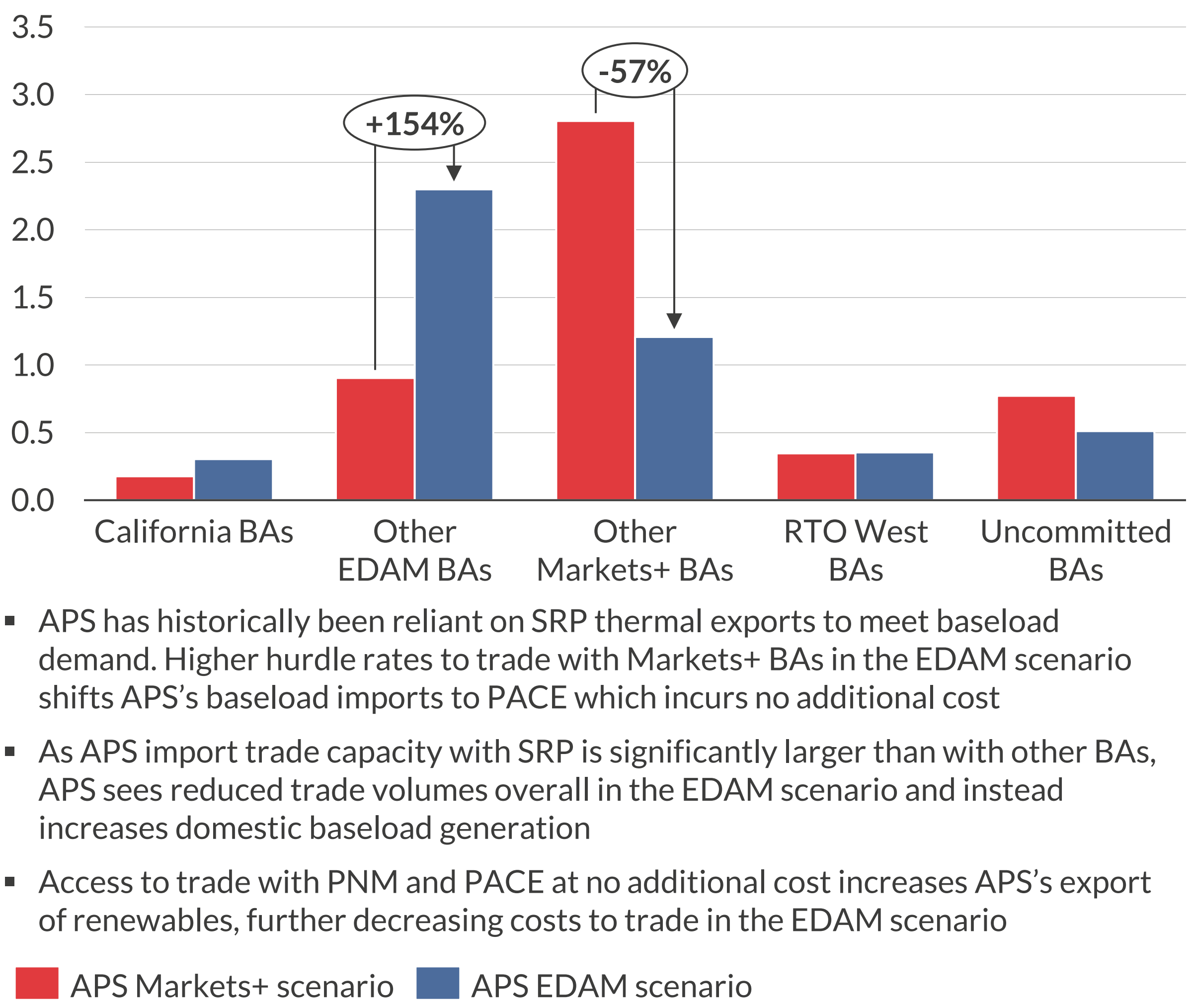
Map of APS and neighboring trading regions



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



- 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

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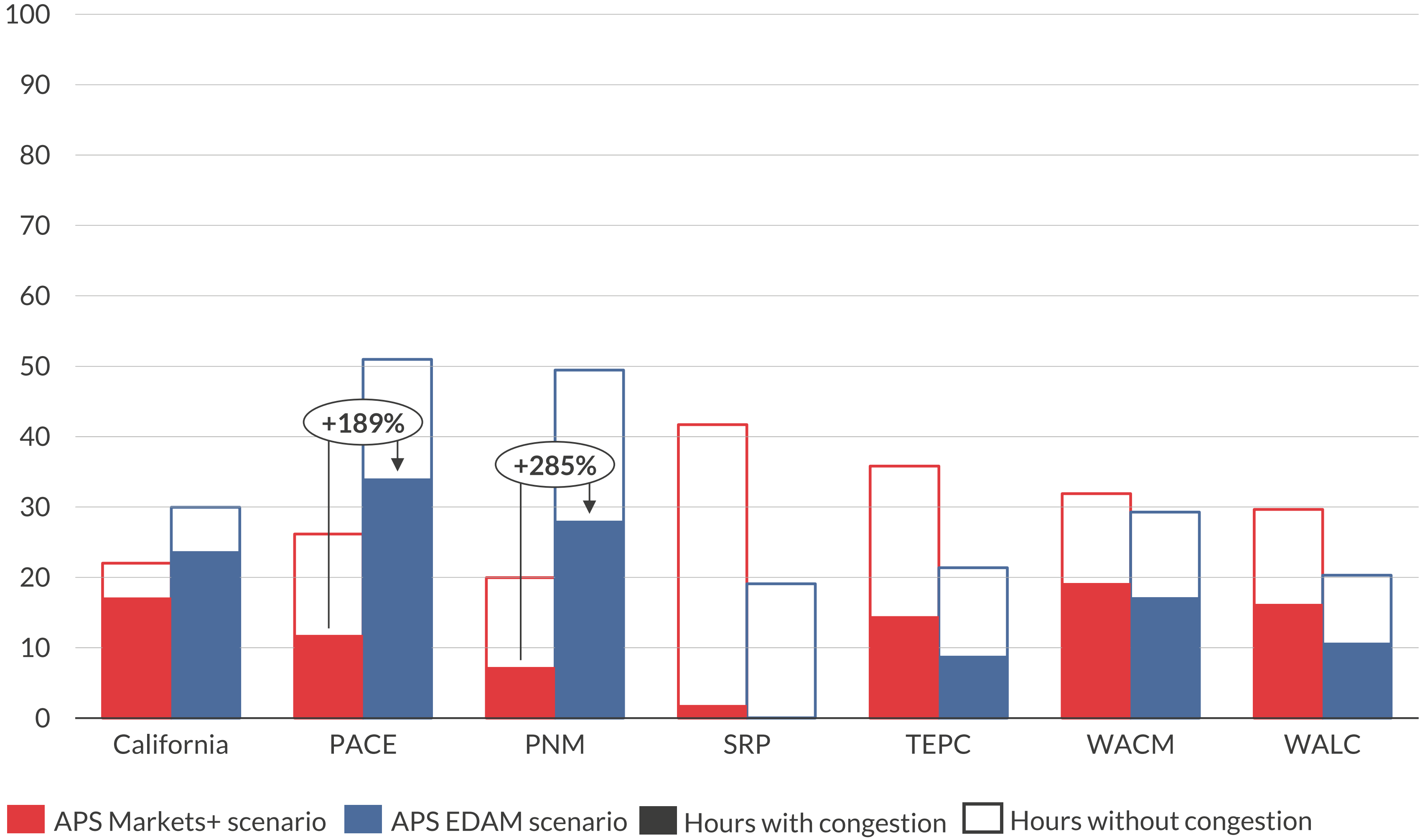
Average annual inter-BA congestion and wheeling trading hours with APS, 2027-2040
% of hours per year



- 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

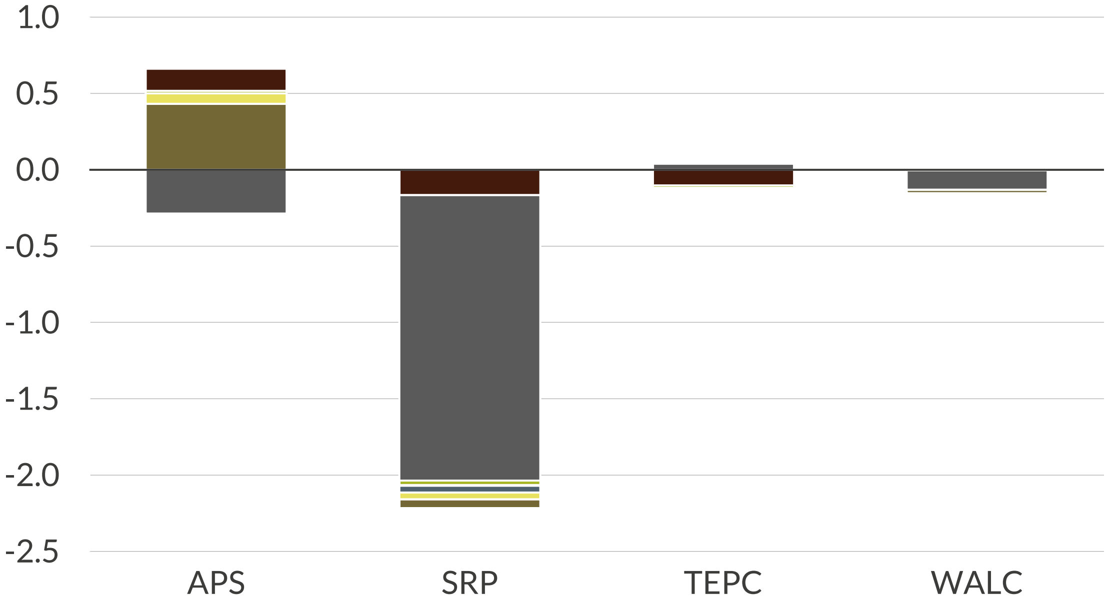
1) Ownership of transmission assumed to be split 50-50 with connecting BA unless data on ownership is available.

Sources: Aurora Energy Research

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

AURORA

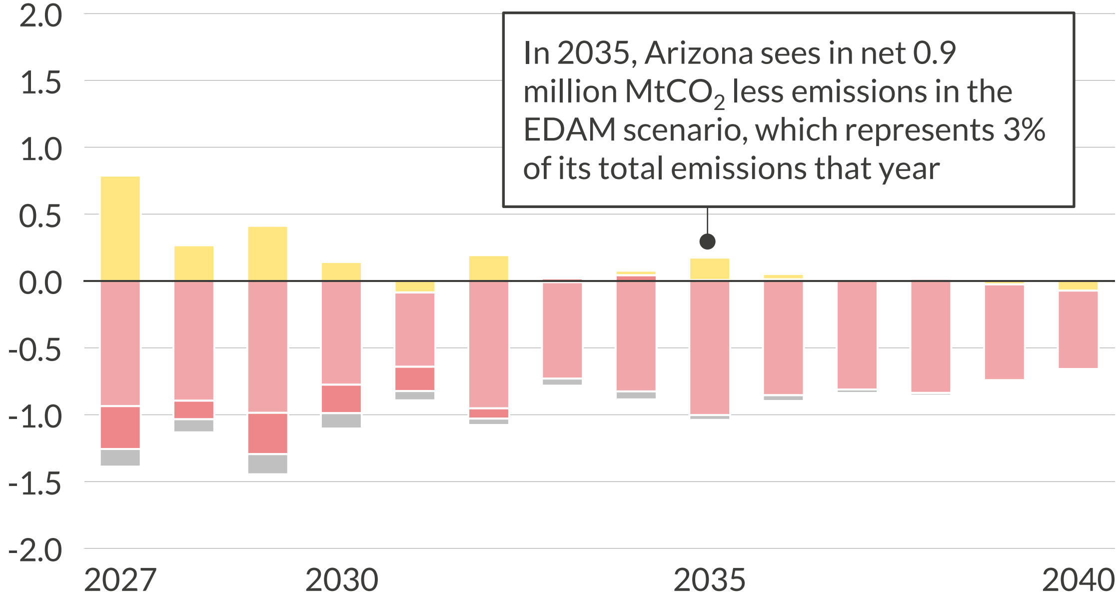
Average annual net electricity production delta[1], 2027-2040
TWh



- 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

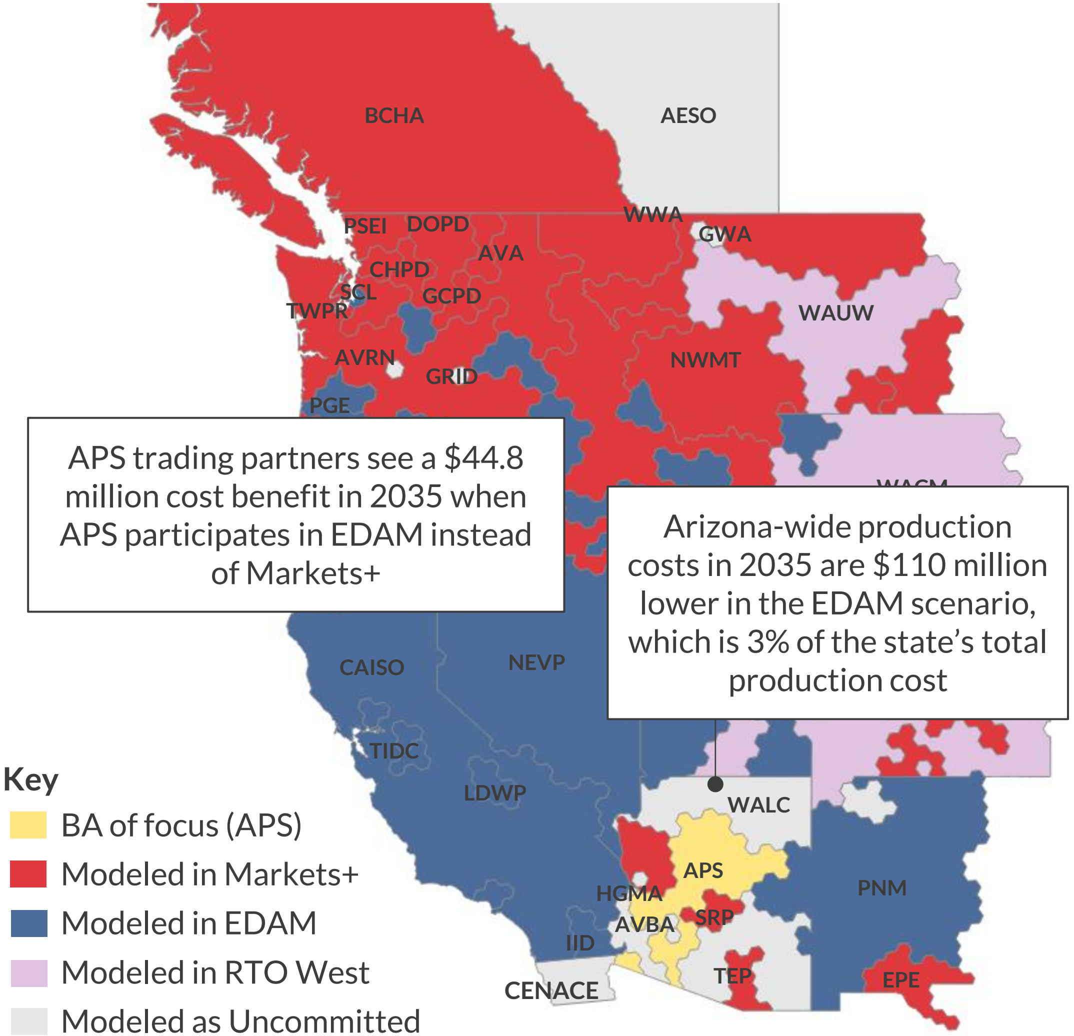
1) Delta is calculated as EDAM scenario – Markets+ scenario. 2) Other RES includes biomass and geothermal.3) Storage technologies report a net charging production; a positive delta indicates less net charging.

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

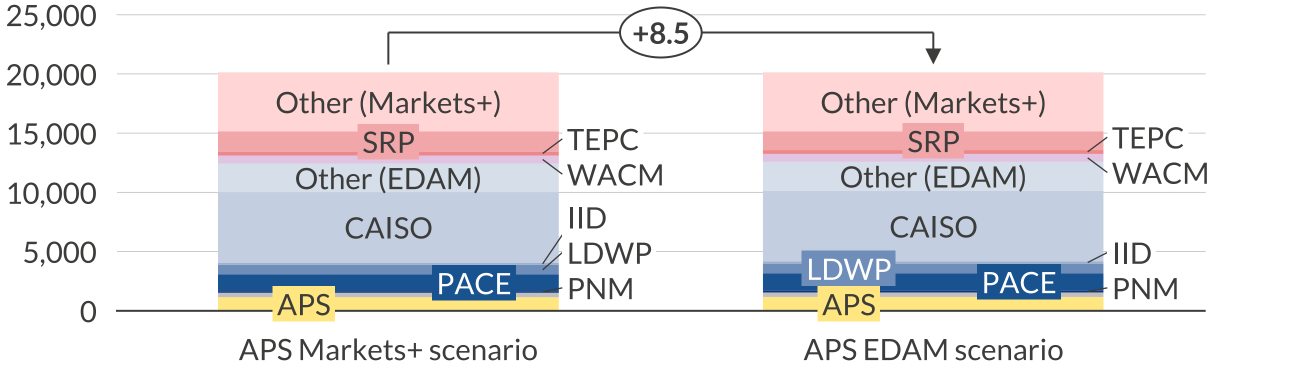
AURORA

Map of modeled balancing authority (BA) market decisions



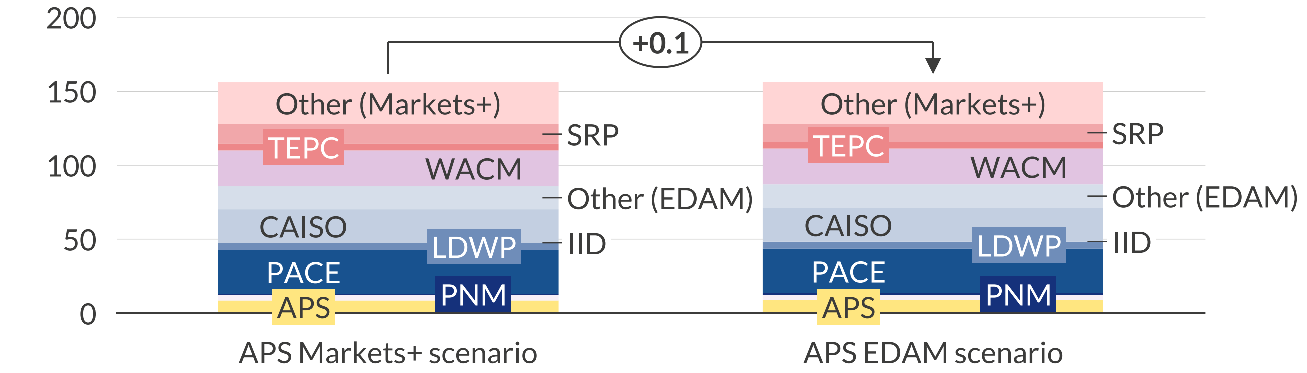
Total WECC-wide production costs in 2035[1]

$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

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+

AURORA

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+

AURORA

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*

	APS in Markets+ → AZ EDAM, excl. WALC	AZ EDAM, excl. WALC → AZ EDAM, incl. WALC
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

WALC joining EDAM drives minimal cost change for APS and significant savings at the state level from increased trading

AURORA

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

	AZ EDAM incl. WALC	AZ EDAM, excl. WALC (with Springerville conversion)	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

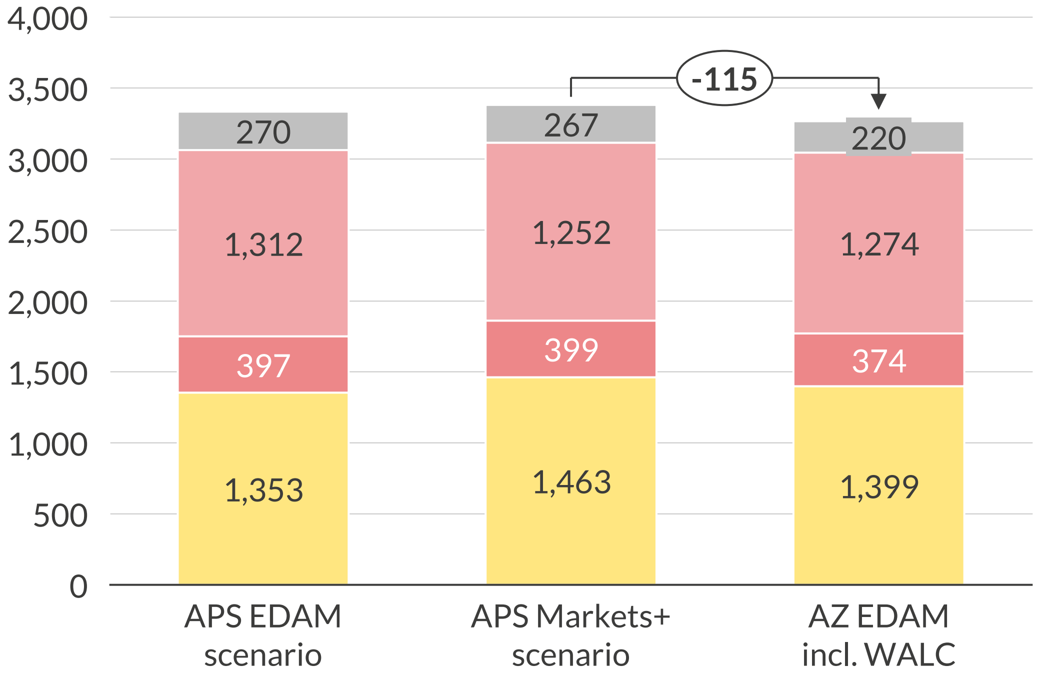
- APS sees an average $1.9mil/year additional cost when WALC joins EDAM alongside TEP, SRP, and APS.
- WALC sits on top of significant thermal capacity; when in EDAM, this increases the amount of baseload generation available for resource sharing. As a result, when WALC remains uncommitted to a DAM, 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

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

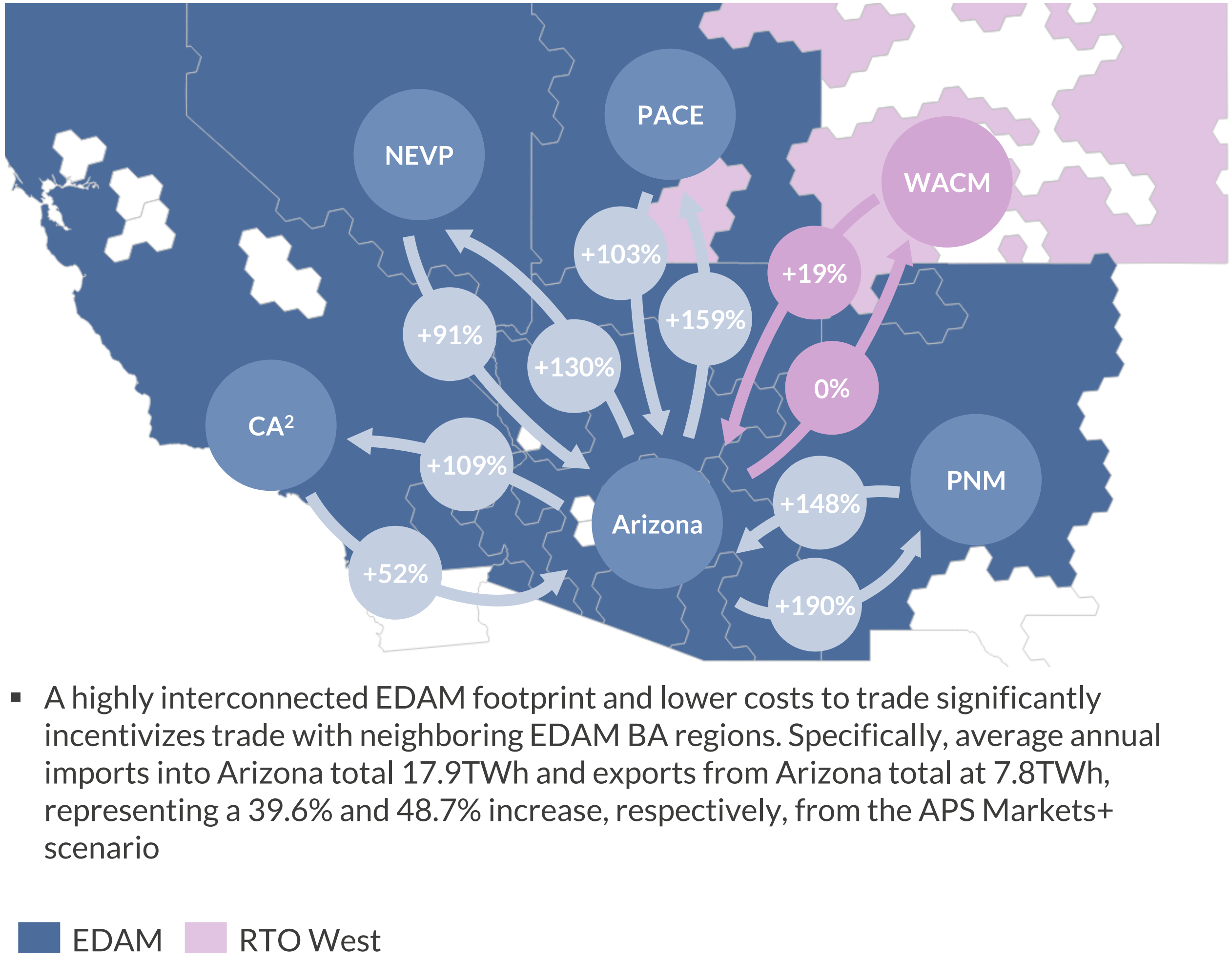
AZ EDAM incl. WALC: An expanded EDAM footprint enables more resource sharing at lower costs, driving reductions in AZ system costs

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

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



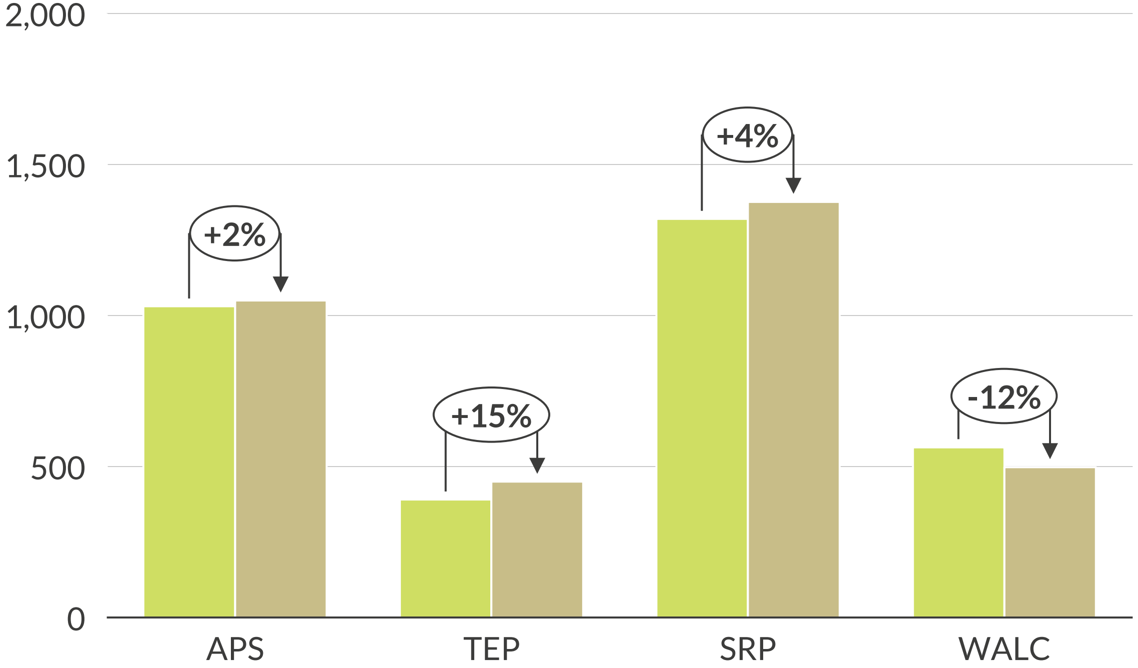
- A highly interconnected EDAM footprint and lower costs to trade significantly incentivizes trade with neighboring EDAM BA regions. Specifically, average annual imports into Arizona total 17.9TWh and exports from Arizona total at 7.8TWh, representing a 39.6% and 48.7% increase, respectively, from the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

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

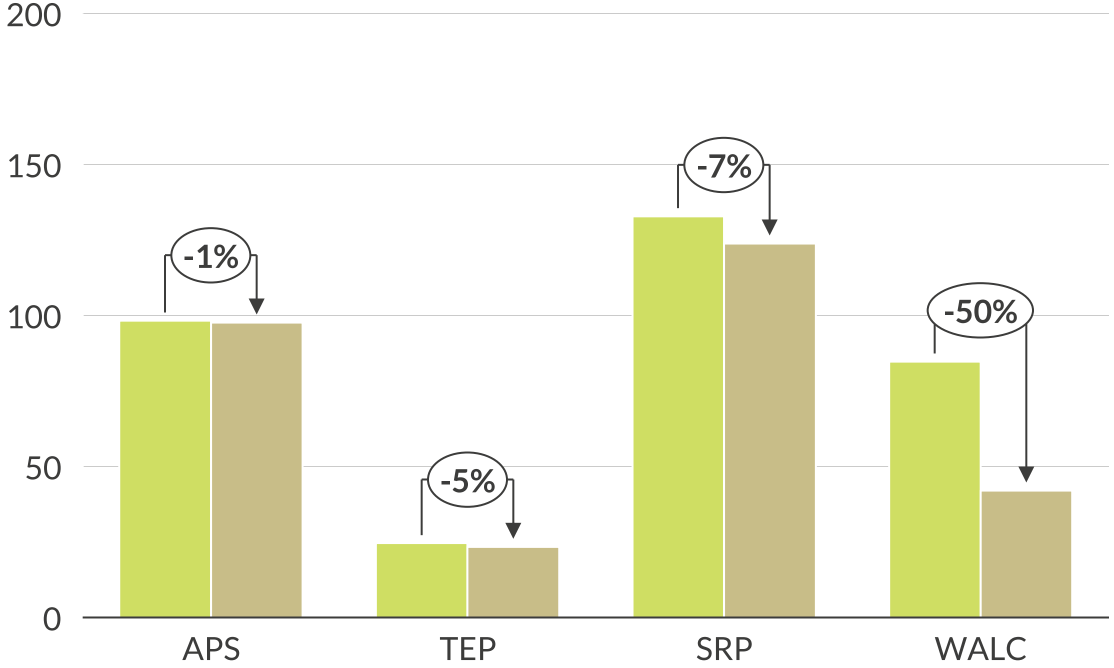
AZ EDAM excl. WALC: Exclusion of WALC drives higher production costs for other AZ BAs and lower congestion and wheeling revenues

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

Sources: Aurora Energy Research

Agenda

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.

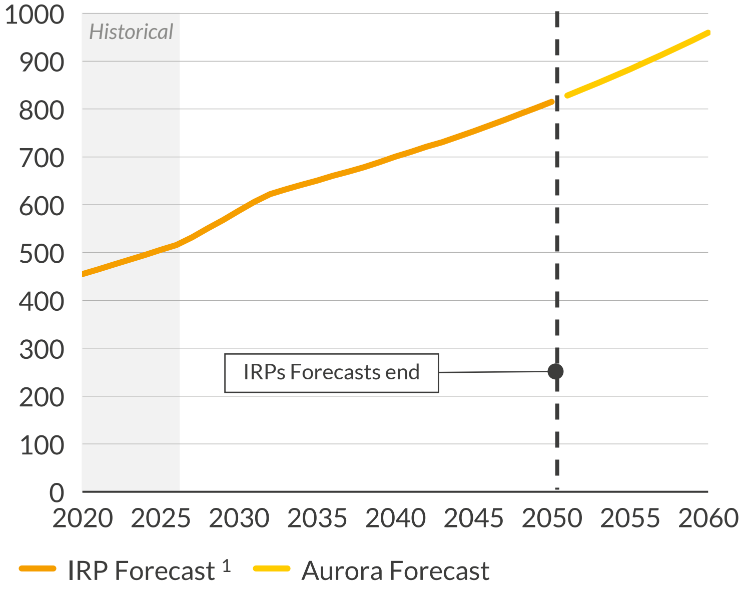
Sources: Aurora Energy Research

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

Demand assumptions

Annual electricity demand

TWh

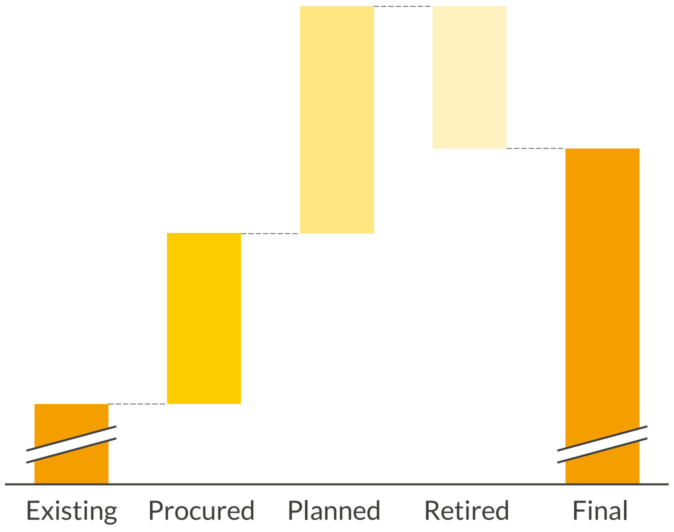


- Utility IRPs are used through their forecast horizon and reflect their assumptions on EVs, data centers and other demand drivers.
- Beyond the IRP period, we extend demand using trend-based assumptions and expected long-term patterns.

Capacity assumptions

Capacity assumptions components

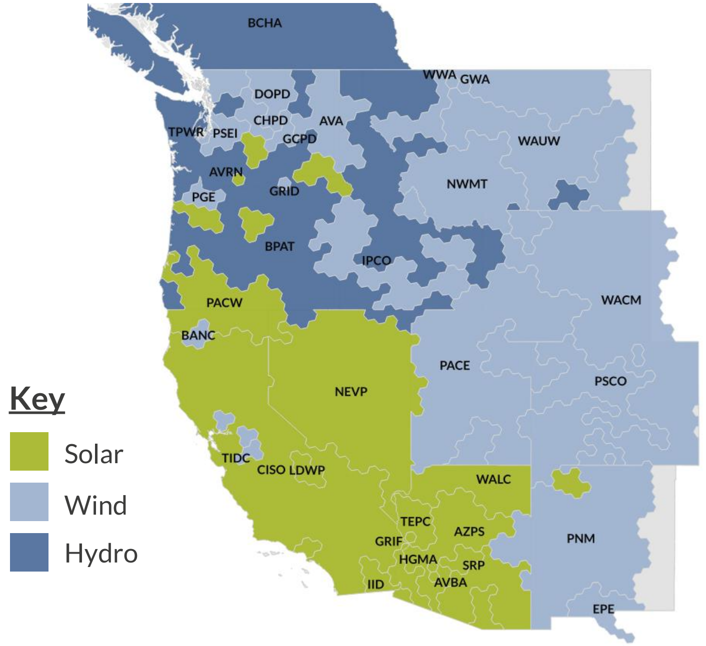
GW



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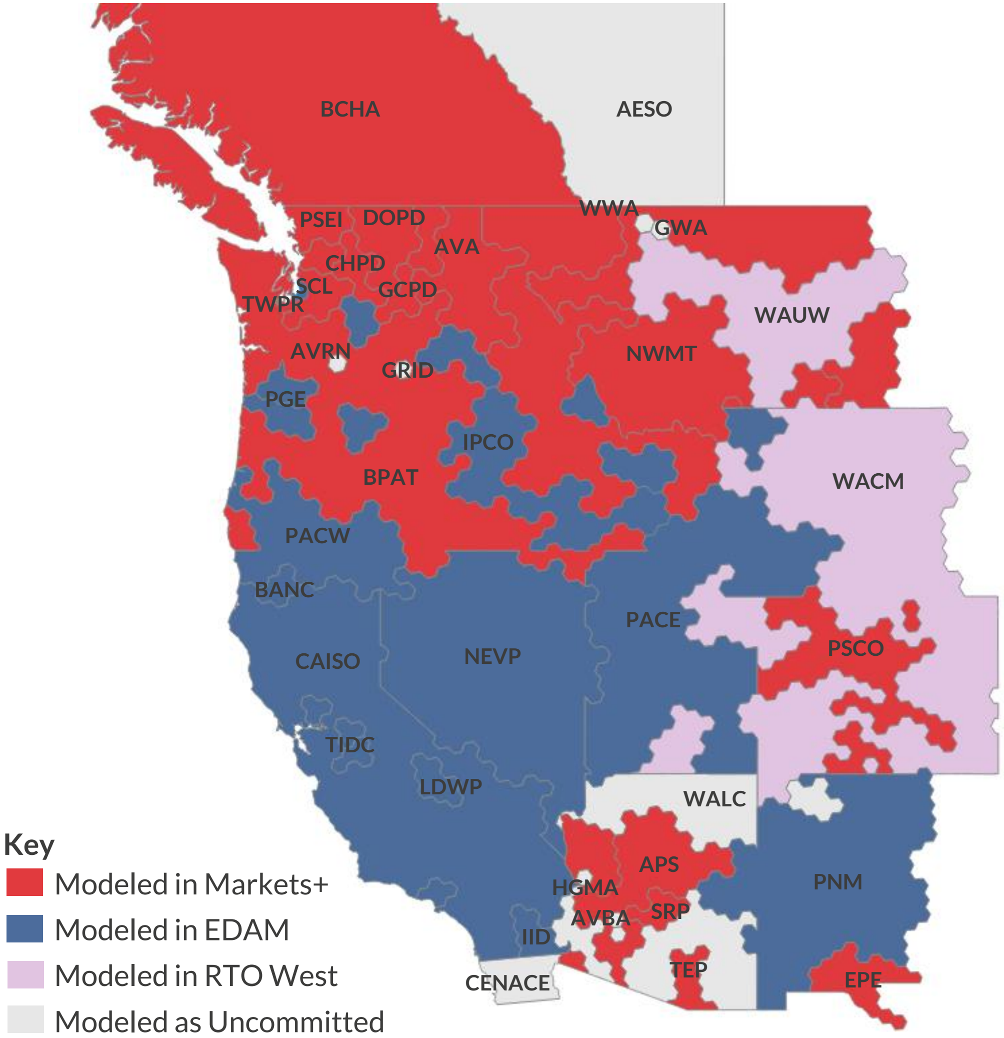
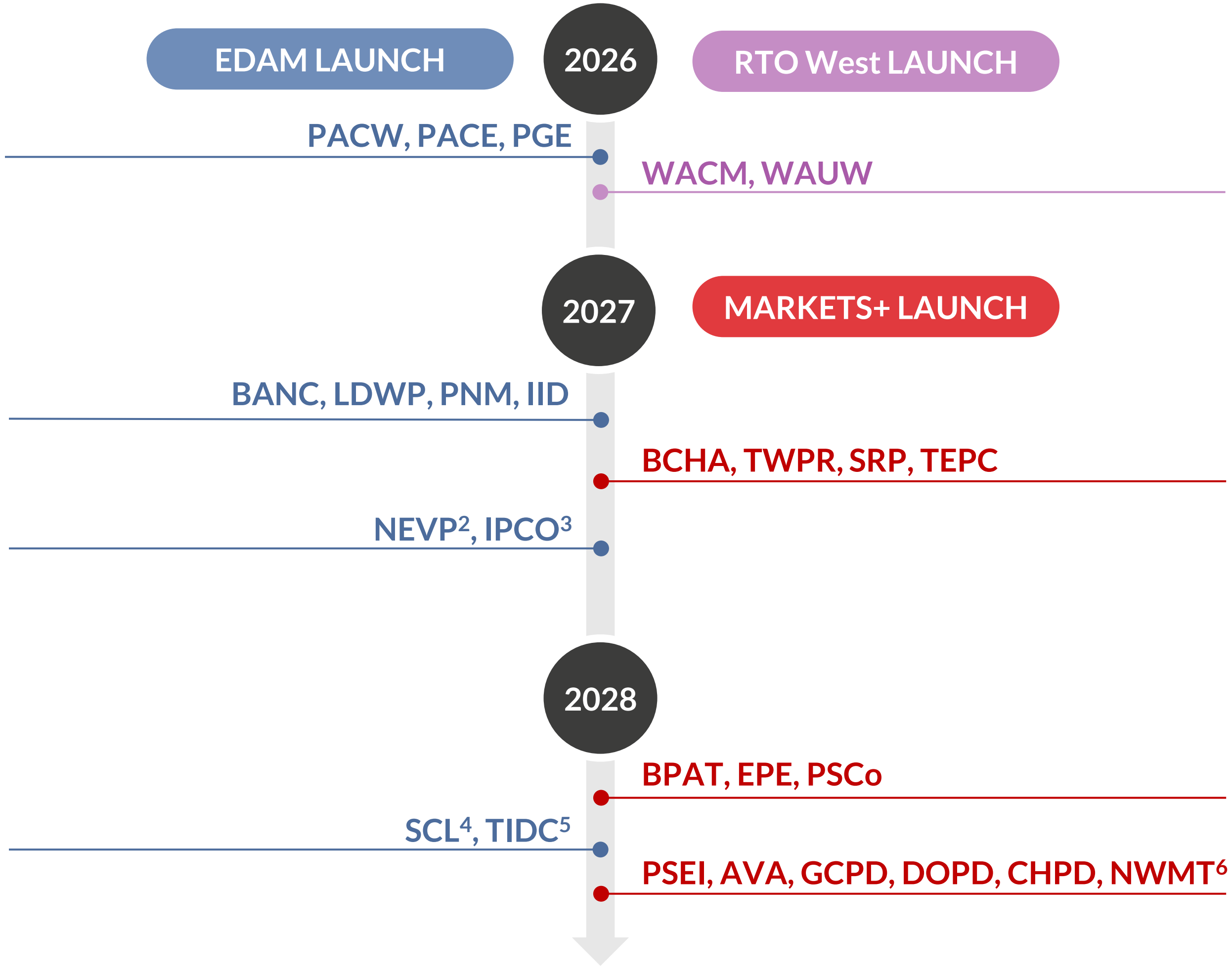
Central outlook on assumed day-ahead market participation[1]



Timeline of assumed day-ahead market participation[1]



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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ENERGY RESEARCH

Western market regionalization: TEP 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 Tucson Electric Power (TEP) balancing authority (BA) under the following Western US market regionalization scenarios (1) TEP participation in Markets+, (2) TEP participation in EDAM, (3) TEP, APS, SRP, and WALC participation in EDAM (AZ EDAM incl. WALC), and (4) TEP, APS, 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 TEP'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 TEP participation in EDAM vs. Markets+ has the following impacts:
    - TEP balancing authority can save **an average of $8.1million/year from participation in EDAM over Markets+**, enabled/mitigated by:
        - **Lower production costs** from decreased baseload thermal generation as TEP is disincentivized to export to Markets+ trading partners
        - **Lower bilateral trading revenue** from decreased overall export volumes and associated revenue, which outweighs the decrease in import costs
        - **Lower congestion and wheeling revenue** due to decreased utilization of transmission capacity from trade with Markets+ BAs, particularly SRP and APS
    - Adding additional baseload thermal capacity to TEP's system, as achieved via conversion of Springerville Generating Station Unit 2 from coal to gas, generates more upside for TEP under the Markets+ configuration as the benefits from additional export potential is larger with a more expansive Markets+ trading footprint
- **Conclusion:** This study finds that TEP sees marginal cost savings and similar emissions levels 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

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TEP sees total costs reduced by an average of $8.1 million/year through 2040 when participating in EDAM as opposed to Markets+

This analysis aims to identify the potential benefits or costs for Tucson Electric Power (TEP) under two Western US market regionalization scenarios: (1) TEP participates in EDAM and (2) TEP 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 TEP EDAM vs TEP Markets+, 2027-2040
$Million/year, real 2024

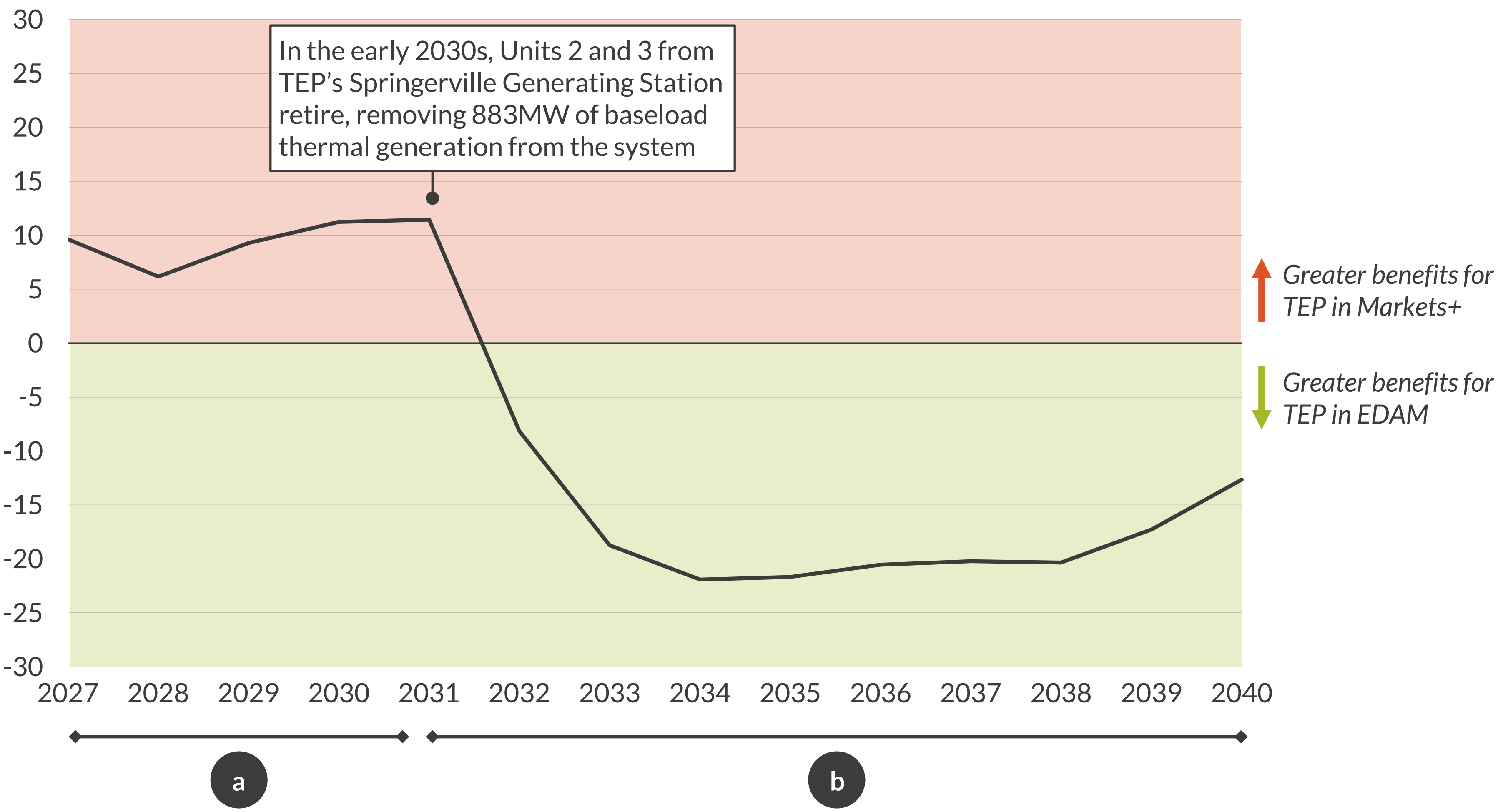
Metric	Day-Ahead Market cases		Average delta, EDAM – Markets+[1]
	TEP EDAM	TEP Markets+	
Production cost	391.5	416.4	**(25.0)**
Bilateral trading costs	(7.1)	(18.0)	**10.9**
Congestion revenue[2]	(12.5)	(18.1)	**5.5**
Wheeling revenue[2]	(4.4)	(4.9)	**0.5**
Annual average costs[3] (TEP)	**367.4**	**375.5**	**(8.1)**

- TEP sees an average $8.1mil/year benefit in total costs when participating in EDAM vs Markets+
- **Production costs** – When in EDAM, TEP sees less baseload thermal generation from reduced exports to Markets+ BAs, resulting in a lower average production cost
- **Bilateral trading costs** – TEP engages in less trade under EDAM as it has access to a smaller trading footprint. In net, lower revenues from decreased exports outweighs the lower costs from decreased imports in the EDAM configuration
- **Congestion and wheeling revenue** – Under the EDAM scenario TEP sees less utilization of its transmission interconnection, particularly to and from SRP[2]

1) A negative delta indicates lower costs when TEP 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 cost benefits for TEP under EDAM vs. Markets+ vary over the forecast, tied to the Springerville Generating Station retirements

TEP annual total system cost delta[1], EDAM – Markets+
$/MWh, real 2024



Over the forecast period, TEP reports a consistent cost benefit under Markets+ prior to the Springerville retirements in the early 2030s, and a cost benefit under EDAM thereafter

(a) Sufficient baseload thermal capacity in TEP places the system in a net exporting position. Access to a wider footprint under Markets+ drives higher export revenues, resulting in a cheaper system cost as compared to the EDAM configuration

(b) TEP coal retirements result in increased thermal imports, particularly from SRP under Markets+. Combined with a higher production cost relative to the EDAM configuration, TEP reports a higher system cost through the 2030s under Markets+

1) A negative delta indicates lower costs when TEP is modeled in EDAM compared to Markets+, demonstrating benefits to joining EDAM.

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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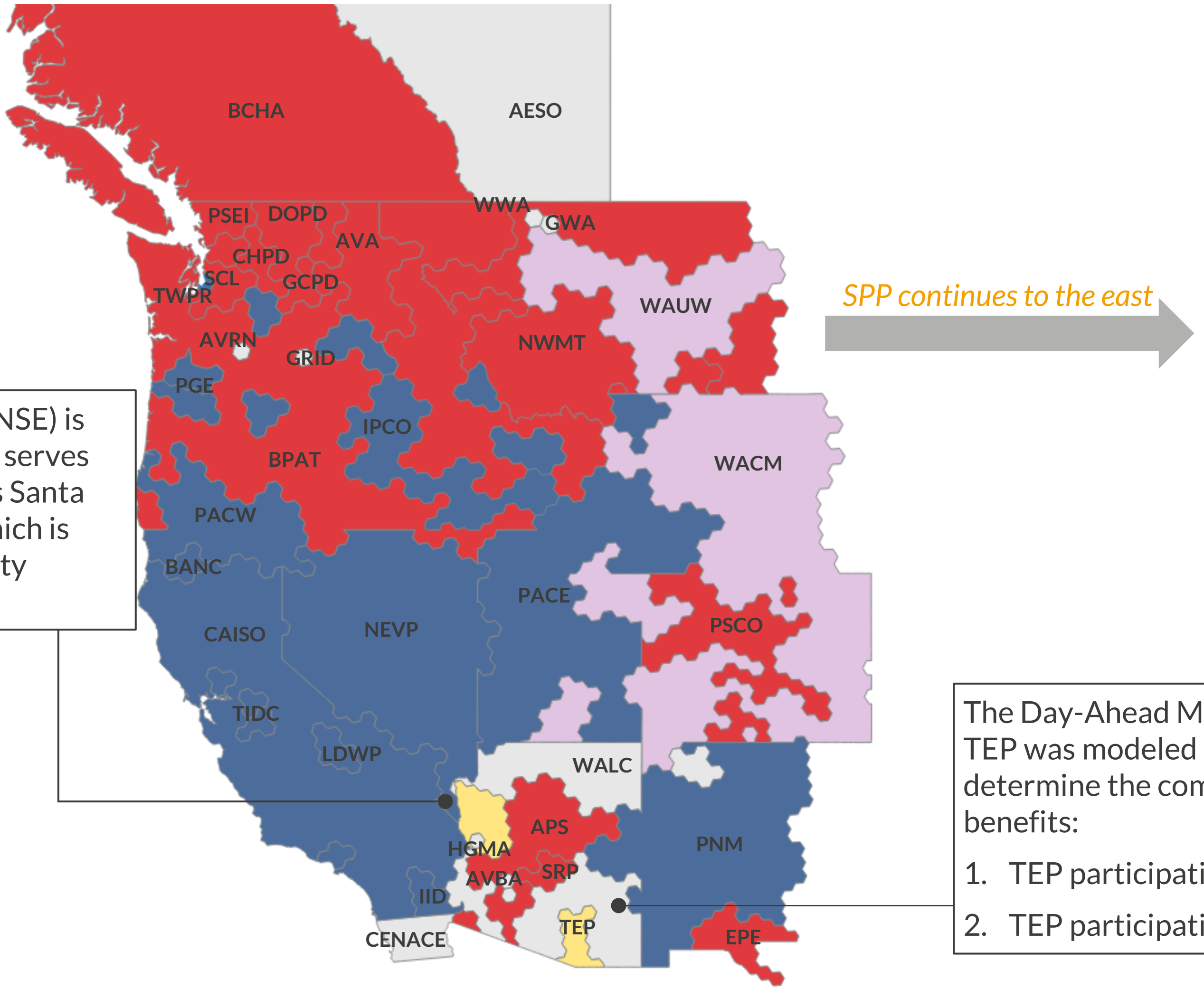
Map of modeled balancing authority (BA) market decisions



UniSource Energy Services (UNSE) is the sister company of TEP and serves electric customers in Arizona's Santa Cruz and Mohave counties, which is within TEP's balancing authority service territory

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

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

Key[1,2]

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

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 TEP BA's capacity mix following TEP's and UNSE's 2023 IRP Preferred Portfolio through to 2038

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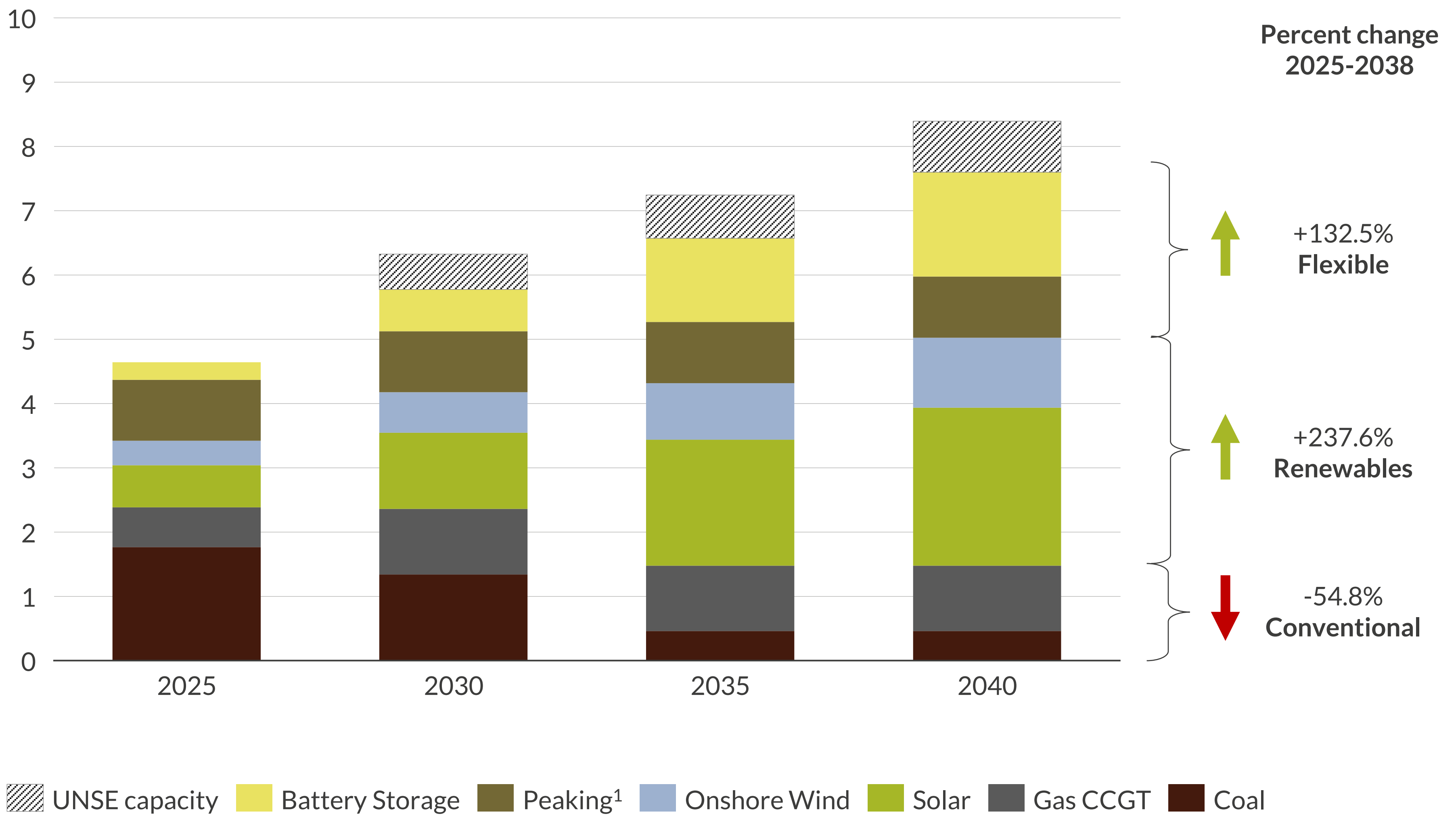
Installed and modeled capacity in TEP Balancing Authority service area
GW



- Aurora modeled TEP installed capacity based on existing installed capacity owned and contracted, with capacity growth through to 2038 following the TEP and UNSE Integrated Resource Plans (IRP), both released in 2023
- Resource additions as detailed in the 2023 IRPs are driven by thermal retirements, particularly Units 1, 2 and 3 of the Springerville Generating Station[2], as well as to accommodate growing large industrial and mining customers
- By 2038, UNSE utility additions total 725MW, of which 41% are renewables, 31% is storage, and 28% is peaking thermal capacity

1) Peaking includes OCGT, reciprocating engines. 2) Retirements of Units 1 and 2 are specified in the 2023 IRP, while retirement of Unit 3 was publicly announced by TEP in December 2023.

Sources: Aurora Energy Research, TEP, UNSE

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

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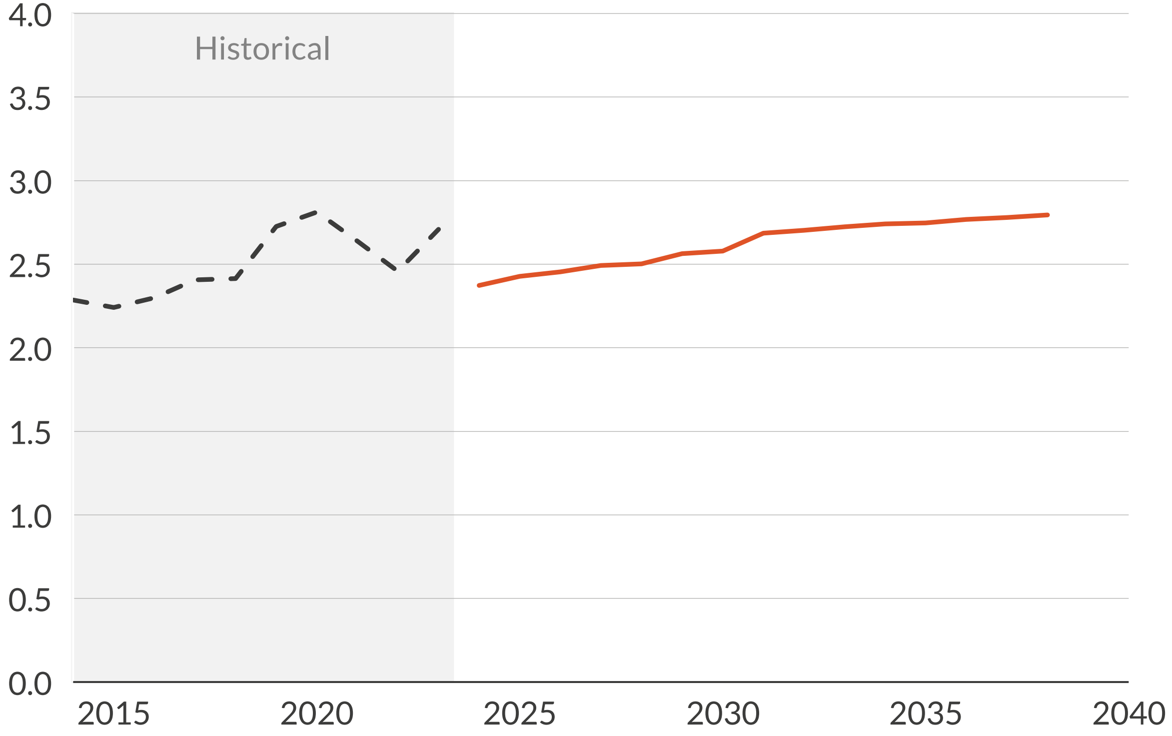
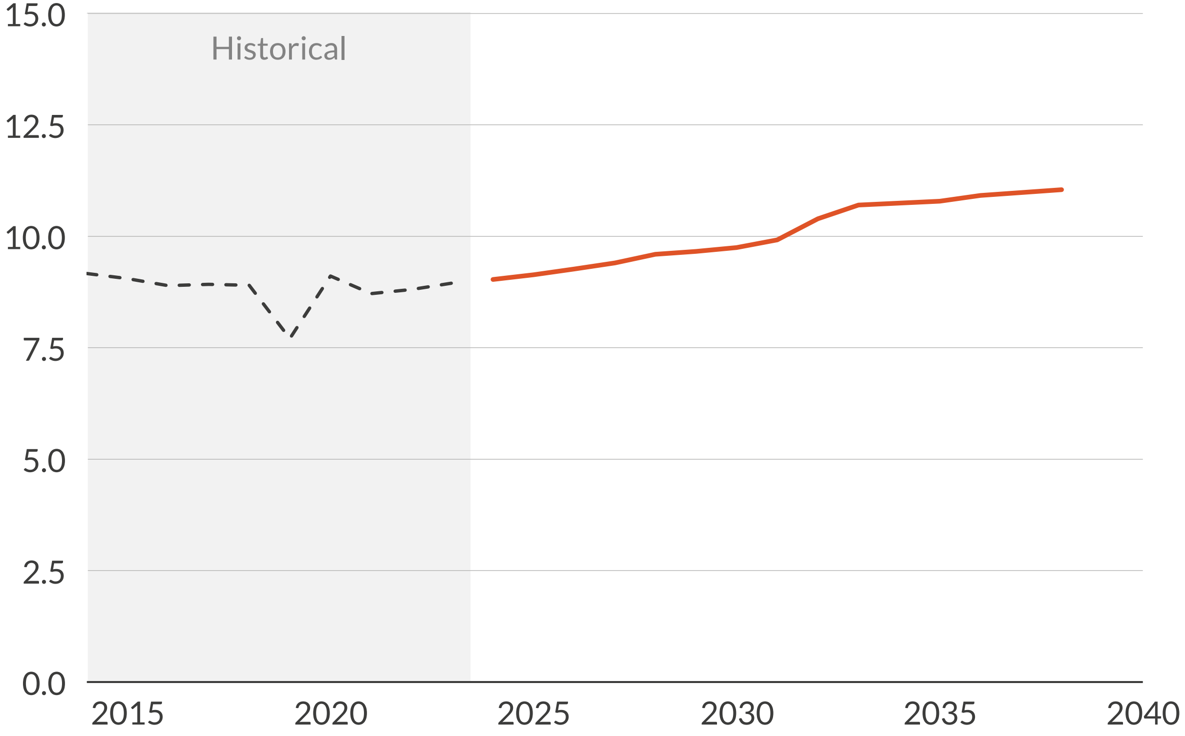
TEP coincidental peak demand[1,2]
GW



TEP annual system load[1,2]
TWh



- TEP's coincidental peak demand forecast grows at an annual compounding rate of 1.23%
- TEP projects that the number of residential customers in the Tucson area will grow by 0.86% annually

- TEP's annual system load forecast grows at an annual compounding rate of 1.5%
- The industrial and mining segments will add 1.5TWh of load to the annual load forecast from 2024 to 2038, representing 65% of the forecast's total increase in load

2023 IRP — Historical

1) Peak demand and forecasted annual system load accounts for energy efficiency, behind-the-meter technologies, and demand response. 2) Historical peak demand and annual load data is pre-DSR.

Sources: Aurora Energy Research, TEP

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

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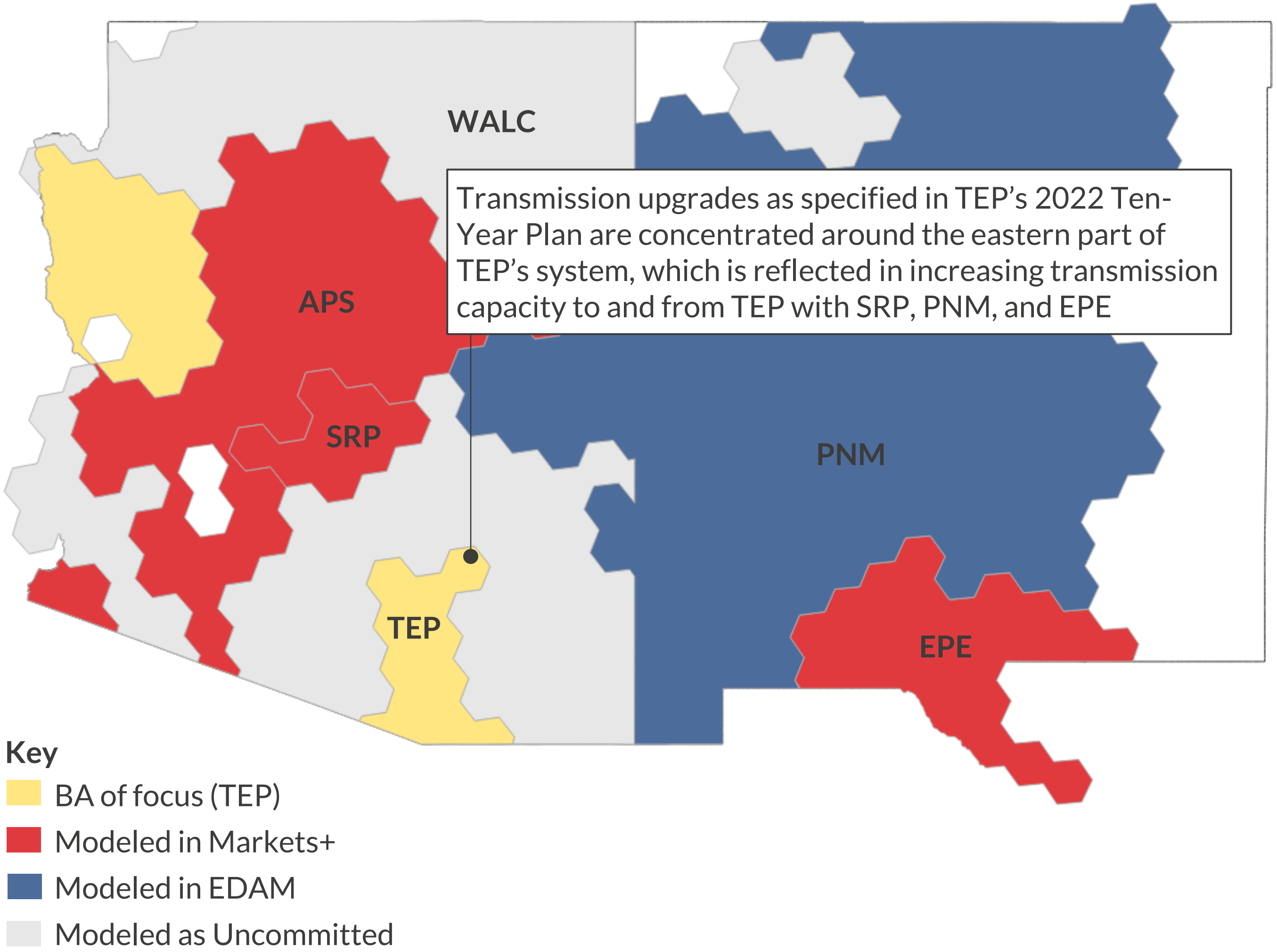
Map of balancing authorities with modeled interchange with TEP



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

Balancing authority	Export[2] transfer limit (MW)	Import transfer limit (MW)
PNM	197.0	216.7
EPE	442.2	106.1
SRP	369.0	708.5
APS	111.3	24.1
WALC	20.8	103.7

Overview of TEP's planned and proposed transmission projects[3]

Project Class	Upgrade Type	Details
500kV lines	New	2 projects
	Upgrade	0 projects
345kV lines	New	4 projects
	Upgrade	0 projects
230kV lines	New	2 projects
	Upgrade	0 projects
138kV lines	New	12 projects
	Upgrade	2 projects
Substations	New	15 projects
	Upgrade	5 projects

1) Transfer limits are modeled at the BA level. BAs identified here show all modeled interchange possibilities for TEP with neighboring BAs. 2) Refers to exports from TEP into listed balancing authorities. 3) Encompassing all projects in TEP's 2022 Ten-Year Transmission Plan.

Sources: Aurora Energy Research, WECC, EIA, TEP

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

Input assumptions for TEP align with the 2023 IRP, with other BA inputs following their respective IRPs where available

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As in TEP standard inputs unless stated otherwise		TEP standard inputs[1]	TEP DAM cases	AZ EDAM, including WALC	AZ EDAM, excluding WALC
Demand	Underlying demand	**Consistent with TEP 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 TEP IRP Balanced Portfolio**, which adds 2.2GW renewables from 2023-2038 **Consistent with the 2023 UNSE IRP Balanced Portfolio,** which adds 0.3GW renewables from 2023-2038			
	Thermal	**Consistent with the 2023 TEP IRP Balanced Portfolio** **Consistent with the 2023 UNSE IRP Balanced Portfolio** – thermals 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	TEP is not subject to any formalized environmental mandates[2]			
	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	TEP is modeled to either join EDAM or Markets+. All other BAs are modeled based on formalized commitment or assumption	TEP, APS, WALC, and SRP are modeled to join EDAM. All other BAs are modeled based on formalized commitment or assumption	TEP, APS, and SRP are modeled to join EDAM. All other BAs are modeled based on formalized commitment or assumption

1) The input assumptions align with Tucson Electric Power's (TEP) 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. 2) TEP has a voluntary goal of net-zero carbon emissions goal by 2050.

Sources: Aurora Energy Research

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

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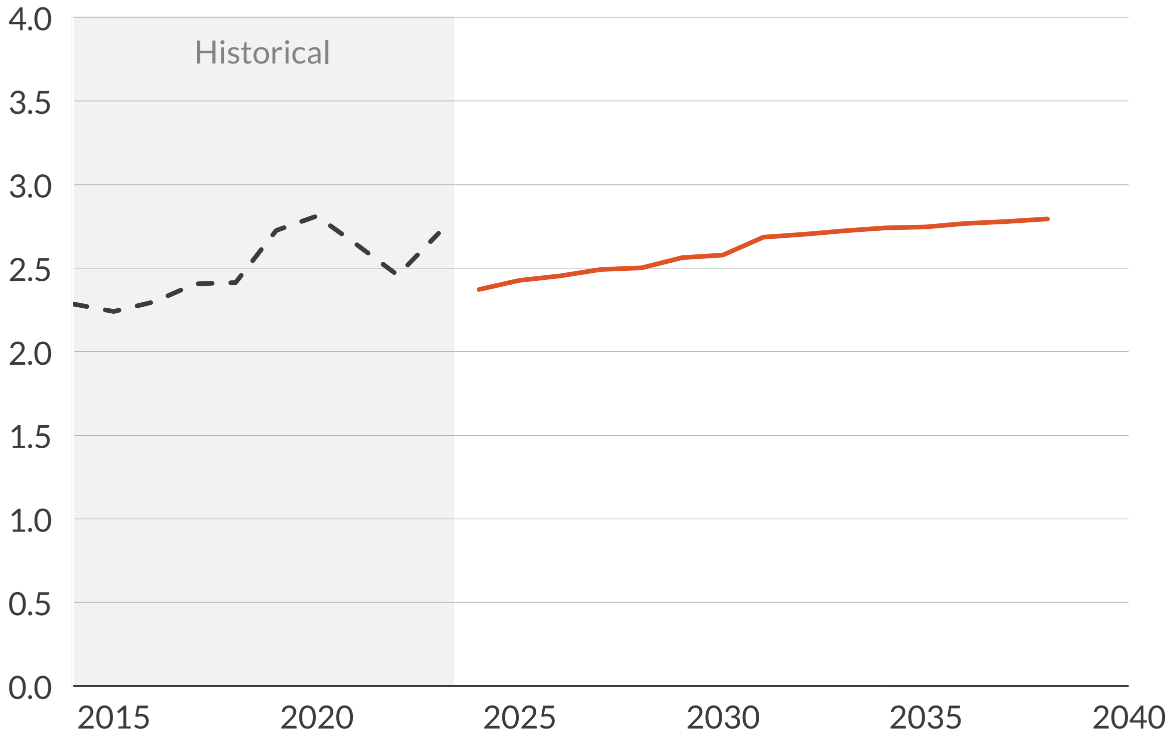
TEP coincidental peak demand[1,2]
GW



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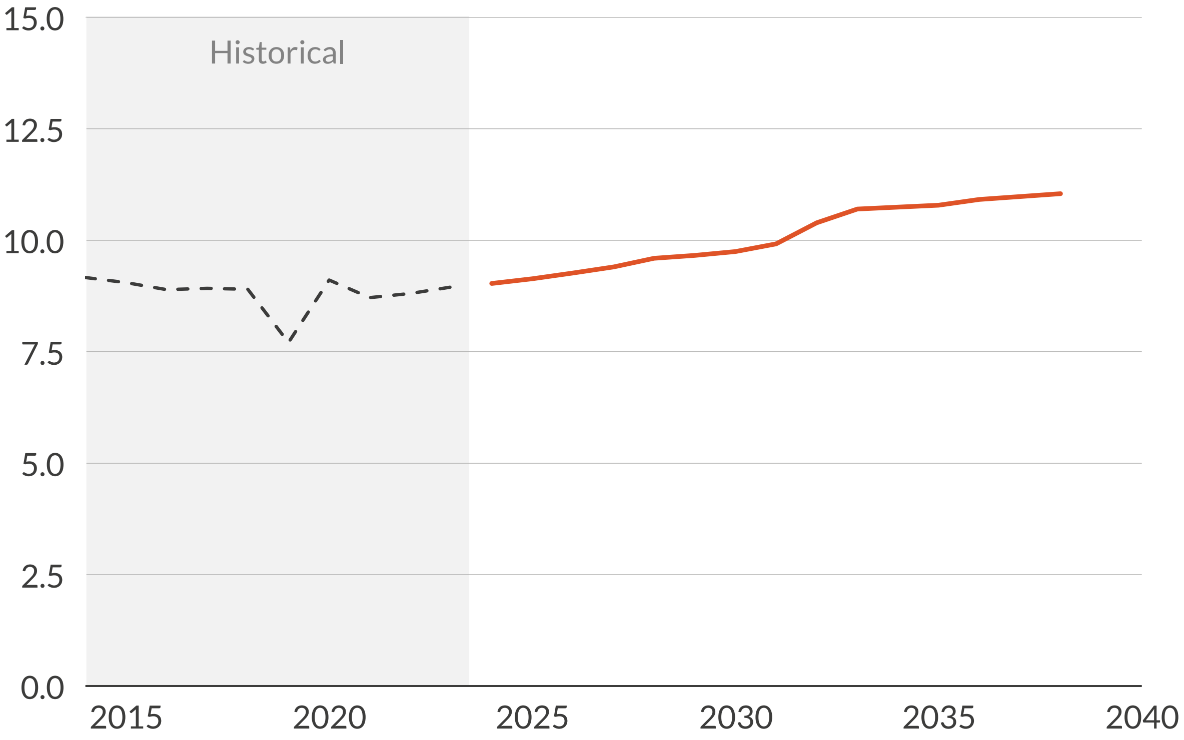
TEP annual system load[1,2]
TWh



- TEP's annual system load forecast grows at an annual compounding rate of 1.5%
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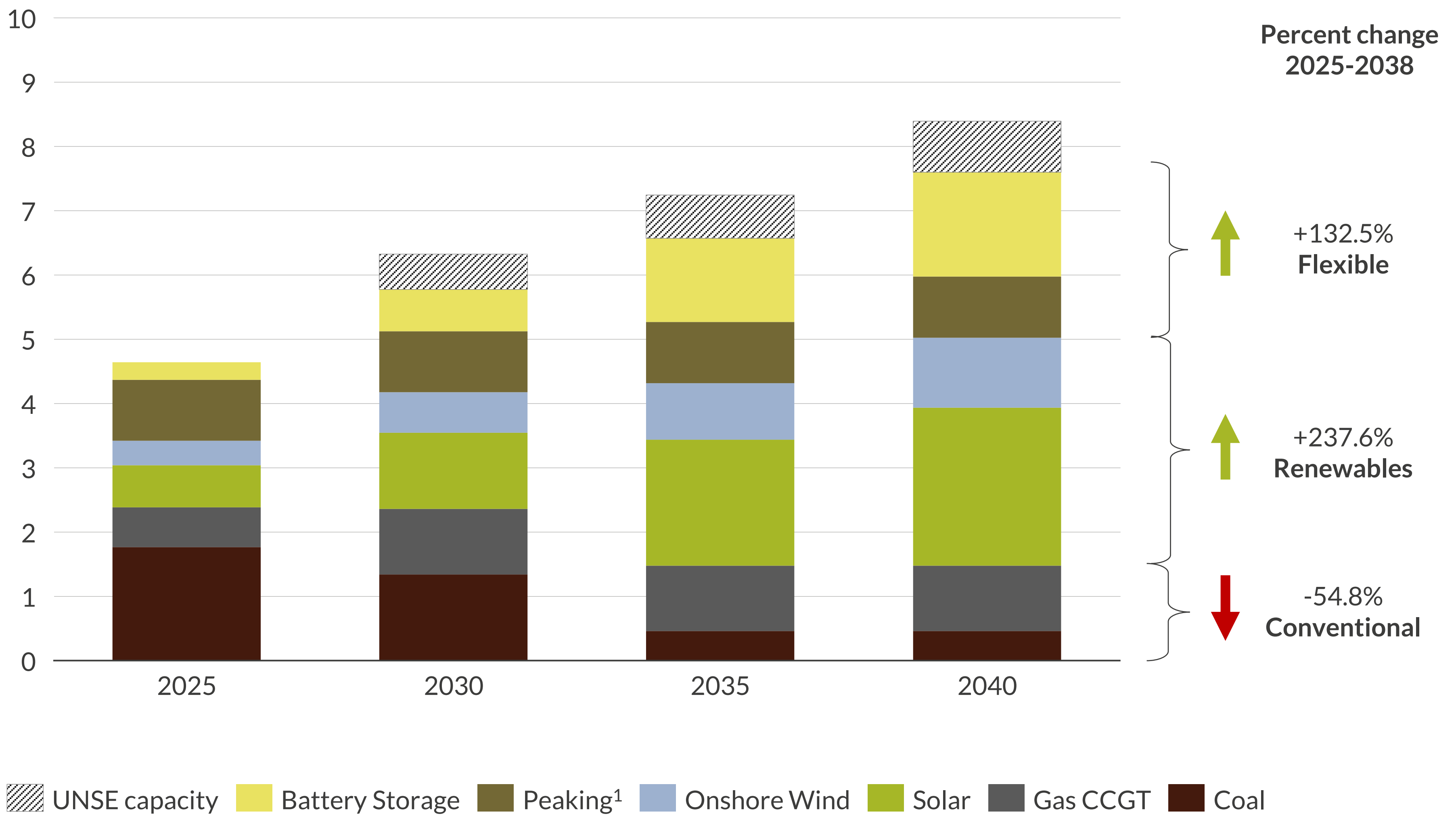
Sources: Aurora Energy Research, TEP

Aurora modeled TEP BA's capacity mix following TEP's and UNSE's 2023 IRP Preferred Portfolio through to 2038

Installed and modeled capacity in TEP Balancing Authority service area
GW



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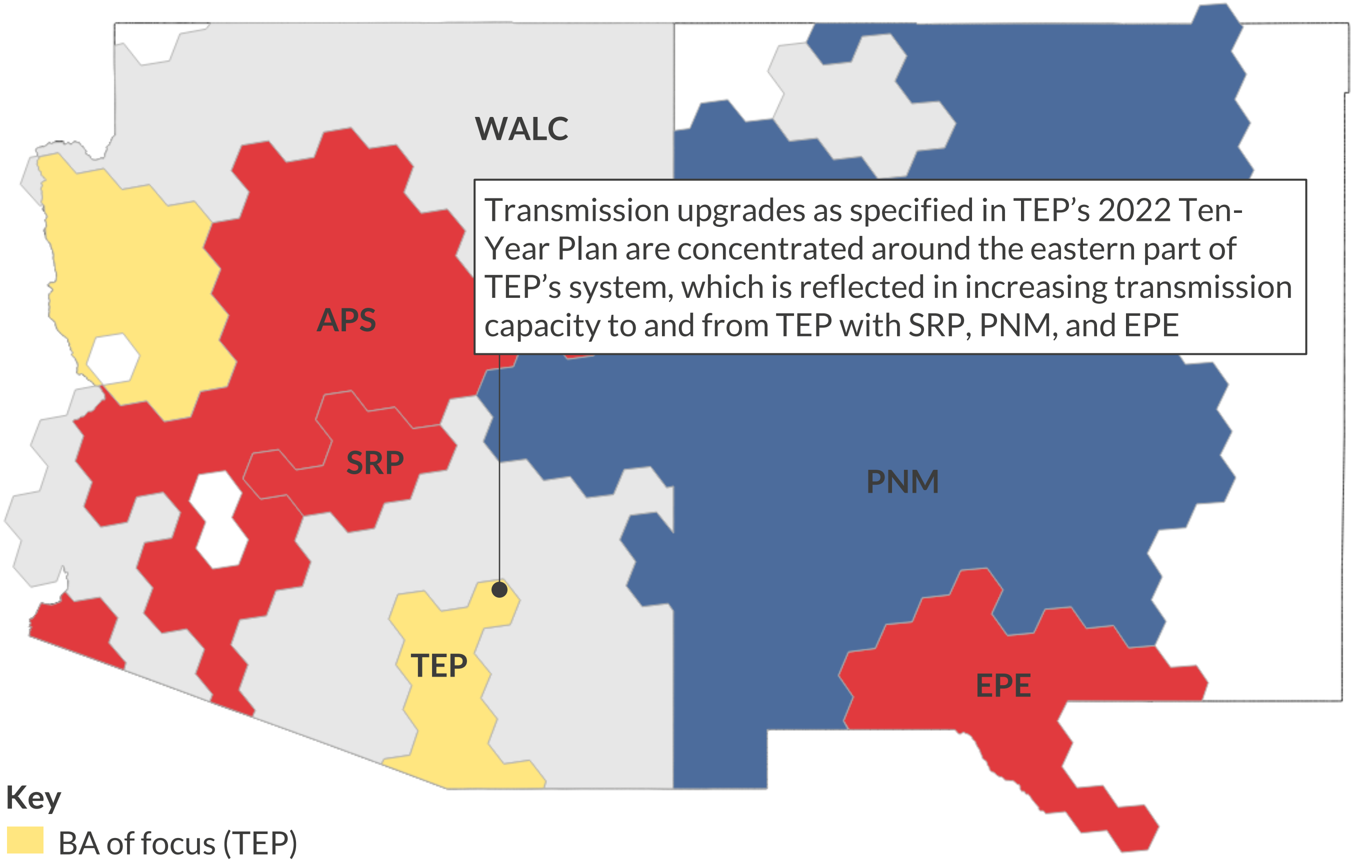
Map of balancing authorities with modeled interchange with TEP



Key
- BA of focus (TEP)
- Modeled in Markets+
- Modeled in EDAM
- Modeled as Uncommitted

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

Balancing authority	Export[2] transfer limit (MW)	Import transfer limit (MW)
PNM	197.0	216.7
EPE	442.2	106.1
SRP	369.0	708.5
APS	111.3	24.1
WALC	20.8	103.7

Overview of TEP's planned and proposed transmission projects[3]

Project Class	Upgrade Type	Details
500kV lines	New	2 projects
	Upgrade	0 projects
345kV lines	New	4 projects
	Upgrade	0 projects
230kV lines	New	2 projects
	Upgrade	0 projects
138kV lines	New	12 projects
	Upgrade	2 projects
Substations	New	15 projects
	Upgrade	5 projects

1) Transfer limits are modeled at the BA level. BAs identified here show all modeled interchange possibilities for TEP with neighboring BAs. 2) Refers to exports from TEP into listed balancing authorities. 3) Encompassing all projects in TEP's 2022 Ten-Year Transmission Plan.

Sources: Aurora Energy Research, WECC, EIA, TEP

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

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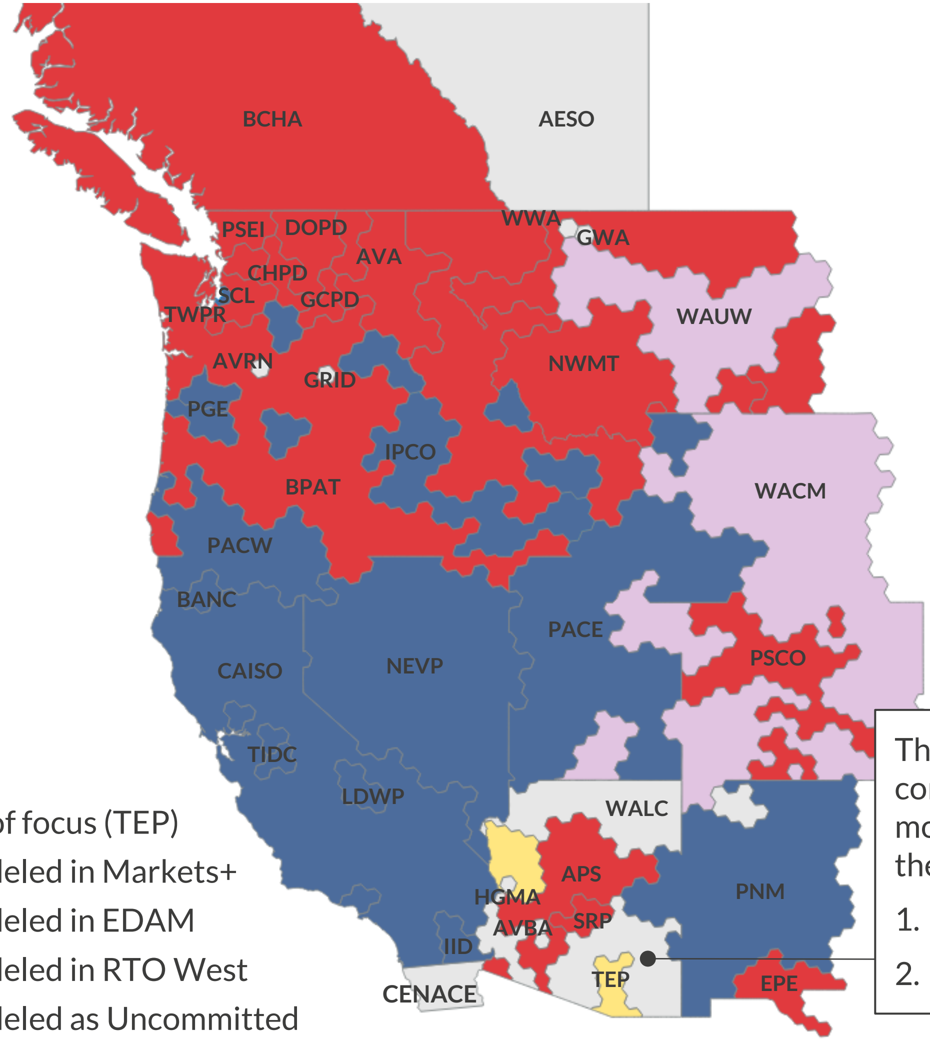
Map of modeled balancing authority (BA) market decisions – TEP DAM cases



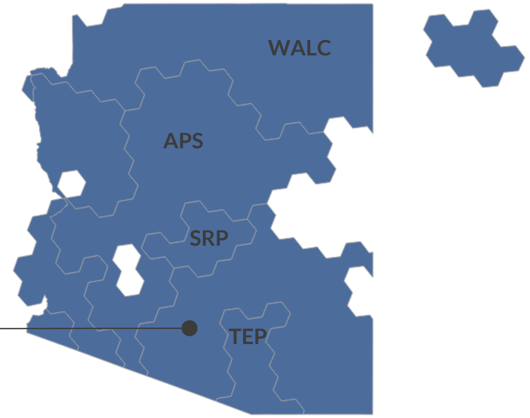
The Day-Ahead Market (DAM) commitment for TEP was modeled under 2 scenarios in the TEP DAM cases:

1. TEP in EDAM
2. TEP in Markets+

Key[1,2]

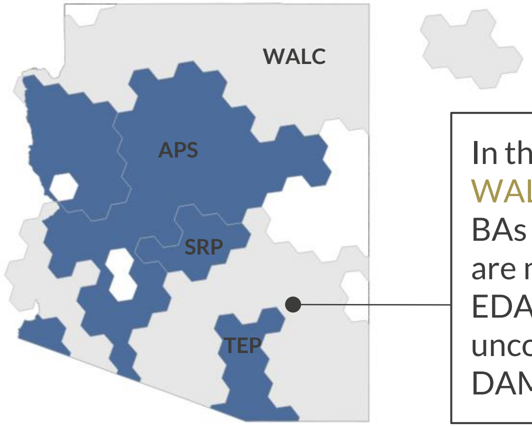
- BA of focus (TEP)
- Modeled in Markets+
- Modeled in EDAM
- Modeled in RTO West
- Modeled as Uncommitted

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

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



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

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

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

TEP sees total costs reduced by an average of $8.1 million/year through 2040 when participating in EDAM as opposed to Markets+

This analysis aims to identify the potential benefits or costs for Tucson Electric Power (TEP) under two Western US market regionalization scenarios: (1) TEP participates in EDAM and (2) TEP 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 TEP EDAM vs TEP Markets+, 2027-2040
$Million/year, real 2024

Metric	Day-Ahead Market cases		Average delta, EDAM – Markets+[1]
	TEP EDAM	TEP Markets+	
A Production cost	391.5	416.4	**(25.0)**
B Bilateral trading costs	(7.1)	(18.0)	**10.9**
C Congestion revenue[2]	(12.5)	(18.1)	**5.5**
C Wheeling revenue[2]	(4.4)	(4.9)	**0.5**
Annual average costs[3] (TEP)	**367.4**	**375.5**	**(8.1)**

X Deep dive to follow

1) A negative delta indicates lower costs when TEP 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

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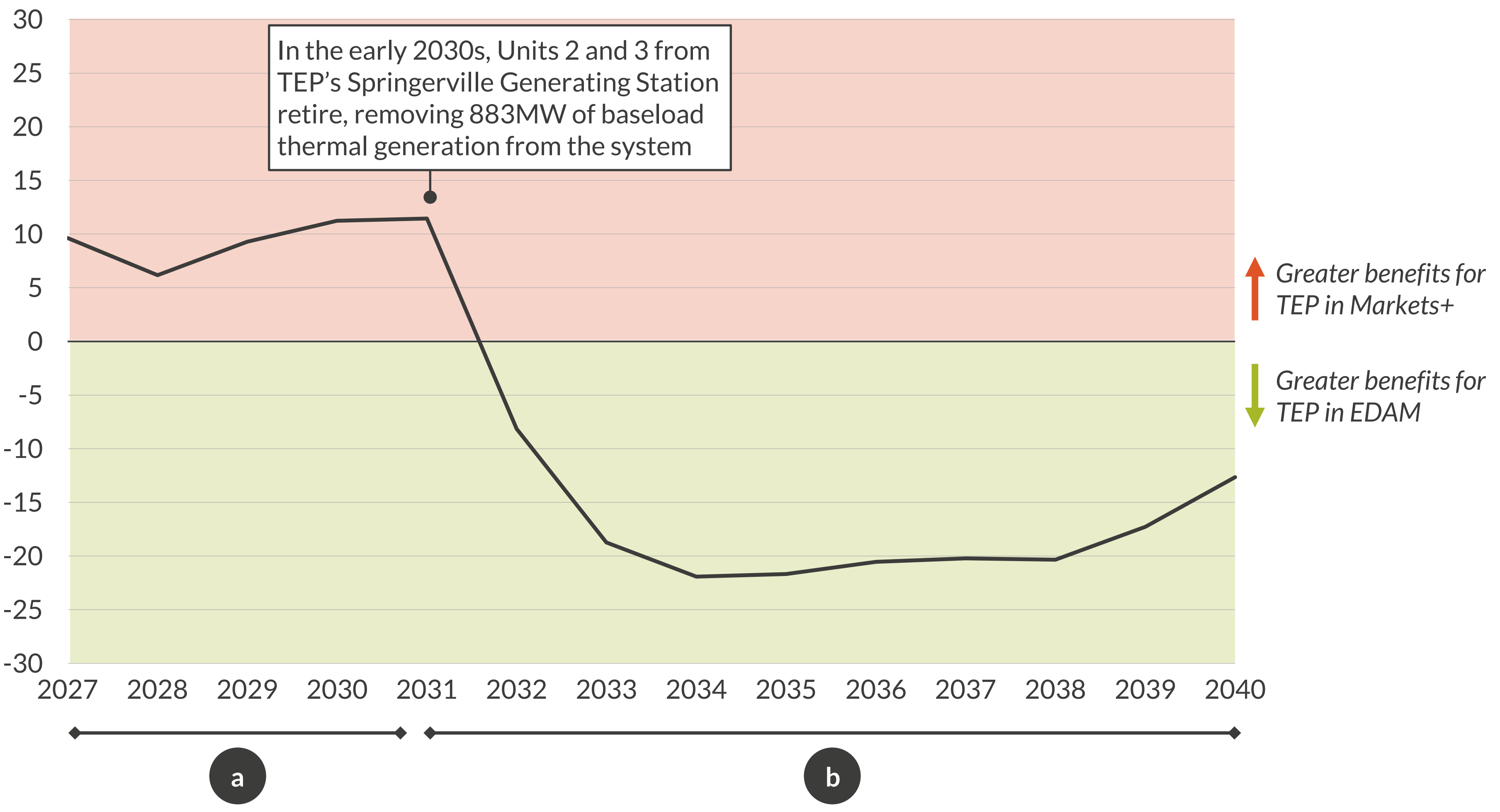
- TEP sees an average $8.1mil/year benefit in total costs when participating in EDAM vs Markets+
- **Production costs** – When in EDAM, TEP sees less baseload thermal generation from reduced exports to Markets+ BAs, resulting in a lower average production cost
- **Bilateral trading costs** – TEP engages in less trade under EDAM as it has access to a smaller trading footprint. In net, lower revenues from decreased exports outweighs the lower costs from decreased imports in the EDAM configuration
- **Congestion and wheeling revenue** – Under the EDAM scenario TEP sees less utilization of its transmission interconnection, particularly to and from SRP[2]

The cost benefits for TEP under EDAM vs. Markets+ vary over the forecast, tied to the Springerville Generating Station retirements

TEP annual total system cost delta[1], EDAM – Markets+
$/MWh, real 2024



Over the forecast period, TEP reports a consistent cost benefit under Markets+ prior to the Springerville retirements in the early 2030s, and a cost benefit under EDAM thereafter

a Sufficient baseload thermal capacity in TEP places the system in a net exporting position. Access to a wider footprint under Markets+ drives higher export revenues, resulting in a cheaper system cost as compared to the EDAM configuration

b TEP coal retirements result in increased thermal imports, particularly from SRP under Markets+. Combined with a higher production cost relative to the EDAM configuration, TEP reports a higher system cost through the 2030s under Markets+

1) A negative delta indicates lower costs when TEP is modeled in EDAM compared to Markets+, demonstrating benefits to joining EDAM.

Sources: Aurora Energy Research

A Lower baseload thermal production in the EDAM scenario from reduced thermal exports drives lower production costs for TEP

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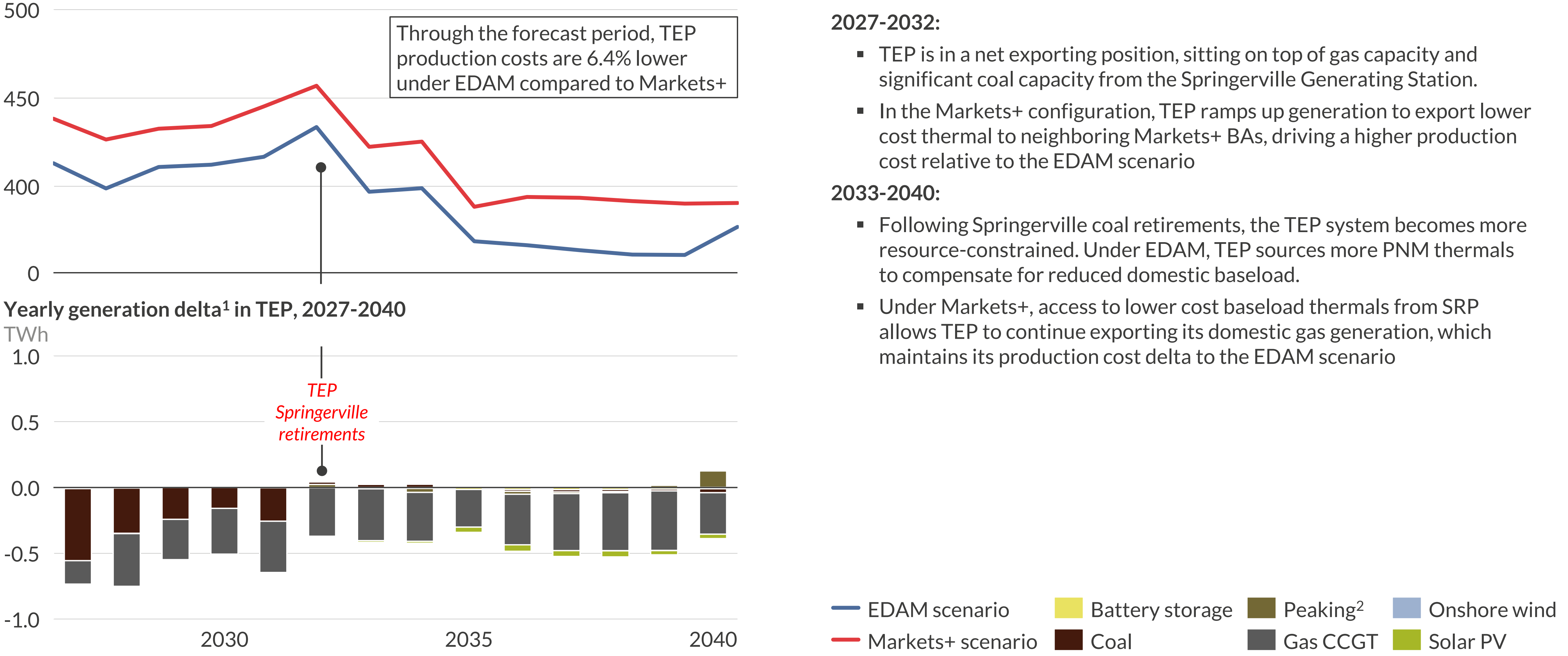
Yearly TEP production cost, 2027-2040
$Million/year, real 2024

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



2027-2032:

- TEP is in a net exporting position, sitting on top of gas capacity and significant coal capacity from the Springerville Generating Station.
- In the Markets+ configuration, TEP ramps up generation to export lower cost thermal to neighboring Markets+ BAs, driving a higher production cost relative to the EDAM scenario

2033-2040:

- Following Springerville coal retirements, the TEP system becomes more resource-constrained. Under EDAM, TEP sources more PNM thermals to compensate for reduced domestic baseload.
- Under Markets+, access to lower cost baseload thermals from SRP allows TEP to continue exporting its domestic gas generation, which maintains its production cost delta to the EDAM scenario

1) Delta is calculated as EDAM scenario – Markets+ scenario. 2) Peaking includes OCGTs and reciprocating engines.

Sources: Aurora Energy Research

B Higher TEP thermal generation under Markets+ creates consistent export revenue upside, while import cost delta to EDAM fluctuates

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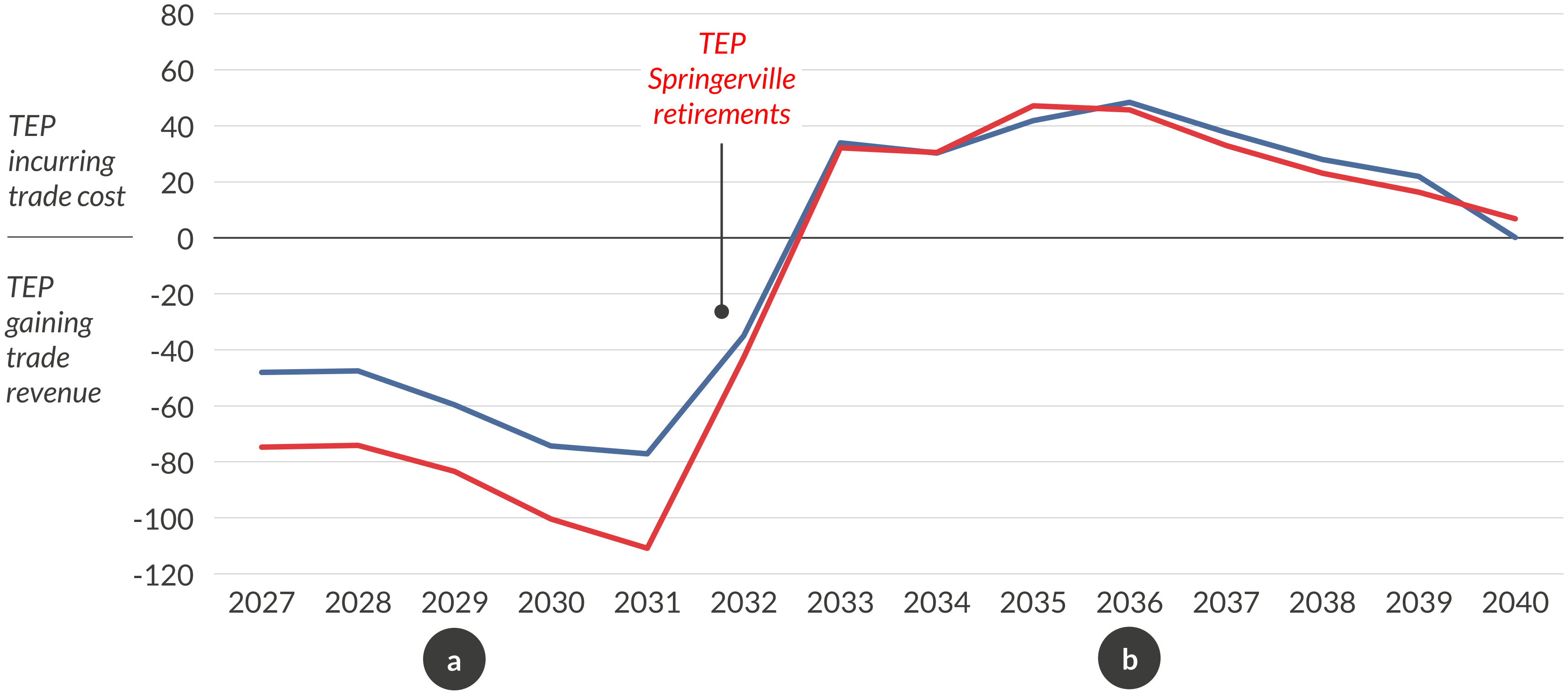
Annual TEP bilateral trading costs (export revenues – import costs)[1]
$Million/year, real 2024



Average delta[2] *$M/year, real 2024*		a	b
	Export revenue	*(42.1)*	*(49.7)*
	Import cost	*(18.0)*	*(47.7)*

EDAM scenario — Markets+ scenario

a TEP exports excess baseload thermal generation at lower costs under Markets+, driving a larger export revenue under Markets+ than EDAM. While TEP incurs lower import costs under EDAM, the net benefit from additional export revenues for TEP under Markets+ outweighs its additional import cost

b Following Springerville retirements, TEP increases its thermal imports, gradually pushing TEP into a net importing system on a cost front. As TEP already exports less under EDAM, the marginal increase in import costs under EDAM is lower, resulting in a similar bilateral trade cost to Markets+. The cost benefit for TEP under Markets+ decreases as its export advantage is diminished

1) Graph shown displays bilateral trading costs; values below zero indicate net trade revenues for TEP in a given year, while values above 0 indicate net costs from trading. 2) Deltas are shown for TEP in EDAM – TEP in Markets+ scenario. A negative delta for export revenue indicates less export revenues for TEP in EDAM, while a negative delta in import costs indicates a cost benefit.
Sources: Aurora Energy Research

C Utilization of transfer capacity to Markets+ BAs decreases with TEP in EDAM, reducing congestion revenues in particular

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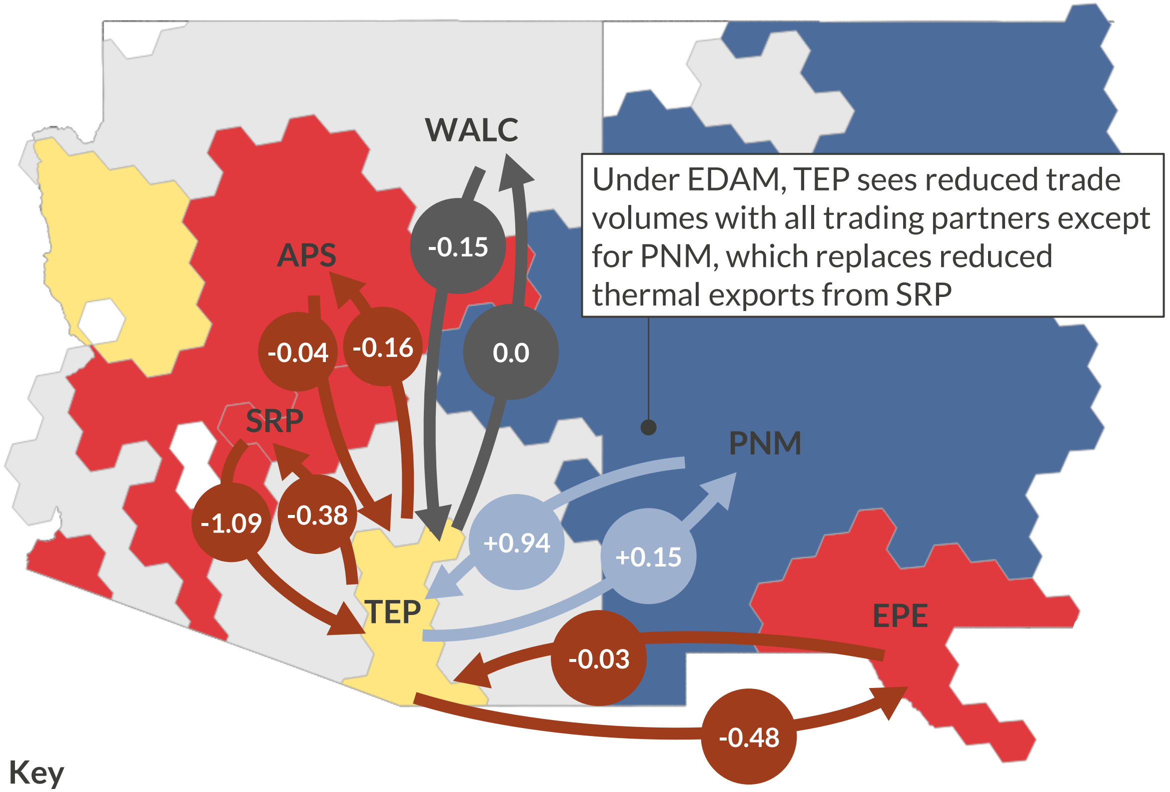
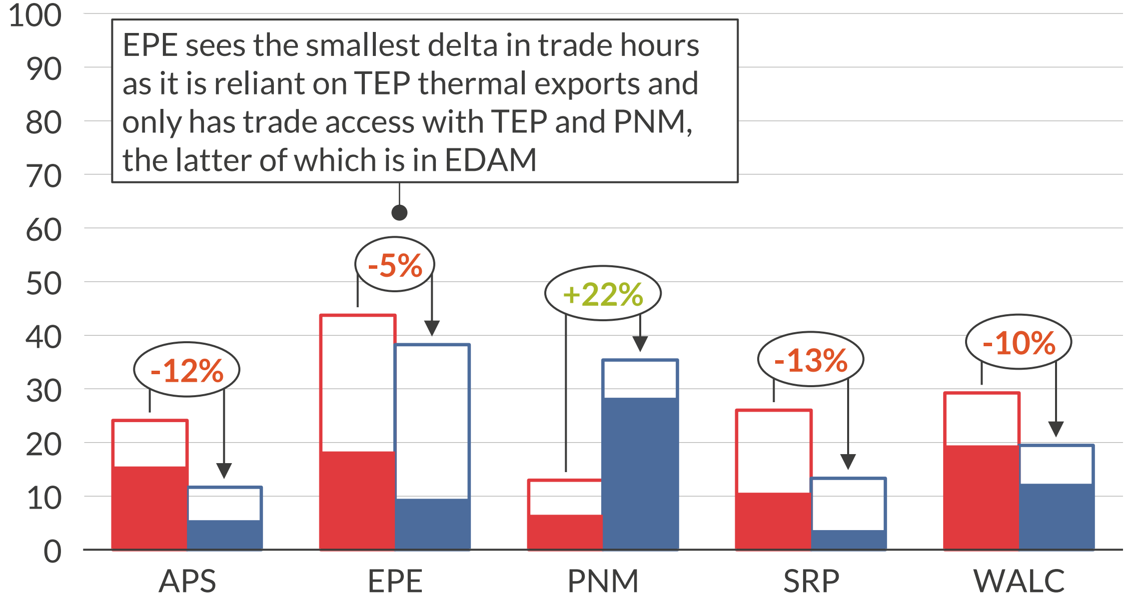
Average annual import and export delta[1] with TEP, 2027-2040
TWh



Key
- BA of focus (TEP)
- Modeled in Markets+
- Modeled in EDAM
- Modeled as Uncommitted

Average annual inter-BA trading hours with TEP, 2027-2040
% of hours per year



- When TEP is in EDAM, interconnection capacity to and from Markets+ BAs, particularly APS and SRP, are less utilized and decrease the frequency of congestion revenue relative to the Markets+ scenario[2]
  - While TEP does see a significant increase in trading hours with PNM under EDAM, the net decrease in trading hours with other BAs outweighs the increase in trade with PNM, resulting in a net decrease in congestion revenues

- Markets+ scenario
- EDAM scenario
- Hours with congestion
- Hours without congestion

1) Delta is calculated as EDAM scenario – Markets+ scenario. 2) Ownership of transmission assumed to be split 50-50 with connecting BA unless data on ownership is available.

Sources: Aurora Energy Research

The conversion of Springerville Unit 2 from coal to gas further accentuates the trading benefits for TEP under Markets+

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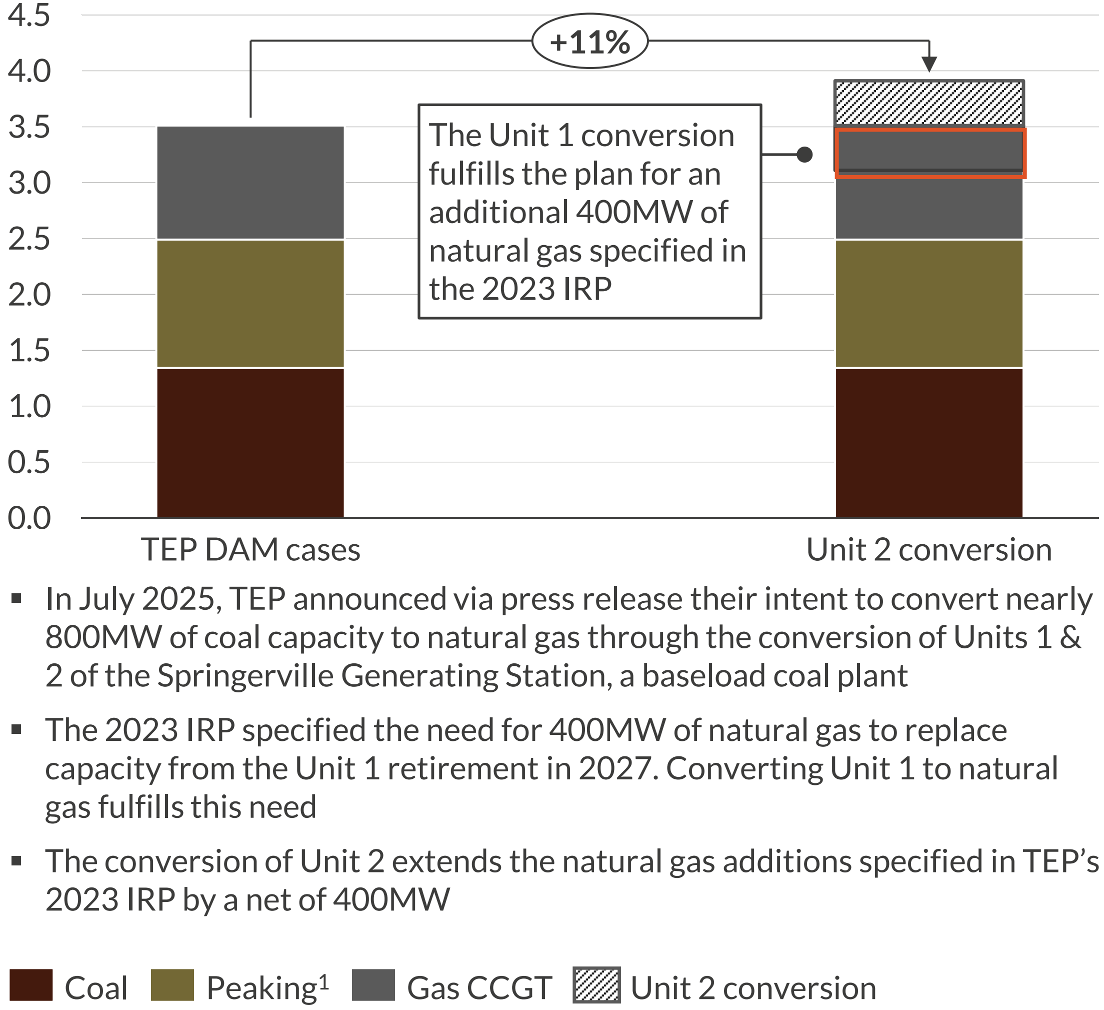
TEP system thermal capacity, 2030
GW



- In July 2025, TEP announced via press release their intent to convert nearly 800MW of coal capacity to natural gas through the conversion of Units 1 & 2 of the Springerville Generating Station, a baseload coal plant
- The 2023 IRP specified the need for 400MW of natural gas to replace capacity from the Unit 1 retirement in 2027. Converting Unit 1 to natural gas fulfills this need
- The conversion of Unit 2 extends the natural gas additions specified in TEP's 2023 IRP by a net of 400MW

Average cost delta breakdown, EDAM – Markets+[2], 2027-2040
$Million/year, real 2024

Metric	TEP DAM cases	Unit 2 conversion	Impact on TEP benefits under EDAM
Production cost	(25.0)	(34.3)	↑
Bilateral trading costs	10.9	25.1	↓
Congestion revenue	5.5	6.4	↓
Wheeling revenue	0.4	1.2	↓
Costs less revenues	**(8.1)**	**(1.7)**	↓

- With additional baseload thermal on the system, TEP production cost increases more in the Markets+ configuration as it is incentivized to export thermal to its wider trading market footprint
- However, TEP benefits from the ability to export more thermal generation in the Unit 2 conversion case, particularly when in Markets+ due to reduced seams costs with neighboring BAs
- As a result, the benefits for TEP under Markets+ configuration increase with a greater amount of baseload capacity on the system, although TEP still reports a system cost benefit under EDAM with the Unit 2 conversion

↑ Greater benefits for TEP in EDAM ↓ Reduced benefits for TEP in EDAM

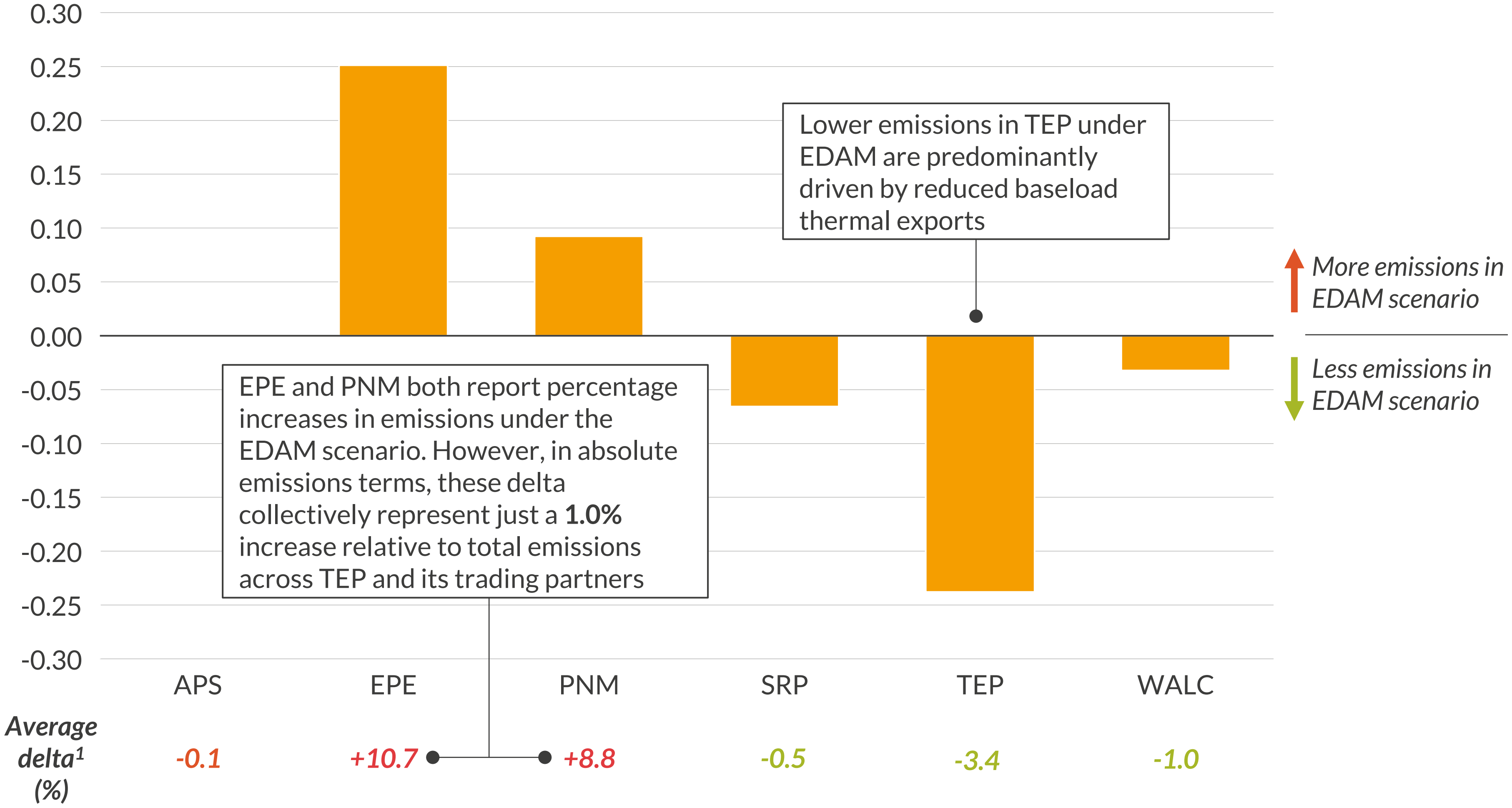
1) Peaking includes OCGT, reciprocating engines. 2) A negative delta indicates lower costs when TEP is modeled in EDAM compared to Markets+, demonstrating benefits to joining EDAM.

Sources: Aurora Energy Research, TEP

Emissions reductions for TEP under the EDAM configuration are offset by increased emissions in EPE and PNM trade partners

Average annual emissions delta for TEP and its trading partners[1], 2027-2040

Million $MtCO_2$



- Historically, TEP has been a key thermal exporter to EPE. Under EDAM, higher seams to trade reduces TEP exports to EPE, forcing the latter to increase domestic baseload thermal and peaking generation, driving up its emissions level
- Under EDAM, TEP imports less thermals from SRP due to higher seams, which concurrently reduces TEP's thermal exports driving its emissions reduction. PNM sees increased emissions from additional thermal exports to TEP to replace less thermals from SRP
- In net, the delta in emissions across TEP and its trading partners between scenarios translates to a <1 percent difference, indicating no material difference in total emissions

1) Delta is calculated as EDAM scenario – Markets+ scenario.

Sources: Aurora Energy Research

WECC-wide production costs and emissions levels are similar across scenarios, with marginal benefit for Arizona in the EDAM scenario

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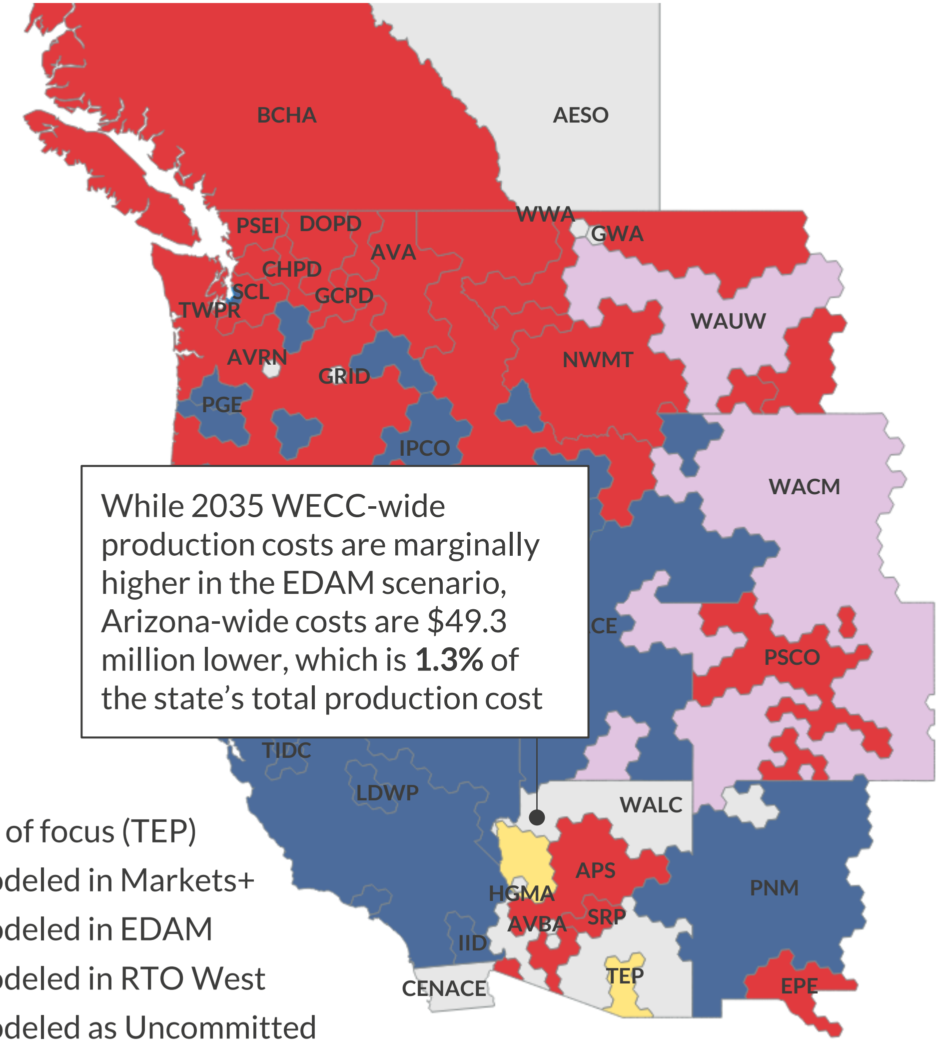
Map of modeled balancing authority (BA) market decisions



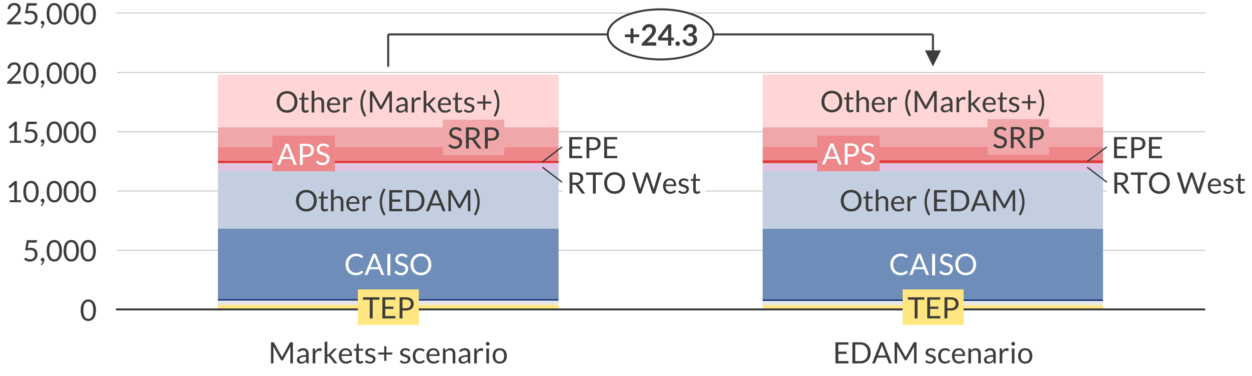
While 2035 WECC-wide production costs are marginally higher in the EDAM scenario, Arizona-wide costs are $49.3 million lower, which is **1.3%** of the state's total production cost

Key

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

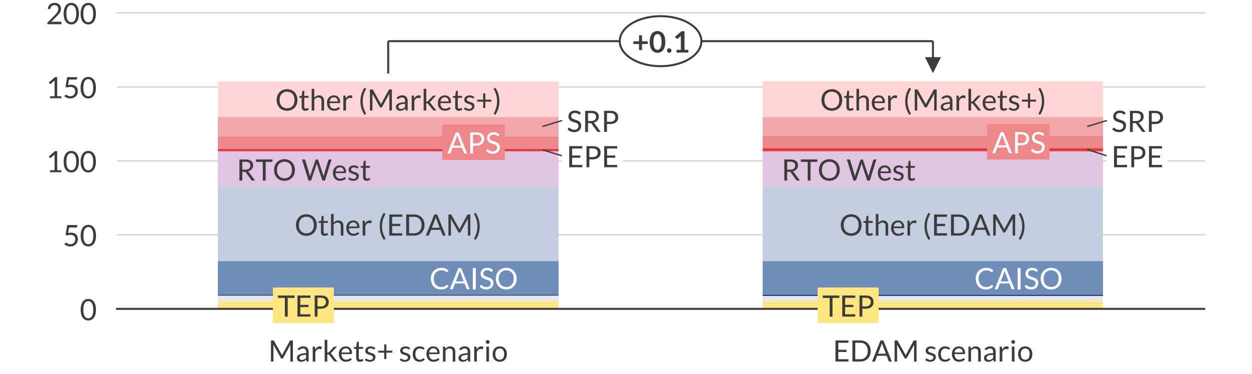
Total WECC-wide production costs in 2035[1]

$Million, real 2024



Total WECC-wide emissions, 2035[1]

Million Mt CO_2



- Emissions levels are similar across scenarios as resource buildout is kept constant and deltas in generation are not at a large enough scale to significantly alter WECC-wide emissions

1) The "Other (Markets+)" category includes AVA, 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

As in TEP DAM cases unless stated otherwise		TEP DAM cases[1]	AZ EDAM, including WALC	AZ EDAM, excluding WALC
Technology	Thermal			**Reflective of TEP July 2025 press release**, which converts Unit 2 of Springerville Generating Station to a natural gas plant, increasing TEP's baseload thermal capacity relative to the other scenarios
Market	Day-Ahead	TEP is modeled to either join EDAM or Markets+. All other BAs are modeled based on formalized commitment or assumption	TEP, APS, SRP, and WALC are modeled to join EDAM. All other BAs are modeled based on formalized commitment or assumption	TEP, APS, and SRP are modeled to join EDAM. All other BAs are modeled based on formalized commitment or assumption

1) The input assumptions align with Tucson Electric Power's (TEP) 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

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System costs for TEP under an all-EDAM footprint in Arizona are comparable to the DAM cases, while AZ-wide costs are minimized

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

	TEP DAM cases			AZ EDAM, incl. WALC		
Metric	TEP EDAM	TEP Markets+	**Delta[1]**	TEP	**Delta to TEP EDAM**	**Delta to TEP Markets+**
Production cost	391.5	416.4	**(25.0)**	390.7	**(0.8)**	**(25.7)**
Bilateral trading costs	(7.1)	(18.0)	**10.9**	7.9	**15.0**	**25.9**
Congestion revenue[2]	(12.5)	(18.1)	**5.5**	(19.1)	**(6.6)**	**(1.0)**
Wheeling revenue[2]	(4.4)	(4.9)	**0.5**	(5.5)	**(1.1)**	**(0.6)**
Annual costs[3] (TEP)	**367.4**	**375.5**	**(8.1)**	**373.9**	**6.5**	**(1.6)**
Annual costs[3] (AZ)	**3,377.1**	**3,347.8**	**29.3**	**3,266.8**	**(110.3)**	**(81.0)**

- Under the AZ EDAM, incl. WALC scenario, TEP sees a 1.8% cost increase relative to TEP EDAM scenario and a 0.4% cost benefit to TEP Markets+ scenario. Broadly, in the all-EDAM footprint, TEP sees lowered production costs as it has access to cheaper imports from the wider EDAM footprint; increased trades also translate into increased congestion and wheeling revenues as shown.
- AZ-wide costs are minimized when all BAs commit to EDAM. AZ benefits significantly from access to a more comprehensive and interconnected footprint. Efficient resource sharing reduces AZ-wide costs by 2.4%-3.3% relative to the TEP 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

TEP total system costs are reduced when WALC joins EDAM as TEP has access to additional thermal imports at no additional trade costs

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Average annual cost breakdown for TEP 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	390.7	449.5	**(58.8)**
Bilateral trading costs	7.9	3.9	**4.0**
Congestion revenue[1]	(19.1)	(17.5)	**(1.6)**
Wheeling revenue[1]	(5.5)	(5.9)	**0.4**
Annual costs[2] (TEP)	**373.9**	**430.1**	**(56.2)**
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 Unit 2 of Springerville to a gas plant. As a result, the additional baseload thermal capacity in TEP likely increases domestic production costs and increases export revenues, which amplifies the deltas reported to the AZ EDAM incl. WALC scenario

- TEP sees an average $56.2mil/year additional cost in the AZ EDAM excl. WALC scenario relative to the AZ EDAM incl. WALC scenario
- The observed delta is partially driven by the additional baseload thermal capacity in TEP in the scenario excluding WALC, which inflates TEP's production costs relative to the scenario including WALC
- WALC has sizable export capacity to TEP; when WALC is in EDAM, lower costs to trade incentivizes WALC thermal exports to TEP, displacing TEP's production costs and increasing its import costs relative to the AZ EDAM excl. WALC scenario

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

AZ EDAM incl. WALC: TEP engages in more trade relative to the DAM cases, with net increase in imports driving higher trade costs

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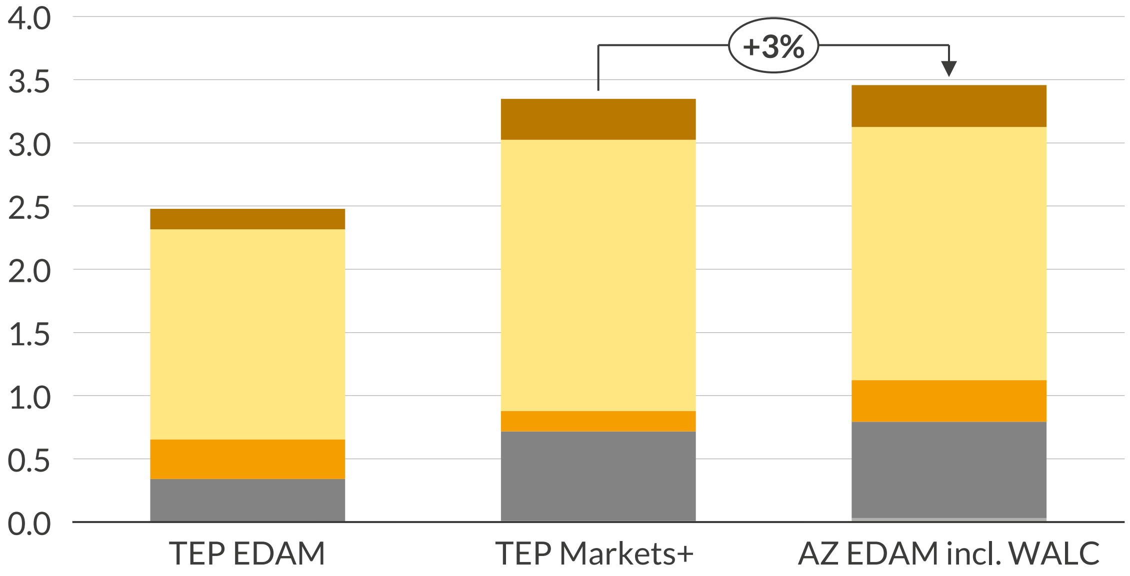
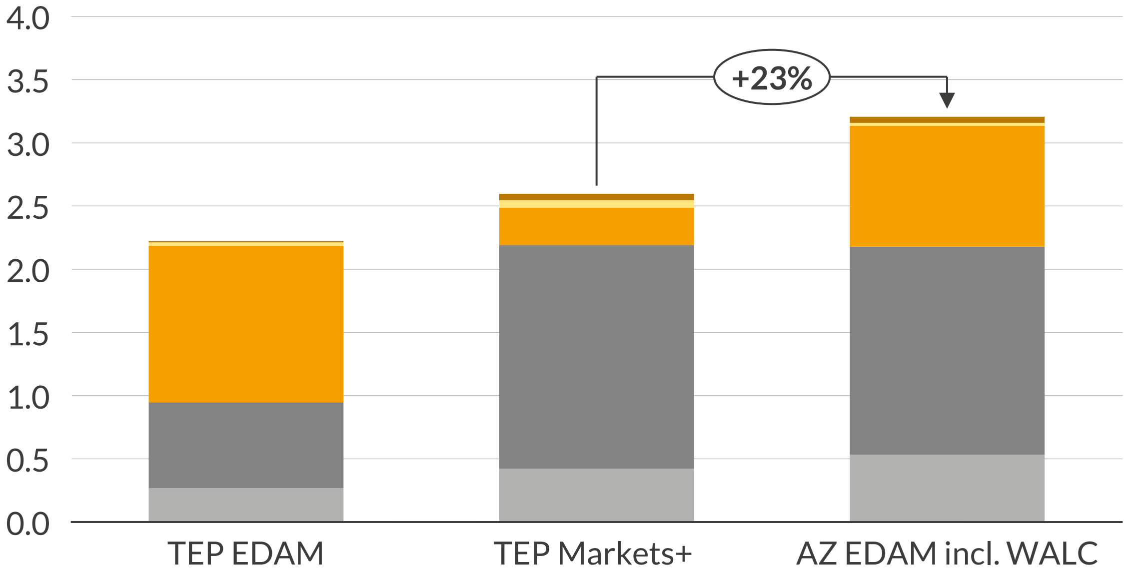
TEP average annual export volumes by BA trading partners
TWh



TEP average annual import volumes by BA trading partners
TWh



- In the AZ EDAM incl. WALC configuration, access to trade with a wider footprint at no additional costs drives higher import and export volumes, as well as increased associated trading revenues from line congestion and wheeling
- Relative to the EDAM scenario, TEP sees an increase in both import and export volumes, particularly to and from SRP which is committed to Markets+ in the DAM cases. Compared to the Markets+ scenario, TEP sees a marginal increase in export volumes and a greater increase in imports from PNM, particularly of thermal generation
- In net, TEP sees overall higher import volumes in the AZ EDAM incl. WALC scenario relative to the Markets+ scenario, driving its lower production cost. Compared to the EDAM scenario, higher import and export volumes in the AZ EDAM incl. WALC scenario results in a comparable production cost

APS EPE PNM SRP WALC

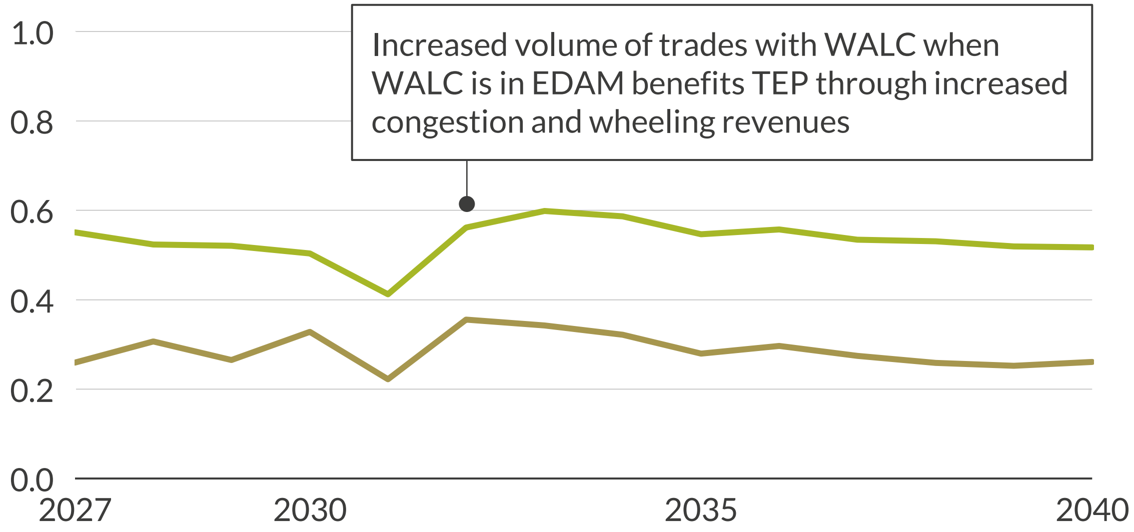
Sources: Aurora Energy Research

AZ EDAM excl. WALC: Additional baseload thermal in TEP and the exclusion of WALC from EDAM drives higher production costs for TEP

AURORA

TEP annual import volumes from WALC

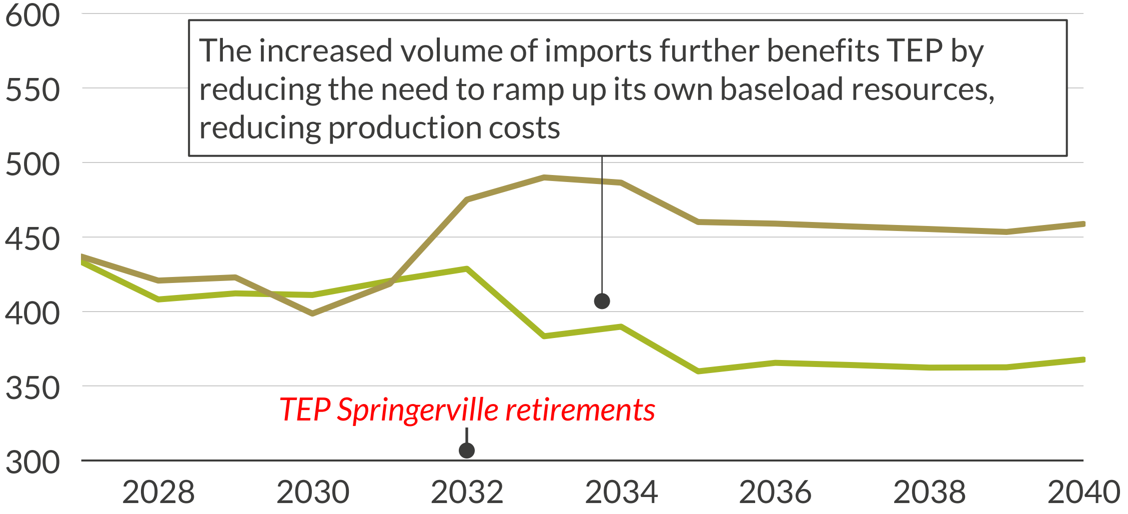
TWh



- When WALC is in EDAM, it is able to trade with TEP at no additional costs. This incentivizes WALC to export more generation to TEP, particularly of thermal generation as WALC sits on significant thermal baseload capacity
- On average, WALC annual import volumes to TEP are 85.5% higher in the AZ EDAM incl. WALC scenario as compared to the AZ EDAM excl. WALC scenario

TEP annual cost of generation

$Million/year, real 2024



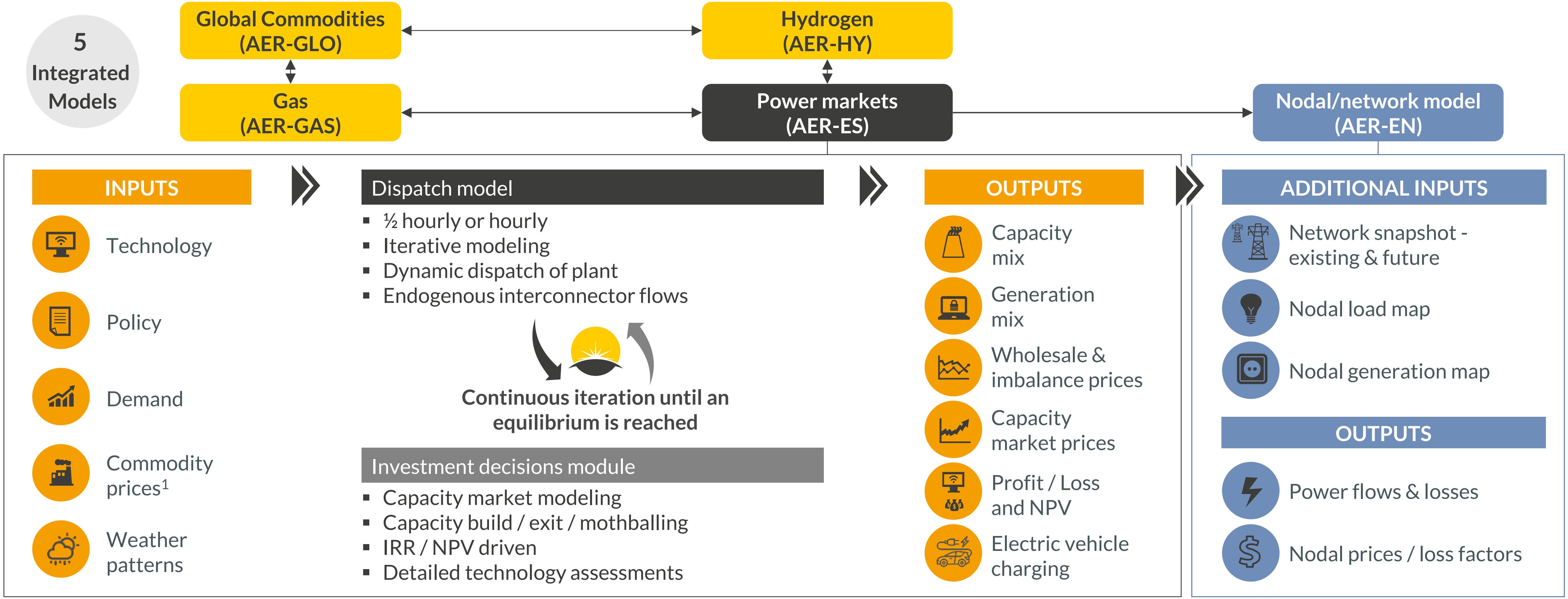
- Prior to the Springerville retirements, TEP sees comparable production costs between scenarios as it has excess coal and gas capacity for exports. As TEP's interconnection capacity for exporting to WALC is low, this minimizes the delta between scenarios
- After the Springerville retirements, access to cheaper WALC thermal exports in the AZ EDAM incl. WALC scenario allows TEP to ramp down its domestic production costs. Conversely, the exclusion of WALC from EDAM and additional TEP baseload thermal capacity under the AZ EDAM excl. WALC scenario together drive a 20.6% increase in production cost post-Springerville retirements relative to the scenario including WALC in EDAM

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

Sources: Aurora Energy Research

Agenda

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



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

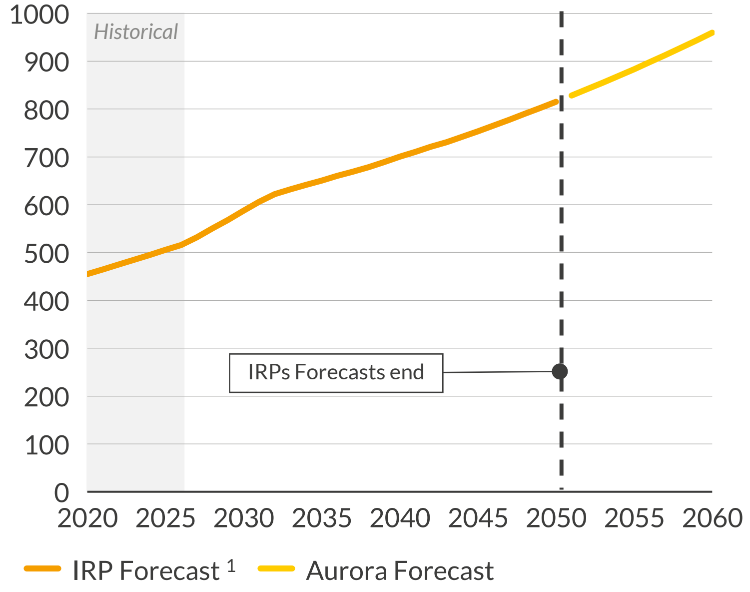
Demand, capacity, and technology assumptions reflect utility integrated resource plans and Aurora's long-term outlook

AURORA

Demand assumptions

Annual electricity demand

TWh

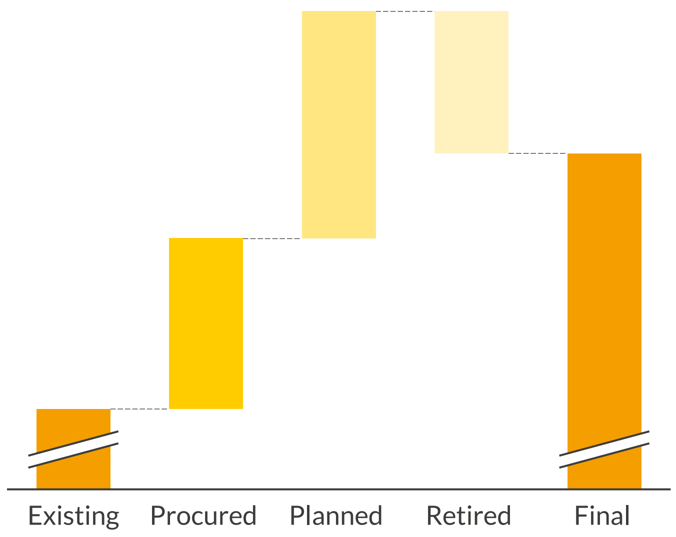


- Utility IRPs are used through their forecast horizon and reflect their assumptions on EVs, data centers and other demand drivers.
- Beyond the IRP period, we extend demand using trend-based assumptions and expected long-term patterns.

Capacity assumptions

Capacity assumptions components

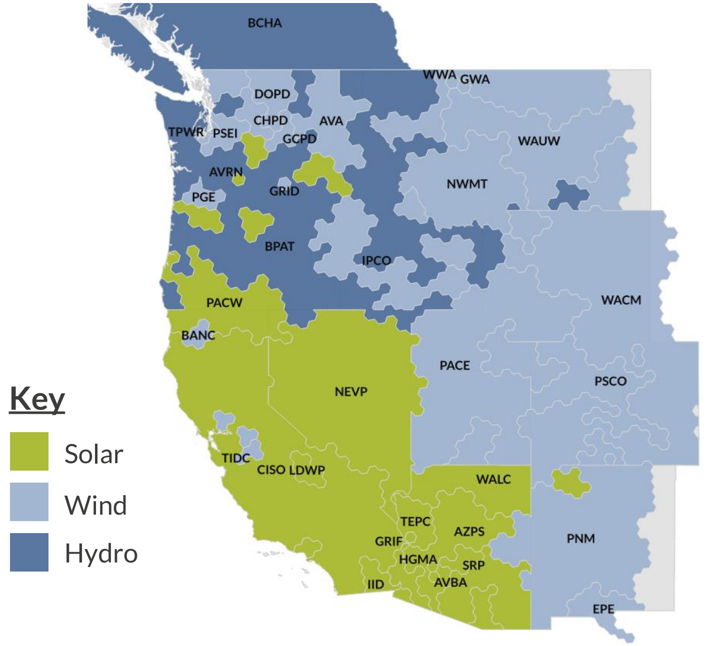
GW



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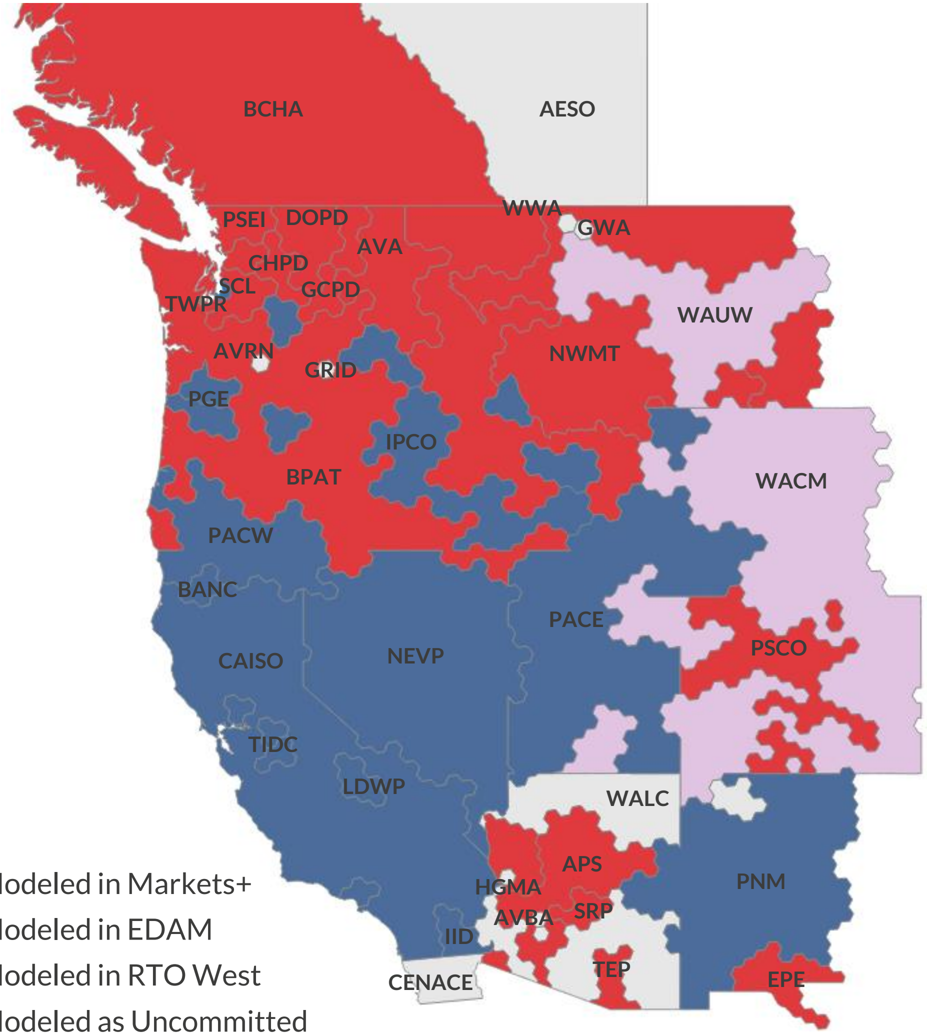
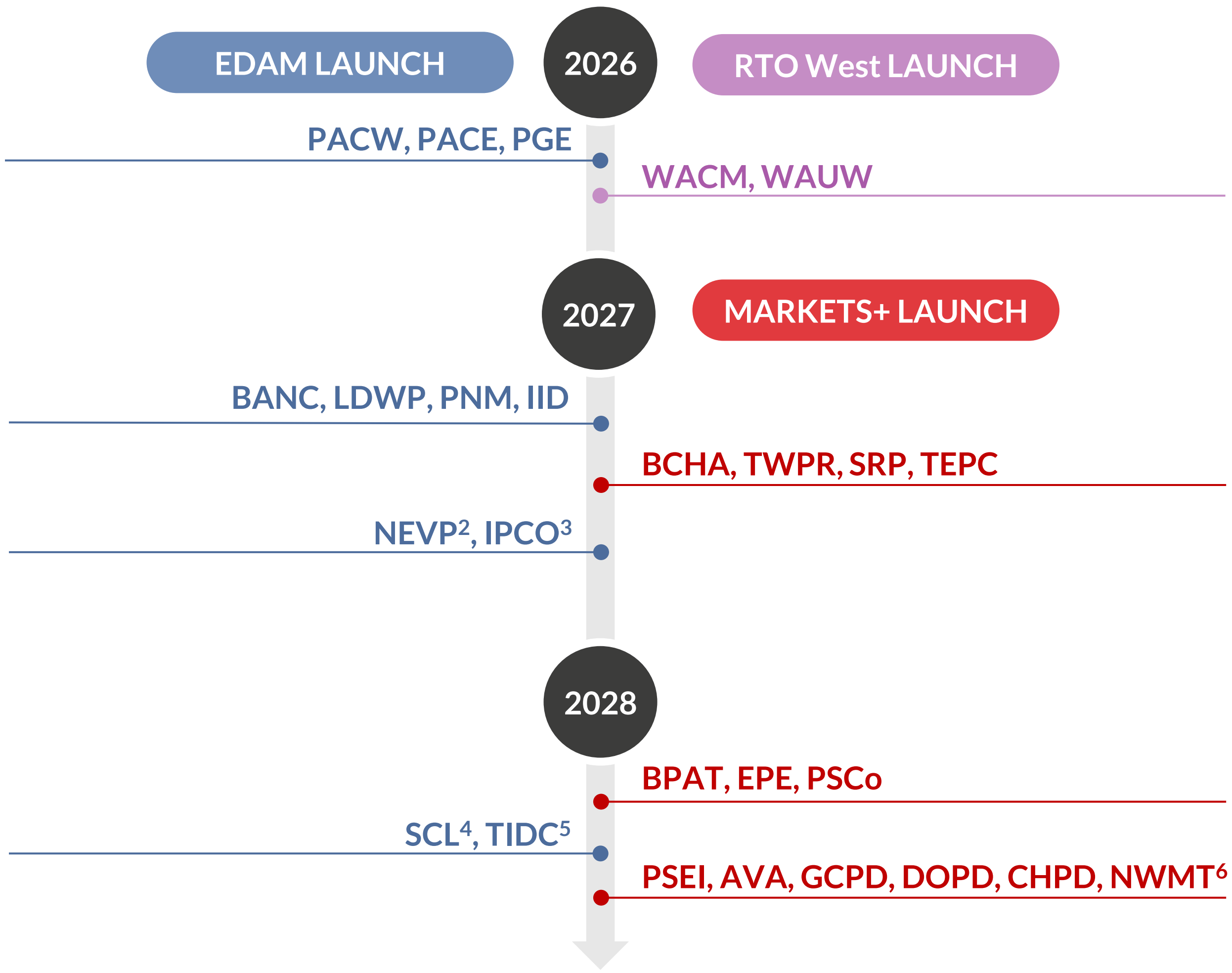
Central outlook on assumed day-ahead market participation[1]



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

Timeline of assumed day-ahead market participation[1]



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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Western market regionalization: SRP Day-Ahead market benefits analysis

Environmental Defense Fund

December 17th, 2025

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SRP sees higher average system costs when Arizona BAs commit to EDAM over Markets+, although this translates to less than <2%

This analysis aims to identify the potential benefits or costs for Salt River Project (SRP) under three Western US market regionalization scenarios: (1) SRP participates in Markets+, (2) SRP, APS, TEP participate in EDAM, and (3) SRP, APS, TEP, WALC participate in EDAM, with all else remaining equal. Comparisons between scenarios include those of various cost categories, generation mix, and emissions outputs.

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

Metric	SRP in Markets+[3]	AZ EDAM, excl. WALC	AZ EDAM, incl. WALC
Production cost	1,426.1	1,376.4	1,327.8
Bilateral trading costs	(35.7)	40.1	91.0
→ Export revenue	(420.0)	(379.2)	(382.2)
→ Import cost	384.2	419.3	473.2
Congestion revenue[1]	(94.1)	(102.7)	(112.0)
Wheeling revenue[1]	(22.5)	(21.2)	(20.6)
Annual costs[2] (SRP)	**1,273.8**	**1,292.6**	**1,286.2**
Annual costs[2] (AZ)	**3,381.7**	**3,342.2**	**3,266.8**

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

- SRP experiences an average $12–19M/year cost increase under AZ EDAM configurations relative to Markets+, though total Arizona-wide costs are lower
- **Production costs:** EDAM increases renewable imports from SP15 and reduces thermal exports to APS, lowering SRP's thermal dispatch and production costs
- **Bilateral trading costs:** The EDAM footprint raises SRP's import volumes and costs, while reducing SRPs export volumes to APS as APS accesses a broader pool of generation. The combination of greater imports and lower exports increases SRP's bilateral trading costs
- **Congestion and wheeling revenue:** EDAM drives higher utilization of SRP's transmission interties, particularly for SP15 imports, increasing congestion and wheeling activity

BAs are modeled to join DAMs based on confirmed or assumed commitments in the SRP Markets+ case, with variations across scenarios

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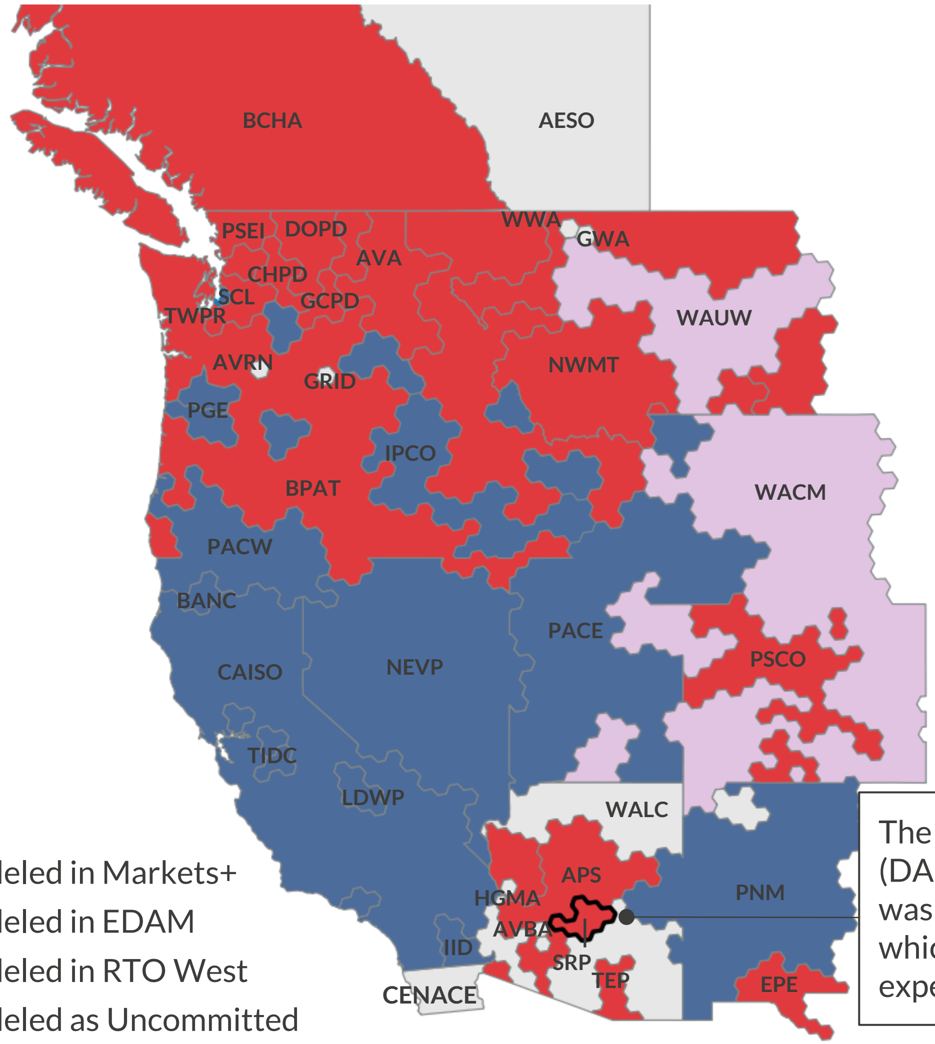
Map of modeled balancing authority (BA) market decisions – SRP Markets+ case

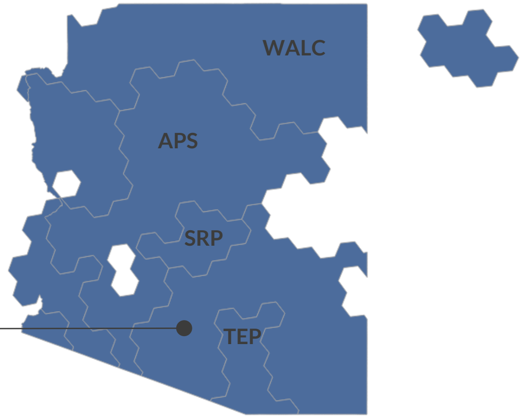


Key[1,2]

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

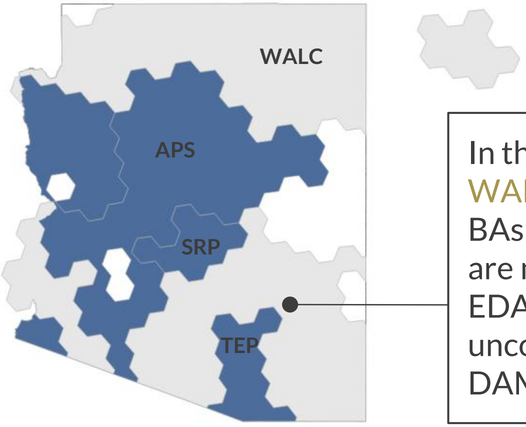
The Day-Ahead Market (DAM) commitment for SRP was modeled under Markets+, which is in line with its expected commitment

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

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



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

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

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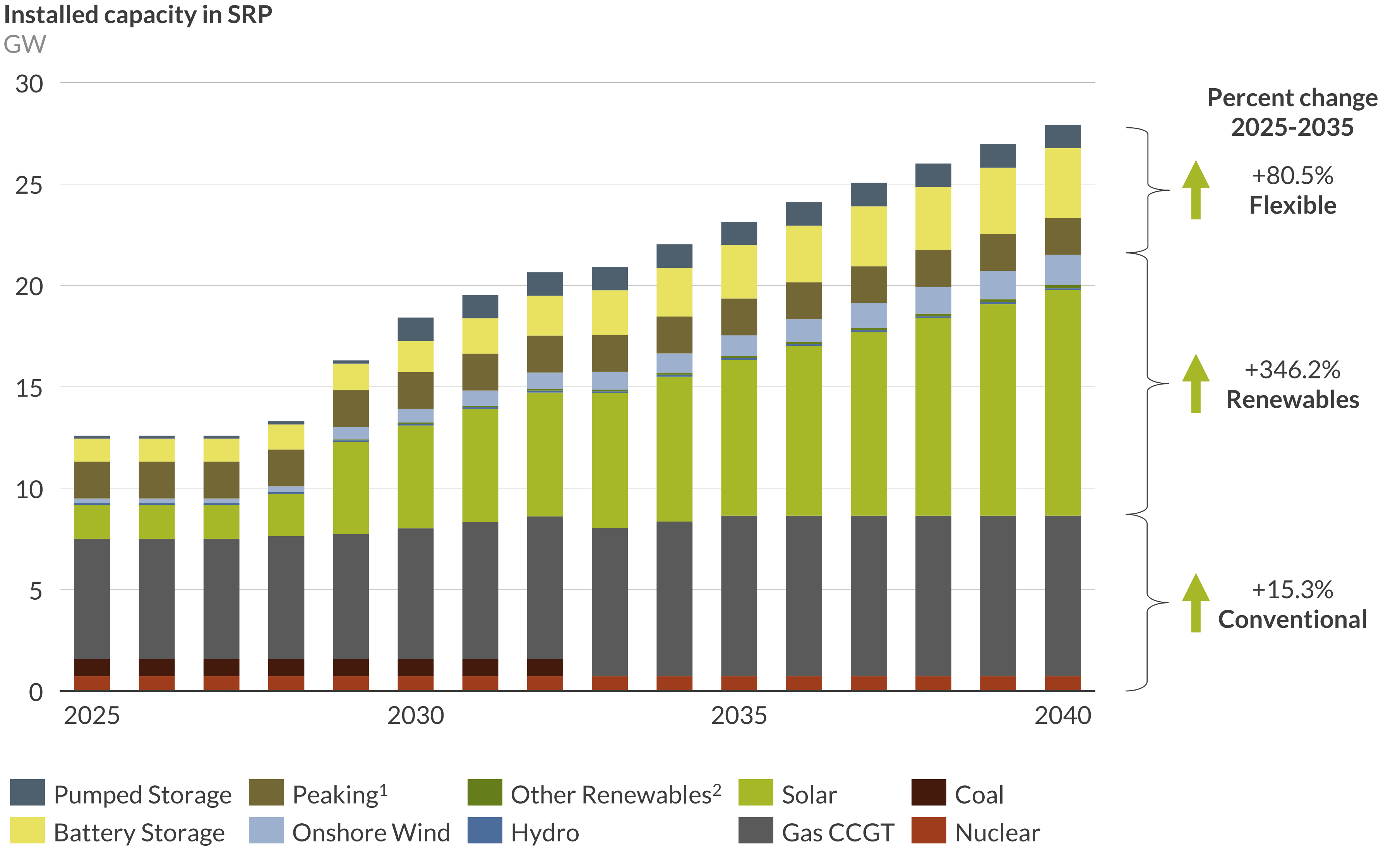
Aurora modeled SRP's capacity mix following SRP's 2023 ISP Balanced System Plan through to 2035



1) Peaking includes OCGT, reciprocating engines. 2) Other Renewables includes biomass and geothermal.

Sources: Aurora Energy Research, SRP

- Aurora modeled SRP installed capacity based on existing installed capacity owned and contracted, with capacity growth through to 2035 following the SRP Integrated System Plan (ISP) released in 2023
- SRP plans to add approximately 11.5GW of new resources by 2035, driven by load growth and thermal retirements. Of note is the utility's commitment to retire its entire coal fleet by 2032
- Although SRP is not included in the RPS program in Arizona, the utility has a goal to reduce carbon emissions to 90% of its 2005 baseline by 2050

SRP forecasts significant load growth throughout the Phoenix metro area as a result of increased commercial activity and population growth

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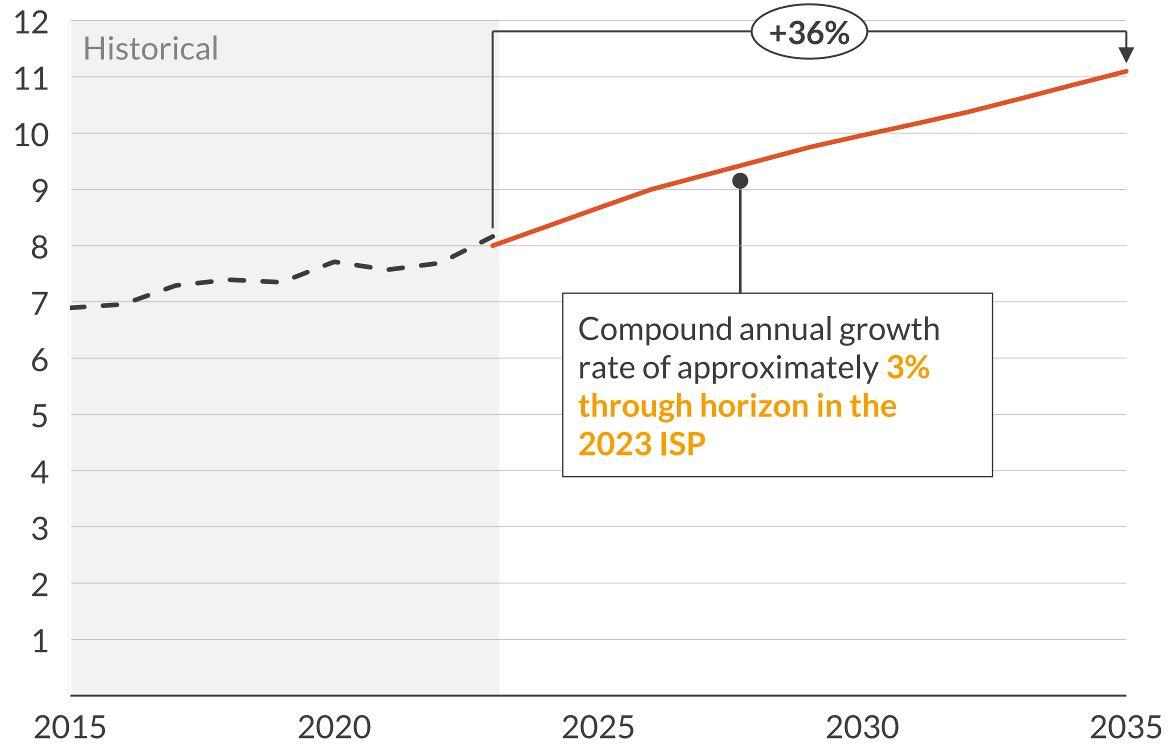
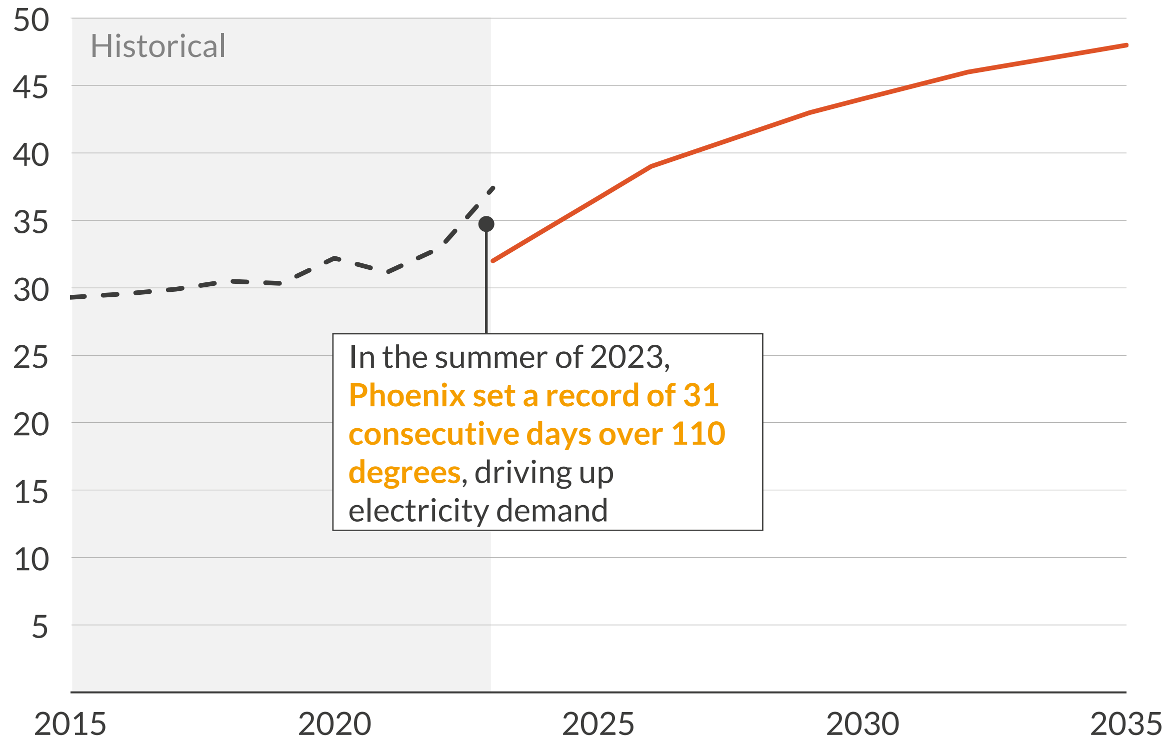
SRP coincidental peak demand[1,2,3]
GW



SRP annual system load[1,2,3]
TWh



- SRP's demand forecast anticipates a 0.67-degree Fahrenheit temperature increase per decade, consistent with the Intergovernmental Panel on Climate Change's Representative Concentration Pathway 4.5
- Demand growth is driven primarily by economic and population growth in the Phoenix metro area, mostly in the southeast portion of SRP's service territory

- SRP has a goal to support the enablement of 500,000 EVs in its service territory by 2035 and plans to manage 90% of EV charging through price plans, dispatchable load management, and other "smart" technologies
- SRP plans to double its demand response capabilities to 300MW by 2035

Historical   2023 ISP

1) Peak demand and forecasted annual system load accounts for energy efficiency, behind-the-meter technologies, and demand response. 2) Historical peak demand and annual load data is post-DSR. 3) Demand forecasts are SRP's "Current Trends" forecast.

Sources: Aurora Energy Research, WECC, SRP

Decreased exports and increased imports drive higher bilateral trade costs for SRP under AZ EDAM configurations

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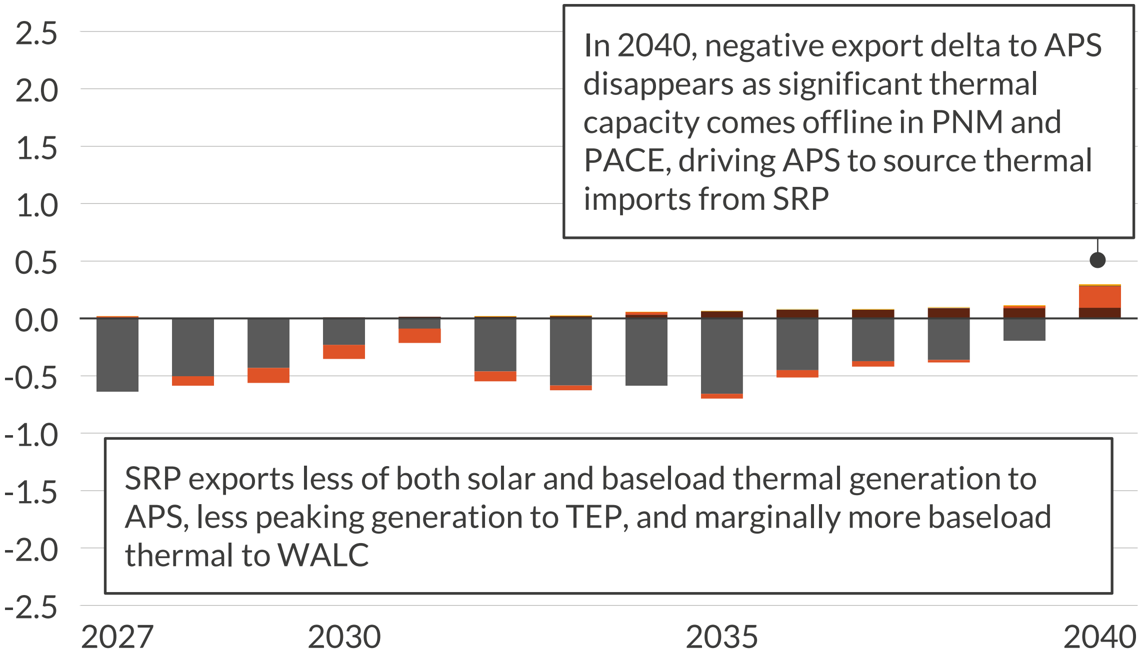
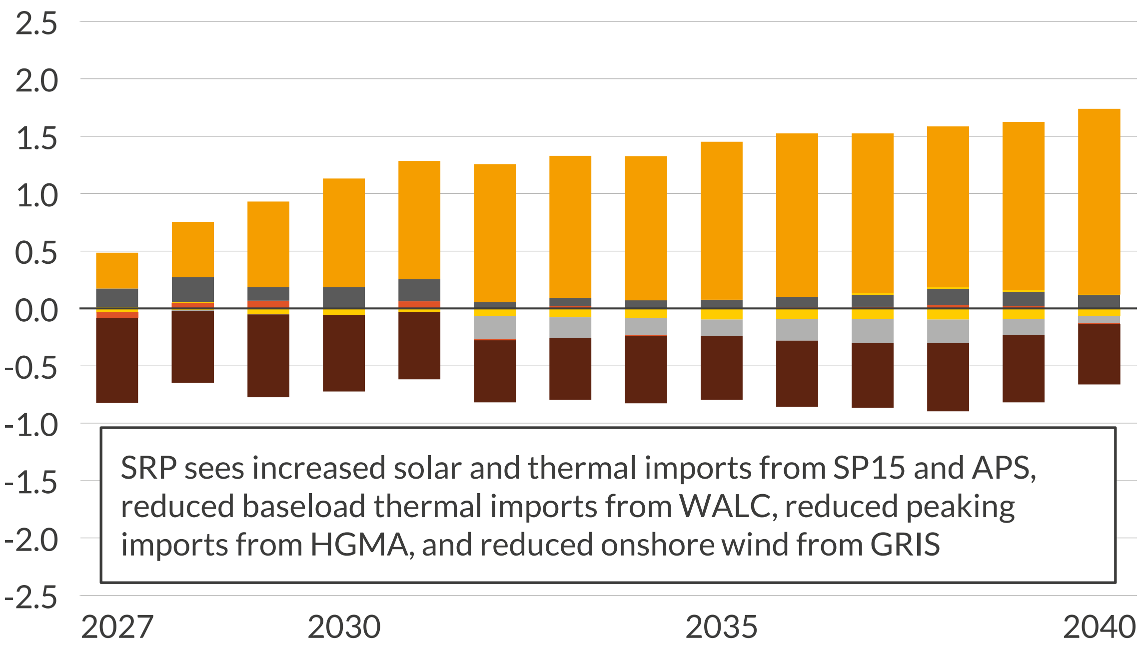
Delta in SRP export volumes, AZ EDAM excl. WALC – SRP Markets+[1] scenario
TWh



- SRP has historically been a significant exporter to APS, particularly of baseload thermal generation
- However, under the EDAM scenarios, APS can access increased renewables and thermal from the wider EDAM footprint, especially from PNM and PACE. As a result, SRP exports less to APS, driving its lower export revenues in the EDAM scenarios relative to the SRP Markets+ scenario

Delta in SRP import volumes, AZ EDAM excl. WALC – SRP Markets+[1] scenario
TWh



- Under the EDAM scenarios, SRP can import from SP15 without facing seams costs. This drives higher imports of both thermals and renewables to SRP, offsetting its domestic baseload generation in tandem
- Under the AZ EDAM excl. WALC scenario, SRP sees reduced imports from WALC relative to the SRP Markets+ scenario as hurdle rates for trade between Uncommitted BAs with EDAM are higher due to synchronization costs. However, this delta disappears under the AZ EDAM incl. WALC scenario when WALC joins the EDAM footprint

SP15 AVBA APS GRIS HGMA TEP WALC

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

Decreased thermal generation in SRP in the AZ EDAM scenarios drives lower production costs relative to the Markets+ scenario

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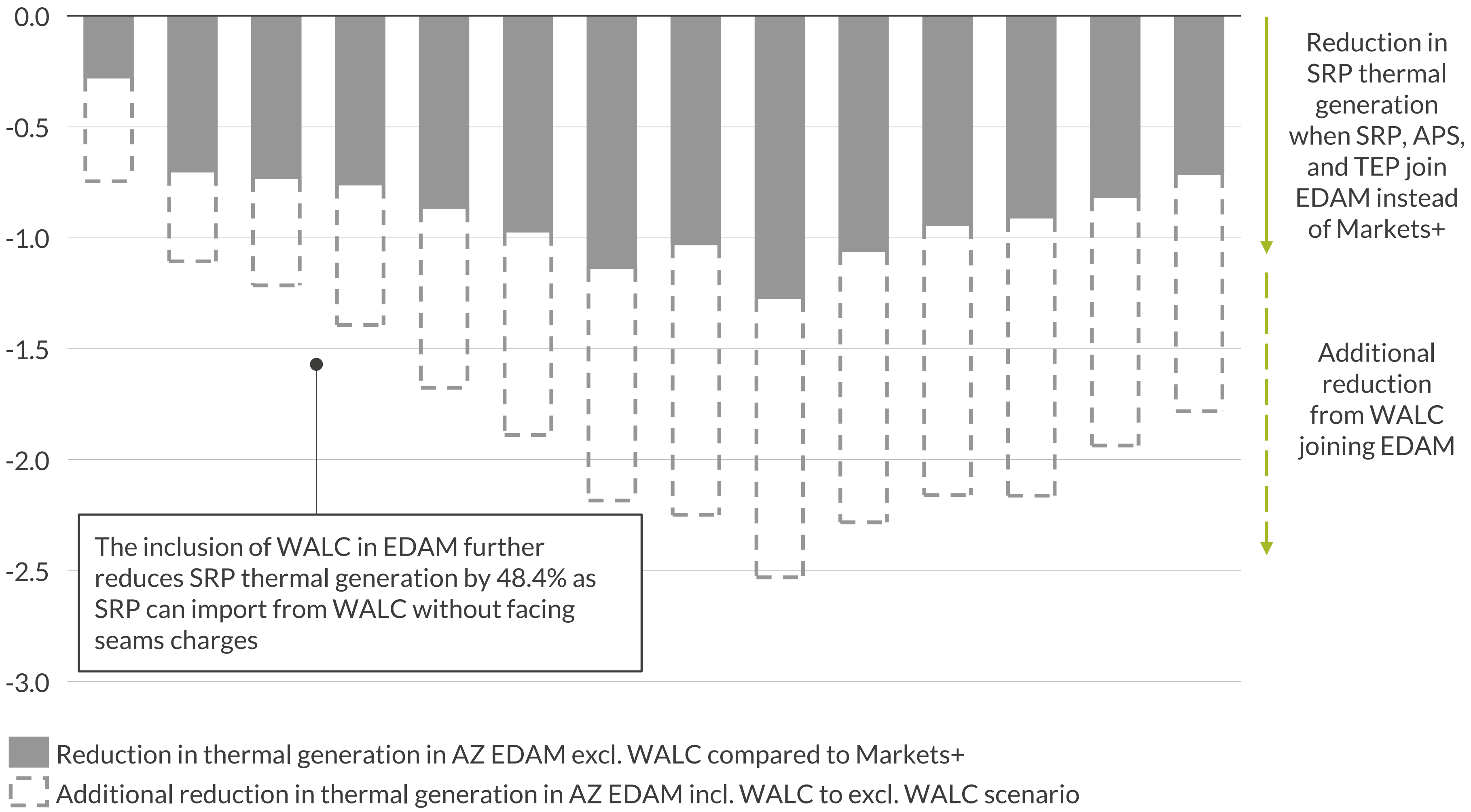
Yearly thermal generation delta in SRP, 2027 – 2040
TWh



- When Arizona participates in EDAM, SRP sees reduced export volumes, particularly to APS, and increased import volumes, particularly from SP15. The increase in net imports reduces domestic production and the associated production cost for SRP under AZ EDAM as opposed to SRP Markets+
- The reduced domestic thermal generation drives a 3.1-4%, or ~0.4MMtCO2, reduction in annual SRP emissions under the AZ EDAM scenarios compared to the Markets+ scenario
- While not quantified in the system cost metrics, there are benefits associated with reduced carbon emissions that can counteract some of the cost increases in the EDAM scenarios

Sources: Aurora Energy Research

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

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