AGENDA

ORANGE COUNTY POWER AUTHORITY
MEETING OF THE LEGISLATIVE AND REGULATORY COMMITTEE

Thursday, March 6, 2025
3:30 p.m.

This meeting will proceed as an in-person meeting at 15310 Barranca Parkway, Suite 250, Irvine, CA 92618. In addition, as a convenience to the public, the Orange County Power Authority is also providing an option for members of the public to remotely view and participate in the meeting. Further details are below. Please note that, in the event of a technical issue causing a disruption in the remote participation option, the meeting may continue unless otherwise required by law.

Note: Any member of the public may provide comments to the Committee on agenda items only by requesting to speak during Item 4. When providing comments to the Committee, it is requested that you provide your name and city of residence for the record. Commenters are requested to address their comments to the Committee as a whole through the Chair. Comments may be provided in the following manner:

To provide comments during the meeting, in-person attendees, please fill out the public speaker slip and provide it to the clerk at the beginning of the meeting. Before Item 4, the Chair or Clerk will ask members of the public to join the queue to provide public comment. The queue will remain open for a reasonable amount of time to allow members of the public sufficient time to request to speak and inform the Committee of the number of speakers. After such time, the queue will be closed and the members of the public who have joined the queue to speak will be recognized at the appropriate time may speak. To join the queue on Zoom video conference by computer or mobile phone, use the "Raise Hand" feature. If joining the meeting using the Zoom dial-in number, you can raise your hand and join the queue by pressing *9. Members of the public will not be shown on video but will be able to speak when called upon.

Comments shall generally be limited to three minutes when speaking, provided that the Chair may equally reduce each speaker's time to accommodate a large number of speakers or a large number of agenda items. If you have anything that you wish to be distributed to the Committee, please provide it via comments@ocpower.org, who will distribute the information to the Members.

The public may participate using the following remote options:

ZOOM WEBINAR

Please click the link below to join the webinar:
Launch Meeting - Zoom

Dial-in: 1-669-900-6833

Webinar ID: 812 9441 5984

1. CALL TO ORDER

2. PLEDGE OF ALLEGIANCE

3. ROLL CALL

4. PUBLIC COMMENTS ON AGENDA ITEMS

Opportunity for members of the public to address the Committee on any items on the agenda.

5. PUBLIC COMMENTS ON NON-AGENDA ITEMS

Opportunity for members of the public to address the Committee on any items not on the agenda but within the jurisdiction of the Committee.

6. COMMITTEE MEMBER ANNOUNCEMENTS

Committee Members may briefly provide information to other members of the Committee and the public, ask questions of staff, or report on conferences, events, or activities related to Authority business. There is to be no discussion or action taken on comments made by Committee Members unless authorized by law.

7. CONSENT CALENDAR

All items listed under the Consent Calendar are considered to be routine and may be enacted by one motion. Prior to the motion to consider any action by the Legislative and Regulatory Committee, any public comments on any of the Consent Items will be heard. There will be no separate action unless members of the Legislative and Regulatory Committee request specific items be removed from the Consent Calendar.

1. MINUTES FOR THE LEGISLATIVE AND REGULATORY COMMITTEE MEETING OF NOVEMBER 13, 2024

Recommended Action:
Approve as submitted.

8. REGULAR CALENDAR

The following items call for discussion or action by the Committee. The Committee may discuss and/or take action on any item listed below if the Committee is so inclined.

1. ADOPT 2025 CALENDAR

Recommended Action:
Adopt 2025 Calendar.

2. AFFORDABILITY - LEGISLATIVE AND REGULATORY UPDATE

Recommended Action:
Receive and file.

3. INTRODUCED LEGISLATION POSITION RECOMMENDATIONS

Recommended Action:
Recommend the Orange County Power Authority Board of Directors take positions on legislation as recommended by Staff.

9. ADJOURNMENT

Compliance with the Americans with Disabilities Act

OCPA meetings comply with the protections and prohibitions of the Americans with Disabilities Act. Individuals with a disability who require a modification or accommodation, including auxiliary aids or services, in order to participate in the public meeting may contact 949-263-2612. Requests for disability-related modifications or accommodations require different lead times and should be provided at least 72-hours in advance of the public meeting.

Availability of Documents

Copies of the agenda and agenda packet are available at www.ocpower.org. Late-arriving documents related to a Committee meeting item which are distributed to a majority of the Committee prior to or during the Committee meeting are available for public review as required by law. Public records, including agenda-related documents, can be requested electronically at clerk@ocpower.org or by mail to 15642 Sand Canyon Avenue, P.O. Box 54283, Irvine, CA 92619-4283. The documents may also be posted at the above website. Such public records are also available for inspection, by appointment, at 15310 Barranca Parkway, Suite 250, Irvine, CA 92618. Please contact clerk@ocpower.org to arrange an appointment.

MINUTES
SPECIAL MEETING
LEGISLATIVE AND REGULATORY COMMITTEE
ORANGE COUNTY POWER AUTHORITY

Wednesday, November 13, 2024

1. CALL TO ORDER

Chair Jung called to order the Special Meeting of the Legislative and Regulatory Committee at 12:00 p.m. on Wednesday, November 13, 2024.

2. PLEDGE OF ALLEGIANCE

Chair Jung led the Pledge of Allegiance.

3. ROLL CALL

Present:	Chair Fred Jung	City of Fullerton
	Director Kathleen Treseder	City of Irvine

4. PUBLIC COMMENTS ON AGENDA ITEMS ONLY

None

5. COMMITTEE MEMBER ANNOUNCEMENTS

None

6. CONSENT CALENDAR

Moved by Director Treseder and seconded by Chair Jung to approve the September 5, 2024, Minutes.

The motion carried unanimously by the following vote:

Ayes:	Chair Jung, Director Treseder
Noes:	None
Absent:	None

1. MINUTES FOR THE LEGISLATIVE AND REGULATORY COMMITTEE MEETING OF SEPTEMBER 5, 2024

Action Taken:
Approved as submitted.

DRAFT

7. REGULAR CALENDAR

1. WEST-WIDE GOVERNANCE PATHWAYS INITIATIVE UPDATE

Regulatory and Legislative Manager, Steven Halligan, provided a summary of the presentation on this item.

Action Taken:
Received and filed.

2. LEGISLATIVE AND REGULATORY POLICY PLATFORM

Regulatory and Legislative Manager, Steven Halligan, provided a summary of the presentation on this item.

Action Taken:
Reviewed and Provided Feedback.

8. ADJOURNMENT

There being no further business to come before the Committee, Chair Jung adjourned the meeting at 12:37 p.m.

Submitted by:

_____

Pat Jacquez-Nares, Board Authority Secretary

DRAFT

ORANGE COUNTY POWER AUTHORITY
Staff Report – Item 8.1

To: Orange County Power Authority Legislative and Regulatory Committee

From: Steven Halligan, Regulatory and Legislative Manager

Approved By: Joe Mosca, Chief Executive Officer

Subject: ADOPT 2025 CALENDAR

Date: March 6, 2025

RECOMMENDED ACTION

Adopt 2025 Calendar.

BACKGROUND

After an extensive review of holidays, and meeting dates and times of member agencies, staff recommend Legislative and Regulatory Committee meetings be held at 3:30 p.m. on the dates below. These dates were chosen to reduce any conflicts with other meetings and holidays.

Thursday, June 5, 2025
Thursday, September 4, 2025
Thursday, December 4, 2025

FISCAL IMPACT

None

ATTACHMENTS

None

ORANGE COUNTY POWER AUTHORITY
Staff Report – Item 8.2

To: Orange County Power Authority Legislative and Regulatory Committee

From: Steven Halligan, Regulatory and Legislative Manager

Approved By: Joe Mosca, Chief Executive Officer

Subject: AFFORDABILITY - LEGISLATIVE AND REGULATORY UPDATE

Date: March 6, 2025

RECOMMENDED ACTION

Receive and file.

BACKGROUND

Staff will provide an update on legislative and regulatory affairs with a focus on affordability measures. Below is a summary of the items that will be covered during the meeting including Executive Order N-5-24 and the corresponding responses, affordability measures introduced in the state legislator, a regulatory update, and a federal update.

ANALYSIS AND DISCUSSION

Executive Order N-5-24

On October 30, 2024, Governor Newsom signed Executive Order (EO) N-5-24 (Attachment 1). EO N-5-24 directed several agencies to file reports related to lowering the cost of energy bills paid across the state. The order directed California Energy Commission (CEC) to examine all electric ratepayer-funded programs it oversees or administers and to identify any programs, and any other regulations that may be unduly adding to rates. The order also directed the California Public Utilites Commission (CPUC) to examine the benefits and costs to electric ratepayers of programs it oversees. These reports were due to the Governor by January 1, 2025. Lastly, the order requested the CPUC and the California Air Resources Board to consult with each other on options to maximize the effectives of California's Climate Credit.

On February 18, 2025, the CPUC released their response (Attachment 2) to EO N-5-24. The report highlights seven areas to address increased rates. Those include 1) All energy-related mandates should be assessed for overall cost-effectiveness with the goal of achieving the lowest possible rates for all customers of each utility. 2) Supplement essential wildfire mitigation programs and extreme weather-related catastrophic event response costs with other sources of funding. 3) Identify cost-reduction measures by integrating wildfire mitigation strategies into the existing General Rate Case process. 4) Equitable rate structures: Refine the elements of Net Energy Metering so that all customers share wildfire mitigation, public purpose programs and system costs. 5) Redistribute the Climate Credit to customers most impacted by increasing electricity

costs. 6) Fund today's and future cost-shifting programs from non-ratepayer sources. 7) Ensure that programs benefitting all electric customers are supported by all customers, including customers of publicly-owned utilities.

The CEC response (Attachment 3) was made public in mid-February and examined all electric investor-owned utility (IOU) ratepayer-supported programs that it oversees and administers. The report focused on four areas, 1) Energy Efficiency programs such as Statewide Codes & Standards Program, 2) California Schools Healthy Air, Plumbing, and Efficiency (CalSHAPE) program, 3) Solar Equipment Lists, and 4) Electric Program Investment Charge (EPIC).

Legislative Affordability Measures

SB 330 – Electrical transmission infrastructure: financing

Senate Bill 330 (SB), introduced by Senator Padilla, on February 12, 2025, would authorize the Governor to establish one or more pilot projects to develop, finance, or operate electrical transmission infrastructure that meet the specified criteria, including, among other things, that the transmission line is identified by the Independent System Operator in its transmission planning process as necessary to support clean energy generation to meet the state's clean energy goals.

In October 2024, Berkeley Law Center for Law, Energy, & the Environment released a report titled Improving Transmission Financing California (Attachment 4). The report was commissioned by the Clean Air Task Force and Net-Zer California who issued an executive summary of the CLEE report titled "Wired for Savings" (Attachment 5). The CLEE report found that some form of public-private partnership could provide significant benefits to deploying lower-cost transmission, due to cost-savings potential and the ability to leverage existing institutions and structures. According to the report a business-as-usual approach to transmission development could—over 40 years—cost ratepayers $100 billion, more than twice the cost of alternative approaches. The difference is due primarily to the higher cost financing used by investor-owned utilities, and what other studies have found to be a lack of sufficient competition in procuring new transmission lines. The use of public sector financing and accompanying institutional changes could reduce costs to ratepayers by as much as 57%—or nearly $60 billion—over the 40-year period. This is equivalent to savings of $1.5 billion per year.

SB 540 – Independent System Operator: independent regional organization

SB 540, introduced by Senator Becker, on February 20, 2025, would authorize the California Independent System Operator (CAISO) to use energy markets governed by an independent regional organization. A factsheet is attached (Attachment 6). Studies have shown that allowing the CAISO to tap into a wider market of electricity resources would provide significant benefits to Californians including cost savings, enhanced grid reliability, and reduced air pollution. One such study prepared by Brattle for the California Energy Commission, titled Preliminary Day-Ahead market Impacts Study is attached (Attachment 7).

CalCCA Electricity Affordability

Ahead of the CalCCA Advocacy Day in January 2025, OCPA staff assisted in the drafting of an Electricity Affordability Explainer to be utilized when meeting with state legislators. The explainer focuses on three main areas, 1) Leveraging the Greenhouse Gas Reduction Fund (GGRF) to

Support Affordability, 2) Reducing ratepayer Costs by Reducing Artificial Resource Adequacy Demand, and 3) Increased Accountability and Transparency. A copy of the Explainer is attached (Attachment 8). Regarding the GGRF, staff advocated for the its use in two ways, one focused on short term bill savings and one on long term bill savings. For the short-term bill savings, the GGRF could be used to boost the California Climate Credit. The use of $650 million in GGRF funding would increase the Climate Credit by approximately $60 per household. For longer-term savings, money from the GGRF could be used to finance policy-driven transmission projects that are approved by CAISO in their Transmission Plan. Another cost-saving measure would be to allow LSEs to trade hourly RA load obligations. It is estimated that this ability would save California ratepayers over $180 million annually. This ability is also being pursued in the regulatory space and is discussed in greater detail below. Lastly, there are several areas where the legislator could increase Accountability and Transparency over the Investor-Owned Utility rates that have the potential to lower customer bills. These include doing an Affordability Analysis for each major policy change the CPUC proposes, audits of IOU Balancing Accounts, enhanced oversight of IOU rate of return, and adequately funding the CPUC and Public Advocates Office.

Regulatory Update

Power Charge Indifference Adjustment Proceeding

On February 11, 2025 the CPUC issued an Order Instituting Rulemaking (OIR) to initiate a new proceeding related to the Power Charge Indifference Adjustment (PCIA). The proceeding will consist of two tracks. The first track will be an expedited track focused on potential modifications to the Market Price Benchmark (MPB). Track two may consider several issues including a review of the revisions to the MPB, consideration of ERRA-specific implementation guidance for RA program changes, changes to Bundled Procurement Plan directions, and consideration of improved PCIA and ERRA mechanisms to reduce rate volatility. The CPUC has identified four objectives of the proceeding:

- Consider and identify reasonable improvements to existing ERRA and PCIA rules, mechanisms, and processes to ensure best practices in utility forecasting and other procurement plan activities;
- Identify ways to mitigate and respond to rate volatility, whether resulting from market conditions or ratemaking constructs;
- Best ensure indifference among bundled and departed customers;
- Provide policy guidance to ensure that individual utility forecast ratemaking proceedings function as efficiently and consistently as possible.

Resource Adequacy Slice of Day Obligation Transactability

On February 12, 2025 CalCCA, presented at the Resource Adequacy (RA) Track 3 Proposal Workshop a proposal on allowing load serving entities (LSE) to transact RA products in the same units denominated in setting RA requirements; in other words, if RA requirements are set on an hourly basis, some or all products should be transactable on an hourly basis. Allowing this transactability will promote affordability by reducing artificial RA scarcity and thus lowering RA prices, and it will minimize over procurement by allowing LSEs to capture diversity. CalCCA estimated that avoiding purchases of RA through trade can reduce direct RA costs by $180 million

per year with $62 million seen by CCAs. They also estimated that an indirect benefit of lowering RA costs by approximately $77 million per year.

Federal Update

While OCPA's routine operations are not federally funded, there are activities that may occur at the Federal level that may impact the energy market that OCPA participates in, potential grants that OCPA may apply to, and tax incentives that our customers and suppliers may take advantage of. One action the federal government has taken is to issue Executive Orders. Staff have attached a summary of the orders (Attachment 9). The impact of these orders is still being researched.

On January 6, 2025, Aurora Energy Research released a study titled "Impact of reform to clean energy tax credits on investment, jobs, and customer bills" (Attachment 10). In the study they found that the removal of tax credits for wind, solar, and battery deployment would increase residential electricity bills by 10% on average in California. This increase in electricity bills is in addition to slowing the growth of renewables in California and the west and a decrease in jobs.

FISCAL IMPACT

None

ATTACHMENTS

1. Executive Order N-5-24
2. CPUC Response to Executive Order N-5-24
3. CEC Response to Executive Order N-5-24
4. Improving Transmission Financing in California – Berkley Law
5. Wire for Savings – Clean Air Task Force and Net-Zero California
6. SB 540 Fact Sheet
7. Preliminary Day-Ahead Market Impacts Study – California Energy Commission
8. CalCCA Affordability Explainer
9. Federal Executive Orders
10. Impact of reform to clean energy tax credits, jobs, and consumer bills – Aurora Energy Research

EXECUTIVE DEPARTMENT
STATE OF CALIFORNIA

EXECUTIVE ORDER N-5-24

WHEREAS California has responded forcefully to the climate crisis with ambitious plans for a clean energy future—one in which the State will achieve carbon neutrality economywide by 2045, and run on 90% clean electricity by 2035 and 100% clean electricity by 2045; and

WHEREAS clean energy will power more of the daily lives of Californians as we move closer to those goals, from our cars and trucks and trains, to our homes and buildings, to our industrial sector; and

WHEREAS it is essential that electric service remains affordable, reliable, and safe for all Californians during our clean energy transition; and

WHEREAS California's over four decades of work to advance appliance and building energy efficiency standards has kept electric bills lower on average in California than many other states, but Californians have seen their electric bills rise in recent years, outpacing the rate of inflation; and

WHEREAS Californians' electric rate increases have been driven largely by the cost of some programs added over time, such as the subsidy provided through the legacy Net Energy Metering program for rooftop solar photovoltaic systems; and

WHEREAS electric rate increases have also been driven by historic investments that are critical to reduce wildfire risk and improve the safety and reliability of the electric grid, particularly in the wake of catastrophic wildfires that devastated communities throughout California in recent years and have been exacerbated by the increasing impacts of climate change; and

WHEREAS in 2023, I released the *Building the Electricity Grid of the Future: California's Clean Energy Transition Plan* to provide a roadmap for keeping electric costs affordable, while effectively managing our energy supply through this transition; and

WHEREAS California regulatory agencies have taken important actions within their authority to advance the cost-effective procurement and deployment of clean energy resources while pursuing opportunities to limit and stabilize costs to Californians, including actions by the California Public Utilities Commission to adjust the Net Energy Metering program subsidies to reflect the growth of the rooftop solar photovoltaic market and the value these systems provide to all customers, and through improved oversight and the imposition of cost controls on private utility expenses; and

WHEREAS the critical work of upgrading and expanding the aging electric transmission and distribution infrastructure that makes up our electric grid to meet future demand is well underway — investments that will ultimately increase the base of electricity customers and help address rising electricity rates while growing the State's economy; and

WHEREAS the upcoming legislative session provides a critical opportunity to take decisive action to rein in those costs by ensuring that private electric utilities and State programs alike are prioritizing the most efficient and effective opportunities to meet energy demand with clean energy resources, informed by the analyses required and requested under this Order; and

WHEREAS the California Climate Credit, a bill credit funded by California's Cap-and-Trade Program, has helped offset hundreds of dollars of electric and natural gas costs on individual ratepayer bills, totaling over $12 billion since 2014.

NOW, THEREFORE, I, GAVIN NEWSOM, Governor of the State of California, in accordance with the authority vested in me by the State Constitution and statutes of the State of California, do hereby issue the following Order to become effective immediately:

IT IS HEREBY ORDERED THAT:

1. The California Energy Commission is directed to examine all electric ratepayer-funded programs it oversees or administers and to identify any programs, and any other regulations that may be unduly adding to rates, for which the electricity system benefits may not be justified by the costs they impose on electric ratepayers, or whose funding might more appropriately come from a source other than ratepayers. The commission shall report to me by January 1, 2025, the results of its analysis and its recommendations for statutory and/or regulatory changes, including the modification or elimination of any Underperforming or underutilized programs and whether any ratepayer funds in any programs remain unused and can be considered for possible return to ratepayers.

2. The California Public Utilities Commission is requested to examine the benefits and costs to electric ratepayers of programs it oversees and rules and orders it has promulgated pursuant to statutory mandates that may be unduly adding to electric rates, or whose funding might more appropriately come from a source other than ratepayers. The commission is requested to report to me by January 1, 2025, the results of its analysis and its recommendations for modifying or repealing any statute that would reduce costs to electric ratepayers without compromising public health and safety, electric grid reliability, or the achievement of the State's 2045 clean electricity goal and the State's 2045 economywide carbon neutrality goal.

3. The California Public Utilities Commission is requested to take immediate action under existing authorities to modify or sunset any underperforming or underutilized programs or orders whose costs exceed the value and benefits to electric ratepayers. The commission is requested to return any unused funds collected from ratepayers for underperforming programs and utility investments in the form of a bill credit, if it identifies such funds.

4. The California Air Resources Board is directed, and the California Public Utilities Commission is requested, to consult with each other on options to maximize the effectiveness of California's Climate Credit—which returned an average of $71 to electric ratepayers on their utility bills this fall. Options to improve the credit, particularly for low-income Californians, should be reported to me by January 1, 2025.

5. The Office of Energy Infrastructure Safety is directed, and the California Public Utilities Commission is requested, to consult with each other on adjustments to utility wildfire safety oversight processes, procedures, and practices that would yield administrative efficiencies and focus utility investments and activities on cost-effective wildfire

mitigation measures that reduce wildfire ignition risk while managing costs to electric ratepayers. Proposals for legislative or regulatory changes should be reported to me by January 1, 2025.

6. The California Public Utilities Commission is requested to pursue, and direct the regulated utilities to pursue, all federal funding opportunities that can help reduce and avoid electric service costs that would otherwise flow into electric ratepayer bills.

IT IS FURTHER ORDERED that, as soon as hereafter possible, this Order be filed in the Office of the Secretary of State and that widespread publicity and notice be given of this Order.

This Order is not intended to, and does not, create any rights or benefits, substantive or procedural, enforceable at law or in equity, against the State of California, its agencies, departments, entities, officers, employees, or any other person.

IN WITNESS WHEREOF I have hereunto set my hand and caused the Great Seal of the State of California to be affixed this 30th day of October 2024.

GAVIN NEWSOM
Governor of California

ATTEST:

SHIRLEY WEBER, PH.D.
Secretary of State

CPUC Response to Executive Order N-5-24

February 18, 2025

California Public Utilities Commission

Thanks to:

Jenny Au, Simon Baker, Aaron Bloom, Adam Banasiak, Dan Buch, Adam Buchholz, Dan Bout, Tory Francisco, Justin Galle, Brooke-Sydney Harbour, Jenneille Hsu, Coby Jacob, Ankit Jain, Forest Kaser, Kapil Kulkarni, Cheryl Lee, Regina Momblanco, Candace Morey, April Mulqueen, Rachel Peterson, Erica Petrofsky, Bridget Sieren-Smith, Jean Spencer, Jeorge Tagnipes, Leuwam Tesfai, Chris Westling, Nick Zanjani

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APPENDIX 28

Preface

The California Public Utilities Commission (CPUC) appreciates the opportunity to respond to Governor Newsom's Executive Order N-5-24. The Governor's Executive Order sets forth an imperative to mitigate the rising costs of electricity service in California. The CPUC shares this sense of urgency and resolve. In the CPUC's annual SB 695 Report, the CPUC provides an analysis of rates and forecasts of rate trends, and for several years has taken actions within the CPUC's authority to mitigate rising costs for ratepayers.

Executive Order N-5-24 requests the CPUC to:

- Examine the benefits and costs to electric ratepayers of programs it oversees and rules and orders it has promulgated pursuant to statutory mandates that may be unduly adding to electric rates, or whose funding might more appropriately come from a source other than ratepayers. Report to Governor Newsom by January 1, 2025, the results of its analysis and its recommendations for modifying or repealing any statute that would reduce costs to electric ratepayers without compromising public health and safety, electric grid reliability, or the achievement of the State's 2045 clean electricity goal and the State's 2045 economywide carbon neutrality goal.

- Take immediate action under existing authorities to modify or sunset any underperforming or underutilized programs or orders whose costs exceed the value and benefits to electric ratepayers. The commission is requested to return any unused funds collected from ratepayers for underperforming programs and utility investments in the form of a bill credit, if it identifies such funds.

- Consult with California Air Resources Board on options to maximize the effectiveness of California's Climate Credit-which returned an average of $71 to electric ratepayers on their utility bills this fall. Options to improve the credit, particularly for low-income Californians, should be reported to me by January 1, 2025.

- Consult with the Office of Energy Infrastructure Safety on adjustments to utility wildfire safety oversight processes, procedures, and practices that would yield administrative efficiencies and focus utility investments and activities on cost-effective wildfire mitigation measures that reduce wildfire ignition risk while managing costs to electric ratepayers. Proposals for legislative or regulatory changes should be reported to me by January 1, 2025.

- Pursue, and direct the regulated utilities to pursue, all federal funding opportunities that can help reduce and avoid electric service costs that would otherwise flow into electric ratepayer bills.

Introduction: Affordability and Clean Energy Success Is Threatened by Rate Impacts

California's Climate Goals in the Energy Sector: A Success Made Possible by Utility Ratepayers

California's climate goals have clean energy as a centerpiece. From 2002 when the state adopted its first Renewables Portfolio Standard (RPS) requirement, utility ratepayers have funded major clean energy achievements. The vision for economywide carbon neutrality is now set forth in the California Air Resources Board's Climate Change Scoping Plan, and the electricity sector is on track to achieve greenhouse gas emissions reductions to achieve the ambitious goal of carbon neutrality by 2045.

The California Constitution and the Public Utilities Code spell out how utility customers have funded this success. The Legislature directs the CPUC, who in turn directs the retail electricity providers (load serving entities) to purchase utility-scale least-cost, best fit clean electricity resources on behalf of their customers. This structure has resulted in cost-competitive clean energy achievements that lead the world.

All new procurement today is emissions-free. What's more, prices for solar, wind, and battery storage that are shared among customers on our interconnected bulk system are decreasing every year.

This is the ratepayer funded clean energy success story of California.

At the same time, California's transportation, buildings and industrial sectors are transitioning away from fossil fuel-supplied energy sources. Electricity is already playing a larger role in powering the economy and addressing the climate crisis demands further expansion of electrification.

However, as the Governor's Executive Order recognizes, electricity ratepayers are now experiencing rising bills due to a number of factors, including the impacts of climate change, and many Californians are struggling to bear the burden of increased costs.

In this report, the CPUC responds to the Executive Order by putting the costs of these programs in context with the total scale of IOU revenue requirements, describes the mechanisms by which these costs are created and shared between customers, and identifies ways that the Legislature and the CPUC can work to improve affordability.

Conclusions in This Report: Options Exist to Save Ratepayers Money Going Forward

Inequitable rate structures and the need for unprecedented climate impact related investments have created a perfect storm driving electricity rate increases. In addition to creating financial hardship, continued rate inflation will put stress on meeting the states climate goals. Electrifying the transportation, building and industrial sectors are critical decarbonization strategies that become increasingly difficult with every increase in electricity rates.

Three areas present opportunities to control costs and reduce electricity bills: first, identifying opportunities to control the growth in utility spending. Second, identifying any opportunities for cost sharing. Third, implementing equitable rates to recover approved costs for wildfire mitigation, public purpose programs and the fixed costs of the grid.

The CPUC's SB 695 report has identified the biggest drivers of rate increases: the growth in spending to address wildfire mitigation and the cost shift that results from legacy Net Energy Metering programs. Secondarily, energization and energy transition related investments in transmission and distribution infrastructure are also putting upward pressure on rates.

This report concludes with strategies that address these costs to save ratepayers money going forward:

1. All energy-related mandates should be assessed for overall cost-effectiveness with the goal of achieving the lowest possible rates for all customers of each utility.
2. Supplement essential wildfire mitigation programs and extreme weather-related catastrophic event response costs with other sources of funding.
3. Identify cost-reduction measures by integrating wildfire mitigation strategies into the existing General Rate Case process.
4. Equitable rate structures: Refine the elements of Net Energy Metering so that all customers share wildfire mitigation, public purpose programs and system costs.
5. Redistribute the Climate Credit to customers most impacted by increasing electricity costs.
6. Fund today's and future cost-shifting programs from non-ratepayer sources.
7. Ensure that programs benefitting all electric customers are supported by all customers, including customers of publicly-owned utilities.

This report also describes ways in which programs add to overall costs and explains the ratepayer impact of how new programs create and distribute new costs and benefits.

Ratepayer-Funded Programs Have Delivered Benefits in California and Across the United States

California's pioneering investments in clean energy technology have had impacts around the world. Customers of investor-owned utilities are funding programs and tariffs that bring many benefits: electricity bills have been the vehicle to fund the incubation and commercialization of technologies,

including photovoltaic solar and battery storage, as well as the means to integrate renewable energy through programs such as time of use rates enabled by investments in advanced metering infrastructure.

Historically, California's programs have supported every stage of technological development:

- **Innovation,** through programs like the Electric Program Investment Charge program (EPIC),
- **Pilots,** like a new program harnessing vehicle-to-grid technology to turn Oakland United School District's newly electrified school bus fleet into a virtual power plant, and
- **Deployment at scale,** such as competitively bid generation projects through the Renewables Portfolio Standard.

These investments continue today through innovation with next-generation smart meters, microgrid technology, smart homes, generation that is increasingly disaggregated, and mechanisms to procure new renewable generation technologies like offshore wind.

As we move through the Innovation, Pilot, and Deployment process, we need to constantly evaluate whether the programs are succeeding on their own terms and whether their benefits outweigh their costs. In addition, the CPUC needs to be constantly evaluating the opportunity costs of the decisions to fund one approach over another. This is especially true of well-established areas like energy efficiency.

For some of these investments, all utility customers are sharing the incremental cost of programs that provide higher-cost individual benefits to a select group of customers or to private industry. Socializing investments can provide substantial benefits, such as helping certain small companies enter the renewable energy industry, providing energy efficiency or distributed energy resources to a group of low-income households, or improving plumbing and ventilation in public schools. These programs can bring important benefits and can avoid certain other costs. However, unless there is a non-utility source of funding, the costs of these investments are divided among all customers, and bill savings for one customer necessarily increases costs for everyone else.

The Nature of Electricity Necessitates Infrastructure Sized to Meet Highest Potential Demand

Unlike commodities such as water, natural gas or gasoline, electricity does not persist if it is not used or stored after it is generated.

Considerable efforts are being made to put excess grid energy to work: batteries use electricity for charging, pumped storage facilities use electricity to move water to generate electricity later, time of use rates encourage customers to shift their energy use to daytime when solar energy is plentiful, and electric vehicles and buildings are a growing source of demand.

Electricity generators are generally compensated through contractual commitments to purchase energy or tariffs, and some are further compensated for the guarantee that they will be ready to serve

demand whenever needed. Likewise, the grid is built to efficiently share electricity generation but must also be sized to meet the highest potential demand. Accordingly, using less energy does not always result in cost savings. While guaranteed load reduction measures are increasingly valuable at times of high usage, at other times, more load can mean lower rates.

One key to future cost reduction is increased electricity consumption from buildings and transportation electrification and other new loads, combined with flexible load measures that are targeted, predictable and controllable for system needs. This can bring relief to all customers: when existing infrastructure is used more efficiently and the same fixed costs are spread across a greater volume of electricity provided, customers' total energy costs can be reduced, and climate change action can be achieved at least cost.

Today's Electricity Rates Trajectory

As the CPUC has detailed in its annual rates report,[1] today's rate increases are not driven by prices of contracts for new renewable energy generation.

Broadly, ratepayer bills are rising because of: wildfire risk reduction surrounding utility infrastructure, inequitable rate structures, programs that require energy procurement that is not needed or is not competitively priced, and programs that provide bill reductions or discounts to one group of ratepayers, thus leaving other customers with a larger share of overall costs.

In 2024, ratepayers of the three largest electric utilities paid a collective $54 billion in rates for the cost of utility services and investments.[2] While the CPUC looks for every opportunity to distribute costs fairly, collecting revenue through rates is inherently regressive: low-income Californians pay a higher share of their income for utility bills than higher-income Californians.[3]

Distributing Costs and Benefits Fairly Is Key to Affordability

The electric system is large and dynamic, and numerous programs distribute the costs and benefits of it differently – and so distributing costs and benefits fairly is essential to affordability.

In a variety of policy decisions, the CPUC seeks to distribute costs progressively and aid California families who most need help reducing their utility bills. The CPUC also seeks to measure programs using cost-effectiveness tools that are continuously vetted by stakeholders. However, rising costs

[1] See the 2024 SB 695 Report or the 2024 Padilla report.

[2] This includes a $12 billion proxy estimate for CCA generation costs, and subtracts the impact of the climate credit.

[3] Severin Borenstein, Meredith Fowlie, and James Sallee "Paying for Electricity in California: How Residential Rate Design Impacts Equity and Electrification" (September 2022). Paying for Electricity in California.

for the system and operations as well as requirements and programs beyond core utility services are causing electricity rates to increase significantly in recent years.

Many of these programs have benefits as well. The question presented by Executive Order N-5-24 is whether costs can be reduced and whether costs and benefits are being distributed in ways most fair to all customers, and in ways that enable California to achieve its clean energy and electrification goals.

The CPUC Has Taken Actions to Mitigate Rising Rates

As the CPUC has recognized in its annual SB 695 reports,[4] electricity rates for customers of California's electric IOUs have been projected to increase faster than inflation. As the economic regulator of the state's IOUs, the CPUC limits approvals to necessary costs and identifies cost saving measures wherever they can be found.

The CPUC's adopted monthly flat rate of $24.15 for those who can pay and $12 per month for low-income customers reflects a positive shift toward more equitable ratemaking practices and movement away from regressive cost collection. The flat rate requires all customers to pay the same amount for a portion of utility costs that do not vary with volume of usage and gives low-income households a discount. It is a more progressive method to allocate costs than per-unit charges. More CPUC actions designed to decrease bills for ratepayers as a whole with a focus on equity are described in the appendix.

The Impact of Legacy Contracts

After California legislation required its IOUs to divest generation assets, long-term clean energy contracts have been essential to meeting reliability needs while supporting emerging clean energy technologies. Such contracts, however, can also lead to long-term costs for ratepayers, particularly when they create ongoing financial commitments like contractual obligations or tariffs that extend benefits to electricity generators over time.

One example of an ongoing cost is legacy renewable energy contracts signed more than a decade ago. Load serving entities are required to procure sufficient energy to serve their customers long before it is needed, which is essential for reliability and for hedging against market volatility. Legacy contracts thus deliver benefits, and also impact ratepayers: in 2024, ratepayers paid an estimated $1.2 billion more than they would pay today for RPS contracts signed between the years 2000 and 2016.[5]

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[4] See the 2024 SB 695 Report.

[5] This estimate includes all RPS contracts signed between 2000 and 2016. This includes Qualifying Facility Standard Offer, ReMAT, BioMAT, and BioRAM. BioMat and BioRAM incurred an estimated $25 million in above-market costs, and ReMAT cost ratepayers approximately $5.4 million.

The CPUC has required utilities to renegotiate lower, market-competitive prices for these contracts when they are up for renewal, but above-market contracts persist.

These legacy contracts, together with other legacy costs, also have the unintended effect of creating a cost-savings value stream for any customer who can independently procure or self-generate electricity and thus off-set higher volumetric charges for energy, while still using the grid. In doing so, these customers avoid legacy and other fixed costs, and necessarily shift costs to other customers.

Many Investor-Owned Utility Programs are Mandated by State Laws

As stated in this report, most electricity programs could be funded through non-ratepayer funds. This would shift costs away from customers.

The Legislature can also take statutory action to repeal or significantly revise mandated electricity programs that result in ratepayer costs that are higher than necessary for safe, reliable, clean electricity.

What is Cost Effectiveness, and How Does it Affect Rates?

When a utility program has costs, rates rise, since those costs are paid on ratepayer bills. Some programs also reduce costs that are borne by ratepayers, but unless these reductions fully offset the costs, ratepayers will experience a rate increase. This section explains why.

Every Utility Program Carries Operational and/or Fixed Costs

In California, as in nearly every state, Investor-Owned Utilities (IOUs) collect operational costs on a "cost of service" model: IOUs are permitted to collect all the costs of providing electricity service to customers. The IOUs' operations are a straight pass-through of costs. Utilities do not earn a profit on these costs.

When IOUs invest in infrastructure – substations, transmission, distribution lines, metering infrastructure, and more – they earn a return on these investments, known as their "authorized rate of return," or profit. The capital invested by the utility plus a rate of return are paid back over time by all customers.

Each year, the total amount of a utility's operational costs and an amortized portion of capital investments is divided up among all customers of the utility and allocated for collection largely according to the amount of electricity used. An electrical bill may also include electricity generation costs charged by a non-utility load serving entity such as a Community Choice Aggregator or an Electric Service Provider.

Together, operational and capital costs include every single utility program. Again, under the structure of the Legislature, the CPUC, and the utilities, every program that the Legislature directs the CPUC to implement via the utilities is either an operational cost, a capital cost, or both, and is paid for by ratepayers. Figure 1 summarizes the 2024 revenue requirement for the three large electric IOUs.

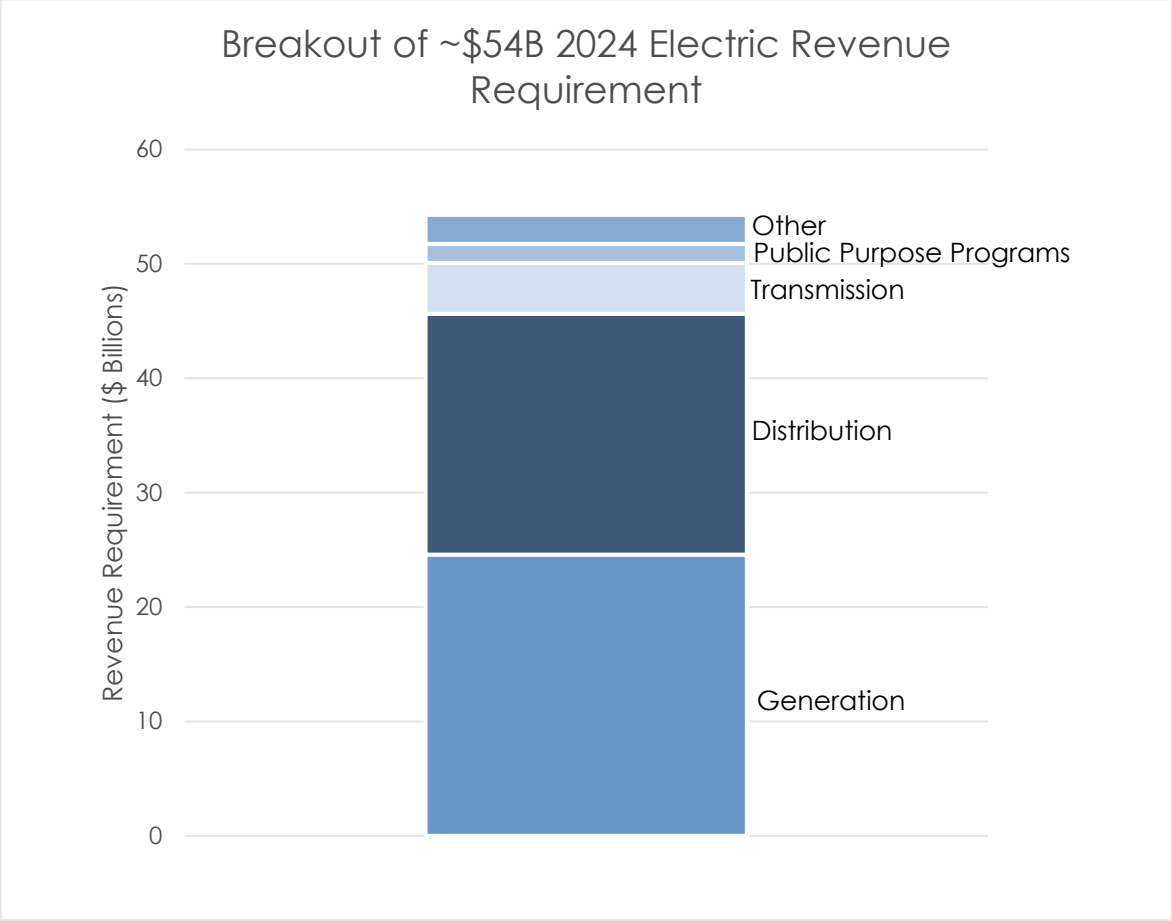


Figure 1. The combined 2024 electric revenue requirement for PG&E, SCE, and SDG&E, after subtracting the California Climate Credit. This estimate uses IOU generation costs as a proxy for Community Choice Aggregator generation costs. The majority of these costs must be paid to the utilities, regardless of electric sales. 2025's revenue requirement is projected to be approximately 5-9% higher than 2024's.

The Capital Costs of the System Are Long-Term Investments That Support Numerous Goals

Capital costs include the physical infrastructure needed to deliver electricity to customers. Much of the recent increase in distribution and transmission costs are upgrades to improve system safety and reliability. This system must be built to meet peak system demand, and costs are not reduced if the

system is used less at certain times of the day on certain days of the year. Long-term investments in the system make the system stronger, more resilient and better able to facilitate electrification of end uses, but they are also sunk costs that must be repaid, and therefore limit California's options to reduce rates.

Under the Current Cost Allocation Structure, Some Customers Pay Less Operational and Fixed Costs While the Majority of Customers Pay More

Under the current cost allocation structure, some advantaged customers pay less than their share of operational and capital costs while disadvantaged customers pay more than their share of both, especially because more advantaged customers have benefitted from the NEM subsidies paid by all other customers. This is partially caused by a policy that eliminates the connection between the revenue an electric utility collects and the amount of energy they sell.

Observers often believe that utilities are seeking to sell more electricity to customers. This is an inaccurate viewpoint. Utilities are indifferent to how much electricity they sell to customers, because of an important energy policy that California adopted in the 1990s that breaks apart electricity sales from utility budgets. Numerous states have followed California's pathbreaking approach, and it has been foundational to the success of programs like energy efficiency and net energy metering. This "decoupled" approach means that if a utility sells more or less electricity in one year, any revenue over-collection or shortfall will either be returned to customers (in the case of over-collection) or collected (in the case of shortfall) the next year. Utilities' revenues are not linked to the amount of electricity they sell, so they have no incentive to sell more or less electricity to any group of customers or to ratepayers as a whole.

Because most operational and capital costs are fixed in advance and allocated on an annual basis, any program that provides rate relief for one customer group results in a shift of operational and fixed costs to another. The second group gets a rate increase, while the first group gets a rate or bill decrease. Figure 2 demonstrates the shifting of such costs from participants in such a program to non-participants. Electricity costs for the customers who don't receive the exemption can rise dramatically – an effect we are seeing today.

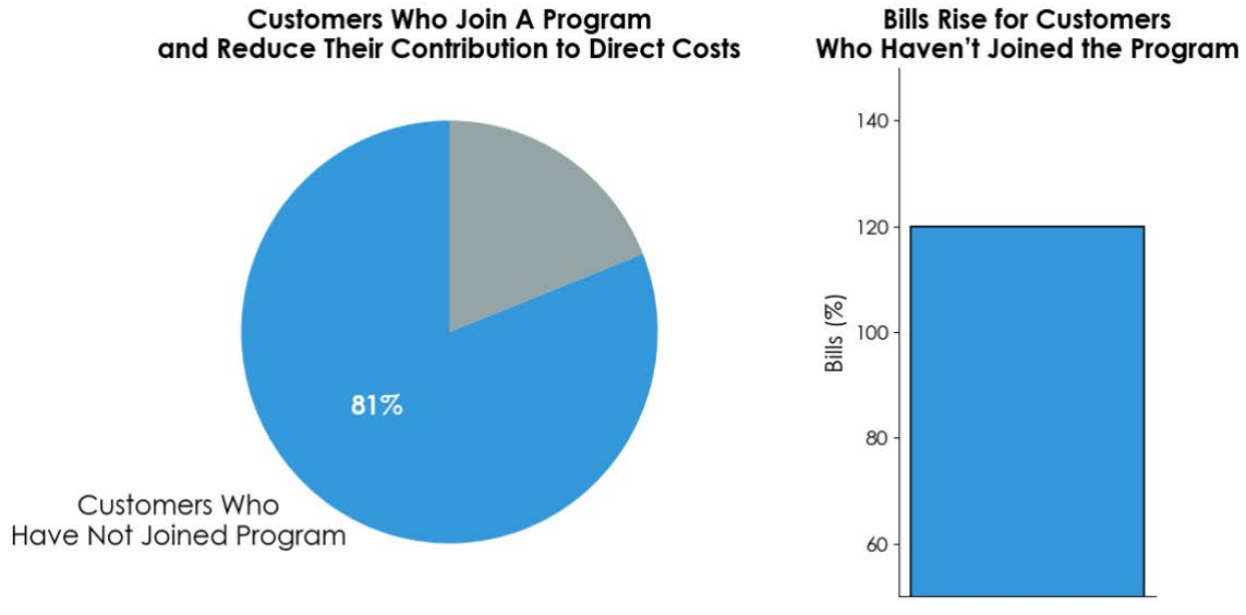


Figure 2. Animation showing the impact on customers who are not participating (blue) in a program, such as NEM 1 and 2, that allows other customers (grey) to reduce their contributions to direct costs. As fewer customers contribute to direct costs, the rest of customers pay higher rates to compensate. This figure is illustrative and does not reflect exact costs of any particular program. To view the animation, open this document in the desktop version Adobe, click on the graphic and "trust" the document.

This happens for a few reasons:

- In the short term, the cost of the entire physical electric system doesn't drop when less electricity is sold. As a result, allowing some customers to not pay for their share of fixed costs moves their share onto everyone else. Some programs may reduce costs in the long term, but only if they directly address the drivers of fixed costs.
- Numerous programs mandated by the Legislature require customers to pay for expensive electricity that would not be able to compete in market-based requests for offers. When utilities, CCAs, or Energy Service Providers are required to compensate generators for expensive electricity, such as for exports from rooftop solar under the Net Energy Metering Tariff, the customers who purchase less electricity overall are purchasing less of the expensive commodity, too. And in turn, the remaining customers who cannot reduce their electricity purchases are paying for a greater share of the more expensive electricity.

In general, the customers who are purchasing less electricity are those who own their homes and can afford to buy or lease rooftop solar panels and in-home battery storage. On that basis, we know that advantaged customers are paying less fixed and operational costs while disadvantaged customers are paying more.

Net Energy Metering

Net Energy Metering (NEM) program costs are one of the largest contributors to rising electricity rates for customers that do not have rooftop solar. According to the Public Advocates Office, the NEM program's and the Net Billing Tariff's (NBT) combined $8.5 billion cost shift constitutes 21-27% of the average non-participating customer's bill.

The NEM 1.0 and NEM 2.0 programs increase electricity bills in two ways: (1) customers pay for the generation that is exported to the grid from another customer's NEM system at a higher rate than other available generation, and (2) customers pay for the part of bill savings experienced by NEM customers because the program allows rooftop customers to bypass their share of direct costs to maintain the electric grid, which other customers without rooftop solar end up paying (see figure 2, above).

IOU customers without rooftop solar are paying NEM customers for the generation they send to the electric grid at a rate that exceeds the cost of generation otherwise available from the grid. NEM 1.0 and NEM 2.0 customers are compensated for electricity exported to the grid at the retail volumetric rate, which exceeds the marginal cost of avoided wholesale generation purchased for that customer. IOU customers without rooftop solar pay this increased cost to NEM customers for 20 years after their grid interconnection dates.

Distributed energy resources, including batteries, electric vehicles, and heat pumps, are a part of California's overall electricity future, and new policies are helping to send improved price signals to these resources so that they can best support electric grid needs. From April 2023 on, new rooftop solar customers—will receive compensation through the new Net Billing Tariff (NBT), which provides compensation that is more aligned with the value of the generation the systems provide to other customers. It also includes more generous subsidies for systems with battery storage compared to rooftop solar. This cost increase, however, is not fully mitigated by the new Net Billing Tariff (NBT): NEM 2 customers who switch to the NBT can create a cost shift that is 76-82% as high as their cost shift under NEM 2.

Cost Effectiveness Approaches

Cost effectiveness is a heavily contested concept. Two approaches have the most direct relevance to rates:[6] the Ratepayer Impact Measure, which identifies the extent to which savings for one customer shifts costs to another, and the Total Resource Cost test, which measures financial costs and benefits to all ratepayers and the utility. Both tests measure exclusively monetary costs, and do not

[6] There are two additional tests described in the CPUC's Standard Practice Manual: the Participant Cost Test, which measures whether a program is financially beneficial to participants, and the Program Administrator Test, which measures costs and benefits to the utility or entity administering the program. The Societal Cost Test measures costs and benefits to society and was recently adopted to use on an informational basis by the CPUC in D.24-07-015.

include non-monetary benefits and costs such as the societal cost of carbon and health or safety benefits.

Generally, when a program's financial benefits to ratepayers outweigh its costs, it will have a Total Resource Cost effectiveness score over 1.0 and it will lower total system costs relative to other resources. Conversely, a score below 1 indicates that a program will raise total system costs relative to the alternative. A score below 1.0 on the Ratepayer Impact Measure indicates that the program raises rates by creating more costs for non-participating customer than it saves for the grid as a whole.

In the time available to prepare this report, the CPUC has not carried out a comprehensive cost effectiveness review of all programs under its purview. In many cases, the statute directing the CPUC to establish the program does not require that the program be cost effective. When the CPUC examines cost effectiveness of an electricity program, it is typically conducted within CPUC proceedings, during which dozens of stakeholders litigate the analysis and results.

Section 1 - Response to Executive Order Request to Review Programs

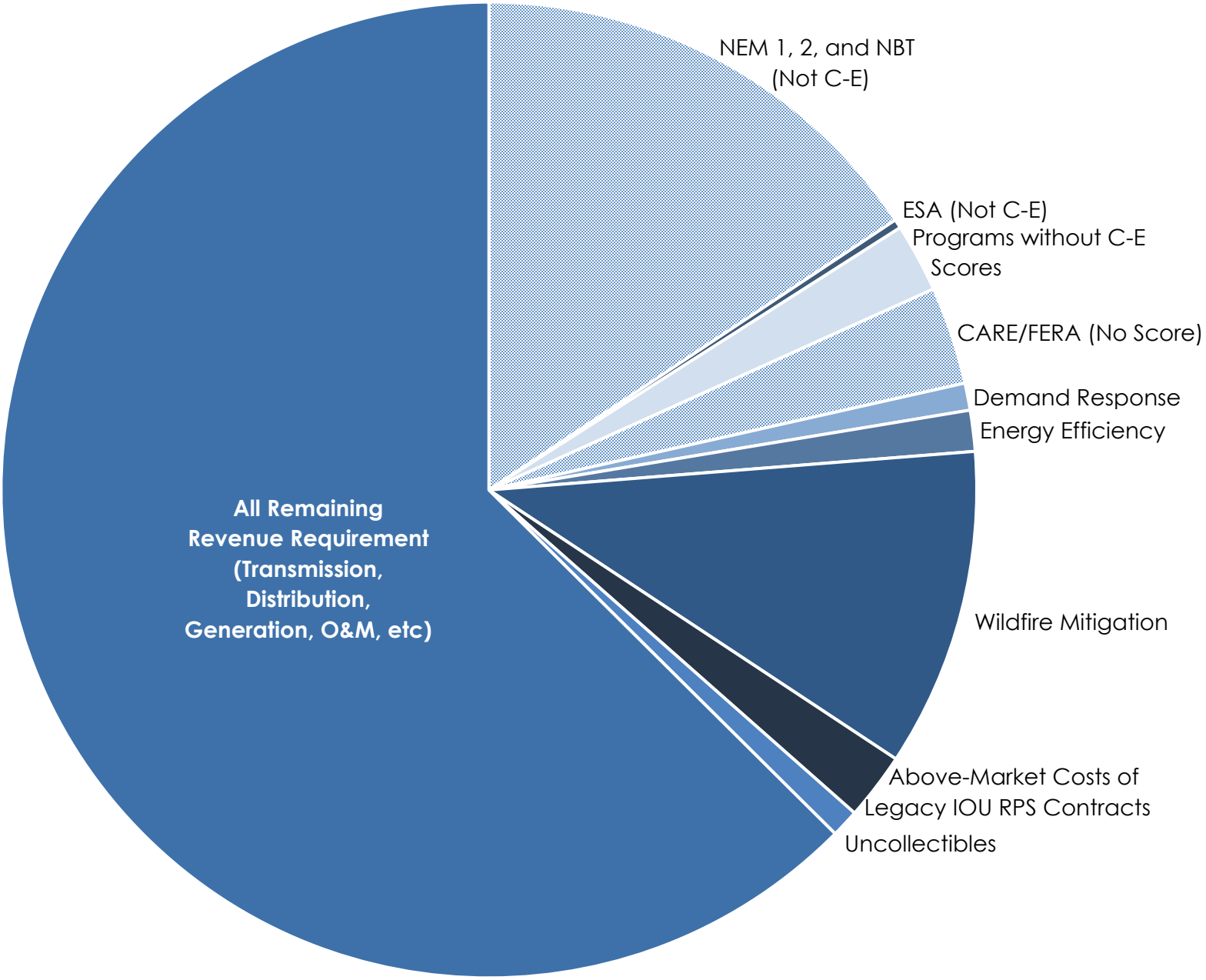


Figure 3 shows the contribution to rates of programs funded through electric IOU revenues. Note that this figure conflates the cost shifting (indicated by textured wedges) visualized in Figure 2 with direct costs like the expense of purchasing energy from biomass incinerators in the BioMAT and

BioRAM programs. The chart is best understood to show the potential impacts on IOU electric revenue collections (and therefore system average rates) if programs were funded outside of electric rates. Eliminating programs whose primary rate impact is through cost shifting would affect which customers pay certain costs, but would have virtually no direct impact on average bills. For example, repealing and eliminating California Alternate Rates for Energy (CARE) would dramatically increase costs for the most vulnerable ratepayers and lower costs for wealthier ratepayers, commercial customers, and industrial customers.[7] It would not impact average bills because savings for one group translate directly into costs for another.

Because each customer class (residential, commercial, industrial) contributes different amounts to each program and cost shift, class-specific impacts would vary from the amount shown in the pie chart. For example, Net Energy Metering and the Net Billing Tariff primarily shift costs within the residential class: funding the cost shift from an outside source would create significantly greater than 15.6% savings for non-participating residential customers.

A full list of programs with their approximate annual costs can be found in the Appendix.

What All of This Means: Opportunities to Cut Rates Today and For the Future

There are opportunities to cut rates today, which will promote affordability. Finding ways to save ratepayers money is essential. The CPUC's analysis shows the following:

1. For context, in 2024 electric ratepayers will pay approximately $54 billion in rates to the three large IOUs and to community choice aggregators. In 2025, revenue requirements are projected to increase an estimated 5-9%.[8]
2. From 2019 to 2024, the IOUs collected approximately $24 billion in wildfire mitigation and insurance premium costs.[9]
3. While the vast majority of industrial, commercial, and residential customers do not have solar panels, the California Public Advocates Office estimates that they will pay approximately $8.5 billion in 2024 for the 15% of customers who do, under the NEM 1,

[7] Approximately three quarters of the CARE subsidy is paid for by non-residential customers. If there were no CARE program, average rates within the residential class would rise: CARE customers would pay approximately $1.9 billion more, while non-CARE residential customers would only save approximately $500 million.

[8] This estimate uses IOU generation costs as a proxy for CCA generation costs, and subtracts the impact of the California Climate Credit. The overall increase in revenue requirement depends on the result of pending proceedings.

[9] Approximately $18 billion was placed into revenue requirements through 2023. See 2024 SB 695 Report, p. 53. At the time of this report's drafting, 2024 costs were estimated to be approximately $6 Billion.

NEM 2, and NBT tariff programs. The Public Advocates office estimates that this cost shift represents 21-27% of residential bills.[10]

4. The flagship low-income discount programs, California Alternate Rates for Energy (CARE) and Family Electric Rates for Energy (FERA) shift approximately $1.75 Billion to non-participating customers. Nearly three quarters of these costs are paid by non-residential customers.
5. The remaining electricity programs that the CPUC orders the IOUs to carry out based on mandates from the Legislature total approximately $2 to $2.5 billion per year. Half of this amount is spent on programs demonstrated to be cost-effective. The remaining half is spent on programs that have benefits and costs, but have not been reviewed for cost-effectiveness.

Based on the above facts, the following are potential principles for consideration. These require statutory changes, budget from another source, or other methods of implementation:

1. **Fund the NEM and NBT Cost Shift From Non-Ratepayer Sources:** Achieve a rate drop in 2025 of approximately 15.6% systemwide[11] by funding $8.5 billion for NEM 1, NEM 2, and NBT customers from non-ratepayer sources. Sustain the rate drop through a commitment to steadily increase the allocation as the number of NBT customers, and the associated cost shift, grows.[12]
2. **Reduce the NEM and NBT Cost Shift:** the cost shift created by NEM 1, 2, and the NBT could be reduced by:
    a. **Shorten legacy periods:** almost all NEM 1 and 2 customers have more than 10 years before they will be defaulted onto the NBT. Nearly half have 15 or more years of this legacy period remaining. By reducing the legacy period from 20 years, NEM 1 and 2 customers could be defaulted onto the Net Billing Tariff sooner. This would save non-participants billions of dollars.
    b. **Tie compensation for excess generation from solar systems to rates in effect when NEM customers interconnected:** Because NEM customers receive retail rates for any excess electricity that passes through their meter, the amount paid by non-NEM customers for this excess energy is increasing over time as rates rise. Tying compensation for excess generation to the rates in effect when a NEM or NBT customer signed up for the tariff would mitigate the increase in cost shifts.
    c. **Establish a Grid Benefits Charge for NEM and NBT customers:** Solar customers use the grid to import and export energy, but a large portion of their

[10] Per the Public Advocates Office. 240822 Public Advocates Office 2024 NEM Cost Shift Fact Sheet.

[11] Per the Public Advocates Office, the NEM 1, 2, and NBT cost shift totals $8.5 billion in 2024. 240822 Public Advocates Office 2024 NEM Cost Shift Fact Sheet.

[12] While the NBT is an improvement over NEM 1 and 2, it does not eliminate the cost shift. NEM 1 and 2 customers have a 20-year legacy period, and the majority connected within the last 5 years. If volumetric electric rates continue to increase, the cost shift from these customers will continue to grow.

existing share of system costs is necessarily moved to other customers' bills when their systems are installed. A monthly charge for NEM and NBT customers would help to reduce the amount that shifts from NEM customer bills to non-NEM customer bills.

   d. **Tying legacy periods to the customer, not the system:** currently, the 20-year legacy period before which NEM 1 and 2 customers are defaulted onto the NBT is linked to the installed system, not the customer. Systems could be converted to the NBT when the home changes ownership or at the end of the legacy period, whichever is sooner, rather than only when the system reaches the end of its legacy period.

3. **Use Stable Non-Ratepayer Funds to Increase the CARE and FERA Discount:** Because fixed costs are high and will remain so for the foreseeable future, a stable source of non-ratepayer funding can be used for a larger direct subsidy to low-income Californians on their electricity bills.
4. **Fund Other Programs From a Non-Ratepayer Source:** Achieve a rate drop of up to approximately 2.3% starting in 2027 through statutory changes in 2025 that fund programs without cost-effectiveness scores from non-ratepayer sources. These programs also provide benefits - repealing them entirely would produce ongoing savings significantly lower than 2.3%, by also eliminating any benefits they provide.
5. **Fund Any Future Cost-Shifting Programs from Non-Ratepayer Sources:** Future programs that give exemptions to certain customer groups should be allocated funding from non-ratepayer sources so that other customer groups do not pay for them.
6. **Use Existing Review Processes of Utility Spending:** The existing General Rate Case (GRC) process is often the best way to ensure that all costs are reasonable and cost-effective, particularly in wildfire-related areas. New programmatic mandates should be evaluated through the GRC instead of standalone applications, such as those to collect costs tracked in memorandum accounts.
7. **If a Program Benefits all Electric Customers, All Electric Customers Should Contribute:** Any program funded by electric ratepayers for the benefit of all of California should be paid for by all electric customers, including the customers of publicly owned utilities.
8. **Prioritize the Needs of Ratepayers:** All energy-related mandates should be assessed for overall cost-effectiveness with the goal of achieving lowest possible rates for all customers of each utility. In addition, statutes ordering the CPUC to prioritize a specific industry's needs, the needs of a specific customer group, or other needs beyond the delivery of safe, reliable and clean energy[13] over the needs of all ratepayers are likely to increase costs.

[13] For example, SB 1090 requires ratepayers to reimburse $85 million in lost local government tax revenue due to the closure of Diablo Canyon Nuclear Plant and pay $128 million in employee retention funding beyond what the CPUC approved. These priorities contribute to increases in PG&E customer bills.

Actions to Be Taken Under the CPUC's Authority

The following are examples of actions the CPUC could take to reduce ratepayer costs:

1. **Open an Energy Efficiency Rulemaking**: The CPUC plans to open a new rulemaking on energy efficiency in 2025. It will include a focus on cost effectiveness.
2. **Move toward incorporating a greater share of ratepayer costs into General Rate Cases for holistic review and decision-making.**
3. **Evaluate new programs for cost-effectiveness** where appropriate. Identify statutory barriers to implementing cost effectiveness tests on mandated programs.
4. **Improve risk-informed spending** by continuing efforts in the Risk-Based Decisionmaking Framework proceeding, directing the utilities to provide better and more consistent information about how they incorporate risk into their GRC funding requests.
5. **Consider reprioritizing transportation electrification spending by focusing on critical grid investments and pausing $1 billion in new ratepayer charges** previously authorized in the Transportation Electrification Framework decision.
6. **Approve lower-cost wildfire risk mitigation methods** where appropriate.
7. **Identify programs meeting the following criteria:**
    a. Programs that require ratepayers to purchase energy from specific generation types that are not competitive with alternative RPS-eligible resources.[14] Removal of costs from rates may require legislative action.
    b. Programs that are underutilitized and could return funds to ratepayers.
8. **Continually improve the efficiency of the CPUC's administrative processes.**

[14] Above-market mandated procurement can occur through tariffs or non-competitively bid contracts.

Section 2 – Response to Executive Order Request to Consider Ways to Improve the Effectiveness of the California Climate Credit

The California Climate Credit is a twice-per-year bill credit automatically provided to all residential and certain qualifying small businesses. Qualifying energy intensive trade-exposed ("EITE") industrial customers also receive the California Industry Assistance credit. The funds originate from the California Cap-and-Trade Program, which requires power plants, fuel providers, and large industrial facilities that emit greenhouse gases to turn in for compliance carbon pollution allowances equal to their greenhouse gas emissions.

The credit is designed to help utility customers during the transition to a low-carbon future by sharing proceeds from the sale of allowances with customers. In 2025, the residential climate credit will total $1.39 billion (an average of $120 per customer), with another $117 million for small businesses and $104 million for EITE industrial customers.

As noted in this report, the burden of high rates does not affect all customers evenly. Pursuant to Executive Order N-5-24, this section explores several potential approaches to maximize the effectiveness of these funds.

The minimal administrative cost is a particular strength of the identified approaches.

Allocating the Climate Credit to Specific Customer Groups

Currently, every residential customer receives a credit on their bill twice per year as their share of the proceeds from California's cap and trade program. In 2025, more than 11.6 million customer accounts will receive an average of $120.

The Climate Credit presents a significant equity opportunity for California. The Climate Credit could be reallocated to customers who need it the most: first, to all customers who receive the CARE benefit, and second, all customers without rooftop solar who are paying for those who have it.

The potential bill credits under three possible alternative approaches are outlined in the table below: allocating the climate credit exclusively to CARE customer accounts, and allocating it to all non-

NEM 1.0, 2.0, and Net Billing Tariff accounts, and allocating it to non-NEM/NBT CARE and FERA customers, along with non-NEM/NBT customers in the hottest climate zones.

Additionally, funding from other sources could be added to the climate credit, increasing the customer benefits shown below.

Allocation	Total Residential Climate Credit, 2025	Estimated Total Benefiting Accounts	Resulting Bill Credit
All Customer Accounts (status quo)	$1.39 Billion	11.6 million	$120
CARE and FERA Customer Accounts only	$1.39 Billion	3.1 million	$454
Non-NEM 1.0, 2.0, or NBT Customer Accounts	$1.39 Billion	9.9 million	$142
Non-NEM/NBT CARE, FERA, and Customers in Hottest Climate Zones			$445[15]

[15] "Reallocating the Residential California Climate Credit to Low-Income Customers." Dollar value may not be directly comparable to others in this table because the workpaper may have used different assumptions.

Volumetric Distribution of Climate Credit

Currently, the Climate Credit is given twice per year in a lump sum. It could be allocated on the basis of usage, reducing the volumetric rate for electricity. While this would not reduce total annual bills, it could potentially make electrification more appealing to ratepayers. It would also reduce month-to-month bill volatility, easing ups and downs of utility bills for many Californians. Any change from a non-volumetric to volumetric return of the climate credit must be reflected in the Cap-and-Trade Regulation.

Rate Reduction if $1.4B Residential Credit were Allocated Volumetrically
$0.023/kWh

Section 3 - Response to Executive Order Request to Recommend Ways to Reduce Wildfire Mitigation Costs

This section is the joint response of the Office of Energy Infrastructure Safety and the CPUC in accordance with Paragraph 5 of Executive Oder N-5-24.

Background

Wildfire represents the single most significant financial and safety risk for California's investor-owned electrical utilities. California is experiencing compounding impacts of climate change, as wildfires become larger, more intense, and harder to contain than ever before. Because wildfire represents such a considerable risk, utilities are required to prepare Wildfire Mitigation Plans (WMPs) describing their strategies for reducing wildfire risk for review and approval by the Office of Energy Infrastructure Safety (Energy Safety). As noted above, between 2019 and 2024, IOUs collected approximately $24 billion from ratepayers to pay for wildfire mitigation costs and insurance premiums.[16]

The WMPs have dramatically improved the way electrical utilities in California understand and reduce the risk of utility-caused wildfire. However, the cost of implementing these plans has resulted in associated wildfire mitigation-related rate pressures.

Wildfire Risk Mitigation Will Continue to Contribute to Electricity Rate Increases

Ignition risk associated with electric lines can be reduced through a variety of approaches including vegetation management, grid hardening, replacing uninsulated lines with covered conductors, and undergrounding.

- Undergrounding: moving above-ground lines beneath the surface.

[16] Approximately $18 billion was collected through 2023. See 2024 SB 695 Report, p. 53. At the time of this report's drafting, 2024 costs were estimated to be approximately $6 Billion.

- Covered Conductor: replacing wires with heavily insulated alternatives that are far less likely to spark than traditional wires.
- Other Grid Hardening and Grid Design: can include replacing wooden poles with fire-resistant materials, replacement or strengthening of infrastructure, segmentation of lines to allow isolation of faults, or adding sensors to cut power when electric faults are detected.
- Vegetation Management: Removing and trimming trees and other vegetation around electrical lines and equipment to reduce the risk of vegetation coming into contact with power lines and reducing the amount of dry vegetation close to electrical equipment.

While each approach reduces wildfire risk to varying degrees, undergrounding raises rates the most and takes the longest to implement. Although undergrounding costs are hard to estimate and vary dramatically because of many factors, including topography, estimates show that undergrounding every IOU distribution line in high fire threat areas could cost an estimated $92-224 billion. Undergrounding transmission would be significantly more costly. In contrast, installing covered conductor would cost approximately one-fourth as much.[17]

Of the four approaches, undergrounding is in certain locations the most effective option, and is therefore an essential tool in utility efforts to reduce wildfire risk. SB 884 facilitates longer-term utility infrastructure undergrounding investments, but does not provide a source of funding for this work other than increases in customer bills.

No matter the approach, the costs associated with hardening the electric grid to reduce the risk of utility-ignited wildfires are borne by ratepayers through increases in electricity rates. The most effective way to reduce the electricity bill impact is to fund these investments from a source other than ratepayers.

Consolidating and Streamlining Utility Funding Requests Will Provide Some Relief

These rate pressures may be reduced through increased transparency and improved coordination of cost approval processes, electric underground infrastructure construction, and fuel treatment efforts.

Currently, electrical utilities request wildfire mitigation funding through multiple mechanisms at the CPUC, including GRCs, memorandum accounts for the recovery of WMP costs, and, prospectively, additional applications for large electrical undergrounding plans. The multiple streams of funding for

[17] Depending on the IOU, undergrounding distribution lines costs $2.3-$5.6 million per mile, while transmission undergrounding is significantly more expensive: the Tehachapi Renewable Transmission Project cost $139 million (in 2025 dollars) per mile to underground. Covered conductor costs $770,000 - $1.35 million per mile. There are approximately 40,000 miles of above-ground IOU distribution lines in California's High Fire Threat Districts. Per-mile costs are drawn from recent IOU filings and CPUC decisions. This calculation is highly uncertain.

wildfire mitigation decrease transparency, complicate oversight, and reduce accountability, leading to increased rates.

The CPUC's GRC process is the most transparent available process and requires the highest levels of cost justification. The GRC allows parties to the proceeding to scrutinize proposed spending forecasts and present evidence in support of lower or higher amounts than those proposed by the electrical utilities. Based on the evidence presented, the CPUC ultimately prospectively approves a fixed amount of funding utilities may recover from ratepayers each year of the four-year GRC cycle. In the case of costs required to implement WMPs, the CPUC is required to allow the utilities to track and record additional costs, above approved GRC forecasts, and seek cost recovery from ratepayers for these expenditures.

Solutions Requiring Legislation

Integrating Wildfire Mitigation Plans into Utility General Rate Cases

The implementation measures included in Wildfire Mitigation Plans (WMPs) are not currently subject to the coordinated cost review and evaluation that other utility programs and investments receive. This may unnecessarily drive costs up and decrease transparency of wildfire-related spending. Applications to recover many of these costs are often filed after the work is completed and involve lengthy, contentious proceedings to evaluate potential overlap with GRC approvals and after-the-fact reasonableness of expenditures. The time delay increases debt carrying costs that must be paid by ratepayers.

The Public Utilities Code could be amended to require utilities to integrate WMP costs into the normal planning and budgeting process (their GRC) instead of treating it as a stand-alone activity. While the CPUC could still authorize utilities to track and recover WMP implementation costs that exceed GRC-authorized amounts, utilities would need to include their entire forecasted amounts in GRC applications. This modification would reduce ratepayer costs by allowing CPUC review of planned expenditures before work is completed and help ensure that utilities choose the most cost-effective mitigations.

The aim of the alignment would be to increase administrative efficiency by reducing the rate at which utilities prepare comprehensive wildfire mitigation plans from once every three years to once every four years. While the WMP process to date has successfully driven electrical utilities to rapidly improve how they understand and address wildfire risk, utilities have matured to the point where they can be expected to incorporate their wildfire mitigation planning into the GRC process. Synchronizing WMP planning with planning for other spending, along with additional procedural changes, would improve clarity and reduce redundancy in the Energy Safety and CPUC review processes. The elimination of more than a dozen CPUC resolutions ratifying WMPs every year

would lead to significant reductions in planning, preparation, review, and litigation expenses for the CPUC, Energy Safety, and utilities.

Finally, this proposal would improve utilities' certainty as to what wildfire mitigation activities must be completed as well as the associated approved budgets thereby avoiding complex factual determinations around the reasonableness of utility incremental spending over GRC approvals.

These changes would largely mirror those proposed in SB 1003 (Dodd, as amended August 28) during the 2023-2024 legislative session. Energy Safety would continue to review and approve or deny WMPs while the revenue approval remains with the CPUC.

This alignment would build on lessons learned from the past five years and prepare California for the next phase of utility wildfire risk reduction. It would also preserve successful features of the current oversight model:

- The reforms keep the focus on mitigating utility wildfire risk. Energy Safety will continue to set requirements and evaluate the quality of WMPs.
- Every year, Energy Safety would assess utility implementation of WMPs and provide feedback to utilities and CPUC.
- Every year, utilities would continue to apply for certification from Energy Safety based on enumerated statutory criteria rooted in proactive investments in safety. By meeting these criteria, the utilities demonstrate their commitment to safety culture, safety based executive compensation, transparent reporting, and continued maturity in their planning efforts. In return, they can be entitled to a presumption of reasonable action in a proceeding before the CPUC to recover costs in the event of a utility related wildfire.
- The CPUC would evaluate and approve wildfire spending costs with attention to cost effectiveness.
- The CPUC would still have authority penalize utilities who do not implement their WMPs.

Reducing the Construction Costs of Burying Electric Utilities

When undergrounding their facilities, electrical utilities do not consistently receive information on the location of other utilities' underground infrastructure until two days before excavation begins. Therefore, contractors installing electric infrastructure are often required to make costly changes during construction to account for previously unknown existing underground facilities, driving up the cost of constructing new underground facilities.

These challenges could be addressed by legislation authorizing Energy Safety's Underground Safety Board to determine how utilities must provide buried facility records to electrical and other utilities during the project planning and design phases. This would be accomplished through processes used by existing 811 underground service alert notification centers. Energy Safety's Underground Safety

Board would need the authority to develop regulations requiring contractors who submit a significant number of 811 tickets to provide advance notice to utility operators in the affected area. This advance notice, which could be integrated into the 811 design process, would enable utility operators to more effectively plan for large-scale projects. This process could also be used to facilitate early Tribal notification of pending excavation activities.

Solutions Actionable on Existing Authority

Energy Safety: Better Fuels Treatment Coordination Between Electrical Utilities and Large Landowners

Electrical utilities generally plan wildfire mitigation activities independently of the extensive coordinated wildfire mitigation work occurring throughout the state. WMP initiatives activities can be costly to plan and implement as stand-alone small-scale projects and are often too limited in scale to protect electric companies' assets from wildland fires. Energy Safety could leverage its existing participation in various wildfire mitigation boards and task forces, along with its relationships with the electrical utilities, to facilitate broader coordination and integrated wildfire mitigation projects between public and private partners.

Coordination of fuel management treatment design, permitting, and environmental review work produces savings for land managers and electrical utilities. Stewardship agreements could allow multiple entities to hire a single contractor to conduct the forest fuel reduction treatments across a broader geographical area.

As an example, the 6,400-acre Liberty Utilities Resilience Corridors Project—coordinated with the U. S. Forest Service— enabled fuel reduction treatment along utility corridors and allowed the Forest Service and Liberty Utilities to share in the costs. Energy Safety can work with existing partners such as the Office of the State Fire Marshal and the California and the Wildfire and Forest Resilience Task Force to identify and facilitate similar projects.

Section 4 – Response to Executive Order Request to Pursue Federal Funding Opportunities

In April 2024, the Commission adopted Resolution E-5254. The Resolution formalized support for IOU pursuit of federal funding opportunities, allowed for the establishment of a memorandum account to track spending on applications and other federal funding costs, and established a process for utilities to seek cost recovery for any required ratepayer cost shares for successful grant applications. Utilities are directed to apply for cost recovery through the existing general rate case (GRC) or application process to ensure that all projects face a sufficient level of scrutiny and opportunity for public engagement.

The utilities have also received multiple letters from CPUC President Alice Reynolds directing them to pursue all available funding opportunities, highlighting upcoming deadlines, and ordering the IOUs to report on their efforts to apply for funding.

These efforts have led to significant successes, including a $15 billion low-interest loan from the Department of Energy. Additional funding is summarized in table A-3 of this report's appendix. The CPUC will continue to strongly support and encourage the IOUs to secure any and all available non-ratepayer funding.

Appendix

CPUC Actions Taken to Reduce Costs

Wildfire Self-Insurance Produces Ratepayer Savings

- Cost of commercial market wildfire insurance has escalated in recent years.
- The CPUC approved proposals for PG&E and SCE to implement wildfire self-insurance, estimated to have resulted in a $467 million ratepayer savings impact in 2023.[18]

Similar savings are anticipated for future years.

Equity Rate Base Exclusion and Optional Securitization Limit Rate Increases

- As directed by AB 1054, the annual revenue requirements approved by the CPUC preclude the IOUs from recovering a Return on Equity on $5 billion in wildfire mitigation capital costs.[19]
- These equity rate base exclusions are forecasted to save ratepayers as much as $2 billion over the lifetime of the assets.
- AB 1054 also allows for securitization of wildfire mitigation capital spending. Securitization benefits ratepayers by allowing the securitized bonds to obtain a lower interest rate than would otherwise be available to finance WMP capital expenditures.[20]

As of July 2024, the CPUC has authorized $10.9 billion in securitization bonds under AB 1054 and SB 901.[21]

Net Billing Tariff (NBT) Limits Cost Increases

- The CPUC reduced electricity bills for IOU customers by reducing the amount customers pay to other IOU customers who install solar or solar-plus-storage systems in the future.[22]
- While Net Energy Metering (NEM) 1.0 and 2.0 programs decrease electricity bills for customers participating in the programs, they increase electricity bills for all other customers. The NBT decision does not change the ongoing increased costs that non-participating customers pay for participants to remain on the NEM 1.0 and NEM 2.0 tariffs. It also does not eliminate future

[18] *See* D.23-01-005 issued in PG&E's 2023 General Rate Case (A.21-06-021) and D.23-05-013 issued in SCE's 2021 General Rate Case (A.19-08-013).
[19] AB 1054 excludes the first $5 billion of the large IOUs' Wildfire Mitigation Plan (WMP) capital spending from earning a return on equity. (AB 1054, Section 18). This limits rate increases directly by eliminating the investor return portion of the return on rate base of $5 billion in WMP capital spending. *See* Chapter IV, Wildfire-Related Costs section for each IOU's total equity rate base exclusion amount.
[20] *See* Chapter IV, Wildfire-Related Costs section for specific Financing Order Application and Decision numbers.
[21] Under PG&E's bankruptcy plan and SB 901, the CPUC also authorized $7.5 billion in securitization (SB 901, Section 32).
[22] *See* D.22-12-056 in proceeding R. 20-08-020.

cost shifts: the NBT reduces the per-customer cost shift by an estimated 18-24% relative to NEM 2.[23]

Virtual Net Billing Tariff (VNBT) and NBT Aggregation Subtariff Limit Cost Increases

- The CPUC reduced electricity bills for IOU customers by reducing the amount customers pay to other IOU customers who install solar or solar-plus-storage systems using the VNBT and NBT Aggregation programs compared to previous Virtual Net Energy Metering (VNEM) and Net Energy Metering Aggregation (NEMA) programs.[24]
- While VNEM and NEMA programs decrease electricity bills for customers participating in the programs, they increase electricity bills for all other customers. The decision does not change the ongoing cost shift created by customers remaining on the NEM 1.0 and NEM 2.0 tariffs. It also does not eliminate future bill increases that occur when other customers install rooftop solar and solar-plus-storage systems using the new tariffs.

Self-Generation Incentive Program Transitioned to Non-Ratepayer Funding Source

- Pursuant to AB 209, the CPUC allocated $280 million from the Greenhouse Gas Reduction Fund to the Self-Generation Incentive Program (SGIP) Residential Solar and Storage Equity budget.
- This allowed the program to continue to support resiliency in low-income and environmental and social justice communities without drawing on ratepayer funds.

Intervention In Federal Transmission Owner Rate Cases Saves Ratepayers Money

- The CPUC continuously advocates in Transmission Owner rate cases at FERC on behalf of ratepayers.
- Ratepayer savings are ongoing and estimated to be $5 billion since 2018, or $700 million per year.

Transmission Project Review (TPR) Process Increases Transparency of Costs

- CPUC designed the TPR Process to provide cost transparency of IOUs' transmission projects before Federal Energy Regulatory Commission whose costs exceed $1 million.[25]
- While not always quantifiable, savings from previous FERC-derived processes between 2020 and 2023 resulted in quantified long-term savings to ratepayers of between $500 million and $1 billion.
- As the TPR Process is more robust than those earlier processes, the affordability benefits to ratepayers are expected to be at least as great.

Implementation of FERC Order Saves Ratepayers Money

[23] Comparing a NEM 2 solar-only customer to an NBT solar and storage customer.

[24] *See* D.23-11-068 in proceeding R.20-08-020.

[25] The TPR Process was established in Resolution E-5252.

- AB 209 reaffirms and clarifies that IOU participation in the CAISO is ordered by the CPUC and not voluntary. This clarification confirms that the IOUs cannot collect additional costs from ratepayers as an incentive to participate in an ISO.
- The Federal Energy Regulatory Commission (FERC) ruled in December 2023 that AB 209 is clear that incentives are not appropriate if an action is already mandatory. This adder will not be allowed in future rate cases and has an estimated cost savings of $86 million in 2024.

The GRC Process is Transparent and Publicly Vetted

- The CPUC's GRC proceedings require a transparent process for analyzing proposed utility costs and high levels of cost justification.
- In GRC proceedings, the CPUC requires evidence of forecasted costs and uses procedures for parties to litigate these forecasts in a public proceeding. **This process enables the commission to identify necessary and cost-effective expenditures and typically leads to approvals that are lower than utility cost recovery requests.**

Revision of Electric Rule 20 Prevents Ratepayers From Funding Inequitable Investments

- The Rule 20A program subsidized the undergrounding of power lines for aesthetic purposes in localized areas and benefits few ratepayers at the expense of the many ratepayers.
- The CPUC discontinued and is phasing down the Rule 20A Program by 2033 to prevent ratepayers from funding inactive and inequitable infrastructure investments.[26]
- The action is estimated to save $74 million annually through 2033.

[26] *See* D.23-06-008 in proceeding R.17-05-010.

Table A-2. Program list.

	Bill or Statute Mandating Program, if Any	Ratepayer Funding ($ Millions, unless otherwise noted)	% Reduction in Average Rates if Funded by Non-Ratepayer Funds	One-Time Savings if Discontinued	Cost Effective? Blank Cells Mean No Evaluation Has Been Conducted
NEM 1 and 2	PU Code Sections 2827 and 2827.1	$8.25 Billion in Cost Shifts[21]	15.2%		No
CARE and FERA	PU Code Section 739.1	$1.75 Billion (1/3rd from residential customers)	3.2%		
Energy Efficiency	PU Code 454.55, 454.56	$810	1.5%		Yes, with non-cost-effective components
Demand Response	PU Code Sections 454.5(b)(9)(C)(i), 380, 400(c), 769	$486	0.9%		Yes, with pilots excluded from cost-effectiveness requirements
Uncollectibles/Arrearage Management Program (AMP)		$483 million in 2025, $204 million from AMP	0.9%		
CalSHAPE (AB 841)	PU Code Sections 1610-1618, 1620-1627, 1630-1633	$331	0.60%		

Net Billing Tariff	PU Code Sections 2827 and 2827.1	$250 million in cost shifts[27]	0.4%		No
Energy Savings Assistance (ESA)	PU Code Section 382	~$140-200 million	0.3%		No
Transportation Electrification Rebate Program		$200	0.40%		
EPIC		$185	0.3%		
BioMAT/BioRAM	PU Code Section 399.20	$150	0.3%		
SOMAH	PU Code Section 2870)	$100	0.2%	$517	
VNEM		Approximately $26 million in 2022[28]	0.04%		No
RES-BCT	PU Code Section 2830	~$30-50 million in cost shifting	0.05%		
DAC-GT/CSGT	PU Code Section 2827.1	$24	0.04%		
SB 1090 – Diablo Canyon Settlement Agreement	PU Code 712.7	$9.48 million in 2024, $213 million total,			

[27] Per the Public Advocates Office. 240822 Public Advocates Office 2024 NEM Cost Shift Fact Sheet.

[28] Decision 23-11-068, page 22.

Microgrid Incentive Program	PU Code 8370, 8371	Low millions in 2024, up to $200 million over 3-6 years			
RISE		$0 in 2024, $50 million total		$50	
AB 841 (Transportation Electrification)	PU Code Sections 740.12, 740.18, 740.19, and 740.20.	Unknown – shifts costs to non-participating customers			
Fuel Cell Net Energy Metering (NEM-FC)	PU Code Section 2827.10	Low millions in cost shifting from 120 MW of capacity – NEM 2 Lookback Study found small cost shift from commercial customers			
NEM-A	PU Code 2827, 2827.1	Low millions in cost shifting			
Solar Equipment List	PU Code Section 2851	$1.28	0.01%		
Clean Energy Financing		$0	0%	$270.5	
SGIP	PU Code 379.6	$0 Unquantified cost shifting	Unquantified	~$129 million	

TECH	PU Code sections 922, 748.6	$0	0%		
Community Renewable Energy Program (CREP)	PU Code sections 769.3 and 913.15	$0	0%		
AB 2109 – Industrial Surcharge Exemption	PU Code Sections 371 and 451.7	Unknown – Shifts costs to non-participating customers	Unknown		

Table A-3. Summary of federal funding secured by IOUs.

Applicant	Project	Award Amount	Description
PG&E, SCE, CEC, CPUC, CAISO, UC Berkeley	CHARGE-2T (**C**alifornia **H**arnessing **A**dvanced **R**eliable **G**rid **E**nhancing **T**echnologies for **T**ransmission) Press Release DOE Factsheet	$600M Federal Share / $901M Ratepayer Share	Reconductor 100+ miles of transmission lines to increase transmission capacity to support renewables integration. Also supports interconnection reform.
PG&E, Redwood Coast Energy Authority, Schatz Energy Research Center at Cal Poly Humboldt	**T**ribal **E**nergy **R**esilience and **S**overeignty (TERAS) Project DOE Fact Sheet	$88M Federal / $89M Ratepayer	Implement nested microgrids serving Hoopa Valley, Yurok, Karuk, and Blue Lake Rancheria tribal lands to drastically reduce outage times.
Liberty Utilities	Project Leapfrog DOE Factsheet	$13M Federal Share / $13M Ratepayer Share	Upgrade the distribution system for real-time information gathering, greater manipulability,

			and faster outage management
CPUC, CEC, CA Infrastructure and Economic Development Bank, CA Labor & Workforce Development Agency	Solar for All EPA Solar for All website	$249.8M	Deliver residential solar for low-income and disadvantaged communities across the state.
PG&E	Maintaining & Enhancing Hydroelectricity Section 247 DOE Award List	$34.5M for 39 different projects	Maintain and improve existing hydropower facilities.
PG&E	Project Polaris DOE Press Release	$15 billion loan	Expand hydropower generation and battery storage, upgrade transmission capacity through reconductoring and grid enhancing technologies, and enable virtual power plants

CALIFORNIA ENERGY COMMISSION

CALIFORNIA NATURAL RESOURCES AGENCY

January 1, 2025

California Energy Commission Response to Executive Order N-5-24

Overview

The California Energy Commission (CEC), as the state's energy policy and planning agency, is responsible for advancing state energy policy, investing in energy innovation, overseeing energy infrastructure, and preparing for energy emergencies. The CEC is also responsible for advancing energy efficiency and developing renewable energy and has done so in part through longstanding building and appliance efficiency programs, as well as more recent, nation-leading energy research, renewable energy, and load flexibility programs. These programs support California's energy and environmental policies, including the transition to entirely clean energy sources by 2045.

The CEC administers dozens of programs funded by a variety of revenue sources. Outside of the recent one-time state and federal funds dedicated to expediting the state's transition to clean energy, most CEC programs are funded by dedicated revenue sources from special funds. One example is the Clean Transportation Program (CTP), which invests up to $100 million annually, leveraging public and private investments to accelerate the development of zero-emission and near-zero-emission technologies and reduce petroleum dependence. The CTP receives revenue from vehicle registration, vehicle identification plates, and smog abatement fees. Another example is fees paid by power plant developers to support the CEC's power plant licensing and compliance activities.

The main fund supporting CEC's operational activities is the Energy Resources Programs Account (ERPA). The revenues in ERPA are linked to the sale of metered electricity, and ERPA revenues support activities at the CEC such as building and appliance standards that have helped California consistently rank as a leading state in energy efficiency – including the #1 ranking in the latest assessment of the American Council for an Energy-Efficient Economy (ACEEE).[1] Since their inception in the late 1970s, these standards have significantly reduced energy consumption and ratepayer bills.

The clean energy programs of the CEC are critical to helping the state rise to meet the energy and climate challenges of today and tomorrow, from grid decarbonization to reliability and affordability. The state has made great strides in decarbonizing the California grid. From January to September 2024, for example, the grid reached 100 percent clean energy for a portion of the day in two out of every three days. The grid's struggles with reliability seemed insurmountable only a couple years ago when extreme weather events, more limited flexible resources, and market dynamics, among other influences, led to outages that disrupted lives and the economy.[2] In contrast, this past summer was the hottest in modern history, and ratepayers experienced no outages from supply shortfalls and zero flex alerts. These

[1] ACEEE State Energy Efficiency Scorecard. https://www.aceee.org/state-policy/scorecard

[2] CAISO, CPUC, CEC (2021) Root Cause Analysis: Mid-August 2020 Extreme Heat Wave. https://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

outcomes reflect tremendous progress. And, while the challenges related to affordability are substantial and impactful, particularly to the state's low-income and disadvantaged communities and tribes, they too are solvable.

The CEC's electric ratepayer-funded programs seed the innovations, deploy the resources and infrastructure, and enable the statewide action needed to mitigate electricity affordability challenges while continuing to decarbonize, modernize, and strengthen the grid. The value of these programs is tangible in the deep efficiencies unlocked through codes, standards, and technology innovation. Moreover, the load growth facilitated through the continued electrification of California's economy could help to stabilize rates and potentially counteract the higher fixed costs on utility bills, depending on rate design and other factors. Ratepayer-supported programs and initiatives advance energy technologies across the economy – including electric vehicles, heavy-duty fleets, and transit; residential, commercial, and industrial heat pumps for space and water heating and highly efficient appliances; advanced renewable energy generation; and integrated controls and battery and thermal storage that enable the state to shape and shift its demand. In this way and more, the CEC programs are integral to a just, clean energy future.

In response to Executive Order N-5-24,[3] the CEC examined all electric investor-owned utility (IOU) ratepayer-supported programs that it oversees and administers, and reports the following:

- **Energy Efficiency:** California's efficiency programs are highly cost-effective to ratepayers and have long been key to achieving affordable bills and meeting the state's energy and environmental goals. The Statewide Codes & Standards Program is funded by electric and gas ratepayers at $56.7 million per year as of 2024, whereas efficiency standards for buildings and appliances are saving billions annually, have saved Californians over $200 billion since inception in the late 1970s, and are set to reach $300 billion in total cumulative economic value to the state by 2030. The CEC recommends retaining the ratepayer supported programs that directly contribute to these foundational efforts, in particular the California Public Utilities Commission (CPUC)-overseen and IOU-managed Statewide Codes & Standards Program. However, the Legislature should consider if the costs of this foundational program should be borne more broadly by electric and gas ratepayers across all of California, given the statewide customer benefits these programs provide.
- **California Schools Healthy Air, Plumbing, and Efficiency (CalSHAPE) Program:** The CalSHAPE program was authorized in 2020 as a COVID-19 urgency measure to re-open schools and improve indoor air quality. Since program implementation, other non-ratepayer funding sources have become available, including the $10 billion Proposition 2 of 2024 and local bond measures. Given the availability of non-ratepayer funding, the Governor and Legislature may consider refunding $196.1 million of unencumbered CalSHAPE funds to electric and gas IOU ratepayers before December 31, 2026.
- **Solar Equipment Lists:** The CEC's Solar Equipment Lists (SELs) provide a standardized, streamlined and cost-effective process for equipment identification that is relied upon by equipment manufacturers, IOUs, publicly-owned utilities (POU), providers of permitting platforms, local governments, certain CPUC and CEC programs, the National Renewable Energy Laboratory (NREL) and other entities across the country. In Spring 2023, the CEC released a public request for information (RFI) to better assess the use cases and benefits of its SELs. California electric utilities' responses to the RFI indicated that by leveraging SELs for interconnection application review, the utilities achieve tremendous cost savings, due to

[3] Executive Order N-5-24 (2024). https://www.gov.ca.gov/wp-content/uploads/2024/10/energy-EO-10-30-24.pdf

reduced review times and labor hours, exceeding the cost to administer the SELs program by several factors. Information from the SELs is utilized in software platforms that assist local governments in streamlining the permitting processes for distributed energy resources (DER). Without information from the SELs, challenges to interconnection and permitting of DERs would increase, potentially slowing down deployment significantly and adversely impacting the growth of the DER industry. However, the IOUs maintain their own SELs list as required by CPUC's Rule 21. Therefore, the CEC recommends identifying an alternate funding source.

Information is also provided on the CPUC-overseen and CEC-administered Electric Program Investment Charge (EPIC).

Energy Efficiency

Program Background and Objectives

Since 1978, building and appliance energy efficiency standards have saved Californians over $200 billion and served as a foundational, highly cost-effective strategy for meeting the state's climate action goals. Appliance standards are estimated to save over 40,000 GWh of annual electricity demand while delivering sizeable reductions in water use and fossil gas consumption. The term "energy" as used below encompasses direct electricity and fossil fuel consumption, embodied energy in the delivery and treatment of potable water, and indirect avoided fuel consumption by power plants due to lowering peak demands. If the state were to credit just the electricity savings at the wholesale price, as opposed to the retail value, energy efficiency from appliance standards alone would be worth $2 billion annually to ratepayers, which is more than the entire annual CPUC budget for energy efficiency and entire annual CEC staff budget combined.

The building code adopted by the CEC in 2024 is estimated to provide California with 30-year benefits of at least $4.8 billion[4] — or over 20 times the roughly $200 million cost of the entire 3-year Statewide Codes & Standards budget, including Energy Commission expenditures, appliance standards, and other energy efficiency standards activities. These highly impactful building and appliance energy efficiency standards are enabled by the electric IOU ratepayer-supported Statewide Codes & Standards Program, which is implemented by the IOUs and delivers critical analytical support for standards development. The Los Angeles Department of Water & Power (LADWP) and the Sacramento Municipal Utility District (SMUD) have also historically contributed to the program. The Statewide Codes & Standards Program is funded at $56.7 million per year as of 2024.[5]

Research and Development (R&D) in energy efficiency and incentive programs for energy efficient technologies ultimately result in new, cost-effective energy efficiency technologies and practices that can be adopted into the state's mandatory building energy code, resulting in significant cost savings to ratepayers in the form of reduced energy bills. In other words, California's national and global leadership in building and appliance energy standards is made possible by ratepayer-funded initiatives on both the code adoption side – in particular the Statewide Codes & Standards Program – and on the research and product development side, such as EPIC.

[4] CEC (2024) Form 399 for the Proposed Changes to the 2025 Building Energy Efficiency Standards. https://efiling.energy.ca.gov/GetDocument.aspx?tn=255315-5&DocumentContentId=90999

[5] CEDARS California Energy Data and Reporting System. https://cedars.cpuc.ca.gov/filings/list/

Program Impact

Energy efficiency has been key to affordable customer electric and gas bills. While California has long had above-average electricity rates, until recent years, Californians still enjoyed some of the lowest bills in the country thanks to their low energy usage. Program expenditures for CEC's building and appliance standards programs have not substantially increased in recent years and are not responsible for the recent increase in energy bills.

California's energy efficiency programs are working. The residential electricity consumption between 2009 and 2019 increased by only 2 percent despite the population growing by 7 percent (which would be expected to cause a matching 7 percent growth in energy demand, all else being equal) as well as a major increase in consumer electronics and air conditioner saturation.[6]

Codes and standards rely on a complex pipeline of market transformation efforts. New energy efficient technologies and techniques are studied and developed in the state's R&D programs such as EPIC. At the next stage of market transformation are voluntary programs that include inducements, marketing, and labeling that drive the new technology to a larger market share. Only once the technology is developed, proven, and has reasonable customer acceptance will it typically be considered for a code or standard, which is further supported by "above code" programs operated by IOUs, community choice aggregators (CCA), and other private groups. Therefore, the significant energy and financial savings achieved through the codes and standards programs depend on – and should be partially attributed to – an ecosystem of R&D programs and energy efficiency inducement programs.

As an example, consider the process of essentially eliminating incandescent bulbs from residential households. R&D funding was spent on developing compact fluorescent and light emitting diode (LED) lighting, measuring their characteristics and their acceptance by consumers. Based on resulting products, labels and inducements were provided to drive the initial scale in the market. Finally, appliance standards required that only efficient, quality bulbs be allowed for sale in the state.

Appliance Efficiency Program

Appliance standards set by the CEC, first adopted in the late 1970s, have transformed the national appliance market and many have since been adopted as national standards. California standards become de facto national standards, and in most cases literally become national standards; the federal legislation instituting the U.S. Department of Energy's (DOE) national program was a direct response to California's standards and a concern from manufacturers that other states would follow California's lead and create a patchwork of requirements. California's standards became the starting point for DOE's consideration and adoption of national standards,[7] a pattern that has repeated for the majority of federal standards now applicable nationwide. This is further supported by "above code" programs operated by IOUs, CCAs and other private groups. California developed the first efficiency standards for all major electricity and gas appliances in the home — refrigerators, air conditioners, furnaces, water heaters, etc. The impacts of early actions continue to be observed in the market. Appliance standards that became effective after 2015 are still accelerating in their energy and financial savings impact given that it takes an average of 10 years for full market turnover of a given appliance. This includes standards for the following:

[6] See the Residential Appliance Saturation Surveys conducted for 2003, 2009 and 2019. https://www.energy.ca.gov/data-reports/surveys/2019-residential-appliance-saturation-study

[7] See Public Resources Code § 25402.

Appliance	Annual avoided GWh (2024)[8]	2024 cost savings (wholesale - $50/MWh)	2024 cost savings (retail - $0.31/kWh)
Battery Chargers	5,290	$ 264.5 M	$ 1,640 M
Lighting	2,331	$ 116.6 M	$ 722.6 M
Computers	1,932	$ 96.6 M	$ 598.9 M
Televisions	1,391	$ 69.6 M	$ 431.2 M
Computer Monitors	347	$ 17.4 M	$ 107.6 M
Portable Electric Spas	35	$ 1.8 M	$ 10.9 M

Combined, these recent standards are responsible for 11,000 GWh of the 40,000 GWh annual total savings attributable to the Appliance Efficiency Program, with the remainder occurring from standards adopted over 10 years ago (for which full stock turnover has effectively taken place). Battery chargers are the largest single contributor to this total, contributing 5,290 GWh in 2024, and these standards are growing rapidly in impact as more products come to use rechargeable battery technology. In fact, CEC staff anticipates a doubling of their impact by 2030.

The Appliance Efficiency Program also reduces gas and water used in equipment, with similarly impressive results. CEC staff estimate annual savings of 127 billion gallons of water resulting from standards adopted in 2015, another 152 billion gallons of annual savings from standards adopted in 2019, and project another 76 billion gallons in annual savings through standards planned for 2025 (after full stock turnover). Additionally, staff estimate annual savings of 1.9 billion therms in direct provision of gas by utilities.

Building Energy Efficiency Standards

The CEC updates the statewide Building Energy Efficiency Standards every three years to improve the energy efficiency of California's buildings, reduce operational costs, lower greenhouse gas emissions, and enhance the resilience of buildings to extreme weather linked to climate change. Recently, the CEC adopted the 2025 code updates, applicable to newly constructed residential and commercial buildings, renovations, and certain other existing buildings, which will advance California's economic, clean energy, climate, and public health goals. This new code is expected to save Californians $4.8 billion in energy costs over its lifetime of 30 years, make homes and buildings more climate-resilient, and reduce

[8] Figures projected to 2024 consistent with published reports, as follows: for lighting, reports published in dockets 16-AAER-04, 15-AAER-06, 17-AAER-07 and 19-AAER-04; for battery chargers, 11-AAER-2 and 18-AAER-02; for computers, computer monitors and televisions, 14-AAER-02 and 16-AAER-02; for portable electric spas, 12-AAER-02G, 15-AAER-02, 18-AAER-01, 18-AAER-02, and 20-AAER-04. All documents available at: https://www.energy.ca.gov/proceedings/dockets/california-energy-commission-dockets

greenhouse gas emissions by about 4 million metric tons—equivalent to the annual energy consumption of over half a million homes.[9]

Finding

The CEC found California's efficiency programs are highly cost-effective to ratepayers and have long been key to achieving affordable bills and meeting the state's energy and environmental goals. The Statewide Codes & Standards Program is funded by electric and gas ratepayers at $56.7 million per year as of 2024, whereas efficiency standards for buildings and appliances are saving billions annually, have saved Californians over $200 billion since inception in the late 1970s, and are set to reach $300 billion in total cumulative economic value to the state by 2030. The CEC recommends retaining the ratepayer supported programs that directly contribute to these foundational efforts, in particular the CPUC-overseen and IOU-managed Statewide Codes & Standards Program. However, the Legislature should consider if the costs of this foundational program should be borne more broadly by electric and gas ratepayers across all of California, given the statewide customer benefits these programs provide.

Without these programs, California's energy efficiency standards for buildings and appliances would be significantly diminished. For instance, 25 highly technical reports were developed to demonstrate the cost-effectiveness and technical feasibility of the updates adopted in the 2025 Building Energy Efficiency Standards; the Statewide Codes & Standards Program prepared and published 19 of these reports. Without the substantial contributions of the Statewide Codes & Standards Program — which includes the three major investor-owned utilities (IOUs), along with support from the LADWP and the SMUD — the statewide impact of the 2025 code updates would have been greatly reduced. This program serves as a cornerstone for advancing energy efficiency standards across the state.

California Schools Healthy Air, Plumbing, and Efficiency (CalSHAPE) Program

Program Background and Objectives

The California Schools Healthy Air, Plumbing, and Efficiency (CalSHAPE) Program was established by Assembly Bill 841 in September 2020 as an urgent energy efficiency measure during the COVID-19 pandemic to help schools improve air quality and reduce energy use while meeting current classroom ventilation requirements, and to assist local educational agencies (LEA) in making much needed upgrades to school infrastructure. Pursuant to Public Utilities Code (PUC) Section 1615(e)(1), the CEC must return all unspent CalSHAPE Program funds to the electric and gas IOU ratepayers by December 1, 2026. The CEC set an encumbrance deadline of October 31, 2024, for new grant agreements to ensure funds are reverted by this date.

CalSHAPE includes two grant programs: the Ventilation Program and the Plumbing Program. The Ventilation Program provides funding for LEAs to assess, maintain, repair, and replace ventilation systems in schools. As required by PUC Section 1631, the Plumbing Program provides funding for LEAs and state agencies to replace aging and water-inefficient plumbing fixtures and appliances with water-conserving plumbing fixtures and appliances. The CalSHAPE Program also creates work opportunities for a skilled and trained workforce and prioritized awards to schools in underserved communities, consistent with the goals of the program.

[9] Estimated utilizing U.S. Environmental Protection Agency Greenhouse Gas Equivalencies Calculator. https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator-calculations-and-references#houseenergy

The CalSHAPE Program is funded by all electric and gas IOU ratepayers with funding collected in calendar years 2021, 2022, and 2023. Public Utilities Code (PUC) Section 1615 (a)(1)(A) required each IOU to allocate a portion of their energy efficiency budgets plus any unspent and uncommitted energy efficiency funds carried over from the previous calendar year to the CalSHAPE Program. This resulted in additional funding being collected from all electric and gas IOU ratepayers. The IOUs transferred $993 million between 2021 and 2023. PUC Section 1616 required 75 percent of the program funding be directed to the Ventilation Program and 25 percent to the Plumbing Program. No additional funding is being collected by the IOUs for the CalSHAPE Program, and the program must return any unused funds to all electric and gas ratepayers by December 1, 2026.

PUC Section 1617 automatically deems these programs cost-effective without ex-post evaluation of the expended funding and specifies that the programs shall not be considered by the CPUC when calculating the overall cost-effectiveness of the IOUs' energy efficiency portfolios. This is uncommon. Standard best practice would be for energy efficiency programs that encourage the deployment of complex energy efficiency projects with varying degrees of energy and costs savings to be evaluated to measure their efficacy and determine the value of these ratepayer-funded investments. The Legislature should consider requiring that these types of programs undergo a robust cost-effectiveness evaluation to ensure the benefits delivered are sufficient to merit the ratepayer contributions that make these programs possible.

The CalSHAPE Program was also allocated $20 million from the Greenhouse Gas Reduction Fund in the Budget Act of 2022, which includes $19 million for grants and $1 million for program administration. The Budget Act of 2022 (Section 2 3360-001-3228 and 3360-101-3228) states that funds shall be used only for HVAC system replacement in the Ventilation Program, as described in PUC Division 1, Part 1, Chapter 8.7 (commencing with Section 1600).

The CalSHAPE Program accepted applications from fall 2021 through summer 2024. As of November 1, 2024, the CalSHAPE Program encumbered $786.8 million, or 78 percent, of the total funding. PUC Section 1615 (d) states that the CEC can use up to $5 million per year for program administration, and since the program runs for six years (January 2021 to December 2026), the CEC has reserved $30 million for administration costs. The CEC has expended $7.5 million on administration through Fiscal Year (FY) 2023-2024 and expects to expend an additional $5 million in FY 2024-2025. The CalSHAPE Program currently has $196.1 million in remaining (unencumbered) funds, which, per statute, will be returned to all electric and gas IOU ratepayers with any additional unspent funds by December 1, 2026.

Program Funding and Impact

For the Ventilation Program, $654 million of $741 million in available funding has been encumbered, and the remaining or unallocated balance is $87 million. Encumbered funding has enabled 625 LEAs to assess, maintain, repair, and replace HVAC systems at 4,676 schools, with 32,035 MTCO2e in forecasted greenhouse gas emission reductions.

For the Plumbing Program, $131.9 million of $241 million in available funding has been encumbered and the remaining or unallocated balance is $109.1 million. Encumbered funding has enabled 228 LEAs to replace aging and water inefficient plumbing fixtures and appliances at 1,489 schools, with an estimated 2.5 billion gallons in water savings with the replacement of 58,974 plumbing fixtures and appliances.

Regarding the program administration, $7.5 million of $30 million in allocated administrative costs have been expended. Administrative tasks include program oversight, application and report review, issuing of checks, technical contract implementation, and completion of program status reports. CEC estimates in order to effectively complete the program, administrative funds would be needed for a minimum of 2 years after final project completion, which is estimated to be December 1, 2028.

CEC Oversight and Quality Control

The Ventilation Program has detailed project requirements, outlined in PUC Section 1620-1627, which include the use of qualified technicians and a skilled and trained workforce to assess and maintain HVAC systems, make minor adjustments and repairs as needed, and produce an HVAC Assessment Report. The HVAC Assessment Report includes information on the condition of the HVAC systems and the filtration and ventilation provided to each classroom as found during the assessment. The CEC has a robust compliance process for Ventilation Program projects, which includes conducting field audits and performing a thorough review of the HVAC Assessment Reports. This oversight is needed to provide quality control of the projects and ensure that grant funds are being used appropriately. However, the detailed oversight may result in some LEAs having to resubmit the HVAC Assessment Report or require the contractor to redo portions of the project if issues are found and may extend the lifetime of the projects.

Finding

The CalSHAPE program was authorized in 2020 as a COVID-19 urgency measure to re-open schools and improve indoor air quality. Since program implementation, other non-ratepayer funding sources have become available, including the $10 billion Proposition 2 of 2024 and local bond measures. Given the availability of non-ratepayer funding, the Governor and Legislature may consider refunding $196.1 million of unencumbered CalSHAPE funds to electric and gas IOU ratepayers before December 31, 2026.

California Solar Equipment Lists (SELs) Program

Program Background and Objectives

Senate Bill 1 (2006) directed the CEC to establish criteria and standards for solar incentive programs under the California Solar Initiative (CSI). In response, the CEC established the Solar Equipment Lists (SELs), which set rating standards for equipment components and systems to assure reasonable performance and facilitate safe and reliable interconnection with California's electricity grid and distribution systems. Over time, while the CSI programs sunset, the broader industry came to rely on the SELs as a primary source for determining equipment compliance with standards required for local government permitting and grid interconnection of DERs across the state. The SELs include thousands of unique equipment models, including solar modules, meters, smart inverters, batteries, energy storage systems, and power control systems that have been validated as meeting national standards. The SELs facilitate substantial improvements in processing of DER interconnection application requests and local government permitting of DERs.

Program Funding and Impact

The Solar Equipment List is currently funded with approximately $1.3 million annually. The CEC continuously receives requests from equipment manufacturers to have the manufacturer's products added to the relevant SEL. The CEC updates the SELs three times each month. In 2024, approximately 8,000 unique models of equipment were validated to meet all requirements and were added to the SELs.

Finding

The CEC's SELs provide a standardized, streamlined and cost-effective process for equipment identification that is relied upon by the equipment manufacturers, IOUs, POUs, providers of permitting

platforms, local governments, certain CPUC and CEC programs, NREL and other entities across the country. In Spring 2023, the CEC released a public RFI to better assess the use cases and benefits of its SELs. California electric utilities' responses to the RFI indicated that by leveraging SELs for interconnection application review, the utilities achieve tremendous cost savings, due to reduced review times and labor hours, exceeding the cost to administer the SELs program by several factors. Information from the SELs is utilized in software platforms that assist local governments in streamlining the permitting processes for DERs. Without information from the SELs, challenges to interconnection and permitting of DERs would increase, potentially slowing down deployment significantly and adversely impacting the growth of the DER industry. However, the IOUs maintain their own SELs list as required by CPUC's Rule 21. Therefore, the CEC recommends identifying an alternate funding source.

Electric Program Investment Charge (EPIC)

Program Background and Objectives

In 2011, the CPUC established the Electric Program Investment Charge (EPIC), a ratepayer funded research, development, and deployment program, and authorized the CEC as one of four administrators alongside California's three largest IOUs, whose ratepayers fund the program – Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric, and Southern California Edison (SCE). The CEC administers 80 percent of the program's total funds, investing in clean energy technologies and approaches to help benefit California IOU ratepayers. All demonstration projects are sited in electric IOU service territories because they are funded by electric IOU ratepayers. The CEC funds projects in all three investment areas of the EPIC program: applied research and development, technology demonstration and deployment, and market facilitation.

The EPIC program is the leading state energy research and development program in the United States. The intent of EPIC is to deliver a range of important benefits to IOU ratepayers including improving energy affordability, incubating lower-cost energy technologies, and reducing the disproportionate burdens of climate change and energy-related emissions on disadvantaged and low-income communities.

Program Funding

EPIC is funded by a ratepayer surcharge on bills of customers of the state's electric IOUs, providing approximately $148 million per year for the CEC's implementation of EPIC – equivalent to approximately 1 cent per person per day. With that contribution, EPIC has provided a stable, sustained source of public investment in energy innovation – critical to supporting the pipeline of technology development from early stages through commercialization and deployment in the state. EPIC endeavors to drive innovation and advances science and technology in energy efficiency, load flexibility, renewable energy and advanced clean generation, transportation, grid transmission and distribution, and energy-related environmental protection, among other areas important to California's electricity system and ratepayers.

In August 2020, the CPUC renewed EPIC program funding for an additional 10 years, through December 31, 2030.[10] All grant funding under the current 2021-2025 EPIC Investment Plan (EPIC 4) is either encumbered or designated for use according to CPUC Decision 22-06-004,[11] Decision 21-07-006,[12] and

[10] CPUC Decision 20-08-042 (2020). 346225760.PDF

[11] CPUC Decision 22-06-004 (2022). 482684526.PDF

[12] CPUC Decision 21-07-006 (2021). 394265545.PDF

related decisions,[13] and will be used accordingly. Future funding under the 2026-2030 EPIC Investment Plan (EPIC 5) will be designated for use according to the upcoming CPUC decision under the EPIC Proceeding (anticipated in 2025) and deployed accordingly.

Program Impact Assessment

The CEC integrates the assessment of benefits into each stage of the funding life cycle. Each R&D topic included in the investment plan includes a summary of potential impacts and expected outcomes if successful, as well as high-level metrics and performance indicators. These impacts and metrics are refined through competitive solicitations and assessed through scoring criteria on impacts and benefits for ratepayers. During project implementation, CEC staff collects data via recipient questionnaires to measure and verify performance. The final report for each project documents technical performance, outreach, technology transfer, and lessons learned. After project completion, CEC staff continues to collect data to assess ratepayer benefits, including through annual surveys and online resources, including Pitchbook and Google Scholar. Because the full impact of clean energy innovations can take several decades, the CEC assesses both achieved and projected benefits.

[13] CPUC EPIC decisions available at: Energy Research Development and Deployment

Berkeley Law | Center for Law, Energy, & the Environment

IMPROVING TRANSMISSION FINANCING *in California*

Alternative Models and Policy Strategies to Increase Affordability

OCTOBER 2024

Policy Report

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The Center for Law, Energy & the Environment (CLEE) channels the expertise and creativity of the Berkeley Law community into pragmatic policy solutions to environmental and energy challenges. CLEE works with government, business, and the nonprofit sector to help solve urgent problems requiring innovative, often interdisciplinary approaches. Drawing on the combined expertise of faculty, staff, and students across the University of California, Berkeley, CLEE strives to translate empirical findings into smart public policy solutions to better environmental and energy governance systems.

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OCTOBER 2024 | POLICY REPORT

IMPROVING TRANSMISSION FINANCING IN CALIFORNIA

Alternative Models and Policy Strategies to Increase Affordability

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I. THE NEED FOR AFFORDABLE TRANSMISSION FINANCING

California will need a significant build-out of new high-voltage transmission lines to meet state goals for renewable energy deployment and a decarbonized grid by 2045, which requires a quadrupling of its current in-state solar and wind capacity. Transmission will be needed to deliver offshore wind power from the North and Central Coast, large-scale solar from the Central Valley, and geothermal from the Salton Sea, among other regions.

But if this new infrastructure is paid for solely through electricity rates, it could increase those rates significantly and potentially undermine the economy-wide transition to clean energy. Rates have already increased roughly 50% over the past three years for investor-owned utility customers in the state, placing political and economic pressure on state leaders to build these lines with as little burden on ratepayers as possible.[1]

In response, UC Berkeley Law's Center for Law, Energy and the Environment (CLEE) presents in this summary policy report a variety of strategies available to policymakers for financing new high-voltage power transmission in California, with the dual goals of 1) reducing costs to ratepayers and 2) accelerating transmission development. With support from Net-Zero California (NZC) and Clean Air Task Force (CATF), CLEE developed these strategies based on a literature review, legal research, multiple interviews, and a convening of transmission experts and stakeholders from government, industry and nonprofit organizations, along with examples of alternative approaches used in other states. In addition, a separate financial analysis by DH Infrastructure and EE-Analysis (see Appendix 2) quantified the potential ratepayer savings of public transmission financing and development models compared to a business-as-usual investor-owned utility scenario, which further informed this report. A more detailed memo, including selected financing options and their specific challenges, can be found in Appendix 1 on page 16.

OVERVIEW: STATUS QUO FINANCING IN CALIFORNIA

Transmission financing strategies employed in California currently include:

- **Investor-owned utility financed and ratepayer funded:** When investor-owned utilities (IOUs) build transmission lines, they pass the cost to consumers through Transmission Access Charges on ratepayers' electricity bills. In California, these utilities include Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E), which recover the costs, along with a guaranteed rate of return, from ratepayers.[2]

- **Private developer funding:** Some transmission projects are funded entirely by private sources, such as when energy project developers finance the transmission they need in conjunction with their projects. These private transmission line owners then receive revenue through the same California Independent System Operator (CAISO) Transmission Access Charge that utilities use.

NOVEL FINANCING STRATEGIES FOR CALIFORNIA

As this report details below, the state could expand or adopt innovative transmission financing strategies to reduce costs, such as:

- **Public co-development:** Public-private partnerships (PPP, or "P3" as used in this report) arrangements, in which both public entities and private developers participate, can be structured in different ways, including:

    - A lease-type P3, in which a government-owned holding company or special purpose vehicle provides financing for the transmission asset but hires a private company to operate the assets.
    - A concession-type P3, in which a government-owned asset is designed, built, operated and financed by a private company over the life of the asset, and then ultimately returned to government at the end of the concession agreement.

- **Public ownership:** Some states have established public agencies that can finance and own transmission lines, including through bonding and other financing authority. These agencies can also participate in public-private partnerships.

As DH Infrastructure details (see Appendix 2), the use of these types of public sector financing, along with targeted institutional changes, can reduce the cost of California's needed transmission build-out by tens of billions of dollars over the next two decades.

KEY FINDINGS AND IMPLEMENTATION CONSIDERATIONS

CLEE convened expert participants to help identify which of these novel financing strategies would be most feasible for California to adopt. Participants included representatives from the California Public Utilities Commission (PUC), the California Independent System Operator, California Natural Resources Agency, non-governmental organizations (NGOs), ratepayer advocacy, the state legislature, and clean energy industry groups, among others.

The convening discussion, and follow-up research and outreach, yielded a number of key findings:

1. **Some form of public-private partnership could provide significant benefits to deploying lower-cost transmission, due to cost-savings potential and the ability to leverage existing institutions and structures**. Exactly which form such a partnership should take is not certain without more detailed evaluation. As noted above, a number of possibilities and considerations exist, and the form of P3 may depend on the particular transmission line, developers, and other project-specific circumstances. However, the basic components of public investment would remain consistent, such as bonding authority and a general P3 structure. Variation may exist in terms of which entity issues the bonds and which sub-elements of a P3 structure meet the needs of the projects and the State.

2. **An example of P3-type financing is the "Citizens-Morongo Model,"** named after the two companies involved, Citizens Energy (a non-profit that shares proceeds with communities) and Morongo Transmission (owned by the Morongo Band of Mission Indians). These groups partnered with utilities SDG&E and SCE to build transmission. The utilities agreed to sell a 30-year leasehold interest to Citizens-Morongo, making Citizens-Morongo a participating owner of transmission assets that the utilities continue to operate. The Federal Energy Regulatory Commission (FERC) approved the ability of Citizens-Morongo to finance with 100% debt rather than a combination of debt and equity, given that these entities do not otherwise have easy access to equity. The Federal Energy Regulatory Commission also approved a fixed, 30-year transmission rate, and Citizens-Morongo's ability to share proceeds with the community helps engender crucial local stakeholder support. Expanding this Citizens-Morongo option to apply more broadly across California will require better understanding of any possible tradeoffs, cost savings, limitations, risks, and streamlining benefits.

3. **Policymakers may endow an existing entity with transmission financing and related P3 authorities, rather than create a new entity.** Currently, California has multiple entities with at least some role in transmission, including the California Independent System Operator, California Public Utilities Commission, California Energy Commission (CEC), California Infrastructure and Economic Development Bank (IBank), and Department of Water Resources. Creating a wholly new public entity, or endowing an existing agency, in California to finance and oversee transmission would entail administrative and procedural changes, which may be more significant for a new public entity.

Any change in the status quo for transmission financing in California will face a number of implementation challenges. Notably, the following considerations are relevant regardless of the structure or entity that holds authority over transmission financing and oversight:

- **Impact on investor-owned utilities.** Under the current system, as noted, these utilities receive a guaranteed rate of return on investment from transmission construction. This return represents a key source of their revenue.

If a different approach to financing precludes or reduces that rate of return, policymakers will need to evaluate the impact on the financial viability of the investor-owned utilities.

- **Public-private partnership concerns in the California Legislature.** Legislators may have concerns about authorizing public-private partnership approaches, in part due to a perception that they require the government to assume private-sector risk while lacking private-sector expertise. However, legislators widely recognize the need to reduce both the cost of transmission and the implementation time. Public-private partnerships could potentially offer some relief for both, and these partnerships already exist in many forms.

- **Lack of clarity on which public entity would lead.** If a public or governmental entity is to have a significant role in transmission financing, policymakers will need to determine whether to create a new entity or if they should provide additional authority to an existing agency or department. In either case, legislators will need to determine the extent of the authorization and responsibilities.

- **Relationship of any new state authority to existing authority.** Agency review and control over transmission siting and related issues is complex and time-consuming, with significant roles for the California Independent System Operator, California Public Utilities Commission, California Energy Commission, and other entities. The role of a new governmental entity, or an existing entity with additional authority, will need to be integrated into the current framework in a manner ensuring clear authority, while not exacerbating current financial and governance challenges.

- **Asset ownership.** If the state is a key part of financing transmission, it will need to determine if it should own some part of the asset. Ownership could be determined through negotiation at various energy agencies, or directly among interested parties, for each transmission line or through legislation, which can also serve to limit public liability for any operational risks.

- **Liability ownership.** With ownership, the issue of liability becomes central, particularly given the role of transmission lines in catastrophic wildfires. Liability could be determined through negotiation or legislation, or a combination of the two. Liability can also be determined differently for specific harms, such as liability for fire versus for injuries from downed power lines.

- **Inverse condemnation**. If a governmental entity has an ownership interest in transmission lines and some form of liability for harm from the lines, policymakers could consider reforms to limit the scope or applicability of inverse condemnation claims for damage to property caused by fires resulting from the lines, as the IOUs currently face.

- **Possible opposition from organized labor.** Public utility unions are often closely tied to the IOUs, and different models of transmission ownership or financing could make the IOUs' financial position, and associated union jobs and pay, more uncertain. Legislative leaders would need to conduct ongoing

engagement and discussion with these unions to ensure their participation and recognition in new models.

- **Availability of engineers.** Most engineers are employed by private developers. Public entities could face challenges hiring engineers with the requisite experience and expertise, which may be a factor in the role of any government entity in overseeing transmission lines and systems.

- **Eminent domain authority.** Eminent domain authority is essential for building new transmission lines, so which entities have that authority, particularly in the P3 context, is a crucial element in determining agency authority and responsibility.

RECOMMENDATIONS

Based on the convening discussion and CLEE research, this report offers the following potential solutions to the identified challenges:

1. **Focus on demonstrating alternative financing arrangements for four to six key transmission regions** and lines in the California Independent System Operator's 20-year transmission outlook that most stakeholders agree are essential. Commonalities and differences among proposed locations, developer options, and other considerations for transmission lines will likely impact potential approaches to financing (see "next steps" below). For example, the potential large-scale solar development in the Westlands Water District area of Fresno County (approximately 110,000 acres with 15-20 gigawatts of solar) may be an ideal project to consider and evaluate, given the need for new transmission as part of the large-scale build-out and the current work to move forward with the project (see "next steps" below).

2. **Engage the Governor's Office to designate a coordinator for high priority lines and support a process to speed implementation and financing.** This approach worked well when Governor Schwarzenegger designated a coordinator for large-scale solar projects, making solar a statewide priority. The coordinator convened meetings with federal, state, and local government officials as well as stakeholders, coordinated state agency participation, and mediated disputes.

3. **Establish a liability backstop for the entity or entities owning new transmission.** As precedent, the California Legislature has established a liability backstop based on actions to reduce fire risk for the IOUs for the existing transmission system.

4. **Minimize risk through insurance, contract, indemnity, and first loss protection, and other mechanisms**, subject to negotiation and legislation, as New Mexico has done through its Renewable Transmission Authority (RETA), discussed in Appendix 1 on page 16.

5. **Modify California Independent System Operator rules to allow for an additional competitive bid process**, opening more transmission to

private development and private funding. Under existing California Independent System Operator rules, some (albeit few) potential transmission lines are already eligible for competitive bids by private developers. The operator has sufficient existing authority to expand the lines eligible for competitive bidding.

6. **Explore credit enhancements from the state or federal government.** Credit enhancements have encouraged investment and reduced borrowing costs in multiple contexts. Examples could include the establishment of a state loan loss reserve, loan guarantee, or loan loss insurance to improve the creditworthiness of private transmission developers seeking financing. The U.S. Department of Energy's Loan Programs Office can also issue credit enhancements to state-administered clean energy programs.

7. **Assess opportunities to finance some transmission lines through general obligation (GO) and revenue bonds**, the former funded by taxpayers through the budget process to build needed infrastructure while reducing transmission costs included on ratepayer bills. However, a GO bond approach should only be implemented after serious consideration because relying on budget and legislative processes for funding can be politically fraught. Legislators could also explore issuing revenue bonds, which do not require voter approval and are used to finance income-generating projects built with the proceeds of the bonds.

8. **Explore options for applying existing federal models to California.** Specifically, convening participants noted that the Western Area Power Administration (WAPA) could potentially finance transmission, or a state version of WAPA could be established (potentially within the Department of Water Resources) to finance transmission and provide electricity at a wholesale rate to municipal utility customers and community choice aggregators. This model is somewhat novel and warrants further evaluation.

CONCLUSION:

Reducing the cost of building needed transmission lines will only become more critical in the coming years, as electricity rates increase due to the strain of climate impacts on the grid and the large build-out required to electrify most energy needs. California policymakers can play a leading role in addressing this issue by exploring alternative options for transmission, potentially by starting with key, high-priority lines. Through an inclusive process, decisionmakers have an opportunity to meet the needs of various stakeholders while accelerating the urgent construction of these lines. Ongoing research, convening, and implementation efforts can lay down a foundation for future work in California, serving as a model for other states and regions interested in pursuing alternative financing.



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1 *See* "2024 Q2 Electric Rates Report," California Public Advocates Office. Available at: https://www.publicadvocates.cpuc.ca.gov/press-room/reports-and-analyses/2024-q2-electric-rates-report (accessed October 18, 2024).

2 Nationwide, electric utilities averaged a 9.71% rate of return in rate cases in the first quarter of 2023, up from an average of 9.54% in 2022. Dan Lowrey, "Electric Beats Gas in Exceeding Authorized Equity Returns over Past 15 Years," S&P Global, May 25, 2023. Available at: https://www.spglobal.com/marketintelligence/en/news-insights/research/electric-beats-gas-in-exceeding-authorized-equity-returns-over-past-15-years#:~:text=The%20average%20ROE%20authorized%20for,observed%20in%20full%20year%202022. (accessed September 9, 2024).



II. APPENDIX I: APPROACHES TO TRANSMISSION FINANCING

This appendix explores options to reduce the cost and time needed for expansion of the electric transmission system within the state of California, as well as the hurdles and challenges to the various options.

The report includes (1) information on the transmission development and financing process in California, (2) a survey and evaluation of financial instruments that may be used to finance transmission, and (3) an initial assessment of potential policy options for California, including options for public financing and public-private partnerships. Finally, the report sets out some initial legal and administrative considerations for various policy solutions.

The cost of transmission in California, currently borne primarily by utility ratepayers, is expected to increase by $45 to $60 billion over the next two decades, potentially spiking California's already high energy rates.[3] Key strategies for reducing this cost include public financing of transmission, public-private partnerships, green banks, credit enhancements (such as loan guarantees), and adoption of technologies that expand the capacity of existing transmission (such as reconductoring). In addition, moving some transmission costs from ratepayers to taxpayers could reduce the burden on electricity rates.

Each strategy has risks and benefits, so some mix of approaches may provide the most value. For example, a new government transmission agency may be best suited to finance major transmission lines that decision-makers have determined to be essential for California's energy grid and renewables deployment, while some form or combination of public and private financing and loan guarantee through the California Infrastructure and Economic Development Bank (IBank) or other state institution may make sense for a subset of transmission needs. This appendix details some of the key risks and benefits, including cost savings, cost to state agencies, need for ongoing expertise, relation of a new agency to existing agencies, state budget uncertainties, risks associated with loan guarantees, impact of loss of revenue for investor-owned utilities, and liability around public ownership of transmission lines, among other considerations.

In light of the cost burden to ratepayers of the current approach to transmission, reforms are essential, and forms of public finance and direct public participation, including some role for a state transmission agency, provide possible benefits and challenges worth exploring.

CALIFORNIA NEEDS MORE TRANSMISSION CAPACITY

In 2022, the California Independent System Operator (CAISO) approved 23 new transmission projects, with an estimated cost of approximately $3 billion.[4] In its 2022-2023 Transmission Plan, the California Independent System Operator identified a further need for $7.53 billion in transmission projects.[5] This figure was based on studies indicating that California will need to add 40 gigawatts to the grid within a decade and 70 gigawatts by 2032 in order to maximize economy-wide electrification, particularly in the transportation and building industries.[6] Looking even further into the future, the California Independent System Operator's 20-year Transmission Outlook estimated that approximately $45 to $60 billion in investment over the next two decades will be necessary for California to reach its greenhouse gas emission reduction targets.[7]

But because transmission development is capital-intensive, access to capital remains a hurdle for would-be developers of transmission infrastructure in California. Under the current system, most transmission is financed by investor-owned utilities (IOUs) and paid for by utility ratepayers. Ratepayers also pay for a rate of return for the IOUs for each project, which can average close to 10%.[8] This rate creates a significant and increasingly unsustainable burden on ratepayers as more necessary transmission lines are constructed. As a result, policymakers should consider and evaluate other options to transmission financing, including public financing, to meet California's objectives.[9]

At the same time, the monetary value of new transmission is increasing because it will help relieve more grid congestion.[10] In 2022, estimated savings from transmission expansion reached a decadal high of $200 to $300 million per 1000 MW of transmission capacity (or $23 to $34 per MWh), varying by region.[11]

PUBLIC FINANCING COULD HELP MEET CALIFORNIA'S TRANSMISSION NEEDS AFFORDABLY

In a recent analysis, the Public Advocates Office of the California Public Utilities Commission (CPUC) estimated that California ratepayers could save up to $28 billion over the coming decades "if California's transmission infrastructure is financed with public investment as opposed to traditional utility-financing."[12] These savings to ratepayers from public financing result from public sector access to lower interest rates, replacing equity in project financing, and reducing taxes owed. The State of California has a better credit rating than do California's IOUs, which makes it easier for the State to raise capital compared to IOUs.[13] In addition, as noted above, IOUs receive a significant rate of return that adds substantial cost and creates an incentive for IOUs to pursue full build-out of transmission projects when alternatives such as reconductoring could be more appropriate. Financing through public bonds can also be tax free, yielding additional savings. Public financing would therefore relieve some of the burden on utility ratepayers. Finally, public financing combined with legislative reform focused on transmission lines determined to be essential to California's clean energy needs

could also streamline build-out, resulting in additional cost savings and accelerating uptake of renewables.

Given the potential benefits of public and public-private financing, this report explores its various pros and cons and implementation considerations, including the creation of wholly new state agencies, expanded authorities for existing agencies, and leveraging municipal and federal agencies that have the potential to finance transmission.

TRANSMISSION OVERVIEW: A LENGTHY, EXPENSIVE, AND COMPARTMENTALIZED PROCESS

This section briefly surveys the transmission development process as context for discussion of transmission financing. Transmission development requires that a project survive an extensive and burdensome regulatory process before federal and state agencies.

Developing Transmission in California

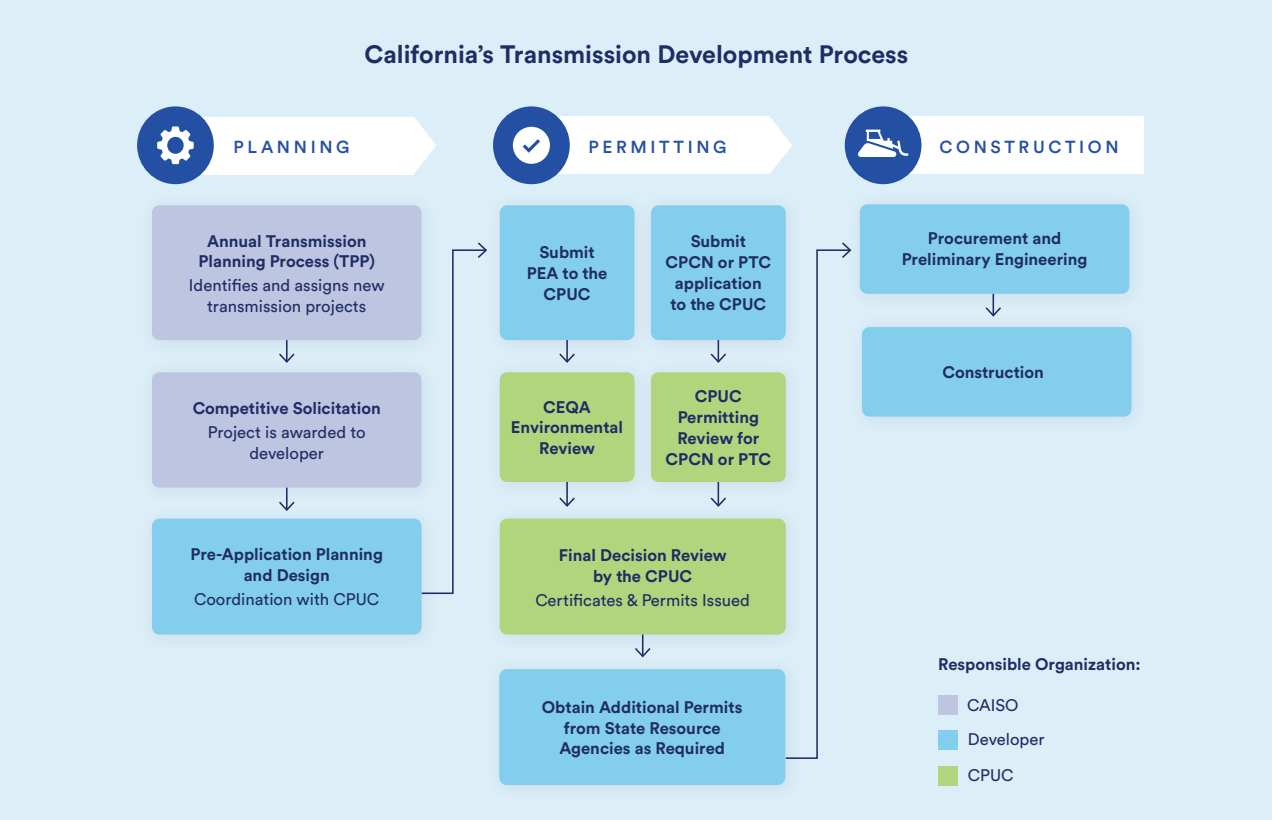


Figure 1: chart from the Clean Air Task Force (Transmission Development in California – What's the Slowdown [Jan 2023]) showing a simplified version of the transmission development process. This chart excludes the Federal Energy Regulatory Commission process for setting rates for interstate/high voltage transmission lines.

Transmission development in California is a lengthy, expensive, and historically "reactive and compartmentalized" process (see Figure 1).[14] It involves the participation of three primary parties: the transmission project developer, the California Public Utilities Commission, and the California Independent System Operator, plus the Federal Energy Regulatory Commission (FERC) when developing high-voltage interstate transmission lines.[15]

First, the California Independent System Operator performs its annual Transmission Planning Process (TPP) to determine which transmission projects are needed on the grid.[16] Through competitive solicitation, the operator awards a project to a particular developer.[17]

The developer coordinates with the California Public Utilities Commission on planning and design for its project before it officially submits its application.[18] Then the developer submits its application for a Certificate of Public Convenience and Necessity (CPCN) or for a Permit to Construct (PTC).[19] The developer also submits its Proponent's Environmental Assessment (PEA) to the California Public Utilities Commission.[20] After receiving the PEA, the commission performs environmental review pursuant to the California Environmental Quality Act (CEQA).[21]

Following its review of the developer's application and its environmental review under CEQA, the California Public Utilities Commission issues a final decision. If the commission decides to approve the project, it issues the relevant certificates and permits.[22] The developer obtains any other necessary permits from state natural resource agencies and then begins procurement, engineering, and construction.[23]

In addition to California state regulations, federal law also applies to transmission projects that implicate "the transmission of electric energy in interstate commerce," placing them within the reach of the Federal Power Act.[24] The Federal Energy Regulatory Commission (FERC) has jurisdiction "over all facilities for such transmission … of electric energy."[25] The Commission also has authority over the transmission revenue requirement, as the agency's jurisdiction covers the establishment of the transmission revenue requirement through the Transmission Access Charge. But the Commission does not have jurisdiction over facilities "only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter."[26] In other words, purely intrastate transmission projects that do not connect to the interstate grid are not subject to Federal Energy Regulatory Commission jurisdiction, but transmission projects that cross state lines or connect to the interstate grid are subject.[27]

Transmission Process Challenges

Beyond navigating the complex transmission permitting process, the transmission development process at both the federal and state levels encounters other legal and regulatory hurdles that can lengthen approval and development timelines and increase cost and risk for developers and ratepayers.

Federal Challenges

Where lines are subject to federal approvals, three primary obstacles can hinder transmission development. First, if lines travel between California and neighboring states, the siting and approval process for those interstate transmission lines is divided among various state and local jurisdictions, making it more difficult for developers to acquire all necessary approvals and increasing the likelihood that one jurisdiction will block transmission even if all the other jurisdictions support the project.[28] Second, the interconnection process is considered "speculative and opaque" because applicants are "unsure of the cost of interconnection until the [grid impact] studies are complete."[29] These studies and the energization process can create considerable uncertainty for and discourage developers. Third, where federal review is needed, lack of federal agency capacity to process permits can increase transmission development timelines.

California Challenges

As identified by the Clean Air Task Force in 2023, similar challenges for timely and cost-efficient transmission development exist for state-level approvals in California as well. Project dates "frequently stretch beyond completion dates anticipated by the California Independent System Operator."[30] Of thirteen projects reviewed in that publication, two were completed but delayed, two were canceled or put on hold by the California Independent System Operator, eight were delayed and incomplete, and one is incomplete but on schedule.[31] Moreover, between 2013 and 2017, estimated final costs of CAISO-approved projects were 33% higher on average than the original costs submitted to the California Public Utilities Commission for those projects.[32] In the California context, three key stages of the process that create most delays include preparation of the project application, California Public Utilities Commission environmental review, and federal agency review, when applicable.[33]

Recent agency coordination and legislation may help address delays and inefficiencies and drive down costs in the transmission development process. In December 2022, the California Independent System Operator, the California Public Utilities Commission, and the California Energy Commission (CEC) entered into a Memorandum of Understanding with the goal of better coordinating transmission and resource planning and implementation across the state.[34] For example, the California Independent System Operator committed that its transmission planning process would "consider and incorporate the scenarios and portfolios developed by the [California Public Utilities Commission] with input from the [California Energy Commission]," and the California Public Utilities Commission in turn agreed that its "siting/permitting process will then give substantial weight to project applications that are consistent with the [Independent System Operator's] final transmission plan."[35] Although it remains to be seen how the CAISO-CPUC-CEC Memorandum of Understanding will actually affect the transmission planning and development process over the medium- and long-term, better interagency coordination may help streamline the onerous approval and development process.

In October 2023, Governor Newsom signed Senate Bill 410 (Becker) to expedite interconnection.[36] The new law requires that the California Public Utilities Commission establish "reasonable average and maximum target energization time periods … and a procedure for customers to report energization delays to the PUC" by September 30, 2024.[37] SB 410 also mandates that the Commission require electrical corporations to

"take remedial actions necessary to achieve the [CPUC's] targets" and that "all reports … be publicly available[.]"[38] In light of recent supply chain bottlenecks that have slowed grid buildout, SB 410 mandates that the Commission formulate and follow "realistic standards" for supply chains and workforce development.[39]

TRANSMISSION FINANCE OVERVIEW

Who Finances Transmission Today

Transmission lines in the U.S. are primarily owned by private, for-profit companies including IOUs, although a minority are owned by public entities including the federal government, municipally-owned utilities, and member-owned electric cooperatives.[40] Most transmission development projects are taken on by incumbent transmission owners, rather than through competitive solicitation.[41] Accordingly, the development of transmission lines is primarily financed up-front by private parties, with IOUs.[42]

Utilities have accelerated their nationwide spending on transmission in recent years, a trend also reflected in California. The California Independent System Operator's 2022-2023 Transmission Plan proposed 45 new transmission projects for California at a combined estimated cost of $7.3 billion.[43] IOUs are already raising capital to build out new transmission lines. For example, in March 2024 PG&E filed a request to raise up to $1 billion for transmission "by leasing parts of its transmission assets to Citizens Energy, a non-profit power provider" with the California Public Utilities Commission.[44]

Public funding of transmission has begun to take on a more prominent role in recent years, particularly at the federal level. The U.S. Department of Energy (DOE) now offers a $2.5 billion Transmission Facilitation Program for revolving loans, a $2.3 billion Grid Resilience State and Tribal Formula Grant Program, and a $3.25 billion Western Area Power Administration Transmission Infrastructure Program.[45] On October 18, 2023, DOE also announced $3.5 billion in Grid Resilience and Innovation Partnerships Program investments, including substantial funds for transmission.[46]

Like the federal government, the state of California has also started to expand public financing options. For example, in 2020, the California Legislature created a $47 million Climate Catalyst Revolving Loan Fund within the California Infrastructure and Economic Development Bank (IBank).[47] The Climate Catalyst Revolving Loan Fund, discussed further below, is a "green bank" intended to support small-scale renewable energy projects and vested with authority to finance transmission.[48]

Transmission costs may also be reduced by innovative engineering approaches, which may inform policymakers' decisions regarding financing policies. For example, reconductoring, or replacing the conductors in existing transmission lines with newer conductors that carry more current, can be a cost-efficient way to increase overall transmission capacity. Reconductoring is eligible for federal loans from DOE under Section 1706 of the Inflation Reduction Act, which establishes the Energy Infrastructure Reinvestment loan program (discussed further below).[49] Notably, reconductoring has not yet been widely adopted nationwide as a strategy to increase transmission capacity, in part because of the dominance of the utilities in the transmission space. Utility companies "earn a guaranteed rate of return on the cost of capital investments such as trans-

mission projects, giving them no reason to strive to reduce those costs," according to the DOE.[50] And because the utilities "don't bear the costs of transmission line losses, which are passed on to customers," they have "little incentive to choose projects that emphasize those long-term savings."[51]

Studies show that reconductoring, along with other grid-enhancing technologies, has the ability to unlock capacity and facilitate interconnection without requiring the construction of entirely new transmission lines.[52] To address the challenge, Federal Energy Regulatory Commission Order 1920 now requires regional transmission planners to consider grid-enhancing technologies (GET) and other advanced grid technologies.[53] However, even if transmission planners pursue these options, the grid will require significant new transmission infrastructure to meet renewable energy deployment goals.

How Transmission is Financed Today

The following table summarizes current and potential instruments for financing transmission projects as well as their primary benefits and drawbacks.

MECHANISM	PROS	CONS
Ratepayer charges: When IOUs build transmission lines themselves, they pass the cost to consumers through Transmission Access Charges on ratepayers' electricity bills.	Currently enables utilities to play a leading role in transmission development with guaranteed profits that support utilities' continued financial viability as providers of electric service.	Results in high and increasing charges to ratepayers, and market distortions where ratepayers are disincentivized from investing in distribution grid assets that rely on less or no transmission.[54] For transmission projects outside of the CAISO planning process, utilities lack incentives to pursue lower-cost options like reconductoring because capital expenses are added to their rate base in ratemaking calculations. For transmission lines within the CAISO planning process, Transmission Access Charges create similar problems.
Private developer funding: Some transmission projects are funded entirely by private energy developers. As one example, a privately funded and operated TransWest wind project in Wyoming is building its own dedicated transmission line to California.	No direct taxpayer expense.	Limited capital and slow development of transmission. Could add high and increasing ratepayer costs.

MECHANISM	PROS	CONS
Public co-development: P3 arrangements, in which both public entities[55] and private developers participate, are an established means of transmission financing. For example, the New Mexico Renewable Energy Transmission Authority (RETA), discussed below, is a state agency that serves as "co-developer" with private development companies on a number of transmission lines.	Rapid deployment of investment. Some degree of public control over projects, depending on the government's ownership share.	Requires significant outlay of government funds.
Public loans: Public entities may issue direct loans to private transmission developers,[56] including by the federal government. For example, DOE is newly empowered to issue loans to transmission projects, through the Transmission Facility Financing program, under the Inflation Reduction Act. Likewise, DOE's Loan Programs Office has authority to issue loans to transmission projects.	Profit for issuing government agency.	Requires upfront outlay of government funds pending repayment.
Public bonds:[57] Public entities may issue bonds in order to raise capital for privately developed transmission projects.[58] For example, the New Mexico RETA issued $50 million in revenue bonds for transmission upgrades to the privately-operated High Lonesome Mesa wind farm.	Defers government and taxpayer expense across long timeframe.	Government and taxpayers must pay interest throughout the life of the bonds.
Credit enhancements: Private and public entities may issue[59] credit enhancements by providing a loan loss reserve, a loan guarantee, or loan loss insurance to improve the creditworthiness of private transmission developers seeking financing. DOE's Loan Programs Office can issue credit enhancements to state-administered clean energy programs "[t]hrough the State Energy Financing Institution (SEFI)-Supported category of the Title 17 Clean[60] Energy Financing Program."	Support private access to investment without directly involving public funds.	Outcomes are subject to private investment decisions outside government control.

MECHANISM	PROS	CONS
Federal funds	Substantial capital inde[61]pendent of state and private funds. Reconductoring projects are eligible for IRA Section 1706 loans.	Outcomes are subject to federal financing decisions outside state government control.

Summary of Financing Mechanisms for California Transmission

Ratepayer Charges

Ratepayers usually pay for transmission built by utilities, either through Transmission Access Charges (TAC) for projects within the California Independent System Operator jurisdiction or through regulator-approved rates for projects outside the operator's jurisdiction. A TAC is "a two-part rate for each megawatt hour of internal load and exports and is used to recover transmission revenue requirements."[62] Notably, "transmission operations and maintenance (O&M) costs account for almost 10 times more cost impact on ratepayers than the upfront costs of transmission infrastructure[.]"[63] These operations and management costs are assessed to ratepayers "for 50 years, the typical lifetime of transmission investments."[64]

In assessing TACs, the utilities do not just recoup their costs: they also turn a profit. Transmission is a capital expense, and the utility earns profits on these expenditures over a long period of time as the related asset depreciates.[65] For transmission lines not approved by the California Independent System Operator — the majority of transmission lines built in California — the capital cost of approved transmission construction is simply added to the utility's rate base for purposes of ratemaking before the California Public Utilities Commission.[66] As public utilities, IOUs earn a guaranteed rate of return on these expenses.

Ratepayer and distributed generation advocates have also criticized ratepayer charges, as currently structured, for creating market distortions that disincentivize local clean energy development.[67] Californians are charged for the transmission system even if they rely exclusively on locally generated electricity that may not require this infrastructure, therefore creating a potential disincentive to invest in the distribution grid.[68]

Bonds

Instead of passing costs directly to ratepayers, one particularly attractive option is to finance transmission by bonds issued by a government agency. These bonds can take two forms: general obligation (GO) bonds or revenue bonds.

GO bonds are paid out of the state general fund and are guaranteed by the full faith and credit of the state.[69] GO bonds must be approved by a majority of the electorate voting at a general election or direct primary.[70] By contrast, revenue bonds are used "to finance an income-generating project, such as water projects, higher education facilities or other public facilities built with the proceeds of the revenue bonds."[71] Income generated by the underlying project pays the principal and interest on its

related revenue bonds.[72] Unlike GO bonds, revenue bonds do not require voter approval, and the state's full faith and credit and taxing power are not pledged towards the repayment of revenue bonds.[73]

A lease revenue bond is a subtype of revenue bond where the "revenue stream paying the debt service on the bond is created from lease payments made by the occupying department to the governmental financing entity which constructs the facility or causes it to be constructed."[74] Regardless of whether the state agency in question issues revenue bonds or lease revenue bonds, it would not need a vote of the electorate to do so.[75] However, from the point of view of an investor, GO bonds have historically been considered "more secure" compared to revenue bonds "because they are backed by the full faith and credit" of the government.[76]

Additionally, the bonds issued by a state authority to support transmission projects may be classified as "green bonds." Green bonds can be unique from other governmental infrastructure bonds in that "(a) they finance projects that reduce/mitigate environmental impacts; (b) offer sufficient, if not robust, project detail in the Official Statement; and (c) ideally, offer an annual disclosure on the funded project's environmental impacts."

As compared to rate-based transmission funding, bonds have advantages and disadvantages. Historically, bonds have been used by government entities to finance large, capital-intensive infrastructure projects for two primary reasons: (1) the total sum is difficult to raise at once and (2) the paid-for project will provide benefits over a period of years, so policymakers consider it fair to make future generations of taxpayers pay their share.[77] Additionally, most state bonds are tax-exempt, meaning that bondholders do not have to pay federal and/or state taxes on the interest they earn.[78]

For energy projects specifically, bonds are often selected as a financing option "because they are familiar, offer low borrowing costs, and have longer terms."[79] Bonds offer "security (e.g., assurance repayment will occur)[.]"[80] If bonds are tax-exempt, their tax-exempt status "often translates to lower borrowing costs compared to alternative financing options."[81] In the transmission context, it may be easier for government agencies to issue bonds than to directly loan or appropriate the full sum it seeks to use to finance a transmission project.

Additionally, the long-term nature of transmission investments is consistent with common justifications for bond financing. Transmission projects are likely to be durable in the long-term, since they can last up to 100 years if properly maintained. This longevity is consistent with the idea that future generations of taxpayers will benefit from, and therefore should contribute to paying for, bonds.[82]

Because bond issuances involve relatively fixed transaction costs (ranging from 1-3% of bond proceeds depending on the size of the issuance), bonds are more cost-efficient "when used for larger dollar amount projects that can achieve economies of scale."[83] Individual transmission projects may be sufficiently large to benefit from relatively low transaction costs of bonding.[84] Or a "pooled" bond issuance comprising multiple issuances for multiple projects would "reduce the transaction cost per dollar of … renewable energy work financed[.]"[85]

When comparing state bonds to state loans, the state could directly loan funds to transmission developers rather than first issuing bonds to raise capital. This approach could be preferable because the government must pay interest on bond financing, but it does not have to pay interest on appropriations.[86]

Ratepayer Perspective: Rates v. Bonds

An important consideration for policymakers is the relative cost of ratepayer-funded transmission as compared to taxpayer-funded transmission to low-income Californians.

Electricity rates are subsidized for qualifying low-income California ratepayers. Under the California Alternative Rates for Energy (CARE) program, low-income ratepayers are entitled to a 30-35% discount on electric bills.[87] In order to qualify, ratepayers must have household incomes below certain thresholds or be enrolled in certain public assistance programs like Medical or SNAP.[88] In light of potential equity concerns, the relative burden of ratepayer financing versus bond financing to low-income Californians will likely be an important topic for future research and a key consideration for policymakers choosing between financing mechanisms. This issue is particularly important given that electricity prices rose 5% over the last year, faster than inflation and the price of any other single commodity, partly due to the costs of transmission. [89]

Credit Enhancements

A credit enhancement is any mechanism that "improves the chances that financing will be repaid."[90] For example, a credit enhancement can take the form of a loan loss reserve, a loan guarantee, or loan loss insurance.[91] Credit enhancements can be used by state governments, the federal government, and private entities.

According to the U.S. Environmental Protection Agency, state governments usually offer credit enhancements either through (1) loan loss reserves (LLR) or (2) interest rate buy-downs (IRB).[92] A LLR is a state government reserve of funds that "will cover a pre-specified amount of loan losses."[93] An IRB is a type of credit enhancement in which the government buys down the market interest rate of a loan by making a payment to the lender, making the loan easier to pay.[94]

MODELS FOR STATE TRANSMISSION FINANCE REFORM

This section of the report discusses various ways that California policymakers can either form new agencies, build out the capacities of existing agencies, or otherwise provide public support to accelerate transmission development. Potential institutional and policy solutions for public financing and other support of transmission in California are summarized as follows:

GOVERNMENT ENTITY	IMPLEMENTATION PATHWAY
A new California "Renewable Energy Transmission Authority"	Create authority to develop public transmission projects or co-develop private transmission projects. Create authority to issue bonds to raise revenue.

GOVERNMENT ENTITY	IMPLEMENTATION PATHWAY
A new California "Green Bank"	Create authority to issue loans.
New municipal-level "Green Banks"	Create authority to issue loans.
California Infrastructure and Economic Development Bank (IBank)	Expand existing authority to issue loans and credit enhancements.
California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA)	Expand existing authority to issue bonds and loans.
California Public Utilities Commission (CPUC)	Create authority to redirect AB 1373 funds from direct power procurement to transmission financing.
Department of Water Resources (DWR)	Expand authority to use transmission lines and establish clear authority to construct transmission lines.
Federal government	Coordinate state government support of public and private applications for strategic loans and project development assistance from the federal government.

Forming New or Expanding Existing Agencies

The California Legislature could consider forming new agencies, including a Renewable Energy Transmission Authority, that could serve as a public transmission developer or a statewide "Green Bank," or authorize municipalities to form their own local "Green Banks."

The creation of a new state agency, such as a Renewable Energy Transmission Authority or a California Green Bank, would raise important legal, budgetary, and governance considerations. Some of these include:

- **Enabling legislation.** A new state agency would require a new organic statute, as opposed to an amendment to an existing agency's organic statute.
- **Budget demands.** A new state agency would require appropriations to build up its staffing, capacity, and physical resources.[95]
- **Governance design.** Creating a new agency would require policymakers to consider how to allocate decision-making authority, for example by establishing a supervisory board or commission with members appointed by the governor or selected by the governor and legislature together.
- **Relationships with existing entities.** Creating a new agency with transmission mandates would require policymakers to consider how to eliminate duplication or avoid interference with the responsibilities of existing bodies such as the California Independent System Operator, the California Energy Commission, and the California Public Utilities Commission.[96]

1. A Renewable Energy Transmission Authority

California could establish a new Renewable Energy Transmission Authority (RETA), drawing inspiration from New Mexico's RETA[97] and the Colorado Electric Transmission Authority.[98] The Public Advocates Office of the California Public Utilities Commission recently recommended that California policymakers explore an infrastructure authority in the style of New Mexico's RETA as a transmission development option that would reduce ratepayer costs.[99]

a. New Mexico Renewable Transmission Authority

New Mexico's RETA was established by the state legislature in 2007 to "plan, finance, develop and acquire high voltage transmission lines and storage projects in order to promote economic development in New Mexico."[100] As of 2021, it was "one of seven state-level transmission authorities in the United States and only the second to have issued Bonds."[101] New Mexico RETA-sponsored projects must include 30% of their power from renewable resources, and current projects are planned to have 100% of their power originate from renewable resources.[102]

The Renewable Transmission Authority Act, which created New Mexico's RETA, may offer lessons for California legislators. The Act, created by House Bill 188 (2007), moved through the New Mexico legislative process with relative ease.[103] Governor Bill Richardson signed the RETA Act into law on March 5, 2007.[104]

The state's RETA is overseen by a mix of legislative and executive appointees.[105] Three members are appointed by the governor and confirmed by the state senate. One is the state treasurer or his designee, one is appointed by the speaker of the house of representatives, and one is appointed by the president pro tempore of the state senate.[106]

RETA has statutory authority to issue bonds and enter into contracts for the lease and operation of its facilities, provided that the agency deposit any revenue into a renewable energy transmission bonding fund.[107] Further, New Mexico RETA can collect payments of "reasonable rates, fees, interest or other charges" to finance the facilities and other services, with the similar deposit requirement. The agency can also borrow money and take out mortgages.[108] According to New Mexico RETA's website, the authority "derives its funding from developers based upon services provided by RETA."[109]

New Mexico RETA is not limited to financing and developing purely public projects — it also has the ability to collaborate with private developers. The organic statute specifically provides that New Mexico RETA may "enter into partnerships with public or private entities[.]"[110] New Mexico actively exercises this authority to partner with private entities on transmission lines, both as a co-developer and as a financier.

For example, the Western Spirit Transmission Line was developed jointly by the RETA and Pattern Energy Group LP, a private energy company.[111] New Mexico RETA is a "co-developer" with a private development company for each of the four transmission lines currently in development — Rio Sol, SunZia, North Path, and the Mora Line Project.[112] And New Mexico RETA provided only financial support — $50 million in revenue bonds — for transmission upgrades to the privately-operated High Lonesome Mesa wind farm.[113]

b. Colorado Electric Transmission Authority

In 2021, the Colorado Legislature created the Colorado Electric Transmission Authority (CETA) as an independent special purpose authority with Senate Bill 21-027.[114] Governor Jared Polis signed the bill into law on June 24, 2021.[115]

Opposition to SB 21-027 was primarily articulated as concern about increased costs to consumers. Xcel Energy-Colorado, the state's largest electric utility, claimed that the bill language "duplicates the existing well-established and transparent transmission planning processes" and raised "concern[] this would result in higher costs for our customers without oversight."[116] Although Xcel Energy phrased its concern about the bill in terms of cost to ratepayers, the bill would also increase potential competition for transmission development in the state. The utility had "recently proposed building a $1.7 billion, 560-mile corridor of transmission lines in mainly rural areas."[117]

Today, CETA is a "transmission builder of last resort" intended to step in where private developers are unable or unwilling to build transmission.[118] CETA has statutory authority to own property and enter into leases and contracts,[119] identify and establish transmission corridors,[120] participate in interstate transmission planning,[121] exercise eminent domain,[122] and issue and sell electric transmission bonds to raise revenue for transmission projects.[123] CETA is anticipated to receive "most of its funding from fees charged to developers and users of CETA-managed systems."[124]

Like New Mexico's RETA, CETA is governed by a mix of executive and legislative appointees, although power is shared more evenly between the two branches of government.[125] Two members of the board of directors are "appointed by the governor with the consent of the senate," one members is the "director of the Colorado energy office" or the "director's designee[,]" three members are "appointed by the speaker of the house of representatives[,]" and three members are "appointed by the president of the senate."[126]

c. Imagining a California RETA

California could implement a RETA with the same kind of flexibility that New Mexico RETA enjoys. Its enabling statute could ensure that the RETA is empowered not only to self-finance and develop transmission lines, but also to collaborate with private developers that can provide additional capital, capacity, and expertise.[127]

2. A state "Green Bank"

California could create a new, public "Green Bank" dedicated to financing transmission statewide. According to the Coalition for Green Capital, a "green bank" is a governmental, quasi-governmental, or nonprofit institution that provides financing for renewable energy and/or transmission projects.[128] A number of jurisdictions have already created freestanding public green banks.[129] Some examples of jurisdictions with green banks include Nevada,[130] Colorado,[131] Connecticut,[132] New York,[133] and Washington D.C.[134] The Connecticut Green Bank, formed in 2011, is the oldest and most established.[135]

An important choice policymakers face when establishing green banks is whether to form them as independent nonprofits or as agencies of the state government. Some green banks are nonprofits created by, but legally separate from, the state government. For example, the Nevada Clean Energy Fund was formed by Nevada's SB 407 (2017) as an independent nonprofit and launched in January 2022.[136] Likewise, Colorado Clean Energy Fund was created as a nonprofit in 2018 by Colorado Governor John Hickenlooper.[137] The Colorado Clean Energy Fund subsequently received a one-time $40 million appropriation from the Colorado Legislature in 2021, but otherwise remains separate from the state government.[138]

However, there are also examples of green banks created not as independent nonprofits but as government agencies. The D.C. Green Bank, for example, was created by the Green Finance Authority Establishment Act of 2018 (D.C. Law 22-155), which established a "Green Finance Authority" within the District government.[139] Likewise, the New York Green Bank is an entity of the New York state government — it is a division of the New York State Energy Research and Development Authority.[140]

In the view of the Coalition for Green Capital, California already has at least one green bank. The Coalition identifies the California Infrastructure and Economic Development Bank (IBank)'s Climate Catalyst Revolving Loan Fund, established in 2022 with $47 million in capital, as a green bank.[141] Therefore, the creation of a new, standalone California green bank could arguably be unnecessary and duplicative of IBank's existing Climate Catalyst Fund.

But there may be advantages to the Legislature creating a new green bank, either as a state government-supported nonprofit or as a state government authority or agency, dedicated to transmission finance rather than building off of the Climate Catalyst Fund. Benefits of a new, transmission-focused green bank may include a greater amount of capital available for projects and increased willingness on the part of a new green bank to fund large, institutional projects rather than smaller, riskier projects which the Climate Catalyst Fund was intended to support.[142]

3. Municipal-level Green Banks

Instead of (or in addition to) a single, statewide green bank, California might decide to allow municipalities to create their own green banks. Municipal green banks can increase the availability of local capital, but this capital would likely be less than a single statewide green bank, and potentially contribute to more piecemeal financing than a statewide green bank.

Municipal-level public banking is an emerging practice in California[143] since the passage of Assembly Bill 825 (2020), which created a process for a local agency to establish a public bank.[144] The text of AB 825 makes it clear that the Legislature intended municipal banks to serve the public interest: "achieving cost savings, strengthening local economies, supporting community economic development, and addressing infrastructure and housing needs for localities[.]"[145]

Because they are governmental and not private banks, municipal banks can be subject to the political priorities of the municipal constituency and directed to finance particular issues, which could include clean energy infrastructure. Therefore, some experts

have noted the potential for municipal banks in California to finance transmission[146] in addition to other renewable energy projects.[147] Municipal-level green banking might also lead to an increase in the community's engagement with, awareness of, and investment in transmission projects of local significance (recognizing that it could also engender additional local opposition).

In addition to generic municipal banks that can choose to support transmission projects — which is now possible under AB 825 — the California Legislature could go even further and explicitly authorize municipal green banking by providing statutory language directed towards the financing of renewable energy projects including transmission lines.

Virginia is already experimenting with this type of municipal-level "green" banking. In March 2021, Virginia passed a law allowing municipalities to create their own green banks.[148] Virginia municipal green banks may do the following:

- Finance investment or support of investment in clean energy technologies to foster the growth and development of renewable energy sources[149]
- Stimulate the demand for renewable energy and the deployment of clean energy technologies that serve end-use customers[150]
- Provide financing or financial support for clean energy technologies[151]

To date, municipal green banks have "focus[ed] on smaller-scale clean energy projects" and not larger projects like transmission.[152]

One model for a discrete municipal-level green bank can be found in the Philadelphia Green Bank,[153] the "nonprofit green bank affiliate" of the Philadelphia Energy Authority, an independent municipal authority focused on energy affordability and sustainability in the City of Philadelphia.[154] The Philadelphia Green Bank launched in 2021 with $250 million to invest.[155] Like Virginia's municipal-level green banking, the Philadelphia Green Bank is aimed mostly at smaller-scale projects: "providing financing solutions that focus mainly on areas that have not traditionally had easy access to capital for green projects including low-income homes, small and medium-sized businesses, nonprofits, and multifamily buildings."[156] Municipal-level green banking may therefore either be a supplementary (not primary) source of financing for transmission or a source of financing for smaller-scale projects.

Expanding Existing Agencies

Instead of creating a wholly new state agency, California policymakers could instead expand the capabilities and legal authorities of existing agencies like the California Infrastructure and Economic Development Bank (IBank), the California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA), the California Public Utilities Commission, and the Department of Water Resources (DWR).

1. Expanding IBank

California could expand IBank's current authority, including its new Climate Catalyst Revolving Loan Fund, and further tailor its authorities for transmission financing.[157]

IBank is a California state agency created in 1994 to finance public infrastructure and private development.[158] One of IBank's primary functions is offering traditional infrastructure loans for projects like street repairs and water treatment plants. These infrastructure loans are currently only available to state and local government entities, not private developers.[159]

a. Loans

The Climate Catalyst Revolving Loan Fund represents IBank's first major foray into renewables infrastructure financing. According to the Climate Catalyst Fund's guidelines, the Fund prioritizes "projects that advance the state's climate goals, covering both climate mitigation (the reduction of climate harms by addressing the root causes of climate change) and climate resiliency (infrastructure investments that improve our ability to withstand and manage the effects of a changing climate)."[160]

At present, the Climate Catalyst Fund supports three categories of projects.[161] These include (1) projects "that reduce wildfire threats through forest biomass management and utilization[,]" (2) projects "that increase access to zero-carbon resources through new clean energy transmission infrastructure[,]" and (3) projects that "promote climate-smart technologies and practices across the agricultural value chain[.]"[162]

Notably, IBank's Climate Catalyst Fund already has specific legal authority to finance transmission.[163] The operative statute provides that IBank shall establish a separate "Clean Energy Transmission Financing Account" within the Fund.[164] Eligible transmission projects must meet the following conditions to receive IBank funding:

- Has at least one interconnection point within a California balancing authority area.[165]
- Has a developer or associated applicant who has previously completed a transmission project in California.[166]
- Will primarily deliver electricity to the Independent System Operator balancing authority area from clean resources located in identified resource areas that do not have adequate deliverability to a California balancing authority area.[167]
- Will support new high-voltage (200 kilovolts or higher) transmission projects or upgrades of existing transmission lines and high-voltage substations that are consistent with the state's reliability and greenhouse gas policy objectives.[168]
- Must also have entered into a project labor agreement that meets the requirements of Section 2500 of the Public Contract Code (including a prevailing wage agreement), target hiring provisions for disadvantaged workers, and offer apprenticeship utilization provisions.[169]

Priority shall be given to transmission projects that have not already been approved through the Independent System Operator's transmission planning process or projects that have not been recently studied in the Independent System Operator's transmission planning process and found to be unneeded or uneconomical.[170]

Additionally, the funded Climate Catalyst project or projects can support new resources located in the Salton Sea region.[171] The 2022 Budget Act specifically "included $250 million for transmission line project financings with an initial focus in Lithium Valley, $200 million in 2022-2023 and $50 million in 2023-2024."[172]

Ultimately, IBank would need expanded staff capacity in order to support transmission financing on the necessary scale. As of report publication, IBank had a total of 37 employees, only two of whom are dedicated to the "Climate Financing" team.[173] But to the extent that IBank already has statutory authority to provide loans to transmission projects — and likely only needs an increase in available funds and staff capacity — it could be a strong contender to lead California's public financing of transmission.

b. Credit Enhancements

Separately from its lending powers, IBank could use its credit enhancement authorities to help private transmission developers seek non-state financing by boosting the creditworthiness of those developers.[174] IBank is empowered to make credit enhancements as "financial assistance for a project."[175]

IBank has issued credit enhancements in the context of its Small Business Loan Guarantee Program, which was intended to help small businesses qualify for a term loan or line of credit.[176] This credit enhancement, as the name of the program suggests, was a loan guarantee.

Compared to public loans, credit enhancements require less initial cost because the state would be guaranteeing a loan, reserving specified funds to cover partial loan losses, or making only an initial payment against loan interest, rather than issuing a loan in its entirety. However, because credit enhancements are not direct public financing, but rather public support for private financing, the underlying financing decisions are subject to the decisions of private investors. Potentially, the state or other credit enhancement provider could impose requirements as a condition for a credit enhancement, similar to conditions imposed on bonds. Additionally, IBank would need to decide which kinds of developers receive its credit enhancements. If IBank were simply subsidizing IOU-developed transmission lines with credit enhancements, this support would probably not address the problem of rising ratepayer expenses.

2. Expanding CAEATFA

California could build off of the California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA),[177] which issues some bonds to green projects.[178]

CAEATFA is a state government authority sitting at the intersection of climate and finance policy. It has five members: the Director of Finance, the Chair of the California Energy Commission, the President of the California Public Utilities Commission, the State Controller, and the State Treasurer (who chairs the authority).[179]

As it currently exists, CAEATFA has a small staff of only 25 employees, with two vacant positions.[180] Of those, 15 employees and 1 vacancy are devoted to the "CHEEF" program for energy efficiency retrofits.[181] Therefore, if CAEATFA were to assume a larger role

in transmission financing, such a mandate would likely need to be accompanied with an increase in capacity and funding.

Compared to other renewable energy state agencies, CAEATFA is a relatively established authority, formed in 1980.[182] The agency was originally named the "California Alternative Energy Source Financing Authority"[183] and was renamed in 1995 to its current name to reflect its expanded mandate.[184]

Although it is a relatively small entity, CAEATFA's statutory mission statement suggests that, with minor statutory amendments, it could be well-suited to finance transmission.[185] CAEATFA's objective is to "advance the state's goals of reducing the levels of greenhouse gas emissions, increasing the deployment of sustainable and renewable energy sources, implementing measures that increase the efficiency of the use of energy, creating high quality employment opportunities, and lessening the state's dependence on fossil fuels[.]"[186]

To that end, CAEATFA is charged with providing "an alternative method of financing in providing and promoting the establishment of both of the following:

- Facilities utilizing alternative methods and sources of energy.[187]
- Facilities needed for the development and commercialization of advanced transportation technologies."[188]

CAEATFA has an expansive toolkit that it may use to financially support deserving projects, including both bonds and loans. First, CAEATFA has broad authority to issue bonds, notes, and other obligations.[189]

Second, CAEATFA can issue loans. CAEATFA's statutory authorities also enable it to "provide financial assistance to a participating party, to enter into loan agreements with a participating party for the financing of a project including creating a lien or security interest in the property, to construct, reconstruct, renovate, replace, lease, as lessor or lessee, and regulate the same, and to enter into contracts for the sale of a project, including installment sales or sales under conditional sales contracts."[190]

CAEATFA currently issues bonds for only two purposes, neither of which relates to transmission. First, CAEATFA issues "Qualified Energy Conservation Bonds," which are tax credit bonds that "can be used for projects that reduce energy consumption in publicly owned buildings, implementing green community programs, rural development involving the production of electricity from renewable energy resources, technologies that capture and sequestration of carbon dioxide produced by fossil fuels, technologies that reduce energy use, and more."[191] Second, CAEATFA issues private activity bonds to provide long-term financing for district heating and cooling.[192]

CAEATFA would likely require a statutory amendment in order to finance transmission, regardless of whether it uses bonds or loans. Nothing in CAEATFA's organic statute specifically references transmission projects. Rather, CAEATFA is generally empowered to support "project[s]," defined broadly as "land, building, improvement to the land or building, rehabilitation, work, property, or structure … [including] machinery and equipment utilized in the state … that utilizes, or is designed to utilize, an alternative source, or that is utilized for the design, technology transfer, manufacture, production, assembly, distribution, or service of advanced transportation technologies or alterna-

tive source components."[193] The CAEATFA's definition of "project" does not include transmission infrastructure. As a result, CAEATFA cannot currently fund "projects" that only constitute transmission lines. And under its present regulations, CAEATFA only actually finances residential and commercial clean energy upgrades.[194] But with additional funding, increased staff capacity, and an explicit statutory directive to fund transmission, CAEATFA could be an important source of public financing for transmission projects in California.

3. Department of Water Resources: Building off AB 1373

New legislation, building off of AB 1373, might permit the state to finance new transmission through revenues generated from direct power procurement. AB 1373 (Garcia, 2023) empowered the DWR, when directed by the California Public Utilities Commission, to directly procure renewable energy.[195] AB 1373 promotes resources like offshore wind and geothermal energy, because those sources "often carry higher maintenance, operation, or development costs, resulting in individual Load-Serving Entities (LSEs) – companies or agencies that provide electrical powers to everyday Californians – forgoing investment[.]"[196] The legislature could relatively straightforwardly add transmission financing to the Department's authority.

a. California Public Utilities Commission

Under AB 1373, the California Public Utilities Commission has authority to identify procurement needs through the existing Integrated Resource Planning (IRP) process and request that the Department of Water Resources procure needed resources after six months.[197] This six-month window is intended to allow other load-serving entities to procure their share of their load if they elect to do so, a long-held principle previously applied to community choice aggregators (CCAs).[198]

Importantly, AB 1373 contains two new financial authorities.[199] First, the bill gives the California Public Utilities Commission the authority to impose a non-bypassable charge to ratepayers to cover the Department of Water Resources' procurement costs, as long as the commission finds that the charge would not "unreasonably increase costs to customers[.]"[200] A new "Eligible Energy Resource Central Procurement Fund" will receive these customer charges and support the Department's procurement activities.[201] Second, AB 1373 gives the Department the authority to issue bonds, if necessary, to fund upfront costs for its central procurement activities.[202] These bonds will be repaid with the ratepayer charges received by the Clean Energy Procurement Fund.[203]

Through these authorities, the bill can provide a stepping-stone for the Department to play a prominent role in transmission development. In particular, AB 1373 direct procurement may provide a new revenue source for transmission financing. Direct procurement under AB 1373 empowers the California Public Utilities Commission to directly charge ratepayers on the Department's behalf, bypassing the IOUs entirely, and funnel the revenues into the Clean Energy Procurement Fund.[204]

AB 1373 alone will not funnel ratepayer charges to transmission financing. Under the current bill text, the Clean Energy Procurement Fund can only be used for limited purposes, which does not include financing for new transmission infrastructure.[205]

The bill authorized payments for the fund only to satisfy "bonds or other contractual obligations," "cost of energy and transmission, scheduling, and other related expenses," and administrative costs incurred through direct procurement.[206]

The legislature specifically provided that the Department of Water Resources is prohibited from "recovering funds pursuant to a nonbypassable charge on the ratepayers of a load-serving entity for purposes other than providing for the department's acquisition costs for eligible energy resources, including transmission, scheduling, financing, program administration, and other related costs[.]"[207]

However, if the Clean Energy Procurement Fund has sufficient revenue from direct procurement charges to ratepayers to cover its expenses with a surplus remaining (even though the California Public Utilities Commission's charges to ratepayers would be limited by the mandate that they not unreasonably increase costs to customers[208]), the fund could serve as a new revenue source for transmission finance in the future.[209] But this purpose would require a statutory change providing that charges could be assessed and withdrawals from the fund made for that purpose.[210]

b. Department of Water Resources

Although the Department has transmission-related authorities, some of which predated AB 1373, these powers are relatively limited. Since the 2000-2001 energy crisis, the Department has had the authority to purchase power on behalf of California's retail customers.[211] The relevant provisions of the Water Code grant the Department some limited powers with respect to transmission. The Department may "pay or provide for the payment of power or use of transmission" facilities related to its contracts to purchase power.[212] The agency may then contract with an electrical corporation "to transmit or provide for the transmission of" power made available by the Department.[213] In 2023, AB 1373 added one more state authority related to transmission; at the request of Department leaders, the California Public Utilities Commission may "order an electrical corporation… to transmit or provide for the transmission of… all electricity made available by the department[.]"[214]

The common thread through these statutory provisions is that the Department of Water Resources may "provide for" transmission and the use of transmission facilities. A conservative reading of this phrase suggests that the Department may make use of *existing* transmission facilities incidental to its power purchase and sale contracts but that it does not have clear authority to create new transmission lines as part of "provid[ing] for" transmission.

If the California Legislature wanted to empower the Department to not only use, but also create, transmission infrastructure, then it could easily do so by sharpening the language in these sections. For example, a revised Section 80102, subdivision (c) of the Water Code might read "[n]otwithstanding any other provision of law, the department may pay or provide for the payment of power, *or for the construction and/or* use of transmission or distribution facilities and other related services prior to the delivery or utilization thereof, provided that the department determines that prepayment is beneficial to ratepayers and that adequate provision has been made for the security of the department."[215]

OTHER OPTIONS FOR PUBLIC SUPPORT

1. Leveraging Federal Support

As the Public Advocates Office has proposed, California could leverage "federal financing programs such as the U.S. Department of Energy's Western Area Power Administration's (WAPA) transmission finance program."[216] According to the Roosevelt Institute, the federal government may be uniquely well-positioned to provide funding for transmission, since as compared to incumbent investor-owned utilities and independent system operators (ISO/regional transmission operators or non-utility private players), it is "a strong regional and interregional mandate, long-term planning horizons, and an ability to absorb the financial risks[.]"[217]

Western Area Power Administration's Transmission Infrastructure Program

California-based transmission projects could take advantage of the Western Area Power Administration's Transmission Infrastructure Program, which has a primary goal to leverage federal funds and attract private and other non-federal investment to support the development of critical transmission and related infrastructure.[218] The Transmission Infrastructure Program manages the Western Area Power Administration's $3.25 billion borrowing authority (referring to funds borrowed by the Administration from the Treasury).[219] The Western Area Power Administration can offer both strategic loans and project development assistance to transmission developers.[220]

In order to receive Administration support, prospective utility-scale transmission projects must demonstrate that they will, at minimum:

- Have at least one terminus in the Western Area Power Administration's 15-state service territory[221]
- Demonstrate a reasonable expectation of repayment[222]
- Facilitate the delivery of clean energy[223]
- Not adversely impact system reliability or operations[224]
- Serve the public interest.[225]

The Western Area Power Administration has previously supported transmission projects, including the 254 MW Electrical District 5 – Palo Verde Hub line in Arizona, which is in active repayment status, and the MATL line delivering wind energy from Montana, which received and fully repaid a $162 million construction loan.[226]

The state could leverage the Western Area Power Administration's Transmission Infrastructure Program through the following:

- Promoting private applications for Administration funding to the federal government and expressing the state government's support for those applications to the Western Area Power Administration.

- Applying, directly or through a private partner, for Administration funding for public-private partnership (P3) projects.

- Applying directly for Administration funding for purely public transmission projects. The U.S. Department of Energy's Western Area Power Administration regulation defines "Project Applicant" only as "an entity that submits a Project Proposal and Business Plan Proposal" and does not seem to distinguish between public and private applicants.[227] Therefore, state governments, if acting as transmission developers, may be eligible for Administration funds.

- Coordinating Administration funds with state government financing options, such as funds from IBank or CAEATFA.

2. Public-Private Partnerships

In addition to supporting purely private transmission projects, the state could enter into public-private partnerships (P3) with private entities, which could encompass virtually all of the institutional options listed above.

Defining P3

P3 commonly refers to long-term (typically 25 or more years) performance-based contracts with public-sector entities in which the private sector takes or shares responsibility and risk for the design-build-finance-operate-maintain (DBFOM) elements of a public infrastructure project.[228]

The state of California has ample experience with P3 development projects, albeit in other contexts. According to the Bay Area Council Economic Institute, in 1989 California was one of the first states to pass P3 legislation, and two of the nation's first P3 highway projects were built in Southern California under that legislation.[229] Potential models for state public-private partnerships may be found in Caltrans's P3 arrangements for transportation projects,[230] the University of California's privatized development projects,[231] and the state-private Hydrogen Fuel Cell Partnership.[232]

Supporters of P3 development argue that it provides an important option for public agencies, which may not have capacity or expertise to complete development projects on their own.[233] But critics argue that P3s may "not provide the transfer of risk that they promise" and that the public sector could ultimately be responsible for any cost overruns, which could result in higher costs for taxpayers and ratepayers.[234]

P3 Transmission

According to the Public Advocates Office, which has encouraged the state to explore public-private arrangements to finance transmission in addition to purely public financing approaches, public-private partnerships "would likely result in intermediate ratepayer savings between the bookends of pure public and pure private investment options."[235]

a. Section 1222: Federal Co-Ownership Model

A potentially illustrative model for public-private transmission development, albeit at the federal level, is the Department of Energy's Section 1222 Program.[236] Under Section 1222, part of the Energy Policy Act of 2005, the Secretary of Energy has authority to "design, develop, construct, operate, own, or participate with other entities in designing, developing, constructing, operating, maintaining, or owning two types of projects[.]"[237]

First, DOE can co-develop electric power transmission facilities and related facilities needed to upgrade existing transmission facilities owned by the Southwestern Power Administration (SWPA) or by the Western Area Power Administration.[238]

Second, DOE can co-develop new electric power transmission facilities and related facilities located within any state in which the Southwestern Power Administration or Western Area Power Administration operates."[239] Section 1222 represented "a broad expansion of federal involvement in electric transmission siting and development[.]"[240] But Section 1222 has been underutilized in the nearly 20 years since its enactment.

DOE issued its first request for proposals under Section 1222 in 2010.[241] In March 2016, DOE published its decision to partner with Clean Line Energy Partners via the Southwestern Power Administration.[242] But this Clean Line project fell apart due to "political and commercial" pressures, and Section 1222 has been neglected since.[243] Despite its underutilization in practice, however, Section 1222 is an important precedent and statutory model for P3 transmission development.

Whether or not a P3 program to encourage transmission development or provide financing requires an act of the California Legislature would depend on how such a program was structured. Not all public-private partnerships exist by virtue of statute.

For example, the Hydrogen Fuel Cell Partnership (H2FCP) is a "collaborative of auto manufacturers, energy companies, fuel cell technology companies and government agencies" that work to promote hydrogen fuel cells.[244] Among other public agencies, the Governor's Office, California Air Resources Board (CARB), and California Energy Commission are members of the H2FCP, which evolved out of 1999's California Fuel Cell Partnership.[245] The H2FCP is a nonprofit public benefit corporation.[246]

If a transmission-promotion P3 were similarly arranged as a nonprofit corporation or as an informal association of state agencies and private entities, then it is possible that, like the H2FCP, it would not require any enabling legislation, so long as the state agencies would act within their existing authorities.[247]

However, if a transmission P3 were to directly apply new state authority into the transmission development process, then enabling legislation, like the legislation that empowered Caltrans to build P3 transportation projects,[248] would be appropriate. For example, as previously discussed, a Renewable Energy Transit Authority (RETA) would need an organic statute before the RETA could enter into P3 arrangements with private developers.[249]

b. The "Citizens/Morongo" Public-Private Model

The "Citizens/Morongo" approach to transmission ownership, financing, and siting may provide a particularly useful model for public-private partnerships in situations where local communities are opposed to and/or will suffer uncompensated losses from transmission projects.

The "Citizens/Morongo" model, a term coined by former Federal Energy Regulatory Commissioner Suedeen Kelly,[250] refers to an ownership arrangement between Citizens Energy, the Morongo Band of Mission Indians, San Diego Gas & Electric, and Southern California Edison.[251] Citizens Energy and the Morongo Band, working as a joint venture, purchased a 30-year leasehold interest in a utility-operated transmission line running through Morongo land.[252] Following approval of the transaction by the Federal Energy Regulatory Commission, the Morongo Band became the first Native American Tribe to have an ownership interest in transmission in the United States.[253]

This "Citizens/Morongo" model is intended to better align the costs and benefits of transmission to local communities in order to accelerate the siting process. As joint owners of the transmission line, Citizens Energy and the Morongo Band distribute the profit made from transmission rates to nearby local governments and the Morongo Tribal government.[254] The Federal Energy Regulatory Commission's sign-off on three aspects of the arrangement were critical.

First, Citizens and Morongo can "raise the capital for the investment with 100% debt rather than a combination of debt and equity. This both lowers the cost of the investment and makes it possible for these entities, which do not have easy access to equity, to participate in the joint venture."[255] Since the Federal Energy Regulatory Commission usually prefers a roughly 50-50 ratio between debt and equity financing, in order to mitigate risk and confirm that transmission developers are capable of raising equity, the Commission's approval of a 100% debt and 0% equity formula is unusual.

Second, the Federal Energy Regulatory Commission approved an "essentially fixed, 30-year transmission rate rather than a stated or formula rate subject to change through a Federal Power Act Section 205 or 206 action."[256] This fixed transmission rate "provides the certainty needed by Citizens/Morongo to procure the long-term debt at the lowest possible rate."[257]

Third, Citizens and Morongo can charge the same rate as that charged by San Diego Gas & Electric and Southern California Edison.[258] Since the utilities' rates "recover costs which they incur but Citizens/Morongo do not (e.g., taxes and return on equity), Citizens/Morongo distributes this part of the revenue to the impacted communities to compensate for the intangible costs of transmission siting borne by them."[259]

The Citizens/Morongo joint venture appears to have been relatively uncontroversial. In addition to its partnerships with major IOUs, the project received support from the "US Department of the Interior, the Governor of California, the California Public Utilities Commission, the California Independent System Operator, Los Angeles Department of Water and Power, California lawmakers, and the Natural Resources Defense Council."[260]

The Citizens/Morongo model was relatively unique because it was financed entirely with long-term, tax-free debt, which may not be a feasible financing strategy for publicly

funded transmission lines such as those developed by a Renewable Energy Transmission Authority. But the Citizens/Morongo model could be replicated in situations where non-public actors seek to expedite siting and construction and are willing to enter into ownership arrangements with public entities that allow for payments to the affected local communities to that end.

As a result, the model might be most useful in situations where local opposition to siting is a major concern for the viability of a proposed transmission project, such as when alternate routes would be prohibitively expensive. Public partners could be federally recognized tribes like the Morongo Band or municipal governments of sufficient size and capacity.

CONCLUSION

The current system, cost, and timing for new transmission represent serious barriers to achieving California's clean energy goals. Some form of public financing and streamlining for at least some portion of new transmission will be needed, but the form and extent of the reform is an open question that needs further evaluation. The initial summary of conclusions in this document offers potential pathways for reform and the necessary steps needed to implement them. Future study could focus on priority transmission lines and assessments of optimal and practical financing options and the policies need to enable them.

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III. APPENDIX II: PUBLIC SECTOR FINANCING OF ELECTRICITY TRANSMISSION LINES IN CALIFORNIA

Public Sector Financing of Electricity Transmission Lines in California

Financial and Institutional Options for Reducing Customer Costs

May, 2024

DH Infrastructure — ECONOMICS & FINANCE —

EE-Analysis
Economics and Energy

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EXECUTIVE SUMMARY

California has established ambitious clean energy deployment goals that require a rapid and extensive build-out of new transmission. A key barrier to this build-out is the high cost of new transmission, which has the potential to substantially increase electricity customer rates.

This report evaluates alternative approaches to financing and developing new transmission in California. We find that the use of public sector financing and targeted institutional changes can reduce the cost of California's needed transmission build-out by tens of billions of dollars over the next two decades. Public-private partnerships (PPPs) with public sector ownership and private sector operation are a promising and cost-effective alternative to the business-as-usual approach of having investor-owned utilities develop all new transmission lines.

Public financing strategies can reduce transmission costs

Transmission is a key and growing component of investor-owned utilities' costs of service. The way these assets are financed and developed has a major bearing on what is ultimately charged to ratepayers.

A public financing approach to deploying transmission can reduce costs in three key ways:

- The use of **low-cost public debt** (bonds) can *directly* reduce costs to ratepayers. Low-cost debt would result in lower debt servicing and therefore a lower transmission tariff. To the extent that such debt replaces equity in the capital structure, the costs to ratepayers would be further reduced, as the cost of equity is considerably higher than the cost of debt. Finally, taxes are also typically lower when returns on capital are lower, putting additional downward pressure on the cost of service.
- The need for **new institutional models** to facilitate public financing, including certain types of PPPs or a wholly public entity, can *indirectly* reduce costs to ratepayers. These models can help to increase competition for the development of new transmission (through more competitive solicitation) as well as reduce the tax obligations of the transmission owner through public ownership. PPPs offer the additional benefit of retaining private sector innovation and efficiency for operating and maintaining the transmission line, and—by using special purpose vehicles to implement projects—can shield the public owner from certain operational risks.
- Accompanying policies that seek to reduce the **length and risks of the pre-investment development phase** could deliver a third tranche of savings. As transmission development is high-risk and requires significant pre-investment capital, investors require a high-risk premium. As a result, policies that reduce the length and risk of this phase, such as clear and predictable siting and permitting processes, would generate *direct* cost reductions.[1]

Estimating the benefit of transmission public financing

We estimate the cost savings that could occur under alternative transmission financing and deployment approaches in California. We use the California Independent System Operator's (CAISO's) 20-Year Outlook as the basis for the analysis, which identifies the new high-voltage transmission lines (230 kV and 500 kV)

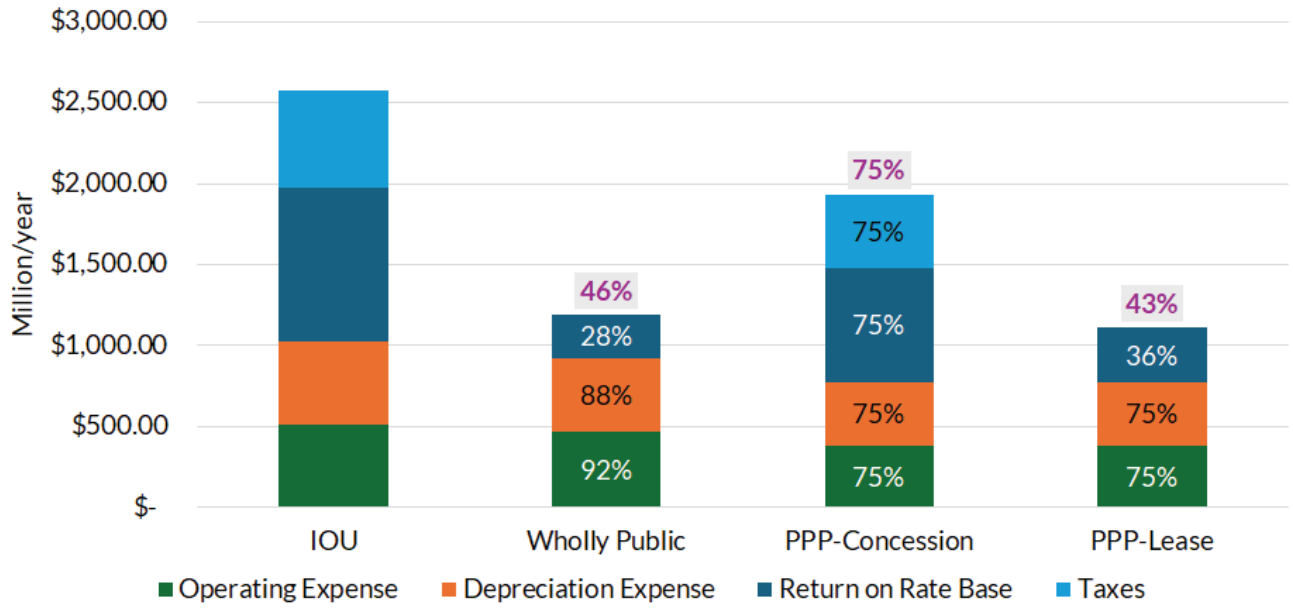
[1] This report evaluates transmission cost savings from the use of low-cost public debt and new institutional models only. We provide a separate and very rough estimate of the potential savings from de-risking pre-investment development further below.

and related upgrades necessary for the state to achieve its SB 100 power sector decarbonization goals. The total capital cost of this new infrastructure—including engineering and construction costs only and excluding all other financing and development costs—is estimated at $25.5 billion.[2]

We considered four alternative scenarios to financing and developing this new infrastructure:

1. A business-as-usual scenario of an investor-owned utility developing, financing, and operating the lines;
2. A wholly government-owned company developing, financing, and operating the lines;
3. A lease-type PPP, in which a government-owned holding company or special purpose vehicle provides financing for the transmission asset, but hires a private company to operate the assets; and
4. A concession-type PPP, in which the government-owned asset is designed, built, operated, and financed by a private company over the life of the asset, and then ultimately returned to the government at the end of the concession agreement.

We find that the business-as-usual approach to transmission development could—over 40 years—cost ratepayers $100 billion, more than twice the cost of alternative approaches. The difference is due primarily to the higher cost financing used by investor-owned utilities, and what other studies have found to be a lack of sufficient competition in procuring new transmission lines.[3] The use of public sector financing and accompanying institutional changes could reduce costs to ratepayers by as much as 57%—or nearly $60 billion—over the 40-year period (Figure ES.1). This is equivalent to savings of $1.5 billion per year.



[2] Note that this figure *excludes* interregional transmission for out-of-state wind that is already being developed. These projects add an additional $5 billion to the total to equal the $30.5 billion amount that is identified in CAISO's 20-Year Outlook. These costs will be paid by the line subscribers.

[3] See, for example: Pfeifenberger, J.P. et al. "Report by Brattle Economists Discusses the Benefits of Competitive Transmission." Prepared for LSP Transmission Holdings, Brattle, June 21, 2021. *https://www.brattle.com/insights-events/publications/report-by-brattle-economists-discusses-the-benefits-of-competitive-transmission/*.

***Figure ES.1**: Total revenue requirement (undiscounted) of four scenarios to develop, finance and operate the CAISO 20-Year Outlook transmission package. The percentages shown on the columns indicate the cost relative to the IOU scenario.*

Similar results can be seen for individual lines. For example, more recent and detailed capital cost estimates have been developed for North Coast offshore wind, where a $7.7 billion line is planned to accommodate 7.2 GW of development.[4] Under the investor-owned utility scenario, this line would have an annual average cost to ratepayers of $774 million. Under a lease-type PPP, this cost would fall to $332 million per year.

Pros and cons of alternative institutional models

Each of the alternative institutional models to facilitate public financing has its own pros and cons. A lease-type PPP could provide the lowest-cost approach to delivering California's transmission goal. A lease-type PPP has the advantage of using lower cost public debt, exemption from certain taxes, and the retention of private sector efficiency in operating and maintaining the transmission line. The contracts with the private sector can also shield the public entity from operational risks and allow for better control of costs.

A key advantage of the lease-type PPP over the concession-type PPP is that the latter relies on private sector financing and the return on equity and commercial debt that comes with that. The wholly public model provides a greater degree of public control but does not build in the participation of the private sector beyond the design and build stage and potentially exposes the state to additional financial and legal risk. The investor-owned utility approach is the most expensive to ratepayers and may forego institutional changes that could increase the speed of transmission deployment.

Discussion and next steps

California's ambitious climate goals require the build-out of a significant amount of new transmission. How this infrastructure is financed, developed, and operated could result in vastly different impacts on ratepayers. This analysis provides evidence that the use of public sector financing in the form of low-cost public debt that displaces equity and provides tax benefits and that is facilitated by either public-private partnership or wholly public models could deliver significant cost savings relative to investor-owned utility approaches.

We highlight three key limitations to this analysis that suggest the cost savings identified in this report may be conservative. The first is that the CAISO 20-Year Outlook capital costs exclude right-of-way acquisition costs.[5] The second is that additional cost savings could be achieved by de-risking the pre-investment project phase.[6] The third is that the cost estimates largely exclude the costs of undergrounding transmission. As

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[4] Zoellick, J. et al. "Northern California and Southern Oregon Offshore Wind Transmission Study." Schatz Energy Research Center, October 1, 2023. https://doi.org/10.2172/2205318.

[5] This is based upon Participating Transmission Owner (PTO) cost guides submitted to CAISO as part of the 20-Year Outlook report: https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/Participating-transmission-owner-per-unit-costs-2023. Right-of-way acquisition costs would be expected to increase the $25.5 billion base estimate and therefore cost savings from public financing.

[6] This report does not attempt to specifically identify policies to shorten the length or reduce the risk of transmission pre-investment development. However, as a simple, illustrative example, if we assume a 50% probability of project failure and pre-investment costs totaling 20% of the total, this would require a 10% risk premium. On a $1 billion project, this would add $100 million to the capital cost. Recent transmission projects in New Hampshire (Northern Pass) and Maine (Hydro-Quebec) with estimated total costs of approx. $1 billion both incurred pre-investment costs equal to 20% and 43%, respectively, of these totals. Overall, policies that provide stronger assurances to successful siting and approval would be expected to directly reduce transmission capital costs.

described in Section 5, if the costs of fire hardening by undergrounding are included, the total cost to customers would 8-10 times the cost of transmission without such measures.

To the extent that a public financing model is of interest and considered viable, an important next step would be to evaluate the legal and/or regulatory changes necessary to establish one or more of the institutional models within California state government. Colorado and New Mexico are two states with alternative transmission models that could be relevant to California. Internationally, tenders for transmission have most often been concession-type PPP contracts, but there is precedent in the United States in other infrastructure sectors with lease-type PPPs, including road and social infrastructure projects (e.g., schools, and hospitals).

SECTION 1 INTRODUCTION

California's electricity sector has a diverse mix of energy sources including natural gas, nuclear power, and renewable energy (solar, wind, hydroelectric power), and is the national leader in solar energy production.[7] California's energy policy framework emphasizes sustainability and environmental protection by transitioning away from fossil fuels, with ambitious goals to reduce greenhouse gas emissions to 40% below 1990 levels by 2030, reaching 90% electricity sector decarbonization by 2035, and achieving, by 2045, carbon neutrality and 100% clean electricity retail sales.[8] To achieve this, California must considerably increase its renewable generation capacity[9] and substantially expand its transmission infrastructure for generation to reach load centers at an estimated investment cost of $30 billion.[10] This is in line with the global trend. According to the International Energy Agency,[11] by 2030, global energy generation is expected to almost double, for which annual investments of around $600 billion will be required for transmission and distribution networks .[12]

Expanding and upgrading the electricity transmission infrastructure to accommodate the growing share of renewable energy poses regulatory, permitting, environmental, funding and debt rating challenges, including potential negative financial impact on consumers. Furthermore, California faces direct impacts from climate change, including increased frequency and severity of wildfires, droughts, and heatwaves that pose additional challenges to energy production, transmission, and distribution systems, requiring robust resilience and adaptation strategies.

California's energy sector operates under a mixed model that includes both publicly owned utilities and investor owned utilities (IOUs). The state has shown a preference for regulating rather than seeking ownership of the IOUs, focusing on oversight through the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC).

Transmission projects in California are governed by a complex regulatory framework that can significantly affect their development, operation, and expansion (See Appendix A:). The state's constitution and regulatory environment prioritize a competitive market structure to encourage efficiency and innovation. The CPUC and the Federal Energy Regulatory Commission (FERC) regulate California's electricity market, imposing rules that protect consumer interests and ensure competition, including transmission access charges and the allocation of transmission costs through transmission tariffs that meet the "just and reasonable" rate doctrine. This

[7] California Energy Commission, "Data Show Clean Power Increasing, Fossil Fuel Decreasing in California," California Energy Commission, current-date, https://www.energy.ca.gov/news/2023-08/data-show-clean-power-increasing-fossil-fuel-decreasing-california.

[8] "California Climate Policy Dashboard," Berkeley Law, accessed March 16, 2024, https://www.law.berkeley.edu/research/clee/research/climate/climate-policy-dashboard/.

[9] "2022 Scoping Plan Documents | California Air Resources Board," accessed March 16, 2024, https://ww2.arb.ca.gov/es/node/20106#.

[10] Darrell Proctor, "CAISO Plan Calls for $30.5 Billion for Transmission—and More Renewable Energy," POWER Magazine, February 3, 2022, https://www.powermag.com/caiso-plan-calls-for-30-5-billion-for-transmission-and-more-renewable-energy/.

[11] "World Energy Investment 2023 – Analysis," IEA, accessed March 16, 2024, https://www.iea.org/reports/world-energy-investment-2023.

[12] "Lack of Ambition and Attention Risks Making Electricity Grids the Weak Link in Clean Energy Transitions - News," IEA, accessed March 16, 2024, https://www.iea.org/news/lack-of-ambition-and-attention-risks-making-electricity-grids-the-weak-link-in-clean-energy-transitions.

regulatory oversight extends to transmission projects, where the aim is to balance the need for infrastructure development with the principles of a competitive market.

The permitting process for electricity transmission projects is complex due to the involvement of multiple regulatory bodies across local, state, and federal levels, stringent environmental regulations like the California Environmental Quality Act (CEQA),[13] and land use and right-of-way acquisition challenges. Projects must navigate through rigorous environmental impact assessments, extensive public and stakeholder engagement, and comply with strict land use and zoning regulations, all of which can significantly delay timelines and escalate costs.

The increasing ratepayer costs of transmission development motivated the CPUC's Public Advocate's Office to question whether the transmission costs could be brought down by replacing IOU investment with public investment. Their initial analysis suggested that a net ratepayer savings of 25% could be achieved (compared to current recovery mechanisms) through lower interest rates, elimination of shareholder returns, and tax benefits not available to private companies.[14]

Further reductions could be achieved by lowering the permitted rate of return for utilities, offering bond financing or other forms of securitization to cover some costs, or substituting financing with direct government spending.[15] With California's need for billions in annual investments to upgrade its power grid and meet clean energy targets, tapping into public financing could result in significant long-term savings for ratepayers. Changes to the ways in which transmission projects are procured, and the institutional models used to develop and operate them, may offer additional, indirect savings because of the impact they could have on the cost of financing, competition for, and taxation of transmission projects.

These initial insights on ways to reduce the ratepayer cost of transmission have motivated this report. The purpose of the report is to provide a more in-depth exploration of options to reduce ratepayer costs, focusing on increased public support in infrastructure development and the institutional models that could support the delivery of such financing. The remainder of the report is structured as follows:

- Section 2 describes the range of possible institutional options that could potentially be used to deliver public financing. These range from wholly public (government) ownership and operation, to wholly private, with mixed Public Private Partnership (PPP) models, in between.
- Section 3 describes the potential direct effects of public financing of transmission and the indirect impacts that could be associated with the use of the alternative institutional models described in Section 2.
- Section 4 identifies a set of transmission lines that could possibly be eligible for public sector financing under alternative institutional models.

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[13] "California Environmental Quality Act (CEQA)," accessed January 19, 2024, https://www.cpuc.ca.gov/ceqa/.

[14] California Public Advocates Office, "Public Investment in Infrastructure Is a Promising Option to Support California's Energy Transition and Reduce Ratepayer Costs," May 16, 2023, https://www.publicadvocates.cpuc.ca.gov/press-room/reports-and-analyses/public-investments-in-infrastructure.

[15] Conservation Strategy Group and Clean Air Task Force, "California Public Finance for Clean Energy Infrastructure: Concept Note," July 2023.

- Section 5 quantifies the possible impact on the cost of service of the direct and indirect effects identified in Section 3.

The evidence suggests that substantial direct cost savings could be achieved through the use of public sector financing, and additional savings could be achieved by delivering such financing through alternative institutional models.

SECTION 2 INSTITUTIONAL OPTIONS FOR PUBLIC FINANCING

Public financing of infrastructure is common throughout the world. State and local governments in the US, and governments internationally issue bonds or use general tax revenue to fund infrastructure investment. The advantages and disadvantages of using public financing are—to some extent—isolated from decisions about which institutions would be involved in providing the financing and developing the infrastructure project. The public sector will almost always be able to borrow at a lower cost than private companies in the same jurisdiction.

There are, however, important interdependencies between the use of public financing, and the institutional model chosen to deliver such financing. The choice of institutional model will determine the creditworthiness of the borrower and hence the cost at which they can borrow. The choice of institutional model may also bring other benefits, such as the introduction of operating efficiencies, or the reduction of tax obligations.

Section 2.1 describes the range of institutional models that have been used to develop electricity transmission infrastructure globally. Section 2.2 describes how rights, responsibilities, and risks are allocated under each of the institutional models.

2.1 THE RANGE OF INSTITUTIONAL OPTIONS

Infrastructure services, including electricity, water and sanitation, transportation, or telecommunications are delivered under a wide range of institutional arrangements that may involve public sector entities, private companies, or both.

Tradition in the United States is for electricity to be delivered by private companies for whom market entry, pricing, and service quality are regulated by state public service commissions or (for interstate service delivery) a federal regulatory agency (FERC).[16] Water supply and sanitation, in contrast, are more often delivered by municipalities and are thus fully publicly owned and operated and there is precedent in many states for the creation of wholly public "power authorities" or "transmission authorities" responsible for various aspects of transmission development and operation. The Colorado Electric Transmission Authority (CETA) and The New Mexico Renewable Energy Transmission Authority (RETA) are two of eight state-level transmission authorities in the United States (there are others in Utah, North Dakota, South Dakota, Wyoming, Kansas, and Idaho). CETA was modeled on New Mexico's RETA, but they differ in that Colorado has a higher population and considerably more internal demand for electricity than New Mexico. RETA is thus more focused on electricity exports.[17]

Box 1: The Colorado Electric Transmission Authority

The Colorado Electric Transmission Authority (CETA) is an independent, special purpose authority of Colorado established in 2021 by state legislators. CETA facilitates the development of electric transmission infrastructure for Colorado and neighboring states. Under sections 4 and 7 of Colorado General Assembly SB21-072, CETA is

[16] The extent and nature of regulation in the US electricity sector has changed substantially since the wave of power sector unbundling in the 1990s, but the transmission and distribution functions are still typically highly regulated.

[17] https://bigpivots.com/. "Colorado's 'Transmission Developer of Last Resort' - Big Pivots." Accessed April 12, 2024. https://bigpivots.com/colorados-transmission-developer-of-last-resort/.

authorized to select a qualified transmission operator to finance, plan, acquire, maintain, and operate eligible electric transmission and interconnected storage facilities.

CETA is entitled to issue revenue bonds, identify, and establish intrastate electric transmission corridors, and coordinate with other entities to establish interstate electric transmission corridors. The authority may also exercise the power of eminent domain to acquire eligible facilities, and collect payments of reasonable rates, fees, and interest from people using eligible facilities.

CETA operates within a strict set of guidelines from the Colorado legislature, which specify that the authority would only develop transmission necessary to achieve Colorado's decarbonization goals if unable to identify another party capable of doing so. Legislation prohibits CETA from competing directly with other transmission providers; it cannot plan, finance, or construct any transmission that another developer has pursued.

While CETA does not function as an active transmission developer, it encourages outside planning by identifying and publicizing projects that it views as necessary and allowing other utilities to take ownership of them. If another party pursues the project, CETA withdraws itself from its development. If no other entity shows interest, CETA may become the developer.

Sources:

"About CETA." Accessed April 12, 2024. https://www.cotransmissionauthority.com/about.
Catlin, Marc, Alex Valdez, Don Coram, and Chris Hansen. Public Utilities Commission Modernize Electric Transmission Infrastructure, Pub. L. No. SB21- 072 (n.d.).
https://bigpivots.com/. "Colorado's 'Transmission Developer of Last Resort' - Big Pivots." Accessed April 12, 2024. https://bigpivots.com/colorados-transmission-developer-of-last-resort/.

Box 2: The New Mexico Renewable Energy Transmission Authority

The New Mexico Renewable Energy Transmission Authority (RETA) was established in 2007 by state legislation to plan, finance, and acquire high voltage transmission lines and storage projects for the development of renewable resources across New Mexico. RETA sponsored projects must draw at least 30 percent of their energy from renewable sources. Currently, all projects plan to use 100 percent renewable energy.

RETA seeks a mutually beneficial collaboration with its private development partners. Their developers are expected to provide transmission design and construction expertise, as well as contributions to RETA administrative expenses via lease agreements. In turn, RETA offers tax exemptions (property, gross receipts, and compensating tax), high-level assistance with and streamlining on permitting and siting, and bond financing if necessary.

RETA has the authority to plan, finance, and acquire transmission; it currently has agreements with several developers to realize its goals. In 2010, the authority commissioned Los Alamos National Labs (LANL) to evaluate statewide transmission concepts and create a long-range infrastructure plan for the state. Today, RETA sponsors two projects that rely on the LANL report findings and recommendations, and as a result, has become the authority to act as a developer and potential owner of a merchant-based transmission project.

RETA's strides in both development and ownership reflect an effort to overcome the existing regulatory barriers to transmission development. RETA partnered with Clean Line Energy Partners (Clean Line) to develop the Western Spirit Project, which creates about 200 miles of construction before connecting with and drawing on the Public Service Company of New Mexico's (PNM) transmission system. To accelerate the project, RETA and PNM approached FERC to request a streamlined approval. Ultimately, FERC did not accept their request due to claims of harm from others in PNM's queue. To this date, none of the intervenors with claims have constructed a line and several intervenors have left the queue.

To date, RETA has completed two operational lines and established plans for four additional projects. Finishing its first project in 2010, the authority provided $50 million in revenue bonds to the upgrade of the High Lonesome Mesa line. In 2021, it completed its second line, a $150 million co-development of RETA and Pattern Energy named Western Spirit.

Currently, RETA is co-developing four lines, all under lease agreements: SunZia, Rio Sol, Mora, and North Path. Sunzia is set to be a $1.8 billion collaboration between RETA and SunZia, starting operation in 2025. The Rio Sol line is a $1.3 billion partnership between RETA and Rio Sol set to begin operating in 2028. Also in development, the Mora line is set to cost $83 million from the partnership of RETA and Lucky Corridor, and expects to start operation at the end of 2024. Finally, the North Path line, from RETA and Invenergy Transmission, remains in the early stages of planning and anticipates completion after 2030.

Sources:

RETA New Mexico. "Creating a Highway for Clean Energy - Transmission Lines NM RETA." Accessed April 12, 2024. https://nmreta.com/transmission-lines/.

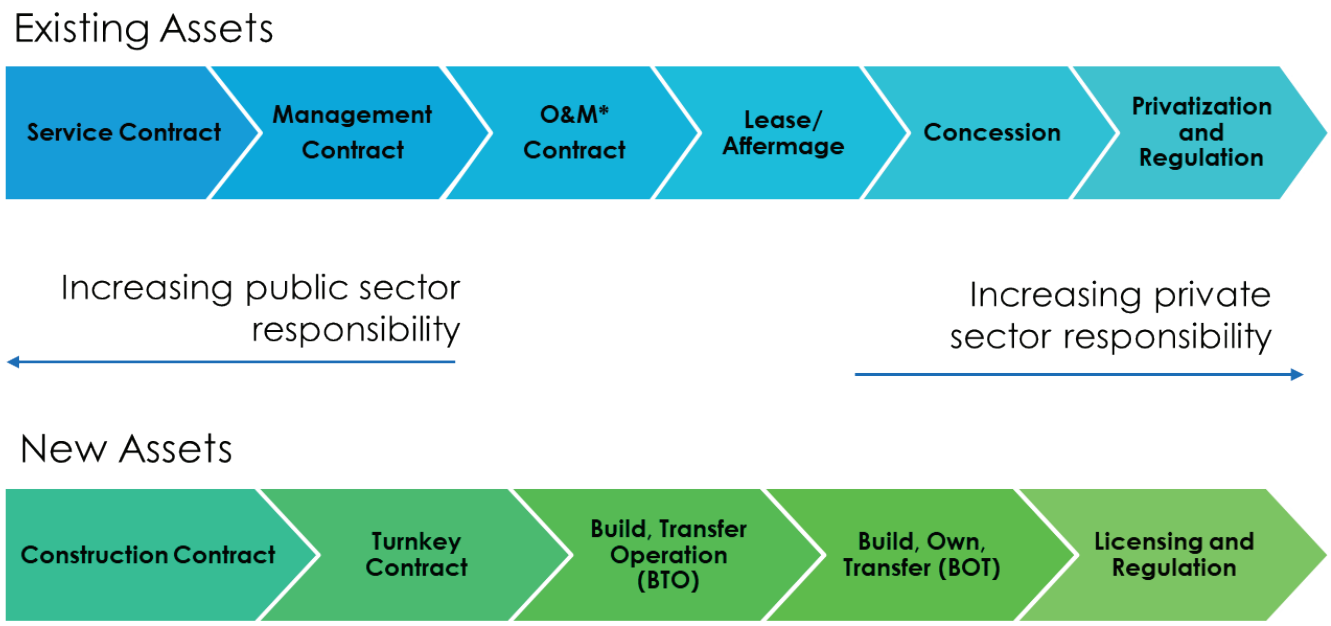
RETA New Mexico. "New Mexico Renewable Energy Transmission and Storage Study Update" February, 2022. Accessed April 12, 2024. *https://nmreta.com/wp-content/uploads/2022/03/010522-RETA-Executive-Summary-FINAL.pdf*.

RETA New Mexico. "New Mexico Renewable Energy Transmission Authority. Presentation to Science, Technology and Telecommunications Committee". September 1, 2023. Accessed April 12, 2024. *https://www.nmlegis.gov/handouts/STTC%20083123%20Item%2010%20%20RETA%20Presentation%2009-01-2023.pdf*.

Between these "wholly private" and "wholly public" institutional models are a range of PPP arrangements in which government has some responsibility for delivering service, and a private company has some responsibility. PPP arrangements are more common internationally than in the United States, but there are examples, especially in the roads sector, where PPP-type arrangements have proven more common than in other sectors.

Figure 2.1 shows the range of possible institutional options from wholly public (on the left of the figure) to wholly private (on the right of the figure), with varieties of PPPs in between. An important distinction shown in the figure is the one between institutional arrangements for existing assets and new assets. This report will focus primarily on PPPs that would involve the creation of new transmission assets.

Figure 2.1: Range of Institutional Options for Delivering Infrastructure Services



Source: Adapted from World Bank Group, ADB, EBRD, GI Hub, IADB, IsDB, OECD, UNECE, and UNESCAP, Public-Private Partnerships: Reference Guide, Version 3 (Washington DC: The World Bank Group, 2017), https://ppp.worldbank.org/public-private-partnership/sites/ppp.worldbank.org/files/documents/PPP%20Reference%20Guide%20Version%203.pdf
*Note: *Operations and maintenance*

2.2 ALLOCATION OF RIGHTS, RESPONSIBILITIES AND RISKS

An important feature of PPP arrangements is the existence of a contract between the public and private partners which details the allocation of rights and responsibilities between the parties, including pricing and the expected level of service. The types of contracts can be distinguished from one another by the allocation of functions between public and private partners. Figure 2.2 compares the allocation of functions between public an private partners for wholly public, wholly private, and three archetypal PPP arrangements.

Figure 2.2: Allocation of Rights and Responsibilities under Alternative Institutional Models

Functions	Public	Public Private Partnerships			Private
	Corporatized Public Entity	**Management Contract**	**Lease or Affermage Contract**	**Concession Contract**	**Divestiture (Privatization)**
Who owns the assets?	Public entity	Public entity	Public entity	Public entity	Private Company
What is the private operator's responsibility?	Managing the operating area	Managing the operating area	Providing utility service	Providing utility service	Providing utility service
Who receives the tariff revenue?	Public entity	Public entity	Private company receives part of tariff to cover O&M; Public entity receives part of tariff to cover capital costs	Private Company	Private Company
How is the private operator remunerated?	N/A	Fixed monthly or annual fee + incentive payments	Operating profit	Total profit	Total profit
Which risk does the private operator bear?	N/A	Loss of remuneration	Risk related to operations and/or demand†	Most risk of service provision (operations and investment)	All risk of service provision (operations and investment)
Who employs the staff?	Public entity	Public entity	Private Company	Private Company	Private Company
Who is responsible for capital expenditure?	Public entity	Public entity‡	Public entity‡	Private Company	Private Company
What is the typical term?	Perpetual	2-5 years	10-15 years	15-30 years	Perpetual

Source: Adapted from United Nations Economic and Social Commission for Asia and the Pacific (UNESCAP), A Primer to Public-Private Partnerships in Infrastructure Development (Bangkok: UNESCAP 2008), https://www.unescap.org/resources/public-private-partnerships-infrastructure-development-primer
Notes:
† Demand risk differs between lease and affermage contracts.
‡ The outside operator may manage implementation.

It is more important to understand the allocation of functions typical for different PPPs than it is to understand the "alphabet soup" of acronyms that are often used to describe different types of PPPs. The functions that matter the most are: designing and building the asset, operating the asset, and financing the asset. The table includes examples of acronyms used to describe projects with each allocation of functions. Table 2.1 summarizes how these functions are typically allocated in "greenfield" projects (i.e., projects that involve new construction).[18]

[18] "Brownfield" projects, on the other hand, involve investment (such as rehabilitation) in existing infrastructure.

Table 2.1: Allocation of Functions in Typical Greenfield PPP Arrangements

Who design and builds?	Who operates and maintains?	Who finances?	Examples of PPP acronyms
Private	Public	Public	Design-Bid-Build (DBB) Design-Build (DB) Build-Transfer (BT)
Private	Private	Public	▪ Design-Build-Lease (DBL) ▪ Build-Transfer-Lease (BTL) ▪ Built-Transfer-Operate (BTO)
Private	Private	Private	▪ Build-Operate-Transfer (BOT) ▪ Build-Own-Operate-Transfer or (BOOT) ▪ Design-Build-Finance-Operate (DBFO) ▪ Build-Own-Operate (BOO)

The allocation of functions is important because it determines which risks the public and private partners must bear, and how they are remunerated. Generally speaking:

- With design and build-type PPP contracts the private partner's revenues come from government payments for design and construction materials and services. These arrangements are often fixed-fee contracts: the public partner pays an agreed fee for the construction and then owns and operates the new asset. With fixed-fee arrangements, the private partner typically assumes the risks associated with construction, such as materials cost overruns or delays.
- With design, build, and operate-type PPP contracts, the private partner's revenues come from user fees (tariffs) or, if user fees cannot be charged, from monthly, quarterly, or annual government payments, sometimes referred to as availability payments. The user fees or government payments are intended to cover the private partner's operating and maintenance expenses. If user fees are charged for the infrastructure service, the private partner must transfer a portion of the user fees to the public partner, as compensation for the public partner's financing of the investment (this is sometimes referred to as a "lease fee"). The private partner assumes risks associated with operating the asset, and the public partner assumes risks related to financing the asset (for example, foreign exchange risk), and the overall asset condition and asset life.

- With design, build, operate and finance-type PPP contracts, the private partner collects user fees (or if user fees cannot be charged) a payment from government which covers all of its operating and maintenance, and financing costs. The private partner therefore assumes most if not all of the risks related to construction, operation and maintenance, financing, and the condition and life of the asset. Government ultimately owns the asset, but during the PPP contract period, the private partner has many rights of ownership, which may include the ability to pledge the assets as collateral for financing, or to dispose of some of the assets. They will also be required to hand over the assets in a certain agreed condition at the end of the contract period.

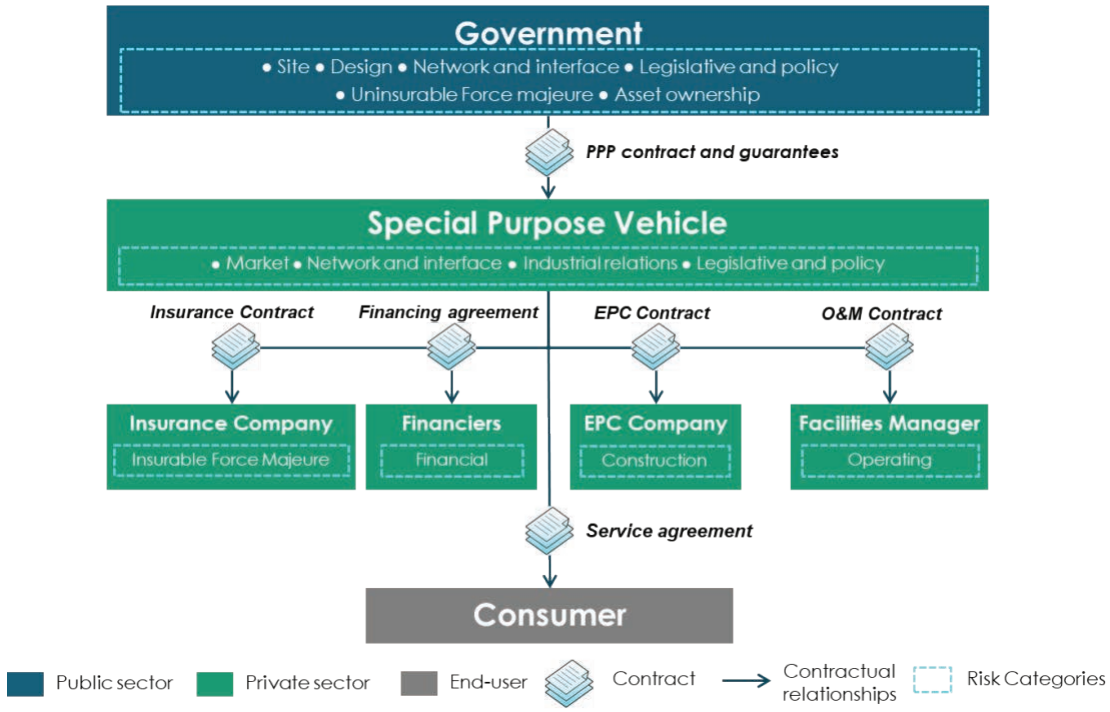
2.3 ADVANTAGES OF PPP ARRANGEMENTS

One of the principal advantages of PPPs is the existence of a contract in which risk allocation between the public and private partners can be made explicit; studies have shown that most of the cost advantages of PPPs are achieved through better risk allocation.[19] Moreover, at the heart of a PPP arrangement is as Special Purpose Vehicle (SPV) or Special Purpose Entity (SPE). The SPV is a separate legal entity created specifically for the PPP project. Its purpose is to isolate the project's assets, liabilities, and risks from those of the sponsoring entities (the public and private partners).

Another advantage of PPPs is the built-in allowance for competition for all aspects of development and operation. A single PPP contract is the binding instrument between the public and the principal private sector partner, but there are then multiple contracts between the principal private partner (the SPV) and its subcontractors for construction, operations, financing, insurance and other functions. Figure 2.3 is a stylized representation of a lease-type PPP contract, and the risks allocated between the various parties.

[19] Pauline Hovy and IMG Rebel, "Risk Allocation in Public-Private Partnerships: Maximizing Value for Money," Discussion Paper, August 2015, https://www.iisd.org/system/files/publications/risk-allocation-ppp-maximizing-value-for-money-discussion-paper.pdf.

Figure 2.3: Illustration of a Lease-Type PPP Arrangement



SECTION 3 PUBLIC FINANCING AND PPPS IN TRANSMISSION PROJECTS

Electricity customer rates or tariffs are determined in large part by the cost of providing service. Electricity sector regulators are concerned with ensuring that asset owners and operators recover the reasonable costs of delivering a given service. In the US, state regulatory commissions have authority only over IOUs. An IOU's cost of service is quantified by its "revenue requirement". The revenue requirement is the sum of a utility's costs, and typically includes operating costs (OPEX), capital costs (CAPEX), a return *of* capital invested (recovered through a depreciation charge or the principal component of debt service), a return *on* capital invested (interest payments to lenders and—if applicable—equity returns to the asset owners), and taxes.

Federal and state regulators in the United States predominantly use a "rate of return" approach to determine an asset owner's revenue requirement.[20] There are other methods (such as the "cash needs" approach used by some municipally owned utilities) but the rate of return approach predominates, and is the methodology FERC allows for determining the revenue requirements of transmission owners and operators who bid in transmission line tenders administered by the CAISO. In California, as with many Federally regulated transmission owners, the three IOUs use a variation of the standard "rate of return" method called "formula rates."[21] These rates are updated annually according to a formula rather than requiring a new rate case with a new test year.[22] A study by the National Association of Regulatory Utility Commissions (NARUC) explains them as "A ratemaking method in which the utility adjusts its base rates outside of a general rate case, usually annually, based on an actual or projected rate of return on rate base or equity that falls outside some commission defined band."[23]

Figure 3.1 is a stylized illustration of the components or "building blocks" of a transmission line owner's revenue requirement, using the rate of return approach. The RR is the sum of the asset owner's return *on* capital invested (a weighting of its borrowing costs and expected equity returns), depreciation (a return *of* the initial capital invested), OPEX costs, and taxes.

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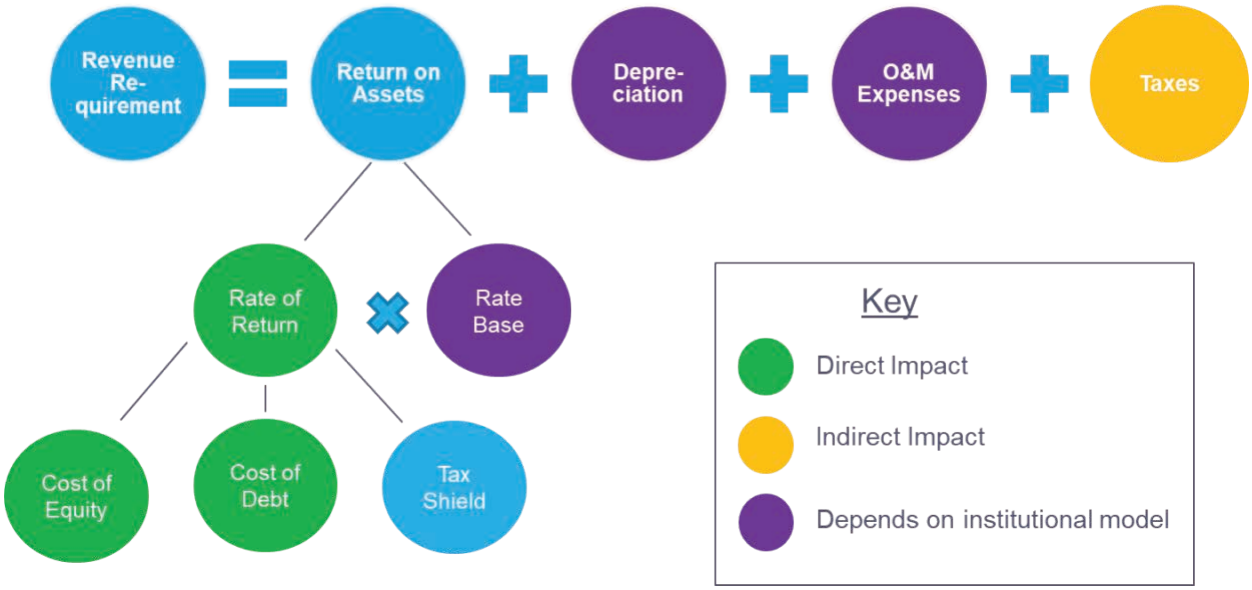
[20] The term "asset owner" is used instead of "utility" because some asset owners (e.g., merchant transmission owners) may not meet some readers' definitions of what is typically considered to be an "electric utility". Ther term "electric utility" is often reserved for IOUs.

[21] "Electric Transmission Rates and FERC Proceedings," accessed February 20, 2024, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/electric-transmission-rates-and-ferc-proceedings.

[22] WIRES Group, "Primer on Transmission Formula Rates," *Wires Group* (blog), February 16, 2023, https://wiresgroup.com/primer-on-transmission-formula-rates/; ELCON, "Formula Rates," *ELCON | Electricity Consumers Resource Council* (blog), accessed December 19, 2023, https://elcon.org/formula-rates/.

[23] Ken Costello, "Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives" (National Regulatory Research Institute (NRRI), April 2014), https://pubs.naruc.org/pub/FA86C519-AF31-D926-BE12-2AC7AE0CD8D6.

Figure 3.1: Building Blocks of the Revenue Requirement



As the figure indicates, some of the impacts of public financing are direct: Reducing the amount of equity in the capital structure and reducing the cost of debt would both reduce the revenue requirement. Other effects are indirect: Reducing the return on equity would—all else equal—reduce corporate taxes owed on that return. Section 3.1 describes these possible direct and indirect impacts.

A third set of possible impacts depends largely on the institutional model chosen for delivering the public financing. There are a range of possible institutional models that could capture the direct and indirect cost savings of public sector financing while also bringing other possible savings to consumers. These impacts are described in Section 3.2.

3.1 DIRECT AND INDIRECT IMPACTS OF PUBLIC FINANCING

Public financing would have a direct impact on a transmission line's rate of return, by reducing the cost of debt and reducing the need for higher cost equity in the capital structure. A reduction in return on equity could also mean lower corporate tax payments, further reducing the RR for a new transmission line.

3.1.1 RATE OF RETURN

The rate of return is—among the components of the revenue requirement—the most obviously and directly affected by public sector financing. The rate of return is a weighted average of the cost debt and cost of equity; it depends on the mix of debt and equity used to finance the transmission asset and the returns expected on debt and equity. In the case of debt, the returns are the interest payment required by lenders on loans; in the case of equity, the returns are what shareholders require in terms of dividend payments and changes in the value of the stock they own.

COST OF DEBT

Governments, and government agencies, are typically able to borrow at lower interest rates than private companies. Public sector borrowers are regarded as more creditworthy because they have the guarantee (explicit or implicit) of government, and government has access to recurring tax revenue. The public sector typically borrows by issuing bonds, with the interest rate determined by the bond "coupon". Public sector entities with better creditworthiness—as measured by their credit ratings—will typically have bonds with lower coupons than those that are viewed as less creditworthy.

Table 3.1: Comparison of State, Power Authority, and IOU Credit Ratings

State/ territory	State credit rating/outlook	Power Authority credit rating/ outlook	Biggest IOU credit rating/outlook
New York	AA+/Stable	AA/Stable	BBB-/Stable (national grid)
Long Island	N/A	A/positive	BBB+/Stable (KeySpan)
Colorado	AA/Stable	AA/Stable	BBB+/Stable (Xcel)
California	AA/Stable	AA/Stable	BB+/Stable (PG&E)

Sources:
"Credit Ratings & Analysis for Financial Markets." *Fitch Ratings*, www.fitchratings.com/#insights. Accessed 2 Apr. 2024. (used for all issuers except LADWP)
"KBRA: Credit Rating Analysis Agency: Bond Rating Agency." *Kroll Bond Rating Agency*, 28 Feb. 2024, www.kbra.com/publications/LVNmTQGn/kbra-assigns-aa-rating-to-the-department-of-water-and-power-of-the-city-of-los-angeles-power-system-revenue-bonds-outlook-is-stable. (used for LADWP)

Public corporations or agencies (such as a power authority) will have lower credit ratings than the state or local governments that own them. This can be seen in the table above by comparing the state of New York's credit rating to that of the New York Power Authority (NYPA) and the Long Island Power Authority (LIPA).

Bonds issued by state and local governments have the added advantage that they are often tax-free, meaning the bondholders (the lenders) do not pay taxes on the payments they receive from the bond issuers (the borrowers). This helps to further reduce the coupon relative to bonds that are not tax-free (e.g., corporate bonds). The IRS also allows a special kind of tax-free bonds for capital projects. IRS Rule 63-20 allows state

and local government to issue tax-exempt revenue bonds for a third party through a) established conduit issuers or b) the creation of nonprofit corporations applicable to IRS Revenue Ruling 63-20. Box 3 describes 63-20 financing and its perceived advantages.

Box 3: IRS 63-20 Alternative Project Delivery

63-20 financing involves a nonprofit corporation issuing tax-exempt bonds on behalf of a state or political subdivision. These bonds are used to finance governmental facilities. The name "63-20" originates from Revenue Ruling 63-20, which outlines the rules for this type of financing. The primary goal is not just tax-exempt financing but also an alternative development approach.

With 63-20 financing a nonprofit corporation issues bonds to finance the development of an asset on behalf of a state or municipal entity. The bond proceeds cover acquisition, construction, and equipping of the facility. The nonprofit issuer manages a private development team responsible for the project. The nonprofit issuer hires a private development team responsible for the project.

The perceived advantages of using 63-20 financing are often describe as the following:

- **Reduced project delivery time:** The approach circumvents the often protracted government financing and procurement processes, leading to faster project delivery.
- **Public assumption of responsibility for permitting.** The SPE secures the required project entitlements upfront, instead of leaving that to a private operator.
- **Operations & maintenance efficiency:** The utilization of private property management allows for improved lifecycle costing and the transfer of O&M risk to the private sector, reducing the likelihood of deferred maintenance.
- **Cost Transparency:** The use of tax-exempt financing results in debt service costs equivalent to traditional public financing options, ensuring transparency and predictability in project costs.
- **Protection from Risk:** The SPE is bankruptcy remote, protecting the public agency from construction and other risks.

Sources:

"Fifty Years of 63-20 Financing: Revisiting an Alternative ..." *MRSC*, mrsc.org/getmedia/530A597A-4D81-41AE-9279-3523D1BE0BAC/m58-63_20.aspx. Accessed 2 Apr. 2024.
Tax-Exempt Financing by Nonprofit Corporations ..., files.klgates.com/files/publication/d1586c6b-e6e4-42df-b131-919ed1d163cc/presentation/publicationattachment/ec29a420-819b-46ab-9e28-9479dc50ec26/tax_exempt_financing_by_nonprofit_corporations.pdf. Accessed 2 Apr. 2024.
63-20-PDB-Improving-upon-P3.Pdf - Public Facilities Group, 2020, publicfacilitiesgroup.org/wp-content/uploads/2020/09/63-20-PDB-Improving-upon-P3.pdf.
Public Facilities Group. *Four Principles: How to Maximize Public Benefits When Using P3 Delivery*, 2020 Public Facilities Group.

COST OF EQUITY

Equity typically has a higher cost than debt because shareholders have higher risks than lenders. Banks making loans to an infrastructure project will have legal rights, determined in loan agreements, which—if it does not receive the expected payments of principal and interest—give it recourse to the assets being financed. Equity owners have little or no such recourse and thus require higher returns to compensate them for the risk of their investments.

To the extent that debt is used instead of equity in the capital structure, it will reduce the overall cost of capital. Capital structures in US electric utilities are typically in the range of 40 to 60 percent debt and 40 to 60 percent equity. This is consistent with the ranges for California's major IOUs which CPUC authorizations ranged in 2021 from 43.00 to 47.50 percent Long-term Debt, 0.50 to 5.00 percent for Preferred Stock, and 52.00 percent Common Equity; actual capital structures in that time ranged from 44.00 to 56.44 percent Long-term Debt, 0.00 to 4.70 percent Preferred Stock, and 43.00 to 56.00 percent Common Equity.[24] Nationwide, annual average Return on Equity (ROE) for electric utilities have ranged from 9.63 percent to 10.81 percent since 2019.[25] Authorized ROEs for California's major IOUs ranged from 10.20 percent to 11.60 percent from 2006-2021, while actual ROE's ranged from -35.38 percent to 13.64 percent in that same period.[26]

Utilities' actual returns on equity can fluctuate for a variety of operational, financial, and regulatory factors, leading to differences between actual ROE and the authorized ROE, the latter of which is used for rate setting but is not a guarantee of any given level of return. For example, in 2021, though SCE was authorized to earn as much as 10.30 percent on equity ; but achieved only 3.45.[27] One of many contributing factors included material losses connected with wildfires in SCE territory in December 2017 and November 2018. Litigation costs, settlement activities, and damages in excess of available insurance resulted in significant losses exceeding $1.3 billion more than original estimates in the third quarter of 2021.[28]

3.1.2 TAXES

Public sector financing could have an indirect impact on taxes if it reduces the rate of return. A lower ROE will—all else equal—reduce the income tax obligations of a regulated transmission line.

3.2 INSTITUTIONAL FACTORS AFFECTING THE REVENUE REQUIREMENT

There are a range of institutional factors which—whereas not directly related to the source of financing—could have an impact on the revenue requirement of a new transmission line. These factors are:

- More competitive procurement, which can bring down CAPEX costs of transmission lines
- Accelerated clearance of pre-construction development, including permitting and regulatory approvals
- Private sector involvement in development and operations, which retains the efficiency advantages of having an experienced private sector operator.

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[24] CPUC, "Capital Structure," accessed 4/1/2024 at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/historical-electric-cost-data/capital-structure

[25] NARUC, "Cost of Capital and Capital Markets Primer for Utility Regulators," December 2019, https://pubs.naruc.org/pub.cfm?id=CAD801A0-155D-0A36-316A-B9E8C935EE4D

[26] CPUC, "Return on Equity," accessed 4/1/2024 at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/historical-electric-cost-data/return-of-equity

[27] California Public Utilities Commission. "Return of Equity." Accessed May 24, 2024, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/historical-electric-cost-data/return-of-equity

[28] Southern California Edison. "2021 Annual Report Edison International and Southern California Edison." 2021. https://download.edison.com/405/files/202210/2021-eix-sce-annual-report.pdf?Signature=bTLt6rslBQQD9tuFM70l7JXo%2BoU%3D&Expires=1716635813&AWSAccessKeyId=AKIAJX7XEOOELCYGIVDQ&versionId=J7O.wRg0NotvVA1WzSMV9w4b4oEXipVL&response-content-disposition=attachment

All of these factors could potentially reduce the RR of a new transmission line; whether they do depends heavily on the institutional model chosen.

3.2.1 MORE COMPETITION

There is evidence that increased competition in the procurement of transmission lines could reduce costs to end-users. Work by consultants at the Brattle Group indicates that more competitive processes in procuring transmission in the US could reduce capital costs by as much as 20-30%.[29] The Brattle Study looked at the results of competitive procurement in transmission in the US, Canada, the UK, Brazil, Chile, and Australia. Similar results can also be seen in competitive auctions in other countries. Box 4 shows, for example, the cost savings from competitive auctions for transmission lines in Peru when concession-type PPPs were used instead of letting the incumbent utility develop and operate the lines.

[29] Pfeifenberger, Johannes P., Judy Chang, Akarsh Sheilendranath, J. Michael Hagerty, Simon Levin, and Wren Jiang. "Report by Brattle Economists Discusses the Benefits of Competitive Transmission." Prepared for LSP Transmission Holdings, Brattle, June 21, 2021. *https://www.brattle.com/insights-events/publications/report-by-brattle-economists-discusses-the-benefits-of-competitive-transmission/*.

Box 4: Competitive Auctions for Transmission in Peru

Since 2002 in Peru, the private sector has competed in bids for 30-year operation and maintenance concession contracts guaranteeing fixed annual payments. PPP investments in electric transmission lines have exceeded 3,600 million Peruvian Sol (about 970K USD) from 2001 to 2020 and are steadily increasing. The successive competitive auctions have been tied to the system operator's biennial transmission expansion planning process since 2006, resulting in substantial whole-of-life cost reductions and increased competition for the investment of transmission systems.

- **Cost Reductions:** Winning bids for 15 projects between 1994 and 2013 were, on average, 36 percent lower than the estimated annual costs. One project developed in 2008 was a remarkable 58 percent lower. Private remuneration linked to 30 years of infrastructure operation ensured a long-term commitment to operational efficiency. This model promoted sustained growth, particularly in high and ultra-high voltage lines, with lower losses over long distances.
- **Increased Competition:** Competitive securities from bidders incentivized significant savings for the country. Competitive bidding led to bids averaging at least 40 percent lower than the government's maximum value in ten tenders from 2015 to 2021. The competitive nature of the auctions resulted in increased participation, fostering a healthier competitive environment. From 2015-2021, PROINVERSIÓN, the entity commissioned to award projects, saw five bidders on average per project in transmission line tenders.

Of the 27 projects awarded since 2008, 16 are operational. Once awarded, transmission projects in Peru cannot start the operational stage until they are granted all the needed permits, including environmental, technical and social approvals. Most of the awarded projects that are not yet operational are delayed in obtaining environmental certifications because of political conflict in the country, and because of delays in acquiring essential permits despite legal deadlines, the need for prior consultation with indigenous communities following recent legal changes, and bureaucratic hurdles in approving schedule extensions. Nonetheless, the overall perception of PPP transmission projects in Peru is positive. In 2023 alone, 14 projects were awarded, with investments totaling over US$ 2,330 million. Of these PPPs, 8 were transmission projects, for a total of US$1.2 billion, which represents more than 53% of the total awarded value. For 2024, 4 groups of transmission projects are expected to be awarded, with a value of more than US$ 900 million.

Beyond cost savings and increased competition, Peru's transmission PPPs have brought about additional benefits such as job creation, enhanced reliability, minimized service disruptions, improved efficiency, and balanced energy prices across regions.

To tackle some of the challenges of implementing PPP projects, recent legal and regulatory changes in Peru's PPP framework, highlighted by the implementation of Legislative Decree No. 1362, aim to streamline processes and enhance transparency, reduce bureaucratic delays and foster better public-private coordination. These reforms are designed to stabilize the investment environment, addressing chronic issues such as contract renegotiations and permit delays, to ensure the timely execution of infrastructure projects.

Sources:

Pedro E. Sanchez and Samuel Oguah, "Private Sector Participation in Transmission Systems: Making It Work," World Bank Group Livewire: A Knowledge Note Series for the Energy & Extractives Global Practice, 2015, *https://ppi.worldbank.org/content/dam/PPI/resources/ppi_publication/web_publication/100989-BRI-VC-PUBLIC-ADD-SERIES-Box393254B-Knowledge-Notes-LW52-OKR.pdf*

PROINVERSIÓN, "Investments in PPP Exceed $ 3,600 Million and Contribute to Sustaining Economic Activity," September 1, 2021, *https://www.investinperu.pe/en/ppp/detalle-noticia/investments-in-ppp-exceed-3600-million-and-contri*

Diana Briones Morey and Diego Morales Alferrano, "Proyectos de transmisión de electricidad: problemas recurrentes y agenda pendiente | IUS 360," April 3, 2023. *https://ius360.com/proyectos-de-transmision-de-electricidad-problemas-recurrentes-y-agenda-pendiente/*.

Cost savings from competitive procurement have an impact on the revenue requirement through the "rate base". The rate base for a transmission line is the asset value of that line at any given point in time. The value of the rate base is driven largely by the capital expenditure (CAPEX) cost of that asset and its age.[30] The CAPEX cost is the cost of building the line but may also include pre-construction project development costs, as FERC's Uniform System of Accounts considers construction costs to includes a wide range of development costs beyond materials & supplies. Some of the other costs include: contract work, labor, privileges and permits, engineering and supervision, legal expenditures, studies, training costs.[31] Financing costs are also allowed as an Allowance for Funds Used During Construction (AFUDC). All of these costs may be included in the rate base once the asset becomes operational.[32]

A reduction in rate base has the following cumulative impacts on a revenue requirement:

- The total dollar return on debt and (if applicable) equity will be lower because the WACC is applied to a lower asset value
- Corporate tax obligations will be lower, because the return is lower
- Depreciation charges will be lower, because the asset cost is lower
- OPEX may also be lower to the extent—as we assume in Section 5—that they are a percentage of CAPEX costs.

There are thus spillover effects of a reduction in rate base, potentially leading to a lower revenue requirement overall and lower tariffs.

3.2.2 ACCELERATED DEVELOPMENT

As noted above, non-construction development costs may be capitalized or "rolled-in" to a utility's rate base and may even be recovered (as Construction Work in Progress, CWIP) before an asset is operational. The longer development period, the higher the costs are likely to be. Moreover, the likelihood of a project going forward reflects risk, which also has a cost in terms of ROE (higher risk projects will typically have a higher ROE).

The extent to which regulators allow such development costs to be included in a rate base will differ by jurisdiction and circumstance. It is therefore difficult to know the magnitude of such costs, but evidence from canceled transmission projects indicates that they are substantial. The costs include expenses for financing arrangements, permitting, and regulatory compliance. Evidence of the magnitude of such expenditures can be seen where projects have been abandoned. As noted above, the Northern Pass project in New Hampshire incurred $318 million in sunk costs for pre-development activities, representing roughly 20% of its estimated total cost of $1.6 billion.[33] Similarly, the Hydro-Québec US transmission line project in Maine saw $450

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[30] The asset's age matters because assets deteriorate over time, and with that deterioration, lose value. See the discussion in Section **Error! Reference source not found.** on depreciation.

[31] "18 CFR Part 101 -- Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act." Accessed April 1, 2024. https://www.ecfr.gov/current/title-18/part-101.

[32] Utilities may also be able to recover some of them before the line is commissioned, as "Construction Work in Progress" or CWIP.

33 Michael Cousineau, "Eversource giving away land bought for failed Northern Pass project," New Hampshire Union Leader, June 26, 2023, https://news.yahoo.com/eversource-giving-away-land-bought-225400675.html

million (43% of the estimated total project costs) spent in pre-development.[34] If there is a 50% probability of failure and a 20% cost for failure, then every developer has to build in a minimum 10% risk adder to the CAPEX.

The potential savings to ratepayers is in reducing the window of time for permitting and regulatory approval as well as reducing the development risk that extended review implies. This could reduce development costs that later enter into the rate base. The savings would come first from reducing the number of years and level of effort utility staff have to work on pre-construction project development. Second, it would come from early termination for projects rejected by regulatory agencies as in the case of Northern Pass. The early termination limits the amount spent on failed projects and thus the risk premium for development.

3.2.3 PRIVATE SECTOR EXPERTISE AND EFFICIENCY

There is an extensive body of literature devoted to analyzing the efficiency and effectiveness of public sector institutions versus private. The literature is—as a whole—largely inconclusive, in part because the results are so often highly dependent on context.

Without entering into specific arguments on either side, there is at least anecdotal evidence that the private sector can be given incentives to operate more efficiently than the public sector in delivering infrastructure services. In the Peru example in Box 4, it is apparent that the private transmission concessionaires helped to reduce whole-of-life costs of transmission and not just CAPEX costs. Common sense also suggests that:

- There are advantages in having a specialized private sector developer and operator who can bring the right skills to a project.
- Giving a developer/operator a profit incentive can be a powerful performance motivator.
- Making potential developers/operators compete *for* a market (i.e., for the exclusive right to earn revenue from a transmission asset) has the potential to reduce costs.

What is clear is that supply chain challenges and skilled labor shortages are one important factor in the delays experienced in developing new transmission lines. The creation of a public sector entity responsible for transmission development would be competing with long-established, experienced private developers and IOUs for materials and labor.

3.2.4 TAXATION

One possible advantage of having a public asset owner—such as Power Authority—is that these public entities are not typically required to pay income taxes and may be exempt from some other taxes, including sales or property tax.[35] NYPA, for example, is exempt from income taxes and properties acquired for its projects.[36] PRPA is similarly exempt from income and property taxes.[37] LIPA is not obliged to pay income tax, but its status for property and sales tax have been the subject of a series of disputes over the years.

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34 "Hydro-Quebec scores legal victory in Maine over $1B US transmission line project," CBC News, April 20, 2023, https://www.cbc.ca/news/canada/montreal/hydro-quebec-1.6816752

35 A utility may, in some circumstances, make "payments in lieu of taxes" to reimburse local governments for foregone property taxes.

36 Tu, Kailin. "Proposed 2023 Budget and 2023–2026 Financial Plan," 2023.

37 https://www.prpa.org/wp-content/uploads/2021/04/Organization-Governance-April-2020.pdf

3.3 COMPATIBLE INSTITUTIONAL MODELS

The discussion above suggests that the most appropriate institutional models will be those that:

- Allow for the use of public debt in financing transmission lines and facilitate savings in other areas, such as taxes.
- Foster competition among bidders in ways that reduce project costs.
- Allow for private sector involvement in development and/or operations.
- Accelerate the transmission development process, especially the period before construction which is the riskiest from an investor perspective.

Table 3.2 summarizes how four possible institutional models, ranging from wholly public to wholly private rank against these criteria.

Table 3.2: How Alternative Institutional Models Can Reduce Costs

	Facilitates Savings from the Use of Public Financing?	Facilitates Competition?	Facilitates Private Sector Involvement?	Accelerates Development?
Wholly Public	Yes	Would likely involve a competitive tender for design and build functions only	Limited to design and build functions	Possibly, but would likely require substantial institutional, legal, and regulatory changes
Lease Contract	Yes, the government is an asset owner	Yes, would involve competitive tender for the design, build, and operate functions over short-term (typically 3-5 years)	Yes, a private sector operator is hired as a lessee	
Concession Contract	Typically, privately financed	Yes, would involve competitive tender for the design, build, and operate functions over the life of the asset	Yes, private sector operator is hired as concessionaire	
Wholly Private (IOUs)	Typically, privately financed	Depends on the type of tender, but for many lines tendered by CAISO, incumbent utilities already have access to property or rights-of-way	Yes, utility is private company	No. Current process takes 5-15 years

A lease contract-type PPP offers—in our view—the best mix of ability to inject public financing, harness other possible benefits of public ownership (e.g., some degree of tax-exempt status and the ability to issue tax-exempt bonds), and involve private sector expertise. Any of the models could conceivably help to accelerate the development process—for example, the creation of a "one stop shop" for expedited regulatory approvals—but would require substantial institutional, legal, and regulatory changes in any case.

The principal disadvantages of other models are:

- The wholly public model does not build in the participation of the private sector beyond the design and build stage.
- The concession-type PPP would mean private sector financing, and the ROE and commercial debt that comes with it. It is conceivable, however, that the public sector could provide some concessional financing (or even grants) to reduce the cost of capital.
- The wholly private model is "business-as-usual", with private sector financing costs, and no solution to the long delays in project development.

As noted in the table, none of the models offers an easy solution to accelerating project development without substantial institutional, legal, and regulatory changes. These would be required, regardless of the model chosen.

Most international tenders for transmission have been concession-type PPP contracts, but there is precedent in the US, and in other infrastructure sectors, with lease-type PPPs. Lease-type contracts have been used, for example, in the development of road projects. Such leases are longer-term than those typically seen for other infrastructure projects, but the principles of upfront public financing and private operation are the same. Box 5 describes some of the projects. In the case of the Pocahontas Parkway, tax-exempt IRS 63-20 financing was used.

Box 5: Lease-type Roads Contracts in the United States

PPPs for infrastructure are more common internationally than in the United States; they have been more common in the US roads sector than in other sectors. The following are examples of lease-type PPPs used in US roads sectors:

- **Chicago Skyway:** In 2004, the Chicago Skyway toll road's lease was awarded to Cintra and Macquarie for $1.83 billion, marking the first long-term lease of an existing toll road in the United States. In 2015, they sold their interest to Calumet Concession Partners LLC, a consortium of Canadian pension funds, for $2.8 billion. Calumet now operates the Skyway, collecting tolls until the lease expires in 2104, ensuring its continued functionality as a crucial transportation link.
- **Indiana Toll Road:** In 2006, the Indiana Finance Authority (IFA) leased the Indiana Toll Road to the Indiana Toll Road Concessions Company (ITRCC) for 75 years, with ITRCC assuming authority in June of the same year. The lease mandated a $200 million investment in capital improvements within the first three years and a total of $4.4 billion over its duration. However, in 2015, ITRCC filed for bankruptcy, leading to the IFA awarding a new 66-year lease to IFM Investors for $5.725 billion.
- **Northwest Parkway:** The Northwest Parkway connects E-470 in Denver to US Route 36 in Broomfield Colorado. It was initially opened in 2003 and financed through toll revenue bonds. The project faced financial challenges due to lower-than-expected traffic volume by 2007, leading to its lease to a private consortium, Northwest Parkway LLC, for 99 years. The agreement entailed an upfront cash payment, the takeover of existing debt, and an annual administrative fee to the Authority over the lease's duration. A portion of the debt was held in escrow pending issuance of notices to proceed by the end of 2018, aiming to extend the parkway's operations.
- **Pocahontas Parkway/Richmond Airport Connector:** The Pocahontas Parkway was primarily financed by tax-exempt revenue bonds totaling $354 million issued by the Pocahontas Parkway Association in 1998 under Virginia's Public Private Transportation Act of 1995. Financing also included a State Infrastructure Bank loan of $18 million and $9 million from the federal government for roadway design. In 2006, a 99-year lease of the Parkway was granted to Transurban, a private Australian toll road operator with US subsidiaries. In exchange for assuming exclusive rights to enhance, manage, operate, maintain, and collect tolls on the Parkway, Transurban committed to constructing the Richmond Airport Connector, a 1.58-mile extension linking the toll road to Richmond International Airport.

Sources:

"Project Profile: Chicago Skyway." *FHWA*, US Department of Transportation Federal Highway Administration, www.fhwa.dot.gov/ipd/project_profiles/il_chicago_skyway.aspx. Accessed 2 Apr. 2024.
"Project Profile: Indiana Toll Road." *FHWA*, US Department of Transportation Federal Highway Administration, www.fhwa.dot.gov/ipd/project_profiles/in_indiana_toll.aspx. Accessed 2 Apr. 2024.
"Project Profile: Northwest Parkway." *FHWA*, US Department of Transportation Federal Highway Administration, www.fhwa.dot.gov/ipd/project_profiles/co_northwest_parkway.aspx. Accessed 2 Apr. 2024.
"Project Profile: Pocahontas Parkway / Richmond Airport Connector." *FHWA*, US Department of Transportation Federal Highway Administration, www.fhwa.dot.gov/ipd/project_profiles/va_pocahontas.aspx. Accessed 2 Apr. 2024.

Lease-type contracts have also been used in social infrastructure projects, including educational facilities, civic buildings, and healthcare facilities. The nonprofit "Grow America" (formerly the National Development

Council) pioneered the approach and an organization called the Public Facilities Group has been involved in disseminating it, and advising on transactions.[38] Box 6 summarizes the principles behind the approach.

Box 6: The "New American" Approach to PPPs

The "New American Approach" involves the following steps:

1. A public agency hires a not-for-profit partner through competitive tender to lead development of the project. The not-for-profit partner will issue the debt and own the facility on behalf of the public agency. The not-for-profit partner is remunerated through a portion of the bond proceeds.
2. The public agency and not-for-profit partner select (again through competitive tender) a development team consisting of a lead developer, general contractor, and architect.
3. The development team works with the public agency and not-for-profit partner to design the project. The not-for-profit partner also secures approval of all project entitlements required to develop the project. The public agency and not-for-profit partner negotiate a long-term lease between themselves for the planned facility.
4. The not-for-profit partner creates a special purpose entity (SPE) to own and finance the asset. The SPE issues bonds (working with a bond underwriter) to sell to investors. The bond proceeds are held by a separate agency appointed as a trustee.
5. The not-for-profit partner staffs the SPE and manages construction and contractor payments. A private property management firm is selected through competitive tender to operate the facility once it is completed.
6. Once construction is completed, the public agency (or the intended beneficiaries) move into the building and the lease takes effect. The public agency makes lease payments (as rent) to the SPE which cover debt service, operating costs, and contributions to a repair and replacement reserve. Repair and replacement reserves are held by the trustee.
7. The property management firm works for the SPE, taking responsibility for managing the facility and undertaking routine operations and maintenance. The management agreement is re-tendered every 3-5 years.
8. Once the public agency has made its last lease payment, the debt is retired and excess funds from the repair and replacement reserve return to the public agency. The public agency may then take on responsibility for property management and ownership of the project.

Sources:

Public Facilities Group. "Our Approach." Public Facilities Group (blog). Accessed April 1, 2024. https://publicfacilitiesgroup.org/our-approach/.

A number of non-IOU companies specialize in owning, operating, and maintaining high-voltage transmission lines and related infrastructure. These are just examples of some of the private partners who may potentially be interested in additional transmission projects in California. Some independent power transmission companies in North America including the ITC Holdings Corp (operating assets in Michigan, Illinois, Iowa, Kansas, Minnesota, Missouri, Oklahoma, and Wisconsin), NextEra Energy Transmission (subsidiaries

[38] Public Facilities Group, "Our Approach," Public Facilities Group (blog), accessed January 12, 2024, https://publicfacilitiesgroup.org/our-approach/.

operating assets in California, Illinois, Indiana, Kansas, Kentucky, Nevada, New Hampshire, New York, Oklahoma, Texas and Ontario, Canada), and Sharyland Utilities LLC (operating assets in Texas and Mexico).[39] Other energy infrastructure companies whose business has been traditionally focused on natural gas pipelines or energy generation assets have also begun entering partnerships to develop transmission capabilities, such as Enbridge's recent partnership with NextEra Energy Canada and OMERS Infrastructure to build and operate the East-West Tie (EWT) Transmission Project, now operational in northern Ontario.[40]

Specialized investment funds that focus on acquiring and managing infrastructure assets, such as Meridiam and Boundless Energy, have also teamed up with grid operators to develop, construct, and operate large-scale transmission assets. Private equity firms also sometimes invest in or acquire and manage electricity transmission assets, either directly or through portfolio companies. For example, Atlantic Power Transmission, LLC. is a Blackstone Infrastructure Partners Portfolio Company, constructing and operating planned transmission systems along the US East Coast.

3.4 CALIFORNIA TRANSMISSION PPP EXAMPLES

Some transmission projects in California can also be classified as PPP projects. Three examples are summarized in Appendix A: a) the Path 15 project completed in 2004, b) the Trans-Bay Cable completed in 2010, and c) the West of Devers Upgrade Project completed in 2021.

In each case, although there was a partnership with a public entity, the tariff included a ROE. In the case of Path 15 and Trans-Bay Cable (catalogued as a critical transmission asset), an initial ROE of 13.5% was granted by FERC as part of a policy to stimulate construction of transmission.[43] The rates for Path 15 and the Trans-Bay Cable were contested, but only the Path 15 ROE was reduced to 10.6%.[44] In the case of the West of

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[39] ITC Holdings Corp. "Home." Accessed May 24, 2024, *https://www.itc-holdings.com/*; Sharyland Utilities. "About." Accessed May 24, 2024, *http://www.sharyland.com/about.aspx*; NextEra Energy Transmission. "Home." Accessed May 24, 2024, https://www.nexteraenergytransmission.com/

[40] Enbridge. "Power transmission." Accessed May 24, 2024 https://www.enbridge.com/about-us/renewable-energy/power-transmission

[41] Shumkov, Ivan. "Italy's Terna, France's Meridiam team up in US to build power links." October 25, 2022. Renewables New. Accessed May 24, 2024. *https://renewablesnow.com/news/italys-terna-frances-meridiam-team-up-in-us-to-build-power-links-802246/*

[42] Chirhart, Paula. "Atlantic Power Transmission LLC, a Blackstone Infrastructure Partners Portfolio Company, Announces $50 Million Commitment to New Jersey Workforce Development." April 22, 2022. Blackstone. Accessed May 24, 2024 *https://www.blackstone.com/news/press/atlantic-power-transmission-llc-a-blackstone-infrastructure-partners-portfolio-company-announces-50-million-commitment-to-new-jersey-workforce-development/*

[43] "Analysis of FERC's Notice of Proposed Rulemaking on Electric Transmission Incentives," Steptoe, accessed March 25, 2024, https://www.steptoe.com/en/news-publications/analysis-of-fercs-notice-of-proposed-rulemaking-on-electric-transmission-incentives.html.

[44] "E-6 ER20-1006-001 | Federal Energy Regulatory Commission," accessed March 24, 2024, https://www.ferc.gov/media/e-6-er20-1006-001.

Devers Upgrade Project, the Morongo Tribe partnered with Southern California Edison (SCE). The Morongo Tribe was granted an ROE of 10.8% based on the approved SCE rate of 10.3% plus a 0.5% premium.[45]

[45] FERC, "Order on Rehearing, Morongo Transmission LLC Transmission Owner Tariff," FERC Docket ER21-669-001, May 5, 2021, https://elibrary.ferc.gov/eLibrary/filedownload?fileid=15786960.

SECTION 4 IDENTIFYING TRANSMISSION PROJECTS FOR PUBLIC FINANCING STUDY

The objective of this study is to estimate possible ratepayer savings that could be achieved through public financing and new institutional arrangements. This is motivated by the increasing costs driven by the renewable buildout.

The California ISO 20-Year Transmission Outlook is the benchmark study for cost savings because it is the longest-term plan and is designed to meet the needs of the renewable generation buildout of Senate Bill 100.[46] The 20-Year Transmission Outlook identifies $30.5 Billion of transmission infrastructure buildout deemed necessary to meet the goals of Senate Bill 100.

However, perhaps not all projects in the 20-Year Transmission Outlook would benefit from the new institutional arrangements. There may also be additional transmission projects outside the 20-Year Transmission Outlook that we should consider as potential candidates.

This section identifies the scope of transmission projects that could take advantage of the new approach. There are two questions:

1. Which source of planned projects should form the set of transmission improvements to examine in the cost savings analysis?
2. Of all the possible transmission projects, which projects could adopt the new institutional arrangement? Some projects are IOU-financed by law and the law cannot be changed quickly or easily.

4.1 TRANSMISSION PROJECTS FOR CONSIDERATION

EXISTING TRANSMISSION MAINTENANCE AND UPGRADES

Existing transmission can and does cause significant cost increases. IOUs have the authority to replace existing equipment and recover the cost under their existing tariffs. This is allowed under the use of existing formula rates. State regulators both in and outside California have identified this activity as a major cause of increasing rates. The CPUC noted that in California:[47]

> …a majority of transmission projects have received no review and approval by the CAISO or the Commission, and in years 2019-2021, these Utility Self-Approved ("self-approved") Projects represented over 63% (i.e., $4.2 billion) of the $6.6 billion of capital additions added to the three TOs' transmission rate bases.

[46] CAISO, "20-Year Transmission Outlook," May 2022, https://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf.

[47] CPUC, "Resolution Establishing the Transmission Project Review Process," Final Resolution E-5252, May 2, 2023, https://webprod103.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/transmission-project-review-process.

Outside California the same issue has been raised through a FERC complaint by the Ohio Consumers' Counsel.[48] The underlying problem is that FERC jurisdictional utilities may replace transmission assets as part of on-going business, and this may only "incidentally" increase transmission capacity.

While these replacement activities that incidentally increase transmission capacity are costly, their regulatory treatment is an area of active litigation. Furthermore, the transmission maintenance and upgrades are a core IOU activity. Transferring those assets and investments to a public or nonprofit entity would face high legal hurdles. *We will not include these projects in our cost analysis.*

CAISO 2022-2023 TRANSMISSION PLAN PROJECTS

The CAISO proposes transmission projects for grid expansion. These are—in theory—eligible to participate in the competitive tender. Any type of entity, including the PPPs proposed here, may participate in the tender.

The CAISO has a tariff-required annual transmission planning process that examines transmission needs over the next ten years. The CAISO 2022-2023 Transmission Plan identified $7.3 Billion of projects. Of these projects the majority were improvements to existing infrastructure such as upgrading transformers from 230 kV to 500 kV, or reconductoring existing lines to allow for a higher thermal limit.

Three projects identified in the 2022-2023 Transmission Plan were eligible for competitive procurement. They amounted to an estimated $3.1 Billion or approximately 43% of the $7.3 Billion total.

The 2022-2023 Transmission Plan included expanded electrification as part of the base case and this partially led to the $1.3 Billion of "Reliability-Driven" projects associated with the higher load.

The distinction of what is and is not eligible to be part of a competitive tender determines the size of the savings that can be achieved. The 2022-2023 Transmission Plan is essential to reverse engineering the criteria used by the CAISO in determining what should be eligible for a competitive tender, and what not. These criteria will be discussed at more length below in Section 4.2.

The CAISO 2022-2023 Transmission Plan does not fulfill the needs imposed by Senate Bill 100 as the 20-Year Outlook does. It also includes many projects that the CAISO has not identified as eligible for competitive tender. These are "reliability-driven" and reflect increased demand from electrification.

While the CAISO 2022-2023 Transmission Plan does not represent the full set of projects required for Senate Bill 100, it *does provide detail that can be used to confirm the criteria the CAISO uses to identify which projects can be submitted to a competitive tender*.

PROJECTS IN THE CALIFORNIA ENERGY COMMISSION OFF-SHORE WIND STUDY

The CEC was charged by Assembly Bill (AB) 525 (Chiu, Chapter 231, Statutes 2021) to produce a strategic for floating offshore wind energy development in federal waters off the California coast. The resulting report estimated the cost of transmission to support off-shore wind turbines on the north coast of California at $7.51-$41.35 Billon.

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[48] Ohio Consumers Counsel, "Ohio Consumers' Counsel Complaint Re Local Transmission Planning Oversight," FERC Docket No. EL23-105-000 (Office of the Ohio Consumers' Counsel, September 28, 2023), https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231205-5021&optimized=false.

This report only looked at transmission for off-shore wind and did not examine the cost of meeting Senate Bill 100. However, *the supporting analysis provides additional details, such as the length of useful life for transmission assets, that will be used in the cost analysis*.

BEST CANDIDATE: CAISO 20-YEAR TRANSMISSION OUTLOOK

The CAISO 20-Year Transmission Outlook provides the best set of proposed transmission projects to evaluate in the cost analysis. However, the CAISO 2022-2023 transmission plan provides details that are useful in determining what criteria determine eligibility for competitive tenders, and the CEC Off-Shore Wind Study provides useful cost modeling details.

4.2 CRITERIA FOR DETERMINING PROJECT ELIGIBILITY

The potential for savings depends on the scope of transmission projects that can use innovative public financing structures. The competitive tenders run by CAISO for new projects provide a straightforward application scenario. These would not require challenging IOU rights or current CAISO practices.

This section will review the regulatory framework supporting—and limiting—competitive tenders.

FERC ORDER 1000

FERC Order 1000 eliminated transmission owners' right of first refusal, the right to build any required new transmission in their area.[49] The existing transmission owners were strongly opposed to the rule and FERC's final rule included text that limited the scope of the change. Incumbent transmission owners maintain control over their existing infrastructure:[50]

> [Order 1000 reforms] do not affect the right of an incumbent transmission provider to build, own, and recover costs for upgrades to its own transmission facilities, such as in the case of tower change outs or reconductoring, regardless of whether or not an upgrade has been selected in the regional transmission plan for purposes of cost allocation.

Further, Order 1000 did not remove the right of rest refusal from "local" transmission, defined as:[51]

> "..a transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation."

Over time the implementation of FERC Order 1000 has interpreted the competitive solicitation requirement as applying when:

a) The transmission project is an expansion of the grid.

b) The project is not part of "local" transmission.

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[49] FERC, "FERC Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities," FERC Docket Docket No. RM10-23-000 (FERC, July 21, 2011), https://www.ferc.gov/sites/default/files/2020-04/OrderNo.1000.pdf.

[50] FERC, at 319.

[51] FERC, at 63.

c) The project is not an upgrade of the transmission owners' facilities.

APPLICATION OF FERC ORDER 1000 IN CALIFORNIA

As the California Public Advocate noted, the application of the FERC criteria in California depends on an arbitrary definition of local transmission as all equipment below 200 kV. The CAISO tariff defines a Local Transmission Facility as:[52]

a) Under the CAISO Operational Control,
b) Is owned by a Participating TO [Transmission Owner or equivalent],
c) Operates at a voltage below 200 kilovolts, and… is located entirely within a Participating Transmission Owner's [PTO] footprint or PTO Service Territory.

As the Public Advocate further pointed out other RTOs have more permissive limits (Southwest Power Pool and ISO-NE have limits of 100 kV, NYISO does not use a kV limit).

The second benchmark test is whether a project can be classified as "upgrade" or an "expansion." An expansion falls under FERC Order 1000 transmission planning and would be subject to competitive procurement, an upgrade does not.

The distinction between "upgrade" and "expansion" does not have a basis in electric power; an increase of 500 MW transfer capacity between two points has the same result however it is categorized. However, if one category is applied the incumbent has an exclusive right, in the other a competitive tender is held.

This second benchmark test is not defined. The next section examines how this has been implemented in practice by the CAISO as part of determining which projects are eligible for competition, and hence innovative financing structures such as PPPs.

ORDER 1000 CRITERIA IMPLICIT IN CAISO DETERMINATION OF COMPETITION ELIGIBILITY IN CAISO 2022-2023 TRANSMISSION PLAN

The CAISO 2022-2023 Transmission Plan approved 46 new transmission projects. Of these only three projects were identified as eligible for competitive procurement, although they were large projects and accounted for 43% of the total cost[53]. These three (numbers 13, 14, and 16) are circled in red in Figure 4.1.

[52] CAISO, "California Independent System Operator Corporation: Fifth Replacement FERC Electric Tariff," Open Access Transmission Tariff, January 1, 2023, https://www.caiso.com/rules/Pages/Regulatory/eTariff.aspx, Appendix A; California Public Advocates Office, "Competitive Solicitation in Transmission Line Development Lowers Ratepayer Costs and Decreases Delays," June 9, 2023, https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/230609-caladvocates-increasing-competitive-solicitation-in-transmission.pdf.

[53] CAISO, "2022-2023 Transmission Plan," May 18, 2023, https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=13E8A7DF-2D59-4BAE-9794-C99CC5945FA5.

Figure 4.1: CAISO 2022-2023 Transmission Plan

No.	Project Name	PTO Area	Geographic Area	Cost ($M)
11	Vista-Etiwanda 230 kV 1 Line Upgrade	SCE	SCE Eastern	13
12	Mira Loma-Mesa 500 kV Underground Third Cable	SCE	SCE Metro	35
13	Imperial Valley–North of SONGS 500 kV Line and Substation	SDG&E	SDG&E	2,288
14	North of SONGS–Serrano 500 kV line	SDG&E / SCE	SDG&E and SCE Metro	503
15	Serrano–Del Amo–Mesa 500 kV Transmission Reinforcement	SCE	SCE Metro	1,125
16	North Gila–Imperial Valley 500 kV line	SDG&E	SDG&E (Potential Joint Project with IID)	340
17	Upgrade series capacitors on HW-NG and HA-NG to 2739 MVA	APS	APS	27

Source: Jeff Billinton, "Decision on ISO 2022-2023 Transmission Plan" (ISO Board of Governors Meeting, California ISO, May 18, 2023), http://www.caiso.com/Documents/Decisionon2022-2023TransmisisonPlan-Presentation-May2023.pdf.

The three competitive projects are all in the Imperial Valley region and are all *new lines*. In contrast, project 15 is classified as a reinforcement although its cost is $1,125 Million.

It appears that only *new lines* are eligible for competitive procurement. The bright line test appears whether the project requires new land, i.e., is a *greenfield* project. Simply replacing the conductors and the towers would not constitute a *new line*. As noted above, FERC specified that tower replacement and reconductoring would be seen as an upgrade to existing facilities owned by the incumbent. Brownfield projects that use existing property and right-of-way, such as adding a third underground cable in project 12 or reconductoring, are not eligible for competitive procurement.

4.3 APPLYING ORDER 1000 CRITERIA TO CAISO 20-YEAR TRANSMISSION OUTLOOK

Here we extend the greenfield/brownfield test to the CAISO 20-Year Transmission Outlook. The following two projects provide an example of how the test is applied. Both are estimated at a $0.5 B cost. Both are 500 kV lines. However, the competitive project is a new line while the second, the IOU project replaces an existing 230 kV line with a 500 kV line. The replacement uses existing property but requires tower replacement.

Table4.1: Sample Classification of Projects

Project Classification	Project	Description	Estimated Cost
Competitive Procurement	North Gila – Imperial Valley 500 kV line	- 85 mi of 500 kV line. - Series compensation.	$0.5 B
IOU Upgrade	Westland 500/230 kV station	- 50 mi of 500 kV line (replacement of 230 kV). - New 500/230 kV substation with two transformers ($200M)	$0.5 B

Using this greenfield/brownfield criteria to identify projects eligible for competitive procurement, we find that approximately 83% of the total estimated costs are eligible for competitive procurement (Table 4.2).

Table 4.2: Summary of Projects Eligible for Competitive Procurement

Type of Project	20-Year Outlook Total ($ B)	Competition Eligible ($ B)	Comments
Changes to Existing Footprint	10.74	10.4	Excludes upgrades to existing infrastructure
Off-Shore Wind	8.11	8.11	Lower total cost than in CEC off-shore wind report[54]
Out-of-State Wind	11.65	6.95	Excludes subscriber lines already under construction (Sunzia and Transwest Express)
Total	30.5	25.46	
Percent of Total	100%	83%	

There were four projects that were deemed not eligible for competitive procurement. These are shown in Table 4.3.

[54] California Energy Commission, "California Energy Commission Draft Commission Report, Volume I: Overview of AB 525 Strategic Plan," CEC Docket Number 17-MISC-01, January 19, 2024, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-MISC-01.

Table 4.3: Projects Ineligible for Competitive Procurement

Project	Description	Cost ($ B)
Westland 500/230 kV station	50 mi of 500 kV line (replacement of 230 kV). New 500/230 kV substation with two transformers ($200M)	0.5
Third Collinsville – Pittsburg 230 kV cable	230 kV cable	0.14
Round Mountain 500/230 kV Transformer	Add one 500/230 kV transformer	0.1
Lugo 500/230 kV Transformers	Add one 500/230 kV transformer	0.1

Box 7 Fire Hardening Measures: Costs and Tradeoffs

"Fire-hardening" refers to a series of measures and improvements designed to enhance the resilience of electric transmission and distribution systems against wildfires. The most effective way to reduce wildfire risk is a process known as "undergrounding." This involves placing power lines and related electrical equipment below the ground, rather than using overhead lines strung on poles or towers. Placing new transmission lines underground is about eight to ten times the cost of building overhead lines; placing new distribution lines underground is typically four to six times more expensive.

Other examples of fire-hardening measures include covering conductors to eliminate line slap arcing, using alternative materials (e.g. composite, steel, concrete, or fire-resistive protection) on or instead of wood poles, and establishing other physical barriers to reduce possible contact with animals or vegetation.

Fire-hardening measures vary in risk-mitigation effectiveness and associated costs per mile when rehabilitating an existing system. Undergrounding reportedly eliminates close to 99 percent of fire risk. Covering conductors, however, may be implemented in half the time, at a third of the cost of undergrounding, and mitigate about 60 percent of fire risks.

There are also tradeoffs to system reliability to consider. Some comparisons suggest underground systems see 50 percent fewer outages, yet the average duration of an underground outage may be up to 58 percent longer. Long-term reliability is also a trade-off. One Maryland utility observed that customers served by a 40-year-old overhead line had better reliability than a 20-year-old underground line.

Sources:

Baker, Matt. "Why We Support the Levels of Undergrounding Approved in PG&E's General Rate Case." California Public Advocates Office. Accessed May 21, 2024. https://www.publicadvocates.cpuc.ca.gov/press-room/commentary/231117-undergrounding-pge-grc

SCE&G. "Underground vs. Overhead Power Lines." ND. https://pdi2.org/wp-content/uploads/2021/03/130-SC-SCANA-Undergroundvs1.pdf

Apparatus & Standards Engineering Group. "Covered Conductor - Everything You Need To Know (Compendium)." Southern California Edison. October 8, 2018. https://www.sce.com/sites/default/files/AEM/Supporting%20Documents/2023-2025/Covered%20Conductor%20Compendium.pdf

California Department of Forestry & Fire Protection, CPUC, PG&E, SCE, SDGE., "California Power Line Fire Prevention Field Guide." 2020. https://www.osfm.fire.ca.gov/media/11015/2020-power-line-fire-prevention-field-guide_20200818.pdf

4.4 FURTHER OBSERVATIONS ON COMPETITION ELIGIBILITY

The projects listed in the CAISO 20-Year Transmission Outlook do not include projects to address electrification demand increases or what CAISO identifies as "reliability-driven" projects rather than driven by the need to access renewable generation. These projects are not competition eligible and amounted to approximately 57% of the total cost. This suggests both that the 20-Year Transmission Outlook represents less than half of the total energy transition cost and that the IOUs will capture 50%-60% of the total new transmission construction.

The implicit greenfield requirement for competitive procurement is a significant barrier to entry for non-incumbent transmission providers. This is especially true in urban areas where permitting and siting is especially difficult.

Workarounds for this issue are beyond the scope of this report. However, it is worth noting that sharing of the right-of-way between incumbents and non-incumbents may be a worthwhile area for investigation. FERC noted in Order 1000 that the order does not change existing right-of-way laws.[55]

[55] FERC, "FERC Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities", at 319.

SECTION 5 REVENUE REQUIREMENT MODEL

Section 3 identified possible cost savings to customers from the use of public sector financing in transmission, and the use of alternative institutional models (from Section 2) to deliver such financing. Section 4 identified the lines that could conceivably be eligible for competitive tender and hence alternative modes of procurement and financing. This section attempts to quantify the possible cost savings—as a change in revenue requirement—on the lines in Table 4.2 that are competition-eligible.[56]

5.1 ASSUMPTIONS

Sensitivity analysis was first used to understand the possible impact on the transmission lines' revenue requirements of changes to the magnitudes of the building blocks shown in Table 5.1. Scenario analysis was then used to simulate a collection of sensitivities that seemed reasonable under alternative institutional models. The "business-as-usual" or base case is an IOU. In this scenario, IOUs are assumed to win CAISO competitive tenders to own and operate the lines. Table 5.1 shows the input assumptions used for the IOU Scenario. We used CAISO's assumptions that the new investments have a 50-year asset life; upgrades have 40-year lives.[57]

Table 5.1: Input Assumptions for IOU Scenario (Business-As-Usual)

Assumption	Assumptions	Value
Cost of equity (%)	Average of PG&E, SCE, SDG&E cost of equity*	10.37
Cost of debt (%)	Average of PG&E, SCE, SDG&E cost of debt*	5.33
Equity participation (%)	Average of PG&E, SCE, SDG&E capital structures*	53.27
Tax rate (%)	Federal = 21%; State = 8.84%	27.98
CAPEX Cost (US$ bln)	As per Table 4.2 (above)	25.46
Depreciation (US$ mln/year)[58]	2%/year for new assets; 2.5%/year for upgrades	513.97
Operating Cost (US$ mln/year)[59]	2% of CAPEX per year	512.80

*Assumptions about cost of equity, cost of debt and capital structure were taken from: (i) Pacific Gas and Electric Company, 2022 Joint Annual Report to Shareholders; (ii) Edison International and Southern California Edison, 2022 Financial & Statistical Report; (iii) Sempra, 2022 Statistical Report, (iv) San Diego Gas and Electric, "Test Year 2023 Cost of Capital Application", California docket A.22-04-12.

Other scenarios were then developed based to include:

[56] Lines not tendered by CAISO may be subject to different regulatory treatment and therefore may have different cost savings potential.

[57] California ISO, 2018-2019 Transmission Plan.

[58] California ISO, 2018-2019 Transmission Plan.

[59] California ISO, 2018-2019 Transmission Plan.

- A "Public Sector" scenario in which a public entity—such as the power authorities or transmission authorities found in some other states—owns and operates the transmission lines
- Two PPP scenarios which include:
    - A lease-type PPP case for this analysis assumes a public sector owner (such as an asset holding company) would—through competitive tender—hire a private contractor to operate and maintain the transmission lines for a period of time (for example, 3-5 years). The public sector entity provides financing and is generally responsible for managing design and construction.
    - A concession-type PPP in which a public sector entity would—through competitive tender—grant a private company (and SPE or SPV) the right to build, finance, own and operate the new transmission lines for a fixed period of time (for example, 40 years) after which time, the line would revert to the public sector.[60]

Table 5.2 summarizes the assumptions of each Scenario.

Table 5.2: Summary of Scenario Assumptions

Variable	IOU Scenario	Wholly Public Scenario	PPP-Lease Scenario	PPP-Concession Scenario
Cost of equity (%)	10.37	N/A	N/A	10.37
Cost of debt (%)	5.33	2.75	4.04	5.33
Equity (%)	53.27	0	0	53.27
Tax rate (%)	27.98	0	0	27.98
CAPEX Cost (US$ bln)	25.64	22.43	19.23	19.23
Operating cost (% of CAPEX)	2	2.1	2	2

The rationale behind the assumptions is as follows:

- A publicly owned entity would finance the transmission lines with 100% public debt. This is why no cost of equity is included in the Public Scenario or the Lease-type PPP Scenario, where the owners of the assets would be public entities (either a power authority or an asset holding company).

[60] The public sector entity may then choose to re-tender the line for refurbishment.

- A publicly owned entity (whether a power authority or an asset holding company) would be able to borrow at rates that the State of California is currently able to borrow at (in the case of a power authority) or at slightly higher rates (as in the case of an asset holding company, but still lower than commercial borrowing rates.
- A publicly owned entity (whether a power authority or an asset holding company) would not pay income taxes and would therefore not have taxes as part of its revenue requirement.
- Transmission lines tendered under the Public Scenario or PPP Scenarios would have lower CAPEX costs than transmission lines tendered by CAISO to the IOUs. This is based on:
    - The Brattle Group report that indicates more competitive processes in procuring transmission in the US could reduce capital costs by 20-30 percent.[61]
    - Evidence from elsewhere in the world that successive competitive tenders for transmission lines under a PPP arrangement can bring down whole-of-life costs substantially, especially under a concession model, because of competitive bidding and because of more efficient risk allocation between the public and private partners.
- An assumption that publicly owned and operated transmission lines would have slightly higher operating costs than privately owned and/or operated lines, because of the absence of a private sector profit incentive and because PPP arrangements typically have lower whole-of-life costs than transmission built by incumbent utilities.

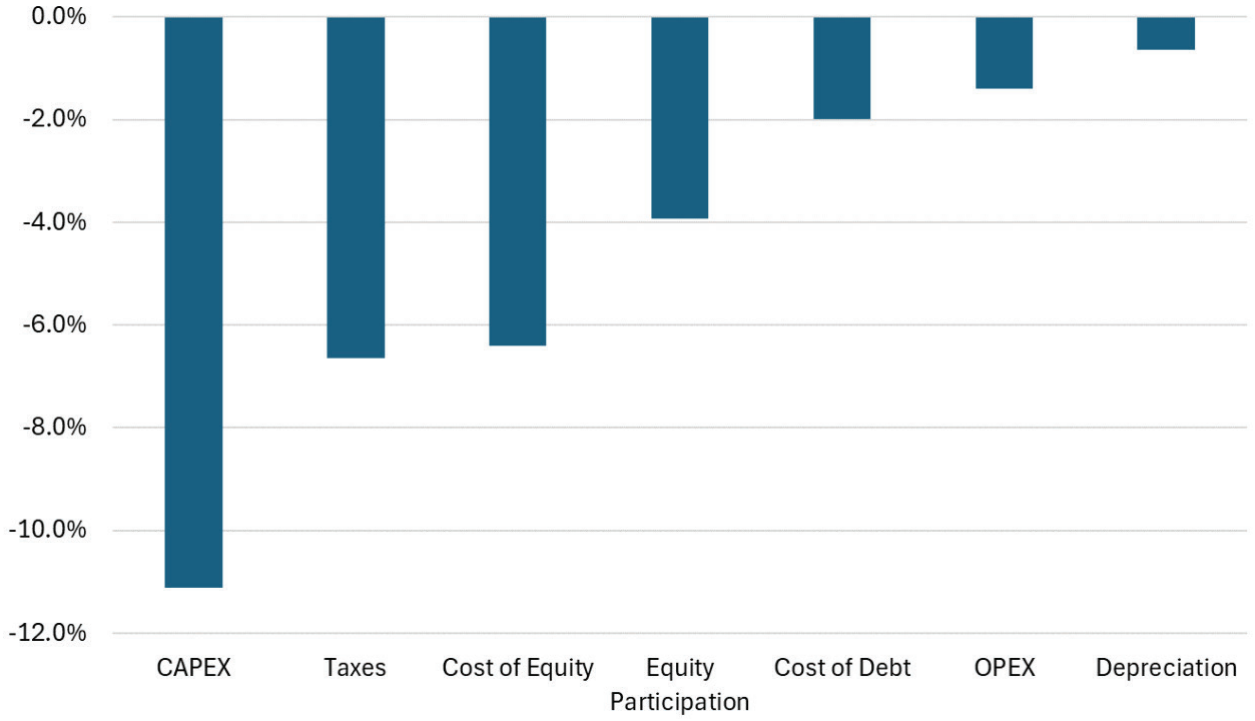
As described in Section 3 many of the input assumptions depend heavily on the detailed design of the institutional options.

5.2 SENSITIVITIES

Figure 5.1 shows the impact of a 10% reduction in the principal inputs to the revenue requirement calculation. This is useful in understanding the biggest drivers of cost in the revenue requirement. As the figures show, the capital cost itself, which makes up the rate base, is the single most influential driver of the RR, followed by taxes, the cost of equity, capital structure and the cost of debt; the impacts on the RR of reductions in OPEX and depreciation are considerably lower.

[61] Pfeifenberger, Johannes P., Judy Chang, Akarsh Sheilendranath, J. Michael Hagerty, Simon Levin, and Wren Jiang. "Report by Brattle Economists Discusses the Benefits of Competitive Transmission." Prepared for LSP Transmission Holdings, Brattle, June 21, 2021. *https://www.brattle.com/insights-events/publications/report-by-brattle-economists-discusses-the-benefits-of-competitive-transmission/*.

Figure 5.1: Impact on RR of a 10% Reduction in Principal Input Variables[62]



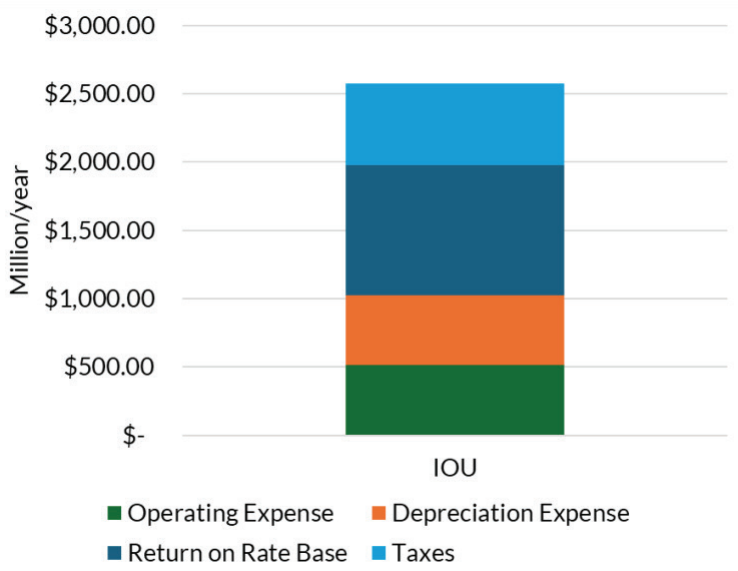
5.3 SCENARIOS

Figure 5.2 shows the revenue requirement under the IOU Scenario defined in Section 5.1. The package of transmission lines would have an average annual revenue requirement of roughly $2.5 billion, or $100 billion over 40 years. If the costs of undergrounding are included (See Box 7), the average annual revenue requirement would be nearly $21 billion, or $825 billion over 40 years.[63]

[62] Based on an estimate of the transmission line's first full-year revenue requirement.

[63] Undergrounding is estimated to increase the capital costs of transmission projects by 8-10 times.

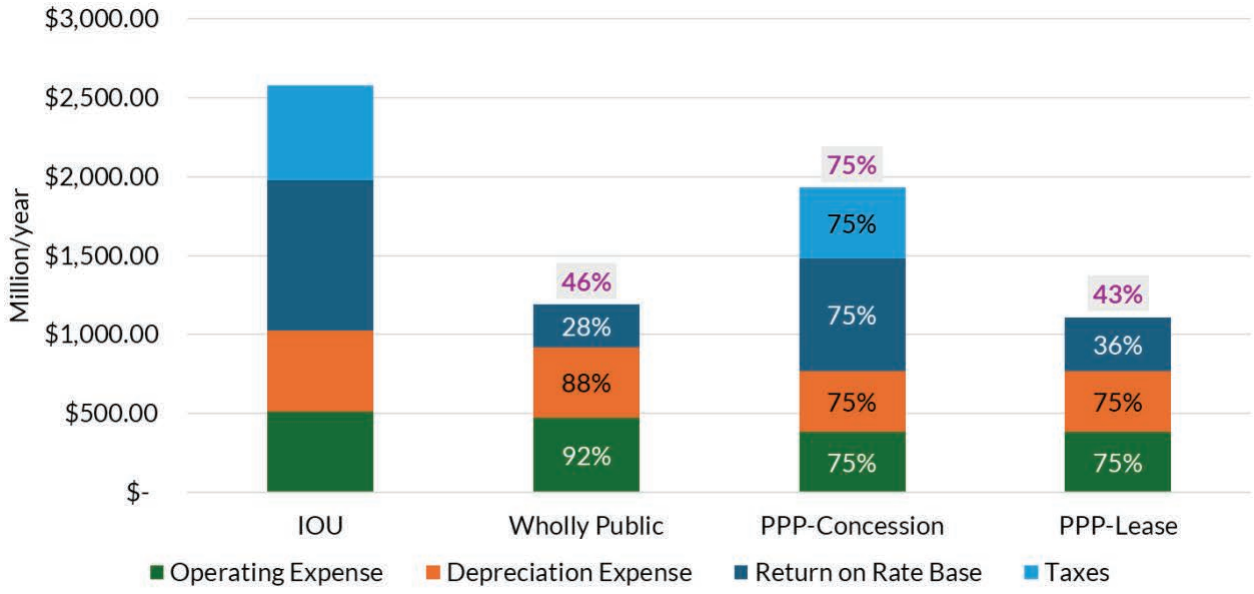
Figure 5.2: Revenue Requirement for Eligible Transmission Lines—Business-as-Usual (BAU) Case[64]



As the figure shows, the return on rate base is the largest cost component under this scenario. It is based on an average of costs of debt, equity, and capital structures of Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDGE), and SCE. The next largest component is income taxes, followed by depreciation and OPEX.

Figure 5.3 compares the IOU Scenario to the other scenarios described in Section 5.1. Sections 5.3.1 through 5.3.2 describe the most important differences between the scenarios, and their results.

Figure 5.3: Comparison of Scenarios—Average Annual Revenue Requirement



[64] Taken as the average over 40 years. Revenue requirements change over time as the rate base is depreciated and the nominal return on the rate base is also reduced. The average assumes, for the simplicity of comparison, that all lines are built at the same time.

5.3.1 PUBLIC SECTOR SCENARIO

The public sector case for this analysis assumes a public entity (for example, a power authority) would own and operate the new transmission lines. The transmission lines would have an average annual revenue requirement of roughly $1.2 billion over 40 years, less than half of the average annual revenue requirement under the wholly public case. Table 5.3 shows the average annual revenue requirement for all lines, disaggregated by cost component, as well as the input assumptions used.

Table 5.3: Comparison of Input Assumptions and RR Components (Public Sector Scenario)

Variable	Average value in Revenue Requirement (US$ million)	Assumption
Return on Rate Base	269.49	100% public debt financing; public sector financing costs
Income Taxes	0	N/A
Depreciation	449.72	2%/year for new assets; 2.5%/year for upgrades
OPEX	471.4	2% of CAPEX per year

As the table shows, OPEX is the largest cost component under this scenario, followed by depreciation, the return on rate base, and taxes. The biggest differences between this Scenario and the IOU Scenario are:

- **Rate base.** It is assumed that CAPEX costs would be 12.5% lower than under the IOU Scenario, based on the assumption that there are more opportunities to introduce competition in procurement under the PPP models than under the Public Sector Scenario.[65]
- **Return on rate base.** The return on rate base is lower because the rate base is lower and it is assumed that the public entity would use 100% debt financing (no equity) at the cost of public sector debt.
- **Taxes.** It is assumed that a public sector entity would not be required to pay state or federal income tax.
- **Operating Costs.** It is assumed that the public sector entity would have slightly higher OPEX costs than a private sector entity. We have assumed OPEX costs of 2.1% of CAPEX instead of (in the IOU case) 2%. PPP arrangements have the benefit of specifying risk allocations upfront, in a contract. This optimization of risk allocation is one of the most important sources of potential cost savings in a lease- or concession-type contract. Moreover, an SPV or SPE is at the heart of a PPP arrangement; this further protects the public owner from liability beyond the project itself.
- **Depreciation.** Depreciation is lower because the value of the rate base is lower.

These differences collectively put the Public Sector Scenario at less than half of the cost of the IOU Scenario.

[65] The basis for these assumptions will be detailed in the forthcoming report which includes this memo as a chapter.

5.3.2 CONCESSION-TYPE PPP

The concession-type PPP case for this analysis assumes a public sector entity would—through competitive tender—grant a private company the right to own and operate the new transmission lines for a fixed period of time (e.g., 40 years) after which time, the lines would revert to the public sector. The transmission lines would have an average revenue requirement of roughly $1.9 billion over 40 years. Table 5.4 shows the average revenue requirement for all lines, disaggregated by cost component, as well as the input assumptions used.

Table 5.4: Comparison of Input Assumptions and RR Components (Concession-Type PPP Scenario)

Variable	Average value in Revenue Requirement (US$ million)	Assumption
Return on Rate Base	710.33	Same financing structure and costs as IOU case but with 25% reduced CAPEX
Income Taxes	451.43	Same as for IOU Case
Depreciation	385.48	Same as for IOU Case
OPEX	384.60	Same as for IOU Case

As the table shows, return on rate base is the largest cost components under this scenario, followed by the taxes, OPEX and depreciation. The differences between this Scenario and the IOU Scenario are:

- **Rate base.** It is assumed that CAPEX costs would be 25% lower than under the IOU Scenario because of the benefits of greater competition in procurement per the Brattle study.[66]
- **Return on rate base.** The return on rate base is lower because the rate base is lower and it is assumed that the public entity would use 100% debt financing. The costs of debt and equity financing, and capital structure are assumed to be the same as in the IOU case as both commercial debt and equity would be needed by the developer.
- **Depreciation.** Depreciation is lower because the value of the rate base is lower.

5.3.3 LEASE-TYPE PPP

The lease-type PPP case for this analysis assumes a public entity would own and operate the new transmission lines and hire a private company to operate and maintain the lines. The transmission lines would have an average revenue requirement of $1.1 billion over 40 years. Table 5.5 shows the annual average revenue requirement for all lines, disaggregated by cost component, as well as the input assumptions used.

[66] Brattle, 2021

Table 5.5: Comparison of Input Assumptions and RR Components (Lease-Type PPP Scenario)

Variable	Average value in Revenue Requirement (US$ million)	Assumption
Return on Rate Base	339.28	100% public debt financing; public sector financing costs
Income Taxes	0	N/A
Depreciation	385.48	2%/year for new assets; 2.5%/year for upgrades
OPEX	384.60	2% of CAPEX per year

As the table shows, OPEX and depreciation are the largest cost components under this scenario, followed by the return on rate base, and taxes. As noted in Section 5.3.1, OPEX with a PPP arrangement is assumed to be lower than a wholly public arrangement because PPP arrangements have the benefit of specifying risk allocations upfront, optimizing risk allocation in a way that reduces costs, and protecting the public owner from liability by virtue of the establishment of an SPV.

The differences between this Scenario and the IOU Scenario are:

- **Rate base.** It is assumed that CAPEX costs would be 25% lower than under the IOU Scenario because of the benefits of greater competition in procurement per the Brattle study.[67]
- **Return on rate base.** The return on rate base is lower because the rate base is lower and it is assumed that the public entity would use 100% debt financing (no equity) and at the cost of public sector debt.
- **Taxes.** It is assumed that a public sector holding company would not be required to pay state or federal income tax.
- **Depreciation.** Depreciation is lower because the value of the rate base is lower.

5.4 CONCLUSION

The estimates above show that substantial possible savings to customers are achievable by using public sector financing for transmission projects. A wholly public delivery model or a lease-type PPP—both of which assume 100% financing with tax free bonds—could cut the annual revenue requirements of transmission lines by more than half. The average annual savings to customers could be as much as nearly $1.5 billion, or a total of $58 billion over a 40-year operation of the transmission lines.[68]

Much of the potential savings are directly related to the removal of equity from the financing structure and the use of lower cost public debt. Other potential savings relate to the institutional model chosen and their potential impact on competition for developing transmission lines; competition which—according to other studies—can reduce capital costs over time. The choice of institutional model also has tax implications: a

[67] Brattle, 2021.

[68] Estimates are not discounted for the time value of money and exclude the costs of fire hardening.

publicly owned transmission line may be liable for less income (and possibly other) taxes than a privately owned line.

Whereas this section uses estimates of the revenue requirement for all lines foreseen to be eligible for competition under the CAISO plan, it is important to note that the opportunities for cost savings depend very little on which transmission line is chosen for analysis. The potential percentage savings would be similar for any line tendered by CAISO. For example, more recent and more detailed CAPEX cost estimates have been developed for a package of transmission investments foreseen to evacuate offshore wind from the North Coast.[69] The $7.7 billion line (referred to as "Alternative 7.2a") is planned to accommodate 7.2 GW of offshore wind development; this will include 480 wind turbines with 9 HVAC floating platforms. The transmission investments will include (i) radial connections via 500kV AC export cables between the proposed offshore wind farms and nearby onshore substations, and (ii) A connection to the planned Fern Road substation in Central Valley, connecting to the main 500 kV transmission line running along the I-5 corridor. Under the IOU scenario, this line would have an annual average revenue requirement of $774 million over 40 years; the same investments would have an annual average revenue requirement of $358 million under the wholly public scenario.

[69] Zoellick, J., G. Adams, A. Mustafa, Aubryn Cooperman, R. Anilkumar, Patrick Duffy, A. Sparks, et al. "Northern California and Southern Oregon Offshore Wind Transmission Study." Schatz Energy Research Center, October 1, 2023. https://doi.org/10.2172/2205318.

APPENDIX A: THE CONTEXT FOR TRANSMISSION DEVELOPMENT IN CALIFORNIA

In general terms, transmission projects are considered as low risk assets due to their predictable performance, "easy" operation and simplicity in their rate of return mechanism,[70] despite conveying intrinsic complications or barriers resulting from their capital-intensive nature, with long payback periods, potential public opposition[71] and their difficulty in assigning costs (public goods dilemma).

While development cost reduction and permitting reform are not the primary focus of this report, we review some key points here.

Regulatory Complexity

The regulation of high voltage transmission in the United States is highly intricate due to several jurisdictions' overlaps between federal, state, district, and territorial authorities.[72] FERC oversees stand-alone transmission services, rates, and infrastructure, including regional wholesale power markets that utilize the transmission grid ("interstate commerce") (excluding certain publicly owned utilities, federal power marketing agencies, and unsynchronized single-state power grids).[73] In contrast, state and local authorities are in charge of generation and distribution (infrastructure and operation), including retail electricity services, and usually oversee transmission lines' siting, permitting, construction, and retail costs within their jurisdictions (intrastate).

All market participants shall have non-discriminatory/open access to the transmission system,[74] through Independent System Operators ("ISOs") and Regional Transmission Operators ("RTOs"),[75] allowing competitive interstate trading and ensuring grid reliability.

Permitting Delays for Transmission on Federal Land

At a federal level, energy transition efforts and the impacts of climate change have brought to light, more than ever, the permitting delays in energy projects and grid infrastructure[76] which have resulted in several

[70] Crédit Agricole Securities, "Project Bond Focus Power Transmission Lines," May 2019, https://www.ca-cib.com/sites/default/files/2020-03/Project-Bond-Focus-2019-Transmission-Lines.pdf.

[71] "Trouble at the End of the Line: Local Activism and Social Acceptance in Low-Carbon Electricity Transmission in Lower Franconia, Germany - ScienceDirect," accessed March 20, 2024, https://www.sciencedirect.com/science/article/abs/pii/S2214629618301233?via%3Dihub.

[72] Joe III DeLosa, Johannes P. Pfeifenberger, and Paul Joskow, "Regulation of Access, Pricing, and Planning of High Voltage Transmission in the U.S.," Working Paper Series, March 5, 2024, https://ceepr.mit.edu/workingpaper/regulation-of-access-pricing-and-planning-of-high-voltage-transmission-in-the-u-s/.

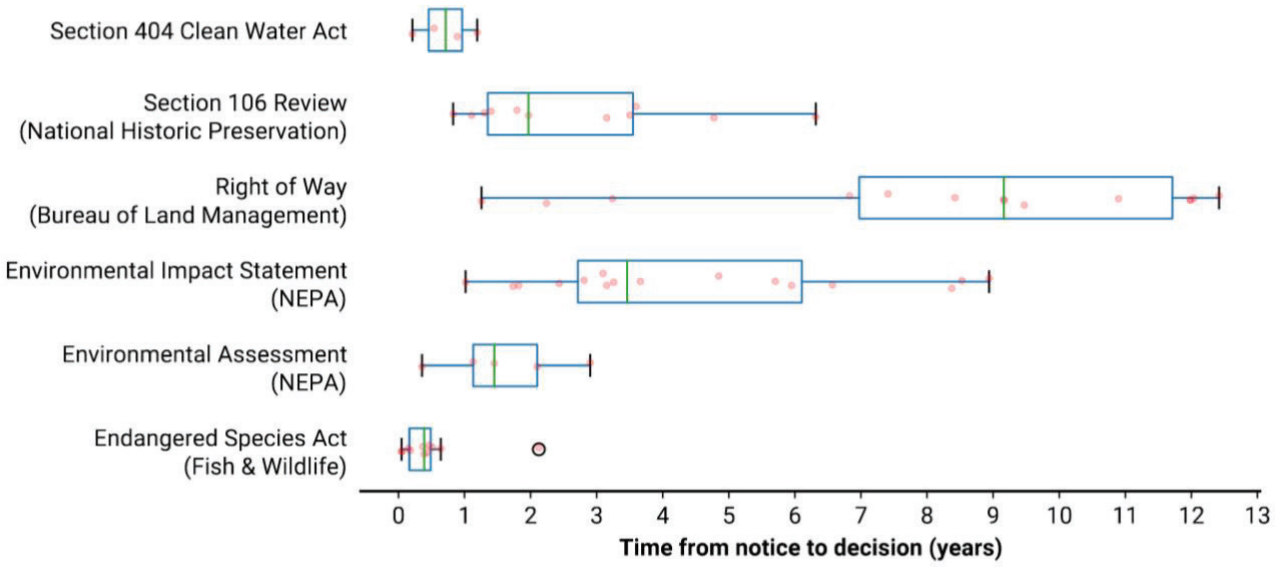
[73] "What FERC Does | Federal Energy Regulatory Commission," accessed March 18, 2024, https://www.ferc.gov/what-ferc-does.

[74] "Order No. 888 | Federal Energy Regulatory Commission," accessed March 18, 2024, https://www.ferc.gov/industries-data/electric/industry-activities/open-access-transmission-tariff-oatt-reform/history-oatt-reform/order-no-888.

[75] "OrderNo.2000-A | Federal Energy Regulatory Commission," accessed March 18, 2024, https://www.ferc.gov/sites/default/files/2020-06/OrderNo.2000-A.pdf.

[76] "Congressional Action on Energy Permitting Remains Stuck, but States, Developers Are Finding Solutions," Utility Dive, accessed March 21, 2024, https://www.utilitydive.com/news/federal-energy-permitting-reform-doe-ferc-congress/705818/.

energy permitting reform bills in Congress[77] and further analysis of potential reforms to the "federal permitting process for clean energy infrastructure."[78] A study by the Brookings Institute[79] reveals that reviews under the National Environmental Policy Act (NEPA) and permitting processes from the Bureau of Land Management (BLM) represent the most significant bottlenecks in permitting delays, particularly for transmission lines and wind projects.[80] The figure below highlights the duration of each permitting phase for 13 projects analyzed (red dots). The preparation of Environmental Impact Statements under NEPA is identified as one of the lengthiest steps in federal permitting, taking a median of 3.5 years, and up to nine years in some instances. However, the process of obtaining right-of-way (ROW) authorization from BLM is even more protracted, with a median duration of over nine years from application submission to BLM approval, largely because it encompasses an NEPA review. This lengthy duration is partly due to the additional layers of review and bureaucratic processes involved.



Source: From Sud, Rayan, Sanjay Patnaik, and Robert Glicksman. "How to Reform Federal Permitting to Accelerate Clean Energy Infrastructure." Brookings Institute, February 2023.

Another example of significant delays is illustrated by New York's Champlain Hudson Power Express Project. This $6 billion 1,250 Megawatts (MW) renewable power transmission initiative, which began its permitting

[77] "Permitting Reform Bills in Congress," Citizens' Climate Lobby, accessed March 21, 2024, https://citizensclimatelobby.org/clean-energy-permitting-reform-in-congress/.

[78] Rayan Sud, Sanjay Patnaik, and Robert Glicksman, "How to Reform Federal Permitting to Accelerate Clean Energy Infrastructure" (Brookings Institute, February 2023), https://www.brookings.edu/wp-content/uploads/2023/02/20230213_CRM_Patnaik_Permitting_FINAL.pdf.

[79] Sud, Patnaik, and Glicksman.

[80] This insight comes from examining a non-representative sample of 13 large and nationally significant projects listed on the Federal Permitting Dashboard, focusing on completed renewable energy and electric transmission projects.

phase in 2010, only received its final permits to commence construction in 2022 and is anticipated to be fully functional by the spring of 2026.[81]

Delays in the Transmission Development Process in California

In California, the process of developing transmission projects is intricate and long-lasting, involving continuous coordination among the California Independent System Operator (CAISO), the CPUC, and utilities for the planning, permitting, and construction phases, which usually result in considerable delays[82,83,84] that tend to increase the costs of projects.

Slow transmission deployment in California is largely due to delays in CAISO's projects' approval and subsequent permit application submissions by IOUs to the CPUC (compounded by lengthy permitting processes). California's transmission permitting process is notably slower than those in New York or Texas, and even other Western states.[85] A study conducted by Southern California Edison concluded that CPUC's average review and approval time across 28 applications was 836 days (about 2.3 years) and for some applications over 1,000 days (about 2.7 years).[86] The figure below[87] shows the considerable delays for a sample of transmission projects in California. Delays within transmission permitting in California are well documented and increasingly high profile. There have been recent efforts within the state to reform the transmission permitting process to reach policy and climate goals.[88]

[81] Champlain Hudson Power Express Project, "Champlain Hudson Power Express Project: Regulatory Documents," TDI CHPExpress, accessed March 18, 2024, https://chpexpress.com/overview-of-public-documents/regulatory-documents/.

[82] "Transmission Development in California – What's the Slowdown?," Clean Air Task Force, accessed March 20, 2024, https://www.catf.us/resource/transmission-development-california-slowdown/.

[83] Alex Breckel et al., "Growing the Grid: A Plan to Accelerate California's Clean Energy Transition" (Clean Air Task Force and Environmental Defense Fund, October 2022), https://www.catf.us/resource/growing-grid-plan-accelerate-californias-clean-energy-transition/.

[84] GridLab and CEERT, "California's Progress in Advancing Transmission Planning and Permitting: A 2023 Review," 2023, https://ceert.org/wp-content/uploads/2023/pdf/231207_CA-progress-in-advancing-transmission-planning-permitting.pdf.

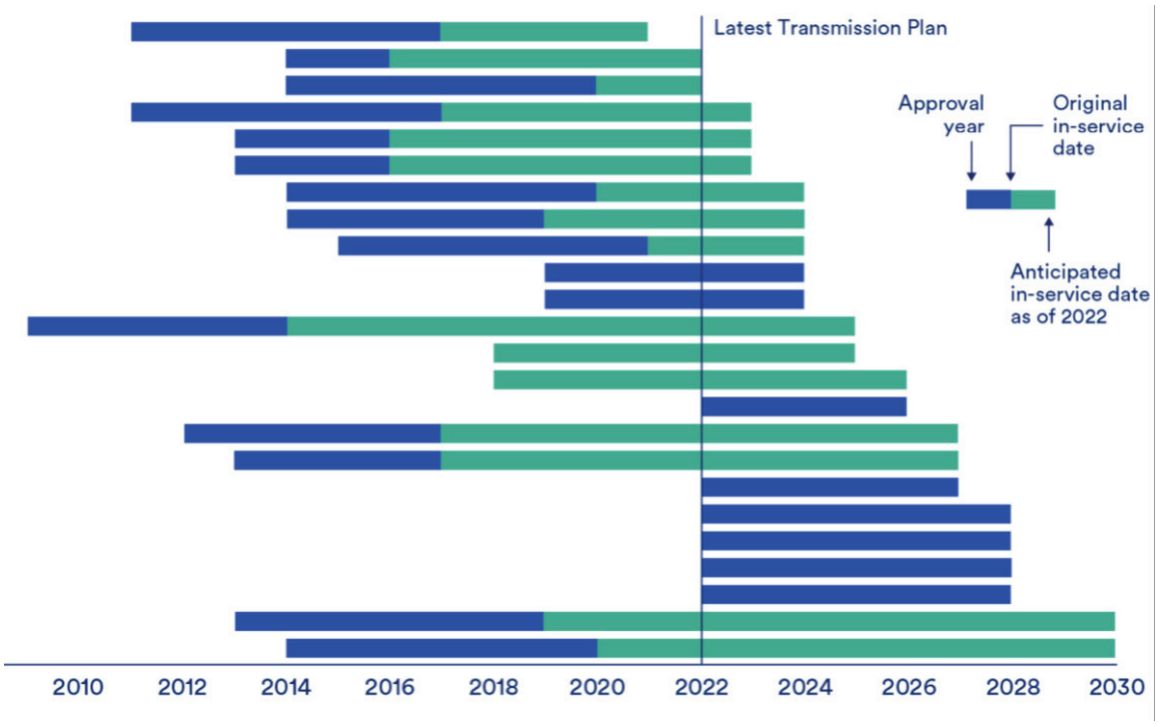
[85] Kara Hunt, "California's Transmission Permitting: Slowest in the West?," Clean Air Task Force, May 30, 2023, https://www.catf.us/2023/05/californias-transmission-permitting-slowest-in-the-west/.

[86] GridLab and CEERT, "California's Progress in Advancing Transmission Planning and Permitting: A 2023 Review."

[87] Breckel et al., "Growing the Grid."

[88] GridLab and CEERT, "California's Progress in Advancing Transmission Planning and Permitting: A 2023 Review."

Figure 5.4: Timelines for Mayor Electricity Transmission Projects in California



Source: Breckel, Alex, Michael Covin, John Herter, Armond Cohen, and Julia Souder. "Growing the Grid: A Plan to Accelerate California's Clean Energy Transition." Clean Air Task Force and Environmental Defense Fund, October 2022.

These delay barriers are found before and during the permitting process stage in California. The delays and risk of rejection during the development phase make transmission development a high-risk business.

While permitting and siting risks are not the focus of this study, we note that the risk and delays significantly increase the cost of transmission. The costs include expenses for financing arrangements (working capital, at a minimum), permitting, and regulatory compliance. For example, the Northern Pass project in New Hampshire incurred $318 million in sunk costs for pre-development activities, representing roughly 20% of its estimated total cost of $1.6 billion.[89] Similarly, the Hydro-Québec US transmission line project in Maine saw $450 million (43% of the estimated total project costs) spent in pre-development.[90] If there is a 50% probability of failure and a 20% cost for failure, then every developer has to build in a minimum 10% risk adder to the CAPEX.

[89] Michael Cousineau, "Eversource giving away land bought for failed Northern Pass project," *New Hampshire Union Leader*, June 26, 2023, https://news.yahoo.com/eversource-giving-away-land-bought-225400675.html

[90] "Hydro-Quebec scores legal victory in Maine over $1B US transmission line project," *CBC News*, April 20, 2023, https://www.cbc.ca/news/canada/montreal/hydro-quebec-1.6816752

Transmission Planning and Tendering Parameters

FERC's Order 1000[91] required that transmission planning cover reliability, economic and public policy needs. It introduced proactive involvement from transmission providers in crafting regional plans, encouraging stakeholder engagement and choosing the most cost-effective solutions for meeting regional transmission requirements, demanding that transmission plans consider both state and federal public policy objectives. Additionally, it stipulated that the expenses for these projects be distributed among transmission customers across the planning region and allowed competitive transmission developers to propose bids for transmission expansions with regional cost allocation, challenging incumbent owners.[92] In this sense, competitive bidding is encouraged for transmission projects but is limited to regional transmission facilities. Specifically, in California, any regional transmission facility that is 200 kV or higher and identified for reliability, policy, or economic reasons must go through competitive solicitation within the CAISO region. Projects under 200 kV that cross more than two transmission service areas or exceed CAISO's jurisdiction are also eligible for competitive bidding. However, upgrades to existing facilities, whether they meet or fall outside these criteria, and projects that are locally funded, do not require solicitation.[93]

[91] FERC, "FERC Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities."

[92] DeLosa, Pfeifenberger, and Joskow, "Regulation of Access, Pricing, and Planning of High Voltage Transmission in the U.S."

[93] "Transmission Development in California – What's the Slowdown?"

APPENDIX B: EXAMPLES OF CALIFORNIA TRANSMISSION PPPS

Path 15 Project

The Path 15 Project is an upgrade of an existing transmission path. It started operations in 2004 (18 months after the beginning of construction), upgrading an existing line and adding an extra 500 kV line over approximately 84 miles, which significantly increased the corridor's capacity (5,400 MW).[94]

Path 15 is an electricity transmission corridor in California, linking the northern and southern parts of the state's power grid (Los Banos and Gates), and part of the Western Electricity Coordinating Council's (WECC) network of transmission paths. The upgrade project was initiated after the California Energy Crisis of 2000-2001 in which Path 15 was identified as a contributing factor to blackouts, reliability issues, and high market prices.

Economic incentives were approved for the development of this Project (that were later contested),[95] that included higher rates of return and accelerated depreciation that would allow better cashflow provision.[96]

The Western Area Power Authority (WAPA) is the public partner and owns the physical transmission line and the associated land, it was also assigned as the project manager and had the role of the lead Federal Agency for the NEPA process, and was also in charge of procuring the required land rights (at an estimated cost of 10% of the project's budget), in exchange of a 10% interest in the rights to the Project. PG&E oversaw construction/refurbishment of substations of existing transmission lines, in exchange for an interest payment and retained ownership of the substations. The primary entity investor was Trans-Elect with ownership of 72% of the transmission system rights entitled to the transmission tariff revenues (today owned by Duke-American Transmission Co. – DATC). PG&E received 18% and WAPA 10%.[97, 98,99]

The new line of Path 15 was subject to a competitive tender (managed by WAPA), structured as a design-build project, with a sole contractor in charge of engineering, procurement, and construction (EPC).[100] The project manager at WAPA claims that this mechanism derived in overall cost reductions of the Project and an

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[94] Anne Warren, "Transmission Infrastructure By Public-Private Model - Law360," November 6, 2009, https://www.law360.com/articles/130713/transmission-infrastructure-by-public-private-model.

[95] "Public Utilities Commission of the State of California, Petitioner v. Federal Energy Regulatory Commission, Respondent Trans-Elect, Inc., et al., Intervenors, 367 F.3d 925 (D.C. Cir. 2004)," Justia Law, January 31, 2024, https://law.justia.com/cases/federal/appellate-courts/F3/367/925/495858/.

[96] WAPA, Transelect, and PGE, "Letter Agreement Filing," FERC Docket No. ER02-11672-000, April 30, 2002, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20020507-0016&optimized=false.

[97] WAPA, Transelect, and PGE.

[98] WAPA and PGE, "Construction And Coordination Agreement," December 30, 2002, https://web.archive.org/web/20130324172556/http://www.wapa.gov/sn/ops/transmission/path15/ConstructionAndCoordinationAgreement.pdf.

[99] Duke Energy, "DATC to Purchase Interest in California's Path 15 Transmission Line," Duke Energy | News Center, 2013, https://news.duke-energy.com/releases/datc-to-purchase-interest-in-california-s-path-15-transmission-line.

[100] "20 Years of Path 15 T-Line – Western Area Power Administration," October 8, 2023, https://www.wapa.gov/20-years-of-path-15-t-line/.

accelerated *mise-en-service* (18 months) than originally anticipated, and that the Project resulted in reduced congestion costs.[101]

Initial funding for this Path 15 upgrade Project was estimated at $306 million USD and it was partly funded by the federal government, but its final cost was approximately $50 million USD below the initial project estimate.[102]

The total financing for the Project (facilitated by four banks: Citigroup, Macquarie, DZ Bank, and Société Générale) reached $220 million USD by September 2003, comprising four key components:

1. Around $95.5 million in takedown bonds to the Trans-Elect NTD Path 15 operating company,
2. $56 million in bonds to the Trans-Elect NTD Holdings Path 15 holding company,
3. a $19.5 million construction overrun facility, and
4. a $38.3 million equity bridge facility provided by Energy Investors Funds Group, ArcLight Energy Partners Fund, and KB Transmission.[103]

In this Project, rates set by Trans-Elect and PG&E are regulated by FERC. The Transmission Revenue Requirement (TRR) was originally estimated by Trans-Elect at around $50 million per year.[104] Under this model, and with CAISO in charge of the operation of the line, FERC authorized revenues based on the cost of service model, granting Trans-Elect a 13.5% ROE, a 50%/50% debt/equity target capital structure, and a fixed revenue requirement (TRR) and a rate moratorium for 36 months following the effective date of the rates (start of operations). FERC approved that PG&E could obtain full recovery of its costs derived from the Project and granted a 200 basis point increase in ROE, allowing accelerated depreciation for facilities constructed (10 years of useful life).[105]

This rate structure and its incentives were contested by the CPUC. Ultimately, the petition for judicial review was denied, with the Court of Appeal recognizing FERC's authority to approve rate incentives for projects like Path 15 that seek to enhance energy supply and address significant transmission bottlenecks. It also concurred with FERC's rationale, emphasizing the need for incentives to stimulate project development and increase energy availability, despite CPUC's objections to the costs and methodology of the incentives.[106] In 2021 a reduction to 10.6% ROE for the new owner Duke-American Transmission Company (DATC) was

[101] "Path 15: A to Z," Electric Energy Online, accessed March 24, 2024, https://electricenergyonline.com/energy/magazine/206/article/path-15-a-to-z.htm.

[102] "Path 15."

[103] Warren, "Transmission Infrastructure By Public-Private Model - Law360."

[104] Trans-Elect, "Trans-Elect NTD Path 15, LLC Application For Participating Transmission Owner Status," March 3, 2003, https://www.caiso.com/Documents/RevisedTrans-ElectNTDPath15_LLCPTOApplication.pdf.

[105] WAPA, Transelect, and PGE, "Letter Agreement Filing."

[106] "Public Utilities Commission of the State of California, Petitioner v. Federal Energy Regulatory Commission, Respondenttrans-Elect, Inc., et al., Intervenors, 367 F.3d 925 (D.C. Cir. 2004)."

ordered by FERC.[107, 108] Furthermore, following these FERC's orders, in February 2023 the CAISO updated the wheeling access charge rates for DATC.[109]

Trans Bay Cable

The Trans Bay Cable (TBC) Project is a high voltage transmission line with a 400 megawatts (MW) capacity (able to provide over 40% of power to San Francisco), running 53 miles from Pittsburg, California, in the East Bay to San Francisco, with a significant portion submerged underwater across the San Francisco Bay, which reduced risks from landing acquisition rights and wildfires. The project, considered as a critical transmission asset, was completed and operational in November 2010.

The TBC project is a PPP that covered development, financing, construction, and operation, between the city of Pittsburg, the Pittsburg Power Company, and Steel River Infrastructure Partners (who acquired Babcock & Brown, the original constructor of the project).[110] It included a $515 million financing package, that closed in August 2007.[111] Its transmission tariff is set by the FERC and revenues are paid by the CAISO.

The Pittsburg Power Company owns the transmission line and equipment, while Trans Bay Cable LLC acquired the transmission system rights for 99 years (before needing to revert them to the City of Pittsburg), with operational control by the CAISO. In 2019, NextEra Energy Transmission acquired TBC from Steel River Infrastructure Partners for about $1 billion.[112]

Following the same incentives model initially approved by FERC in the Path 15 Project, TBC proposed a 13.5% ROE, with a three-year rate moratorium, a 50/50 debt/equity capital structure, and a 30-year depreciation period for the project.[113] A TRR of around $134 million was approved, of which 99.9% corresponds to the Base TRR and the rest to the Transmission Revenue Balancing Account Adjustment. In 2019 TBC requested an increase of its TRR to over $157 million and to maintain the enhanced 13.5% ROE, which was contested by the CAISO and other parties. FERC stated that TBC's "rates may yield substantially excessive revenues." FERC ordered a hearing and settlement judge procedures for a full evaluation of TBC's proposed ROE and overall TRR for final determination.[114] A settlement was reached in 2020 increasing TBC's

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[107] "Analysis of FERC's Notice of Proposed Rulemaking on Electric Transmission Incentives."

[108] DATC Path 15, LLC, "DATC Path 15, LLC, Unopposed Offer of Settlement," FERC Docket Nos. ER20-1006-000 and EL20-43-000, June 17, 2021, https://elibrary.ferc.gov/eLibrary/search.

[109] "Updated Wheeling Access Charge Rates Effective 6/13/22 and 1/1/23," accessed March 24, 2024, http://www.caiso.com/Documents/updated-wheeling-access-charge-rates-effective-61322-and-1123.html.

[110] "Babcock & Brown Infrastructure Fund Gets Acquired," *Reuters*, May 17, 2009, sec. Funds, https://www.reuters.com/article/idUSN17287902/.

[111] Warren, "Transmission Infrastructure By Public-Private Model - Law360."

[112] Umesh Ellichipuram, "NextEra Energy Transmission to Acquire TBC for Nearly $1bn," *Power Technology* (blog), November 21, 2018, https://www.power-technology.com/news/nextera-energy-tbc/; "NextEra Energy Transmission Completes Acquisition of Underwater Transmission Cable System," NextEra Energy Newsroom, accessed March 25, 2024, https://newsroom.nexteraenergy.com/2019-07-16-NextEra-Energy-Transmission-completes-acquisition-of-underwater-transmission-cable-system.

[113] FERC, "Order Accepting Operating Memorandum," FERC Docket No. ER05-985-000, July 22, 2005, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20050722-3056&optimized=false.

[114] FERC, Order Accepting and Suspending Proposed Tariff Revisions and Establishing Hearing and Settlement Judge Procedures, No. ER19-2846-000 (FERC November 21, 2019).

tariffs (to a TRR of around $136.5 million) but also TBC had to refund the CAISO for the excess charged after the previous provisional approval from FERC, the 13.5% ROE was maintained.[115]

West of Devers Project - Morongo Transmission

The West of Devers Project is a $1 billion Southern California Edison Co. (SCE) initiative to upgrade existing transmission lines enhancing capacity by 3.2 GW between Riverside County and areas east of Los Angeles.[116] This project crosses Morongo Reservation land, for which the Morongo Native American Tribe granted SCE a 50-year right-of-way through its reservation. The approval of this arrangement enables the avoidance of an estimated $500 million cost to reroute transmission lines around the Reservation.[117]

In exchange for this right-of-way, the Morongo Tribe received the right to invest in the transmission with debt and receive a FERC transmission tariff, including an ROE. Morongo Transmission LLC (Morongo Transmission) received the right to invest up to $400 million (or 50% of the project's final cost) in the project. Morongo Transmission was allowed to finance its investment entirely with debt. Approved in 2021 by the CAISO, Morongo Transmission became the first Native American tribe as a participating transmission owner,[118]

Profits from transmission rates were to be distributed to impacted communities. The arrangement was outlined in the Development and Coordination Agreement (DCA).[119] This was an innovative PPP agreement between SCE and Morongo to finance a part of the project, marking a pioneering arrangement between a utility and a Native American tribe.

In 2014 FERC approved Morongo Transmission's capital cost recovery methodology, including a hypothetical capital structure and a formula rate for operating costs recovery. The DCA was later amended to allow Morongo Transmission additional investment options.[120]

In December 2020, Morongo filed a request with the FERC (Docket No. ER21-669) for a transmission formula rate related to its investment in the West of Devers Upgrade Project. Morongo's revenue requirement consisted of capital and operating costs, with a proposal of a TRR of over $40 million, a base ROE of 10.3% (SCE's authorized ROE), and an RTO Participation Adder of 100 basis points, and its commitment to transfer

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[115] Trans Bay Cable LLC, "Uncontested Offer of Settlement," FERC Docket ER19-2846-001, September 4, 2020, https://www.ferc.gov/.

[116] "CAISO Board Approves Native American Tribe as Transmission Owner," accessed December 12, 2023, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/caiso-board-approves-native-american-tribe-as-transmission-owner-62499840.

[117] "Landmark FERC Decision Paves Way for Clean Energy Tribal-Private Partnerships," Jenner & Block LLP | Law Firm - Jenner & Block | Landmark FERC Decision Paves Way for Clean Energy Tribal-Private Partnerships, accessed March 25, 2024, https://www.jenner.com/en/news-insights/news/landmark-ferc-decision-paves-way-for-clean-energy-tribal-private-partnerships.

[118] "Morongo Becomes First Native American Tribe to Be Approved as a Participating Transmission Owner in Nation – Morongo," accessed March 25, 2024, https://morongonation.org/news/morongo-becomes-first-native-american-tribe-to-be-approved-as-a-participating-transmission-owner-in-nation/.

[119] "West of Devers Upgrade Row Agreement.Pdf," accessed March 25, 2024, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M080/K274/80274785.PDF.

[120] "Notational Order 2021-05-05 | Federal Energy Regulatory Commission," accessed March 25, 2024, https://www.ferc.gov/news-events/events/notational-order-2021-05-05-05052021.

operational control to CAISO.[121] FERC approved the proposed TRR and adjusted the RTO Participation Adder to 50 basis points.

With approval of Morongo Transmission's tariff, FERC granted a unique ratemaking methodology, featuring 100 percent debt financing, a fixed 30-year transmission rate, and parity with the rates charged by utilities, benefitting landowners by honoring their contribution, simplifying regulatory decisions by reducing local contention, ensuring transmission customers are not financially disadvantaged, and supporting transmission developers by facilitating easier siting approval and reducing litigation risks.[122]

SCE updates yearly the Morongo West of Devers Rate Year Cost, which by the end of 2023 was of $7.59 million, compared to $11.5 million in the previous update, a decrease of $3.9 million, mainly attributable to property taxes.[123]

[121] "Morongo Transmission Requests a 100 BP ROE Incentive from FERC," Energy Central, January 21, 2021, https://energycentral.com/c/tr/morongo-transmission-requests-100-bp-roe-incentive-ferc.

[122] Suedeen Kelly, "If Only Transmission Lines Were like Rose Bushes," November 29, 2023, https://www.jenner.com/en/news-insights/publications/if-only-a-transmission-line-were-like-a-rose-bush-wires-quarterly-newsletter.

[123] "2024 Annual Update WOD Filing Letter.Pdf," accessed March 25, 2024, https://www.sce.com/sites/default/files/Regulatory/OpenAccessInformation/MorongoWOD/2024%20Annual%20Update%20WOD%20Filing%20Letter.pdf.

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CLEAN AIR TASK FORCE

NET-ZERO CALIFORNIA



Wired for Savings

Evaluating the Impact of Alternative Transmission Financing and Development Models on California Ratepayers

Executive Summary

An unprecedented expansion in electrical transmission is key to meeting California's climate goals. However, there is a risk that traditional investor-owned utility financing and development of this multi-billion-dollar infrastructure portfolio could substantially increase consumer rates.

Net-Zero California (NZC) and Clean Air Task Force (CATF) commissioned research to evaluate whether alternative transmission financing and development models could generate ratepayer savings. The analysis was limited to the California Independent System Operator's 20-Year Outlook, which identifies the new high-voltage transmission lines needed to meet the state's energy demand in 2045.

The results show the potential for substantial ratepayer savings of up to $3 billion per year, or about $123 billion over 40 years, to the extent this infrastructure is financed and developed through a public-private partnership.

The key drivers of savings include: using low-cost public debt to replace equity in the capital structure; ensuring competitive selection of the transmission line developer; public ownership to reduce taxes; and private operations to increase efficiency. This portfolio of actions could also increase the speed of transmission development.

Existing California state agencies have some, but not all, of the authority necessary to implement a public financing and development strategy. Further work is needed to identify the optimal implementation of a public-private partnership or similar model in California.

Overview

California set ambitious clean energy deployment goals, requiring that renewable and zero-carbon energy resources supply 100 percent of electric retail sales to customers by 2045.[1] Delivering on this goal will require quadrupling clean energy capacity[2] alongside an enormous expansion in new transmission to bring these resources from various regions, including the North and Central Coast (offshore wind), Central Valley (solar), and Salton Sea (geothermal), to load centers.

This presents an issue where rates could further increase to pay for this grid infrastructure and potentially undermine the transition to clean energy. With rates having increased by about 50 percent in the last three years for many investor-owned utility (IOU) customers,[3] proactive actions are needed to bring down energy costs and keep rates as low as possible.

Stakeholders have identified multiple strategies with the potential to reduce rates, such as equitable rate reform,[4] increased use of grid-enhancing technologies,[5] an expansion in western power markets,[6] and removing non-essential utility programs from electric bills.[7] NZC and CATF partnered to evaluate a less-examined strategy with potential for significant upside: changing the way transmission infrastructure is financed and developed in California.

This policymaker brief summarizes two analyses commissioned by NZC and CATF to investigate this issue:

1. **A financial analysis** by DHInfrastructure (DHI) and EE-Analysis (EEA) that quantifies the potential ratepayer savings of alternative transmission financing and development models compared to a IOU financing and development scenario.[8]
2. **A legal and policy analysis** by UC Berkeley's Center for Law, Energy and the Environment (CLEE) that identifies potential options and challenges to implementing an alternative transmission financing and development model in California. The CLEE analysis also examines a series of near-term policymaker recommendations to address these challenges.[9] The CLEE report incorporates feedback from an in-person convening of transmission experts held in June 2024.

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1 Senate Bill 100 (SB 100, De León, Chapter 312, Statutes of 2018)

2 SB 100 Joint Agency Report (2021) https://www.energy.ca.gov/sb100

3 California Public Advocates Office, 2024. 2024 Q2 Electric Rates Report

4 Natural Resources Defense Council, 2024. Equitable rate reform is required to meet our climate goals.

5 SB 1006 (Padilla): https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202320240SB1006.

6 West-Wide Governance Pathways Initiative: https://www.westernenergyboard.org/wwgpi/.

7 California Public Advocates Office, 2023. California's facing climate and electricity rate crises. Here's how to solve them.

8 DHInfrastructure and EE-Analysis, 2024. Public sector financing of electricity transmission lines in California.

9 UC Berkeley Center for Law, Energy and the Environment, 2024. Improving transmission financing in California: Policy strategies to increase affordability.

Background on California transmission financing and development

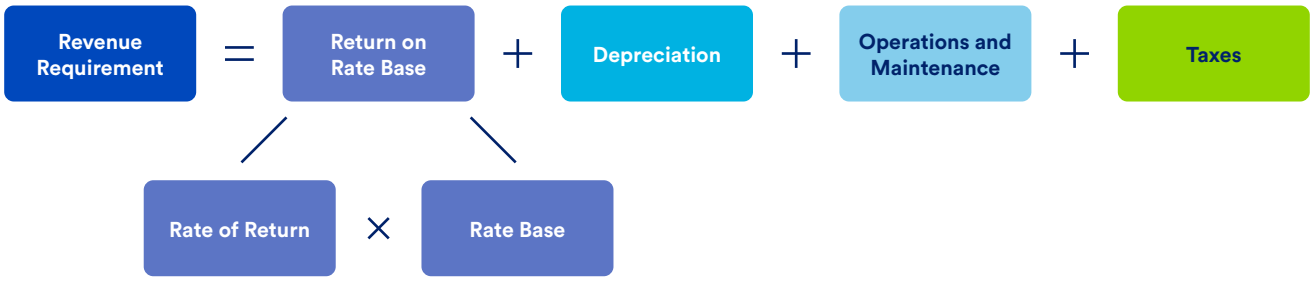
Transmission lines in California are primarily owned, financed and developed by private, for-profit IOUs. The three main IOUs are Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric, who collectively own and operate the majority of transmission lines in the state. IOUs must file with the Federal Energy Regulatory Commission (FERC) for approval to recover their transmission costs in rates for projects identified as part of a formal planning process, such as the California Independent System Operator's (CAISO) annual Transmission Planning Process (TPP), or separately by the IOUs themselves.[10] FERC authorizes cost recovery, and IOUs are able to obtain financing (including third party debt and equity) to develop projects.

Transmission in the rate base

Transmission currently comprises about 30 percent of the California IOU rate base, representing a key factor in determining electric rates (Figure 1).[11] This amount is expected to grow considerably in the coming years. CAISO's 2024 20-Year Outlook identifies $46 to $63 billion of new high-voltage transmission to achieve the state's SB 100 goal.[12] Significant expansion of lower-voltage transmission will also be needed.[13] As project financing (cost of capital) and development have the potential to substantially increase overall transmission costs, actions to minimize rate impacts are needed.

Figure 1 – Calculating the Revenue Requirement

The "revenue requirement" refers to the total revenue that IOUs are authorized to collect from ratepayers in a given year. The book value of an IOU's generation, distribution and transmission assets (rate base), and just as importantly the cost of capital associated with servicing that rate base (rate of return), directly impacts what is ultimately charged to ratepayers. Transmission is a key and growing component of the IOU rate base. Note: this graphic shows simplified processes regulated by FERC and California Public Utilities Commission to determine revenue requirements for IOU-owned transmission and distribution assets, respectively.



[10] IOU "self-approved" transmission projects are an example of non-TPP projects. For more information, see pp. 30-31 of the 2023 California Electric and Gas Utility Costs Report.

[11] California Public Utilities Commission, 2024. 2023 California Electric and Gas Utility Costs Report.

[12] California Independent System Operator, 2024. 2024 20-Year Transmission Outlook. High-voltage is defined as transmission lines and related upgrades equal to or greater than 230 kV.

[13] CAISO's 2024 20-Year Outlook is limited to identifying potential high-voltage transmission needs but recognizes the need for expansions in lower-voltage transmission, which would also add to the rate base.

Alternative financing and development approaches

NZC and CATF commissioned DHI and EEA to evaluate whether alternative approaches to transmission financing and development could generate cost savings. The research identified three key opportunities: the use of low-cost public debt; new institutional models to facilitate public financing; and reducing the risk of pre-investment development. These opportunities are summarized below.

I. The use of low-cost public debt (bonds) could directly reduce costs to ratepayers by enabling lower interest rates, replacing equity in the capital structure, and reducing taxes.

a. **Lower interest rates:** A public entity issuing a bond typically provides access to the lowest-cost debt due to the high credit rating of governments, resulting in lower debt servicing and therefore a lower revenue requirement compared to traditional private sector borrowing.

b. **Debt replacing equity:** To the extent that public debt replaces equity in the capital structure, costs would be further reduced, as the cost of equity (dividends) is considerably higher than the cost of debt (interest).

c. **Reducing taxes:** Public bonds and loans are in many cases tax-exempt. Additionally, a lower rate of return (i.e., more debt vs. equity) will further reduce income tax obligations.

II. New institutional models to facilitate public financing, including certain types of public-private partnerships or a wholly public development model, could indirectly reduce costs to ratepayers.

A new or expanded public agency or authority that facilitates public financing could enable a range of additional cost reductions. For example, a public-private partnership (PPP) could help to increase competition for the development of new transmission, which has been shown to reduce costs.[14] Public ownership, whether as part of a PPP or wholly public model, could reduce tax obligations. PPPs offer the additional benefit of retaining private sector innovation and efficiency for operating and maintaining a transmission line and—by using special purpose vehicles to implement projects—can shield the public owner from certain operational risks.

III. Accompanying policies that seek to reduce the length and risks of pre-investment development could deliver a third tranche of savings.

As transmission development is high risk and requires significant pre-investment capital, investors require high risk premiums. As a result, policies that reduce the length and risk of this phase, such as clear and predictable siting and permitting processes, could generate direct cost reductions.[15]

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[14] Pfeifenberger, J. et al. The Brattle Group. (April 2019). *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*. https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf

[15] For more information on the transmission planning and permitting process, see CATF's factsheet: "Transmission Development in California – What's the Slowdown?"

Evaluating the alternative models for ratepayer savings

DHI and EEA analyzed the potential savings that could occur under alternative transmission financing and development models in California. CAISO's 20-Year Outlook, which identifies a portfolio of high-voltage transmission lines and related upgrades necessary to achieve the state's SB 100 goal, was used as a basis for the analysis. The analysis examined four alternative models for financing and developing this new infrastructure, which leverage a combination of the approaches outlined above:

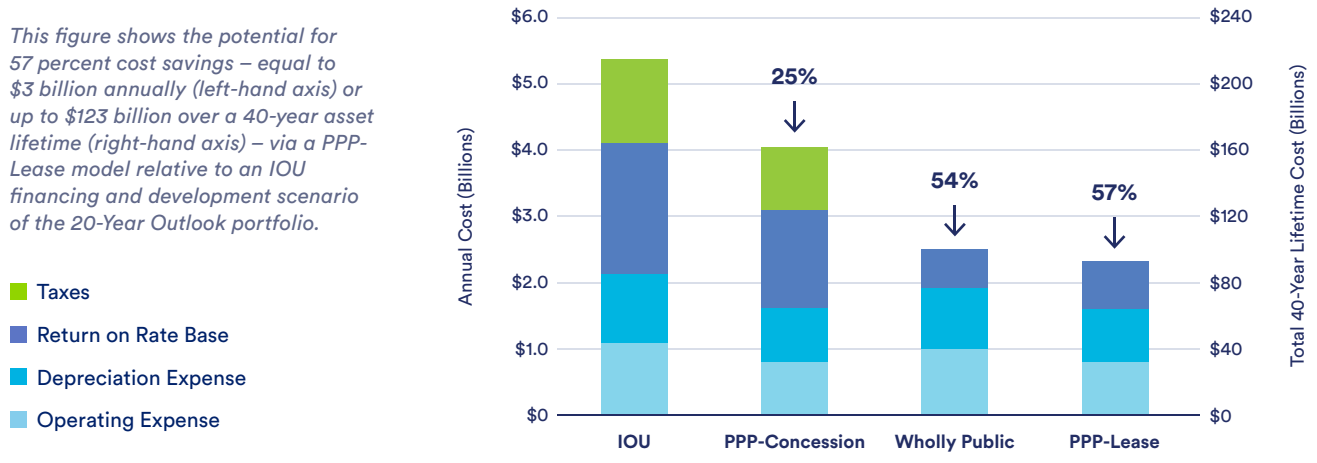
1. **IOU Financing and Development:** A current scenario of an IOU developing, financing, and operating transmission lines.
2. **Wholly Public:** A wholly government-owned entity developing, financing, and operating the lines.
3. **Public-Private Partnership (Concession):** A concession-type PPP in which a private company designs, builds, operates, and finances a publicly-owned asset over the life of the asset, and the asset is ultimately returned to the government at the end of the concession agreement.
4. **Public-Private Partnership (Lease):** A lease-type PPP, in which a government-owned holding company or special purpose vehicle provides financing for the transmission asset but hires a private company to build and operate the assets.

The estimated cost of the 2024 20-Year Outlook infrastructure is between $39 and $54 billion for engineering and construction costs only.[16] Adding in financing and development costs, this number increases to up to $216 billion over 40 years under a IOU financing and development scenario.

Alternative approaches show significant opportunity to reduce the financing and development costs by as much as 57 percent, or up to $123 billion, over the same period. This is equivalent to ratepayer savings (or a reduction in the revenue requirement) of $3 billion per year. The results are summarized in Figure 2.[17]

Figure 2 – Alternative Financing Models: Annual and Total Cost Savings Potential

This figure shows the potential for 57 percent cost savings – equal to $3 billion annually (left-hand axis) or up to $123 billion over a 40-year asset lifetime (right-hand axis) – via a PPP-Lease model relative to an IOU financing and development scenario of the 20-Year Outlook portfolio.



[16] Note that Figure 2 excludes interregional transmission for out-of-state wind that is already being developed. These costs will be paid by the line subscribers. It additionally does not include costs for upgrades to existing utility transmission facilities that are likely not eligible for competitive solicitation.

[17] Figure updated to reflect the 2024 20-Year Transmission Outlook; original analysis by DHI and EEA used inputs from the 2022 Outlook.

DHI and EEA also applied these results to individual lines. For example, recent and detailed capital cost estimates have been developed for North Coast offshore wind, where a $7.7 billion line is planned to accommodate 7.2 GW of development.[18] Under the IOU model, this line would have an annual average cost to ratepayers of $774 million. Under the PPP-Lease model, this cost would fall to $332 million.

The drivers of the cost savings, identified in Figure 3, include: using low-cost public debt to replace equity in the capital structure; ensuring competition in the procurement of the lines; public ownership to reduce taxes; and private operations and maintenance to increase efficiency.

The analysis found the PPP-Lease model, which contains all these elements, provides the lowest-cost approach to delivering California's transmission goals, followed by a wholly public model. A key advantage of the PPP-Lease model is the blend of public and private sector involvement which leverages the strengths of each sector.

A PPP-Lease model offers exemption from certain taxes, retention of private sector expertise and cost-effectiveness through competitive bidding and contracts, and the use of lower cost public debt. A concession-type PPP is comparatively more costly as it retains private sector financing.

Figure 3 – Alternative Financing Models: Drivers of Cost Savings

This figure highlights the cost drivers modeled in the alternative transmission development scenarios.

		Financing and Development Models			
		IOU	PPP-Concession	PPP-Lease	Wholly Public
Drivers of Cost Savings	Low-Cost Public Debt	✗	✗	✓	✓
	Competitive Solicitation	✗	✓	✓	✓
	Tax-Exempt Public Ownership	✗	✗	✓	✓
	Efficient Private Operations	✗	✓	✓	✗

Study limitations

DHI and EEA identified key limitations that suggest the cost savings described above are likely conservative.

- CAISO's 2024 20-Year Outlook capital costs exclude costs associated with right-of-way acquisition and undergrounding transmission for wildfire mitigation.
- The 2024 20-Year Outlook capital costs only include new transmission and related upgrades greater than 230 kV, leaving out smaller lines and IOU "self-approved" projects.[19]
- The scenarios do not model additional savings that could be achieved by de-risking the pre-investment development phase.

[18] Schatz Energy Research Center, 2023. Northern California and Southern Oregon Offshore Wind Transmission Study.

[19] IOUs are also able to "self-approve" rates for certain transmission projects that do not expand capacity of the grid, such as repair and replacement projects for maintaining the grid. Between 2013 and 2022 self-approved projects accounted for 50 percent ($11 billion) of their collective transmission investment. California Public Utility Commission. (April 2024). *2023 California Electric and Gas Utility Costs Report*. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2024/2023-ab-67-report.pdf

Potential implementation options

DHI and EEA's financial analysis identifies the potential cost savings associated with financing and developing transmission under alternative models. To accompany this financial analysis, and situate it in the California context, NZC and CATF commissioned CLEE to conduct a legal and policy review of California agency authorities and structures. CLEE identified a range of potential models that build on existing transmission permitting or financing authorities and draw inspiration from other state and federal models. CLEE considered the benefits and drawbacks of creating new authorities, such as a California Renewable Energy Transmission Authority, or a California Green Bank, which could both finance new transmission and facilitate PPPs.

CLEE also evaluated expanding authorities of existing agencies, including the California Infrastructure and Economic Development Bank, the California Alternative Energy and Advanced Transportation Financing Authority, and the Department of Water Resources, all of which have some existing bonding authority or ability to procure energy resources. Finally, CLEE identified the potential use of federal financing programs through the Western Area Power Administration's Transmission Infrastructure Program, which has $3.25 billion of borrowing authority and the ability to offer loans.[20]

Policymaker recommendations

With an opportunity for ratepayer savings of up to 57 percent when compared to the IOU financing and development scenario, or $3 billion per year and $123 billion over 40 years on the 20-Year Outlook portfolio, California policymakers should further evaluate the potential of public financing and development models to reduce the cost of transmission and consider advancing near-term actions.

The passage and signing of AB 3264 (Petrie-Norris) is a critical next step for further evaluating the cost savings potential of alternative financing and ownership models. AB 3264 directs the Public Utilities Commission, Energy Commission, California Infrastructure and Development Bank, and CAISO to conduct a study to evaluate public financing, costs and benefits of different ownership models, and other proposals to reduce the cost to ratepayers of expanding the transmission grid.[21] State agencies may consider leveraging the analyses underlying this brief as an input to delivering this study by the July 1, 2025 due date.

In addition to further evaluation, policymakers should consider advancing near-term actions. CLEE identified several potential actions to facilitate transmission public financing and speed transmission development, which emerged from a convening of experts including state government, grid operators, non-profits, ratepayer advocates, and industry associations. These near-term actions include:

1. **Focus on demonstrating alternative financing and development arrangements for key transmission lines identified in the CAISO 20-Year Outlook.** Commonalities and differences between proposed locations, developer options, and other considerations for transmission lines will likely shape approaches to financing. For example, the potential large-scale solar development in the Westlands Water District area of Fresno County (approximately 110,000 acres with 15-20 gigawatts of solar) may have different needs than the approximately 14.7 GW of Northern California offshore wind across multiple resource areas and substations.
2. **Establish a liability backstop for whatever entity or entities own new transmission.** As precedent, the California Legislature has established a liability backstop based on actions to reduce fire risk for IOUs operating the existing transmission system.

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[20] For more information on the pros, cons and trade-offs of these model options, see Appendix I of the CLEE report.

[21] AB 3264 (Petrie-Norris) (2024) Chapter 762. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202320240AB3264

3. **Minimize risk through insurance, contract, indemnity, and first loss protection, and other mechanisms,** subject to negotiation and legislation, as New Mexico has done through its Renewable Energy Transmission Authority (RETA).[22]

4. **Modify CAISO rules to allow for an additional competitive bid process**, opening more transmission to private development and private funding. Under existing CAISO rules, some (albeit few) potential transmission lines are already eligible for competitive bids by private developers. CAISO has sufficient existing authority to expand the lines eligible for competitive bidding.

5. **Explore credit enhancements from the state or federal government.** Credit enhancements have encouraged investment and reduced borrowing costs in multiple contexts. Examples could include the establishment of a state loan loss reserve, loan guarantee, or loan loss insurance to improve the creditworthiness of private transmission developers seeking financing. The federal Department of Energy's Loan Programs Office can also issue credit enhancements to state-administered clean energy programs.

6. **Assess opportunities to finance some transmission lines through general obligation bonds**, funded by taxpayers through the budget process. This can remove some transmission costs from the revenue requirement. Legislators could explore issuing revenue bonds, which do not require voter approval and are used to finance income-generating projects built with the proceeds of the bonds.

7. **Explore options for applying existing federal models to California.** Specifically, workshop participants noted that the Western Area Power Administration (WAPA) could potentially finance transmission, or a state version of WAPA could be established to finance transmission and provide electricity at a wholesale rate to municipal utility customers and community choice aggregators. This is a novel model and warrants further evaluation.

8. **Engage the Governor's Office to designate a coordinator for high priority lines** and support a process to speed implementation and financing. This approach worked well when Governor Schwarzenegger designated a coordinator for large-scale solar projects, making solar a state-wide priority. The coordinator convened meetings with federal, state, and local government officials as well as stakeholders, coordinated state agency participation, and mediated disputes.

[22] For more information on New Mexico RETA, see Appendix I of the CLEE report.

SB 540 - Pathways Initiative

SUMMARY

SB 540 provides the California Independent System Operator (CAISO) the authority necessary to implement the Pathways Initiative Proposal *if* it determines an independent regional organization (RO) meets specific requirements. The bill allows CAISO to tap into a wider market of electricity resources which studies have shown stand to provide significant benefits to Californians including cost savings, enhanced grid reliability, and reduced air pollution.

While prior attempts to create a wider regional market have failed out of concerns that California would lose control over its environmental policies, SB 540 enables an innovative approach that would secure the gains of an expanded market while protecting California's ability to set and enforce its own procurement, environmental, reliability, and other public policies.

PROBLEM

For many years, California's energy regulators have explored how they could optimize available energy supplies across other western states to expand our energy markets and enable an affordable, clean, and reliable grid.

Studies have shown that there are significant benefits for California in an expanded energy market. For example, a Stanford Woods Institute (2024) study found that an expanded market would relieve strain on the electric grid during extreme heat events–in an expanded market scenario the grid was strained 40% fewer hours.[1] A study commissioned by the California Energy Commission (CEC) found that under an expanded market, California would save nearly $800 million per year and gas generation would fall by 31%, moving us closer to our 100% clean energy goals while reducing air pollution.[2] However, these benefits only materialize if other states want to join the regional market, a market they are wary of if it's solely under California's control.

Several different proposals, that would reassure other Western states of California's willingness to work jointly, have made their way before the Legislature. Most recently, AB 538 (Holden, 2023) would have transformed CAISO into a regional transmission organization (RTO). However, these previous efforts have failed over reasonable concerns about losing control of the state's critical public policies.

The Pathways Proposal offers a way to solve these problems. Instead of creating an RTO, the Pathways Proposal creates an RO that only governs the market rules for energy markets while retaining CAISO's role as a California-governed balancing authority so that California and CAISO retain control over procurement, environmental, reliability, and other public policies.

CURRENT LAW

Existing law enables CAISO to, and instructs how it will, manage the transmission grid and related energy markets. It requires, among other things, that CAISO manage those markets in a manner that maximizes efficiency, reduces costs to consumers, protects public health and the environment, and ensures reliability. However, additional authority is required in order for CAISO and California utilities to use energy markets overseen by an RO as proposed by the Pathways Initiative.

THIS BILL

SB 540 enables the CAISO and California utilities to participate in energy markets governed by a separate, independent regional

[1] Stanford Woods Institute: "Grid Regionalization in the West"

[2] Brattle: "Preliminary Day-Ahead Market Impacts Study"

organization. If the RO meets specific criteria, CAISO would be authorized to enact a resolution allowing the RO's rules to govern CAISO's energy markets. The CAISO would continue to be the operator of the energy markets.

SB 540 does *not* transfer authority for transmission planning, transmission cost allocation, balancing authority functions, or reliability coordination–this authority would remain with the existing CAISO board structure. The bill also does not immediately authorize utilities to enter a market governed by an RO, CAISO must first demonstrate the RO meets a number of statutory requirements before moving control of the market rules to the RO including: confirming that California regulatory agencies and CAISO retain control over Renewables Portfolio Standard requirements, climate policy, other procurement requirements, transmission planning, CAISO's interconnection queue, and resource adequacy requirements; requiring that the RO provides a procedure for withdrawal from the market, should it no longer benefit California to participate; maintaining the capability to operate its own market, should California decide to withdraw from the RO; ensuring the RO is obligated to make decisions in an open process; making funding available for consumer advocates to engage in the process, and more.

The expanded market that SB 540 would enable will save ratepayers money, improve grid reliability, and reduce air pollution from power plants in California by:

1) Optimizing the use of generation, storage and transmission resources.
2) Securing California's ability to export excess renewables rather than curtailing them and importing them from other states when available.
3) Allowing California to draw upon a wider set of Western renewable resources when our grid is stressed.
4) Making less use of back-up diesel generators and the oldest, dirtiest gas plants during system peaks.

SB 540 will ensure that we reach our climate goals in the most cost-effective and reliable manner possible by tapping into a much wider set of Western resources–lowering energy bills, improving grid reliability, and reducing pollution in front-line communities, while also retaining control of our procurement, environmental, reliability, and other public policies.

SUPPORT

Coalition of California Utility Employees (co-sponsor)
State Association of Electrical Workers (co-sponsor)
Environmental Defense Fund (co-sponsor)
Natural Resources Defense Council (co-sponsor)
American Clean Power–California
California Community Choice Association
California Environmental Voters
Clean Energy Buyers Association
Pattern Energy
Peninsula Clean Energy

FOR MORE INFORMATION

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DOCKETED	
Docket Number:	24-IEPR-01
Project Title:	General Scope
TN #:	261300
Document Title:	Presentation - Preliminary Day-Ahead Market Impacts Study
Description:	*** THIS DOCUMENT SUPERSEDES DOCUMENT TN #264264***6A. John Tsoukalis, Brattle-Group
Filer:	Raquel Kravitz
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	1/27/2025 8:55:48 AM
Docketed Date:	1/27/2025

Preliminary Day-Ahead Market Impacts Study

IMPACT OF MARKET FOOTPRINTS ON CALIFORNIA CUSTOMERS

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Evan Bennett
Alison Savage Brooks

PREPARED FOR

STATE OF CALIFORNIA
ENERGY COMMISSION

January 24, 2025

Brattle



Overview of the Study and Drivers of Benefits

Several utilities in CA and neighboring states have committed to joining EDAM, while other utilities in the western U.S. are exploring a different day-ahead market (Markets+) that will not include CA.

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

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

Market Dynamics and Expected Outcomes

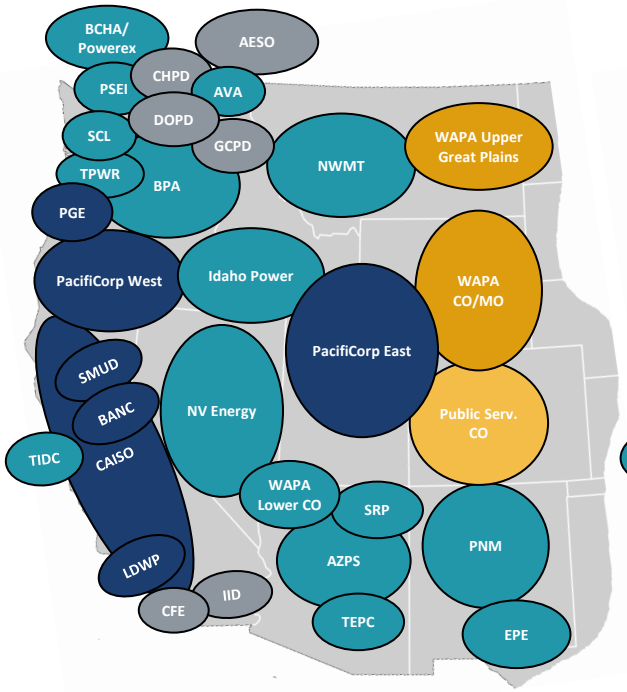
Larger and More Diverse Pool Transmission and Generation Resources	• **Shift from less efficient to more efficient resources, leading to production cost savings for customers.** ***Customer Cost Savings*** ↑ • **Emissions potentially decline due to shift to more efficient generation.** ***Potential Environmental Benefit*** ↔ • **Better management of extreme weather events and unexpected grid challenges (e.g., outages).** ***Reliability Benefit*** ↑ • **Reduced sale of short-term transmission service, as transmission is "donated" to the market (offset by EDAM TRR Settlement).** ***Customer Cost Increase*** ↓
Reduced Curtailment of Wind and Solar due to Increased Resource and Load Diversity	• **Lower emissions due to avoided curtailed energy displacing fossil generation.** ***Environmental Benefit*** ↑ • **Lower power costs for customers due to zero variable cost energy displacing higher variable cost energy.** ***Customer Cost Savings*** ↑ • **Better investment environment for renewable projects.** ***Customer Cost Savings*** ↑
Increased Trading between Market Members	• **Reduced bilateral trading as markets trades become more profitable, lost bilateral trading margins.** ***Customer Cost Increase*** ↓ • **Increased market congestion and transfer revenues.** ***Customer Cost Savings*** ↑

Simulated Market Footprints

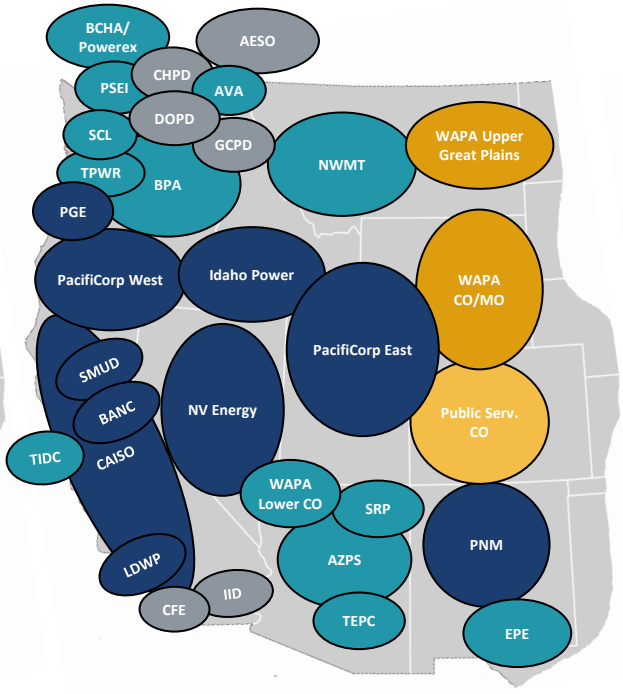
Markets+ (DA & RT)
EDAM (also in WEIM)
SPP RTO West (*co-optimizes w/ M+*)
WEIS
WEIM

To test the impacts for California DA market participation benefits of several potential DA market outcomes, we simulated four market footprints

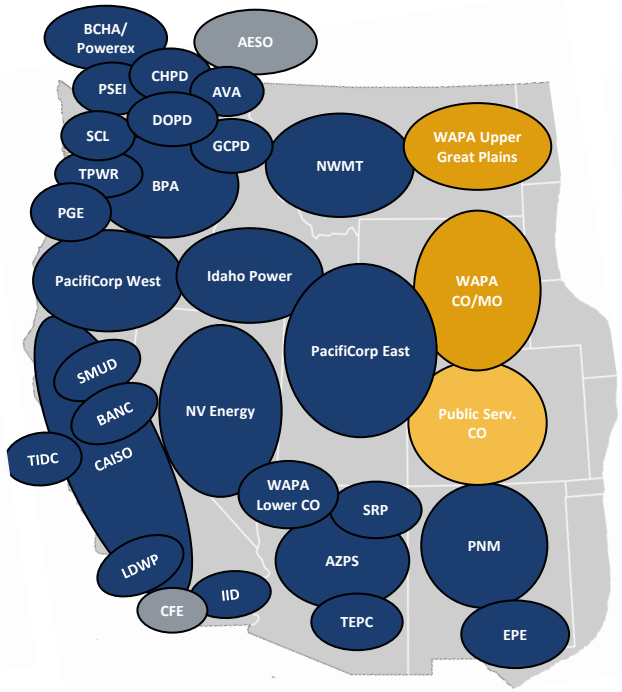
Baseline Case
(Approved EDAM Commitments)



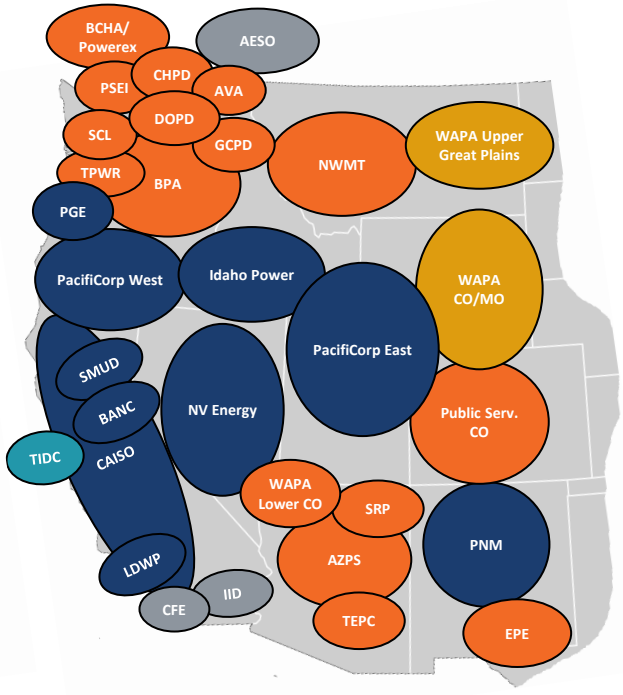
Baseline+ Case
(Likely EDAM Commitments)



Expanded EDAM Case
(Maximum EDAM Potential)



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

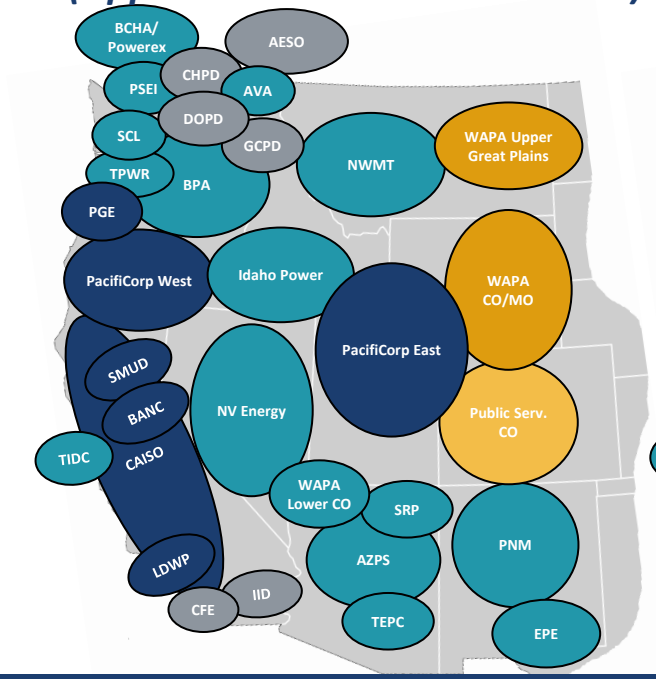


EDAM (also in WEIM)
SPP RTO West
WEIS
WEIM

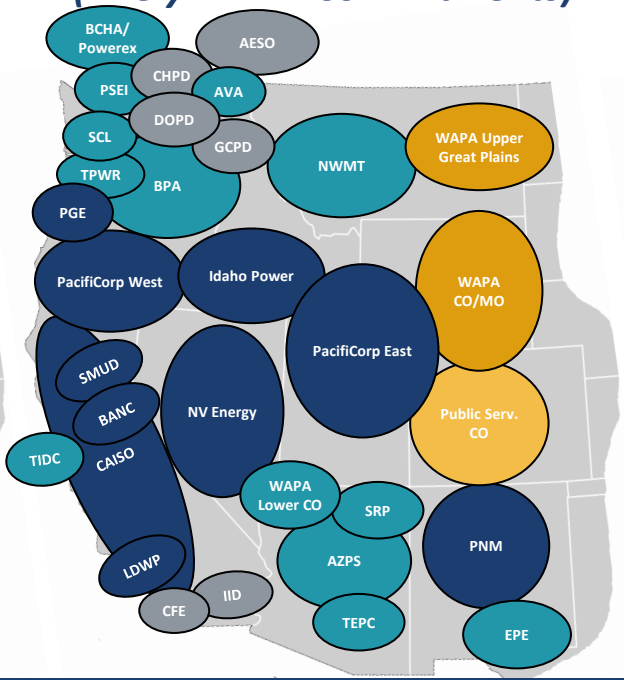
CA Customer Benefits Increase with the Size of the EDAM Footprint

Expansion of EDAM footprint could produce over $500 million/year in market benefits to CA customers

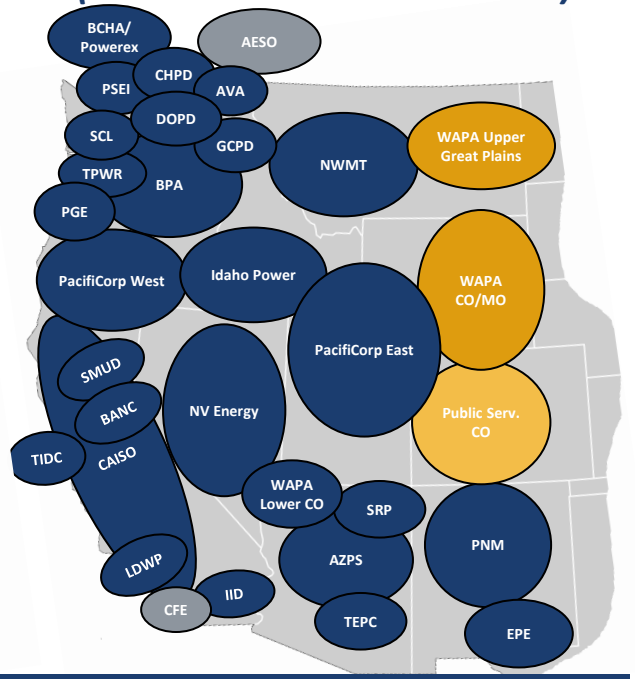
Baseline Case
(Approved EDAM Commitments)



Baseline+ Case
(Likely EDAM Commitments)



Expanded EDAM Case
(Maximum EDAM Potential)



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

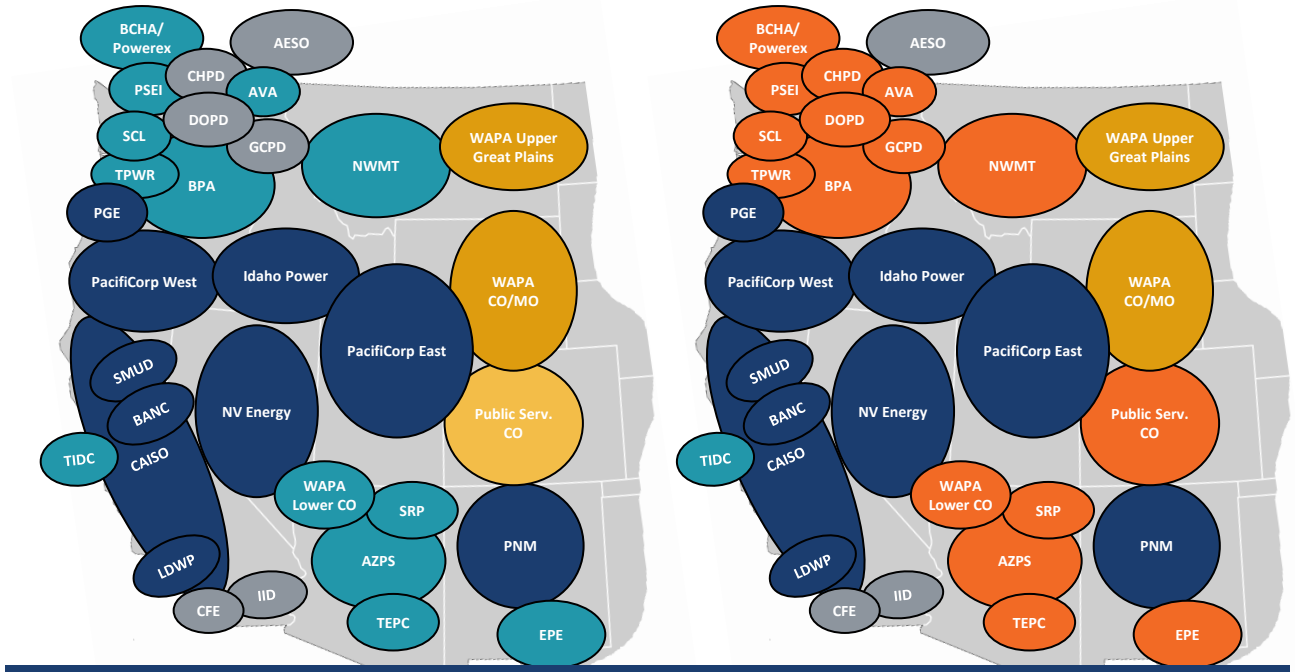
- These benefits are incremental to the benefits of the formation of EDAM with the Baseline footprint of committed entities
- Intermediate EDAM footprints likely to produce benefits between the Baseline+ and Expanded EDAM "bookend"

Markets+ (DA & RT)
EDAM (also in WEIM)
SPP RTO West
WEIS
WEIM

California Benefits from a Two Market Outcome

Baseline+ Case
(Likely EDAM Commitments)

Split Market Case
(Likely EDAM Entities w/ Markets+)
(Assumes Relatively Efficient Seams)



	Baseline+ Case	Split Market Case
CA Total System Cost ($million per year)	$4,399	$4,217
Δ to Baseline+		$182

CA Benefits ~$500 million/year higher in the Expanded EDAM Case *(see previous slide)*

Two offsetting effects lead to a small gain for CA customers in the Split Market case:

- CA customers experience a loss from utilities leaving the WEIM *(~40% of load in WEIM today).*
- CA customers benefit from increased access to low-cost resources in the M+ footprint due to elimination of seams in the WECC and increased DA trading at the market seam.

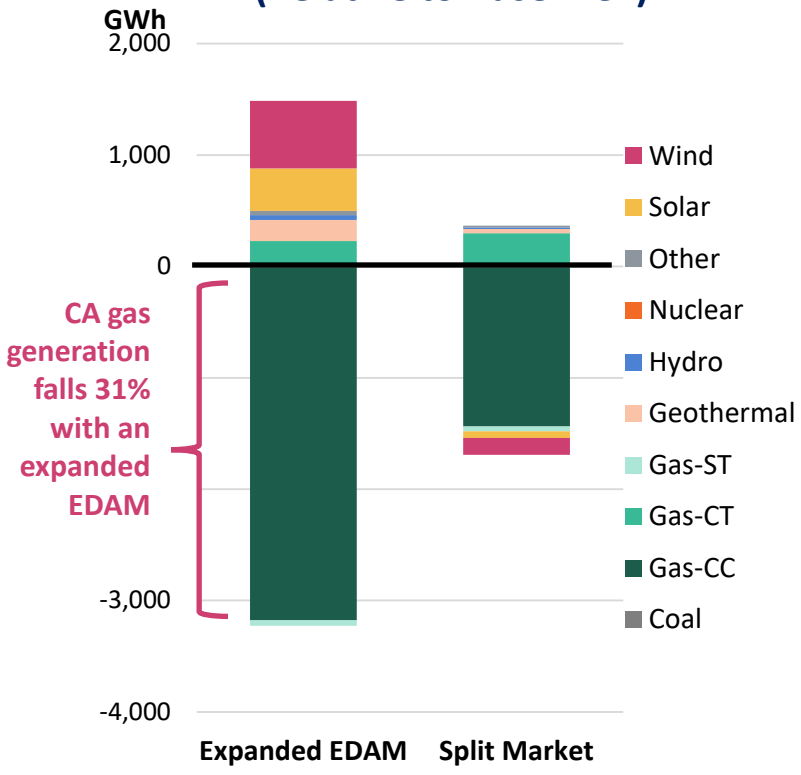
Several assumptions drive this result:

- A relatively efficient seam between M+ and EDAM *(lower trading costs than bilateral trading in the Baseline cases).*
- Hourly modeled real-time trading at the seam fails to capture full loss from utilities leaving WEIM, which optimizes on a sub-hourly level.
- M+ co-optimizes with RTO West, giving low-cost thermal resources in that region hurdle-free access major CA import locations (*e.g.*, Malin, PV).
- The Split Market case assumes ~60% of load in the WEIM today joins EDAM; assuming more of the WEIM leaves would increase the loss to CA customers.

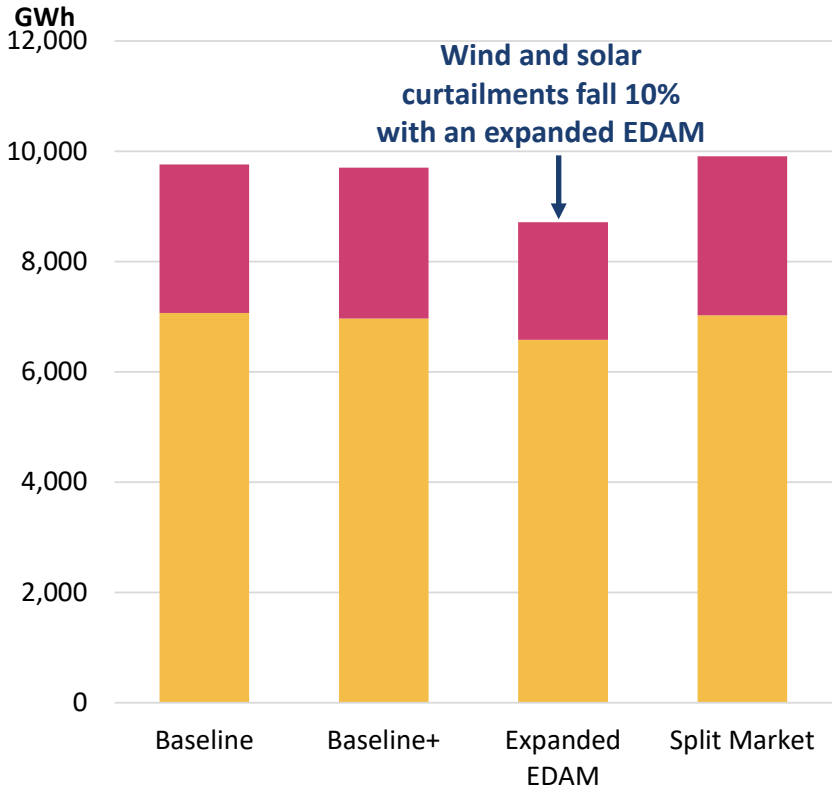
GHG Emissions Impacts

The expansion of EDAM reduces gas generation and the curtailment of wind and solar in California, resulting in lower GHG emissions in the state.

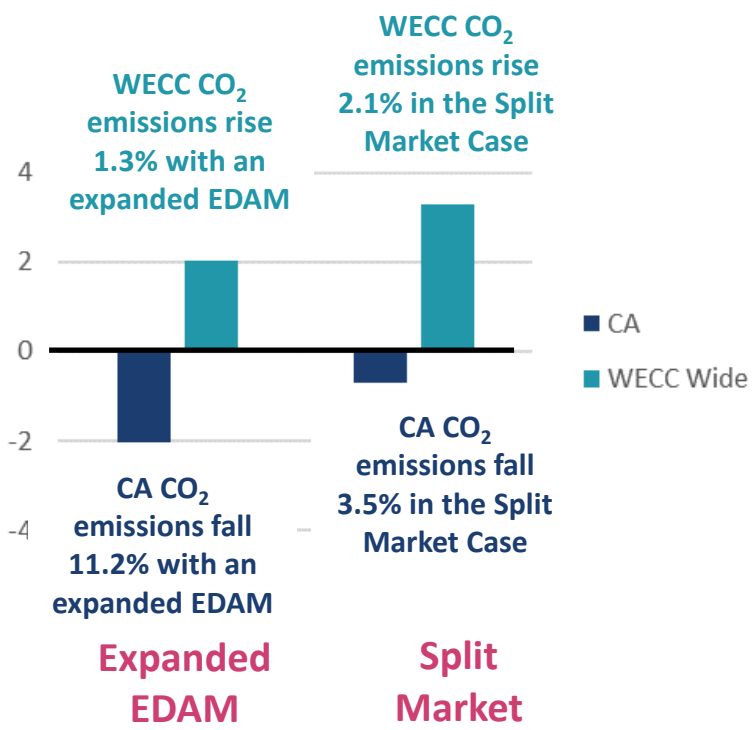
California-Wide Generation (Relative to Baseline+)



Total California Curtailments by Case



Change in CO_2 Emissions

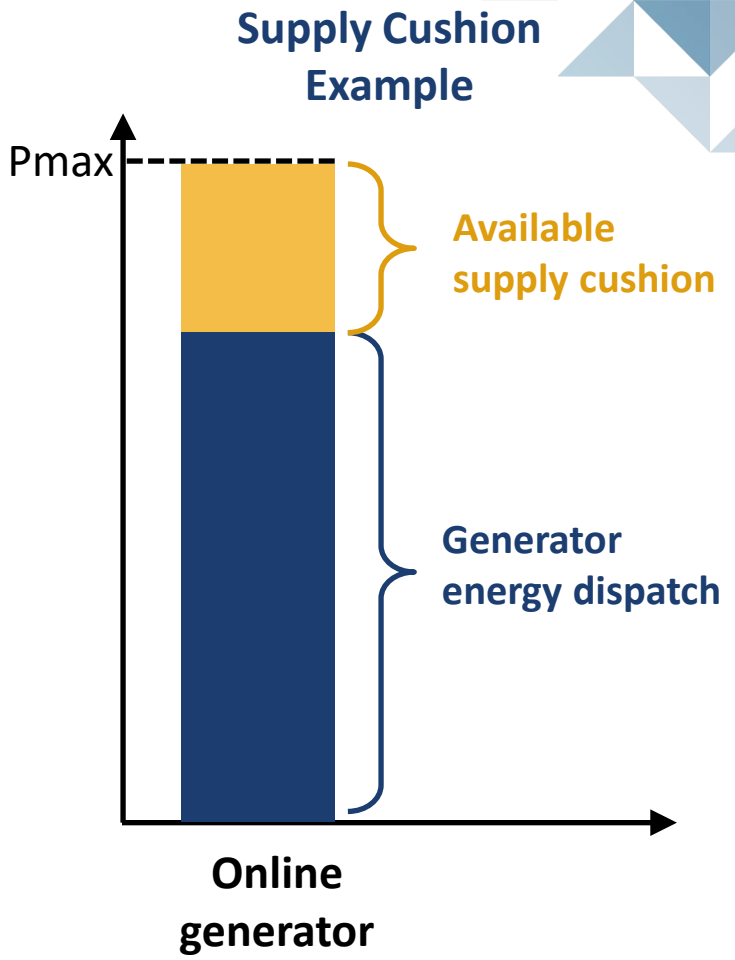


Market Supply Cushion Overview

Market supply cushion is the total unutilized capacity accessible by participants from available market generation in each hour, i.e., the available generating capacity not committed to serving load.

- It *includes* generators that are online and below maximum output
- It *excludes* resources that are on planned or forced outage
- Storage resources are further limited by their stored energy
- We conservatively assume that hydro, wind, and solar provide no incremental supply cushion.

We use this metric as a proxy for the impacts of market footprint on access to capacity, especially during tight-supply periods with high risk of resource adequacy shortfalls.

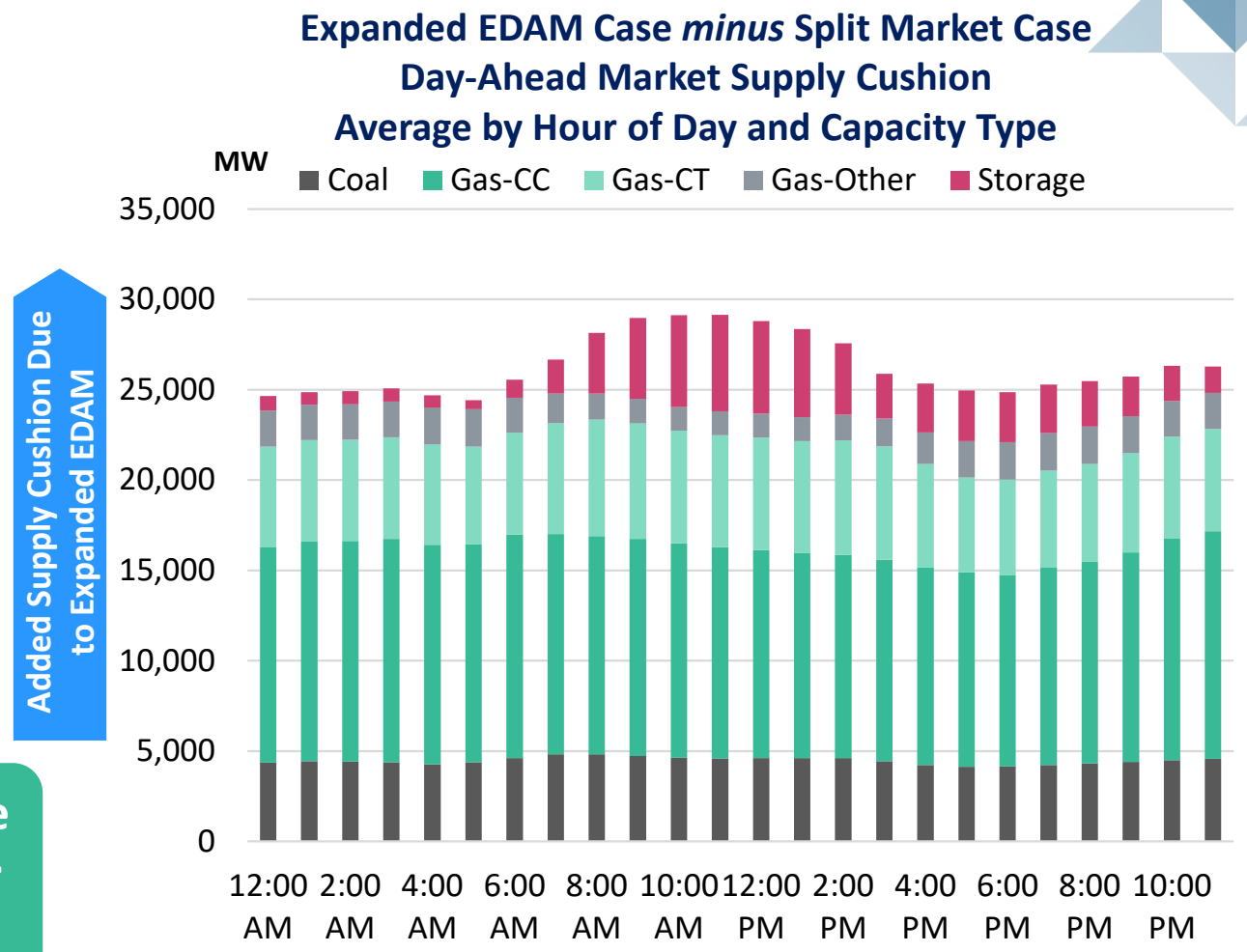


Expanding the EDAM footprint Increases Supply Cushion

The supply cushion in the EDAM footprint is significantly higher in the Expanded EDAM case relative to the Split Market case.

- The supply cushion is ~25,000 MW more in the Extended EDAM case than the Split Market case.
- Higher supply cushion in midday hours when storage is charging.
  - The Expanded EDAM case has more storage in the EDAM compared to the Split Market case, as well as a higher average state-of-charge due to increased renewables diversity in the larger footprint.

Focusing on the 10 tightest hours of the year, the supply cushion in the EDAM is 20,000 MW larger in the Expanded EDAM case than in the Split Market case (27.8% of load vs. 24% of load)



Estimated Benefits are Conservatively Low

The benefits of regional markets are likely understated due to several factors:

- **Overstated Bilateral Market Efficiency:** our simulation of bilateral markets is more efficient than reality
  - Hourly model fails to captures the benefit of real-time markets to economically and reliability manage energy imbalances through sub-hourly re-dispatch and energy exchange across market members.
  - The model assumes all balancing authorities have optimal security-constrained unit-commitment and dispatch (SCUC and SCED) in both DA and RT, making the simulated dispatch more optimal than reality.
  - Inefficient utilization of transmission by bilateral trades is not fully modeled, understating the extent M+ and EDAM will be able to make better use of all physically and contractually available transmission.
  - Transmission outages are not modeled, which would magnify the benefit of SCED-based congestion management in EDAM and M+ compared to the bilateral markets.
- **Normalized loads and fuel prices:** the model uses weather-normalized loads and averaged monthly natural gas prices without daily volatility
  - Challenging market conditions (beyond the included heat wave and cold snap), such during as the 2022 gas price spikes or 2024 MLK Day cold snap, will magnify benefits from a regional market. Illustrated by the WEIM experience of much higher benefits during those events.
  - The Base Case does not reflect the limited liquidity of bilateral market during challenging market conditions

Brainstorming Possible Further Analysis

The four cases simulated provide significant insight on the impact of market expansion for CA and raise questions for future analyses to address.

- **Footprint Assumptions:**
  - Simulate a "Status Quo" case without any EDAM footprint, which would allow us to calculate the benefit of EDAM forming relative to just the WEIM.
  - The Expanded EDAM and Split Market cases represent two approximate bookends, we could test intermediate footprints with different combinations of utilities joining EDAM or Markets+.
- **Market Seam Assumptions:**
  - The level of coordination that will be achieved between the two markets is unknown. Future sensitivities could explore the impact to CA customers of different forms coordination and co-optimization across market seams.
  - Sub-hourly modeling could be used to calculate the benefit of 15-minute and 5-minute optimization conducted by the WEIM for CA customers and WEIM/EDAM members.
- **Resource mix, load forecasts, and fuel price assumptions**
- **Impact of extreme weather volatility**
  - Weather-relative system conditions – load, thermal generation outages, and renewable production
  - Daily and regional gas price volatility

Appendix A: Modeling Assumptions and Detailed Results

Timeline of the Brattle Team's Western Markets Studies

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

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

1 Pre-2022 Studies

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

2 2022 EDAM Study

2022 EDAM Benefits Study

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

3 2023-24 EDAM-M+ Studies

Comparative EDAM-M+ Studies

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

4 This Study

CEC Pathways Study

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

Multi-Functional Simulation of WECC

Markets/RTO Functions & Configurations

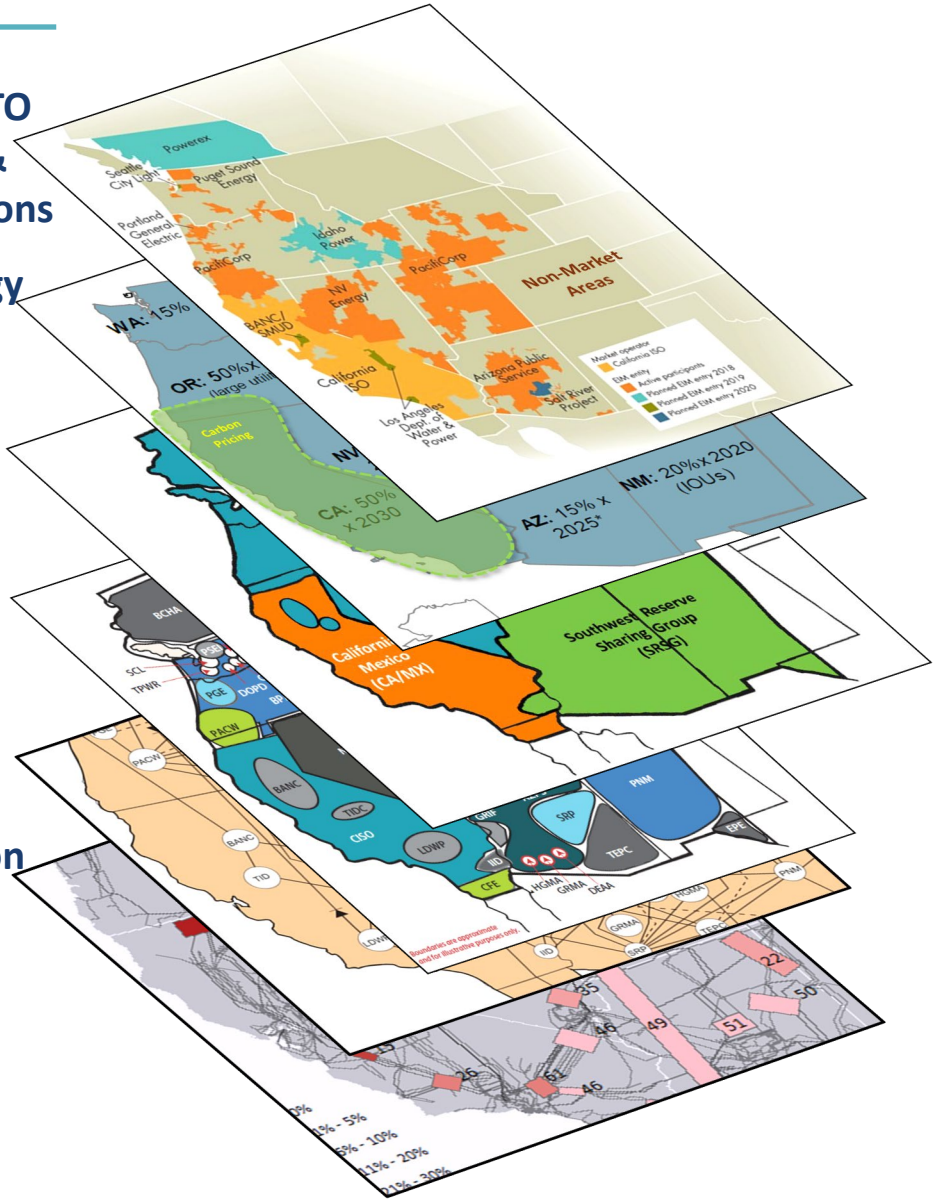
Clean Energy Policies

Reserve Sharing

BAA Functions

Bilateral Contract Paths and Transmission Rights

Physical Flows and Constraints



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

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

Key Model Features

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

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

California-Wide Day-Ahead Market Expansion Benefits

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

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

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

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

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

Interpretation of Benefits in CAISO

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

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

California Adjusted Production Cost in the EDAM Case

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

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

California-Wide Adjusted Production Cost

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

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

California Adjusted Production Cost in the Split Market Case

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

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

California Adjusted Production Cost

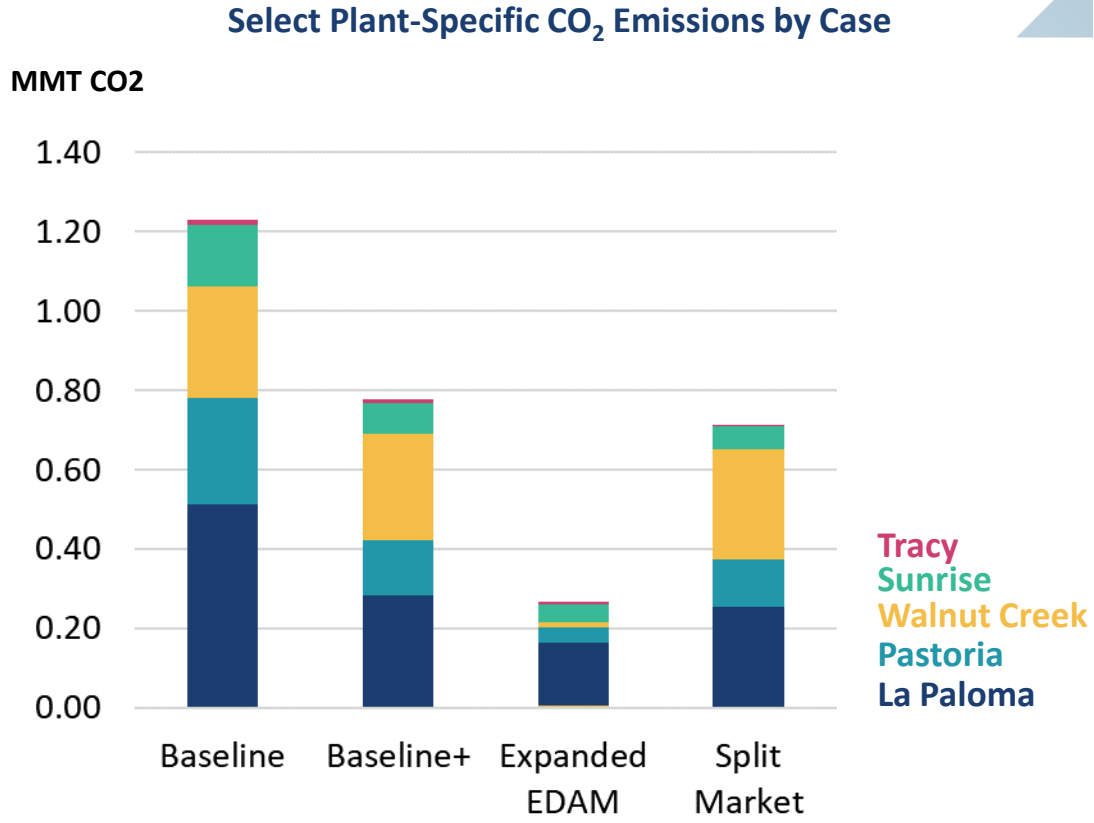
			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	
Production Cost	(+)	[1]	344,267	342,887	**-1,379**	$4.18	$4.00	**-$0.19**	1,439,851	1,370,114	**-$69,737**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

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

Gas Generation in California

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

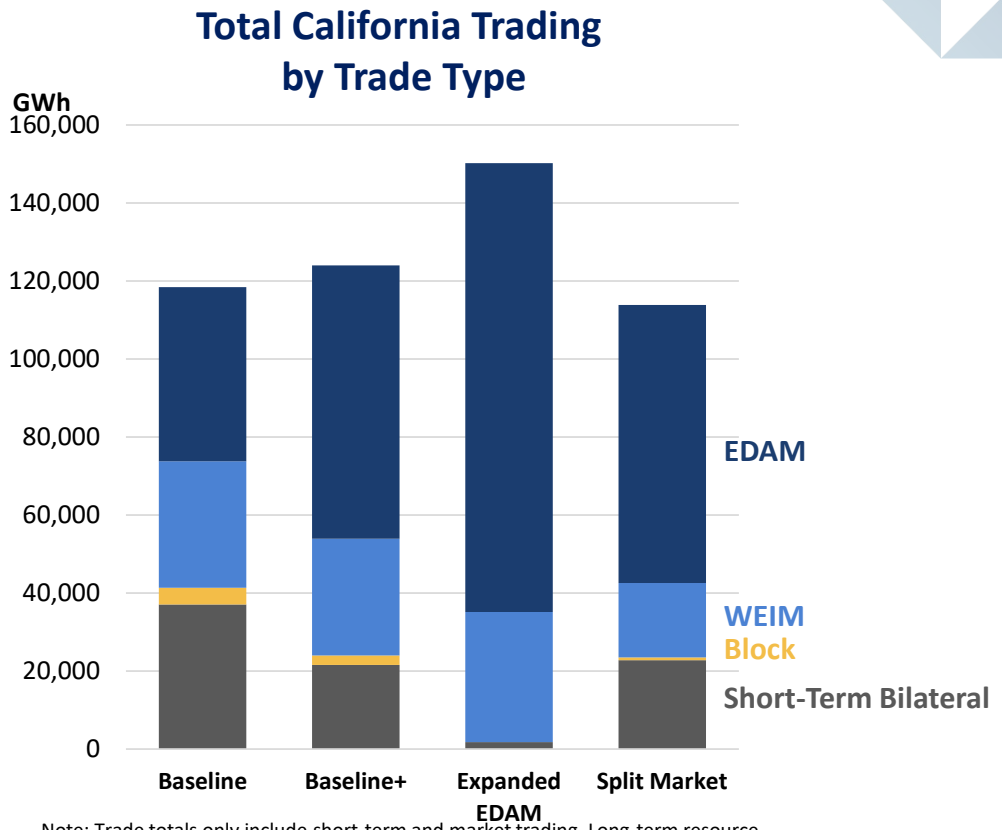
- Emissions from some of the larger gas plants in California fall across the board, but dramatically more in the Expanded EDAM case.
- The decline in gas generation in the Expanded EDAM case is broadly consistent across all areas of California.



California Trading Volume by Case

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

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

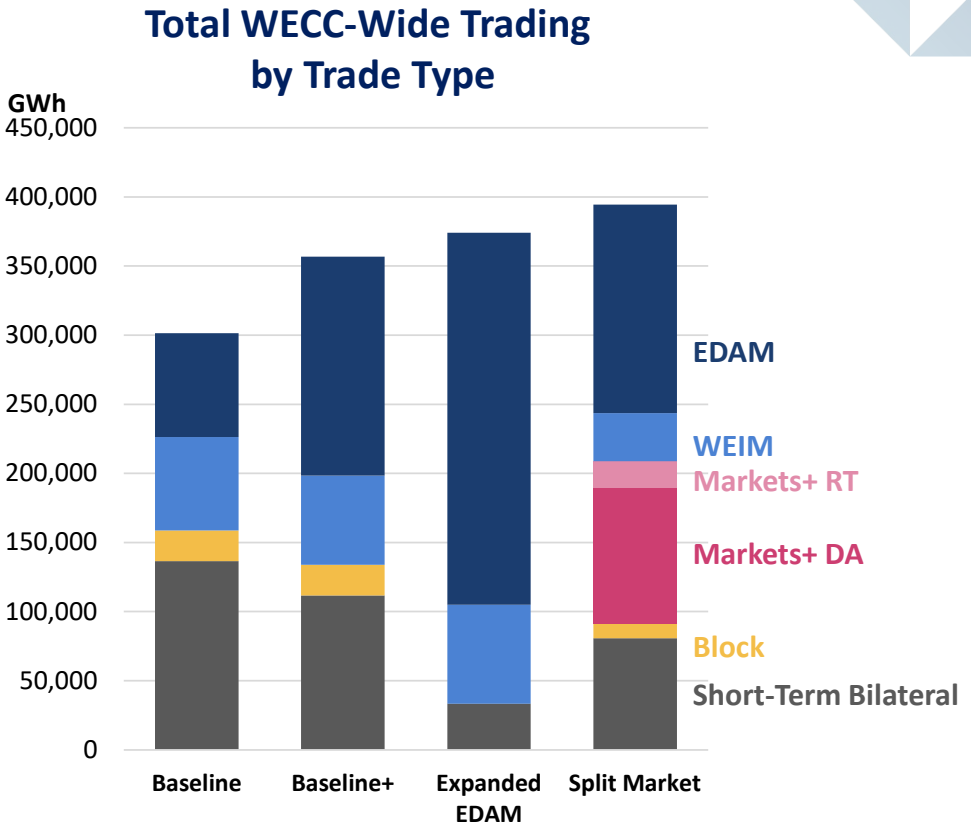


Note: Trade totals only include short-term and market trading. Long-term resource contracts are not included in these totals. Short-term bilateral trades include EDAM-Markets+ seam trades.

WECC-Wide Trading Volume by Case

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

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



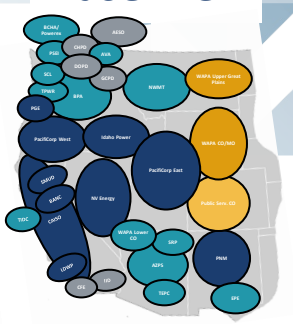
Note: Trade totals only include short-term and market trading. Long-term resource contracts are not included in these totals. Short-term bilateral trades include EDAM-Markets+ seam trades.

California Trading Changes: Baseline+ to Expanded EDAM

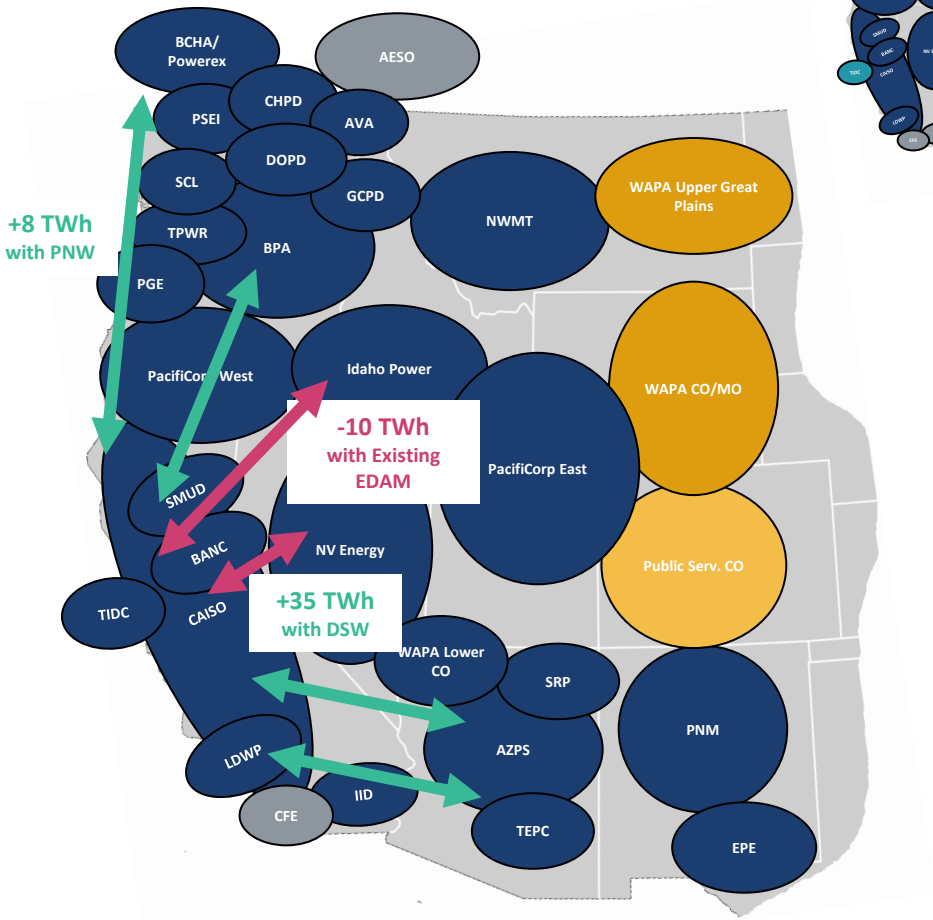
In the Expanded EDAM case, California trading increases with the new EDAM participants in the Desert Southwest and Pacific Northwest

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

Baseline+



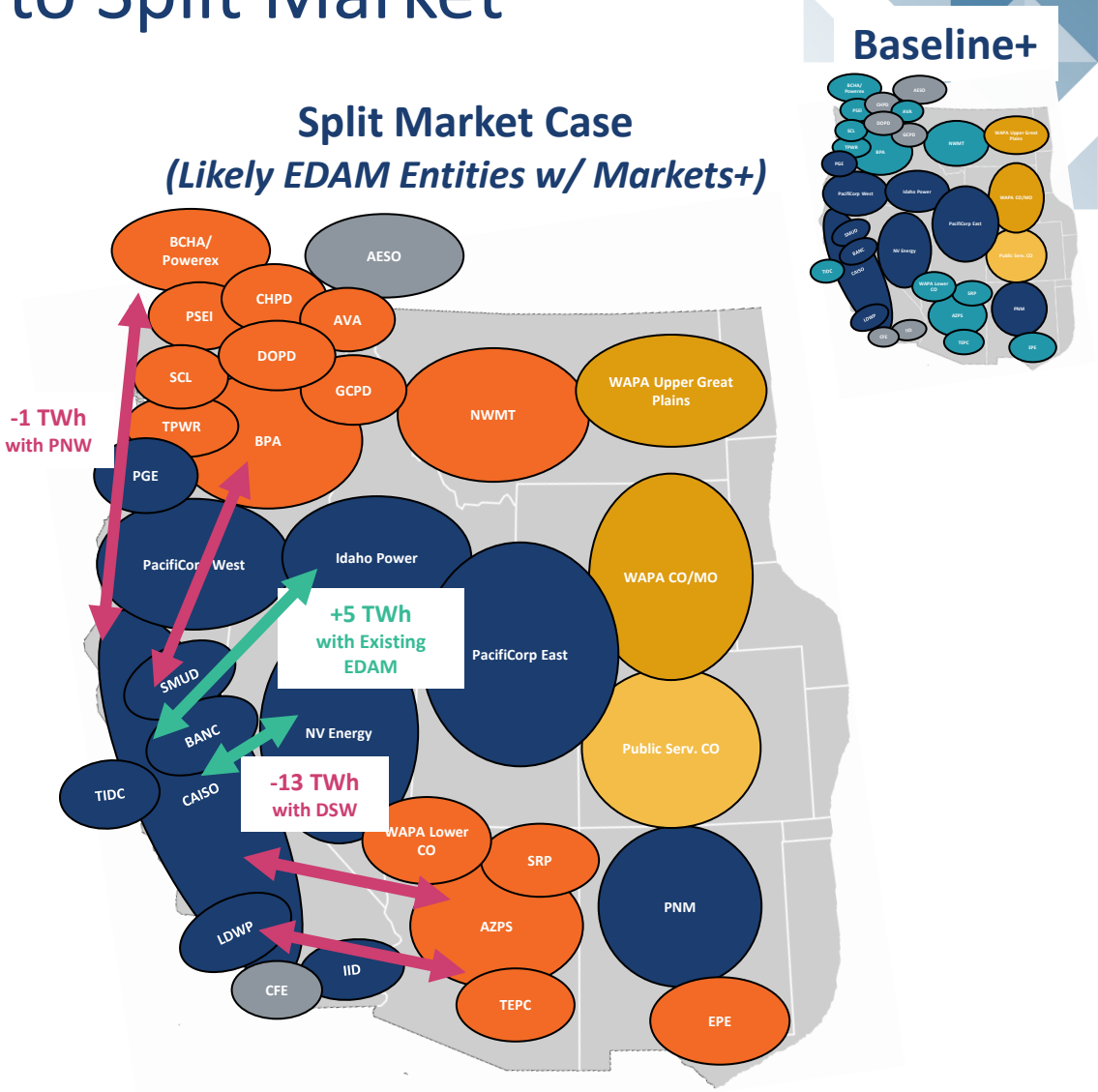
Expanded EDAM Case
(Maximum EDAM Potential)



California Trading Changes: Baseline+ to Split Market

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

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



Appendix B:
Individual BAA Benefits

Individual BA Benefits: **CAISO**

Compared to the Baseline+ case, CAISO sees benefits in the Expanded EDAM case of $471 million/yr compared to $171 million/yr in the Split Market case

- **CAISO sees an APC benefits in both cases,** though about $136 million more in EDAM
- **Short-term wheeling revenues fall more in the Expanded EDAM case,** declining $22 million from Baseline+ to Split Market compared to the EDAM decline of $60 million
- **Total trading revenues increase $134 million in the EDAM case compared to just $3 million in the Split Market case**

Summary of CAISO System Costs by Case ($ Millions)

	Baseline	Baseline+	Expanded EDAM	Split Market
Adjusted Production Cost	$4,642	$4,441	$4,115	$4,250
Short-Term Wheeling Revenues	$171	$85	$25	$63
Trading Revenues				
Bilateral Trading Revenues	$111	$88	$23	$61
WEIM Congestion Revenues	$47	$55	$41	$31
EDAM Congestion and Transfer Revenues	$146	$185	$398	$238
EDAM Transfer Revenue	*$113*	*$112*	*$228*	*$123*
EDAM Congestion Revenue	*$33*	*$72*	*$170*	*$115*
Net TRR Settlement		$9	$80	$9
Total System Production Cost and Market Revenues	**$4,167**	**$4,019**	**$3,548**	**$3,848**
Benefit Relative to Baseline		**$148**	**$619**	**$319**
Benefit % of Baseline Production Cost and Market Revenues		***4%***	***15%***	***8%***
Benefit Relative to Baseline+			**$471**	**$171**
Benefit % of Baseline+ Production Cost and Market Revenues			***12%***	***4%***

CAISO Adjusted Production Cost in the EDAM Case

CAISO's adjusted production costs fall $326 million in the EDAM case, driven by:

- **(1)** **$112 million/yr reduction in production costs** as CAISO generation declines on the net by ~1000 GWh (~2,000 GWh lower gas generation offset by ~1,000 GWh more renewables and other generation)
- **(2)** **$40 million/yr increase in purchase costs** as CAISO purchases about 2,900 GWh more in the day-ahead to offset declining gas generation
- **(3)** **$250 million/yr increase in sales revenue** as CAISO sells about 2,400 GWh more in the day-ahead and does so at an average price about $3.0/MWh higher than in Baseline+

CAISO Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	
Production Cost	(+)	[1]	295,759	294,762	**-996**	$4.17	$3.81	**-$0.37**	1,234,372	1,121,700	**-$112,672**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	53,447	56,344	**2,897**	$56.04	$54.23	**-$1.81**	2,995,068	3,055,363	**$60,295**	**(2)**
Real-Time Market		[5]	6,488	6,488	**0**	$41.38	$38.27	**-$3.11**	268,462	248,274	**-$20,188**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	73,205	75,653	**2,448**	-$0.60	$2.44	**$3.03**	-43,575	184,255	**$227,830**	**(3)**
Real-Time Market		[8]	6,054	5,506	**-547**	$16.65	$22.93	**$6.28**	100,804	126,274	**$25,470**	
Total Cost *(Negative Difference = Benefit)*		[9]	**276,435**	**276,435**	**0**	**$16.06**	**$14.89**	**-$1.18**	4,440,673	4,114,808	**-$325,865**	
% Change in APC											***-7.3%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

CAISO Adjusted Production Cost in the Split Market Case

CAISO's APC falls $190 million in the Split Market case, driven by:

- **(1)** **$55 million/yr decrease in production cost** due to gas generation falling by ~930 GWh (non-gas generation also declines, with renewable curtailments increasing ~260 GWh)
- **(2)** **$67 million/yr decrease in purchase cost despite higher purchase volumes** as the remaining EDAM market generation mix is renewable heavy
- **(3)** **$58 million/yr increase in sales revenue** as volumes and average sales prices increase slightly due to opportunities to sell into EDAM and Markets+

CAISO Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	
Production Cost	(+)	[1]	295,759	294,501	**-1,258**	$4.17	$4.01	**-$0.17**	1,234,372	1,179,767	**-$54,605**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	53,447	54,741	**1,294**	$56.04	$53.94	**-$2.09**	2,995,068	2,952,969	**-$42,099**	**(2)**
Real-Time Market		[5]	6,488	6,181	**-307**	$41.38	$39.34	**-$2.04**	268,462	243,149	**-$25,312**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	73,205	73,593	**388**	-$0.60	$0.20	**$0.79**	-43,575	14,409	**$57,984**	**(3)**
Real-Time Market		[8]	6,054	5,395	**-659**	$16.65	$20.59	**$3.94**	100,804	111,097	**$10,293**	
Total Cost *(Negative Difference = Benefit)*		[9]	**276,435**	**276,435**	**0**	**$16.06**	**$15.38**	**-$0.69**	4,440,673	4,250,380	**-$190,292**	
% Change in APC											***-4.3%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

Individual BA Benefits: **LDWP**

Compared to the Baseline+ case, LDWP sees a benefit in the Expanded EDAM case of $66 million/yr compared to $18 million/yr in the Split Market case

- **LDWP sees an APC benefits in both cases**, $38 million in EDAM and $18 million in the Split Market case
- **Short-term wheeling revenues decline most in the Expanded EDAM case, falling $13 million**
- **Total trading revenues increase $24 million in the Expanded EDAM case compared to just $6 million in the Split Market case**

Summary of LDWP System Costs by Case ($ Millions)

	Baseline	Baseline+	Expanded EDAM	Split Market
Adjusted Production Cost	$371	$354	$328	$336
Short-Term Wheeling Revenues	$38	$13	$0	$6
Trading Revenues				
Bilateral Trading Revenues	$40	$39	$0	$17
WEIM Congestion Revenues	$7	$9	$4	$5
EDAM Congestion and Transfer Revenues	$17	$13	$81	$46
EDAM Transfer Revenue	-$25	-$6	$17	-$8
EDAM Congestion Revenue	$42	$19	$64	$54
Net TRR Settlement		-$2	$26	-$2
Total System Production Cost and Market Revenues	**$269**	**$281**	**$216**	**$263**
Benefit Relative to Baseline		**-$13**	**$53**	**$6**
Benefit % of Baseline Production Cost and Market Revenues		***-5%***	***20%***	***2%***
Benefit Relative to Baseline+			**$66**	**$18**
Benefit % of Baseline+ Production Cost and Market Revenues			***23%***	***6%***

LDWP Adjusted Production Cost in the EDAM Case

LDWP's adjusted production costs fall $26 million in the EDAM case, driven by:

- **(1)** **$8.5 million/yr reduction in production costs** as LDWP generation declines on the net by ~3 GWh (~120 GWh lower gas generation offset by ~117 GWh more renewables and other generation)
- **(2)** **$14 million/yr decrease in purchase costs** due to reduced average cost of purchasing in the EDAM market by about $2/MWh
- **(3)** **$3 million/yr increase in sales revenue** as LDWP sells about 7 GWh more in the day-ahead and does so at an average price about $2.7/MWh higher than in Baseline+

LDWP Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	
Production Cost	(+)	[1]	21,157	21,154	**-3**	$1.29	$0.89	**-$0.40**	27,272	18,764	**-$8,508**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	7,928	7,955	**27**	$46.43	$44.59	**-$1.84**	368,108	354,708	**-$13,400**	**(2)**
Real-Time Market		[5]	431	412	**-19**	$27.01	$27.84	**$0.83**	11,642	11,466	**-$176**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	1,067	1,074	**7**	-$7.72	-$5.01	**$2.71**	-8,237	-5,383	**$2,854**	**(3)**
Real-Time Market		[8]	2,179	2,177	**-2**	$28.10	$28.72	**$0.62**	61,232	62,528	**$1,296**	
Total Cost *(Negative Difference = Benefit)*		[9]	**26,270**	**26,270**	**0**	**$13.48**	**$12.48**	**-$1.00**	354,027	327,793	**-$26,235**	
% Change in APC											***-7.4%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

LDWP Adjusted Production Cost in the Split Market Case

LDWP's APC falls $18 million in the Split Market case, driven by:

- **(1)** **$0.3 million/yr decrease in production cost** due to ~10 GWh of reduced gas generation (non-gas generation increases by ~40 GWh)
- **(2)** **$14 million/yr reduction in purchase costs** as the remaining EDAM market is very renewable heavy renewable heavy
- **(3)** **$1 million/yr increase in sales revenue** as volumes and average sales prices increase slightly due to opportunities to sell into EDAM and Markets+

LDWP Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	
Production Cost	(+)	[1]	21,157	21,204	**47**	$1.29	$1.27	**-$0.02**	27,272	27,004	**-$269**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	7,928	7,952	**24**	$46.43	$44.53	**-$1.91**	368,108	354,077	**-$14,031**	**(2)**
Real-Time Market		[5]	431	407	**-24**	$27.01	$27.97	**$0.96**	11,642	11,379	**-$263**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	1,067	1,083	**15**	-$7.72	-$6.36	**$1.36**	-8,237	-6,886	**$1,351**	**(3)**
Real-Time Market		[8]	2,179	2,210	**32**	$28.10	$28.56	**$0.46**	61,232	63,137	**$1,905**	
Total Cost *(Negative Difference = Benefit)*		[9]	**26,270**	**26,270**	**0**	**$13.48**	**$12.80**	**-$0.68**	354,027	336,209	**-$17,819**	
% Change in APC											***-5.0%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

Individual BA Benefits: **BANC**

Compared to the Baseline+ case, BANC sees a benefit in the Expanded EDAM case of $10 million/yr compared to a loss of $4 million/yr in the Split Market case

- **BANC's adjusted production cost remains about the same in all three cases**
- **Short-term wheeling revenues decline $4 million in EDAM**
- **Total trading revenues increase $10 million in the Expanded EDAM case but decline $2 million in the Split Market case**
- ***BANC benefits and results are not inclusive of SMUD, which is reported separately***

Summary of BANC System Costs by Case ($ Millions)

	Baseline	Baseline+	Expanded EDAM	Split Market
Adjusted Production Cost	$56	$57	$56	$59
Short-Term Wheeling Revenues	$5	$4	$0	$4
Trading Revenues				
Bilateral Trading Revenues	$15	$10	$0	$8
WEIM Congestion Revenues	$2	$1	$0	$1
EDAM Congestion and Transfer Revenues	$0	$1	$21	$1
EDAM Transfer Revenue	-$6	-$5	-$6	-$5
EDAM Congestion Revenue	$7	$6	$27	$6
Net TRR Settlement		-$1	$3	-$1
Total System Production Cost and Market Revenues	**$34**	**$42**	**$31**	**$46**
Benefit Relative to Baseline		**-$8**	**$2**	**-$12**
Benefit % of Baseline Production Cost and Market Revenues		***-23%***	***7%***	***-36%***
Benefit Relative to Baseline+			**$10**	**-$4**
Benefit % of Baseline+ Production Cost and Market Revenues			***24%***	***-11%***

BANC Adjusted Production Cost in the EDAM Case

BANC's adjusted production costs fall $1.7 million in the EDAM case, driven by:

- **(1)** **$17 million/yr reduction in production costs** as BANC generation declines on the net by ~260 GWh (~325 GWh lower gas generation offset by ~64 GWh more renewables and other generation)
- **(2)** **$5 million/yr increase in purchase costs** as BANC purchases about 140 GWh more in the day-ahead to offset declining gas generation and make additional market sales
- **(3)** **$11 million/yr decrease in sales revenue** due to ~$5/MWh decrease in day ahead market prices received

BANC Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	
Production Cost	(+)	[1]	6,206	5,944	**-262**	$12.63	$10.28	**-$2.35**	78,379	61,077	**-$17,302**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	689	834	**144**	$44.22	$46.49	**$2.27**	30,483	38,755	**$8,271**	**(2)**
Real-Time Market		[5]	303	247	**-56**	$42.32	$37.52	**-$4.80**	12,824	9,270	**-$3,554**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	1,201	927	**-274**	$46.64	$41.74	**-$4.90**	56,015	38,684	**-$17,331**	**(3)**
Real-Time Market		[8]	193	293	**100**	$42.69	$50.17	**$7.48**	8,224	14,704	**$6,479**	
Total Cost *(Negative Difference = Benefit)*		[9]	**5,804**	**5,804**	**0**	**$9.90**	**$9.60**	**-$0.30**	57,447	55,713	**-$1,733**	
% Change in APC											***-3.0%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

BANC Adjusted Production Cost in the Split Market Case

BANC's APC rises $1.6 million in the Split Market case, driven by:

- **(1)** **$11 million/yr reduction in production cost** due to ~200 GWh decreased gas generation(non-gas generation falls also, with renewable curtailments increasing ~14 GWh), but does not offset revenue loss
- **(2)** **$3 million/yr increase in purchase costs** despite falling real time prices because of increased day ahead purchases
- **(3)** **$10 million/yr decrease in sales revenue** as day-ahead sales volumes decrease and real-time volumes only increase by ~12 GWh

BANC Adjusted Production Cost

		GWh			$/MWh			Total ($1000s/Year)			
Cost Components		**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	
Production Cost	(+) [1]	6,206	5,994	**-212**	$12.63	$11.24	**-$1.39**	78,379	67,376	**-$11,002**	**(1)**
Purchases Cost	(+) [3]										
Day-Ahead Market + Bilateral	[4]	689	776	**86**	$44.22	$44.47	**$0.25**	30,483	34,497	**$4,014**	**(2)**
Real-Time Market	[5]	303	288	**-15**	$42.32	$39.35	**-$2.96**	12,824	11,352	**-$1,471**	
Sales Revenue (Negative = Cost)	(-) [6]										
Day-Ahead Market + Bilateral	[7]	1,201	1,049	**-152**	$46.64	$42.57	**-$4.07**	56,015	44,653	**-$11,361**	**(3)**
Real-Time Market	[8]	193	204	**12**	$42.69	$46.60	**$3.91**	8,224	9,530	**$1,306**	
Total Cost *(Negative Difference = Benefit)*	[9]	**5,804**	**5,804**	**0**	**$9.90**	**$10.17**	**$0.28**	57,447	59,043	**$1,596**	
% Change in APC										***2.8%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

Individual BA Benefits: **SMUD**

Compared to the Baseline+ case, SMUD sees a slight loss in the Expanded EDAM case of $9 million/yr compared to a benefit of $4 million/yr in the Split Market case

- **SMUD adjusted production cost remains about the same in all three cases,** but declines slightly more in the Split Market case
- **Total trading revenues decline $6 million in the Expanded EDAM case but increase $1 million in the Split Market case due to increased internal California trading**

Summary of SMUD System Costs by Case ($ Millions)

	Baseline	Baseline+	Expanded EDAM	Split Market
Adjusted Production Cost	$74	$73	$72	$70
Short-Term Wheeling Revenues	$0	$0	$0	$0
Trading Revenues				
Bilateral Trading Revenues	$16	$15	$0	$15
WEIM Congestion Revenues	$4	$4	$4	$4
EDAM Congestion and Transfer Revenues	$6	$6	$15	$7
EDAM Transfer Revenue	$3	$4	$11	$3
EDAM Congestion Revenue	$3	$2	$5	$4
Net TRR Settlement		-$1	-$6	-$1
Total System Production Cost and Market Revenues	**$48**	**$49**	**$58**	**$45**
Benefit Relative to Baseline		**-$1**	**-$11**	**$2**
Benefit % of Baseline Production Cost and Market Revenues		***-3%***	***-22%***	***5%***
Benefit Relative to Baseline+			**-$9**	**$4**
Benefit % of Baseline+ Production Cost and Market Revenues			***-18%***	***8%***

SMUD Adjusted Production Cost in the EDAM Case

SMUD's adjusted production costs fall $1 million in the EDAM case, driven by:

- **(1)** **$0.1 million/yr increase in production costs** as SMUD generation increases by ~100 GWh, mostly from renewables and geothermal
- **(2)** **$3 million/yr increase in purchase costs** as SMUD purchases about 60 GWh more in the day-ahead
- **(3)** **$4 million/yr increase in sales revenue** as SMUD sells about 200 GWh more in the day-ahead and does so at an average price about $0.1/MWh higher than in Baseline+

SMUD Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	
Production Cost	(+)	[1]	12,180	12,289	**109**	$0.82	$0.83	**$0.00**	10,044	10,179	**$135**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	2,022	2,081	**59**	$50.40	$51.49	**$1.10**	101,888	107,144	**$5,256**	**(2)**
Real-Time Market		[5]	861	802	**-59**	$41.24	$41.52	**$0.28**	35,520	33,317	**-$2,203**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	2,101	2,283	**182**	$25.26	$25.38	**$0.12**	53,069	57,934	**$4,866**	**(3)**
Real-Time Market		[8]	707	634	**-73**	$30.67	$33.22	**$2.55**	21,679	21,053	**-$626**	
Total Cost *(Negative Difference = Benefit)*		[9]	**12,255**	**12,255**	**0**	**$5.93**	**$5.85**	**-$0.09**	72,704	71,652	**-$1,052**	
% Change in APC											***-1.4%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

SMUD Adjusted Production Cost in the Split Market Case

SMUD's APC falls $2 million in the Split Market case, driven by:

- **(1)** **$13 million/yr increase in production cost** due to a reduction of ~6 GWh of generation
- **(2)** $**4 million/yr decrease in purchases cost** because of slight reductions in price and volume in the day-ahead and real-time markets
- **(3)** **$2 million/yr reduction in sales revenues** due to a $1.3/MWh drop in day-ahead prices and ~50 GWh fewer sales in the real-time market

SMUD Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	
Production Cost	(+)	[1]	12,180	12,174	**-6**	$0.82	$0.83	**$0.00**	10,044	10,056	**$13**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	2,022	2,015	**-7**	$50.40	$49.16	**-$1.24**	101,888	99,068	**-$2,820**	**(2)**
Real-Time Market		[5]	861	855	**-6**	$41.24	$39.91	**-$1.33**	35,520	34,121	**-$1,399**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	2,101	2,128	**28**	$25.26	$23.98	**-$1.28**	53,069	51,040	**-$2,029**	**(3)**
Real-Time Market		[8]	707	660	**-47**	$30.67	$33.15	**$2.48**	21,679	21,875	**$195**	
Total Cost *(Negative Difference = Benefit)*		[9]	**12,255**	**12,255**	**0**	**$5.93**	**$5.74**	**-$0.19**	72,704	70,330	**-$2,373**	
% Change in APC											***-3.3%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

Individual BA Benefits: **IID**

Compared to the Baseline+ case, IID sees a benefit in the Expanded EDAM case of $18 million/yr compared to a loss of $9 million/yr in the Split Market case

- IID's adjusted production cost doesn't change in the Expanded EDAM case, but increases $9 million in the Split Market case
- Short-term wheeling revenues decline $6 million in EDAM and increase $6 million in the Split Market case
- Total trading revenues increase $13 million in the Expanded EDAM case but decline $3 million in the Split Market case

Summary of IID System Costs by Case ($ Millions)

	Baseline	Baseline+	Expanded EDAM	Split Market
Adjusted Production Cost	-$83	-$85	-$85	-$74
Short-Term Wheeling Revenues	$13	$5	$0	$11
Trading Revenues				
Bilateral Trading Revenues	$15	$4	$0	$4
WEIM Congestion Revenues	$6	$3	$5	$0
EDAM Congestion and Transfer Revenues	$0	$0	$15	$0
EDAM Transfer Revenue	$0	$0	$6	$0
EDAM Congestion Revenue	$0	$0	$9	$0
Net TRR Settlement			$11	
Total System Production Cost and Market Revenues	**-$116**	**-$97**	**-$115**	**-$89**
Benefit Relative to Baseline		**-$19**	**-$1**	**-$27**
Benefit % of Baseline Production Cost and Market Revenues		***16%***	***-1%***	***-23%***
Benefit Relative to Baseline+			**$18**	**-$9**
Benefit % of Baseline+ Production Cost and Market Revenues			***18%***	***-9%***

IID Adjusted Production Cost in the EDAM Case

IID's adjusted production costs remains relatively steady, due to:

- **(1)** **$0.2 million/yr reduction in production costs** as IID generation increases by ~45 GWh, all from renewable and other non-gas generation
- **(2)** **$5 million/yr decrease in purchase costs** as IID purchases about 100 GWh more in the day-ahead and reduces sales in the real time market
- **(3)** **$5 million/yr decrease in sales revenue** as BANC reduces sales volume by ~240 GWh in the real time market despite increased prices

IID Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	
Production Cost	(+)	[1]	7,301	7,346	**45**	$5.81	$5.79	**-$0.01**	42,401	42,551	**$150**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	478	635	**157**	-$3.09	-$2.87	**$0.22**	-1,477	-1,823	**-$345**	**(2)**
Real-Time Market		[5]	858	520	**-338**	$21.90	$28.14	**$6.24**	18,778	14,631	**-$4,147**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	3,068	3,176	**108**	$40.50	$39.44	**-$1.07**	124,249	125,245	**$997**	**(3)**
Real-Time Market		[8]	733	489	**-244**	$28.17	$29.96	**$1.79**	20,645	14,640	**-$6,005**	
Total Cost *(Negative Difference = Benefit)*		[9]	**4,837**	**4,837**	**0**	**-$17.61**	**-$17.48**	**$0.14**	-85,191	-84,525	**$666**	
% Change in APC											***-0.8%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

IID Adjusted Production Cost in the Split Market Case

IID's APC increases $11 million in the Split Market case, driven by:

- **(1)** **$0.3 million/yr increase in production cost** due to limited shifts in production and prices
- **(2)** **$20 million/yr decrease in purchases cost** as the remaining EDAM market is very renewable heavy, resulting in a $12/MWh decrease in day-ahead prices
- **(3)** **$31 million/yr decrease in sales revenue** as IID reduces sales by ~840 GWh across day-ahead and real-time markets

IID Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	
Production Cost	(+)	[1]	7,301	7,399	**98**	$5.81	$5.77	**-$0.04**	42,401	42,674	**$273**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	478	247	**-231**	-$3.09	-$14.68	**-$11.59**	-1,477	-3,623	**-$2,146**	**(2)**
Real-Time Market		[5]	858	155	**-703**	$21.90	$2.70	**-$19.20**	18,778	418	**-$18,361**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	3,068	2,893	**-175**	$40.50	$38.70	**-$1.80**	124,249	111,976	**-$12,273**	**(3)**
Real-Time Market		[8]	733	71	**-662**	$28.17	$19.58	**-$8.59**	20,645	1,385	**-$19,260**	
Total Cost *(Negative Difference = Benefit)*		[9]	**4,837**	**4,837**	**0**	**-$17.61**	**-$15.28**	**$2.34**	-85,191	-73,892	**$11,299**	
% Change in APC											***-13.3%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

Individual BA Benefits: **TIDC**

Compared to the Baseline+ case, TIDC sees a benefit in the Expanded EDAM case of $17 million/yr compared to $2 million/yr in the Split Market case

- **TIDC's adjusted production cost declines $12 million in the Expanded EDAM case but just $2 million in the Split Market case**
- **Total trading revenues increase $6 million in the Expanded EDAM case and don't change in the Split Market case**

Summary of TIDC System Costs by Case ($ Millions)

	Baseline	Baseline+	Expanded EDAM	Split Market
Adjusted Production Cost	$112	$112	$100	$110
Short-Term Wheeling Revenues	$0	$0	$0	$0
Trading Revenues				
Bilateral Trading Revenues	$1	$1	$0	$1
WEIM Congestion Revenues	$1	$0	$0	$0
EDAM Congestion and Transfer Revenues	$0	$0	$7	$0
EDAM Transfer Revenue	$0	$0	-$2	$0
EDAM Congestion Revenue	$0	$0	$8	$0
Net TRR Settlement			-$2	
Total System Production Cost and Market Revenues	**$110**	**$111**	**$95**	**$109**
Benefit Relative to Baseline		**-$2**	**$15**	**$1**
Benefit % of Baseline Production Cost and Market Revenues		***-1%***	***14%***	***1%***
Benefit Relative to Baseline+			**$17**	**$2**
Benefit % of Baseline+ Production Cost and Market Revenues			***15%***	***2%***

TIDC Adjusted Production Cost in the EDAM Case

TIDC's adjusted production costs fall $12 million in the EDAM case, driven by:

- **(1)** **$44 million/yr reduction in production costs** as TIDC's gas generation declines by ~575 GWh
- **(2)** **$30 million/yr increase in purchase costs** as TIDC purchases about 710 GWh more in the day-ahead to offset declining gas generation
- **(3)** **$0.4 million/yr decrease in sales revenue** and reduces day ahead sales given the large price drop of $59/MWh in the day ahead market

TIDC Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	**Baseline+**	**EDAM**	**Difference**	
Production Cost	(+)	[1]	1,664	1,089	**-575**	$28.48	$3.24	**-$25.24**	47,383	3,529	**-$43,854**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	1,439	2,150	**711**	$40.01	$44.91	**$4.90**	57,582	96,556	**$38,974**	**(2)**
Real-Time Market		[5]	144	2	**-141**	$54.34	$67.78	**$13.44**	7,804	144	**-$7,660**	
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	9	0	**-8**	$73.37	$14.18	**-$59.19**	625	3	**-$623**	**(3)**
Real-Time Market		[8]	3	6	**3**	$71.28	$88.53	**$17.25**	207	490	**$283**	
Total Cost *(Negative Difference = Benefit)*		[9]	**3,235**	**3,235**	**0**	**$34.60**	**$30.83**	**-$3.77**	111,937	99,736	**-$12,201**	
% Change in APC											***-10.9%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost. Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

TIDC Adjusted Production Cost in the Split Market Case

TIDC's APC falls $2 million in the Split Market case, driven by:

- **(1)** **$4 million/yr decrease in production cost** due to ~50 GWh reduction of gas generation (TIDC does not have renewable generation)
- **(2)** **$2 million/yr increase in purchases cost** because of ~94 GWh of increased purchases to compensate for gas generation reduction
- **(3)** **$0.1 million/yr increase in sales revenue** caused by increases in real-time revenues despite a $2.9/MWh decrease in day-ahead prices

TIDC Adjusted Production Cost

			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	
Production Cost	(+)	[1]	1,664	1,617	**-47**	$28.48	$26.74	**-$1.74**	47,383	43,237	**-$4,147**	**(1)**
Purchases Cost	(+)	[3]										
Day-Ahead Market + Bilateral		[4]	1,439	1,533	**94**	$40.01	$40.68	**$0.67**	57,582	62,366	**$4,785**	
Real-Time Market		[5]	144	98	**-46**	$54.34	$54.32	**-$0.02**	7,804	5,328	**-$2,476**	**(2)**
Sales Revenue (Negative = Cost)	(-)	[6]										
Day-Ahead Market + Bilateral		[7]	9	4	**-4**	$73.37	$70.47	**-$2.90**	625	289	**-$336**	
Real-Time Market		[8]	3	9	**6**	$71.28	$72.23	**$0.95**	207	622	**$416**	**(3)**
Total Cost *(Negative Difference = Benefit)*		[9]	**3,235**	**3,235**	**0**	**$34.60**	**$34.01**	**-$0.59**	111,937	110,019	**-$1,918**	
% Change in APC											***-1.7%***	

Note: Total production cost is calculated as the sum of [1] + [2] + [3] - [6] as sales are revenues, not costs.A positive $ amount in sales is a benefit to the entity, while a positive in purchases is a cost.
Curtailment cost/PTC value only shows the change in cost of curtailments are a price of $30/MWh for a curtailment.

Appendix C:
Description of Benefit Metrics

Benefit Metric: Adjusted Production Cost

Adjusted Production Cost (APC) is a standard metric used to capture the direct variable energy-related costs from a customer impact perspective

The APC is calculated for the BAU cases and the market cases to determine the market related reductions in APC

- By using the generation price of the exporter and load price of the importer for sales revenues and purchase costs, the APC metric does not capture wheeling revenues and the remaining portion of the value of the trade to the counterparties (see next slide)

The APC is the sum of production costs and purchased power less off-system sales revenue:

(+) Production costs (fuel, startup, variable O&M, emissions costs) for generation owned or contracted by the load-serving entities

(+) Cost of bilateral and market purchases valued at the BAA's load-weighted energy price ("Load LMP")

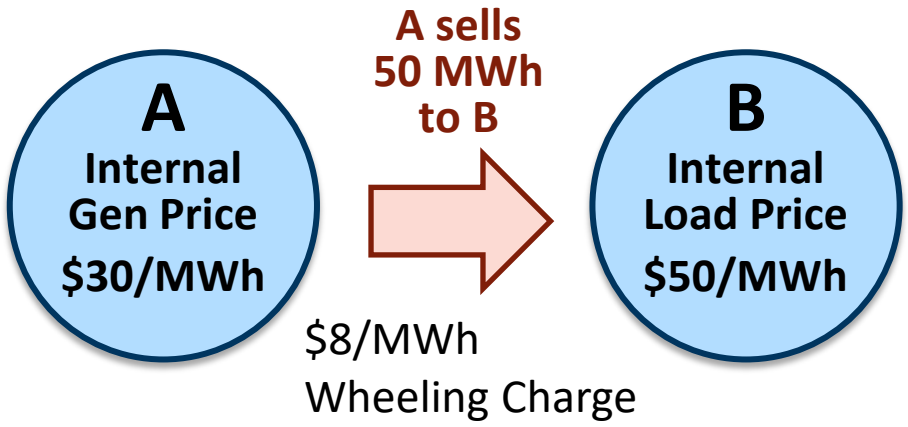
(–) Revenues from bilateral and market sales valued at the BAA's generation-weighted energy price ("Gen LMP")

Benefit Metrics: Wheeling Revenues, Trading Gains

Based on the simulation results, we also estimate several additional impacts from increased trading facilitated by the market reforms, which is not fully captured in APC

- **Wheeling Revenues:** collected by the exporting BAAs based on OATT rates
- **Trading Gains:** buyer and seller split 50/50 the trading margin (and congestion revenues in EIM/EDAM)

EXAMPLE: Bilateral Trade



The APC metric only uses area-internal prices for purchase cost and sales revenues, which does not capture part of the value:

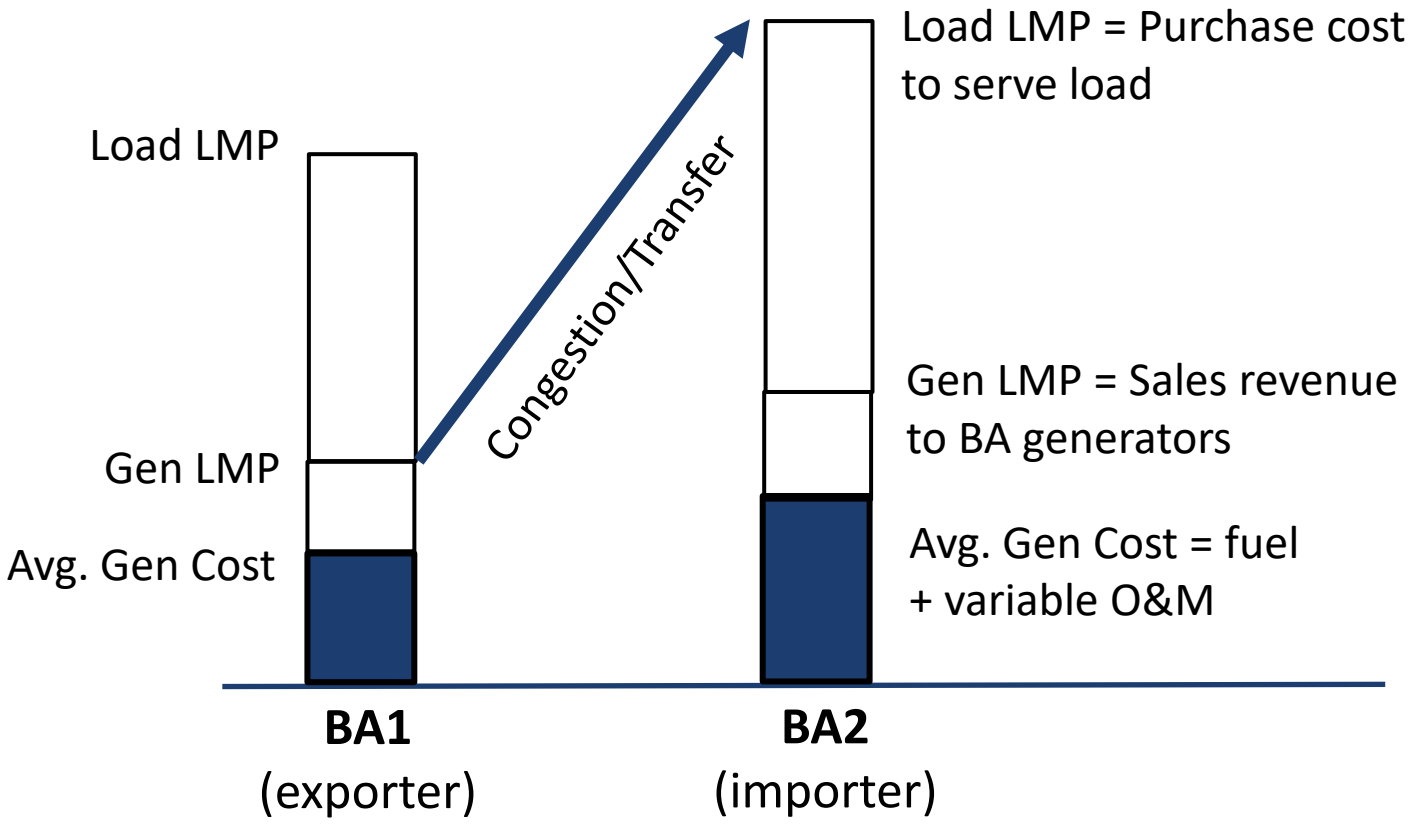
- A receives $30×50MWh=$1,500 in APC sales revenues
- B pays $50×50MWh=$2,500 in APC purchase costs

➔ $1,000 of trading value not captured in APC metric

Trading value = $20/MWh Δprice x 50 MWh = $1000

- Exporter A receives wheeling revenues: $8/MWh x 50MWh = $400
- Remaining $600 trading gain split 50/50: both A and B receive $300

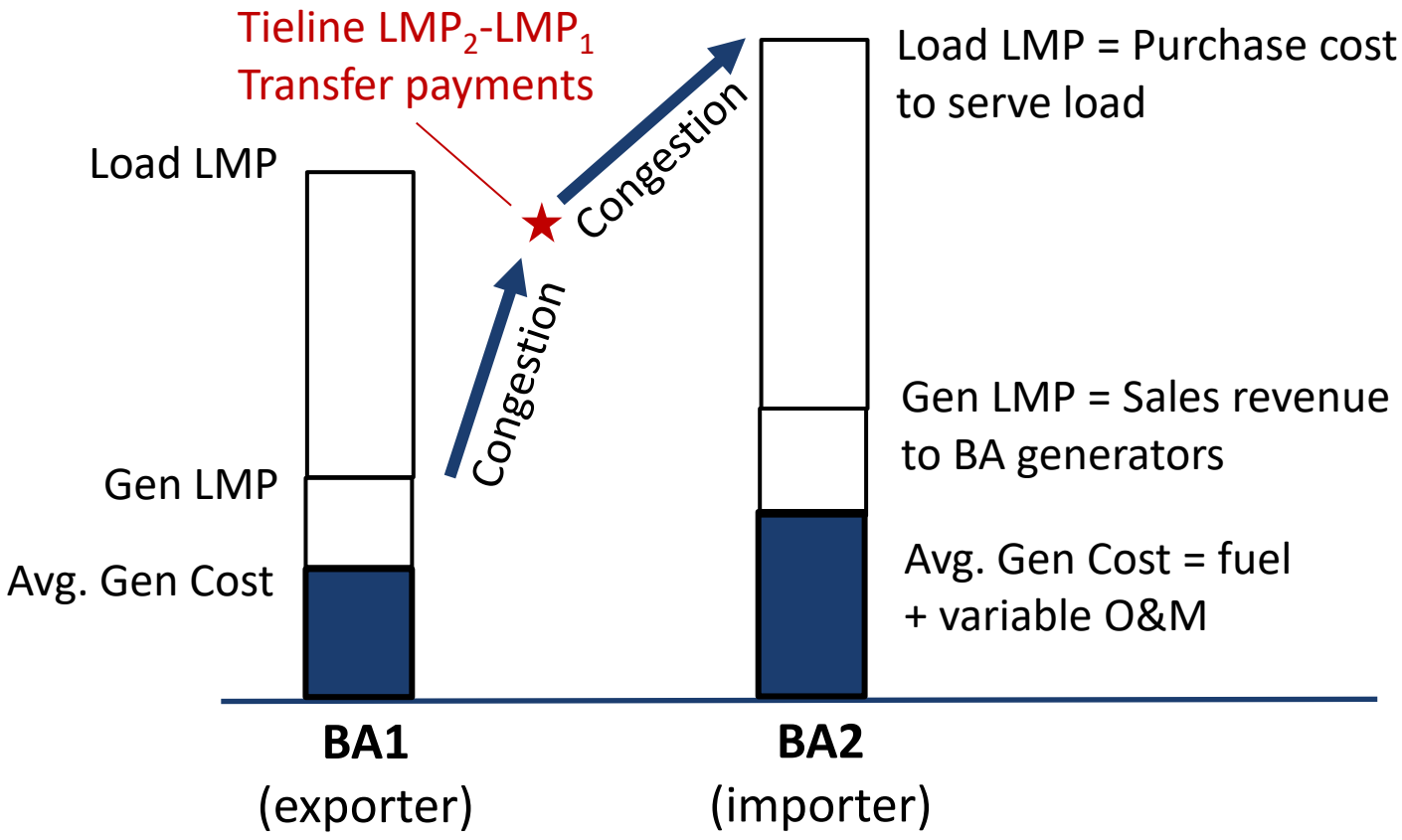
Illustration of Markets+ Congestion Revenues



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

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

Illustration of EDAM Congestion and Transfer Revenues



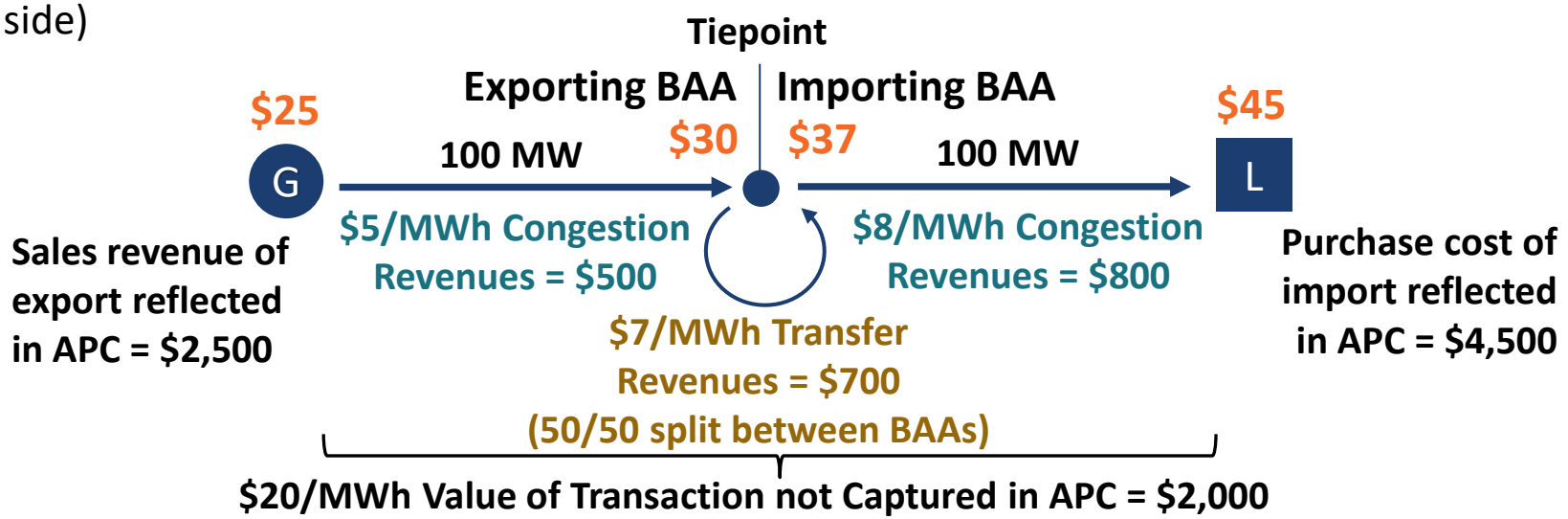
EDAM congestion and transfer revenues estimated based on individual tieline LMPs:

- **Congestion Payment (to exporter) = MW x (Tie LMP_1 – Gen LMP_1)**
- **Congestion Payment (to importer) = MW x (Load LMP_2 – Tie LMP_2)**
- **Transfer Payment (split 50/50) = MW x (Tie LMP_2 – Tie LMP_1)**

Illustration of Congestion/Transfer Revenues vs. APC

Generators and loads get paid/pay the prices within their BAAs

- Therefore, congestion on internal transfers (between a member's own gen and load) is captured in the APC metric.
- However, congestion/transfer revenue on external transactions (to neighboring members) is not captured in APC.
- In the example below, for an external market transaction, the selling BAA has a price of $25 and the purchasing BAA has a price of $45.
  - The $20 difference between the seller and buyer is the congestion and transfer revenue.
  - **$5/MWh of congestion revenue** is allocated to the seller ($30 on their side of the intertie less $25 internal gen price)
  - **$8/MWh of congestion revenue** is allocated to the buyer ($45 internal load price less $37 on their side of the intertie)
  - **$7/MWh of transfer revenue** is split 50/50 between the buyer and seller ($37 on the buyer side of the intertie less $30 on the seller side)



Appendix D: Overview of Power System Optimizer (PSO)

Key Modeling Assumption Sources

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

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

Overview of Modeling Approach

We utilize the WECC ADS nodal production cost model as a starting point imported into Power System Optimizer (PSO), as refined during the EDAM feasibility study and follow-on engagements

Utilized the Polaris Power System Optimizer (PSO), an advanced market simulation model

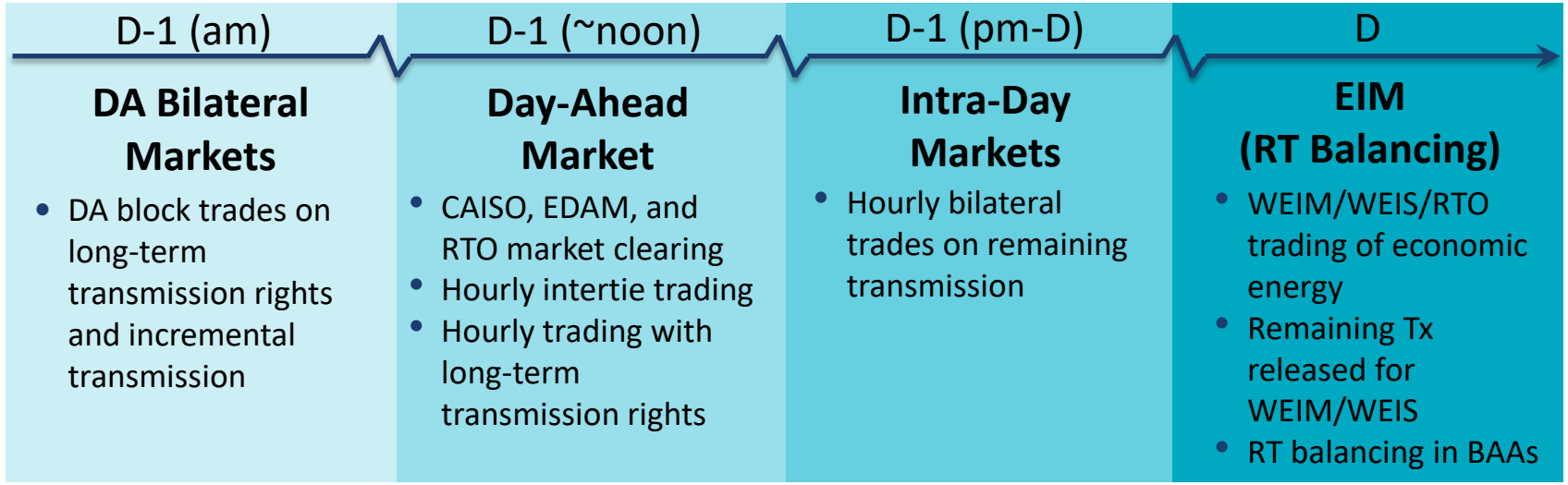
- Nodal mixed-integer model representing each load and generator bus in the WECC
- Licensed through Enelytix
- Detailed operating reserve and ancillary service product definition
- Detailed representation of the transmission system (both physical power flows and contract paths)
- Sub-hourly granularity (but used hourly simulations due to limited data availability)
- Designed for multiple commitment and dispatch cycles (e.g., DA and RT) with different levels of foresight
- EDAM feasibility study assumptions updated to reflect the most recent utility resource plans and forecasts of system conditions and costs

ENELYTIX® powered by PSO

PSO is uniquely suited to simulate bilateral trading, joint dispatch, imbalance markets, and RTOs, reflecting multiple stages of system operator decision making

Independent Simulation of Multiple Time Horizons

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



Independent real-time decision cycle used to simulation EIM functions

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

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

Simulating Several Wholesale Market Cycles in PSO

The model setup for wholesale market simulation effort contains several cycles to simulate unit commitment and dispatch decisions in three different timeframes and within different market structures. For example, cycles simulated can include are:

- **Day-Ahead Unit Commitment Cycle:** the model optimizes unit commitment decisions, 24 hours at a time (with 48-hour look ahead), for long-lead time resources such as coal and nuclear plants, based on their relative economics and operating characteristics (e.g., minimum run time, maintenance schedules, etc.), transmission constraints, and trading frictions. The model ensures that enough resources are committed to serve forecasted load, accounting for average transmission losses and the need for ancillary services. Separate regions' commitment decisions are segregated through higher hurdle rates on imports and exports. Trading within a single balancing area, like the various RTO sub-zones, is not subject to any hurdles.
- **Day-Ahead Economic Dispatch Cycle:** the model solves for the optimal level of hourly day-ahead dispatch and trading in 24-hour forward-looking optimization cycles, with 48-hour look ahead periods. Dispatch across the study footprint is optimized based on resource economics. In this cycle, the model also co-optimizes ancillary service procurement for each area. The high hurdle rates for unit commitment are lowered to enable more bilateral trading between balancing areas.
- **Intra-day trading:** the model simulates market activity through one-hour optimization horizons. Trading is assumed to utilize unused transmission, represented as the difference between their day-ahead trading volume and the total contract path limits. No unit re-commitment is allowed due to the non-firm nature of the transactions. Changes to generation availability, such as forced outages, which were not "visible" during the day-ahead cycle become visible during this cycle.
- **Real-Time Cycle:** this cycle simulates the operation of the real-time imbalance markets, such as through EIM transactions. In this cycle, the model can re-optimize dispatch levels and unit commitment decisions for fast-start thermal resources (based on the assumption that the real-time market design allows for unit re-commitment). Deviations from day-ahead forecasts (due to uncertainty) need to be balanced in real-time.

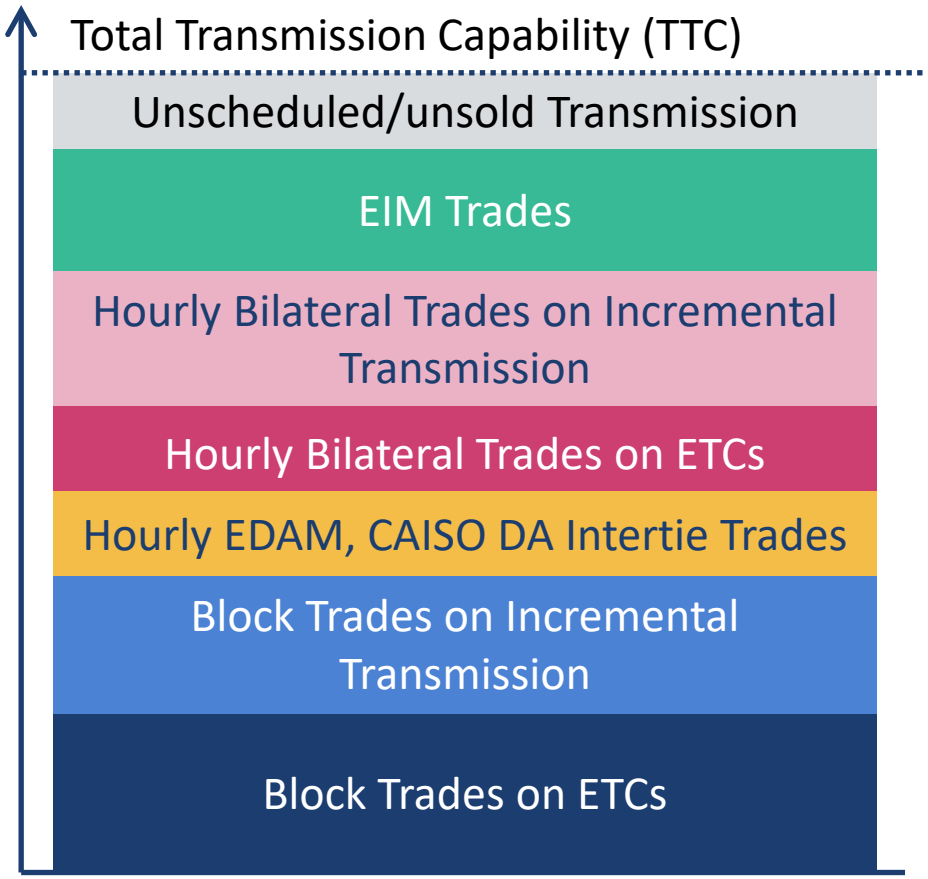
These cycles can take on different assumptions, depending on market structure. In a bilateral setting, all are set up to analyze utility-specific unit commitment and dispatch decisions, with each of them including hurdle rates and transmission fees that limit the amount of economic transactions that can take place between the utilities. In EIM and EDAM+EIM scenarios, all of the cycles are set up to simulate market-wide optimization of unit commitment and dispatch, including the EDAM "reference pass" cycle. In the EDAM case, there would be no hurdle rates between EDAM participants in any of the cycles, allowing the model to optimize both unit commitment and dispatch in the market footprint on both a day-ahead and real-time basis.

Types of Trades and Transmission Reservations Modelled

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

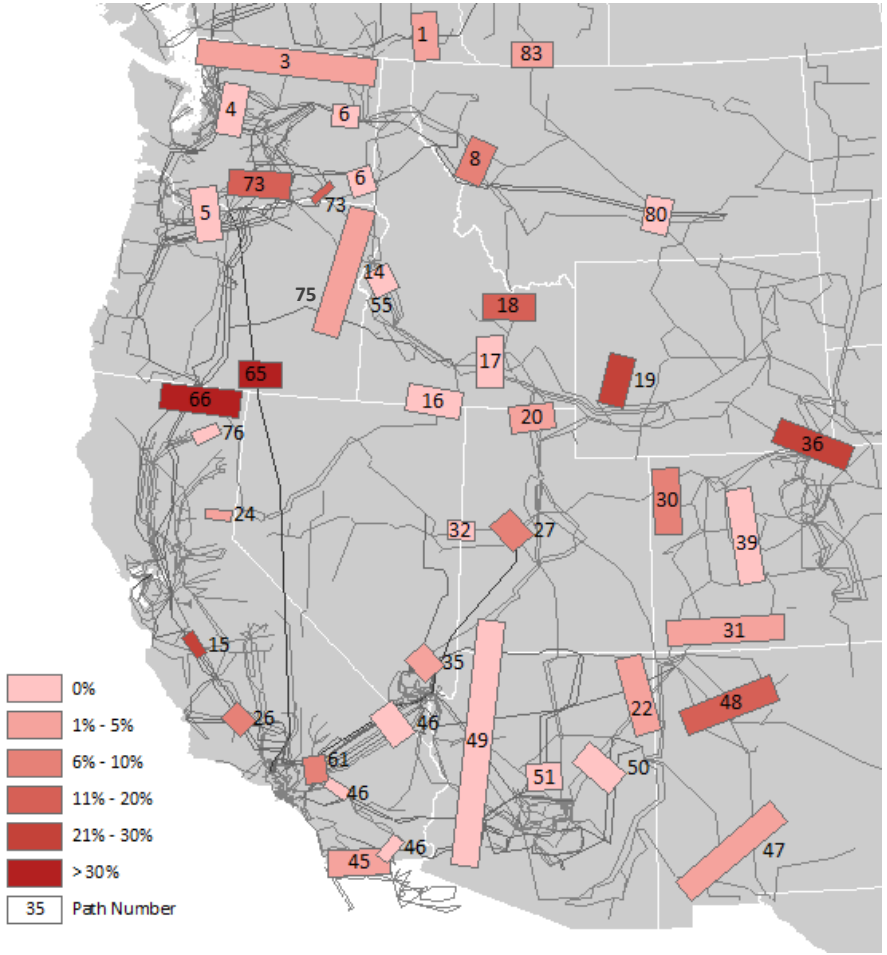
- Existing long-term transmission contracts (ETCs) and incrementally purchased transmission
- Total reservations on each contract path is limited by the total transfer capability (TTC)
- Trades are structured as blocks or hourly
- Bilateral trades between BAAs, at major hubs, or across CAISO interties
- Account for renewable diversity and day-ahead forecast uncertainty vs. real-time operations
- Unscheduled transfer capability released for EIM trades in real-time

Types of Trades Modeled



Nodal Simulations Based on Physical Transmission

WECC-Defined Paths Modeled



Limits on the physical transmission system include all the paths defined in WECC Path Rating Catalogue

- Additional transmission paths to represent congestion internal to each BA
- Limits on all paths and constraints reflect updates provided by the study participants

ENELYTIX® powered by PSO

Power System Optimizer (PSO), developed by Polaris Systems Optimization, Inc. is a state-of-the-art market and production cost modeling tool that simulates least-cost security-constrained unit commitment and economic dispatch with a full nodal representation of the transmission system, similar to actual RTO and ISO market operations. Such nodal market modeling is a commonly used method for assessing the operational benefits of wholesale market reforms (e.g., JDAs, EIMs, RTOs).

PSO can be used to test system operations under varying assumptions, including but not limited to: generation and transmission additions or retirements, de-pancaked transmission and scheduling charges, changes in fuel costs, novel environmental and clean energy regulations, alternative reliability criteria, and jointly-optimized generating unit commitment and dispatch. PSO can report hourly or sub-hourly energy prices at every bus, generation output for each unit, flows over all transmission facilities, and regional ancillary service prices, among other results. Comparing these results among multiple modeled scenarios reveals the impacts of the study assumptions on the relevant operational metrics (e.g. power production, emissions, fuel consumption, or production costs). Results can be aggregated on a unit, state, utility, or regional level.

PSO has important advantages over traditional production cost models, which are designed primarily to model dispatchable thermal generation and to focus on wholesale energy markets only. The model can capture the effects of increasing system variability due to large penetrations of non-dispatchable, intermittent renewable resources on thermal unit commitment, dispatch, and deployment of operating reserves. PSO simultaneously optimizes energy and multiple ancillary services markets on an hourly or sub-hourly timeframe.

Like other production cost models, PSO is designed to mimic ISO operations: it commits and dispatches individual generating units to meet load and other system requirements, subject to various operational and transmission constraints. The model is a mixed-integer program minimizing system-wide operating costs given a set of assumptions on system conditions (e.g., load, fuel prices, transmission availability, etc.). Unlike some production cost models, PSO simulates trading between balancing areas based on contract-path transmission rights to create a more realistic and accurate representation of actual trading opportunities and transactions costs. This feature is especially important for modeling non-RTO regions.

One of PSO's distinguishing features is its ability to evaluate system operations at different decision points, represented as "cycles," which occur at different times ahead of the operating hour and with different amounts of information about system conditions available. Under this sequential decision-making structure, PSO can simulate initial cycles to optimize unit commitment, calculate losses, and solve for day-ahead unit dispatch targets. Subsequent cycles can refine unit commitment decisions for fast-start resources and re-optimize unit dispatch based on the parameters of real-time energy imbalance markets. The market structure can be built into sequential cycles in the model to represent actual system operation for utilities that conduct utility-specific unit commitment in the day-ahead period but participate in real-time energy imbalance markets that allow for re-optimization of dispatch and some limited re-optimization of unit commitment. For example, PSO can simulate an initial cycle that determines day-ahead unit commitment decisions that reflects the constraints faced by, and decisions made by, individual utilities when committing their resources in the day-ahead timeframe. The initial day-ahead commitment cycle is followed by cycles that simulate day-ahead economic dispatch, including bilateral trading of power, and a real-time economic dispatch, reflecting trades in real time (whether bilateral or optimized through an EIM or RTO). Explicit commitment and dispatch cycle modeling allows more accurate representation of individual utility preference to commit local resources for reliability, but share the provision of energy around a given commitment.



Electricity Affordability

According to the California Legislative Analyst's Office January 2025 report, California's residential electricity rates are the second highest in the nation (after Hawaii) and "close to double those in the rest of the nation." Increasing rates are largely driven by rising distribution and transmission costs. Between 2020 and 2023, investor-owned utilities' distribution revenue requirement grew by 42% and transmission by 34%. In comparison, IOU generation costs grew only 4%. Meeting California's energy goals requires affordable rates that encourage increased electrification. Community choice aggregators (CCAs) across the state are dedicated to reducing consumer costs while preserving climate goals. CCAs have identified three opportunities where policymakers could provide ratepayer relief now and in the future.

1. Leverage the Greenhouse Gas Reduction Fund (GGRF) to Support Affordability

California's quarterly cap-and-trade greenhouse gas allowance auctions generate an average of $4.2 billion annually for the state's GGRF. The Legislature appropriates these funds for a variety of purposes; roughly 65% are continuous appropriations and the remainder is available for discretionary appropriation. Separately, IOUs receive an allocation of allowances from the Air Resources Board that they monetize in the auction. For 2022, the allocation produced $1.4 billion for distribution to customers in the form of the California Climate Credit.

Investments of GGRF funds to boost the California Climate Credit can provide immediate ratepayer relief. An additional $650 million per year in GGRF funding would increase the Climate Credit by approximately $60 annually per household. The credits could be provided to customers monthly or allocated for the four summer months (June-September) when electricity rates are highest.

- Alternatively, GGRF funds could be allocated for policy-driven transmission projects that are approved by the California Independent System Operator in the grid operator's annual Transmission Plan. This would support affordability in the future by buying down the costs of building transmission infrastructure vital to the achieving the state's climate goals.

2. Reduce Ratepayer Costs by Reducing Artificial Resource Adequacy Demand

California load-serving entities (LSEs) must meet their resource adequacy (RA) obligations on an hourly basis but are required to transact with a resource for all hours that it provides RA. If an LSE is short of RA in only one hour, for example, it may be required to procure RA for the full 16 hours a resource operates to fill that hour. This mismatch leads to unnecessary costs for ratepayers due to overprocurement, higher RA prices driven by artificial demand, and non-compliance penalties levied upon LSEs.

- Permitting LSEs to trade hourly load obligations would reduce the cost of RA procured to meet customer requirements through lower prices, less overprocurement, and fewer penalties, which, for non-profit LSEs, flow through directly to customers. CalCCA estimates that adopting hourly load obligation trading would save California ratepayers over $180 million annually.

3. Increase Accountability and Transparency

The California Public Utilities Commission (CPUC) is responsible for regulating IOUs and implementing policies as directed by the Legislature. The Legislature can encourage long-term fiscal discipline by implementing recommendations included in the California State Auditor (CSA) report on the CPUC and expanding the requirements for considering the impact of the Commission's actions on affordability.

- **CPUC Affordability Analysis.** Requiring the Commission to publish an "Affordability Analysis" for each major policy change it proposes would increase awareness of the affordability impacts of CPUC decision-making. When considering changes to existing policies or implementing new policies, the CPUC should be required to quantify the potential rate impacts associated with a proposed policy and consider potential alternatives and their price tag.

- **Audits of IOU Balancing Accounts.** The CSA report recommends more frequent audits of spending tracked and costs recovered via IOU balancing accounts. The Legislature should implement this recommendation and adopt new requirements for the California Public Advocates Office (PAO) and CPUC to review and audit IOU balancing accounts that (1) present a risk of a material rate increase and (2) present a risk of double recovery.

- **Enhance Oversight of IOU Rate of Return.** Because rates are set on a forecast basis, an IOU's actual rate of return may exceed its authorized rate of return. The Legislature should direct an annual CPUC review of actual IOU returns and provide a report explaining the factors contributing to any excess return. The Legislature further should direct the CPUC to increase verification of IOU work to ensure the IOU is spending its authorized budget as proposed in its General Rate Case.

- **Adequately Fund the CPUC and PAO.** The CPUC and PAO require sufficient funding to ensure each has the resources necessary to adequately scrutinize utility spending requests. With more resources, the CPUC and PAO are better able to process utility spending requests and audit actual spending. Greater oversight will encourage IOU spending discipline.

Executive Order Summary

Wind Energy Moratorium (Signed January 20, 2025)

- Withdraws all areas of the Outer Continental Shelf from new or renewed wind energy leasing. The withdrawal does not affect "rights under existing leases in the withdrawn areas."
- Directs the Attorney General and the Interior Secretary to "conduct a comprehensive review of the ecological, economic, and environmental necessity of terminating or amending any existing wind energy leases, (and) identifying any legal bases for such removal." There is no explicit timeline for when this review must be completed.
- Prohibits agencies from issuing "new or renewed approvals, rights of way, permits, leases, or loans for onshore or offshore wind projects pending the completion of a comprehensive assessment and review of Federal wind leasing and permitting practices." There is no explicit timeline for when this review must be completed.
- Directs Interior to place a temporary moratorium on the Lava Ridge Wind Project in Idaho's Magic Valley while Interior reviews the Record of Decision related to BLM's final Environmental Impact Statement for this project.
- According to the federal permitting dashboard, there were seven offshore wind projects whose permitting was underway (all on the East Coast) and several more in earlier stages (5 off the California coast) at the time of this order.
- According to a recent NREL study, only about 4% of total utility-scale land-based renewable energy (wind, solar, geothermal) is generated on federal lands.

Declaring A National Energy Emergency (Signed January 20, 2025)

- Citing an "inadequate and intermittent energy supply," this order declares a national emergency.
- The term "energy" or "energy resources" in this order is defined as: crude oil, natural gas, lease condensates, natural gas liquids, refined petroleum products, uranium, coal, biofuels, geothermal heat, the kinetic movement of flowing water, and critical minerals. Note no inclusion of wind, solar, or storage.
- The order calls out the U.S. Northeast and West Coast regions specifically, claiming that "dangerous" state and local policies in those regions "jeopardize our Nation's core national defense and security needs, and devastate the prosperity of not only local residents but the entire United States population."
- Directs agencies to use existing "lawful" emergency authorities "to facilitate the identification, leasing, siting, production, transportation, refining, and generation of domestic energy resources."
- Directs agencies to identify and use existing emergency authorities "to facilitate the supply, refining, and transportation of energy in and through the West Coast of the United States, Northeast of the United States, and Alaska."

Executive Order Summary

- Tasks the Army Corps and other agencies to identify and report on all "planned or potential" energy projects that could be considered for emergency treatment and expedited permitting under the Clean Water Act and Endangered Species Act.
- Directs the Defense and Interior Departments to assess and report on DOD's "ability to acquire and transport the energy, electricity, or fuels needed to protect the homeland and to conduct operations abroad." The assessment is directed to examine "potentially insufficient (energy) transportation and refining infrastructure" nationwide, with a specific focus on "such vulnerabilities within the Northeast and West Coast."

Unleashing American Energy (Signed January 20, 2025)

- Establishes the policy of the U.S. to encourage energy exploration and production on Federal lands and waters, eliminate the "electric vehicle (EV) mandate," and promote consumer choice in vehicles and appliances, among other things.
- Directs all agencies to review all existing regulations and policies to identify those that impose an "undue burden" on the development of domestic energy resources — with particular attention to oil, natural gas, coal, hydropower, biofuels, critical mineral, and nuclear energy resources.
- Directs agencies to prioritize "efficiency and certainty" over any other objectives that could otherwise "add delays and ambiguity" to the energy permitting process. Orders agencies to "undertake all available efforts to eliminate all delays within their respective permitting processes" and allows agencies to use emergency authorities to expedite permitting for energy projects they deem "essential for the Nation's economy or national security."
- Orders all agencies to "immediately pause the disbursement of funds" appropriated through the IRA or IIJA. An OMB memo later clarified that the guidance in this section only applies to grants and loans, not tax credits.

Putting America First In International Environmental Agreements (Signed January 20, 2025)

- Directs the U.S. Ambassador to the United Nations to formally withdraw the U.S. from the Paris Climate Agreement and revoke any "purported financial commitment" made by the U.S. under the UN's framework, effective immediately. The agreement, adopted by 196 countries at COP21 in December 2015, aims to hold the increase in global average temperature to below 2 degrees Celsius above pre-industrial levels.
- Orders any agency that plans or coordinates international energy agreements to "prioritize economic efficiency, the promotion of American prosperity, consumer choice, and fiscal restraint in all foreign engagements that concern energy policy."

Imposing Duties to Address the Flow of Illicit Drugs Across Our Northern Border (Signed February 1, 2025)

Executive Order Summary

- Imposes an additional 25% tariff on all goods imported from Canada – excluding energy imports, which are subject to an additional 10% tariff – beginning on February 4, 2025. ***The enforcement of this order was later delayed 30 days on February 3, 2025.***

Imposing Duties to Address the Synthetic Opioid Supply Chain in the People's Republic of China (Signed February 1, 2025)

- Imposes an additional 10% tariff on all goods imported from China beginning on February 4, 2025. This includes major imports from China like solar panels, batteries and electronics.
- In response, China announced a raft of retaliatory actions, including a 15% tariff on U.S. coal and liquefied natural gas products as well as a 10% tariff on crude oil, agricultural machinery and large-engine cars, which took effect on February 10. China also announced added export controls on several critical minerals used to make popular electronic equipment, as well as an antitrust investigation into Google.

Imposing Duties to Address the Situation at Our Southern Border (Signed February 1, 2025)

- Imposes an additional 25% tariff on all goods imported from Mexico beginning on February 4, 2025. ***The enforcement of this order was later delayed 30 days on February 3, 2025.***

Adjusting Imports of Aluminum into The United States (Signed February 11, 2025)

- Increases the tariff rate on all imported aluminum to 25% for all nations beginning March 12, 2025.

Adjusting Imports of Steel into The United States (Signed February 10, 2025)

- Increases the tariff rate on all imported steel to 25% for all nations beginning March 12, 2025.

Establishing the National Energy Dominance Council (Signed February 14, 2025)

- Will advise the President on how to make the country more energy dominant (with specific attention to crude oil, natural gas, lease condensates, natural gas liquids, refined petroleum products, uranium, coal, biofuels, geothermal heat, the kinetic movement of flowing water, and critical minerals). Within 100 days, the council must recommend to the President how to "rapidly and significantly increase electricity capacity," and on how to rapidly approve energy infrastructure (and undefined term, but likely references oil and gas). The council must consult with officials from state, local, and tribal governments and individuals from the private sector to solicit feedback on how best to expand all forms of energy production. DOE is Vice Chair.

Ensuring Accountability for All Agencies (Signed February 18, 2025)

Executive Order Summary

- Establishes the policy of the executive branch to increase Presidential oversight and control of all federal agencies, including independent regulatory agencies and commissions, by:
    - Requiring agencies to submit all proposed and final regulatory actions to the White House for review and approval by the President and the OMB Director;
    - Tasking the OMB Director with establishing performance standards and management objectives for independent agency heads and to report to the President on their performance;
    - Ordering the OMB Director to review and adjust independent agencies' funding obligations;
    - Requiring all independent agencies to install a "White House Liaison" position within their respective agencies; and
    - Giving the President and the Attorney General ultimate authority to interpret the law for the executive branch.

AURORA ENERGY RESEARCH

Impact of reform to clean energy tax credits on investment, jobs and consumer bills

Public report | January 6, 2025



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This independent report analyses the potential impact of reform to clean energy tax credits on investment, jobs, and consumer bills

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- The Inflation Reduction Act of 2022 (IRA) extended and expanded the Clean Energy Tax Incentives available to businesses, in particular 48E, the technology-neutral Investment Tax Credit (ITC) and 45Y, the technology-neutral Production Tax Credit (PTC)
- This report quantifies the impacts of removing the ITC and PTC available for utility-scale onshore and offshore wind, solar PV and battery storage on investment, generation capacity, job creation, and wholesale and retail power prices between 2025 and 2040 across competitive power markets in the United States: ERCOT, CAISO, PJM, MISO, NYISO, ISO-NE and SPP.
- The analysis in this report is based on Aurora's modeling of two distinct scenarios: the base case, where tax credits are continued, and the Tax Credit Removal scenario where the ITC and PTC are removed for wind, solar and battery deployment. See more details in the Appendix.

Study limitations

- All analysis in this report address dynamics within the seven competitive wholesale electricity markets—representing around two-thirds of total US power consumption – and excludes regulated regions such as the WECC[1] and the SERC[2] in western and southeastern states.
- Results are likely to be a conservative estimate of the impact on investment, jobs, and clean tech deployment. The study focuses only on wind, solar and storage ITC/PTCs. Other clean energy policies (e.g. support for electric vehicles, hydrogen, CCS), behind-the-meter projects, and the potential impact on other sectors like manufacturing were not considered as part of the project scope.

About Aurora Energy Research

- Aurora Energy Research is a leading global provider of independent power-market forecasts and analytics for critical investment and financing decisions.
- This report is fully independent, technology-agnostic, and does not advocate for any specific policy or regulation.

1) Western Electricity Coordinating Council. 2) Southeastern Electric Reliability Council.

Executive Summary

1 **Across US competitive electricity markets[1], the removal of tax credits for wind, solar, and battery deployments could result in at least $336bn less investment and 237GW less clean energy deployed over the next 15 years – all amid rapidly growing electricity demand.**

- Rapid electricity demand growth data centers and electrification across the US is driving a need for new generation capacity. Clean energy deployment averaged 25GW per year for the last five years.
- On an absolute basis, New York and Texas are the states that see the largest decline in clean energy investment—losing $4.4bn/year and $3.3bn/year on average through 2040, respectively.
- In relative terms, the removal of tax credits impacts investment in the Great Plains and Midwest most acutely, where total foregone clean energy investment exceeds 3% of 2023 state GDP.

2 **Decreased capacity would result in 97,000 net fewer American jobs created in construction, maintenance, and operations of power generation facilities.**

- Utility-scale renewables employed over 150,000 people across the United States in 2023. The clean energy job sector grew 4.2% from 2022 to 2023.
- Elimination of tax credits costs at least 103,000 full-time jobs across clean energy generation technologies. This is only partially offset by an increase in 6,000 fossil fuel jobs, resulting in a net loss of 97,000 energy jobs.
- These estimates are likely conservative since they do not capture indirect impacts (e.g. resulting from higher power prices) or the impact on regulated regions covering a third of the country's electricity demand.

3 **Removal of tax credits increases residential electricity bills by 10% on average, and up to 22% in certain states by 2040.**

- On average, annual power bills increase $142/year for consumers by 2040.
- Bills are expected to rise most sharply in states where average residential power prices are already high, like New York ($39/month increase) and Minnesota ($22/month increase), but also in states where residential energy demand is highest, such as Texas ($29/month increase) and Louisiana ($21/month increase).

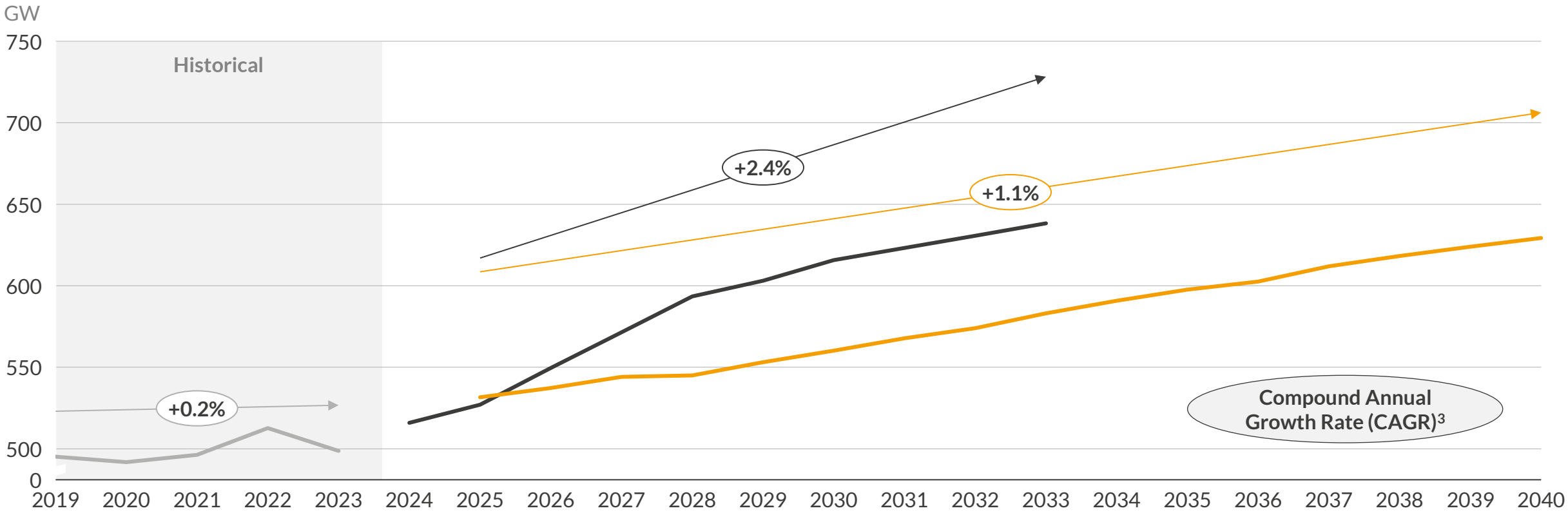
1) CAISO, ERCOT, ISO-NE, MISO, PJM, NYISO, SPP.

Sources: Aurora Energy Research, ERCOT

Accelerating power demand growth from electrification and data centers is driving the need for new generation capacity across the United States

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Historical and forecasted peak load, aggregated across the seven competitive Independent System Operators (ISO)[1,2]



- After relatively flat load growth over the last decade, grid operators are forecasting a combined 2.4% annual growth rate in load between 2025 and 2033 as data centers and the continued electrification of industry, transportation, and homes raise power demand across the country.
- Aurora also forecasts an acceleration in power demand growth, albeit more conservative across competitive markets with a CAGR of 1.1% per year through 2040.

Historical — ISO forecast aggregation[1,2] — Aurora Central forecast aggregation

1) CAISO, ERCOT, ISO-NE, MISO, PJM, NYISO, SPP. For more details on ISOs, see appendix. 2) SPP short-term load forecast is available through 2029; values are extrapolated linearly through 2033 here to match data availability from other ISOs. 3) Annualized average rate of growth.

Sources: Aurora Energy Research, historic data and ISO forecasts come from respective ISOs

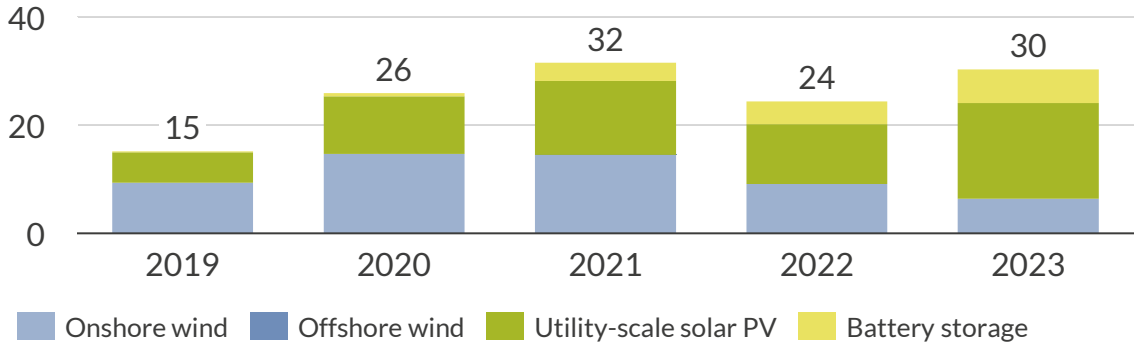
In the last five years, 127GW of clean energy has been deployed across the US, bringing with it new jobs and contributing to stable electricity prices

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1 127GW of utility-scale wind, solar, and battery storage have been deployed since 2019 across the US, aided by federal tax credits

Annual US-wide clean energy deployment by technology

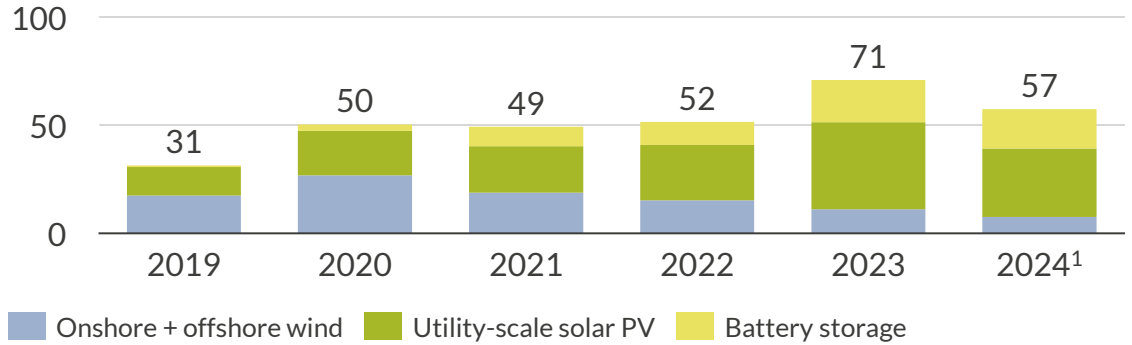
GW



2 Over $300bn in public and private investments have been made in wind, solar, and storage deployments since 2019

Actual clean energy investment by technology[4]

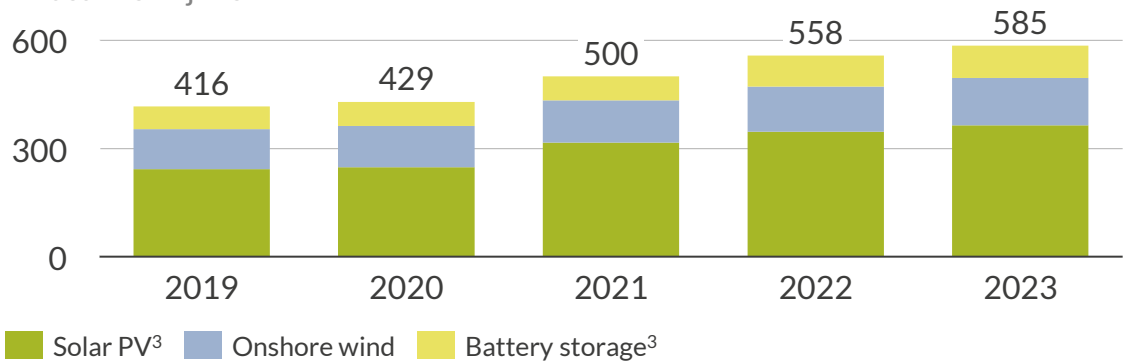
$ billion (2023 real)



3 Clean energy jobs have grown in line with investment, growing to 54% of total electric power jobs in 2024

Full-time jobs by technology[4]

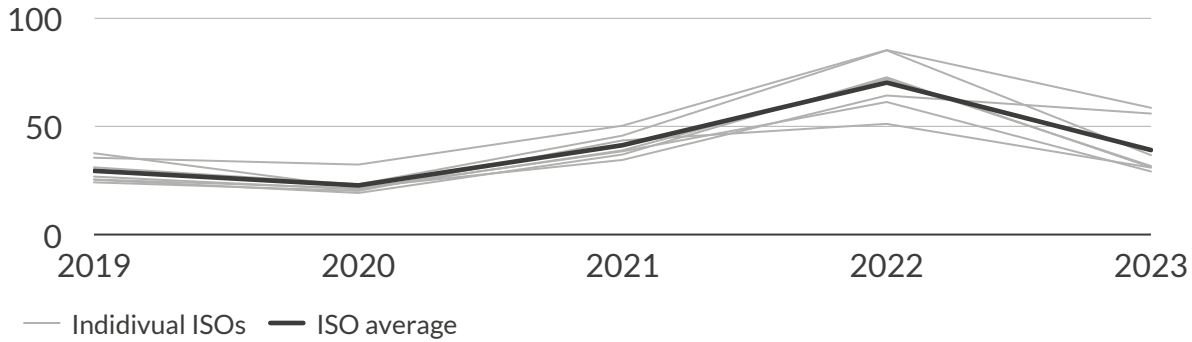
Thousands of jobs



4 Electricity prices have remained relatively flat over the past five years, due in part to rapid renewables penetration and limited load growth

Day-ahead wholesale electricity prices by ISO[2]

$/MWh (nominal)



1) 2024 data through end of Q3. 2) To increase readability, this graph excludes February 2021 prices in ERCOT, when Winter Storm Uri skyrocketed average day-ahead wholesale prices to $1,483/MWh. Including February, average 2021 day-ahead wholesale price in ERCOT was $155/MWh. 3) Includes both utility-scale and residential / behind-the-meter capacity. 4) These numbers do not include the investment or jobs in manufacturing for these technologies.

Sources: Aurora Energy Research, Rhodium, EIA, individual ISOs, US Department of Energy

In this study, Aurora modelled the seven competitive power markets in the US to explore the impact of tax credit removal on generators and consumers

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Aurora base case assumptions and Tax Credit Removal scenario methodology

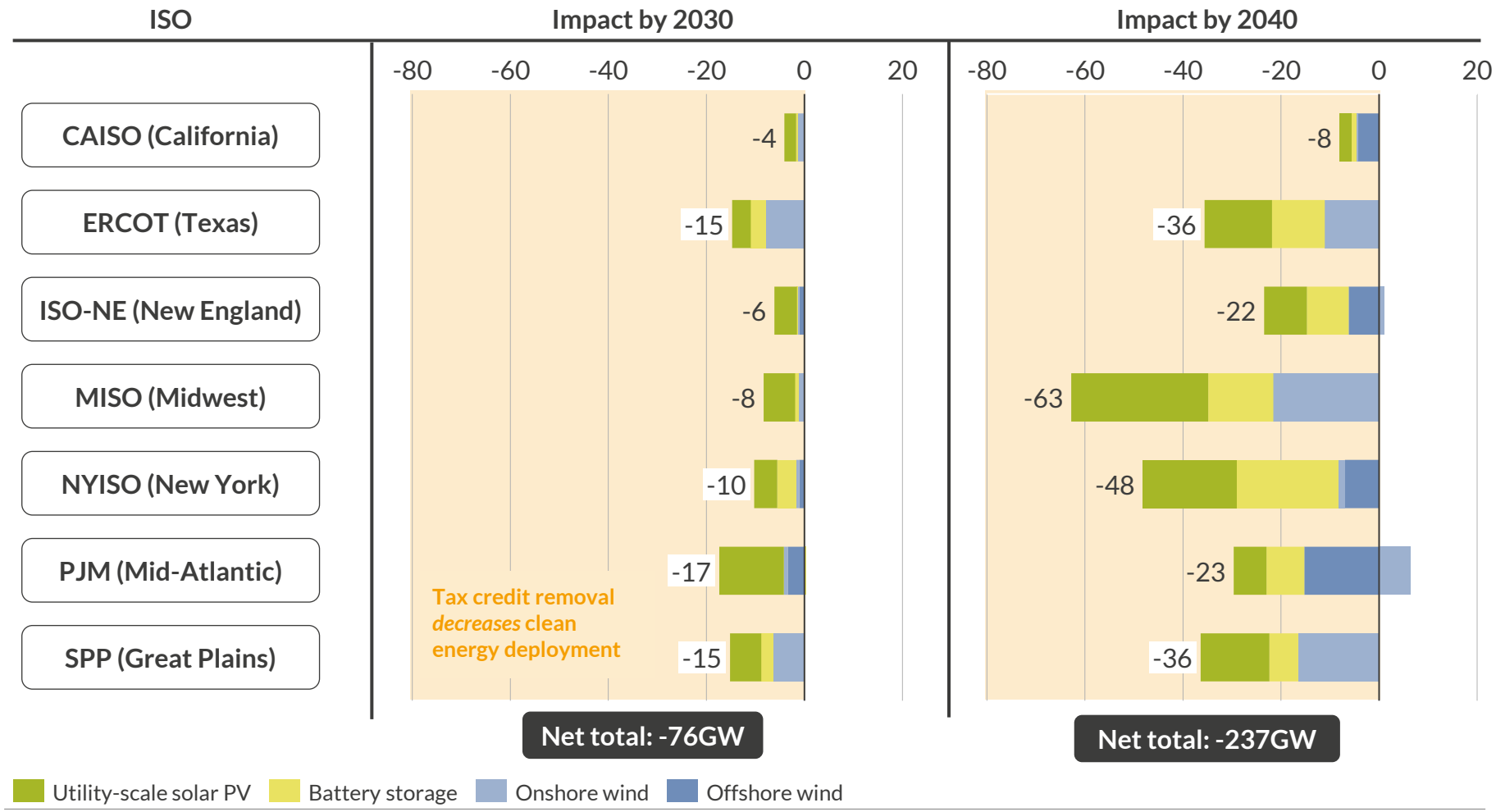
Key assumption	Aurora Base Case	Tax Credit Removal scenario
Capacity build	▪ Aurora's production cost and capacity expansion modelling yields detailed forecasts for plant-level economic build and retirements out to 2060 across competitive wholesale markets, with all assets meeting a target rate-of-return.	▪ Tax credit removal impacts project economics.
Investment	▪ Calculated based on project CAPEX for new build assets.	▪ Impact of capacity build across competitive markets is translated into investment impact in all states building solar PV, onshore and offshore wind, or BESS.
Jobs	▪ Data from industry publications[1] and academic research are used to estimate job creation per MW of installed capacity by technology.	▪ Capacity changes relative to the base case are translated into increases and decreases in jobs by technology.
Electricity prices	▪ Hourly wholesale prices are modelled out to 2060 across competitive electricity markets (Independent System Operators – ISOs) internally consistent with capacity build.	▪ Historical data from EIA are used to correlate wholesale and residential electricity prices from 2014-2023. This correlation is applied to Aurora's forecasted wholesale prices to project retail rate impacts by state. For a view on wholesale electricity prices in states covered by multiple ISOs, we take a load distribution as proxy.
Load growth	▪ Aurora takes a comprehensive view on load growth across the modelled ISOs, considering population growth, electrification (of transportation, heating, oil and gas operations, etc.), and data center expansion.	▪ No changes to load assumptions in the Tax Credit Removal scenario.
Tax credits	▪ Aurora assumes all clean energy projects achieve base PTC and ITC rates; Energy Community adder depends on project location. Credit stepdown in the mid 2030s reflects policy uncertainty. *See appendix slide for more details.*	▪ PTCs and ITCs for wind, solar, and batteries are discontinued in 2025; safe harbor assumptions means projects under construction today can still receive tax credits, but no projects beyond this time frame receive tax credits. *See appendix slide for more details.*

1) Including the DoE's US Energy Employment and Jobs Report.

Sources: Aurora Energy Research, EIA, US Department of Energy

A rollback of federal tax credits could reduce clean energy deployment 76GW by 2030 and 237GW by 2040

Cumulative capacity delta to base case resulting from tax credit removal by ISO (Independent System Operator)
GW



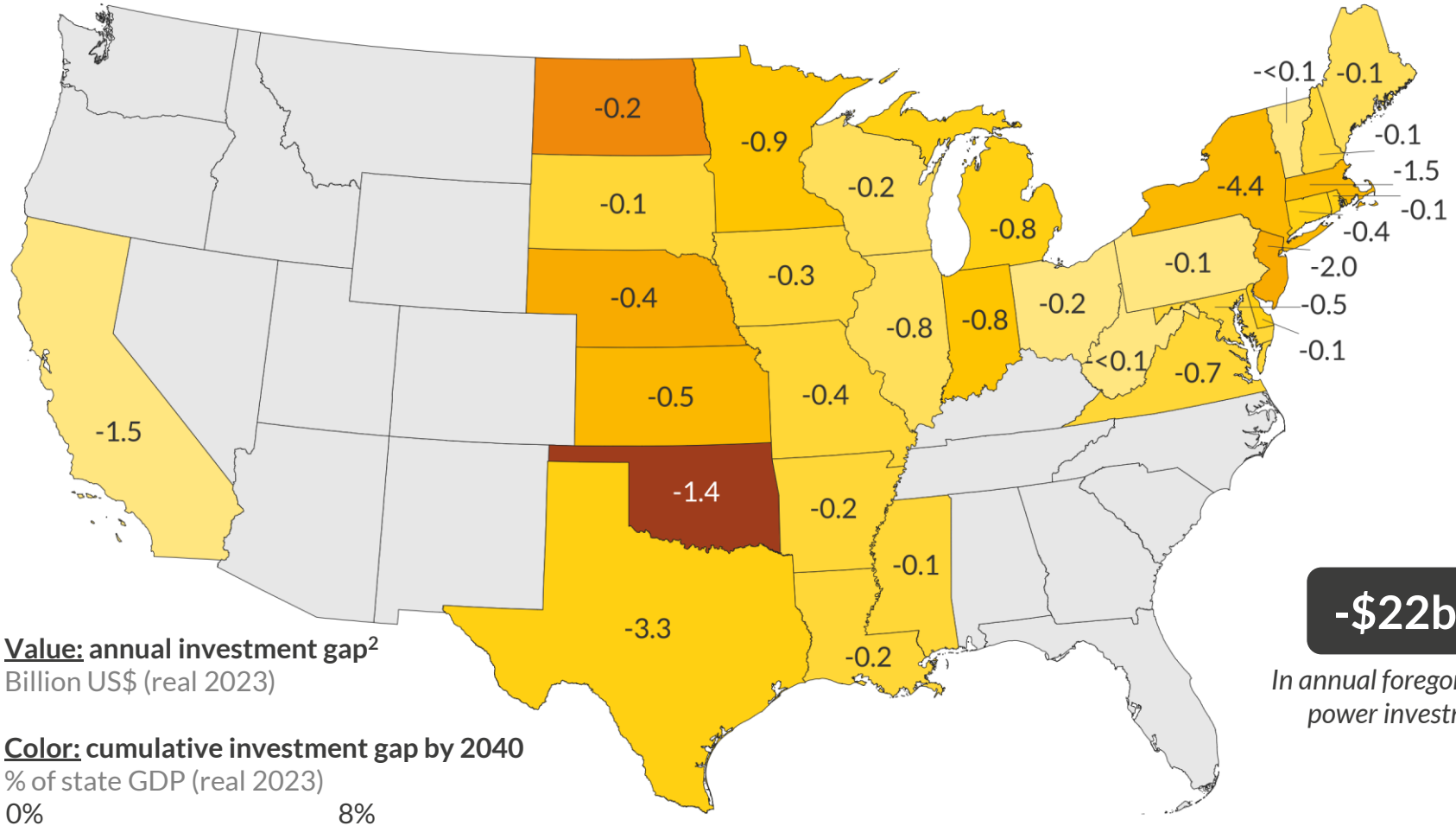
- Across competitive electricity markets in the United States, 76GW less clean energy projects are deployed by 2030 in a world without tax credits supporting the deployment of solar PV, wind, and battery storage technologies, and 237GW by 2040. Compared to the 256GW of capacity operational in 2023, this is a substantial reduction in future growth.
- Utility-scale solar PV is most impacted by the discontinuation of tax credits, seeing 41GW less buildout by 2030 and 93GW less by 2040.
- Offshore wind capacity is reduced 33GW by 2040; this affects coastal regions, where state support for offshore wind deployment is insufficient to make up for loss of federal support.

Sources: Aurora Energy Research

Removal of tax credits could lead to a loss of $22bn/year in clean power investment

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Investment gap for clean power deployment[1], Tax Credit Removal scenario relative to base case



Value: annual investment gap[2]
Billion US$ (real 2023)

Color: cumulative investment gap by 2040
% of state GDP (real 2023)

0% 8%

-$22bn

In annual foregone clean power investment

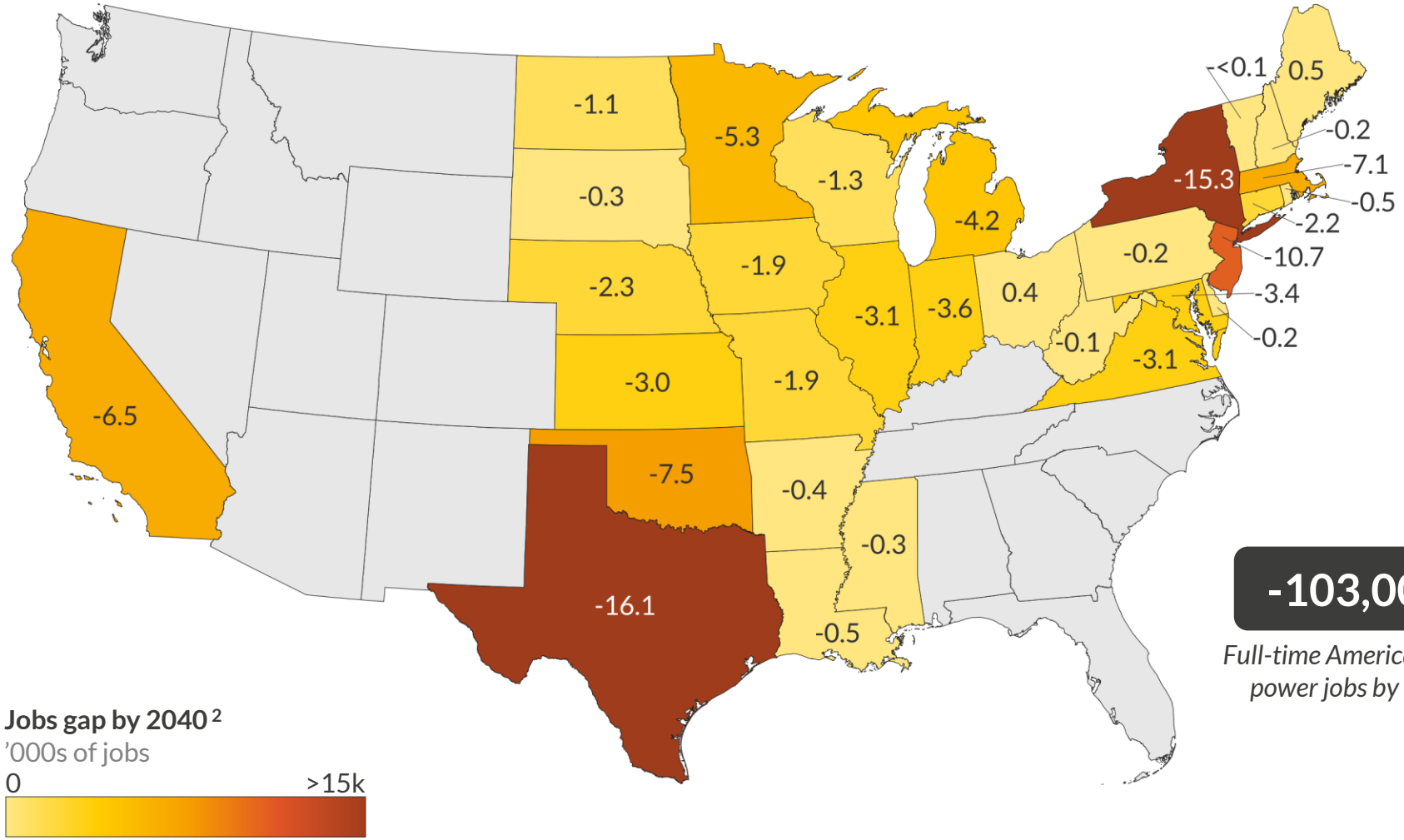
- ISO-wide investment in battery storage, solar, and wind projects totalled $57 billion in Q1-Q3 of 2024.
- Texas saw $24.8 billion, or 1% of state GDP, invested in the last 4 quarters alone. Tax credit removal would cut investment by twice that amount by 2040.
- New York and Texas alone would lose out on $116bn in investment, or 34% of the total.
- Cumulative investment lost in the Great Plains states is between 3 and 5% of 2023 GDP, and as much as 8% in Oklahoma.
- These numbers do not include the impact on investment in manufacturing of wind, solar and battery technologies.

1) Analysis available for deregulated wholesale markets covering 31 states and the District of Columbia. Includes impact to deployment of utility-scale wind, solar, and battery storage systems; excludes impact to manufacturing sector. 2) Delta with Aurora baseline forecast for 2025-2040.
Sources: Aurora Energy Research, Rhodium Group-MIT/CEEPR Clean Investment Monitor

Elimination of tax credits for wind, solar, and battery deployment puts at risk 31,000 jobs by 2030 and at least 103,000 jobs by 2040

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Jobs gap for clean power deployment by 2040[1,2]



-103,000

Full-time American clean power jobs by 2040

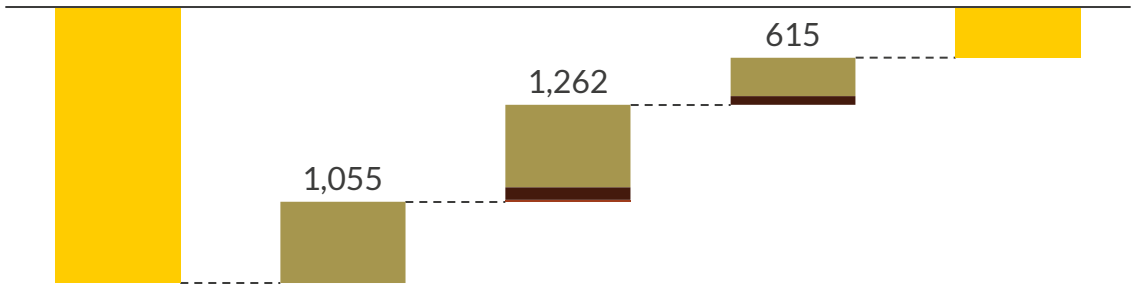
- Utility-scale wind, solar, and battery technologies employed over 150,000 people across construction, maintenance and operation, and professional services in 2023.
- Jobs in clean energy grew 4.2% from 2022 to 2023, more than double the speed of the overall economy at 2.0%.
- Cutting tax credits would be equivalent to 3+ years of lost jobs growth in American clean energy deployment and maintenance.
- These numbers do not include the impact on jobs in manufacturing of wind, solar and battery technologies.

1) Analysis available for deregulated wholesale markets covering 31 states and the District of Columbia. Includes impacts on construction and operation of utility-scale wind, solar, and battery storage systems; excludes impacts on manufacturing sector. 2) Delta with Aurora baseline forecast for 2040, assuming constant relationship between new capacity and job creation.
Sources: Aurora Energy Research, US Department of Energy, IWEC, GWEC, Aldieri et al. (2020)

Job losses are partially offset by a 6,000 increase in the fossil fuel sector, though not enough to make up for the 103,000 clean energy jobs lost

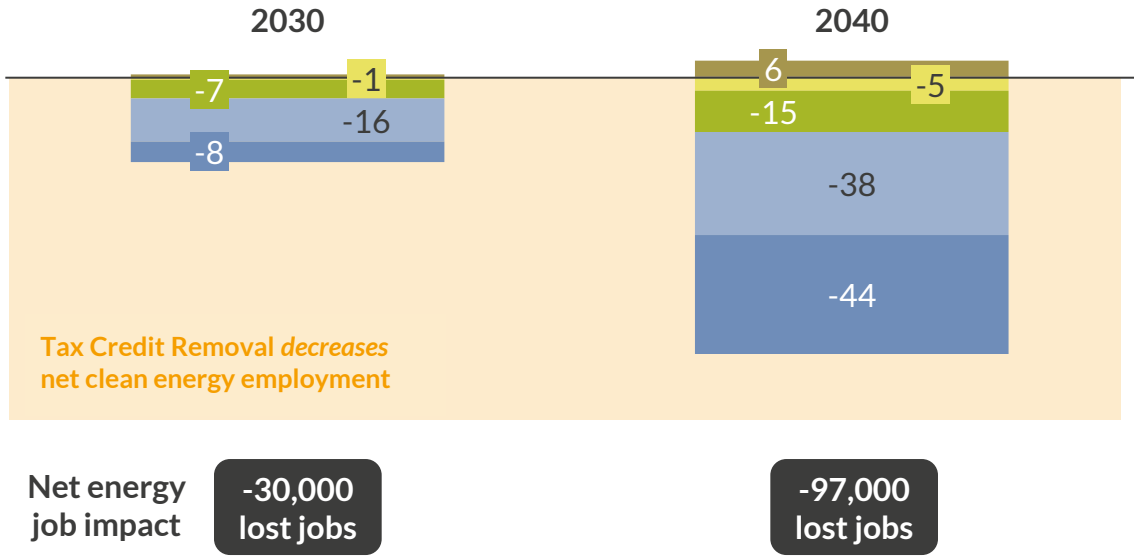
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Electricity production comparing Tax Credit Removal scenario to base case (2025-2040), TWh



- The loss in clean electricity generation from the discontinuation of tax credits means that demand must be met in other ways, primarily through fossil-fuel fired generation such as natural gas and coal.
- Most demand is made up through more production from existing plants (35%), meaning these plants are running for longer hours and/or at higher output levels. Some projects that retired in the base case scenario see longer lifetimes in Tax Credit Removal scenario because of more favorable economics due to clean energy decline (making up 17% of lost generation), and the rest is made up for by new build thermal plants (29%).

Job impact by technology in Tax Credit Removal scenario relative to base case
Thousands of jobs



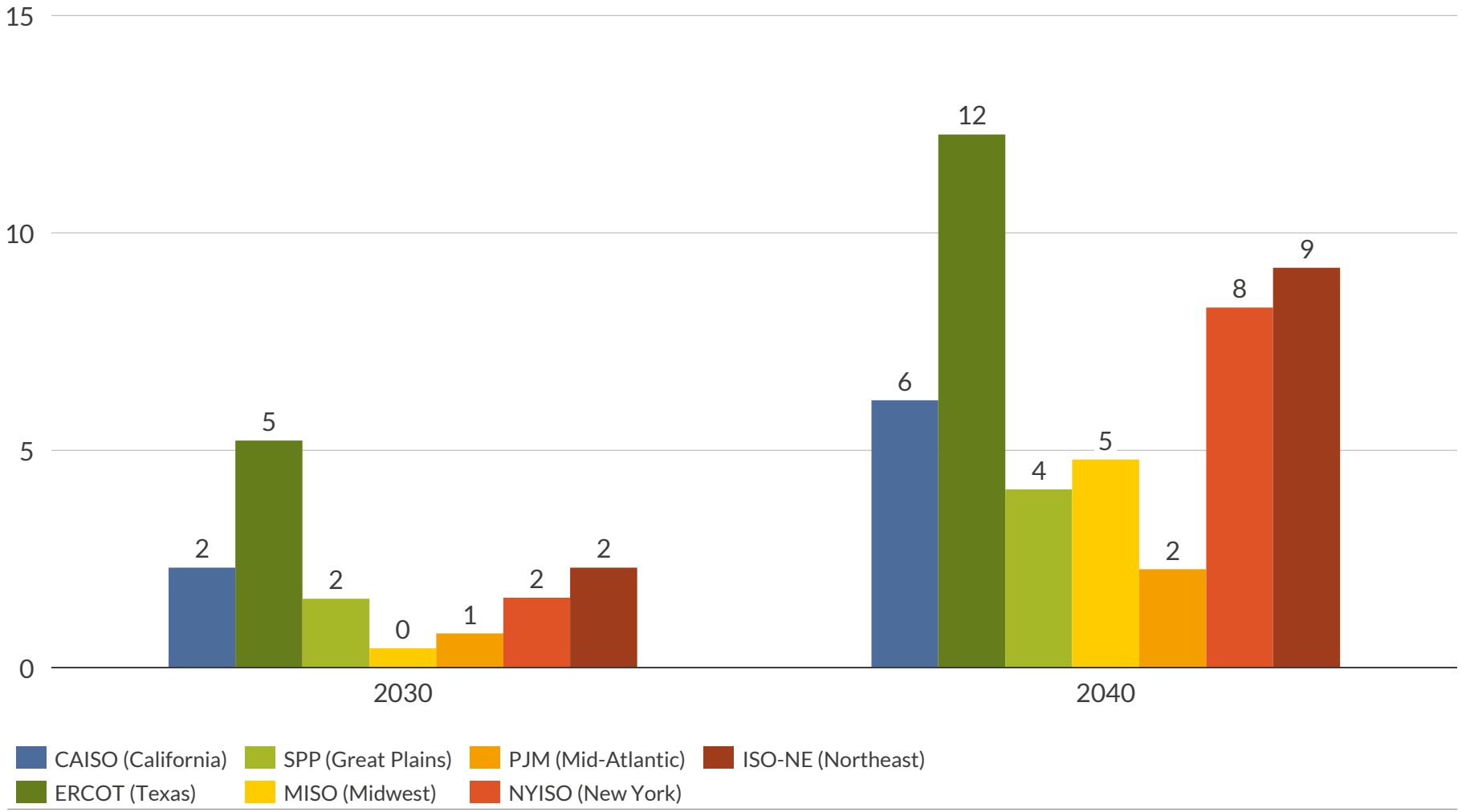
- The increase in fossil-fueled fired generation lends to more jobs, though not enough to make up for the loss of clean energy jobs.
- Higher load factors from operational plants results in minimal new jobs, construction of new thermal plants altogether create four thousand new jobs.

1) The reduction in onshore wind, offshore wind, and solar PV generation in the Tax Credit Removal scenario relative to base case. 2) Other balancing effects include increased generation from dispatchable non-gas, coal, or nuclear plants (e.g. hydro), reduced battery storage losses from less battery storage on the system, reduced demand from price-responsive demand technologies (such as Bitcoin mines in ERCOT).

Sources: Aurora Energy Research, EIA

Removal of tax credits leads to higher wholesale power prices across markets

Around the Clock (ATC) price deltas by US ISO, Tax Credit Removal scenario relative to base case
$/MWh (2023 real)



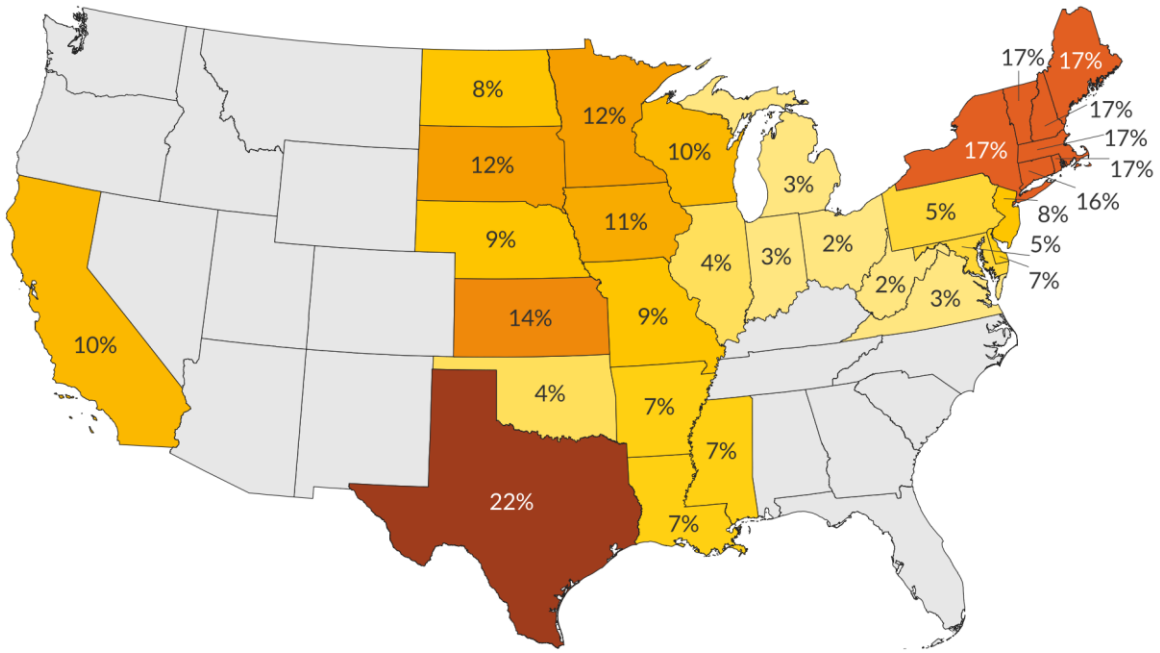
- The elimination of tax credits for renewables and storage deployment results in wholesale power prices rising across every competitive market throughout the next two decades.
- ERCOT (ISO covering the majority of Texas) is disproportionately impacted by tax credit removal. Given high load growth in the state and a lack of state policies supporting clean energy deployment the state loses a lot of cheap electricity generation, raising wholesale electricity prices by $5/MWh by 2030 and $12/MWh by 2040.
- Wholesale power prices rise much faster through the 2030s due to lower investment in renewable energy in a world without clean energy tax credits.

Sources: Aurora Energy Research

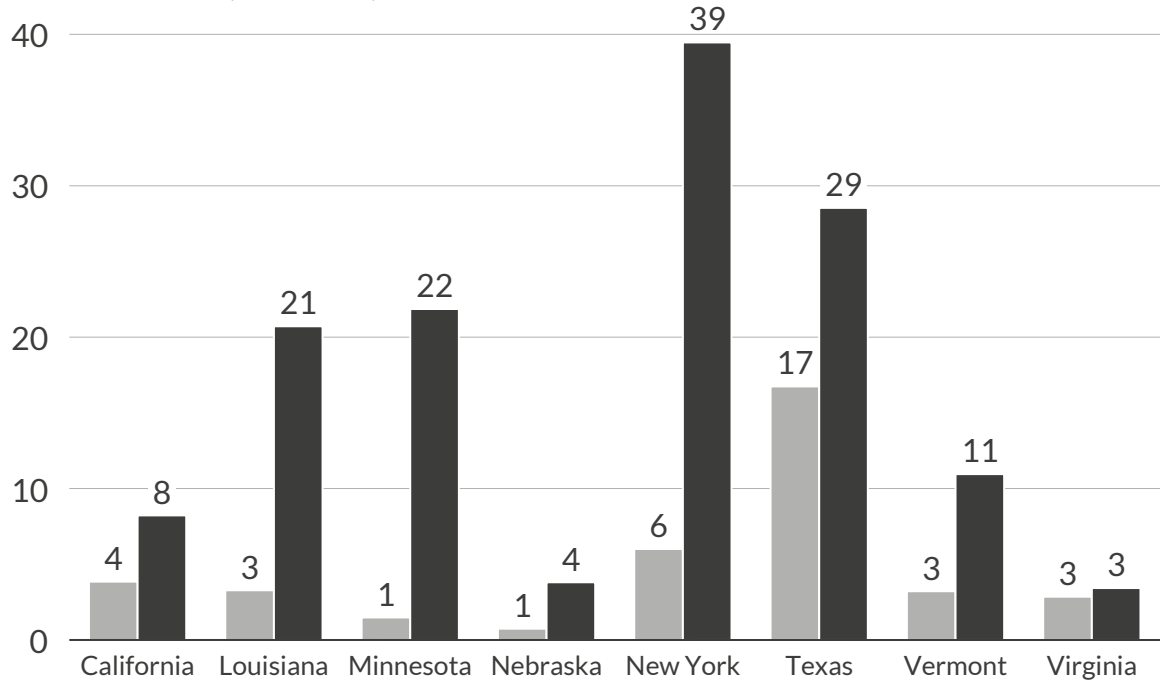
By 2040, removal of tax credits could raise retail rates by ~10% and yearly energy bills by ~$142 on average

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Retail rate increases by state, 2040[1,2]
% delta from base case



Monthly residential energy bill increases by selected state[2,3]
$ over base case (2023 real)



- Without tax credits to incentivize renewable energy development, average retail electricity rates are expected to be 3% higher in 2030, rising to 10% higher on average by 2040.[1,2]
- Removing 169GW of low marginal cost wind and solar generation from the system by 2040 leads to higher power prices rise as more expensive generation must be used to meet demand.

- Monthly residential energy bills are likely to rise sharply in states where consumers have the highest energy demand (Louisiana, Texas) or already pay high average rates (New York).

1) Compared to estimated retail prices in 2040 from a baseline scenario with investment and production tax credits. In this scenario, renewable energy generation is typically replaced with gas and peaking generation, which has a higher short run marginal cost.
2) Analysis available for deregulated wholesale markets covering 31 states and the District of Columbia. No data available for states in gray. 3) Forecasted retail rate multiplied by state-specific 2023 average monthly residential demand
Sources: Aurora Energy Research, EIA

Agenda

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I. Additional context

II. Additional results

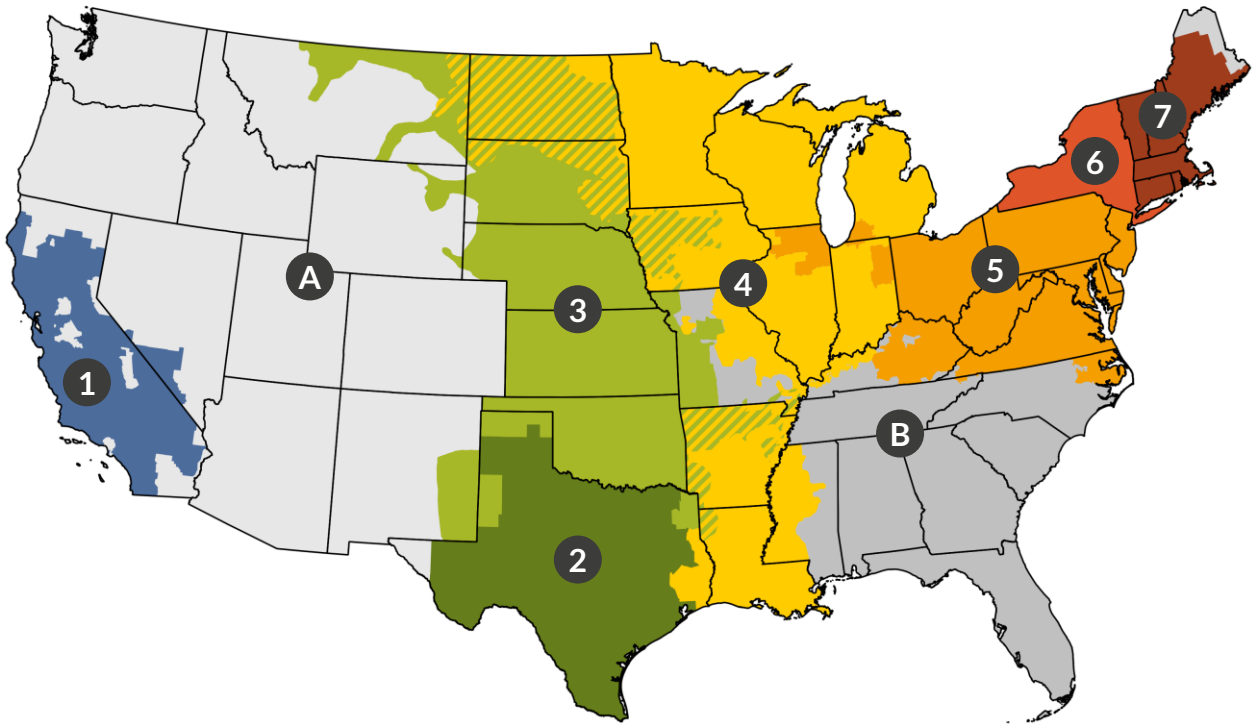
III. About Aurora

Aurora models all seven competitive electricity markets in the United States

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Two thirds of overall electricity demand in the lower 48 states is served by Independent System Operators (ISOs). ISOs use competitive market mechanisms that allow independent power producers and non-utility generators to trade power. The WECC and SERC regions remain vertically integrated by utility or balancing authority (BA).

Map of US wholesale electricity markets[1]



ISO	Installed capacity,[2] GW	Annual load,[3] TWh	Projected peak load growth[4]	Renewables penetration[3]
CAISO 1	82	220	9.7%	42%
ERCOT 2	140	447	9.2%	41%
SPP 3	100	284	9.9%	40%
MISO 4	200	656	6.0%	20%
PJM 5	219	770	3.7%	10%
NYISO 6	44	147	17.0%	24%
ISO-NE 7	38	110	11.4%	18%

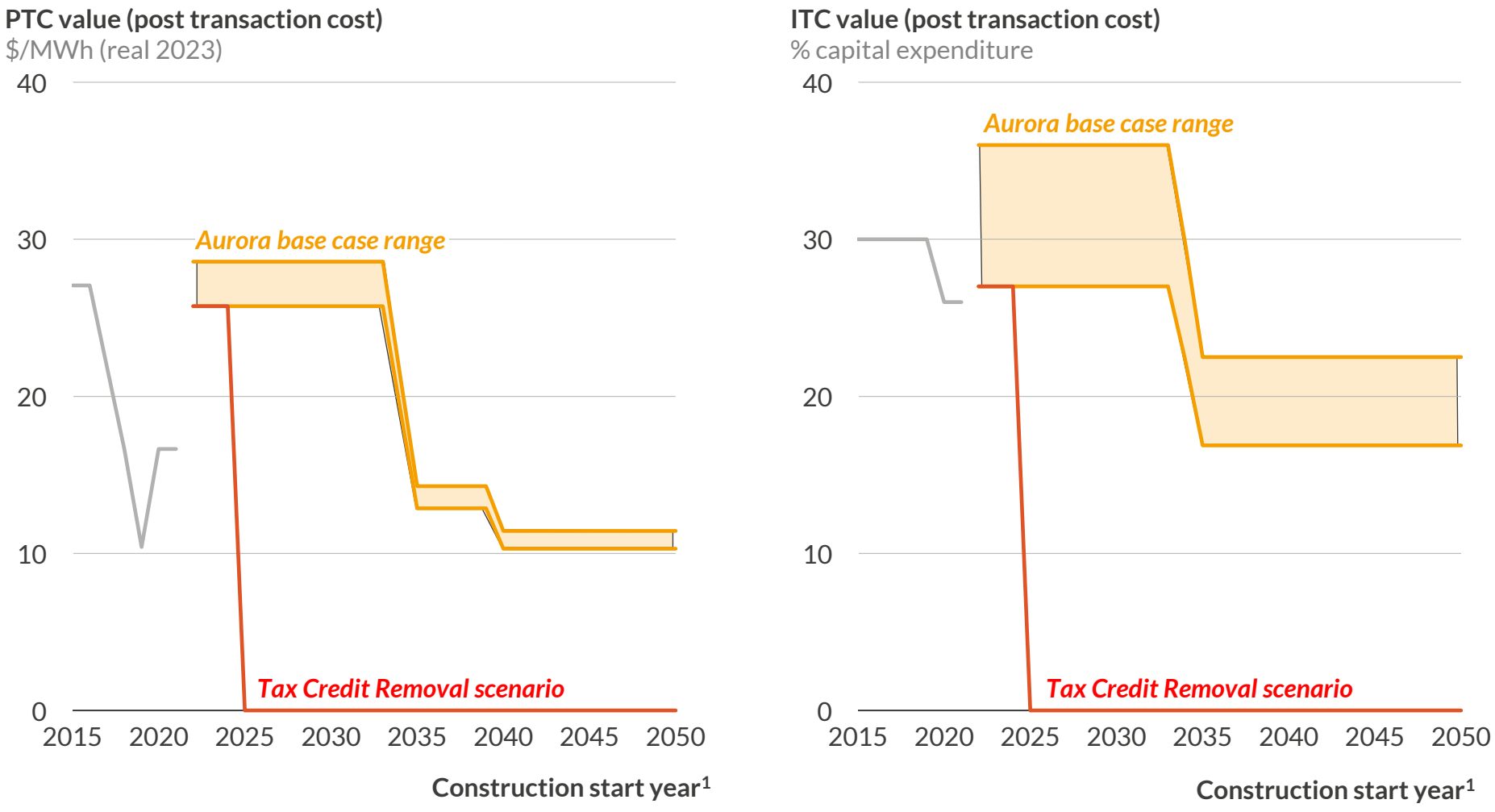
Non-ISO	
WECC A	*Out of scope for this study*
SERC B	

1) Gray areas are regulated, meaning they are vertically integrated utilities responsible for the production, transportation, and sale of electricity to consumers. 2) Data from December 2023 EIA 860m and ERCOT CDR. Includes capacities of plants not bidding fully into wholesale or capacity market. 3) 2023 data. 4) Compares 2024 through 2030. SPP data from individual ISO market report.

Sources: Aurora Energy Research, FERC, NERC, individual ISOs

Aurora assumes a minimum $25.7/MWh PTC and 27% ITC; the Tax Credit Removal scenario eliminates these values in 2025

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- The Aurora base case assumes all economically-built projects meet labor requirements; some projects realize the Energy Community adder depending on location. No projects in the base case achieve the Domestic Content adder.
- ITC adders are relatively more attractive than PTC adders: ITC adders are 10p.p. additions to the base rate + wage requirement values, whereas PTC adders are a 10% addition of the base rate + wage requirement values.
- Values step down in the base case in the 2030s to reflect some level of policy uncertainty.
- All PTC and ITC value is subject to a 10% haircut per Aurora's assumptions, reflecting some value lost to tax credit transactions.

1) Legacy project rules enable a 4 year construction time for projects. 2) Excludes transaction costs.

Sources: Aurora Energy Research, EPA

Agenda

AURORA

I. Additional context

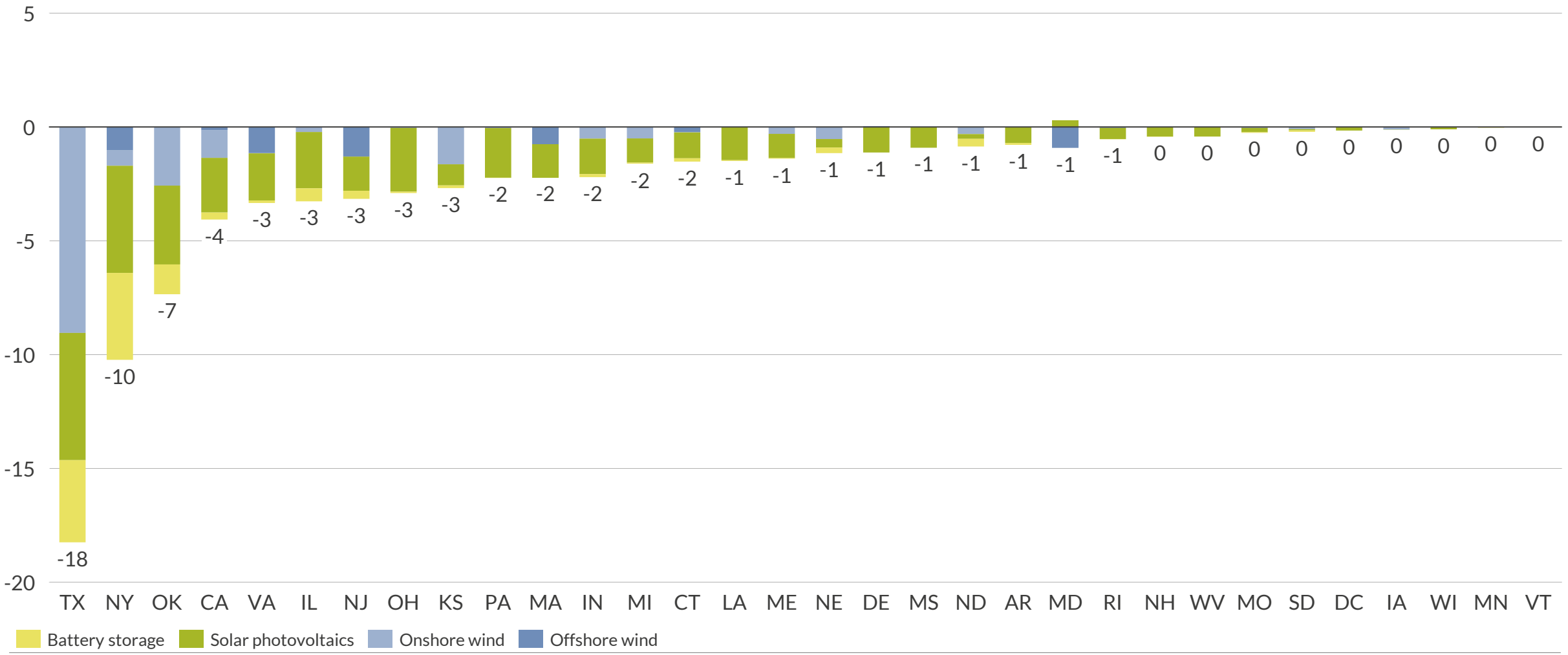
II. Additional results

III. About Aurora

Capacity delta by state, 2030

AURORA

Installed capacity deltas compared to base case by state[1]
GW (2030)



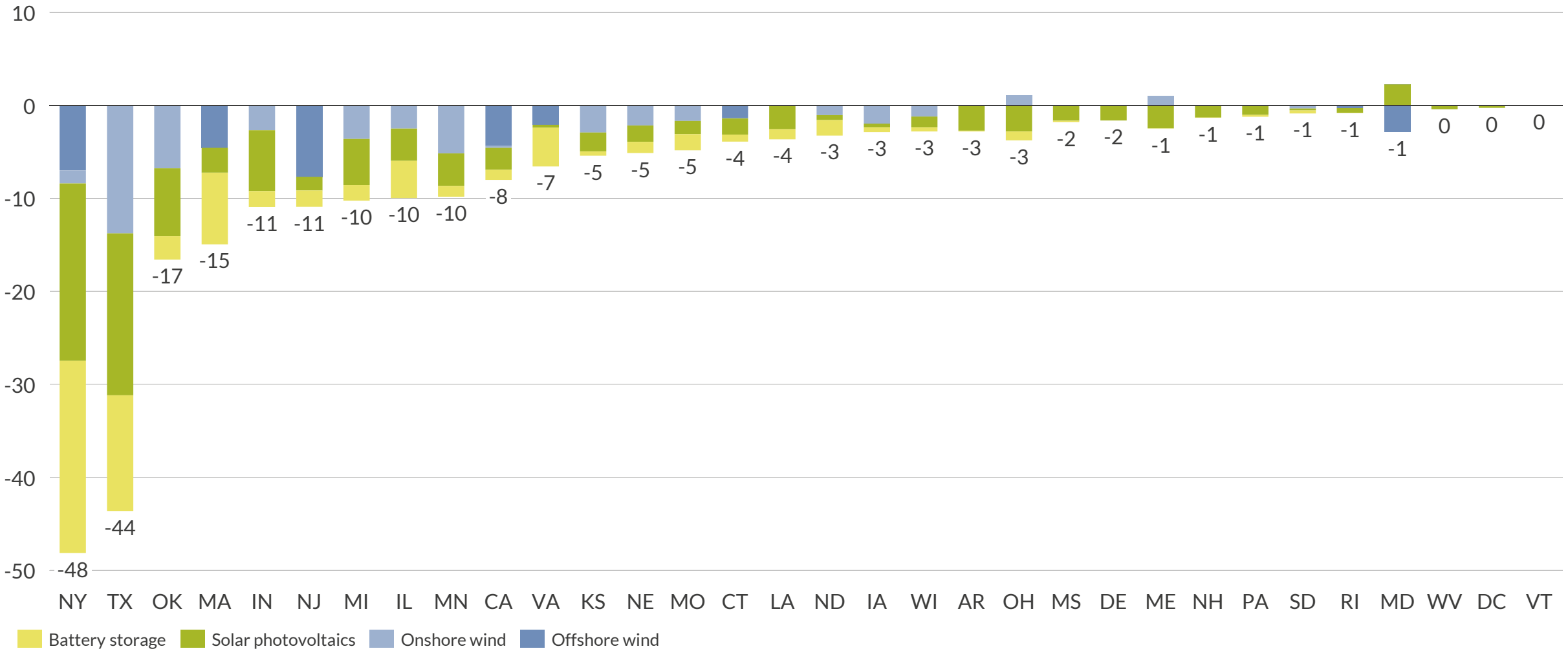
1) Analysis available for deregulated wholesale markets covering 31 states and the District of Columbia.

Sources: Aurora Energy Research

Capacity delta by state, 2040

AURORA

Installed capacity deltas compared to base case by state[1]
GW (2040)



1) Analysis available for deregulated wholesale markets covering 31 states and the District of Columbia.

Sources: Aurora Energy Research

Results by state, 2030

State	Battery storage delta (MW)	Solar photovoltaics delta (MW)	Onshore wind delta (MW)	Offshore wind delta (MW)	Total capacity delta (MW)	Investment delta ($bn, 2023 real)	Clean energy jobs delta	Monthly retail price delta (%)	Monthly retail price delta ($, 2023 real)
Arkansas	-82.5	-696.6	-5.0	0.0	-784.1	-0.89	-127	0.1%	$0.18
California	-305.8	-2406.2	-1205.4	-150.0	-4067.4	-6.69	-1710	3.5%	$3.85
Connecticut	-141.2	-1143.0	-8.3	-229.4	-1521.8	-2.16	-518	4.0%	$6.28
Delaware	0.0	-1121.4	20.9	0.0	-1100.5	-1.18	-168	2.7%	$3.55
District of Columbia	0.0	-159.8	0.0	0.0	-159.8	-0.17	-27	1.5%	$1.25
Illinois	-577.1	-2467.2	-225.0	0.0	-3269.3	-3.65	-654	1.2%	$1.62
Indiana	-139.7	-1548.0	-516.0	0.0	-2203.7	-2.74	-733	0.9%	$1.35
Iowa	0.0	-6.0	-110.0	0.0	-116.0	-0.19	-100	1.2%	$1.38
Kansas	-115.6	-924.7	-1644.0	0.0	-2684.2	-3.91	-1642	7.4%	$5.12
Louisiana	-30.0	-1457.6	-5.0	0.0	-1492.6	-1.66	-250	1.5%	$3.29
Maine	-23.4	-1063.0	-304.6	0.0	-1390.9	-1.79	-453	3.8%	$4.53
Maryland	0.0	283.9	-2.1	-913.0	-631.2	-2.98	-1187	1.5%	$1.58
Massachusetts	1.4	-1457.0	0.0	-760.8	-2216.4	-4.02	-1270	3.9%	$5.24
Michigan	-52.4	-1057.7	-506.1	0.0	-1616.3	-2.07	-636	1.0%	$1.38
Minnesota	-15.0	-6.0	-10.0	0.0	-31.0	-0.04	-11	1.0%	$1.48
Mississippi	0.0	-906.0	-5.0	0.0	-911.0	-1.04	-156	1.4%	$1.97

Sources: Aurora Energy Research

Results by state, 2030

AURORA

State	Battery storage delta (MW)	Solar photovoltaics delta (MW)	Onshore wind delta (MW)	Offshore wind delta (MW)	Total capacity delta (MW)	Investment delta ($bn, 2023 real)	Clean energy jobs delta	Monthly retail price delta (%)	Monthly retail price delta ($, 2023 real)
Missouri	-29.6	-186.0	-43.5	0.0	-259.1	-0.32	-72	2.1%	$2.40
Nebraska	-245.5	-378.8	-529.1	0.0	-1153.4	-1.57	-556	1.1%	$0.74
New Hampshire	-8.9	-421.0	0.0	0.0	-429.9	-0.47	-71	3.8%	$5.05
New Jersey	-354.0	-1496.5	-1.6	-1306.0	-3158.0	-6.64	-2039	2.7%	$3.31
New York	-3818.7	-4706.2	-668.5	-1035.6	-10228.9	-14.48	-3049	3.1%	$6.01
North Dakota	-338.0	-207.4	-312.5	0.0	-857.9	-0.98	-339	2.5%	$2.01
Ohio	-64.8	-2805.7	-38.0	0.0	-2908.5	-3.30	-507	0.7%	$0.67
Oklahoma	-1312.6	-3457.4	-2581.2	0.0	-7351.2	-9.38	-2991	-2.1%	-$1.71
Pennsylvania	-2.0	-2180.3	-53.0	0.0	-2235.3	-2.53	-412	1.8%	$2.49
Rhode Island	-7.9	-483.0	0.0	-44.8	-535.7	-0.69	-142	3.8%	$3.81
South Dakota	-62.5	-58.0	-94.7	0.0	-215.3	-0.26	-99	3.3%	$2.16
Texas	-3608.8	-5590.9	-9051.9	0.0	-18251.6	-23.42	-9329	11.2%	$16.75
Vermont	-7.5	-3.0	0.0	0.0	-10.5	-0.01	-1	3.8%	$3.22
Virginia	-107.4	-2069.7	-15.0	-1147.0	-3339.2	-6.58	-1915	2.0%	$2.87
West Virginia	0.0	-409.0	-16.0	0.0	-425.0	-0.49	-83	1.5%	$2.72
Wisconsin	0.0	-93.4	-13.9	0.0	-107.3	-0.14	-28	0.8%	$0.88

Sources: Aurora Energy Research

Results by state, 2040

AURORA

State	Battery storage delta (MW)	Solar photovoltaics delta (MW)	Onshore wind delta (MW)	Offshore wind delta (MW)	Total capacity delta (MW)	Investment delta ($bn, 2023 real)	Clean energy jobs delta	Monthly retail price delta (%)	Monthly retail price delta ($, 2023 real)
Arkansas	-82.5	-2717.3	22.3	0.0	-2777.5	-2.78	-439	7.0%	$15.85
California	-1094.5	-2366.2	-204.2	-4350.0	-8014.9	-22.08	-6527	9.7%	$8.22
Connecticut	-757.6	-1748.0	-7.4	-1376.2	-3889.2	-6.71	-2209	16.5%	$18.47
Delaware	0.0	-1618.0	26.0	0.0	-1592.1	-1.81	-247	7.4%	$8.68
District of Columbia	0.0	-256.9	0.0	0.0	-256.9	-0.27	-43	3.8%	$2.77
Illinois	-4004.0	-3475.6	-2483.1	0.0	-9962.7	-11.40	-3092	4.0%	$6.25
Indiana	-1714.7	-6543.0	-2671.6	0.0	-10929.2	-12.47	-3615	3.3%	$5.32
Iowa	-500.0	-400.0	-1954.0	0.0	-2854.0	-4.02	-1860	10.7%	$13.11
Kansas	-463.9	-2037.3	-2904.6	0.0	-5405.8	-7.40	-2986	14.1%	$8.95
Louisiana	-1078.8	-2554.8	-2.0	0.0	-3635.6	-3.68	-503	6.7%	$20.72
Maine	-23.4	-2460.0	1016.7	0.0	-1466.6	-0.84	503	16.7%	$15.25
Maryland	0.0	2247.8	16.7	-2821.0	-556.5	-7.61	-3418	4.9%	$4.05
Massachusetts	-7697.6	-2664.6	1.7	-4564.7	-14925.2	-22.73	-7137	16.6%	$16.48
Michigan	-1663.8	-4977.6	-3597.4	0.0	-10238.8	-12.34	-4184	3.0%	$4.93
Minnesota	-1143.3	-3500.0	-5162.9	0.0	-9806.2	-12.82	-5310	12.4%	$21.85
Mississippi	-162.1	-1627.2	-2.0	0.0	-1791.3	-1.91	-285	6.9%	$8.61

Sources: Aurora Energy Research

Results by state, 2040

AURORA

State	Battery storage delta (MW)	Solar photovoltaics delta (MW)	Onshore wind delta (MW)	Offshore wind delta (MW)	Total capacity delta (MW)	Investment delta ($bn, 2023 real)	Clean energy jobs delta	Monthly retail price delta (%)	Monthly retail price delta ($, 2023 real)
Missouri	-1747.0	-1420.2	-1659.2	0.0	-4826.4	-5.65	-1851	8.9%	$10.44
Nebraska	-1217.0	-1746.0	-2152.5	0.0	-5115.6	-6.38	-2313	8.7%	$3.81
New Hampshire	-9.0	-1306.8	0.0	0.0	-1315.7	-1.36	-219	16.7%	$16.30
New Jersey	-1753.6	-1471.6	12.7	-7680.3	-10892.8	-29.41	-10724	8.0%	$9.11
New York	-20672.0	-19106.5	-1395.6	-6979.9	-48154.0	-66.04	-15296	17.1%	$39.46
North Dakota	-1662.7	-541.5	-1027.9	0.0	-3232.0	-3.62	-1130	8.4%	$5.89
Ohio	-957.2	-2792.5	1054.5	0.0	-2695.2	-2.26	417	1.9%	$1.56
Oklahoma	-2512.3	-7303.5	-6762.4	0.0	-16578.2	-21.01	-7479	3.9%	$2.29
Pennsylvania	-197.6	-1014.9	0.9	0.0	-1211.6	-1.63	-182	5.3%	$6.45
Rhode Island	-7.9	-544.0	0.0	-269.1	-821.0	-1.45	-455	16.7%	$13.44
South Dakota	-331.6	-205.8	-324.9	0.0	-862.4	-1.01	-350	12.4%	$7.02
Texas	-12474.7	-17406.2	-13758.2	0.0	-43639.1	-50.12	-16150	22.1%	$28.54
Vermont	-7.5	0.0	0.0	0.0	-7.5	-0.01	-1	16.7%	$10.96
Virginia	-4158.1	-317.8	43.3	-2080.0	-6512.6	-11.25	-3109	2.8%	$3.44
West Virginia	0.0	-406.0	14.1	0.0	-391.9	-0.44	-55	2.4%	$4.18
Wisconsin	-451.2	-1166.2	-1185.6	0.0	-2803.0	-3.48	-1293	10.3%	$9.46

Sources: Aurora Energy Research

Agenda

AURORA

I. Additional context

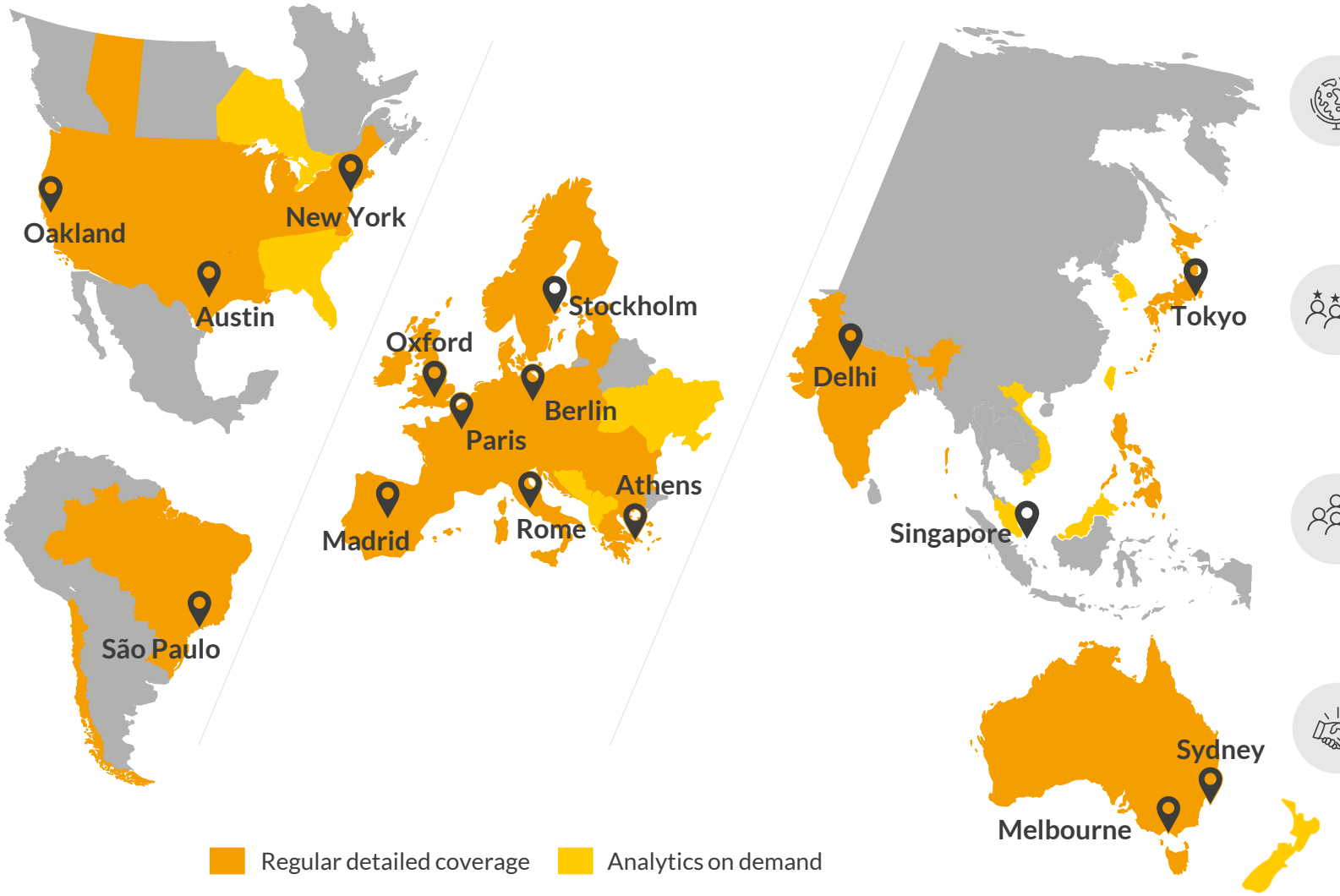
II. Additional results

III. About Aurora

Aurora provides independent forecasts and data-driven intelligence for the global energy transition

AURORA

- Power markets
- Renewables & PPAs
- Storage
- Grid & Congestion
- Electric vehicles
- Hydrogen H_2
- Carbon CO_2
- Natural gas



16 offices

900+ market experts

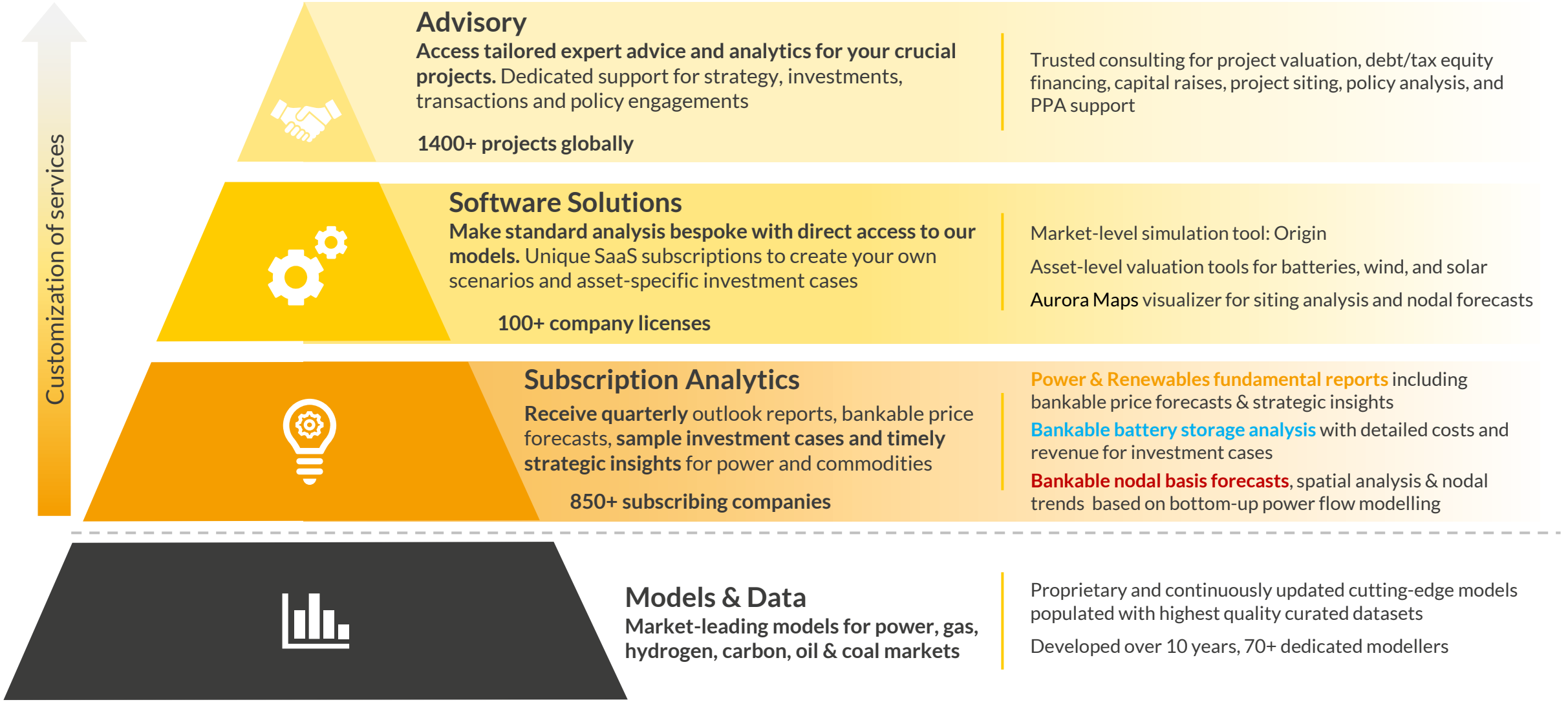
850+ subscribing companies

150+ transactions supported in 2024

Source: Aurora Energy Research

Our market-leading models underpin a comprehensive range of seamlessly integrated services to best suit your needs

AURORA



Source: Aurora Energy Research

Aurora services: subscriptions providing price forecasts and market analytics for AURORA developers, asset owners, investors, energy consumers, and regulators

Subscription Analytics: Receive regularly updated forecasts, sample investment cases and timely deep-dives

Ad-hoc customized support:

1 Power & Renewables



Keep up to date on a specific power market; zonal price curves as well as in-depth quarterly reports and events to keep a pulse on market *(Quarterly updates)*

What the service is:
- Bankable monthly forecasts (2050) to support asset financing , scenario analysis; in-depth fundamental analysis to underpin your investment strategies
- Roundtable discussions, workshops and ongoing support from dedicated teams

Assorted use case examples:
- Understanding a market at depth and keeping up to date with market and policy developments, with on-call, ad hoc support
- Reliable, bankable wholesale price forecasts to support asset financing and valuations - six scenarios updated quarterly

2 Flexible Energy Add-on



Go deep on battery and peaker business case economics and fundamentals. Understand hourly granularity of a specific market to build investment cases *(Quarterly updates)*

What the service is:
- Detailed analysis and hourly granular forecasts for power, balancing, and ancillary services plus investment case data for battery & peakers
- Roundtable discussions, workshops and ongoing support from dedicated teams

Assorted use case examples:
- Developer seeking to understand detailed battery costs and revenue streams/stacking across various configurations
- Investor comparing differences in BESS gross margin, IRR, NPV across hubs and entry years with representative nodal basis

3 Nodal Add-on



Understand nodal economics and trends through bottom-up power flow modelling. Site specific valuation, congestion, curtailment and other uses cases *(Quarterly updates)*

What the service is:
- Bankable nodal forecasts, spatial congestion analysis, site-specific valuation and other features through bottom-up power flow modelling
- Roundtable discussions, workshops and ongoing support from dedicated teams

Assorted use case examples:
- Investor evaluating site specific risks and implications during phase 1 of a transaction
- Developer seeking to identify the drivers and trends in congestion patterns and nodal pricing outcomes throughout the system to support early development pipeline

4 Advisory



Best for: Custom projects or transactions that need dedicated expert support. Typically, transaction diligence and asset valuations

What the service is:
- Tailored expert advice and analytics support to deliver diligence on a specific project including advisory transactions, policy views, and strategy insights

Assorted use case examples:
- Developer seeking bespoke nodal forecast and asset valuation with sensitivity analysis
- Investment firm seeking due diligence support to derisk a specific transaction
- Regulator seeking to understand policy impact of market reforms

Unique, proprietary, in-house modelling capabilities underpin Aurora's superior analysis

AURORA

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 modelling
- Dynamic dispatch of plant
- Endogenous interconnector flows

Continuous iteration until an equilibrium is reached

Investment decisions module

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

OUTPUTS

- Capacity mix
- Generation mix
- Power & Ancillary Service 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 specifications modelled for each plant

c. 85k investment hours on modelling capabilities

~15k model runs per week

80+ strength of modelling team globally

Quarterly updates through subscription research

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

Source: Aurora Energy Research

Details and disclaimer

Publication
Impact of reform to clean energy tax credits on investment, jobs and consumer bills

Date
January 6, 2025

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AURORA
ENERGY RESEARCH

ORANGE COUNTY POWER AUTHORITY
Staff Report – Item 8.3

To: Orange County Power Authority Legislative and Regulatory Committee

From: Steven Halligan, Regulatory and Legislative Manager

Approved By: Joe Mosca, Chief Executive Officer

Subject: INTRODUCED LEGISLATION POSITION RECOMMENDATIONS

Date: March 6, 2025

RECOMMENDED ACTION

Recommend the Orange County Power Authority Board of Directors take positions on legislation as recommended by Staff.

BACKGROUND

The deadline to introduce legislation in the California Legislator was February 21. In total over 2,300 bills were introduced. Staff have identified 118 bills (Attachment – 2025 Orange County Power Authority Bill Tracker) to analyze and monitor. Staff track bills in several categories including but not limited to affordability, building standards, energy sources, CEQA, transmission, decarbonization, demand forecasting, electrification, IOU rate cases and oversight, and workforce development.

ANALYSIS AND DISCUSSION

Currently, staff have identified two bills to take a support position on. One bill, related to allowing the CAISO to join an independent regional organization falls under the OCPA Policy Platform. However, the second bill is related to The Brown Act and public meetings and does not fall under the Policy Platform. Details of the two bills are below.

SB 540 (Becker and Stern) - Independent System Operator: independent regional organization

SB 540 provides the California Independent System Operator (CAISO) with the authority necessary to implement the Pathways Initiative Proposal if it determines an independent regional organization (RO) meets specific requirements. The bill allows CAISO to tap into a wider market of electricity resources which studies have shown stand to provide significant benefits to Californians including cost savings, enhanced grid reliability, and reduced air pollution.

The expanded market that SB 540 would enable will save ratepayers money, improve grid reliability, and reduce air pollution from power plants in California by:

1) Optimizing the use of generation, storage and transmission resources.

2) Securing California's ability to export excess renewables rather than curtailing them and importing them from other states when available.

3) Allowing California to draw upon a wider set of Western renewable resources when our grid is stressed.

4) Making less use of back-up diesel generators and the oldest, dirtiest gas plants during system peaks

SB 540 already has broad support including the Coalition of California Utility Employees, Environmental Defense Fund, Nature Resources Defense Council, State Electrical Workers, and many more.

Recommended position: Support

SB 239 (Arreguin) - Open meetings: teleconferencing: subsidiary body

SB 239 would allow a subsidiary body to use alternative teleconferencing provisions – primarily to participate remotely as long as they appear on camera during the open portion of the meeting that is publicly accessible via the internet. A primary in person location would still be required for the public to participate. SB 239 defines subsidiary body as described in Section 54952(b), serves exclusively in an advisory capacity, and is not authorized to take final action on legislation, regulations, contracts, licenses, grants, permits, or other entitlements. After consulting with OCPA General Counsel, it was determined that the Community Advisory Committee would fall under these provisions and thus be allowed to participate remotely as long as the conditions of SB 239 are met. Staff believe this bill will allow additional members of the Community to participate on the Community Advisory Committee. Allowing some members to participate remotely would also eliminate emissions associated with traveling to the in-person meeting.

Recommended position: Support

FISCAL IMPACT

None

ATTACHMENTS

1. 2025 Orange County Power Authority Bill Tracker
2. SB 540
3. SB 239

Orange County Power Authority 2025 California Bill Tracker

Updated 2/25/2025

Bill #	Author	Title	Category	Summary	Status
AB 13	Ransom	Public Utilities Commission: membership: reports.	CPUC Reporting	This bill would require that 4 members of the commission represent the geographic locations of the 4 State Board of Equalization districts, existing as of January 1, 2026, and one member be an at-large member with unspecified qualifications, as specified. The bill would prohibit an elected member of, or an employee of, the Legislature or an employee of the executive branch from serving as a member of the commission within one year after leaving the position as an elected member or employee.	Amended 2/24. Asm Utilities and Energy
AB 23	DeMaio	The Cost of Living Reduction Act of 2025.	Affordability	This bill, the Cost of Living Reduction Act of 2025, would declare the intent of the Legislature to enact subsequent legislation to reduce the cost of living in California by undertaking specified activities, including, among other things, by suspending all state taxes and fees on gasoline and electric and gas utilities and by requiring the Little Hoover Commission to provide a report on methods to reduce the cost of living in other areas, as provided.	Introduced
AB 39	Zbur	General plans: Local Electrification Planning Act.	Local Programs	This bill, the Local Electrification Planning Act, would require a city, county, or city and county, on or after January 1, 2027, but no later than January 1, 2030, to prepare and adopt a specified plan, or integrate a plan in the next adoption or revision of the general plan, that includes locally based goals, objectives, policies, and feasible implementation measures that include, among other things, the identification of opportunities to expand electric vehicle charging, as specified, and includes policies and implementation measures that address the needs of disadvantaged communities, low-income households, and small businesses for equitable and prioritized investments in zero-emission technologies that directly benefit these groups. For these purposes, the bill would authorize a city, county, or city and county to incorporate by reference into the general plan a previously adopted similar plan that meets the above-described requirements, as specified. By increasing the duties of local public officials, the bill would establish a state-mandated local program.	Asm Local Government
AB 44	Schultz	Energy: electrical demand forecasts.	Demand Forecasts	Existing law requires the State Energy Resources Conservation and Development Commission, at least every 2 years, to conduct assessments and forecasts of all aspects of energy industry supply, production, transportation, delivery and distribution, demand, and prices. Existing law authorizes the commission to require the submission of demand forecasts from electrical utilities, among other entities, to perform its assessments and forecasts.This bill would state the intent of the Legislature to enact subsequent legislation that would require the commission to develop a set of technical guidance and load modification protocols to enable the state to reduce or modify its electrical demand forecast to improve grid reliability, as provided.	Introduced

Orange County Power Authority 2025 California Bill Tracker

Updated 2/25/2025

Bill #	Author	Title	Category	Summary	Status
AB 61	Pacheco	Electricity and natural gas: legislation imposing mandated program and requirements: third-party review.	Programs	This bill would request the office to establish, by January 1, 2027, a program to, upon request of the Legislature, analyze legislation that would establish a mandated requirement or program or otherwise affect electrical or gas ratepayers, as specified. The bill would request the office to develop and implement conflict-of-interest provisions that would prohibit a person from participating in an analysis for which the person knows or has reasons to know that the person has a financial interest. The bill would establish the Energy Programs Benefit Fund in the State Treasury and continuously appropriate the moneys in the fund to the office to support the work of the office in providing analyses under the bill. The bill would repeal these provisions on January 1, 2031.	Asm Utilities and Energy
AB 93	Papan	Water resources: demands: artifical intelligence	Energy Demand	This bill would express the intent of the Legislature to enact future legislation that would maintain water and energy efficiency to the extent that new technology, including, but not limited to, artificial intelligence, increases the demands on already limited resources.	Introduced
AB 99	Ta	Electrical corporations: rates.	Affordability	This bill would prohibit an electrical corporation from proposing, and the commission from approving, a rate increase above the rate of inflation, unless the rate increase is approved by a majority of the electrical corporation's customers voting in an election conducted according to specified requirements, and except when the commission determines that the costs underlying the rate increase are directly related to safety enhancements and modernization or to higher commodity or fuel costs.	Asm Utilities and Energy
AB 222	Bauer-Kahan	Data centers: energy usage reporting and modeling.	Data Centers	This bill would require the Energy Commission to require operators of data centers to annually report energy consumption and performance data, as specified. The bill would require the Energy Commission to include energy consumption trends for data centers in its integrated energy policy reports. The bill would require the Energy Commission to adopt energy efficiency performance standards, as described, for data centers. The bill would require the Energy Commission to adopt regulations to implement these requirements on or before January 1, 2027.	Asm Utilities and Energy
AB 267	Macedo	Greenhouse Gas Reduction Fund: high-speed rail: water infrastructure and wildfire prevention	GGRF	This bill would suspend the appropriation to the High-Speed Rail Authority for the 2026–27 and 2027–28 fiscal years and would instead require those amounts from moneys collected by the state board to be transferred to the General Fund. The bill would specify that the transferred amounts shall be available, upon appropriation by the Legislature, to augment funding for water infrastructure and wildfire prevention.	Asm Transportation

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Bill #	Author	Title	Category	Summary	Status
AB 273	Sanchez	Greenhouse Gas Reduction Fund: high-speed rail: infrastructure improvements	GGRF	This bill would eliminate the continuous appropriation of 25% of the annual proceeds of the Greenhouse Gas Reduction Fund to the High-Speed Rail Authority on June 30, 2026. The bill, beginning with the 2026–27 fiscal year, would instead require 25% of the annual proceeds of the Greenhouse Gas Reduction Fund to be transferred to the General Fund and for those moneys, upon appropriation, to be used to augment funding provided to local governments to improve infrastructure.	Asm Transportation
AB 275	Petrie-Norris	Office of Emergency Services: wildfire response: SoCal Edison-funded helitanker	Wildfires	This bill would state the intent of the Legislature to enact legislation to make the SoCal Edison-funded Quick Reaction Force firefighting helitanker program permanent and maintained by the Office of Emergency Services. The bill would make related findings and declarations.	Introduced
AB 286	Gallagher	Electricity: mandatory rate reduction.	Rates	The commission shall reduce the kilowatt-per-hour rate for electricity charged to ratepayers by not less than 30 percent.	Introduced
AB 303	Addis	Battery energy storage facilities	Battery Storage	This bill would prohibit the authorization of a development project that includes a battery energy storage system capable of storing 200 megawatthours or more of energy if the development project is located within 3,200 feet of a sensitive receptor or is located on an environmentally sensitive site, as specified.	Introduced
AB 305	Arambula	Energy: nuclear facilities	Nuclear Power	This bill would exempt small modular reactors, as defined, from those provisions. This bill would require the PUC, on or before January 1, 2028, to adopt a plan to increase the procurement of electricity generated from nuclear facilities and to phase out the procurement of electricity generated from natural gas facilities.	Introduced
AB 306	Schultz and Rivas	Building regulations: state building standards	Building Standards	This bill would, from June 1, 2025, until June 1, 2031, inclusive, prohibit a city or county from making changes to the above-described building standards unless a certain condition is met, including that the commission deems those changes or modifications necessary as emergency standards to protect health and safety. By requiring a city or county to take certain actions relating to building standards, this bill would impose a state-mandated local program.	Asm Housing and Community Development
AB 368	Ward	Energy: building standards: passive house standards	Building Standards	This bill would require the commission to evaluate the passive house energy efficiency standards, and, if appropriate, adopt those standards, or any elements that align with the state's existing requirements, as an alternative compliance pathway for the building efficiency standards established by the Energy Commission.	Introduced
AB 388	Rogers	Electrical corporations and gas corporations	Spot	Spot Bill	Introduced

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Bill #	Author	Title	Category	Summary	Status
AB 420	Petrie-Norris	Public Utilities Commission: proceedings	CPUC	This bill would authorize an interested person to submit a written ex parte communication during a quiet period if the commission modifies, rather than materially modifies, a proposed decision.	Asm Utilities and Energy
AB 434	DeMaio	Construction and safety standards: battery storage facilities	Battery Storage	This bill would state intent of the Legislature to enact subsequent legislation regulating the construction and safety of battery storage facilities.	Introduced
AB 441	Hadwick	Wildfire prevention: Office of Wildfire Technology Research and Development: wildfire	Wildfires	Would repeal provisions related to the Office of Wildifre Technology Research and Development.	Asm Emergency Management
AB 442	Hadwick	California Environmental Quality Act: exemption: prescribed fire, thinning, and fuel reduction	Wildfires	This bill would exempt from CEQA prescribed fire, thinning, or fuel reduction projects undertaken within a community with a single ingress and egress evacuation route.	Asm Natural Resources
AB 443	Bennett	Energy Commission: integrated resource policy report: curtailed solar and wind generation: hydrogen production	Hydrogen	This bill would require the commission, as part of the 2027 edition of the integrated energy policy report, to include an assessment of the potential for using curtailed solar and wind generation to produce hydrogen, as provided. The bill would define curtailed solar and wind generation for this purpose and require the assessment to do specified things, including to provide an estimate of how much hydrogen could feasibly and reliably be produced using energy from curtailed solar and wind generation. The bill would repeal its provisions on January 1, 2029.	Introduced
AB 472	Rogers and Connolly	Energy: offshore wind generation	Offshore Wind	This bill would amend the definition of “infrastructure” described above to include port infrastructure for offshore wind energy development, and would require the 5-year infrastructure plan to include, beginning in the 2027–28 fiscal year, and contingent upon an appropriation for this purpose, an assessment of funding needs for port infrastructure for offshore wind energy development, as specified. The bill would require the Governor, in consultation with specified entities, to assess federal, state, and local funding opportunities, including general obligation bonds and funding from the private sector, that can help build port infrastructure for offshore wind energy development.	Introduced

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Bill #	Author	Title	Category	Summary	Status
AB 526	Papan	Energy: new in-state geothermal energy generation	Geothermal	The bill would require the Energy Commission, on or before June 1, 2026, to evaluate and quantify the maximum feasible capacity of new in-state geothermal energy to achieve reliability, ratepayer, employment, and decarbonization benefits, and to establish megawatt in-state next-generation geothermal planning goals for 2035 and 2045, as specified.	Introduced
AB 527	Papan	California Environmental Quality Act: geothermal exploratory projects	Geothermal	This bill would provide that a geothermal exploratory project, as defined, that the lead agency determines meets specified criteria is conclusively presumed to have satisfied the requirements of CEQA for the geothermal exploratory project, including to support the issuance of any permit, funding, or other approval by a state or local agency, as provided. The bill would require, for a project undertaken by a private entity that satisfies the requirements of CEQA pursuant to this provision, the project applicant to certify to the lead agency that either the entirety of the project is a public work or that certain prevailing wage requirements are satisfied.	Introduced
AB 531	Rogers	Geothermal powerplants and geothermal field development projects: certification and environmental review	Geothermal	This bill would expand the types of facilities eligible to be certified as environmental leadership development projects by the Energy Commission to include geothermal powerplants and geothermal field development projects, as defined.	Introduced
AB 615	Davies	Power facilites: emergency response and action plan	Power Facilities	This bill would require the application to also contain an emergency response and action plan that incorporates impacts to the surrounding areas in the event of an emergency and that would be conducted and coordinated with local emergency management agencies, unified program agencies, and local first response agencies. The bill would require that the plan include analysis and feedback from the local emergency management agencies as to whether the proposed facility requires supplemental first responder capabilities and meets National Fire Association 855 Standard as it relates to setbacks, as specified. The bill would require the plan to be paid for by the applicant.	Introduced
AB 705	Boerner	Public Utilites Comission	CPUC	Spot bill	Introduced
AB 716	Carillo	Energy: Hydrogen Program	Hydrogen	Spot Bill	Introduced

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Bill #	Author	Title	Category	Summary	Status
AB 737	Qurik-Silva	Energy: building decarbonization: notice and recordation of a decarbonization charge	Decarbonization	This bill would additionally add gas corporations to the definition of “energy supplier” for purposes of the above-described provisions.	Introduced
AB 738	Tangipa and Patterson	Energy: building standards: photovoltaic requirements	Building Standards	This bill would, until January 1, 2029, require residential construction intended to repair, restore, or replace a residential building damaged or destroyed as a result of a disaster in an area in which a state of emergency has been proclaimed by the Governor to comply only with the requirements regarding photovoltaic systems pursuant to those regulations, if any, that were in effect at the time the damaged or destroyed building was originally constructed and would prohibit that construction from being required to comply with any additional or conflicting photovoltaic system requirements in effect at the time of repair, restoration, or replacement. The bill would only apply to the construction of a building if certain conditions are met with respect to the building owner’s income and insurance coverage, and to the location and square footage of the construction.	Introduced
AB 740	Harabedian	Integrated energy policy report: virtual power plants	VPP	This bill would require the Energy Commission, as part of the integrated energy policy report, to include modeling of the effects of virtual power plants on electricity costs and rate reduction and to submit to the Legislature a virtual power plant implementation plan that includes goals and milestones. The bill would require each electrical corporation to annually report to the commission its contribution towards meeting the load-shift goal.	Introduced
AB 745	Irwin	Electricity: transmission projects: review and approval	Transmission Projects	This bill would, consistent with the commission’s authority to review and approve new transmission line projects undertaken pursuant to the Independent System Operator planning process, require the commission to review and approve transmission line projects, including the extension, expansion, upgrade, or other modification of existing transmission lines, initiated by an electrical corporation.	Introduced
AB 777	Rodriguez	Electricy Oversight Board	Electricy Oversight Board	This bill would add to the board 2 more nonvoting legislative members, a 2nd member of the Assembly, appointed by the Speaker of the Assembly, and a 2nd member of the Senate, appointed by the Senate Committee on Rules.	Introduced
AB 825	Petrie-Norris	Energy: cost framework: rseidential rates	Rates	This bill would require the PUC to submit an update to that report to the Legislature every two years following the initial submission, providing an evaluation of the implementation and impact of the framework, and the usage of the framework, identifying the specific requests by an electrical corporation or gas corporation for which the framework was employed by the PUC in evaluating the requests.	Introduced

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Bill #	Author	Title	Category	Summary	Status
AB 841	Patel	Business: battery storage	Battery Storage	It is the intent of the Legislature to enact legislation relating to battery storage requirements for private businesses.	Introduced
AB 854	Petrie-Norris	Environmental quality: greenhouse gas emissions: permit streamlining	Permitting	This bill would state the intent of the Legislature to enact subsequent legislation to adopt permit streamlining guidance for projects that will reduce greenhouse gas emissions.	Introduced
AB 864	Ward	Hazardous waste: solar photovoltaic modules	Solar Panel Recycling	This bill would exempt solar photovoltaic modules not identified as hazardous waste and treated as universal waste, as defined, from state hazardous waste regulations, if transferred to a designated recycler for legitimate recycling, as described, and if the facility meets specified criteria relating to registration permits, as provided.	Introduced
AB 881	Petrie-Norris	Carbon Capture, Removal, Utiliziation, and Storage Program	Carbon Capture, Removal, Utiliziation, and Storage Program	Spot Bill	Introduced
AB 884	Essayli	Campaign contributions: investor-owned utilities	IOU	This bill would prohibit an investor-owned utility from making a contribution to a candidate for elective state office and would prohibit a candidate for elective state office from accepting a contribution from an investor-owned utility.	Introduced
AB 915	Petrie-Norris	Clean Energy Reliability Investment Plan	Clean Energy Reliability Investment Plan	This bill would appropriate $900,000,000 from the General Fund to the commission for the 2025–26 fiscal year to be allocated for the Clean Energy Reliability Investment Plan for local incentive grants to increase investment in clean energy infrastructure.	Introduced
AB 941	Zbur	California Environmental Quality Act: electrical infrastructure projects	CEQA	This bill would require the commission to determine whether to certify the environmental impact report for an electrical infrastructure project that is a priority project, as defined, no later than 270 days after the commission determines that an application for an electrical infrastructure project is complete, except as specified.	Introduced
AB 942	Calderon	Public utilities: rates	Rates	Spot Bill	Introduced
AB 1016	Gonzalez	California Renewables Portfolio Standard Program	RPS	Spot Bill	Introduced

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Bill #	Author	Title	Category	Summary	Status
AB 1017	Boerner	Public utilities: electrical and gas corporations: distribution capacity	Distribution Capacity	This bill would require electrical or gas corporations, in a report required to be submitted annually to the commission, to include in the report the capacity of its electrical or gas distribution system, respectively.	Introduced
AB 1020	Schiavo	Wildfire Fund	Wildfire Fund	Spot Bill	Introduced
AB 1104	Pellerin	Solar energy resources	Solar	It is the intent of the Legislature to enact legislation relating to solar energy resources.	Introduced
AB 1117	Schultz	Electricity rates: optional dynamic rate tariffs	Rates	This bill would require the commission, through a new or existing proceeding, to develop optional dynamic rate tariffs applicable to each large electrical corporation for the large electrical corporation's commercial and industrial customers on or before July 1, 2028, and for its other customers, including residential customers, on or before July 1, 2030. The bill would require each optional dynamic rate tariff to include, at minimum, specified components, including dynamic transmission and distribution rates that reflect real-time grid conditions and certain nonbypassable charges, as specified.	Introduced
AB 1156	Wicks	Agricultural land use: conversion to solar-use easements	Solar	This bill would, instead, require the right or interest in the parcel acquired by the city or county described above to be for a term of years, rather than an indefinite period, and the covenant with the county or city contained in the easement described above to run with the land for a term of years, rather than indefinitely. The bill would make these changes applicable only to easements rescinded and converted to solar use pursuant to these provisions after January 1, 2026.	Introduced
AB 1167	Berman	Public utilities: rates	Rates	Spot Bill	Introduced
AB 1174	Alanis	Clean Transportation Program: eligible programs and projects: electrical vehicle	EVSE	This bill would add to the categories of programs and projects eligible for funding under the Clean Transportation Program programs and projects to deter and combat vandalism of publicly available electric vehicle charging stations.	Introduced
AB 1180	Valencia	Public utilities: rates	Rates	Spot Bill	Introduced

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Bill #	Author	Title	Category	Summary	Status
AB 1207	Irwin	Climate change: market-based compliance mechanism	Cap-and-Trade	This bill would state the intent of the Legislature to enact subsequent legislation to reauthorize the California Greenhouse Gas Cap-and-Trade Program.	Introduced
AB 1222	Bauer-Kahan	Public utilities: judicial review	IOUs	This bill would prohibit the commission from authorizing electrical corporations to recover from their ratepayers the costs associated with seeking judicial review of a commission's decision from a federal agency, or a state or federal court. The bill would require the electrical corporation to track those costs.	Introduced
AB 1223	Nguyen and Krell	Public utilities	IOUs	It is the intent of the Legislature to enact subsequent legislation related to public utilities.	Introduced
AB 1228	Essayli	Electricity: expedited utility distribution infrastructure undergrounding program	Infrastructure	This bill would specify that the approval of a distribution infrastructure undergrounding plan is not a project for purposes of the California Environmental Quality Act, as specified.	Introduced
AB 1238	DeMaio	Energy: gas stoves	Electrification	This bill would prohibit state agencies and local governments from adopting or enforcing a rule, regulation, resolution, or ordinance that directly or indirectly results in prohibiting the use of gas stoves in residential or nonresidential buildings.	Introduced
AB 1260	Ward	Electricity: renewable energy subscription programs	Community Renewables	The bill would require the PUC, on or before March 1, 2026, to modify the community renewable energy program to ensure the program meets the bill's requirements or to adopt a new program and to adopt a final decision by September 1, 2026. The bill would require the State Energy Resources Conservation and Development Commission to evaluate community solar and storage projects as a load-modifying resource so that those projects may be counted as a load-modifying resource.	Introduced
AB 1273	Patterson	Public utilities: electricity rates	Rates	This bill would prohibit the commission from placing the consideration of an application from an electrical corporation for a rate increase on its consent calendar.	Introduced

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Bill #	Author	Title	Category	Summary	Status
AB 1280	Garcia	Energy	Energy	This bill would authorize the I-bank to provide financial assistance in connection with the financing or refinancing of a new category of climate catalyst projects, those that enable the decarbonization of industrial facilities' use of heat and power, including, but not limited to, industrial heat pump and thermal energy storage projects, as specified, with the State Energy Resources Conservation and Development Commission and the State Air Resources Board as consulting agencies. This bill would establish and implement an Industrial Facilities Thermal Energy Storage Program within the Long-Duration Energy Storage Program to provide financial incentives for eligible projects to decarbonize industrial facilities' use of heat and power, as specified.	Introduced
AB 1285	Committee on Emergency Management	State Fire Marshal: lithium-ion battery facilities: guidance	Battery Storage	This bill would require the State Fire Marshal, in consultation with the Office of Emergency Services, to develop fire prevention, response, and recovery measures for utility grade lithium-ion battery storage facilities, as specified.	Introduced
AB 1295	Patterson	Public utilities: billing statements: additional costs attributable to state requirements or programs	Billing	This bill would require each public utility to provide to its customers information on the additional costs that are attributable to state requirements or programs, including those imposed by statute, regulation, the commission, or the State Energy Resources Conservation and Development Commission. The bill would require this information to be provided quarterly on the customer billing statement in a visible area and in a similar size and font as the billing information.	Introduced
AB 1301	Petrie-Norris	Electricity: Power Exchange	Power Exchange	This bill would abolish the Power Exchange and would make various conforming changes.	Introduced
AB 1302	Wallis	Puiblic utilities: rates	Rates	Spot Bill	Introduced
AB 1334	Wallis	Solar energy: official state energy	Solar	This bill would establish solar energy as the official state energy.	Introduced
AB 1342	Soria	Electricity: rates	Rates	This bill would declare the intent of the Legislature to enact subsequent legislation to establish policies to reform the regulation of electricity rates for residential customers.	Introduced
AB 1347	Carrillo	Electrical modernization zones	Electrical modernization zones	This bill would state the intent of the Legislature to enact subsequent legislation that would create electric modernization zones in order to meet the needs of high-growth economic areas throughout the state, as specified	Introduced

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Bill #	Author	Title	Category	Summary	Status
AB 1372	Papan	Electricity: electrified commuter railroads: regenerative braking: net energy	Rates	This bill would state the intent of the Legislature to enact subsequent legislation that would require an electrical corporation, electric service provider, or community choice aggregator and an operator of an electrified commuter railroad that produces electricity through the regenerative braking of electric trains, including the Peninsula Corridor Joint Powers Board, to, upon completing certain technical studies, adopt or modify a tariff or contract that requires the electrical corporation, electric service provider, or community choice aggregator to bill the operator only for its net energy.	Introduced
AB 1404	Ortega	Electrical Corporations: connections: affordable housing projects	Rates	This bill would require an electrical corporation to connect an affordable housing project, as defined, to the electrical distribution grid within 60 days, except as specified. The bill would require the commission to streamline any necessary review on an affordable housing project that is ready to connect but sitting vacant and that has not been connected by an electrical corporation within the required 60 days. The bill would delay the effective date of a rate increase approved by the commission for the greater of either the amount of time the electrical corporation took, beyond 90 days from receipt of the project building plans, to provide a final contract, or the amount of time the electrical corporation took, beyond the 60 days allowed, to connect the most recently completed affordable housing project within the electrical corporation's service area.	Introduced
AB 1408	Irwin	Electricity: rates	Rates	This bill would require that the customer be provided with no less than 2 years, instead of one year, of bill protection during which the total amount paid by the residential customer for electric service is prohibited from exceeding the amount that would have been payable by the residential customer under that customer's previous rate schedule.	Introduced
AB 1410	Garcia	Public utilities: service outages and updates: alerts	Outages	This bill would require each public utility to automatically enroll customers in alerts for service outages and updates. The bill would require customers to be provided with the opportunity to opt-out of any alerts the customer does not wish to receive, except as provided. The bill would require each public utility to annually verify a customer's preferred contact method.	Introduced
AB 1423	Irwin	Transportation electrification: charging station uptime: regulatiosn: violations	EVSE	This bill would instead require the Energy Commission, in consultation with the Public Utilities Commission, to adopt tools to increase uptime for all charging stations and set standards for how all charging stations are required to notify customers about the availability and accessibility of publicly available charging infrastructure.	Introduced

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Bill #	Author	Title	Category	Summary	Status
AB 1436	Avila Farias	Biomethane procurement targets	Biomethane	This bill would instead require that biomethane delivered to California through a common carrier pipeline meet either of the specified requirements, rather than both. The bill would also additionally add the displacement of conventional natural gas that results in a reduction in greenhouse gas emissions as one of the specified environmental benefits.	Introduced
AB 1484	Bennett	Energy reliability	Spot	Spot Bill	Introduced
SB 24	McNerney	Electrical and gas corporations.	Spot	Spot Bill	Referred to Com. On RLS.
SB 57	Padilla	Data centers: rates.	Data Centers	This bill, the Ratepayer and Technological Innovation Protection Act, would require the commission, on or before July 1, 2026, to establish a special rate structure for data centers, as defined, that, among other things, protects residential ratepayers and small businesses and prevents cost shifts to those existing ratepayers and ensures electrical grid investments to serve data centers are fully recovered, as specified.	Senate E. U. & C.
SB 58	Padilla	Sales and Use Tax Law: exemptions: certified data center facilities	Data Centers	This bill would, on and after January 1, 2025, provide a partial exemption from those taxes with respect to the gross receipts from the sale, storage, use, installation, assembly, repair, maintenance, or other consumption of data center equipment, as defined, used at or for the benefit of a certified data center facility, as defined. The bill would require a data center facility to meet specified requirements in order to receive certification from the California Department of Tax and Fee Administration, including requirements relating to job creation, investment, and renewable energy procurement requirements. The bill would require the department to revoke certification where a data center facility obtains certification and subsequently fails to meet these requirements after reasonable opportunity for the data center facility to cure noncompliance, as provided.	Senate REV. & TAX
SB 80	Caballero	The Fusion Research and Development Innovation Hub Program.	Fusion	This bill would create the Fusion Research and Development Innovation Hub Program within GO-Biz to accelerate the development and growth of fusion energy by advancing fusion science and technology with the goal of delivering the world's first fusion energy pilot plant in the state by 2040. The bill would require, among other things, GO-Biz to designate fusion research and development innovation hubs considering certain factors for advancing research and development diversity, including a network of hubs in geographically diverse regions that reflects the distribution of California's diverse workforce and energy needs.	Senate B., P. & E.D.

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Bill #	Author	Title	Category	Summary	Status
SB 86	McNerney	California Alternative Energy and Advanced Transportation Financing Authority Act: sales and use tax exclusion.	Fusion	This bill would extend indefinitely the authorization to provide financial assistance in the form of a sales and use tax exclusion for projects approved by the authority. The bill would increase the maximum cumulative amount of the sales and use tax exclusions authorized under these provisions to $300,000,000 per calendar year. The bill would add electrical generation facilities using nuclear fusion technology to the types of projects qualifying for this sales and use tax exclusion. The bill would make other conforming changes.	Senate REV. & TAX
SB 88	Caballero	Air resources: carbon emissions: biomass.	Biomass	This bill would require the state board, on or before January 1, 2027, to finalize the standardized system and historic baseline described above. The bill would require the state board, on or before January 1, 2028, to adopt a method of quantification or a lifecycle model for avoided carbon emissions, including, but not limited to, carbon dioxide, methane, and black carbon, from wildfire from the application of prescribed fire to forest biomass resources and agricultural biomass resources, and to develop a carbon credit or offset protocol for biochar and other beneficial carbon-removal products that result from the avoidance of megafires and prescribed fire using existing methodologies.	Senate E.Q.
SB 239	Arreguin	Open meetings: teleconferencing: subsidiary body	Teleconferencing	This bill would authorize a subsidiary body, as defined, to use alternative teleconferencing provisions and would impose requirements for notice, agenda, and public participation, as prescribed. The bill would require the subsidiary body to post the agenda at the primary physical meeting location. The bill would require the members of the subsidiary body to visibly appear on camera during the open portion of a meeting that is publicly accessible via the internet or other online platform, as specified. The bill would also require the subsidiary body to list a member of the subsidiary body who participates in a teleconference meeting from a remote location in the minutes of the meeting.	Sen Local Government
SB 252	Valladares	CEQA: exemption: undegrounding powerlines	CEQA	This bill would exempt from the provisions of CEQA a project to underground powerlines.	Sen Environmental Quality
SB 254	Becker	Electrical Corporations: nonbypassable charge	Spot	Spot Bill	Referred to Com. On RLS.

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Bill #	Author	Title	Category	Summary	Status
SB 256	Perez	Electricity: electrical infrastructure	Infrastructure	This bill would state the intent of the Legislature to enact legislation to enhance the resiliency and reliability of California's electrical infrastructure in areas prone to wildfires, earthquakes, and other natural disasters by requiring electrical utilities to prioritize the undergrounding of power lines, the implementation of microgrid technologies, and the strengthening of public safety power shutoff standards and accountability, while ensuring the utilization of labor standards that promote a skilled workforce, and providing the commission with the ability to immediately access all relevant electrical fault data related to natural disasters.	Referred to Com. On RLS.
SB 282	Wiener	Residential heat pump systems: water heaters and HVAC: installations	Heat Pumps	This bill would require the commission, on or before January 1, 2027, to establish a statewide certification program for licensed contractors of residential heat pump water heaters and heat pump heating, ventilation, and air conditioning (HVAC) systems to obtain a heat pump installation certification, and would require the commission to create a state training program, as described, on residential heat pump water heaters and heat pump HVAC systems for purposes of the certification program, as specified.	Senate E. U. & C.
SB 283	Laird	Battery Energy storage facilities: emergency response plans and emergency action plans	Battery Storage	Spot Bill	Referred to Com. On RLS.
SB 285	Becker	Net zero greenhouse gas emissions goal: carbon dioxide removal: regulations	GHG Emissions	This bill would, for the purpose of meeting, or tracking progress against, any state requirement to achieve net zero emissions of greenhouse gases, or for the purpose of reporting offsets against any of a reporting entity's greenhouse gas emissions as part of reporting required pursuant the Climate Corporate Data Accountability Act, authorize only qualified carbon dioxide removal, as defined, to be used to reduce the state's or an entity's greenhouse gas emissions and would require qualified carbon dioxide removal used for those purposes to meet certain requirements, as specified.	Sen Environmental Quality
SB 298	Caballero	State Energy Resources Conservation and Development Commission: seaports: plan: alternative fuels	Alternative Fuels	This bill would require the State Energy Resources Conservation and Development Commission (Energy Commission), in coordination with the Transportation Agency and the state board, to develop a plan on or before December 31, 2030, for the use and deployment of alternative fuels at California's public seaports, as provided. The bill would require the Energy Commission to convene a working group to advise the Energy Commission on the development of information required by the plan, as specified.	Senate E. U. & C.

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Bill #	Author	Title	Category	Summary	Status
SB 302	Padilla	Personal Income Tax Law and Corporation Tax Law: exclusions: environmental credits	Tax Credits	This bill, in conformity with federal law, for taxable years beginning on or after January 1, 2023, would exclude from gross income a refund payment made for the specified federal environmental credits described above and any payment received by a transferor as consideration for a transfer, as provided. The bill would also prohibit a transferee from deducting the amount paid as consideration for the transfer, in conformity with federal law.	Sen Revenue and Taxation
SB 314	Padilla	Weights and measures: electric vehicle supply equipment	EVSE	This bill would authorize an EVSE that has been audited or tested by the manufacturer or supplier to be used commercially without further testing during the remainder of the inspection period adopted by the Secretary of Food and Agriculture, but not until it has been sealed by a sealer. The bill would, until January 1, 2028, among other things, exempt an EVSE installed in a workplace for the exclusive use of its employees, or installed in a residence, including a multifamily residential dwelling, for the exclusive use of the residents, from specified laws, and would authorize an EVSE, following installation, to be used in connection with the sale of electricity as a motor vehicle fuel without being placed into service by a service agency or sealer, a specified. The bill would authorize a county to take specified actions in order to support county oversight of EVSE and build capacity. The bill would require the Division of Measurement Standards to develop an optional pathway for compliance with specified laws using factory auditing and inspection for the EVSE, and to consider specified information when developing the pathway for compliance.	Sen Business, Professions and Economic Development
SB 326	Becker and Laird	Wildfire safety: The California Wildfire Mitigation Strategic Planning Act	Wildfires	This bill would require the deputy director, on or before January 1, 2027, and every 3 years thereafter, to prepare a Wildfire Risk Mitigation Planning Framework sufficient to quantitatively evaluate wildfire risk mitigation actions, as provided. The bill would require the framework to allow for geospatial evaluation and comparison of wildfire risk mitigation actions, as defined, sufficient to direct coordinated mitigation efforts and long-term collaborative mitigation planning. The bill would require the deputy director to, each year the framework is completed, submit a copy of the framework to the Legislature, the Office of Energy Infrastructure Safety, and the Public Utilities Commission for review and consideration.	Sen Governmental Organization
SB 327	McNerney	Nuclear fusion: research data sharing	Nuclear	This bill would state the intent of the Legislature to enact subsequent legislation that would develop standards for nuclear fusion research data sharing.	Referred to Com. On RLS.

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Bill #	Author	Title	Category	Summary	Status
SB 330	Padilla	Electrical transmission infrastructure: finacning	Transmission	This bill would authorize the Governor to establish one or more pilot projects to develop, finance, or operate electrical transmission infrastructure that meet the specified criteria, including, among other things, that the transmission line is identified by the Independent System Operator in its transmission planning process as necessary to support clean energy generation to meet the state's clean energy goals. The bill would require the Governor to designate existing state agencies, local public agencies, tribal organizations, or joint powers authorities to implement the pilot projects. The bill would authorize the pilot projects to develop, finance, operate, and maintain electrical transmission lines and all works, facilities, improvements, and property, or portions thereof, necessary or convenient for the conveyance of electricity, as specified. The bill would authorize the Governor to issue guidelines regarding application and certification of pilot projects.	Senate E. U. & C.
SB 331	Padilla	State Energy Resources Conservation and Development Commission: certifcation of facilities: electrical transmission projects	Transmission	The bill would authorize an electrical corporation that files an application with the PUC to authorize the new construction of any electrical transmission facility to simultaneously submit to the Energy Commission an application for certification of the facility, as specified. The bill would authorize the Energy Commission to recover the reasonable administrative costs incurred from evaluating an application, as specified. The bill would provide that the Energy Commission's certification of a facility proposed by an electrical corporation satisfies and replaces the PUC's obligations under CEQA with respect to that facility. The bill would prohibit the PUC from approving an application until after the Energy Commission has issued a decision on certification of the proposed facility. Because these provisions would be part of the Public Utilities Act and a violation of these requirements or a PUC action implementing these requirements would be a crime, the bill would impose a state-mandated local program.	Senate E. U. & C.

Orange County Power Authority 2025 California Bill Tracker

Updated 2/25/2025

Bill #	Author	Title	Category	Summary	Status
SB 332	Wahab	Investor-Owned Utilities Accountability Act	IOU Oversight	**1)** This bill would require the Energy Commission, in coordination with the public advisor and the Public Utilities Commission (PUC), on or before March 31, 2026, to issue a request for proposals for a team to develop a study. The bill would require the study to (1) conduct a historical energy justice assessment of the investor-owned utility's (IOU) operations and impacts, (2) complete a comparative analysis of the benefits and challenges of transitioning the IOUs to a successor entity in order to identify a recommended model, and, (3) if the study finds that it is in the best long-term interests of the people and ecologies of California to transition away from an investor-owned utility model, create a justice-centered implementation plan for managing the transition. **2)** This bill would, among other things, prohibit a utility, including an electrical corporation, local publicly owned electric utility, gas corporation, and local publicly owned gas utility, from disconnecting a customer's residential service for nonpayment if the customer has a household income at or below 200% of the federal poverty line. The bill would prohibit a utility from disconnecting a customer's residential service for nonpayment if the customer's household is the residence of certain persons, including, among other persons, a person who is pregnant or 0 to 12 weeks postpartum. **3)** This bill would require each electrical corporation, on or before April 1, 2026, to submit a proposed executive compensation structure to the PUC that is structured to promote safety as a priority and to ensure public safety through performance metrics, as provided. **4)** This bill would prohibit, for proposed rate increases subject to PUC approval and a finding that the new rate is just and reasonable, an electrical corporation from proposing a compounded annual rate increase on residential customers above the increase in the Consumer Price Index. **5)** Beginning with the fiscal year commencing July 1, 2026, and ending with the fiscal year ending June 30, 2036, this bill would require the PUC to annually allocate $100,000,000 of the revenues received by the electrical corporations from that allocation of greenhouse gas allowances to the Transformative Climate Communities Program and to the Community Resilience Center Program, as specified. **6)** This bill would require each electrical corporation to annually contract with an independent and reputable third party to audit all of the electrical corporation's equipment and electrical lines and identify any equipment or electrical lines that have outlived their useful life.	Introduced
SB 348	Hurtado	State Air Resources Board: Low-Carbon Fuel Standard	LCFS	This bill would state the intent of the Legislature to enact future legislation that would, among other things, require the board to revise the Low-Carbon Fuel Standard program, as provided. The bill would make related findings and declarations.	Referred to Com. On RLS.

Orange County Power Authority 2025 California Bill Tracker

Updated 2/25/2025

Bill #	Author	Title	Category	Summary	Status
SB 371	Cabaldon	Electrical and gas corporations: new construction: application: analysis of greenhouse gases	GHG Emissions	This bill would require the application to also include an analysis of the greenhouse gas emissions associated with the project over the useful life of the plant, line, or extension.	Introduced
SB 377	Grayson	Biomethane procurement targets	Biomethane	This bill would instead require that biomethane delivered to California through a common carrier pipeline meet either of the specified requirements, rather than both. The bill would also additionally add the displacement of conventional natural gas that results in a reduction in greenhouse gas emissions as one of the specified environmental benefits.	Introduced
SB 500	Stern	Energy: reliability planning assessment: integrated energy policy report	IEPR	This bill would require that the assessment also include the status of utility transmission upgrades and electrical grid infrastructure capacity, PUC approvals of applications for certificates of public convenience and necessity and permits to construct utility and independent projects, and applications for permits for projects from the Energy Commission and the queue of projects from the Independent System Operator, include the expected completion dates for both system and local resources, and report on the use of fossil fuel by certain facilities constructed by, purchased by, or under contract with the Department of Water Resources, as specified. The bill would require the Energy Commission to quarterly publish on its internet website and update a tracking energy development dashboard that synthesizes and publishes the information included in the assessment and reported on California energy resources in the energy almanac.	Introduced
SB 533	Richardson	Electric vehicle charging stations: internet based applications	EVSE	This bill would create an exception to the above-described provisions that authorizes an electric vehicle charging station to require that payment for charging services be made through the use of an internet-based application and require the use of that internet-based application for admission to the premises.	Introduced
SB 540	Becker and Stern	Independent System Operator: independent regional organization	Regional Organization	This bill would delete the above-described provisions providing for the transformation of the ISO into a regional organization. The bill would authorize the ISO and the electrical corporations that are participating transmission owners whose transmission systems are operated by the ISO, in lieu of the ISO managing related energy markets, as provided, to use energy markets governed by an independent regional organization, provided that specified requirements are satisfied.	Introduced

Orange County Power Authority 2025 California Bill Tracker

Updated 2/25/2025

Bill #	Author	Title	Category	Summary	Status
SB 559	Stern	Electricity: deenergization events: communications	Deenergization events	This bill would require, at the start of a deenergization event, an electrical corporation to immediately notify local emergency management organizations and local utility districts about the impacts of the deenergization, as specified. The bill would require detailed status information on restoration efforts to be made available to emergency management organizations, public safety officials, customers, and the public in real-time, with regular progress updates issued at intervals of no more than 12 hours, for all impacted circuits, as specified.	Introduced
SB 593	Hurtado	Power surges: ratepayer notice	Notice	This bill would require a utility, which includes a community choice aggregator, an electrical corporation, and a local publicly owned electric utility, to develop and implement a system to notify a ratepayer of a power surge, as defined. The bill would require the notification to be transmitted within 5 minutes of detecting a power surge and to include specified information. The bill would also require a preemptive warning of a power surge, as provided, under specified circumstances. The bill would require a utility to install and maintain equipment capable of detecting power surges and to submit quarterly reports to the commission regarding power surges, as provided. The bill would require a utility to compensate a ratepayer for damages to electrical systems, appliances, or devices caused by a power surge if the power surge resulted from utility equipment failure or negligence, to process claims for compensation within 30 days of receipt, and to offer financial incentives or rebates for the installation of whole-house surge protection systems by ratepayers.	Introduced
SB 620	Stern	Public utilities: general rate cases: electrical grid infrastructure	General Rate Cases	This bill would require the commission to prioritize the gathering, analysis, and independent verification of utility data used to justify general rate case proposals to ensure the cost-effective use of ratepayer funds for capital investments in electrical distribution and transmission grid infrastructure and the operation and maintenance of that infrastructure.	Introduced
SB 636	Menjivar	Electrical or gas corporations: deferment of payments: hardship	Disconnections	This bill would prohibit an electrical or gas corporation from disconnecting service of a customer who meets certain criteria, including making a hardship request based on certain circumstances, as provided. The bill would require the corporation to grant that customer a 6-month deferment for any and all payments due from the date that the deferment is granted. Upon the expiration of the deferment period, the bill would require the corporation to enroll the customer into its arrearage management program for any and all debts on the customer's account. The bill would authorize the commission to adopt rules to implement these provisions.	Introduced

Orange County Power Authority 2025 California Bill Tracker

Updated 2/25/2025

Bill #	Author	Title	Category	Summary	Status
SB 708	Alvarado-Gil	Public Utilities Commission: quorum for the transaction of business	CPUC	Spot Bill	Introduced
SB 710	Blakespear	Property taxation: active solar energy systems: extension	Solar	Under existing property tax law, this exclusion remains in effect only until there is a subsequent change in ownership, but an active solar energy system that qualifies for the exclusion before January 1, 2027, will continue to receive the exclusion until there is a subsequent change in ownership. Existing law repeals these exclusion provisions on January 1, 2027. This bill would, beginning with the 2026–27 fiscal year, extend the exclusion indefinitely, and would limit the exclusion to customer-sited active solar energy systems, as defined.	Introduced
SB 714	Archuleta	Zero-emission vehicles: workforce development: Clean Energy Workforce Training Council	Workforce Development	This bill would state the intent of the Legislature to enact legislation that would establish a zero-emission vehicle workforce development pilot project and a Clean Energy Workforce Training Council, as provided.	Introduced
SB 752	Richardson	Sales and use taxes: exemtions: California Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project: transit	Tax on ZE Buses	The Sales and Use Tax Law provides various exemptions from those taxes, including, until January 1, 2026, an exemption from those taxes with respect to the sale in this state of, and the storage, use, or other consumption in this state of, specified zero-emission technology transit buses sold to specified public agencies that are eligible for specified incentives from the State Air Resources Board. This bill would extend the exemption for specified zero-emission technology transit buses until January 1, 2028.	Introduced
SB 755	Blakespear	California Procurement Climate Information Act	California Procurement Climate Information Act	This bill, the California Procurement Climate Information Act, would require the department, beginning January 1, 2027, to require a large contractor and significant contractor, as defined, to report their greenhouse gas emissions and climate-related financial risk, as specified. The bill would require the report to include, for large contractors, an annual disclosure of scope 1 emissions, scope 2 emissions, scope 3 emissions, and climate-related financial risk, as specified, and for significant contractors, an annual disclosure of scope 1 emissions and scope 2 emissions, as specified.	Introduced
SB 782	Perez	Enhanced infrastructure financing district	Enhanced infrastructure financing district	This bill would make additional findings and declarations that public benefits will accrue if local agencies, excluding schools, are provided a means to, among other things, mitigate wildfires by financing heavy equipment for vegetation clearance, undergrounding of local publicly owned electric utilities, and other firefighting equipment.	Introduced

Orange County Power Authority 2025 California Bill Tracker

Updated 2/25/2025

Bill #	Author	Title	Category	Summary	Status
SB 787	McNerney	Energy: Task Force on Equitable Clean Energy Supply Chains and Industrial Policy in California	Task Force on Equitable Clean Energy Supply Chains	This bill would require the commission, on or before March 1, 2026, to designate a person, within the commission, to serve as the Senior Counselor on Industrial Policy and Clean Energy Development and would specify the senior counselor's duties. The bill would require the senior counselor, on or before March 1, 2026, to convene the Task Force on Equitable Clean Energy Supply Chains and Industrial Policy in California, as provided, and would specify the duties and responsibilities of the task force. The bill would require the task force, on or before June 1, 2027, to submit to the Legislature a report on, among other things, its recommendations on strategies that would maximize the impact of state funds on promoting certain clean energy industries. The bill would require the Senior Counselor on Infrastructure, upon the issuance of the report, but on or before January 1, 2028, to convene certain state agencies to develop a workplan to implement the recommendations made in the report.	Introduced
SB 801	Hurtado	Greenhouse gases: reduction	GHG Emissions	This bill would state the intent of the Legislature to enact subsequent legislation that would require the state to consider any potential cost burden to Californians as it works on achieving its climate goals, including its greenhouse gas emissions goals and standards under the California Global Warming Solutions Act of 2006.	Introduced
SB 803	Durazo	California Conservation Corps: Green Collar Certification Program	California Conservation Corps	This bill would require the Director of the California Conservation Corps to establish a Green Collar Certification Program that provides young persons participating in the corps with skills and education relating to reducing carbon emissions in residential and nonresidential buildings, preparing communities for environmental disasters, and developing conservation infrastructure projects that stabilize shorelines and restore ecological habitats, as provided.	Introduced
SB 810	Dahle	Electricity: ratepayer-funded programs: reports	Reporting	Existing law requires the State Energy Resources Conservation and Development Commission (Energy Commission) to administer various programs, such as the Electric Program Investment Charge program, that are funded by a charge on electrical ratepayers. Existing law requires the Public Utilities Commission (PUC) to require electrical corporations to implement various programs, such as energy efficiency programs, that are funded by electrical ratepayers. Under its authority, the Governor has issued an executive order directing the Energy Commission and the PUC to examine electrical ratepayer-funded programs under their respective jurisdictions and to identify programs and regulations that may be unduly adding to electricity rates for which the benefits provided may not be justified by the costs imposed on electrical ratepayers. The executive order requires those 2 commissions to report back to the Governor by January 1, 2025. This bill would require the Energy Commission and the PUC, by July 1, 2025, to each submit to the Legislature a report containing certain information required by the executive order.	Introduced

Orange County Power Authority 2025 California Bill Tracker

Updated 2/25/2025

Bill #	Author	Title	Category	Summary	Status
SB 836	Rubio	Electricity: transmission planning and permitting	Transmission	Existing law requires the Energy Commission and PUC, in coordination with the Independent System Operator, every 5 years, to review and update, as necessary, the memorandum of understanding and a related workplan to ensure the memorandum and workplan reflect the coordination that is needed to help meet the state's energy goals. This bill would require those entities to review and update, as necessary, the memorandum every 3 years, rather than every 5 years.	Introduced
SB 840	Limon and McGuire	Greenhouse gases: market-based compliance mechanism	Cap-and-Trade	This bill would state the intent of the Legislature to enact subsequent legislation to reform, and extend the operation of, the market-based compliance mechanism.	Introduced
SB 842	Stern	Energy: firm zero-carbon resources	Zero-Carbon Resources	This bill would state that it is the intent of the legislature to enact future legislation to support the deployment of firm zero-carbon energy resources in order to enhance local reliability, improve grid resilience, and reduce ongoing ratepayer costs.	Introduced

SENATE BILL No. 540

Introduced by Senators Becker and Stern

February 20, 2025

An act to amend Section 337 of, to add Section 345.6 to, to repeal Section 352 of, and to repeal Article 4 (commencing with Section 355) of, Article 5 (commencing with Section 359) of, and Article 5.5 (commencing with Section 359.5) of, Chapter 2.3 of Part 1 of Division 1 of, the Public Utilities Code, relating to electricity.

LEGISLATIVE COUNSEL'S DIGEST

SB 540, as introduced, Becker. Independent System Operator: independent regional organization.

Existing law provides for the establishment of an Independent System Operator (ISO) as a nonprofit public benefit corporation and requires the ISO to ensure efficient use and reliable operation of the electrical transmission grid consistent with achieving planning and operating reserve criteria no less stringent than those established by the Western Electricity Coordinating Council and the North American Electric Reliability Council. Existing law, the Clean Energy and Pollution Reduction Act of 2015, provides for the transformation of the ISO into a regional organization, with the approval of the Legislature, pursuant to a specified process. That process provides that modifications to the ISO's governance structure, through changes to its bylaws or other corporate governance documents, will not become effective until the ISO, the Public Utilities Commission, the State Energy Resources Conservation and Development Commission, the State Air Resources Board (state board), the Governor, and the Legislature take specified actions on or before January 1, 2019.

This bill would delete the above-described provisions providing for the transformation of the ISO into a regional organization. The bill

would authorize the ISO and the electrical corporations that are participating transmission owners whose transmission systems are operated by the ISO, in lieu of the ISO managing related energy markets, as provided, to use energy markets governed by an independent regional organization, provided that specified requirements are satisfied. The bill would authorize the ISO, on or after January 1, 2027, to implement tariff modifications accepted by the Federal Energy Regulatory Commission to operate the energy markets whose rules are governed by an independent regional organization if the governing board of the ISO adopts a resolution, as specified, finding that each of the specified conditions have been, or will be, adopted by the independent regional organization. The bill would require the ISO to maintain the necessary technical capability to operate energy markets, as specified, and would require the ISO to continue its functions and responsibilities as a balancing authority, as provided.

Existing law requires the Power Exchange to provide an efficient competitive auction, open on a nondiscriminatory basis to all suppliers, that meets the loads of all exchange customers at efficient prices, and authorizes the Power Exchange governing board to form appropriate technical advisory committees composed of market and nonmarket participants to advise the governing board on relevant issues.

This bill would delete these provisions.

Vote: majority. Appropriation: no. Fiscal committee: yes. State-mandated local program: no.

The people of the State of California do enact as follows:

SECTION 1. Section 337 of the Public Utilities Code is amended to read:

337. (a) The Independent System Operator governing board shall ~~be composed of~~ *comprise* a five-member independent governing board of directors appointed by the Governor and subject to confirmation by the Senate. Any reference in this chapter or in any other provision of law to the Independent System Operator governing board means the independent governing board appointed under this subdivision.

(b) A member of the independent governing board appointed under subdivision (a) may not be affiliated with any actual or potential participant in any market administered by the Independent System Operator.

(c) (1) All appointments shall be for three-year terms.

(2) There is no limit on the number of terms that may be served by any member.

(d) The Oversight Board shall require the articles of incorporation and bylaws of the Independent System Operator to be revised in accordance with this section, and shall make filings with the Federal Energy Regulatory Commission as the Oversight Board determines to be necessary.

(e) For ~~the~~ purposes of the initial appointments to the Independent System Operator governing board, as provided in subdivision (a), the Governor shall appoint one member to a one-year term, two members to a two-year term, and two members to a three-year term.

~~(f) This section becomes inoperative on the date on which the governance modifications set forth in Section 359.5 become effective and is repealed on January 1 of the following year.~~

SEC. 2. Section 345.6 is added to the Public Utilities Code, to read:

345.6. (a) In lieu of the Independent System Operator managing related energy markets as provided in subdivision (b) of Section 345.5, the Independent System Operator and the electrical corporations that are participating transmission owners whose transmission systems are operated by the Independent System Operator may use energy markets governed by an independent regional organization if all of the following requirements are satisfied:

(1) The independent regional organization is a nonprofit corporation whose governance documents include a corporate obligation to respect the authority of each state that has a load-serving entity or balancing authority participating in the market to set its own procurement, environmental, reliability, and other public interest policies.

(2) The governing board of the independent regional organization maintains a public policy committee consisting of members of the governing board of the independent regional organization that engages with states, local power authorities, and federal power marketing administrations about potential impacts to state, local, or federal policies before it approves a tariff change for filing at the Federal Energy Regulatory Commission.

(3) The governing board of the independent regional organization maintains a relationship with and seeks input from a body of state regulators or similar body to receive the views of state regulators.

(4) The independent regional organization makes funding available for a consumer advocate organization that represents the interests of one or more consumer advocate offices authorized in state law and facilitates engagement by those offices in the markets governed by the independent regional organization.

(5) The independent regional organization maintains an office of public participation to provide information and education to members of the public about issues and initiatives at the independent regional organization, including facilitating engagement in those processes.

(6) In addition to any independent market monitoring activity required by a Federal Energy Regulatory Commission order, the independent regional organization maintains access to independent market analysis for the governing board of the independent regional organization on the impacts of market dynamics or rule changes to minimize overall costs to end-use consumers.

(7) Subject to appropriate confidentiality provisions, market data is available to the commission and the Public Advocate's Office, and other states' commissions and public advocate offices, to the same or greater extent as existed on December 31, 2024, for the markets governed by the Independent System Operator.

(8) There is a stakeholder process designed to provide nonbinding advice to the governing board of the independent regional organization.

(9) The independent regional organization is obligated to conduct meetings and make decisions in an open process with transparent, documented rationales, and all meetings of the governing board of the independent regional organization are publicly noticed and, excluding executive sessions, are available to remote participants, recorded and posted on the independent regional organization's internet website, open to the public, and subject to open record requirements.

(10) The Independent System Operator continues to operate the energy markets, subject to the market rules determined by the independent regional organization as accepted by the Federal Energy Regulatory Commission.

(11) The market rules of the independent regional organization continue to provide greenhouse gas emissions information and protocols sufficient to enable entities subject to the State Air Resources Board's rules to demonstrate compliance.

(12) The independent regional organization permits and provides a procedure for withdrawal by any participant with reasonable prior notice.

(b) On or after January 1, 2027, the Independent System Operator may implement tariff modifications accepted by the Federal Energy Regulatory Commission to operate the energy markets whose rules are governed by an independent regional organization, as provided in subdivision (a), if the governing board of the Independent System Operator adopts a resolution finding that each of the requirements of paragraphs (1) through (12), inclusive, of subdivision (a) have been or will be adopted by the independent regional organization. The governing board of the Independent System Operator may adopt the resolution if the Independent System Operator satisfies all of the following requirements:

(1) The meeting is open to the public, available to remote participants, recorded, and posted on the Independent System Operator's internet website.

(2) The Independent System Operator issues a notice of the meeting and proposed findings not less than 90 days before the meeting.

(3) The notice explains the basis for finding that each requirement of paragraphs (1) through (12), inclusive, of subdivision (a) will be met.

(4) The notice provides an opportunity for written comments on the proposed findings.

(5) The Independent System Operator issues written responses to any comments not less than 20 days before the meeting.

(c) (1) The Independent System Operator shall maintain the necessary technical capability to operate energy markets in a manner that enables California electrical corporations, local publicly owned electric utilities, and other applicable market participants to withdraw from the markets governed by the independent regional organization and instead the Independent System Operator would provide separate market services for those entities.

(2) This section does not modify the commission's authority to direct an electrical corporation to withdraw from an energy market governed by an independent regional organization in response to federal action or any other significant change in market rules or operations detrimental to California consumers or California procurement, environmental, reliability, or other public interest policies.

(d) (1) The Independent System Operator shall continue its functions and responsibilities as a balancing authority as they existed before enactment of this section, and maintain compliance with applicable reliability standards as developed, adopted, and enforced by the North American Electric Reliability Corporation, the Western Electricity Coordinating Council, or the Federal Energy Regulatory Commission.

(2) The Independent System Operator shall not change its balancing authority area from that which existed on December 31, 2024, except as follows:

(A) Standard accretion of new transmission lines, substations, and other equipment by participating transmission owners.

(B) The Independent System Operator may combine its balancing authority area with another California balancing authority if the combination is mutually agreed upon.

(C) The Independent System Operator may use its subscriber participating transmission owner tariff.

(3) This section does not change the responsibilities of the Independent System Operator under Section 345.5, including managing the transmission grid, planning for transmission expansion, and complying with Section 25308 of the Public Resources Code.

(e) The Independent System Operator may act as a vendor, through a contract with the independent regional organization, of market operation services, generation dispatch services, transmission operation services, transmission planning services, reliability coordination, balancing authority compliance or operation services, or other electrical system services.

(f) For purposes of this section, the terms "balancing authority," "balancing authority area," and "California balancing authority" have the same meanings as provided in Section 399.12.

SEC. 3. Section 352 of the Public Utilities Code is repealed.

~~352. (a) The Independent System Operator may not enter into a multistate entity or a regional organization as authorized in Section 359 unless that entry is approved by the Oversight Board.~~

~~(b) This section becomes inoperative on the date on which the governance modifications set forth in Section 359.5 become effective and is repealed on January 1 of the following year.~~

SEC. 4. Article 4 (commencing with Section 355) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code is repealed.

SEC. 5. Article 5 (commencing with Section 359) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code is repealed.

SEC. 6. Article 5.5 (commencing with Section 359.5) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code is repealed.

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SENATE BILL No. 239

Introduced by Senator Arreguín

January 30, 2025

An act to add Section 54953.05 the Government Code, relating to local government.

LEGISLATIVE COUNSEL'S DIGEST

SB 239, as introduced, Arreguín. Open meetings: teleconferencing: subsidiary body.

Existing law, the Ralph M. Brown Act, requires, with specified exceptions, that all meetings of a legislative body, as defined, of a local agency be open and public and that all persons be permitted to attend and participate. The act generally requires for teleconferencing that the legislative body of a local agency that elects to use teleconferencing post agendas at all teleconference locations, identify each teleconference location in the notice and agenda of the meeting or proceeding, and have each teleconference location be accessible to the public. Existing law also requires that, during the teleconference, at least a quorum of the members of the legislative body participate from locations within the boundaries of the territory over which the local agency exercises jurisdiction, except as specified.

Existing law, until January 1, 2026, authorizes specified neighborhood city councils to use alternate teleconferencing provisions related to notice, agenda, and public participation, as prescribed, if, among other requirements, the city council has adopted an authorizing resolution and ⅔ of the neighborhood city council votes to use alternate teleconference provisions, as specified.

This bill would authorize a subsidiary body, as defined, to use alternative teleconferencing provisions and would impose requirements for notice, agenda, and public participation, as prescribed. The bill

would require the subsidiary body to post the agenda at the primary physical meeting location. The bill would require the members of the subsidiary body to visibly appear on camera during the open portion of a meeting that is publicly accessible via the internet or other online platform, as specified. The bill would also require the subsidiary body to list a member of the subsidiary body who participates in a teleconference meeting from a remote location in the minutes of the meeting.

The bill would require the legislative body that established the subsidiary body electing to use teleconferencing pursuant to these provisions to establish the subsidiary body by charter, ordinance, resolution, or other formal action to make specified findings by majority vote, before the subsidiary body uses teleconferencing for the first time and every 12 months thereafter. The bill would require the subsidiary body to approve the use of teleconference by $\frac{2}{3}$ vote before using teleconference pursuant to these provisions.

The bill would exempt from these alternative teleconferencing provisions a subsidiary body that has subject matter jurisdiction over police oversight, elections, or budgets. The bill would require any member of a subsidiary body who is an elected official to comply with specified agenda and quorum requirements to participate in a meeting through teleconferencing pursuant to this section, and would require any final recommendations adopted by a subsidiary body to be presented at a regular meeting of the legislative body that established the subsidiary body.

Existing constitutional provisions require that a statute that limits the right of access to the meetings of public bodies or the writings of public officials and agencies be adopted with findings demonstrating the interest protected by the limitation and the need for protecting that interest.

This bill would make legislative findings to that effect.

The California Constitution requires local agencies, for the purpose of ensuring public access to the meetings of public bodies and the writings of public officials and agencies, to comply with a statutory enactment that amends or enacts laws relating to public records or open meetings and contains findings demonstrating that the enactment furthers the constitutional requirements relating to this purpose.

This bill would make legislative findings to that effect.

Vote: majority. Appropriation: no. Fiscal committee: no. State-mandated local program: no.

The people of the State of California do enact as follows:

SECTION 1. Section 54953.05 is added to the Government Code, to read:

54953.05. (a) (1) The definitions in Section 54953, as that section may be amended from time to time, apply for purposes of this section.

(2) For purposes of this section, "subsidiary body" means a legislative body that meets all of the following:

(A) Is described in subdivision (b) of Section 54952.

(B) Serves exclusively in an advisory capacity.

(C) Is not authorized to take final action on legislation, regulations, contracts, licenses, grants, permits, or other entitlements.

(b) A subsidiary body may use teleconferencing without complying with paragraph (3) of subdivision (b) of Section 54953, if the subsidiary body complies with all of the following:

(1) The teleconferenced meetings shall be conducted in a manner that protects the statutory and constitutional rights of the parties or the public appearing before the subsidiary body.

(2) Each member of the subsidiary body shall participate through both audio and visual technology.

(3) The subsidiary body shall provide at least one of the following as a means by which the public may remotely hear and visually observe the meeting, and remotely address the subsidiary body:

(A) A two-way audiovisual platform.

(B) A two-way telephonic service and a live webcasting of the meeting.

(4) The subsidiary body shall give notice of the meeting and post agendas as otherwise required by this chapter.

(5) The subsidiary body shall designate a primary physical meeting location where members of the public may physically attend, observe, hear, and participate in the meeting. At least one staff member of the subsidiary body shall be present at the primary physical meeting location during the meeting. The subsidiary body shall post the agenda at the primary physical meeting location, but need not post the agenda at a remote location.

(6) In each instance in which notice of the time of the teleconferenced meeting is otherwise given or the agenda for the

meeting is otherwise posted, the subsidiary body shall also give notice of the means by which members of the public may access the meeting and offer public comment.

(7) The agenda shall identify and include an opportunity for all persons to attend and address the subsidiary body directly pursuant to Section 54954.3 via a call-in option or via an internet-based service option.

(8) In the event of a disruption that prevents the subsidiary body from broadcasting the meeting to members of the public using the call-in option or internet-based service option, or in the event of a disruption within the subsidiary body's control that prevents members of the public from offering public comments using the call-in option or internet-based service option, the subsidiary body shall take no further action on items appearing on the meeting agenda until public access to the meeting via the call-in option or internet-based service option is restored. Actions taken on agenda items during a disruption that prevents the subsidiary body from broadcasting the meeting may be challenged pursuant to Section 54960.1.

(9) Notwithstanding Section 54953.3, an individual desiring to provide public comment through the use of an internet website, or other online platform, not under the control of the subsidiary body, that requires registration to log in to a teleconference may be required to register as required by the third-party internet website or online platform to participate.

(10) The members of the subsidiary body shall visibly appear on camera during the open portion of a meeting that is publicly accessible via the internet or other online platform.

(A) The visual appearance of a member of the subsidiary body on camera may cease only when the appearance would be technologically impracticable, including, but not limited to, when the member experiences a lack of reliable broadband or internet connectivity that would be remedied by joining without video, or when the visual display of meeting materials, information, or speakers on the internet or other online platform requires the visual appearance of a member of a subsidiary body on camera to cease.

(B) If a member of the advisory body does not appear on camera due to challenges with internet connectivity, the member shall announce the reason for their nonappearance when they turn off their camera.

(C) A member shall publicly disclose at the meeting before any action is taken, whether any other individuals 18 years of age or older are present in the room at the remote location with the member, and the general nature of the member's relationship with any such individuals.

(11) The subsidiary body shall not require public comments to be submitted in advance of the meeting and must provide an opportunity for the public to address the subsidiary body and offer comment in real time.

(A) A subsidiary body that provides a timed public comment period for each agenda item shall not close the public comment period for the agenda item, or the opportunity to register, pursuant to paragraph (9), to provide public comment until that timed public comment period has elapsed.

(B) A subsidiary body that does not provide a timed public comment period, but takes public comment separately on each agenda item, shall allow a reasonable amount of time per agenda item to allow public members the opportunity to provide public comment, including time for members of the public to register pursuant to paragraph (9), or otherwise be recognized for the purpose of providing public comment.

(C) A subsidiary body that provides a timed general public comment period that does not correspond to a specific agenda item shall not close the public comment period or the opportunity to register, pursuant to paragraph (9), until the timed general public comment period has elapsed.

(12) A member of the subsidiary body who participates in a teleconference meeting from a remote location shall be listed in the minutes of the meeting.

(c) In order to use teleconferencing pursuant to this section, the legislative body that established the subsidiary body by charter, ordinance, resolution, or other formal action shall make the following findings by majority vote before the subsidiary body uses teleconferencing pursuant to this section for the first time, and every 12 months thereafter:

(1) The legislative body has considered the circumstances of the subsidiary body.

(2) Teleconference meetings of the subsidiary body would enhance public access to meetings of the subsidiary body.

(3) Teleconference meetings of the subsidiary body would promote the attraction, retention, and diversity of subsidiary body members.

(d) The legislative body shall approve the use of teleconferencing by two-thirds vote before using teleconference pursuant to this section.

(e) This section shall not apply to a subsidiary body that has subject matter jurisdiction over police oversight, elections, or budgets.

(f) Notwithstanding subdivision (b), any member of a subsidiary body who is an elected official shall comply with paragraph (3) of subdivision (b) of Section 54953 to participate in a meeting through teleconferencing pursuant to this section.

(g) Any final recommendations adopted by a subsidiary body shall be presented at a regular meeting of the legislative body that established the subsidiary body.

SEC. 2. The Legislature finds and declares that Section 1 of this act, which adds Section 54953.05 to the Government Code, imposes a limitation on the public's right of access to the meetings of public bodies or the writings of public officials and agencies within the meaning of Section 3 of Article I of the California Constitution. Pursuant to that constitutional provision, the Legislature makes the following findings to demonstrate the interest protected by this limitation and the need for protecting that interest:

By removing the requirement for agendas to be placed at the location of each public official participating in a public meeting remotely, this act protects the personal, private information of public officials and their families while preserving the public's right to access information concerning the conduct of the people's business.

SEC. 3. The Legislature finds and declares that Section 1 of this act, which adds Section 54953.05 to the Government Code, furthers, within the meaning of paragraph (7) of subdivision (b) of Section 3 of Article I of the California Constitution, the purposes of that constitutional section as it relates to the right of public access to the meetings of local public bodies or the writings of local public officials and local agencies. Pursuant to paragraph (7) of subdivision (b) of Section 3 of Article I of the California Constitution, the Legislature makes the following findings:

This act is necessary to provide opportunities for public participation in meetings of specified public agencies and to promote the attraction and retention of members of those agencies.

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