Western market regionalization: PSCo Day-Ahead market benefits analysis

Full report

Environmental Defense Fund

May 30th, 2025

Agenda

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Executive Summary

- Under SB 21-072, Xcel (PSCo) is mandated to join an organized wholesale utility market by 2030. The utility has announced its intention to join SPP's Markets+ to fulfil this mandate, and is awaiting approval from the Colorado Public Utilities Commission
- This study aims to quantify the potential impacts on costs, generation mix, and emissions for the Public Service Company of Colorado (PSCo) balancing authority (BA) under two Western US market regionalization scenarios: (1) PSCo participation in EDAM and (2) PSCo participation in Markets+
- The analysis employs Production Cost Modeling across the WECC balancing authorities to compare the market outcomes driven by PSCo's Day-Ahead market (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 PSCo
- This study finds that PSCo participation in EDAM vs. Markets+ has the following impacts:
  - When participating in EDAM over Markets+, PSCo balancing authority can **save an average of $13.2million/year from participation in EDAM over Markets+**, enabled/mitigated by:
    - **Lower production costs** due to lower reliance on thermal generation, which is replaced in large part by wind
    - **Higher congestion and wheeling revenue** due to higher utilization of transmission infrastructure facilitating trades between PNM and PACE
    - **Higher bilateral trading costs** due to different governance structures between EDAM and RTO West which WACM is joining, driving higher hurdle rates for importing from WACM
  - Emissions levels resulting from the DAM decision do not vary significantly, primarily due to the assumption of the same capacity mix in each scenario. Under both scenarios, Xcel (PSCo) following the 2024 Just Transition Solicitation capacity mix meets the emissions targets specified under SB 19-236
- **Conclusion**: This study finds that PSCo sees additional cost savings and similar emissions levels from participation in EDAM compared to participation in Markets+, under the specific capacity mix, load, DAM configuration, and transmission capacity assumed for this analysis

Sources: Aurora Energy Research

PSCo sees total costs reduced by an average of $13.2 million/year through 2060 when participating in EDAM as opposed to Markets+

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

Average cost breakdown for PSCo under EDAM vs Markets+ DAM, 2028-2060
$Million/year, real 2024

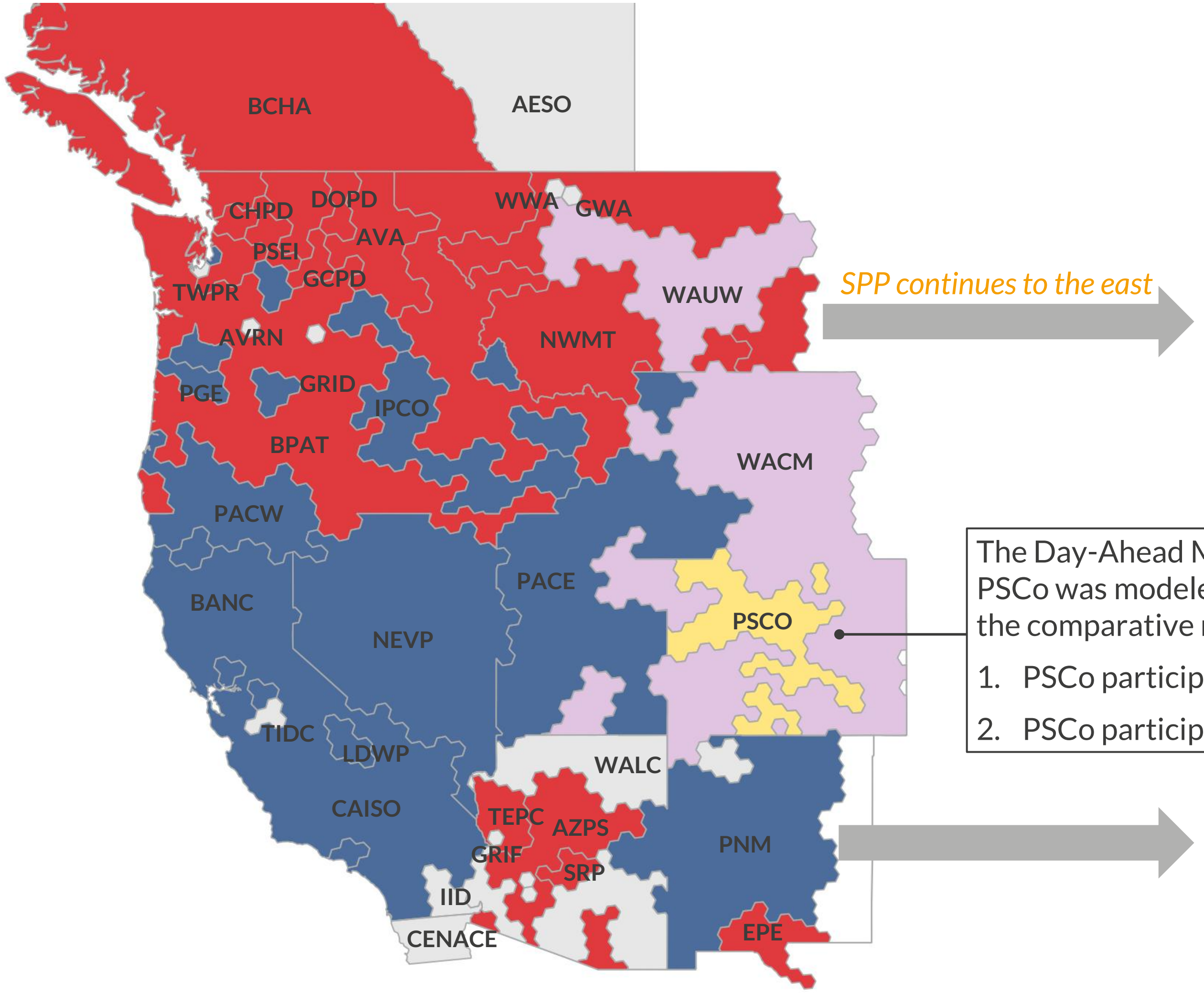
Metric	EDAM	Markets+	Delta (EDAM – Markets+)[1]	Average delta, 2028-2040	Average delta, 2041-2060
Production cost	857.4	862.3	(4.9)	(1.2)	(7.4)
Bilateral trading costs	231.9	227.0	4.9	0.2	8.0
Congestion revenue	(85.8)	(72.9)	(12.8)	(9.2)	(15.2)
Wheeling revenue	(5.5)	(5.1)	(0.4)	(1.0)	(0.0)
Costs less revenues	998.0	1,011.2	(13.2)	(11.2)	(14.6)

1) A negative delta indicates lower costs when PSCo 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
Sources: Aurora Energy Research

- PSCo sees an average $13.2mil/year benefit in total costs when participating in EDAM vs. Markets+
- **Production costs** - When participating in EDAM, greater wind generation and lower gas production drive down energy production costs
- **Bilateral trading costs** - PSCo is a net importer in all scenarios, primarily from WACM. This dynamic creates additional bilateral trading costs for PSCo in the EDAM scenario, where imports from WACM are subject to additional friction charges
- **Congestion and wheeling revenue** – Under the EDAM scenario PSCo sees higher utilization of its transmission interconnection to facilitate trades between PACE and PNM[2]

The composition of each offering in the West is modeled based on confirmed and likely commitments as announced by each BA

Map of modeled balancing authority (BA) market decisions



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

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

Key[1,2]

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

1) BAs with announced leanings or commitments as of May 15th are modeled as participating in the respective offering. BAs that are undecided or have no public leaning as of May 15th 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 PSCo utility portfolio following the JTS through 2050; PSCo BA capacity includes resources from other utilities

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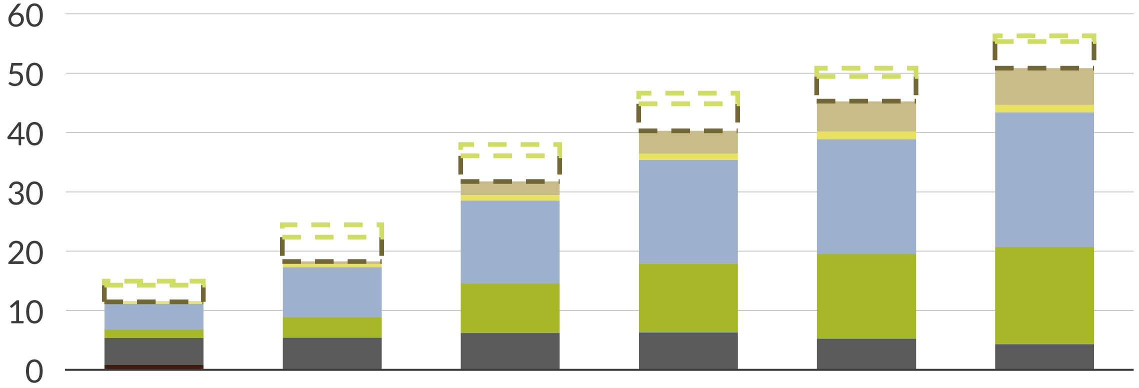
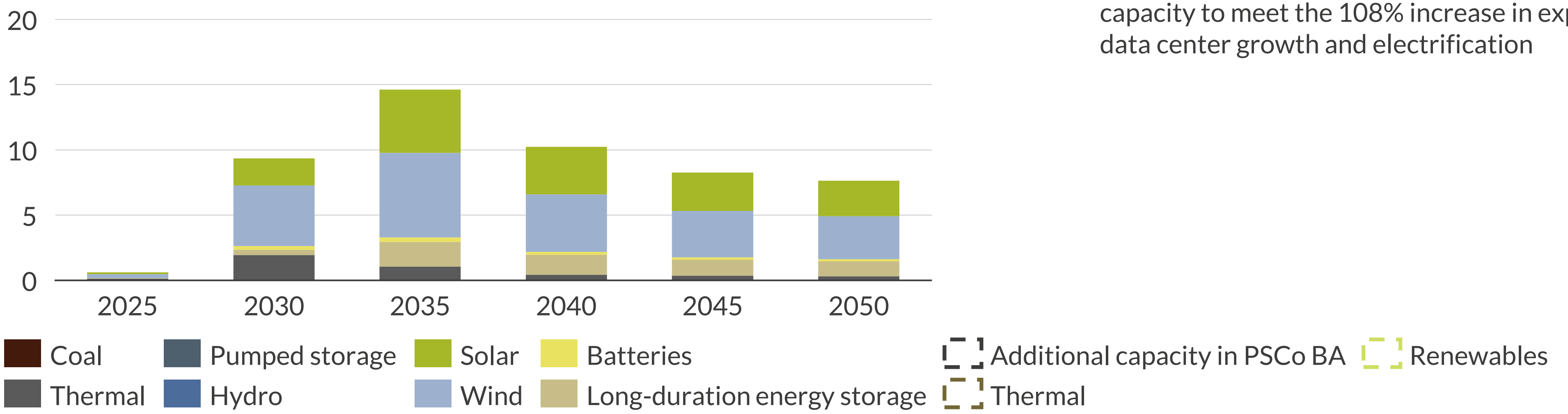
Installed capacity, PSCo utility and PSCo Balancing Authority Area[1]

GW



Capacity additions in 5-year increments following the JTS[2]

GW



- Aurora modeled PSCo installed capacity based on existing installed capacity owned and contracted to utilities within PSCo territory, with capacity growth throughout the forecast for PSCo utility following the Just Transition Solicitation (JTS) released in 2024
- Retirements of 1.8GW of coal and gas by 2031 as outlined in the JTS are included in Aurora's forecast
- About 10GW of renewables, storage, and new CCGTs are planned to come online in the next 5-6 years to replace the retiring conventional resources
- The technologies procured in the JTS are designed to meet 2030 and 2050 emissions targets under SB 19-236, while procuring enough capacity to meet the 108% increase in expected load by 2050 driven by data center growth and electrification

1) Capacity serving the PSCo BA load includes capacity within Blackhills, Tristate CO, and other LSEs under PSCo BA territory. 2) Xcel (PSCo)provides their preferred portfolio in lump capacity additions for the periods from 2025 through 2031 and 2031 through 2050. The lump capacity amounts have been distributed across years following annual load growth, which varies year to year

Sources: Aurora Energy Research, Xcel (PSCo)

Under both Day-Ahead markets, PSCo is compliant with SB 19-236 emissions targets in 2030 and 2050

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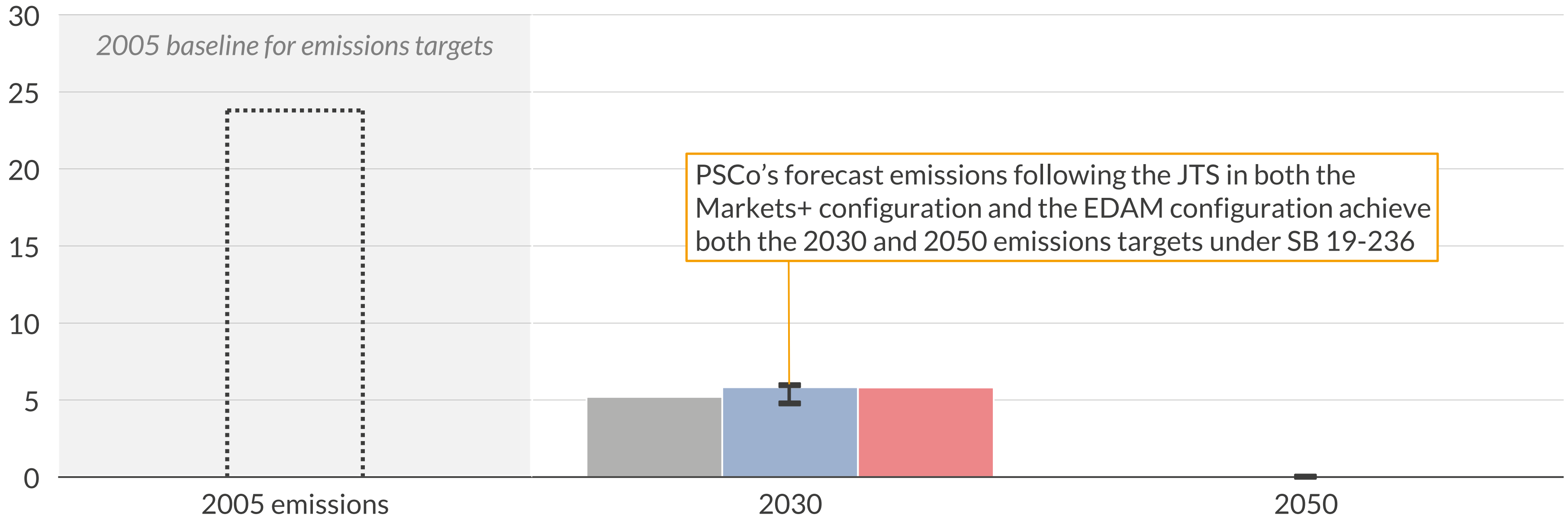
Xcel (PSCo) CO_2 emissions forecast[1]
Million $MTCO_2e$



Colorado SB 19-236 Targets

2005 Baseline

Colorado utilities are required to cut their emissions relative to their 2005 levels

2030

By 2030, **each utility must cut its emissions from Colorado retail sales by 80% from its 2005 levels**. Its plan to do so is compliant if it is found to achieve at least a 75% reduction in emissions by 2030 by the Air Pollution Control Division

2050

Utilities are required to target 100% of sales coming from clean energy by 2050

2005 baseline emissions | JTS forecast | PSCo in EDAM | PSCo in Markets+ | Emissions compliance range[2]

- The CPUC accepted Xcel (PSCo)'s 2021 Clean Energy Plan. The 2024 JTS sees accelerated procurement to meet the same emissions reduction requirements while serving new load demands
- Retirements of ~1.8GW conventional coal and gas resources, with renewables and storage replacements, enables PSCo to reach 2030 targets
- Emissions are similar between the two modeled scenarios for PSCo participation in EDAM and Markets+ given the capacity mix was held constant. Marginal differences in emissions are driven by variation in carbon intensity of imports and exports

1) Results shown here are the emissions for Xcel (PSCo) utility as the largest LSE within the BA territory. SB 19-236 targets only apply to electricity providers serving at least 500,000 customers in Colorado; Xcel (PSCo), Black Hills, and Tri-State are qualifying utilities 2) Using 2005 emissions level as a baseline, which was 23.8MMTCo2e
Sources: Aurora Energy Research, Xcel (PSCo), Colorado Air Pollution Control Division

Aurora considers transfer limits between regions when modeling the Western Interconnection

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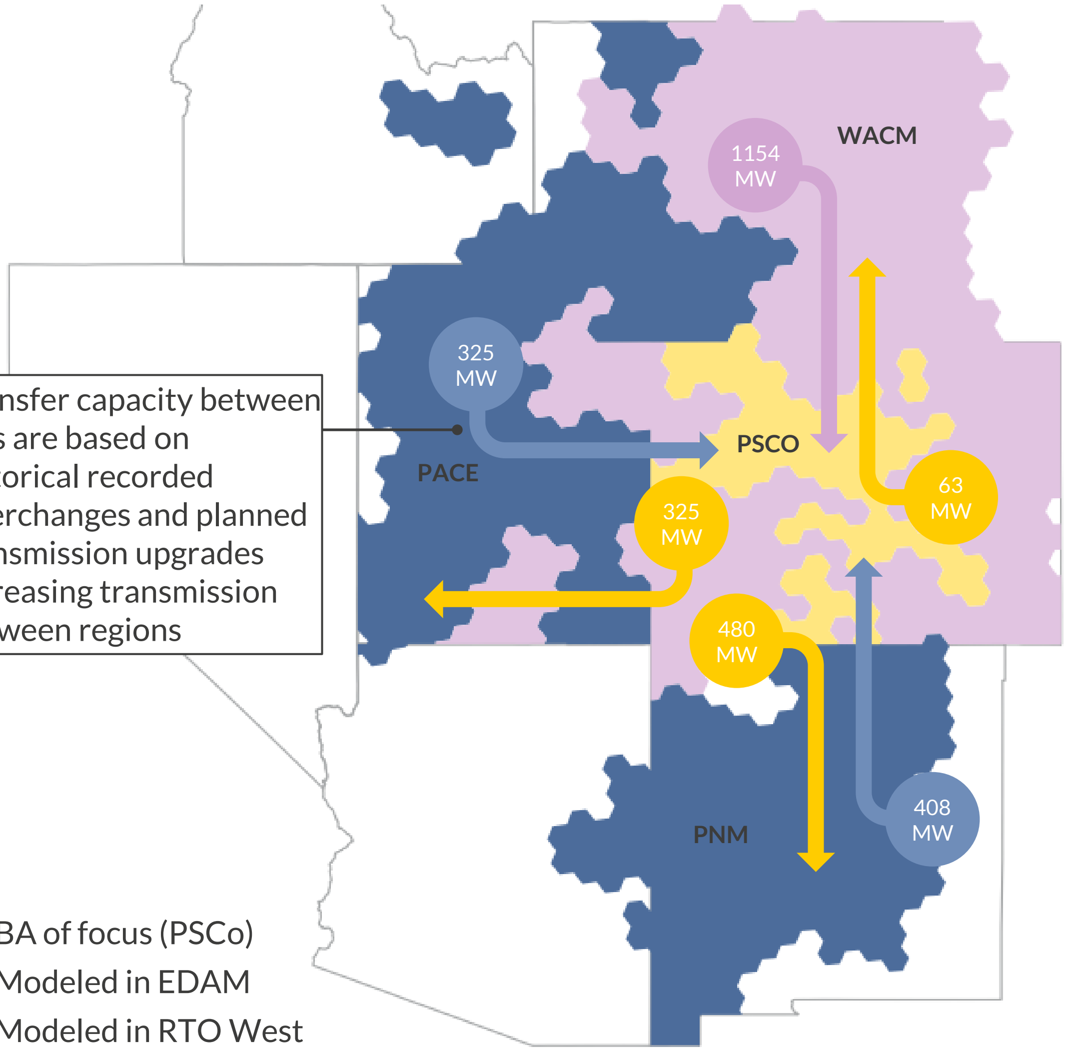
Modeled transfer limits to and from PSCo in 2032[1]



Transfer capacity between BAs are based on historical recorded interchanges and planned transmission upgrades increasing transmission between regions

Key
- BA of focus (PSCo)
- Modeled in EDAM
- Modeled in RTO West

Transmission projects modeled with impacts on Net Transfer Capability (NTC)

Project name	Modeled year in-service	Description
Colorado Power Pathway (CPP) Segments 1-5	Segment 1: 2026 Segment 2 + 3: 2025 Segment 4 + 5: 2027	Connects PSCo system into eastern Colorado, accommodating the addition of up to 5GW nameplate capacity
CPP extension (May Valley – Longhorn)	2032	Connects PSCo system into eastern Colorado
Colorado Electric Transmission Authority (CETA) Southeast Concept	2032	345kV line from the Longhorn substation in CO to the Gladstone substation in NM
CETA Northwest Concept	2032	345kV line from CO Craig substation to UT PacifiCorp Gateway South transmission line via Coyote substation

1) Transfer limits are modeled at the BA level. BAs identified here show all modeled interchange possibilities for PSCo with neighboring BAs

Sources: Aurora Energy Research, WECC, EIA, CETA, Xcel

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Input assumptions for PSCo align with the 2024 JTS, with other BA inputs following their respective IRPs

The input assumptions align with Xcel (PSCo) Just Transition Solicitation IRP, which was submitted to the PUC for approval in October 2024, where available. These assumptions include demand, new build capacity, and retirements. Aurora standard input assumptions for modeling the West are used elsewhere.

Aurora assumption unless stated otherwise		Base Case
Demand	**Underlying demand**	**Consistent with Xcel JTS Base forecast Annual Energy (GWh)** growth rate for Xcel (PSCo) utility, with additional demand for separate LSEs within PSCo BA service area
Commodities	**Gas price**	Henry Hub prices increase to $4.5/MMBtu in 2030 and $5.4/MMBtu in 2060. CIG prices, which represent PSCo, increase to $4.1/MMBtu in 2030 and $5.1/MMBtu in 2060.
	Coal price	Stable coal price across forecast horizon
Technology	**Renewables**	**Consistent with the 2024 JTS plan**, which adds +40GW in renewables.
	Thermal	**Consistent with 2024 JTS plan** – thermal exits modeled as outlined.
	Hydro	P60 hydro availability throughout the Western Interconnection
Policy	**Pollution standards**	Xcel (PSCo) meets SB 19-236 emissions reductions targets applicable to LSEs serving at least 500,000 customers
	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 PSCo. Washington and California carbon markets link and prices increase to $101/ton by 2035 and level off at $140/ton.

Sources: Aurora Energy Research

The composition of each offering in the West is modeled based on confirmed and likely commitments as announced by each BA

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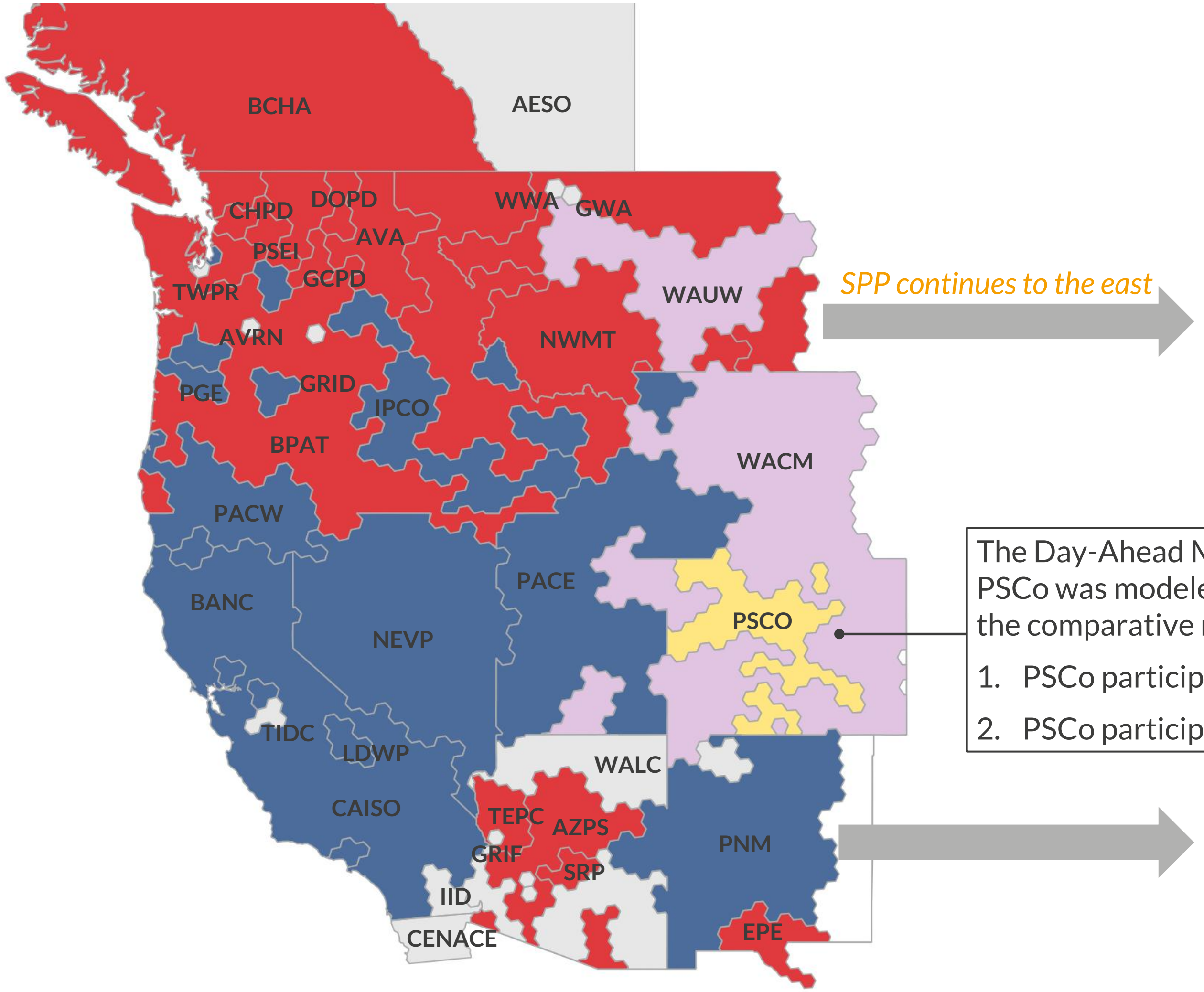
Map of modeled balancing authority (BA) market decisions



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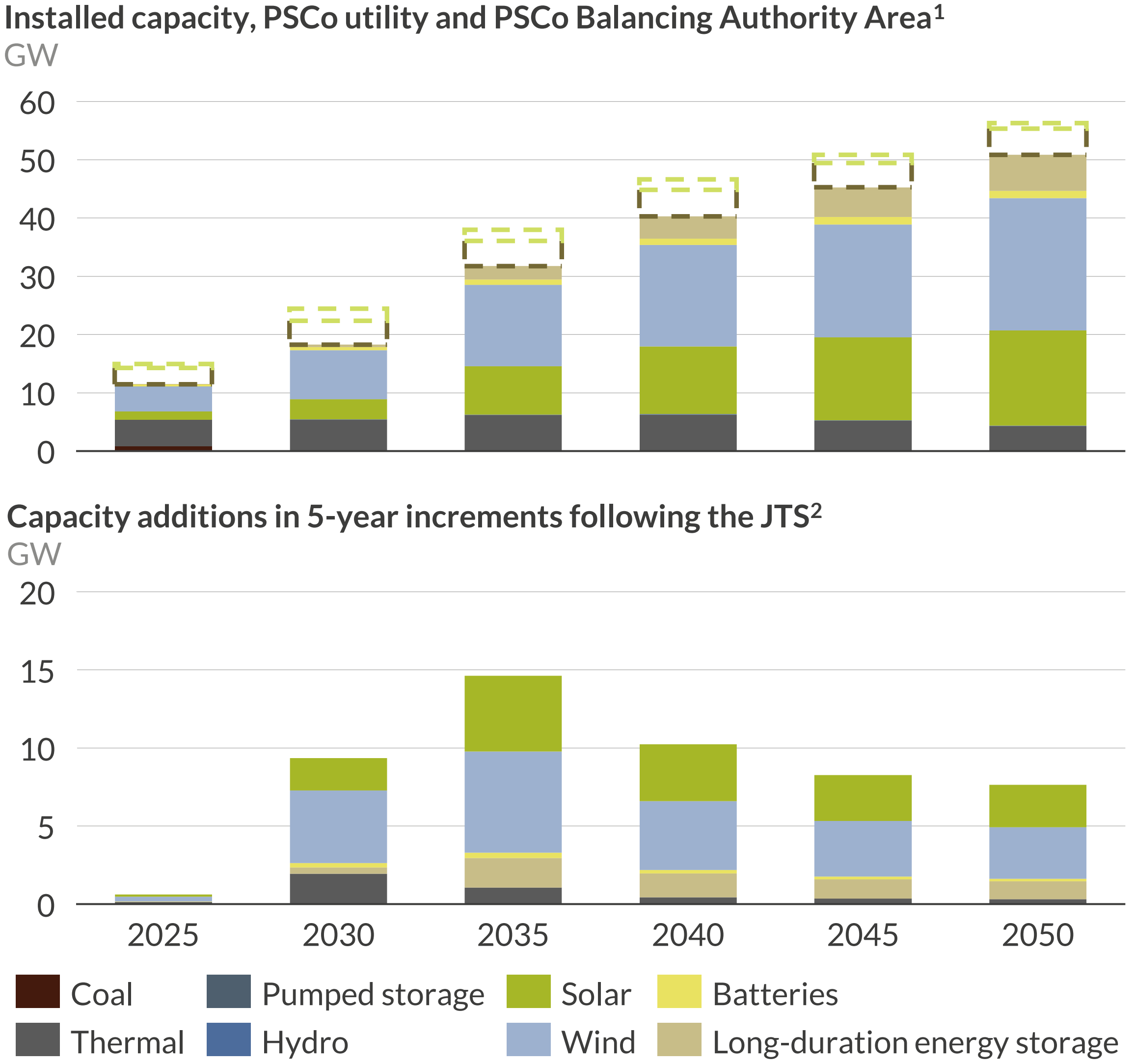

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Sources: Aurora Energy Research, Xcel (PSCo)

PSCo Balancing Authority demand forecast is modeled to follow the JTS growth rates through 2050

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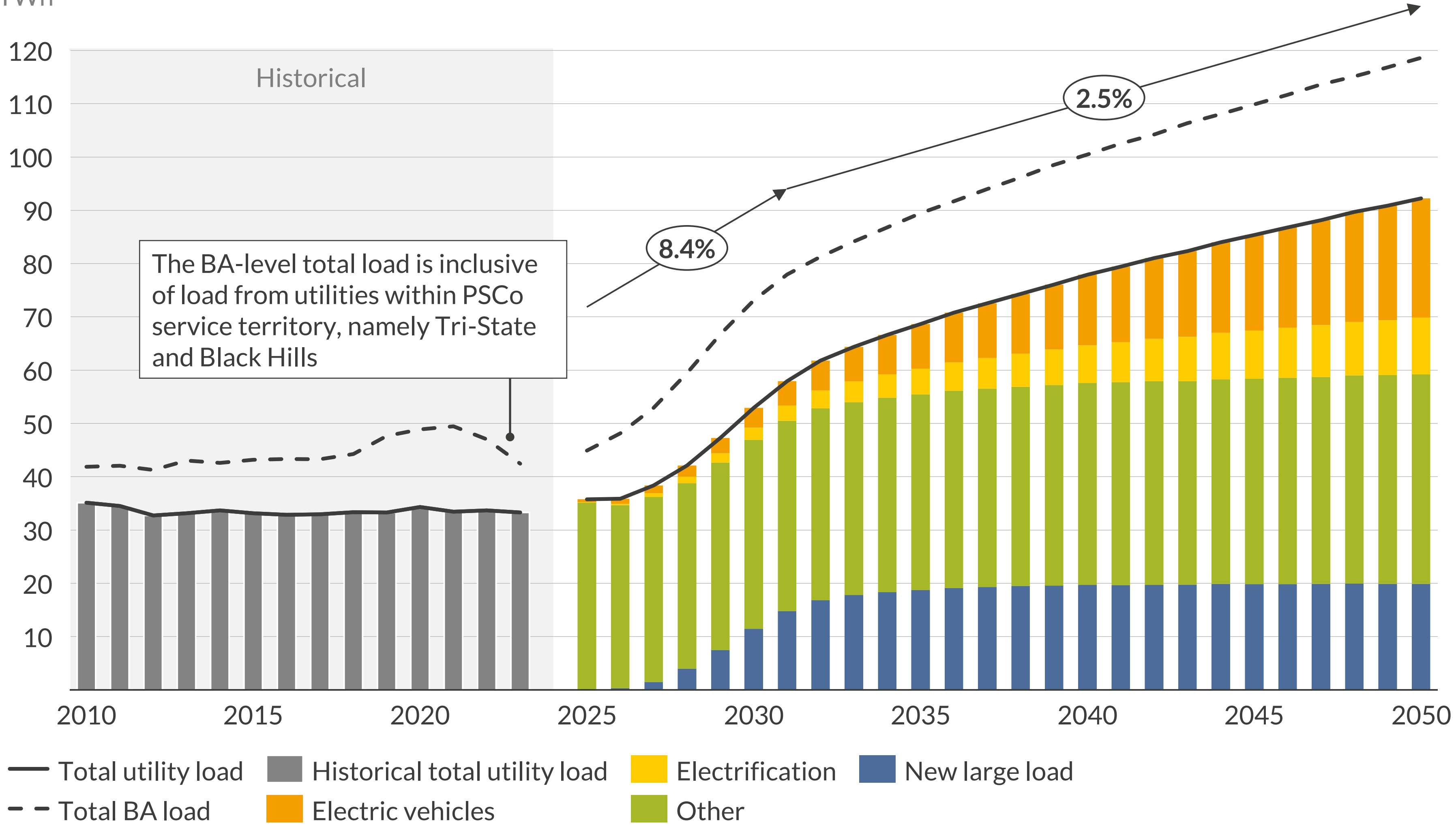
Xcel (PSCo) segmented annual system load[1]
TWh



- Although annual load was flat for the previous five years, Xcel (PSCo)'s base annual load forecast grows at a compounded annual growth rate of 8.4% through 2031 driven primarily by new large load customers
  - New large-load customers explain 66% of new load from 2025-2031
- Electrification adds 2.8TWh to annual load, explaining 12% of growth
- Sales to Xcel's retail customers[2] are also driving the increase in annual load, averaging 7.9% growth

1) Forecasted annual system load is at generation, post-demand side management. 2) Customers directly serviced by Xcel (PSCo), including residential, commercial, and industrial customers. It does not include wholesale customers, including utility customers.
Sources: Aurora Energy Research, Xcel (PSCo)

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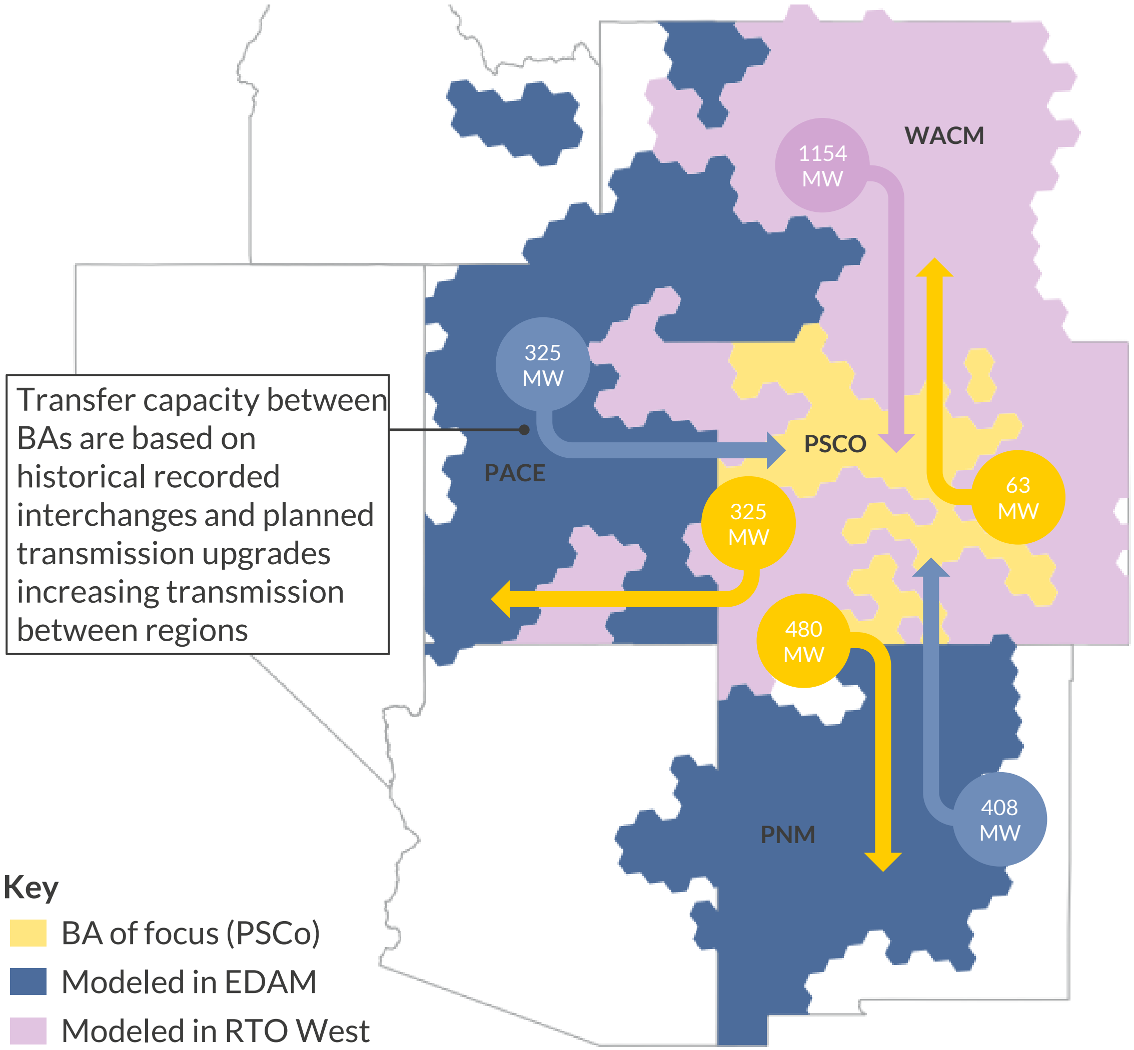
Modeled transfer limits to and from PSCo in 2032[1]



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1) Transfer limits are modeled at the BA level. BAs identified here show all modeled interchange possibilities for PSCo with neighboring BAs

Sources: Aurora Energy Research, WECC, EIA, CETA, Xcel

Even with lower interstate transmission build-out, PSCo sees a $4.2million/year cost benefit to participation in EDAM

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Interstate transmission projects studied to date by the Colorado Electric Transmission Authority (CETA) that have been identified as drivers of reduced congestion hours and congestion costs were modeled to quantify the cost impacts on PSCo under both Markets+ and EDAM. These projects include the Southeast Concept and the Northwest Concept, with the former increasing modeled transfer capability to PNM and the latter increasing modeled transfer capability to PACE.

Average cost breakdown for PSCo under EDAM vs Markets+ DAM, 2028-2060

$Million/year, real 2024

No additional interstate Tx projects			
Metric	EDAM	Markets+	Delta[1]
Production cost	950.3	945.4	4.9
Bilateral trading costs	197.3	200.8	(3.6)
Congestion revenue[2]	(42.5)	(43.4)	0.9
Wheeling Revenue[2]	(22.4)	(16.0)	(6.4)
Costs less revenues	1082.6	1086.8	(4.2)

- Lower hurdle rates for trades with WACM when modeling PSCo in Markets+ provide access to imports at a lower cost, particularly of thermal generation
- The lower production costs for PSCo in Markets+ compared EDAM is partially mitigated by higher bilateral trading costs, reducing the benefits to Markets+ in these categories

Addition of CETA Southeast Concept			
Metric	EDAM	Markets+	Delta[1]
Production cost	903.1	908.5	(5.4)
Bilateral trading costs	221.0	215.8	5.3
Congestion revenue[2]	(74.9)	(63.5)	(11.5)
Wheeling Revenue[2]	(5.2)	(5.6)	0.4
Costs less revenues	1043.9	1055.1	(11.2)

- Additional transmission capacity to PNM incentivizes more trading activity between PSCo and PNM
- As PSCo is a net exporter to PNM, this increases export costs for the EDAM configuration more so relative to Markets+, resulting in comparatively higher increase in trading costs for EDAM

Addition of CETA Northwest Concept			
Metric	EDAM	Markets+	Delta[1]
Production cost	900.4	895.6	4.8
Bilateral trading costs	209.8	213.8	(3.9)
Congestion revenue[2]	(57.2)	(56.2)	(1.0)
Wheeling Revenue[2]	(21.5)	(14.4)	(7.1)
Costs less revenues	1031.6	1038.8	(7.2)

- When PSCo is modeled in EDAM, trading with PACE, which is also modeled in EDAM, is incentivized by the reduced hurdle rates within the same DAM footprint
- As a result, inter-BA line utilization to PACE increases, driving higher congestion revenues for PSCo in EDAM than in the Markets+ scenario

1) Delta calculated EDAM – Markets+. Negative values indicate a cost saving (benefit) for PSCo in EDAM. 2) Ownership assumed to be split 50-50 with connecting BA unless data on ownership is available

Sources: Aurora Energy Research, CETA

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

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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PSCo sees total costs reduced by an average of $13.2 million/year through 2060 when participating in EDAM as opposed to Markets+

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$Million/year,

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A	Production cost	857.4	862.3	(4.9)	(1.2)	(7.4)
B	Bilateral trading costs	231.9	227.0	4.9	0.2	8.0
C	Congestion revenue	(85.8)	(72.9)	(12.8)	(9.2)	(15.2)
C	Wheeling revenue	(5.5)	(5.1)	(0.4)	(1.0)	(0.0)
	Costs less revenues	998.0	1,011.2	(13.2)	(11.2)	(14.6)

X Deep dive to follow

- PSCo sees an average $13.2mil/year benefit in total costs when participating in EDAM vs. Markets+
- **Production costs** - When participating in EDAM, greater wind generation and lower gas production drive down energy production costs
- **Bilateral trading costs** - PSCo is a net importer in all scenarios, primarily from WACM. This dynamic creates additional bilateral trading costs for PSCo in the EDAM scenario, where imports from WACM are subject to additional friction charges
- **Congestion and wheeling revenue** – Under the EDAM scenario PSCo sees higher utilization of its transmission interconnection to facilitate trades between PACE and PNM[2]

1) A negative delta indicates lower costs when PSCo 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

Sources: Aurora Energy Research

A The price of generation to serve load, shown by PSCo baseload prices, are similar under both DAMs, with PSCo in EDAM seeing a ~$0.25/MWh premium

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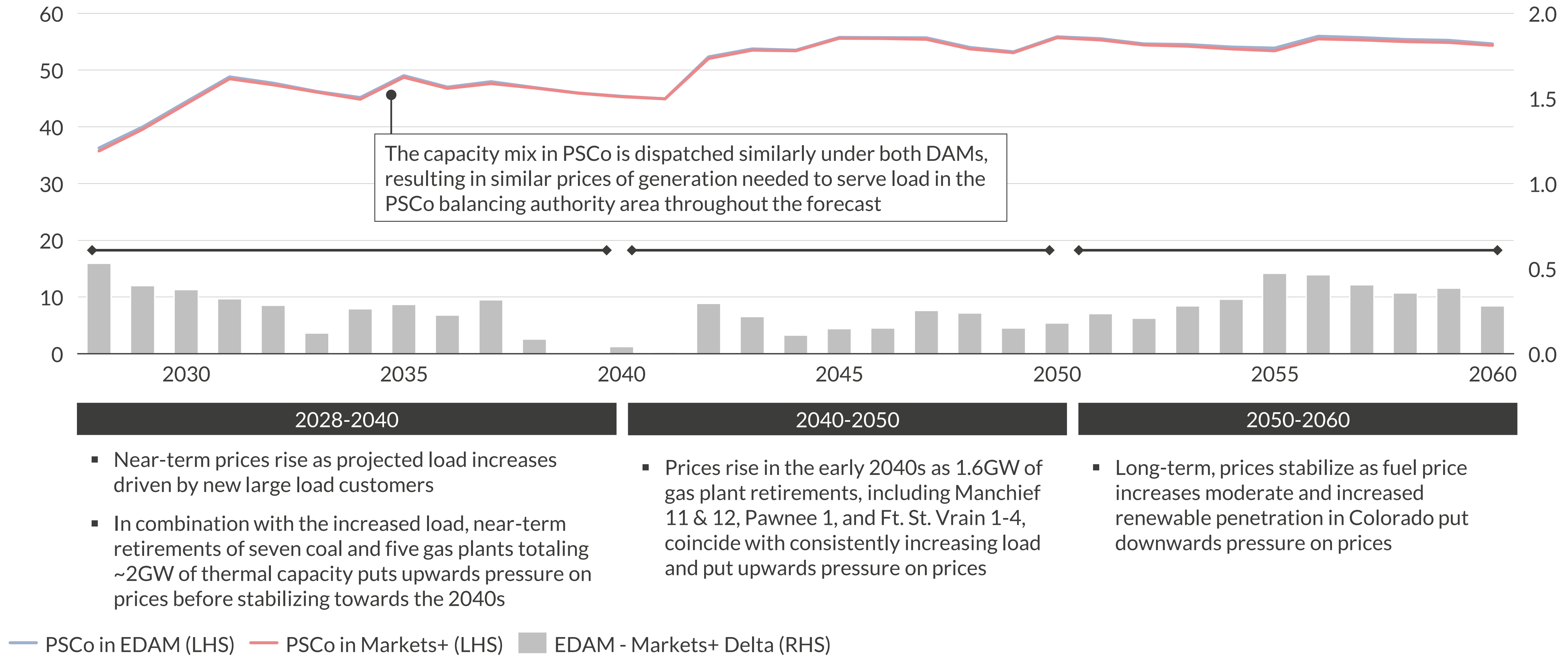
Baseload energy prices, PSCo[1]
$/MWh, real 2024

Baseload energy price delta, PSCo in EDAM vs. PSCo in Markets+[2]
$/MWh, real 2024



2028-2040	2040-2050	2050-2060
▪ Near-term prices rise as projected load increases driven by new large load customers ▪ In combination with the increased load, near-term retirements of seven coal and five gas plants totaling ~2GW of thermal capacity puts upwards pressure on prices before stabilizing towards the 2040s	▪ Prices rise in the early 2040s as 1.6GW of gas plant retirements, including Manchief 11 & 12, Pawnee 1, and Ft. St. Vrain 1-4, coincide with consistently increasing load and put upwards pressure on prices	▪ Long-term, prices stabilize as fuel price increases moderate and increased renewable penetration in Colorado put downwards pressure on prices

1) Baseload prices in PSCo represent the price of generation, which is the cost LSEs pay for generation used to serve load 2) Delta is EDAM – Markets+

Sources: Aurora Energy Research

B PSCo in EDAM incurs higher bilateral trading costs due to costlier imports from WACM and increased import volumes relative to Markets+

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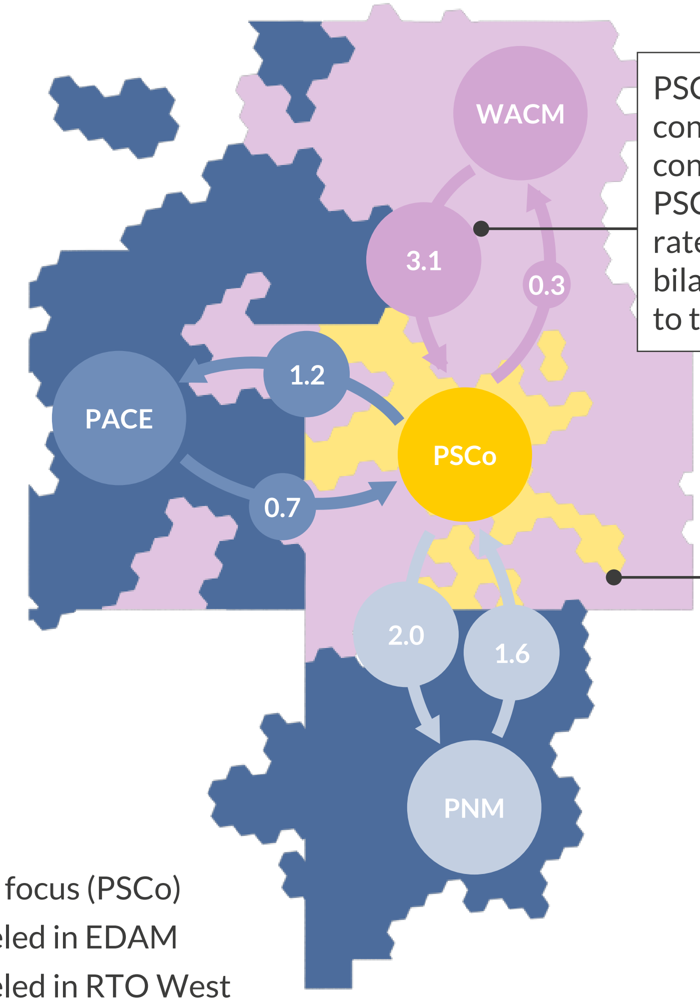
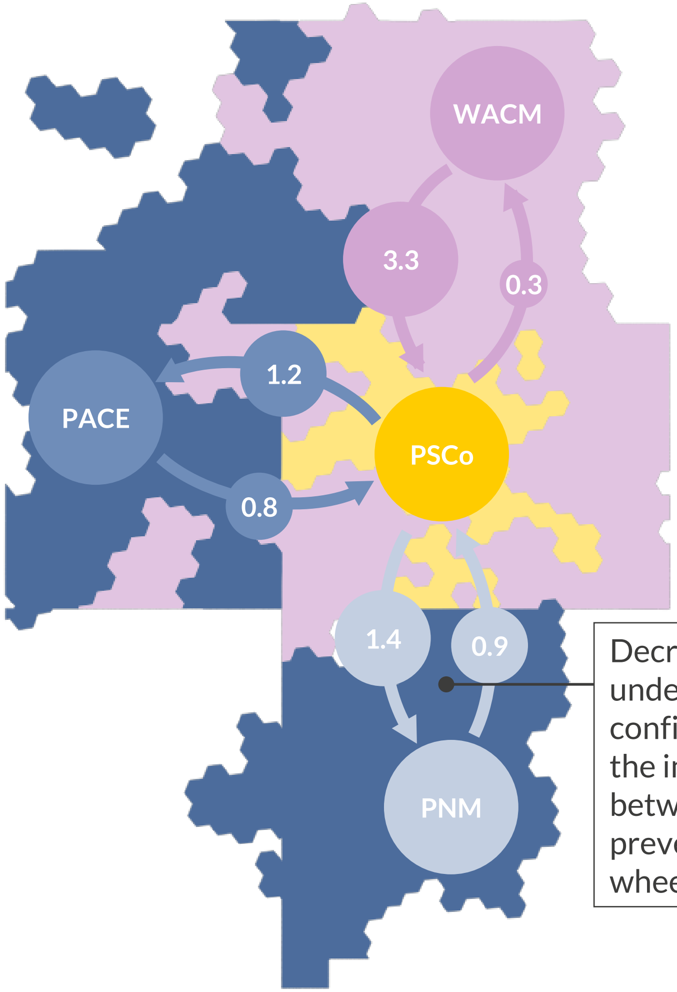
EDAM scenario - Average PSCo imports and exports in 2028-2060
TWh



PSCo imports from WACM continue under both DAM configurations, however when PSCo is in EDAM the hurdle rates are larger, driving up bilateral trading costs relative to the Markets+ configuration

When participating in EDAM, PSCo connects PNM to the rest of the EDAM footprint without incurring seam costs, increasing the volume of trades between the two regions

Markets+ scenario - Average PSCo imports and exports in 2028-2060
TWh



Decreased trades with PNM under the Markets+ configuration demonstrate the impact of seams between markets preventing PNM from wheeling through PSCo

Key
- BA of focus (PSCo)
- Modeled in EDAM
- Modeled in RTO West

1) Delta is EDAM – Markets+

Sources: Aurora Energy Research, WECC, EIA, CETA, Xcel

C Utilization of transfer capacity to PNM significantly increases with PSCo in EDAM, driving up congestion and associated revenues

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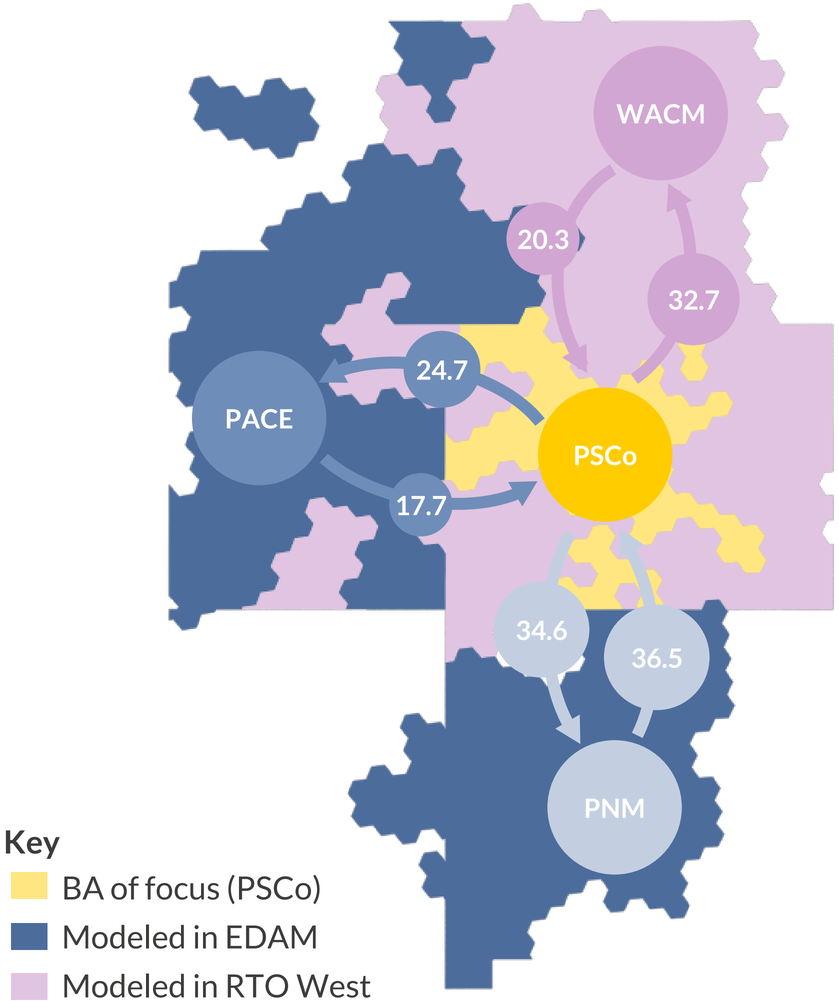
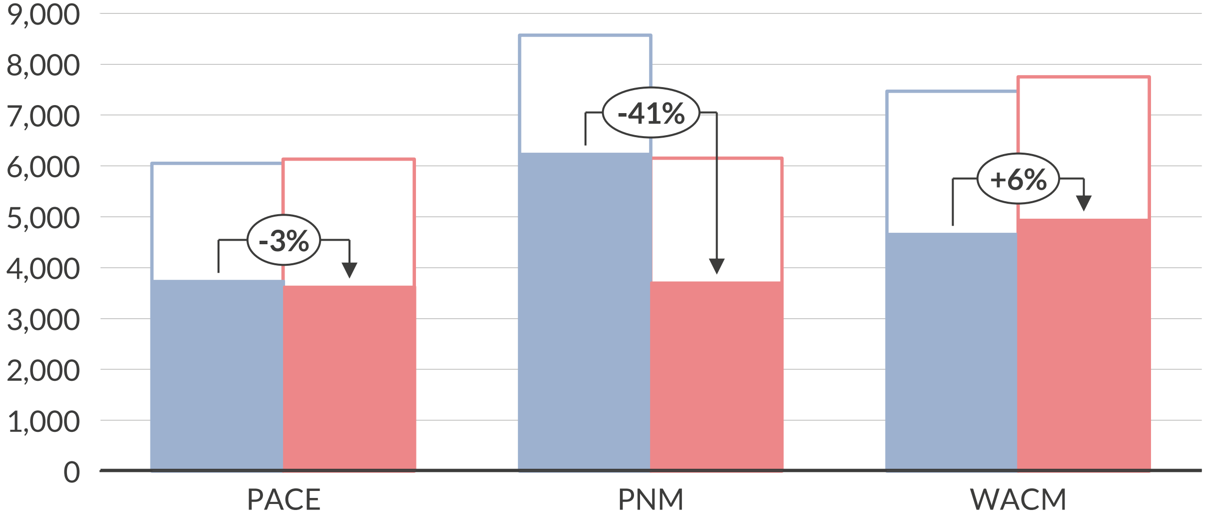
Average annual % congested hours with PSCo in EDAM scenario, 2028-2060
%



Average annual inter-BA trading hours with PSCo, 2028-2060
Hours



- When PSCo is in EDAM, interconnection capacity to and from PACE and PNM are more highly utilized and increase the frequency of congestion revenue relative to the Markets+ scenario[1]
- Similarly, when PSCo is in Markets+, utilization of interconnection to WACM and associated congestion frequency increases as well. The delta between scenarios is less significant in this case however given PSCo consistently trades large volumes with WACM in both DAM configurations
- In trading hours without congestion, PSCo trades with BAs outside of the same DA footprint are subject to wheeling revenues and costs. When PSCo is in EDAM, these trading periods with PACE and PNM see no additional cost or revenue

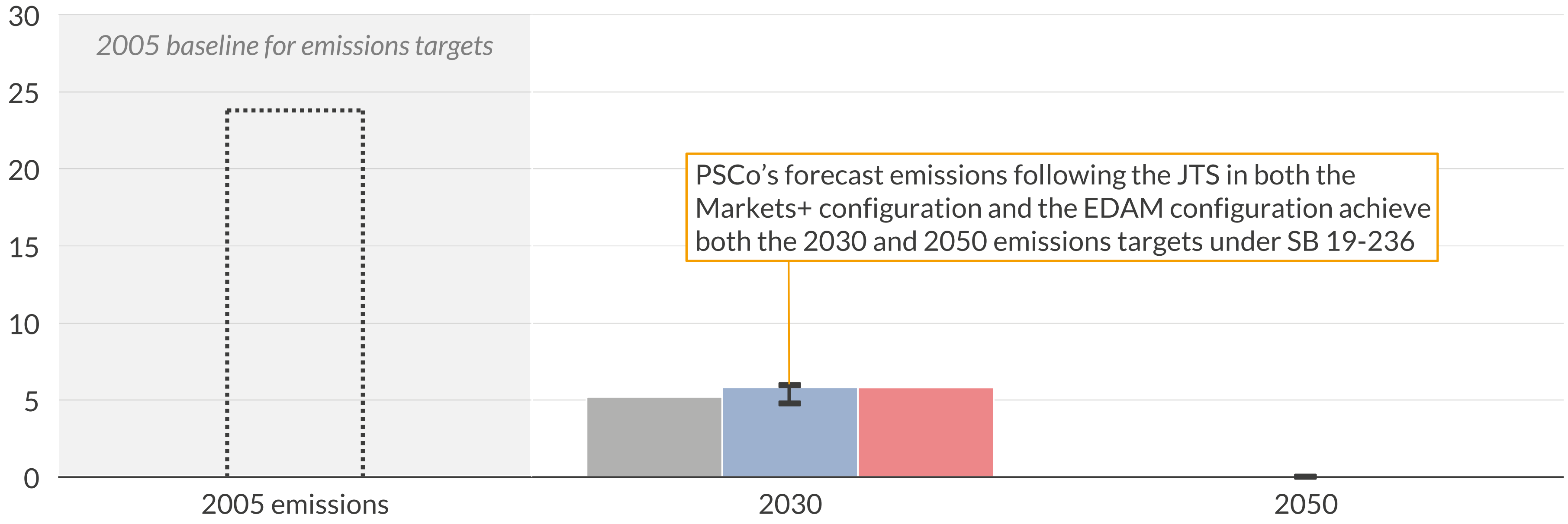
EDAM scenario
Markets+ scenario
Hours with congestion
Hours without congestion

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

Sources: Aurora Energy Research

Under both Day-Ahead markets, PSCo is compliant with SB 19-236 emissions targets in 2030 and 2050

Xcel (PSCo) CO_2 emissions forecast[1]
Million $MTCO_2e$



Colorado SB 19-236 Targets

2005 Baseline

Colorado utilities are required to cut their emissions relative to their 2005 levels

2030

By 2030, **each utility must cut its emissions from Colorado retail sales by 80% from its 2005 levels**. Its plan to do so is compliant if it is found to achieve at least a 75% reduction in emissions by 2030 by the Air Pollution Control Division

2050

Utilities are required to target 100% of sales coming from clean energy by 2050

2005 baseline emissions | JTS forecast | PSCo in EDAM | PSCo in Markets+ | Emissions compliance range[2]

- The CPUC accepted Xcel (PSCo)'s 2021 Clean Energy Plan. The 2024 JTS sees accelerated procurement to meet the same emissions reduction requirements while serving new load demands
- Retirements of ~1.8GW conventional coal and gas resources, with renewables and storage replacements, enables PSCo to reach 2030 targets
- Emissions are similar between the two modeled scenarios for PSCo participation in EDAM and Markets+ given the capacity mix was held constant. Marginal differences in emissions are driven by variation in carbon intensity of imports and exports

1) Results shown here are the emissions for Xcel (PSCo) utility as the largest LSE within the BA territory. SB 19-236 targets only apply to electricity providers serving at least 500,000 customers in Colorado; Xcel (PSCo), Black Hills, and Tri-State are qualifying utilities 2) Using 2005 emissions level as a baseline, which was 23.8MMTCo2e
Sources: Aurora Energy Research, Xcel (PSCo), Colorado Air Pollution Control Division

WECC-wide production cost and emission impacts are similar across scenarios, with benefits in EDAM due to a more connected footprint

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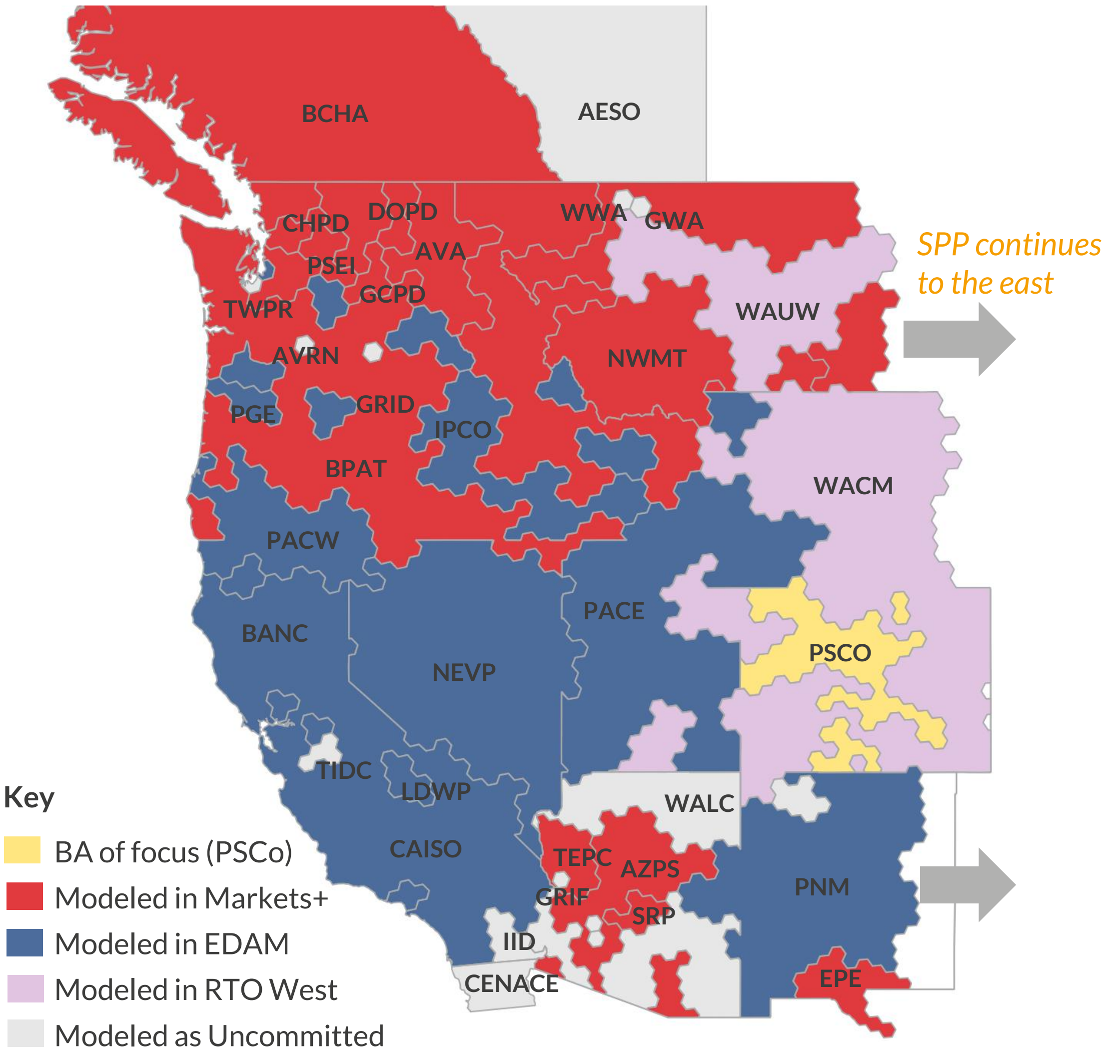
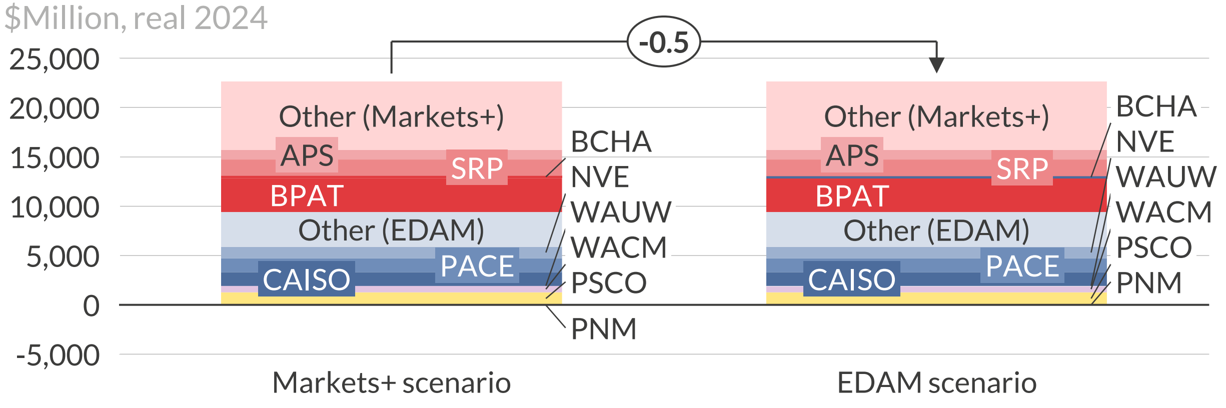
Map of modeled balancing authority (BA) market decisions



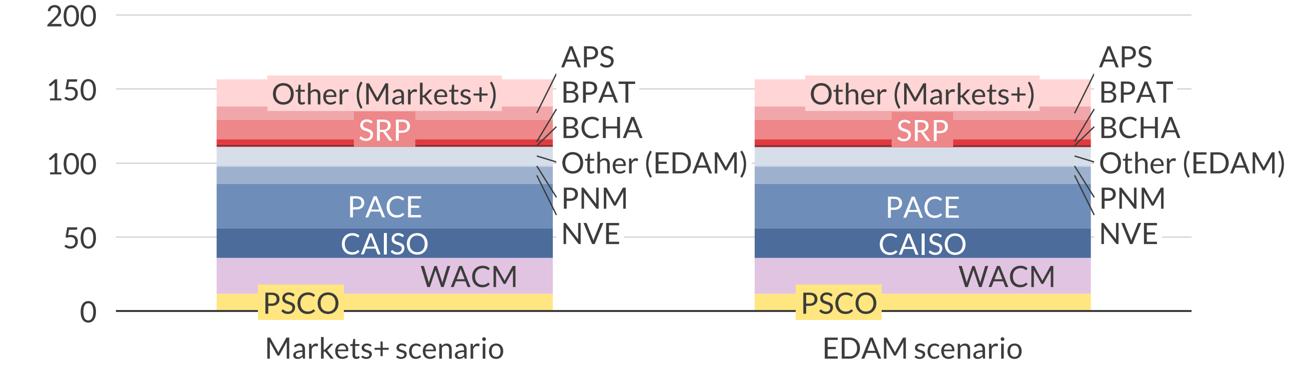
Total WECC-wide production costs in 2035[1]

$Million, real 2024



Total WECC-wide emissions, 2035

Million Mt CO2



- With PSCo in EDAM, both it and PNM benefit from increased interconnection to the EDAM footprint, resulting in $0.5 million lower production costs in 2035
- With the same capacity mix throughout the west, PSCo participation in either DAM results in similar dispatch of resources and similar resulting emissions

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

Sources: Aurora Energy Research, CAISO, SPP

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

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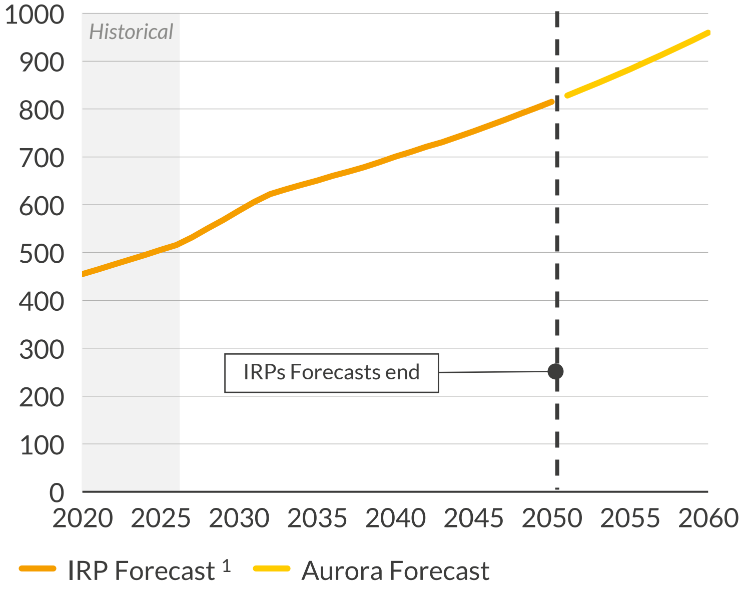
Demand assumptions

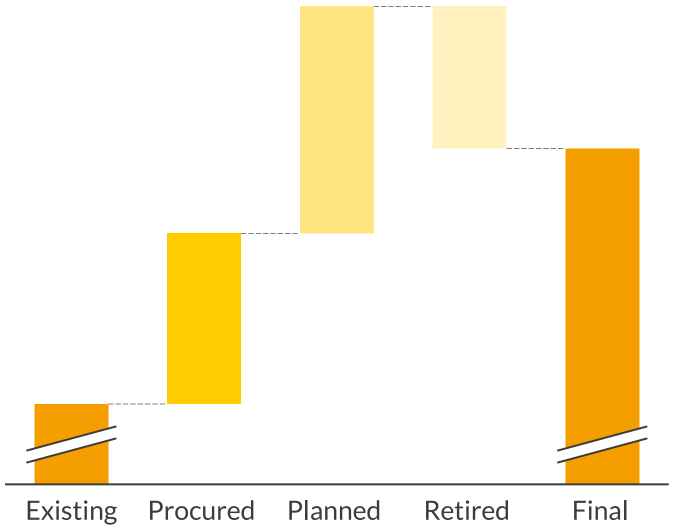
Annual electricity demand
TWh



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

Capacity assumptions

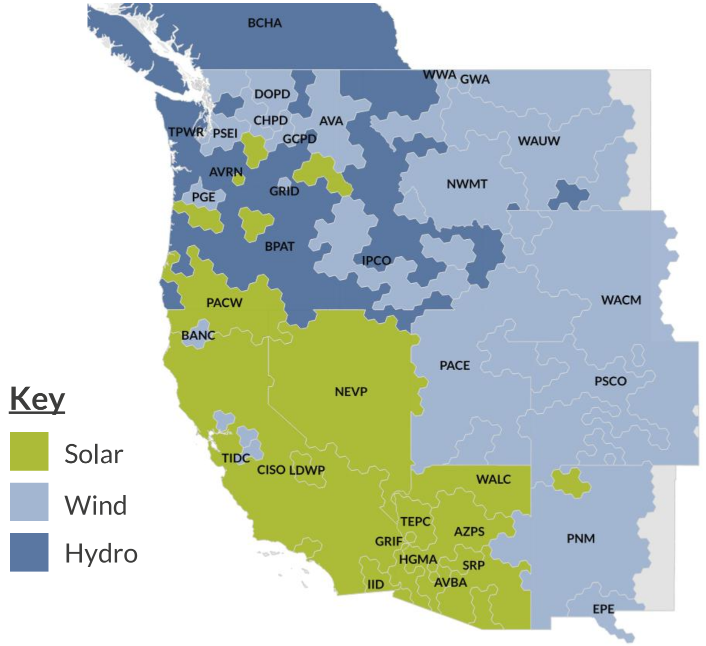
Capacity assumptions components
GW



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

Technology assumptions

Technology with highest load factor by BA[2]



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

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

Sources: Aurora Energy Research

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

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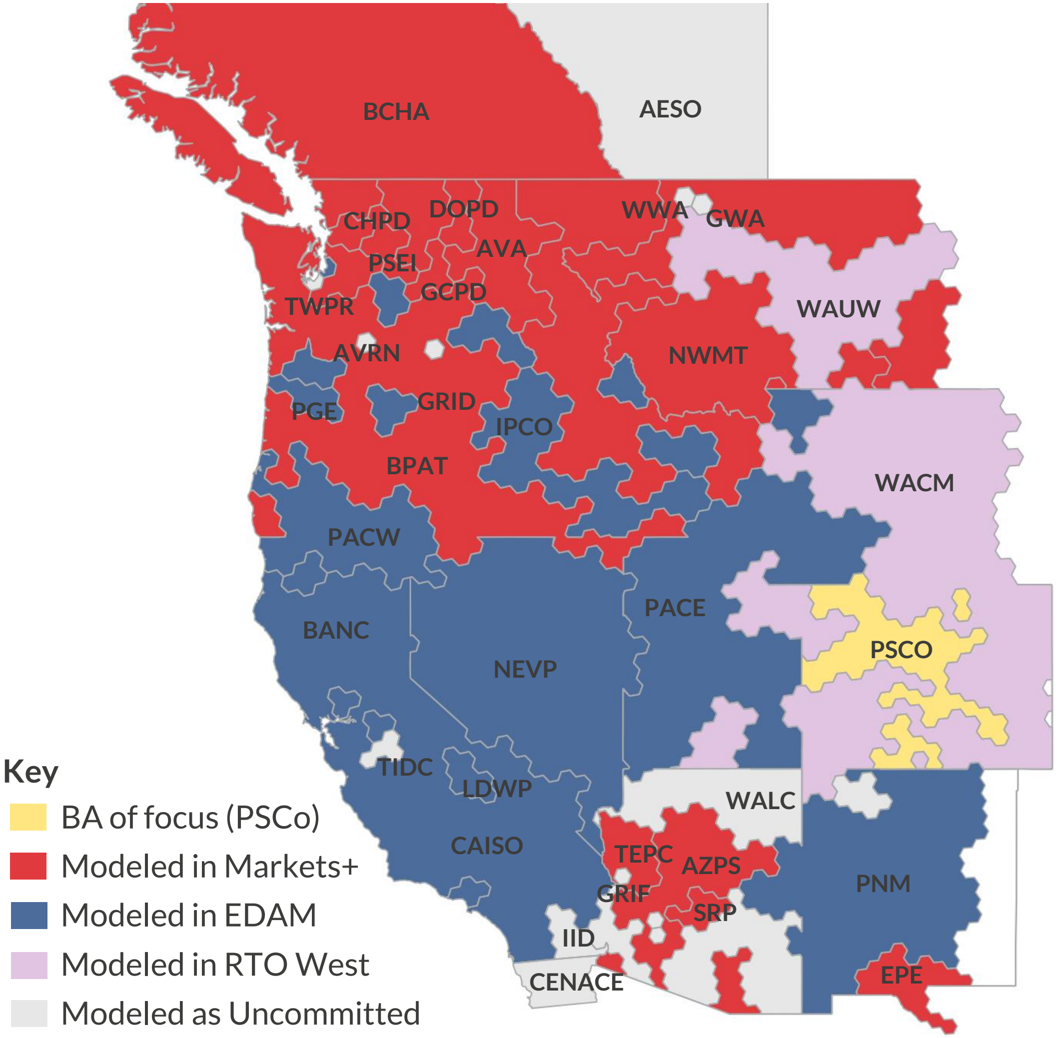
Central outlook on assumed day-ahead market participation[1]



Timeline of assumed day-ahead market participation[1]

EDAM LAUNCH | 2026 | RTO West LAUNCH

- **PACW, PACE, PGE** – Confirmed
- **WACM, WAUW** – Confirmed

2027 | MARKETS+ LAUNCH

- **BANC, LDWP, PNM** – Confirmed
- **BCHA, TWPR, AZPS, SRP, TEPC** – Confirmed
- **NEVP[2], IPCO[3]** – Confirmed, *Assumed*

2028

- **BPAT, EPE** – Confirmed
- **SCL[4], TIDC[5]** – *Assumed*, Confirmed
- **PSEI, AVA, GCPD, DOPD, CHPD, NWMT[6]** – *Assumed*

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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