2075 Woodside Road | Redwood City, CA 94061
(650) 260-0005 | peninsulacleanenergy.com

Regular Meeting of the Board of Directors of the Peninsula Clean Energy Authority (PCEA)
AGENDA

Thursday, April 24, 2025
6:30 pm

PLEASE NOTE: This meeting will be held in a hybrid format with both in-person and Zoom participation options for members of the public; Board members shall appear in person.

In-Person Meeting Locations:
PCEA Lobby, **2075 Woodside Road, Redwood City, CA 94061**
Los Banos City Hall, Conference Room A, **520 J Street, Los Banos, CA 93635**
Hyatt Regency Sacramento **1209 L Street, Sacramento, CA, US, 95814**

Zoom, **Virtual Meeting Link:** https://pencleanenergy.zoom.us/j/87496649657
Meeting ID: 874-9664-9657 **Passcode:** 2075 **Phone:** +1 (669) 444-9171

This meeting of the Board of Directors will be held at the Peninsula Clean Energy Lobby: 2075 Woodside Road, Redwood City, CA 94061 and Los Banos City Hall, Conference Room A, 520 J Street, Los Banos, CA 93635 and by teleconference pursuant to California Assembly Bill 2449 and the Ralph M. Brown Act, CA Gov't Code. Section 54950, et seq. **Members of the Board are expected to attend the meeting in person** and should reach out to General Counsel for Peninsula Clean Energy, Jennifer Stalzer, with questions or accommodation information (jstalzer@smcgov.org). For information regarding how to participate in the meeting remotely, please refer to the instructions at the end of the agenda. In addition, a video broadcast of the meeting can be viewed at https://www.peninsulacleanenergy.com/board-of-directors following the meeting.

Public Participation

The PCEA Board meeting may be accessed through Zoom online at https://pencleanenergy.zoom.us/j/87496649657. The webinar ID is: 874-9664-9657 and the passcode is 2075. The meeting may also be accessed via telephone by dialing +1(669) 444-9171. Enter the webinar ID: 874-9664-9657, then press #. (Find your local number: https://pencleanenergy.zoom.us/u/kTlH1Ocod). Peninsula Clean Energy uses best efforts to ensure audio and visual clarity and connectivity. However, it cannot guarantee the connection quality.

Members of the public can also attend this meeting physically at the **Peninsula Clean Energy Lobby** at 2075 Woodside Road, Redwood City, CA 94061 or **Los Banos City Hall**, Conference Room A, 520 J Street, Los Banos, CA 93635.

Written public comments may be emailed to PCEA Board Clerk, Nelly Wogberg (nwogberg@peninsulacleanenergy.com) and such written comments should indicate the specific agenda item on which the member of the public is commenting.

Spoken public comments will be accepted during the meeting in the Board Room(s) or remotely through Zoom at the option of the speaker. Please use the "Raise Your Hand" function in the Zoom platform, or press *6 if you phoned into the meeting, to indicate that you would like to provide comment.

Please note that Peninsula Clean Energy Board of Directors meetings are a limited public forum, and all public comment must relate to something that is within the subject matter jurisdiction of the Board. If comments do not relate to the subject matter jurisdiction of the Board, we will stop the comment and move on to the next speaker. General Counsel will assist in identifying comments that are not related to the subject matter jurisdiction of the Board.

ADA Requests

Individuals who require special assistance or a disability related modification or accommodation to participate in this meeting, or who have a disability and wish to request an alternative format for the meeting, should contact Nelly Wogberg, Board Clerk, by 10:00 a.m. on the day before the meeting at (nwogberg@peninsulacleanenergy.com). Notification in advance of the meeting will enable PCEA to make reasonable arrangements to ensure accessibility to this meeting, the materials related to it, and your ability to comment.

Closed Captioning is available for all PCEA Board meetings. While watching the video broadcast in Zoom, please enable captioning.

CALL TO ORDER / ROLL CALL / APPROVE TELECONFERENCE PARTICIPATION UNDER AB 2449

This item is reserved to approve teleconference participation request for this meeting by Director pursuant to Brown Act revisions of AB 2449 due to an emergency circumstance to be briefly described.

PUBLIC COMMENT

This item is reserved for persons wishing to address the Board on any PCEA-related matters that are not otherwise on this meeting agenda. Public comments on matters listed on the agenda shall be heard at the time the matter is called. Members of the public who wish to address the Committee are customarily limited to two minutes per speaker. The Board Chair may increase or decrease the time allotted to each speaker.

ACTION TO SET AGENDA AND TO APPROVE CONSENT AGENDA ITEMS

1. Approval of Revised Load Management Standard (LMS) Plan for Submission to California Energy Commission (CEC)
2. Approval of Minutes from the March 27, 2025 Board of Directors Meeting

REGULAR AGENDA

3. Chair Report (Discussion)
4. CEO Report (Discussion)
5. Community Advisory Committee Report (Discussion)
6. Briefing on SB 540 (Becker) - Western Pathways Bill (Discussion)
7. Approval of the Program Plan for California Public Utilities Commission (CPUC) FLEXmarket Program (Action)
8. Discussion of the Distributed Energy Resources Framework 2025 - 2030 (Discussion)
9. Approval of the Budget Billing Program for Peninsula Clean Energy Customers (Action)
10. Board Members' Reports (Discussion)

INFORMATIONAL REPORTS

11. Community Energy Programs Quarterly Report
12. Marketing, Outreach Activities, and Media Relations Quarterly Report
13. Legislative Update
14. Report on California Community Power (CCP) Joint Powers Authority
15. Social Media FAQ's
16. Acronym List

ADJOURNMENT

Public records that relate to any item on the open session agenda are available for public inspection. The records are available at the Peninsula Clean Energy offices or on PCEA Website at: https://www.peninsulacleanenergy.com.

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Options for Joining

- Videoconference with Computer Audio - see Option 1 below
- Videoconference with Phone Call Audio - see Option 2 below
- Calling in via Telephone/Landline - see Option 3 below

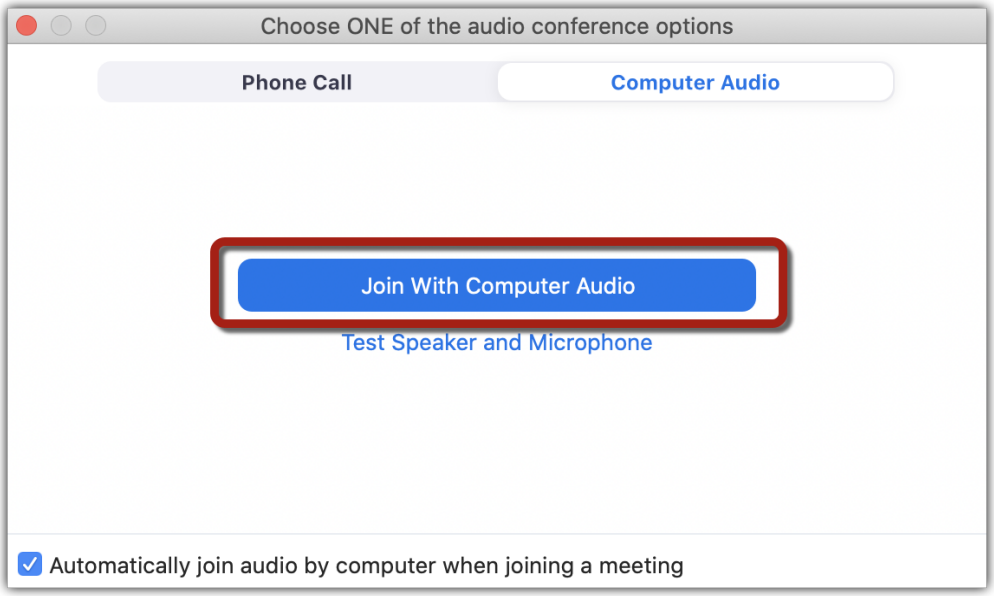
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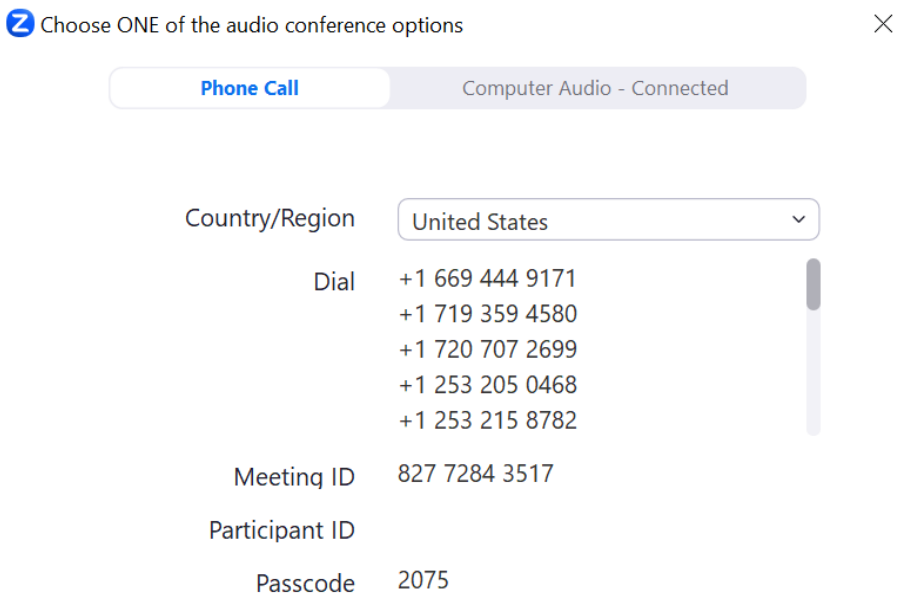


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- You will be instructed to enter the meeting passcode **2075 followed by #.**

PENINSULA CLEAN ENERGY

PENINSULA CLEAN ENERGY AUTHORITY
JPA Board Correspondence

DATE: April 16, 2025
MEETING DATE: April 24, 2025
VOTE REQUIRED: Majority Vote

TO: Honorable Peninsula Clean Energy Authority Board of Directors

FROM: Jeremy Waen, Senior Director of Regulatory Policy

SUBJECT: Approval of Revised Load Management Standard (LMS) Plan for Submission to California Energy Commission (CEC)

BACKGROUND

Pursuant to 20 Cal. Code Regs. §1623.1, the California Energy Commission ("CEC") requires Community Choice Aggregators (CCA) to develop and approve a Load Management Standard ("LMS") plan for the real-time management of customer load. This load management aims to reduce load at peak and to reduce overall costs. The California Energy Commission's regulation relies primarily on the creation of "marginal cost-based" (MCB) hourly rates as the tool to shift customer load out of expensive-to-serve hours. As an alternative, CCAs are authorized to use customer programs that can respond to hourly signals, if marginal cost-based rates are not feasible or cost-effective. Peninsula Clean Energy (PCE) duly developed an LMS plan, which was approved on April 25, 2024. The plan was submitted to the CEC on May 7, 2024.

Subsequent to that submission, the Peninsula Clean Energy Board approved two measures that help meet the goals of the Load Management Standard: first, joining PG&E's Hourly Flex Pricing pilots and second, moving forward with potential adoption of a Distributed Energy Resource Management System (DERMS) platform. This plan update reflects these two actions as well as other developments with PCE's programs.

DISCUSSION

I. Summary of Today's Request

Since the Board's approval of PCE's LMS plan on April 25, 2024, and its submission to the CEC on May 7, 2024, PCE staff has been in close correspondence with CEC staff regarding the approval of the document. After review, CEC staff recommended that PCE's LMS plan be updated to include: (1) PCE's actions to implement the LMS plan, and (2) specificity regarding plans to move customers' energy usage off-peak hours with customer programs. PCE staff has incorporated these updates for Board approval, with both the clean and redlined versions included.

The updated plan now reflects:

1. PCE's Board approval of participation in Pacific Gas and Electric Company's (PG&E) Expanded Pilots 2, and Vehicle to Grid Integration (VGI) Real Time Pricing pilot to comply with the LMS on October 24, 2024, and PCE's Advice Letter PCEA-039-E on November 1, 2024, noticing the CPUC that PCE is participating PG&E's Hourly Flex Pricing (HFP) pilots.

2. Further detail on efforts to establish a DERMS platform and other developments in PCE's programmatic efforts.

Since this revision reflects actions already taken by the Board and serves to assist the CEC in approving PCE's LMS plan, staff recommends the approval of the updated PCE LMS plan.

II. Regulatory Background

The CEC established the LMS regulation in April 2023 to require Large CCAs, including PCE, to use MCB rates and programs to encourage energy use at off-peak hours and improve equity, efficiency, and reliability of the electric system. PCE is required to submit an LMS Compliance Plan outlining how PCE will meet the LMS regulation requirements.

The LMS requires PCE to analyze an hourly MCB rate for each customer class based on cost-effectiveness, equity, feasibility, and benefits to decide whether to adopt such rates. If adopted, the MCB rates must be available for customers to enroll in by July 1, 2027. The PCE Board opted to leverage IOU pilots to satisfy this requirement.

If a large CCA were to conclude that the implementation of an MCB rate is not technically feasible, cost-effective, equitable or beneficial, then it must propose cost-effective marginal-cost responsive load flexibility programs for compliance. PCE's programs are moving toward being able to satisfy this requirement as an alternative pathway if PCE were to decide in the future to discontinue a MCB rate. If adopted, these programs must be available for customer enrollment by July 1, 2027.

III. PCE's Approach

a. Rate Offerings

The first substantive update of the LMS is a discussion of PCE's strategy for implementing MCB rates. PCE found, based on substantial evidence in light of the whole record, that designing and implementing its own MCB rates is not likely to be cost-effective or technically feasible as an approach to meeting the goals of the LMS. Instead, to implement PCE's MCB rates for its residential, commercial, and industrial classes, PCE has chosen to focus staff resources on participation in two of PG&E's HFP pilots: the Expanded Pilot 2 and the VGI pilots. PCE declined to participate in the Expanded Pilot 1 (Agricultural) because the PCE Board found that this pilot would not be cost-effective due to the small number of agricultural customers among PCE's customer base and a lack of peak-coincident load. The PCE Board approved participation in PG&E's Expanded Pilot 2 and VGI pilot to comply with the LMS on October 24, 2024. PCE anticipates enrolling customers in the pilots by June 1, 2025, or earlier if feasible, to comply with CEC regulations.

b. Customer Program Offerings

The second update includes updates to PCE's program offerings. These programs are not

strictly necessary at this time to comply with the LMS standard because of the participation in the HFP pilots. However, these programs could be used in future as an alternate path to compliance if they were upgraded to be able to respond to MCB hourly signals. PCE currently offers a portfolio of load flexibility programs with a diversity of enabling technologies, and different tiers of engagement to provide options for customers. Following is a list of current and planned program offerings, including several pilots that are being tested for reliability, load reduction, and customer adoption: Solar and Storage for Public Buildings, Residential Solar and Storage, FLEXmarket, Residential Electrification Direct Install, and GovEV. Each of these programs is envisioned potentially to become MCB signal-responsive programs to either supplement or serve in place of MCB rates in future years. The timeline and feasibility of the rollout of MCB signals to these load flexibility technologies will be evaluated in future development of PCE's DERMS platform.

Taken together, these updates document PCE's actions since the initial plan submittal to advance PCE's load management strategies to achieve the goals shared by PCE and the CEC.

FISCAL IMPACT

None.

ATTACHMENTS:
Final Revised LMS Compliance Plan (14 MAR 2025).pdf
Final Revised LMS Compliance Plan REDLINES 2(14 MAR 2025).pdf

Load Management Standard Compliance Plan

Peninsula Clean Energy Authority

Revised March 15, 2025

1. Introduction

Peninsula Clean Energy Authority (PCE) supports the overall objectives of the Load Management Standard (LMS) since these strategies are important for PCE's goal of serving its customers 100% renewable energy on a high time-coincident basis in coming years. Since this requires the matching of load to the generation of PCE's contracted variable energy generation resources, load shifting is a critical strategy for PCE to achieve this goal. PCE looks forward to working with the California Energy Commission (CEC) in the coming years to develop cutting-edge and cost-effective approaches to achieving the overall goals of the standard.

1.1. About PCE

PCE, a community choice aggregator (CCA), provides electricity service to residents and businesses in San Mateo County and the City of Los Banos in Merced County. Formed in February 2016, PCE is a joint powers authority, consisting of the County of San Mateo, all twenty of its towns and cities, and the City of Los Banos in Merced County. Following a comprehensive feasibility study, consistent with Assembly Bill (AB) 32 voluntary action pathways, elected officials from each member jurisdiction unanimously agreed to form PCE to meet their local climate action goals and for the benefit of San Mateo County. In 2020, following another comprehensive feasibility study, elected officials from the City of Los Banos voted to join PCE.

PCE provides cleaner electricity, and at lower rates, than the incumbent investor-owned utility (IOU), Pacific Gas and Electric Company (PG&E). PCE plans for and secures commitments from a diverse portfolio of energy-generating resources to reliably serve the electric energy requirements of its customers over the near-, mid-, and long-term planning horizons. PCE was assigned an investment-grade credit rating from Moody's in May 2019 and S&P in June 2023, the second of the three CCAs in California to obtain investment-grade credit ratings. PCE's programs include advancing the adoption of electric transportation and transitioning building fossil fuel uses to low-carbon electricity.

As part of its mission-driven, collaborative, not-for-profit, locally focused roots, PCE is committed to two key organizational priorities:

- Deliver 100% renewable energy on an annual basis and align renewable energy supply with customer demand each and every hour of the day in the coming years.
- Contribute to San Mateo County reaching the state's goal to be 100% free of greenhouse gasses (GHG).

PCE is also committed to the following several strategic goals:

- Secure sufficient, low-cost, clean sources of electricity that achieve PCE's priorities while ensuring reliability and meeting regulatory mandates.
- Strongly advocate for public policies that support PCE's organizational priorities.

- Implement robust energy programs that reduce GHG emissions, align energy supply and demand, and provide benefits to community stakeholder groups.
- Develop a strong brand reputation that drives participation in PCE's programs while ensuring customer satisfaction.
- Employ sound fiscal strategies to promote long-term organizational sustainability.
- Ensure organizational excellence by adhering to sustainable business practices and fostering a workplace culture of innovation, diversity, transparency, and integrity.

The importance of these goals for the communities of San Mateo County is underscored by the 2019 declaration of a climate emergency by the Board of Supervisors calling on local agencies and jurisdictions to work "to achieve carbon neutrality throughout San Mateo County and to implement other actions to address climate change."[1]

1.2. The Role of PCE's Board of Directors

PCE is governed by its Board of Directors (Board). Each member jurisdiction from San Mateo County, plus the city of Los Banos, has one seat on PCE's Board (except for San Mateo County, which has two) for a total of 23 elected officials acting as board members. In addition, the Board has two board member director emeritus selected from former directors who participate in board activities as non-voting members.

The Board is responsible for setting the overall strategy for PCE, including rate setting and energy procurement decisions.[2] The decisions of the Board are binding requirements for PCE.

In addition to operating the CCA program, PCE also implements a range of customer programs to facilitate decarbonization and access to electrification, especially for disadvantaged customers. Generally, PCE does not receive cost recovery from the California Public Utilities Commission (CPUC) for these programs but funds them through rates or grants from outside sources.

1.3. The CEC Load Management Standard

In 1974, the California State Legislature passed the Warren-Alquist Act establishing the CEC. At its inception, the CEC was granted specific authority including but not limited to implementing load management standards.[3] The CEC updated these standards in 2022 to

[1] County of San Mateo Board of Supervisors, Resolution No. 19-847: Adopt a resolution endorsing the declaration of a climate emergency in San Mateo County that demands accelerated actions on the climate crisis and calls on local jurisdictions and agencies to join together to address climate change (2019).
[2] Public Utilities Code § 366.2.
[3] California Energy Commission, *2022 Load Management Standards Rulemaking Fact Sheet*, 1 (2022), https://www.energy.ca.gov/sites/default/files/2022-10/Load_Management_Fact_Sheet_ADA.pdf

enhance statewide demand flexibility, and the new amendments effective as of April 2023 are what this plan addresses.[4]

The CEC established its LMS regulation based on the definition of load management as "any utility program or activity that is intended to reshape deliberately a utility's load duration curve."[5] The primary objectives of the regulation are to:

- Encourage energy use at off-peak hours.
- Encourage daily and seasonal peak load control to improve equity, efficiency, and reliability of the electric system.
- Decrease or delay the need for new electrical capacity.
- Reduce GHG emissions and fossil fuel consumption.

To ensure progress toward these goals, the CEC is requiring California's large Publicly Owned Utilities (POU), large IOUs, and large CCAs to submit LMS Plans outlining how they will meet the LMS regulation requirements.

The LMS regulation requires each large POU, IOU, and CCA to analyze an optional hourly marginal cost-based (MCB) rate for each customer class. The proposed rate should be evaluated based on five factors: (i) cost-effectiveness, (ii) equity, (iii) technical feasibility, (iv) benefits to the grid, and (v) benefits to customers. If the CCA deems the implementation of an MCB rate is not feasible based on one or more of the five factors, then it must propose cost-effective load flexibility programs for compliance and conduct an evaluation using the same five metrics. Compliance may be modified or delayed if the CCA can show that despite good faith effort, requiring timely compliance would result in reduced system efficiency or reliability, extreme hardship, technological infeasibility, or lack of cost-effectiveness to the CCA.

[4] 20 Cal. Code Regs. §§ 1621-1625.
[5] Public Resources Code § 25132.

Table 1 outlines the goals set forth in the LMS regulation, along with the expected completion date identified by the CEC and PCE's progress status toward meeting that deadline.

Table 1. Progress Toward LMS Goals

LMS Section	Description	Deadline	PCE Status
§1623.1(c)	Upload existing time-dependent rates to the Market Informed Demand Automation Server (MIDAS) database.	October 1, 2023	Completed with ongoing updates
§1623(c)	Provide customers access to their Rate Identification Numbers (RIN) on billing statements and in online accounts using both text and quick-response (QR) code.	March 31, 2024	Awaiting PG&E billing changes
§1623.1(a)(1)	Develop and submit to PCE's Board an LMS plan.	April 1, 2024	Submitted to the Board March 22, 2024
§1623.1(a)(3)(A)	Submit to the CEC the Board-approved LMS plan.	May 31, 2024	
§1623(c)	Develop and submit to the CEC, in conjunction with the other obligated utilities, a single statewide RIN access tool.	Oct. 1, 2024	Ongoing, through CalCCA participation
§1623.1(b)(3)	Submit to the CEC a list of load flexibility programs deemed cost effective by PCE.	Oct. 1, 2024	
§1623.1(a)(3)(C)	Submit annual reports to the CEC demonstrating implementation of plan, as approved by the PCE Board.	Annually	
§1623.1(b)(2)	Submit to the PCE Board for approval at least one MCB rate for the customer class(es) for which it will materially reduce peak load.	July 1, 2025	
§1623.1(b)(2)	Offer customers voluntary participation in either an MCB rate, if approved by the Board, or a cost-effective load flexibility program.	July 1, 2027	
§1623.1(b)(5)	Conduct a public information program to inform and educate affected customers why MCB rates or load flexibility programs and automation are needed, how they will be used, and how these rates and programs can save customers money.	Goal date not specified	Ongoing currently
§1623.1(a)(1)(C)	Review the plan at least once every 3 years after it is adopted and submit an update to the PCE Board if there is a material change.	Triennially	

2. PCE LMS Plan

2.1. Overview

The PCE Board does not find, based on substantial evidence in light of the whole record, that designing and implementing its own MCB rates to be likely to be cost-effective or technically feasible as an approach to meeting the goals of the LMS, as discussed below, consistent with the findings specified in 20 Cal. Code Regs. § 1623.1(a). However, PCE is participating in two of PG&E's Hourly Flex Pricing (HFP) rate pilots as a more effective approach to LMS-compliant rate offerings. The PCE Board approved participation in PG&E's Expanded Pilot 2 and Vehicle to Grid Integration (VGI) pilot to comply with the LMS on October 24, 2024. PCE will provide an update on the expansion of the pilots in its next LMS Compliance Plan report. Subsequently, PCE filed Advice Letter (AL) PCEA-039-E on November 1, 2024, noticing the CPUC that PCE is participating PG&E's HFP pilots.[6]

2.2. RTP Pilots

To implement PCE's MCB rates for its residential, commercial, and industrial classes, PCE will focus staff resources on participation in two of PG&E's HFP pilots: the Expanded Pilot 2 and the VGI pilots. PCE has declined to participate in the Expanded Pilot 1 (Agricultural) because the PCE Board finds that this pilot would not be cost-effective due to the small number of agricultural customers among PCE's customer base and a lack of peak-coincident load.

2.2.1. Rate Design

The MCB rates PCE will offer through PG&E's HFP pilots will be based on deviations from historical usage at marginal rates driven by dynamic hourly prices. The dynamic prices include marginal generation capacity costs as approved in D.21-11-016 and allocation as specified in D.22-08-002 and marginal energy costs as approved in D.21-11-016, based on PG&E Default Load Aggregation Point (DLAP), adjusted for line losses.[7] Marginal transmission and distribution costs will be based on forecasted load on a representative circuit with similar load characteristics to the customer's circuit, but annual average load-weighted prices will not vary geographically for equity reasons.[8] The rate design will incorporate a fixed cost collection subscription mechanism as outlined in the California Flexible Unified Signal for Energy (CalFUSE) proposal, with no scalers or adders.

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[6] Peninsula Clean Energy Authority Advice Letter 049-E "Notice to the Commission of Participation in the PG&E Expanded Pilot 2" (November 1, 2024) available at https://www.peninsulacleanenergy.com/wp-content/uploads/2024/11/PCE-AL-39E_Expanded-Pilot-2-Opt-in-1.pdf

[7] Pacific Gas and Electric Company, 2023 LMS Compliance Plan (2023).

[8] Pacific Gas and Electric Company, 2023 LMS Compliance Plan (2023).

The Expanded Pilot 2 and VGI pilots are anticipated to be available without participation limits to all of our residential, commercial, and industrial customers. These pilots are available to all customers based on the terms defined by PG&E and per the regulatory approvals.[9] PCE is not imposing any participation cap. Pilot descriptions are included below.

- Expanded Pilot 2: Under the Demand Flexibility proceeding (R.22-07-005), PG&E was directed to expand a pilot program developed by Valley Clean Energy (VCE) and PG&E in response to the 2021 grid reliability challenges. PG&E must now extend the pilot developed with VCE to serve residential, commercial, and industrial customers. The pilot is being rolled out via "Automation Service Providers" (ASPs), who currently provide automation services to existing devices installed in homes and businesses. PG&E has an enrollment target of 50 MWs under the pilot, which is currently scheduled to conclude by December 31, 2027.
- VGI Pilots: Under the Transportation Electrification proceeding (R.18-12-006), PG&E was directed to develop two VGI pilots with a dynamic pricing rate to serve residential and commercial customers. Both pilots provide upfront incentives for bidirectional electric vehicle (EV) charging equipment in phase 1 and then require customers to enroll under a dynamic pricing rate during phase 2. Across its entire service territory, PG&E is planning to enroll 200 commercial customers under the VGI commercial pilot. The dynamic rate is expected to be available for 12 months under both pilots or until funding is exhausted.

PCE anticipates enrolling customers in the pilots by June 1, 2025, or earlier if feasible, to comply with CEC regulations.

PCE is not participating in PG&E's Expanded Pilot 1, which targets agricultural customers. PCE staff determined that offering a pilot rate program to our agricultural customers would not result in material peak load reduction or be cost effective, based on the following factors:

- Lack of shiftable peak load: PCE has only 129 agricultural customers which represent 0.4% of PCE's peak load.
- Administrative burden: The administrative burden of implementing the Expanded Pilot 1 would very likely exceed the benefits gained from the program, and limit staffing resources which could be applied to the pilots more applicable to PCE's customer base.

[9] CPUC Decision 24-01-032, PG&E's Advice Letter 7222-E1, Advice Letter 7222-E-A2, Advice Letter 7222-E-B3, Advice Letter 7223-E-A4 and Advice Letter 7223-E-B5 for the Expanded Pilots, and PG&E's Advice Letter 7234-E-A6, and CPUC's Resolutions E-5192, E-5326 and E-5358 for the Vehicle Grid Integration (VGI) Pilots (Regulatory Approvals), (together the "Hourly Flex Pricing Pilots", or "HFP Pilots")

Since our agricultural customer class is small, and does not have high demand during peak periods, implementing this pilot for agricultural customers would not have a significant effect on our peak loads, even if participation and responsiveness to MCB rates were high. Therefore, PCE's Board did not find it cost effective to offer MCB rates to our agricultural customer class.

As PG&E has indicated, it will no longer be able to make the necessary updates to its billing system to implement a more permanent dynamic pricing solution until after July 1, 2027. We anticipate that the pilot programs will be extended to customers beyond that date, subject to CPUC approval. Should either the CPUC decline to extend these pilots past that date or PCE deem that continued participation is not the most cost-effective approach to enabling load shifting, PCE will submit an LMS plan revision to update our plan for offering either MCB rates or marginal cost signal responsive programs to all customer classes for which they are cost effective, or both, as provided for in 20 Cal. Code Regs. § 1623.1. Until such time as the CPUC makes its decision, such a determination of continued participation would be premature.

In addition to the MCB rate pilots, PCE will continue to deploy programs that can respond to MCB signals, as described below. Under this approach, most or all customers will likely have multiple vehicles for creating load flexibility. Both the MCB rates and the marginal cost signal responsive programs are anticipated to interact with the statewide RIN tool pursuant to 20 Cal Code Regs. § 1623 (c) when it becomes available.

2.3. Evaluation

2.3.1. Cost-Effectiveness

PCE's strategy of participation in the CPUC-sponsored pilots is informed by some of the cost and feasibility considerations of designing and implementing its own separate MCB rates. The cost-effectiveness of any MCB rate offering depends on whether the value of any load shift to the customer and PCE exceeds the costs of implementation of the proposal. Evaluation of cost-effectiveness will be a continuous and ongoing effort as the results from the HFP pilots become available. Since CCAs are excluded from cost recovery for expenditures in support of wider grid benefits, the analysis of cost-effectiveness is necessarily narrower than it would be for either IOUs or POUs.

Evaluation of the costs of implementing an MCB rate include a variety of fixed and per-customer costs. Fixed costs include, but are not limited to:

- Personnel costs for staff to design and maintain MCB rates.
- Management costs to obtain data from the California Independent System Operator (CAISO) and PG&E to calculate hourly costs.
- Software and system costs for design, maintenance, and operations.

- Contractor costs to implement MCB rates, including customer education and support.
- Software and upload costs associated with the MIDAS database interface.

In addition, per-customer costs include, but are not limited to:

- Data charges
- Vendor charges

At this time, the costs associated with the creation, implementation, and maintenance of the MCB rates for PCE are difficult to ascertain because many elements are still unknown. In addition to the implementation costs, it is unknown whether and how the CPUC will require PG&E to provide real-time billing quality customer data, the costs associated with obtaining these data, and any required technical or data handling costs. Since PCE would be spreading comparable fixed costs across a small customer base, it is less likely that the value of the marginal improvement in load shifting over PCE's existing Time-of-Use (TOU) rates would be enough to justify these fixed costs, compared to larger Load Serving Entities (LSE). PCE's comparable fixed costs would be recovered from a smaller rate base, resulting in higher per-customer costs. PCE anticipates participation in PG&E's HFP pilots may shed light on some of these costs going forward.

By the same token that the costs of implementation are difficult to determine, the value of any load shift that might result from an MCB rate is also difficult or impossible to assess at this time. The value of the load shift depends on participation rate, how much load is shifted, in what hours, and the value of that load shift. In principle, the amount of load shift could be determined for each hour if the elasticity of electricity demand in each hour were known; however, evaluating these elasticities would require considerable data for all hours and would have significant uncertainties. In addition, it would be necessary to know how the MCB rate values would differ from existing TOU rates in each of these hours.

Currently, several components of the marginal costs would be difficult to ascertain at this time. While hourly energy costs are currently generated in the CAISO market, the hourly capacity values are unclear. The resource adequacy (RA) program is shifting to a 24-hour slice-of-day framework, which would theoretically generate differential values of capacity in different hours. However, until the slice-of-day framework has been in place for some years, it will be impossible to assess what the capacity value of energy use in one hour might be relative to the energy use in a different hour. In addition, there are no currently accepted methodologies in use for the assessment of the hourly value of transmission and distribution costs. As discussed below in the context of technical feasibility, several components of hourly costs are not currently available, making the evaluation of the value of load shift difficult or meaningless to calculate.

Determining the net value of any load shift would also require offsetting the cost of serving new load in the hour to which electricity use is shifted. This in turn would require an

understanding of whether reduced load in various hours would result in overall load reductions (load shed) or a shift to other hours (load shift), and if so, to which hours. Furthermore, the value of a given shift (e.g., from 8 p.m. to 11 p.m.) is likely to vary by day of the week. Even if only within-day shifts are assessed, this constitutes nearly 50,000 pairwise shifts between hours across the year, even assuming that a single week can be representative of all hours in the month. This calculation would require extremely large quantities of data that are not available at this time. Thus, a full cost-effectiveness assessment is currently difficult or infeasible.

Given the difficulties in evaluating the cost-effectiveness of an MCB rate today, PCE is strongly interested in the data and key lessons to be derived from participating in CPUC-sponsored IOU pilots. Should the data on both responsiveness and costs be available, PCE anticipates being able to more fully analyze the costs and benefits of such programs in future years.

2.3.2. Equity

Significant equity concerns are raised by MCB rates because any error from the true cost raises the prospect of unrecovered costs. If any kind of adder is required to cover these unrecovered costs, this is likely to represent a cost shift onto non-participating customers. PCE anticipates that participation in any MCB rate offering is likely to be primarily by wealthier and more sophisticated customers able to afford the technology required to truly take advantage of such a rate. Non-participating customers should not bear increased costs because of such rate structures. However, since the actual costs that would be realized are difficult to determine a priori, costs recovered through MCB rates are likely to be highly variable, as customers are almost guaranteed not to respond as forecast in every billing period. Thus, the MCB rates would need to incorporate conservative assumptions about costs recovered through these rates and err on recovering more costs from participating customers. However, if these rates are intentionally conservative to ensure adequate cost recovery in all billing periods, then the economic benefits of participating would be blunted. As such, ensuring equity impacts are avoided likely limits the utility of MCB rates in the first place.

A second major point of concern is possible exposure of low-income customers to real-time market prices. Customers may elect to sign up for new rates without an understanding of the risks or, because most loads are inelastic, with limited ability to react. This can result in extreme customer costs during extreme weather or other significant events.

2.3.3. Technical Feasibility

MCB rates also face several technical prerequisites that would need to be satisfied before implementation of an MCB rate. PCE faces some of the similar challenges as PG&E, including the lack of transmission and distribution marginal costs currently called for in the regulation. Assessing the hourly and locational costs is difficult to ascertain with reliable

methodologies. Consequently, there is no obvious data source to access hourly values to use as inputs to an MCB rate.

In addition, the hourly capacity costs are currently impossible to assess, because CPUC jurisdictional entities are transitioning to a new hourly capacity construct currently. The 24-hour slice-of-day framework will generate differential value of capacity in different hours. However, the CPUC has not finished implementing the slice-of-day methodology and several cost containment proposals remain unresolved. Over time, hourly capacity costs should be established by the market, but until LSEs develop expertise in trading hourly products over some years, it will be impossible to assess the capacity value in each hour.

In addition, since PCE is not its own billing agent, additional prerequisites exist and remain to be resolved including access to billing quality daily-hourly data on a timely basis. This likely requires CPUC action to order PG&E to provide such data to PCE. PCE is an active participant in the DER Data Access proceeding at the CPUC (R.22-11-013) to assist the CPUC in making the requisite data available to enable the rates and programs PCE would like to implement.

PCE strongly supports the goals of load shifting as a key cost-containment strategy, but there are a significant number of prerequisites that remain to be implemented on a usable, statewide basis.

2.3.4. Benefits to the Grid

If PG&E pilots are successful in shifting load to cheaper-to-serve times of day beyond what the TOU rates already achieve, this could provide marginal cost savings in the medium term. However, unpredictable customer behavior may actually impose costs on the grid as well.

The changing nature of the grid supply may mean that this value will diminish as California shifts to a fully decarbonized grid. Variable energy resources vary strongly not just by hour, but seasonally. In PCE's modeling of achieving a fully decarbonized energy supply that meets PCE's load on an hourly basis with 100% renewable energy, the most important constraints on the grid are likely to shift from concerns about capacity during net peak load periods to daily energy constraints during seasons with low solar over a 24-hour cycle. These constraints will arise in winter months, during which lower solar production to charge storage will drive constraints in the early morning hours. A portfolio that has both sufficient generation and storage to be capable of meeting overnight winter loads with diminished generation will have considerable excess energy to serve peak load with zero marginal cost energy at other times of the year. What this means is that if storage is capable of meeting load whenever it occurs, then load shifting from one hour to another will deliver few if any grid benefits. In contrast, shifting load from one season to another would be far more significant, but it is difficult to conceive of how this might be

accomplished and whether an MCB rate would incentivize investments in such technologies.

In addition, MCB rates may drive customer behavior in ways that force greater distribution costs. In particular, there are some indications that TOU rates have concentrated EV charging in hours immediately after the end of high TOU rate periods. This can actually increase the need for distribution investment to address new higher peak demands outside of TOU hours. If EV drivers move their charging to a small number of low-price hours in response to MCB rates, peak demand on the distribution circuits during those hours could spike. This would require significant distribution investments to accommodate new, higher peak demand. For example, if MCB rates send a signal to charge during solar hours based on CAISO wholesale market prices, that may drive very high loads on particular distribution circuits, triggering large-scale upgrades. Thus, responding to grid-level signals may drive high costs on specific circuits. Since the bulk of retail rates are made up of transmission and distribution charges, increasing these investments may swamp any benefit seen on energy generation costs. The interplay of these dynamics is difficult to predict, meaning that the net benefit to the grid from MCB rates is impossible to assess and may result in a net detriment to the grid.

In the medium term, the key analysis is the degree to which an MCB rate will shift load from expensive hours to cheaper ones. However, absent critical data on the hourly elasticity of electricity as described above, that analysis is currently not feasible to do.

2.3.5. Benefits to Customers

The benefits to participating customers depend on whether existing TOU rate differentials are greater or less than the hourly differences in marginal costs. In theory, if the difference between high-rate hours and low-rate hours is less than the hourly differences in marginal costs, then shifting to an MCB rate may save customers money if they can shift loads to relatively cheaper hours. Under a TOU rate, customers already save money by shifting load outside of the peak window. The benefit to customers then depends on whether customers would save even more money under an MCB rate, but that depends on the details of how the MCB and TOU rates compare in each hour and which hours customers shift usage to and from. Thus, determining whether customers would or would not realize rate benefits will depend on the actual rates by hour relative to existing TOU rates. Since the MCB rates are not currently feasible to develop, it is not possible to analyze the degree of benefits to customers currently.

3. Rate Identification Number

Since CCA bills are controlled and printed by the IOU billing agent (PG&E in this case), PCE has limited input on the design and placement of Rate Identification Numbers (RIN) on the customer billing statements. However, PCE is working with its third-party provider for data

management and billing services, Calpine Energy Solutions (Calpine), and PG&E to comply with LMS requirements for RINs.

3.1. RINs and QR Codes on Customer Bills

PCE, Calpine, and PG&E have agreed to utilize the Electronic Data Interchange (EDI) 810 files to pass through RINs to PG&E for inclusion on the customer billing statements. The RINs are expected to be available to customers via billing statements and online customer accounts by April 2024.

Per PG&E's LMS Compliance Plan, the IOU will include the RIN and QR code on the customer billing statement in the rate schedule code section of the electric service agreement details page. PG&E has stated that it does not plan to include a QR code that links to a webpage.

3.2. Statewide RIN Access Tool

PCE has participated in CEC-led workshops on the development of the Statewide RIN Access Tool and provided input on the process, when able. However, PCE's involvement in the development of the tool is limited, as it has been with the design and placement of the RINs on the customer billing statements, which IOUs control. Nonetheless, PCE has been working with the other LSEs to design and implement the statewide RIN tool, pursuant to 20 Cal. Code Regs. § 1623(c). A proposed plan for the tool was submitted by a subset of LSEs to the CEC for review on October 1, 2024. We will continue to work with the other LSEs and the CEC to establish appropriate mechanisms for the implementation and maintenance of the statewide RIN tool in a timely manner subject to the tool's approval by the Commission.

4. Load Flexibility Programs

4.1. Overview

In addition to the MCB rate approach above, PCE is also developing a series of programs that can become MCB signal-responsive programs to either supplement or serve in place of MCB rates in future years. PCE is also pursuing more cost-effective approaches of "right sizing" transportation and building electrification infrastructure to constrain costs and address peak loads

Load flexibility and grid reliability are key elements of PCE's decarbonization strategy. PCE has multiple offerings currently and is exploring a number of additional leading-edge options for its customers. These programs will likely play a central role in PCE's load-shifting strategy to meet the objective of the LMS.

PCE has established the following objectives for its distributed resources programs:

- Provide grid benefits, especially peak shaving to reduce wholesale costs and carbon intensity, aiding further penetration of renewables.
- Enable resilience.
- Lower operating costs for customers.
- Make electrification more economically beneficial.
- Create scalable deployment through sustainable models.

PCE's approach includes a focus on avoiding unnecessary capacity increases which can result in added costs and reliability challenges. This includes guidelines for residential electrification within 100-amp service,[10] use of low-power charging in multi-family buildings, and fleet infrastructure planning.[11] In addition, PCE programs emphasize continuous load shaping, in contrast to event-driven curtailment, to maximize the benefits of load shaping for customers and the grid.

PCE has focused on developing a portfolio of flexible and effective load-shaping programs aimed at significantly reducing grid peak loads. PCE has also worked to innovate with technology and software providers to advance functionality that will allow for broad participation and help maximize potential resources, optimized for customer and grid needs. Multiple approaches are being continually assessed and PCE is learning from these initiatives to inform future program designs and the technology needed to scale adoption.

PCE currently offers a portfolio of load flexibility programs with a diversity of enabling technologies, and different tiers of engagement to provide options for customers. Following is a list of current and planned program offerings, including several pilots that are being tested for reliability, load reduction, and customer adoption.

4.1.1. Distributed Energy Resources Management System Deployment

In support of enabling automated responsiveness to any load flexibility signals, including MCB signals, PCE is planning on incorporating its load flexibility programs under a Distributed Energy Resource Management System (DERMS) platform. PCE published a request for proposals (RFP) for Customer Demand Flexibility Services in September 2024 and has selected a vendor for the development of its DERMS platform. PCE will evaluate the development of dynamic pricing signals under its DERMS platform by mid-2026.

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[10] Blake Herrschaft, *Design Guidelines for Home Electrification*, 7-12 (2023), https://www.peninsulacleanenergy.com/wp-content/uploads/2023/04/Design-guidelines-for-home-electrification-v041223.pdf

[11] *San Carlos Case Study: EV chargers for your fleet, less is more*, Peninsula Clean Energy, https://www.peninsulacleanenergy.com/san-carlos-case-study-ev-chargers-for-your-fleet-less-is-more/; *Access to slow EV chargers could speed up EV adoption among renters*, Canary Media, https://www.canarymedia.com/articles/ev-charging/access-to-slow-ev-chargers-could-speed-up-ev-adoption-among-renters

4.1.2. Solar and Storage for Public Buildings

Overview: Public agencies have significant interest in the deployment of solar and storage systems to reduce costs and provide resilience for power outages and emergencies. In addition, the Inflation Reduction Act's "direct pay" provisions allow public agencies to access the Investment Tax Credit without an intermediary, improving the economics of distributed generation systems. PCE operates an aggregate solar and storage program aimed at improving the economics of distributed solar and storage for public agencies. This program operates in cohorts in which PCE assumes the role of developer, providing upfront project development services, procurement, and financing under a PCE-supplied power purchase agreement (PPA) for the local government agency. Systems are then deployed by a construction firm under contract with PCE. PCE owns the systems and provides ongoing operations and maintenance support with a performance guarantee. The storage systems will provide backup power for outages and dispatch for grid peak load reduction.

Status: This program was launched in 2020 with significant legal and site development work to establish the program. Construction of the initial 12 systems with 1.7 MW of solar are nearing completion.[12] The second round of the program included 24 sites for approximately 3.5 MW PV is under construction. A third round to incorporate storage is in development. Additional solar and storage sites are in development with as much as 6 MW of storage. Dispatch may be administered directly through a PCE distributed energy resource management system (DERMS), battery management systems, or contractually specified with service providers.

4.1.3. Residential Solar and Storage

Overview: Residential storage systems, typically paired with solar, are growing in popularity. Currently in PCE territory, there are approximately 34,000 systems with a total of 71.6 MW of storage.[13] With the state's adoption of the Net Billing Tariff, it is expected that residential solar and storage adoption will grow. PCE has had a residential solar and storage program since 2020. That program has provided outreach and incentives for customers to adopt solar and storage systems. The systems are installed by a competitively selected provider and the storage systems dispatch at the grid peak as specified under the contract between PCE and the provider.

Status: PCE's residential solar and storage program completed its enrollment phase between 2020 and 2023. Nearly 400 new system installations were completed, and an additional 200 existing systems were enrolled. (PCE is also enabling a further 200-300 systems at low-income customer sites, funded by a combination of the Self-Generation and Investment Tax Credit.) Under the agreement with the provider, the provider offers

[12] *US climate law introduces billion-dollar 'game-changer' for nonprofits*, Canary Media https://www.canarymedia.com/articles/climatetech-finance/us-climate-law-introduces-billion-dollar-game-changer-for-nonprofits

[13] Q4 2023 PG&E Interconnection Data for Peninsula Clean Energy service territory

battery storage dispatch during the evening peak, and PCE purchases the rights to this capacity over a 10-year term. The dispatch capacity is factored into PCE's annual load forecast submitted to the CEC, and subsequently, the CEC reduces PCE's forecasted RA capacity as a result of a lower forecasted peak load. PCE is continually working with the provider to further optimize the dispatch schedule to maximize the grid value, such as by concentrating as much energy capacity into a narrower, 2-hour dispatch window. In addition, PCE anticipates developing a follow-on program that will again provide support to homeowners in deploying solar and storage systems, while also providing capacity services to the grid. Dispatch may be administered directly through a PCE DERMS or contractually specified with service providers.

4.1.4. FLEXmarket

Overview: PCE utilizes the innovative FLEXmarket program to provide incentives to project implementers based on the measured grid benefits. PCE is implementing this approach because most energy efficiency programs do not adequately target load-shaping benefits. In addition, incentives are not targeted based on grid benefits nor measure actual results. This program operates across all customer classes for permanent load shifting achieved by targeted energy efficiency and beneficial electrification. The program utilizes Normalized Metered Energy Consumption (NMEC) methodology to assess projects based on their actual performance weighed against grid benefits with the Avoided Cost Calculator (ACC). This is a CPUC-funded program.

Status: PCE launched its FLEXmarket program in 2023 for both the commercial and residential sectors and has successfully enrolled projects in the first iteration of the program. Initial program emphasis has been on attracting service providers and proving the general model of the program. PCE anticipates continuing the program subject to CPUC approval.

4.1.5. Residential Electrification Direct Install

Overview: PCE operates an income-qualified direct install program for electric appliances – replacing aging, polluting methane gas systems. This program has upgraded approximately 300 homes with heat pump water heaters or other efficient electric measures. Under the program, PCE has piloted whole-home electrification of 5 single-family homes to assess costs and demonstrate electrification that minimizes grid impacts by fully electrifying within 100 amps.[14] Finally, PCE has also piloted an advanced load-

[14] *Yes, it's possible to electrify a home on just 100 amps*, Canary Media, https://www.canarymedia.com/articles/electrification/yes-its-possible-to-electrify-a-home-on-just-100-amps

shaping technology in space and water heating combo systems which can shift load in both applications through the thermal storage and advanced system logic.[15]

Status: This program will be substantially expanded in 2024 to allow for whole-home electrification. Numerous innovations are envisioned to be incorporated into this program including electrification within 100 amps, as well as the potential use of advanced combo systems, and integration of load shaping for water heaters and thermostats, possibly through a PCE DERMS. Separate from this program, PCE currently provides incentives to customers for the installation of load-shaping combo systems.

4.1.6. GovEV

Overview: The GovEV program helps local municipal fleets plan for fleet electrification by providing technical assistance for vehicle replacement purchasing and the installation of EV chargers. As a component of this program, PCE produces a charging optimization plan, which outlines the cost potential of managed charging for their specific fleet. PCE is also making the ChargePilot charge management system by The Mobility House free for fleets, as part of the GovEV program for one year. The ChargePilot system (optional to fleets but recommended) will help shift more fleet charging to occur during off-peak hours and mitigate demand charges, as well as provide insights into EV charging metrics for fleet managers.

Status: The program is open, and 10 fleets are currently enrolled. Installation projects are expected to begin in Calendar Year (CY) 2025.

4.1.7. Electric Vehicle Managed Charging

Overview: PCE ran an EV Managed Charging Pilot in collaboration with EV.energy and researchers at UC Davis but determined that the response was small and the program not cost-effective. PCE's territory has one of the state's fastest adoption rates for EVs with over 45,000 EVs on the road today and EVs accounting for over one-third of new vehicle sales. Managing EV charging is a high priority for PCE with an emphasis on residential charging, where most evening charging is occurring, and shifting vehicle load daily out of the evening peak. In addition, minimizing the secondary midnight peak that can affect local distribution networks is also a priority. PCE has focused on leading-edge strategy by using vehicle telematics, which controls EV charging through the vehicle as opposed to charger-based load management. Because the installed base of smart chargers is very small and such chargers are expensive, the telematics approach holds greater promise because nearly all vehicles can participate without special equipment.

[15] TRC / Rupam Singla, *Harvest Thermal Pilot: Measurement and Verification Report* (2023), https://www.peninsulacleanenergy.com/wp-content/uploads/2024/02/PCE-Harvest-Pilot-MV-Final-Report.pdf

Status: PCE recently completed and analyzed its second phase pilot of managed charging with EV.energy and researchers at UC Davis. The amount of load shift was minor, in large part because customers who opted to participate were more tech-savvy than typical and mostly already shaping their load. In light of the lackluster effectiveness of the pilot, PCE is not moving forward with this particular program design.

4.1.8. Program Design to Meet LMS Goals

Each of these programs is envisioned to incorporate remote dispatch DERMS or comparable technologies, which will enable all of these programs to become automated MCB signal responsive programs, as envisioned in 20 Cal. Code Regs. § 1623.1(a)(1)(B). The timeline and feasibility of the rollout of MCB signals to these load flexibility technologies will be evaluated in future development of PCE's DERMS platform.

4.2. Evaluation

PCE closely evaluates all programs it executes and anticipates that load-shaping programs will be evaluated with the following criteria:

- Amount of grid peak load reduction
- Consistency and reliability of load reduction
- Customer participation rate
- Cost of recruitment and operation
- Customer benefits, impacts, and satisfaction

4.2.1. Cost-Effectiveness

The costs associated with implementing a new load flexibility program include the following:

- Program development. This includes the costs associated with program design and setup, including integrating such programs with internal and external systems.
- Program administration. This involves ongoing costs to administer the program, including marketing, customer recruitment, customer education, development, and maintenance of customer tools, and any upfront or ongoing incentive payments that are part of the design.
- Technology and implementation costs. Each new load flexibility program requires significant investments in new technology platforms. These include external software systems that must be procured to communicate with and dispatch devices, as well as internal systems that must be developed and configured to integrate the external software.

PCE, as a CCA, may derive certain avoided cost value streams such as reduced RA costs and extreme event energy market costs. However, aside from CPUC-funded programs such as FLEXmarket, PCE does not have access to other value streams such as avoided distribution grid costs. Quantification of cost benefits is challenging and of limited

confidence due to the volatile nature of the energy market, as described in the analysis of MCB rates above.

4.2.2. Equity

PCE has a major focus on equity across its programs. PCE's primary method of delivering equity benefits is in keeping generation rates low. Since inception, PCE has provided generation rates at least 5% below PG&E for all customers resulting in over $100 million in savings for the community since 2016. In 2024 PCE is currently keeping rates flat resulting in 10-15% savings for customers compared to PG&E for even greater savings. In addition, in December 2023 PCE provided customers in the income-qualified California Alternate Rates for Energy (CARE) / Family Electric Rate Assistance (FERA) programs each a rebate of $300.

PCE has numerous programs targeted at delivering additional equity benefits. These programs include an EV charging incentive and technical assistance for apartment buildings, income-qualified incentives for e-bikes and EVs, and the above-mentioned home direct-install program.

PCE offerings are geared towards ensuring financial benefits for customers and ensuring access to additional benefits such as functional appliances, etc. Load shaping provides a potential additional tool for reducing customer costs, helping ensure shiftable load is occurring under the most favorable rates. However, most loads in low-income households have little or no shifting capacity. It is essential that households are not penalized for inflexible loads. In addition, while some customer segments are interested in technology it is important that participation not introduce undue complexity, especially in this segment. Therefore, any technologies introduced need high reliability and effective passive operation with as little resident intervention as possible.

4.2.3. Technical Feasibility

Load shaping measures as described above have been technically demonstrated by PCE or other parties. PCE currently engages in a "direct control" approach with EVs (a type of DERMS but only for EVs), contractually based load shaping for its residential storage, and a market-based "shaped" incentive structure in FLEXmarket.

However, real-time responsiveness introduces numerous added levels of complexity. Assets would need to be integrated through a DERMS as a management platform. However, the DERMS landscape is extremely fragmented. Currently, DERMS providers are only able to successfully dispatch a subset of deployed assets, even within an asset type (battery, vehicles, etc.). In addition, customers must retain override capabilities based on specific needs, particularly for batteries which may be needed for power outages in extreme weather, and vehicles for travel needs. Customers, service providers, and manufacturers in many cases can have competing objectives (e.g., backup vs. grid services) and interest in

enrolling in competing programs. In principle, a portfolio approach could yield confidence that a predictable dispatch capacity can be achieved for an event-based program. However, PCE's approach of daily "permanent" load shift offers the advantage of high predictability for the customer and other parties.

Furthermore, for real-time programs, data integration for the price signals would need to be established reflecting real-time conditions and PG&E billing systems would need to be restructured to allow billing based on those prices. A price signal system must address common standards for calculation, availability of data on a real-time basis, high up-time platform for serving the data, mechanism for customer visibility, and other complexities. PG&E's billing system would require major updates of a platform already strained by high complexity, and billing information would need to be presented in a digestible manner for the customer with associated education and customer service support. Both of these areas are major barriers.

4.2.4. Benefits to the Grid

Load shaping provides several grid benefits including reducing costs, increasing reliability, and reducing emissions. Load shaping that is responsive to real-time conditions could potentially increase those benefits to the degree that responsive load shaping is able to provide additional load reductions, above that provided by permanent load shaping, at moments of grid strain.

However, different objectives would necessitate visibility to specific conditions. ISO-level load, transmission congestion, load aggregation points, and distribution circuit conditions each have distinct values that can contribute to the value of load shifting but are not necessarily easily evaluated in real-time by asset controllers, like PCE. Thus, PCE may be able to assess grid value at the level of generation costs but may have difficulty incorporating other grid benefits, except to the degree that data becomes available for other areas.

4.2.5. Benefits to Customers

Customer benefits of load shaping generally are assessed by PCE in relation to economic value. Specifically, cost reductions after considering customer installation costs and the change in operating costs. As noted above, PCE emphasizes permanent load shifting as a means of maximizing the operating cost benefits. Reliability is also an important benefit though this is difficult to quantify.

5. Conclusions

PCE strongly supports the goals of the LMS and is already working diligently to implement leading programs and approaches to deliver load flexibility in a cost-effective and technically feasible manner. Although load-flexibility technologies have many technical

and policy prerequisites that must be satisfied before such approaches can deliver the full potential benefits, PCE is committed to deepening its current approaches and exploring the feasibility of other approaches as they become available. PCE has committed to participate in the IOU HFP pilots to offer MCB rates to our customers. PCE anticipates receiving data on effectiveness and feasibility from that program going forward. While the IOU HFP pilots move forward, PCE is also moving forward on deploying a DERMS platform to enable MCB signal responsive programs as an alternative or supplement to MCB rates in coming years.

Load flexibility is a key tool for PCE's core objective to provide its customers with 100% renewable energy in all hours. Given PCE's goals, it anticipates working with the CEC to develop new approaches and to provide real-world, on-the-ground expertise from the lessons derived from this work going forward.

Load Management Standard Compliance Plan

Peninsula Clean Energy Authority

Revised March 15, 2025

Deleted: January 30

1. Introduction

Peninsula Clean Energy Authority (PCE) supports the overall objectives of the Load Management Standard (LMS) since these strategies are important for PCE's goal of serving its customers 100% renewable energy on a high time-coincident basis in coming years. Since this requires the matching of load to the generation of PCE's contracted variable energy generation resources, load shifting is a critical strategy for PCE to achieve this goal. PCE looks forward to working with the California Energy Commission (CEC) in the coming years to develop cutting-edge and cost-effective approaches to achieving the overall goals of the standard.

1.1. About PCE

PCE, a community choice aggregator (CCA), provides electricity service to residents and businesses in San Mateo County and the City of Los Banos in Merced County. Formed in February 2016, PCE is a joint powers authority, consisting of the County of San Mateo, all twenty of its towns and cities, and the City of Los Banos in Merced County. Following a comprehensive feasibility study, consistent with Assembly Bill (AB) 32 voluntary action pathways, elected officials from each member jurisdiction unanimously agreed to form PCE to meet their local climate action goals and for the benefit of San Mateo County. In 2020, following another comprehensive feasibility study, elected officials from the City of Los Banos voted to join PCE.

PCE provides cleaner electricity, and at lower rates, than the incumbent investor-owned utility (IOU), Pacific Gas and Electric Company (PG&E). PCE plans for and secures commitments from a diverse portfolio of energy-generating resources to reliably serve the electric energy requirements of its customers over the near-, mid-, and long-term planning horizons. PCE was assigned an investment-grade credit rating from Moody's in May 2019 and S&P in June 2023, the second of the three CCAs in California to obtain investment-grade credit ratings. PCE's programs include advancing the adoption of electric transportation and transitioning building fossil fuel uses to low-carbon electricity.

As part of its mission-driven, collaborative, not-for-profit, locally focused roots, PCE is committed to two key organizational priorities:

- Deliver 100% renewable energy on an annual basis and align renewable energy supply with customer demand each and every hour of the day in the coming years.
- Contribute to San Mateo County reaching the state's goal to be 100% free of greenhouse gasses (GHG).

PCE is also committed to the following several strategic goals:

- Secure sufficient, low-cost, clean sources of electricity that achieve PCE's priorities while ensuring reliability and meeting regulatory mandates.
- Strongly advocate for public policies that support PCE's organizational priorities.

- Implement robust energy programs that reduce GHG emissions, align energy supply and demand, and provide benefits to community stakeholder groups.
- Develop a strong brand reputation that drives participation in PCE's programs while ensuring customer satisfaction.
- Employ sound fiscal strategies to promote long-term organizational sustainability.
- Ensure organizational excellence by adhering to sustainable business practices and fostering a workplace culture of innovation, diversity, transparency, and integrity.

The importance of these goals for the communities of San Mateo County is underscored by the 2019 declaration of a climate emergency by the Board of Supervisors calling on local agencies and jurisdictions to work "to achieve carbon neutrality throughout San Mateo County and to implement other actions to address climate change."[1]

1.2. The Role of PCE's Board of Directors

PCE is governed by its Board of Directors (Board). Each member jurisdiction from San Mateo County, plus the city of Los Banos, has one seat on PCE's Board (except for San Mateo County, which has two) for a total of 23 elected officials acting as board members. In addition, the Board has two board member director emeritus selected from former directors who participate in board activities as non-voting members.

The Board is responsible for setting the overall strategy for PCE, including rate setting and energy procurement decisions.[2] The decisions of the Board are binding requirements for PCE.

In addition to operating the CCA program, PCE also implements a range of customer programs to facilitate decarbonization and access to electrification, especially for disadvantaged customers. Generally, PCE does not receive cost recovery from the California Public Utilities Commission (CPUC) for these programs but funds them through rates or grants from outside sources.

1.3. The CEC Load Management Standard

In 1974, the California State Legislature passed the Warren-Alquist Act establishing the CEC. At its inception, the CEC was granted specific authority including but not limited to implementing load management standards.[3] The CEC updated these standards in 2022 to

[1] County of San Mateo Board of Supervisors, Resolution No. 19-847: Adopt a resolution endorsing the declaration of a climate emergency in San Mateo County that demands accelerated actions on the climate crisis and calls on local jurisdictions and agencies to join together to address climate change (2019).
[2] Public Utilities Code § 366.2.
[3] California Energy Commission, *2022 Load Management Standards Rulemaking Fact Sheet*, 1 (2022), https://www.energy.ca.gov/sites/default/files/2022-10/Load_Management_Fact_Sheet_ADA.pdf

enhance statewide demand flexibility, and the new amendments effective as of April 2023 are what this plan addresses.[4]

The CEC established its LMS regulation based on the definition of load management as "any utility program or activity that is intended to reshape deliberately a utility's load duration curve."[5] The primary objectives of the regulation are to:

- Encourage energy use at off-peak hours.
- Encourage daily and seasonal peak load control to improve equity, efficiency, and reliability of the electric system.
- Decrease or delay the need for new electrical capacity.
- Reduce GHG emissions and fossil fuel consumption.

To ensure progress toward these goals, the CEC is requiring California's large Publicly Owned Utilities (POU), large IOUs, and large CCAs to submit LMS Plans outlining how they will meet the LMS regulation requirements.

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The LMS regulation requires each large POU, IOU, and CCA to analyze an optional hourly marginal cost-based (MCB) rate for each customer class. The proposed rate should be evaluated based on five factors: (i) cost-effectiveness, (ii) equity, (iii) technical feasibility, (iv) benefits to the grid, and (v) benefits to customers. If the CCA deems the implementation of an MCB rate is not feasible based on one or more of the five factors, then it must propose cost-effective load flexibility programs for compliance and conduct an evaluation using the same five metrics. Compliance may be modified or delayed if the CCA can show that despite good faith effort, requiring timely compliance would result in reduced system efficiency or reliability, extreme hardship, technological infeasibility, or lack of cost-effectiveness to the CCA.

[4] 20 Cal. Code Regs. §§ 1621-1625.
[5] Public Resources Code § 25132.

Table 1 outlines the goals set forth in the LMS regulation, along with the expected completion date identified by the CEC and PCE's progress status toward meeting that deadline.

Table 1. Progress Toward LMS Goals

LMS Section	Description	Deadline	PCE Status
§1623.1(c)	Upload existing time-dependent rates to the Market Informed Demand Automation Server (MIDAS) database.	October 1, 2023	Completed with ongoing updates
§1623(c)	Provide customers access to their Rate Identification Numbers (RIN) on billing statements and in online accounts using both text and quick-response (QR) code.	March 31, 2024	Awaiting PG&E billing changes
§1623.1(a)(1)	Develop and submit to PCE's Board an LMS plan.	April 1, 2024	Submitted to the Board March 22, 2024
§1623.1(a)(3)(A)	Submit to the CEC the Board-approved LMS plan.	May 31, 2024	
§1623(c)	Develop and submit to the CEC, in conjunction with the other obligated utilities, a single statewide RIN access tool.	Oct. 1, 2024	Ongoing, through CalCCA participation
§1623.1(b)(3)	Submit to the CEC a list of load flexibility programs deemed cost effective by PCE.	Oct. 1, 2024	
§1623.1(a)(3)(C)	Submit annual reports to the CEC demonstrating implementation of plan, as approved by the PCE Board.	Annually	
§1623.1(b)(2)	Submit to the PCE Board for approval at least one MCB rate for the customer class(es) for which it will materially reduce peak load.	July 1, 2025	
§1623.1(b)(2)	Offer customers voluntary participation in either an MCB rate, if approved by the Board, or a cost-effective load flexibility program.	July 1, 2027	
§1623.1(b)(5)	Conduct a public information program to inform and educate affected customers why MCB rates or load flexibility programs and automation are needed, how they will be used, and how these rates and programs can save customers money.	Goal date not specified	Ongoing currently
§1623.1(a)(1)(C)	Review the plan at least once every 3 years after it is adopted and submit an update to the PCE Board if there is a material change.	Triennially	

2. PCE LMS Plan

2.1. Overview

The PCE Board does not find, based on substantial evidence in light of the whole record, that designing and implementing its own MCB rates as likely to be cost-effective or technically feasible as an approach to meeting the goals of the LMS, as discussed below, consistent with the findings specified in 20 Cal. Code Regs. § 1623.1(a). However, PCE is participating in two of PG&E's Real-Time Pricing (HFP) rate pilots as a more effective approach to LMS-compliant rate offerings. The PCE Board approved participation in PG&E's Expanded Pilot 2 and Vehicle to Grid Integration (VGI) pilot to comply with the LMS. PCE will provide an update on the expansion of the pilots in its next LMS Compliance Plan report. Subsequently, PCE filed Advice Letter (AL) PCEA-039-E on November 1, 2024, noticing the CPUC that PCE is participating PG&E's HFP pilots.[6]

2.2. RTP Pilots

To implement PCE's MCB rates for its residential, commercial, and industrial classes, PCE will focus staff resources on participation in two of PG&E's HFP pilots: the Expanded Pilot 2 and the VGI pilots. PCE has declined to participate in the Expanded Pilot 1 (Agricultural) because the PCE Board finds that this pilot would not be cost-effective due to the small number of agricultural customers among PCE's customer base and a lack of peak-coincident load.

2.2.1. Rate Design

- The MCB rates PCE will offer through *PG&E's* HFP pilots will be based on deviations from historical usage at marginal rates driven by dynamic hourly prices. The dynamic prices include *marginal generation capacity costs* as approved in D.21-11-016 and allocation as specified in D.22-08-002 and marginal energy costs as approved in D.21-11-016, based on PG&E Default Load Aggregation Point (DLAP), adjusted for line losses.[9] **Marginal Transmission and** distribution costs will be based on forecasted load on a representative circuit with similar load characteristics to the customer's circuit, but annual average load-weighted prices will not vary geographically for equity reasons.[10] The rate design will incorporate a fixed cost collection subscription mechanism as outlined in the California Flexible Unified Signal for Energy (CalFUSE) proposal, with no scalers or adders.

[6] Peninsula Clean Energy Authority Advice Letter 049-E "Notice to the Commission of Participation in the PG&E Expanded Pilot 2" (November 1, 2024) available at https://www.peninsulacleanenergy.com/wp-content/uploads/2024/11/PCE-AL-39E_Expanded-Pilot-2-Opt-in-1.pdf

[9] Pacific Gas and Electric Company, 2023 LMS Compliance Plan (2023).

[10] Pacific Gas and Electric Company, 2023 LMS Compliance Plan (2023).

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Deleted: The status of PG&E's RTP pilots is in flux as the IOU is awaiting feedback from the CPUC regarding its expansion requests. PG&E details how the expanded pilots will comply with LMS in its LMS Compliance Plan submitted October 2, 2023.¶

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Pilots are in progress and proposed for PG&E's service area, which have made (or will make) RTP rates available to customers in the next few years. These pilots will continue to provide important learnings to inform RTP rate design. The Valley Clean Energy (VCE) AgFIT agricultural water pumping pilot is available to agricultural customers in VCE's service area and inc ... [1]

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The Expanded Pilot 2 and VGI pilots are anticipated to be available without participation limits to all of our residential, commercial, and industrial customers. These pilots are available to all customers based on the terms defined by PG&E and per the regulatory approvals.[12] PCE is not imposing any participation cap. Pilot descriptions are included below.

- Expanded Pilot 2: Under the Demand Flexibility proceeding (R.22-07-005), PG&E was directed to expand a pilot program developed by Valley Clean Energy (VCE) and PG&E in response to the 2021 grid reliability challenges. PG&E must now extend the pilot developed with VCE to serve residential, commercial, and industrial customers. The pilot is being rolled out via "Automation Service Providers" (ASPs), who currently provide automation services to existing devices installed in homes and businesses. PG&E has an enrollment target of 50 MWs under the pilot, which is currently scheduled to conclude by December 31, 2027.
- VGI Pilots: Under the Transportation Electrification proceeding (R.18-12-006), PG&E was directed to develop two VGI pilots with a dynamic pricing rate to serve residential and commercial customers. Both pilots provide upfront incentives for bidirectional electric vehicle (EV) charging equipment in phase 1 and then require customers to enroll under a dynamic pricing rate during phase 2. Across its entire service territory, PG&E is planning to enroll 200 commercial customers under the VGI commercial pilot. The dynamic rate is expected to be available for 12 months under both pilots or until funding is exhausted.

PCE anticipates enrolling customers in the pilots by June 1, 2025, or earlier if feasible, to comply with CEC regulations.

PCE is not participating in PG&E's Expanded Pilot 1, which targets agricultural customers. PCE staff determined that offering a pilot rate program to our agricultural customers would not result in material peak load reduction or be cost effective, based on the following factors:

- Lack of shiftable peak load: PCE has only 129 agricultural customers which represent 0.4% of PCE's peak load.
- Administrative burden: The administrative burden of implementing the Expanded Pilot 1 would very likely exceed the benefits gained from the program, and limit staffing resources which could be applied to the pilots more applicable to PCE's customer base.

[12] CPUC Decision 24-01-032, PG&E's Advice Letter 7222-E1, Advice Letter 7222-E-A2, Advice Letter 7222-E-B3, Advice Letter 7223-E-A4 and Advice Letter 7223-E-B5 for the Expanded Pilots, and PG&E's Advice Letter 7234-E-A6, and CPUC's Resolutions E-5192, E-5326 and E-5358 for the Vehicle Grid Integration (VGI) Pilots (Regulatory Approvals), (together the "Hourly Flex Pricing Pilots", or "HFP Pilots")

Since our agricultural customer class is small, and does not have high demand during peak periods, implementing this pilot for agricultural customers would not have a significant effect on our peak loads, even if participation and responsiveness to MCB rates were high. Therefore, PCE's Board did not find it cost effective to offer MCB rates to our agricultural customer class.

As PG&E has indicated, it will no longer be able to make the necessary updates to its billing system to implement a more permanent dynamic pricing solution until after July 1, 2027. We anticipate that the pilot programs will be extended to customers beyond that date, subject to CPUC approval. Should either the CPUC decline to extend these pilots past that date or PCE deem that continued participation is not the most cost-effective approach to enabling load shifting, PCE will submit an LMS plan revision to update our plan for offering either MCB rates or marginal cost signal responsive programs to all customer classes for which they are cost effective, or both, as provided for in 20 Cal. Code Regs. § 1623.1. Until such time as the CPUC makes its decision, such a determination of continued participation would be premature.

Deleted: As previously stated, PCE will explore whether to adopt similar rates if PG&E implements an RTP rate in the future....

In addition to the MCB rate pilots, PCE will continue to deploy programs that can respond to MCB signals, as described below. Under this approach, most or all customers will likely have multiple vehicles for creating load flexibility. Both the MCB rates and the marginal cost signal responsive programs are anticipated to interact with the statewide RIN tool pursuant to 20 Cal Code Regs. § 1623 (c) when it becomes available.

2.3. Evaluation

2.3.1. Cost-Effectiveness

PCE's strategy of participation in the CPUC-sponsored pilots is informed by some of the cost and feasibility considerations of designing and implementing its own separate MCB rates. The cost-effectiveness of any MCB rate offering depends on whether the value of any load shift to the customer and PCE exceeds the costs of implementation of the proposal. Evaluation of cost-effectiveness will be a continuous and ongoing effort as the results from the HFP pilots become available. Since CCAs are excluded from cost recovery for expenditures in support of wider grid benefits, the analysis of cost-effectiveness is necessarily narrower than it would be for either IOUs or POUs.

Evaluation of the costs of implementing an MCB rate include a variety of fixed and per-customer costs. Fixed costs include, but are not limited to:

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- Personnel costs for staff to design and maintain MCB rates.
- Management costs to obtain data from the California Independent System Operator (CAISO) and PG&E to calculate hourly costs.
- Software and system costs for design, maintenance, and operations.

- Contractor costs to implement MCB rates, including customer education and support.
- Software and upload costs associated with the MIDAS database interface.

In addition, per-customer costs include, but are not limited to:

- Data charges
- Vendor charges

At this time, the costs associated with the creation, implementation, and maintenance of the MCB rates are difficult to ascertain because many elements are still unknown. In addition to the implementation costs, it is unknown whether and how the CPUC will require PG&E to provide real-time billing quality customer data, the costs associated with obtaining these data, and any required technical or data handling costs. Since PCE would be spreading comparable fixed costs across a small customer base, it is less likely that the value of the marginal improvement in load shifting over PCE's existing Time-of-Use (TOU) rates would be enough to justify these fixed costs, compared to larger Load Serving Entities (LSE), PCE's comparable fixed costs would be recovered from a smaller rate base, resulting in higher per-customer costs.

By the same token that the costs of implementation are difficult to determine, the value of any load shift that might result from an MCB rate is also difficult or impossible to assess at this time. The value of the load shift depends on participation rate, how much load is shifted, in what hours, and the value of that load shift. In principle, the amount of load shift could be determined for each hour if the elasticity of electricity demand in each hour were known; however, evaluating these elasticities would require considerable data for all hours and would have significant uncertainties. In addition, it would be necessary to know how the MCB rate values would differ from existing TOU rates in each of these hours.

Currently, several components of the marginal costs would be difficult to ascertain at this time. While hourly energy costs are currently generated in the CAISO market, the hourly capacity values are unclear. The resource adequacy (RA) program is shifting to a 24-hour slice-of-day framework, which would theoretically generate differential values of capacity in different hours. However, until the slice-of-day framework has been in place for some years, it will be impossible to assess what the capacity value of energy use in one hour might be relative to the energy use in a different hour. In addition, there are no currently accepted methodologies in use for the assessment of the hourly value of transmission and distribution costs. As discussed below in the context of technical feasibility, several components of hourly costs are not currently available, making the evaluation of the value of load shift difficult or meaningless to calculate.

Determining the net value of any load shift would also require offsetting the cost of serving new load in the hour to which electricity use is shifted. This in turn would require an understanding of whether reduced load in various hours would result in overall load

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reductions (load shed) or a shift to other hours (load shift), and if so, to which hours. Furthermore, the value of a given shift (e.g., from 8 p.m. to 11 p.m.) is likely to vary by day of the week. Even if only within-day shifts are assessed, this constitutes nearly 50,000 pairwise shifts between hours across the year, even assuming that a single week can be representative of all hours in the month. This calculation would require extremely large quantities of data that are not available at this time. Thus, a full cost-effectiveness assessment is currently difficult or infeasible.

Given the difficulties in evaluating the cost-effectiveness of an MCB rate today, PCE is strongly interested in the data and key lessons to be derived from participating in CPUC-sponsored IOU pilots. Should the data on both responsiveness and costs be available, PCE anticipates being able to more fully analyze the costs and benefits of such programs in future years.

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2.3.2. Equity

Significant equity concerns are raised by MCB rates because any error from the true cost raises the prospect of unrecovered costs. If any kind of adder is required to cover these unrecovered costs, this is likely to represent a cost shift onto non-participating customers. PCE anticipates that participation in any MCB rate offering is likely to be primarily by wealthier and more sophisticated customers able to afford the technology required to truly take advantage of such a rate. Non-participating customers should not bear increased costs because of such rate structures. However, since the actual costs that would be realized are difficult to determine a priori, costs recovered through MCB rates are likely to be highly variable, as customers are almost guaranteed not to respond as forecast in every billing period. Thus, the MCB rates would need to incorporate conservative assumptions about costs recovered through these rates and err on recovering more costs from participating customers. However, if these rates are intentionally conservative to ensure adequate cost recovery in all billing periods, then the economic benefits of participating would be blunted. As such, ensuring equity impacts are avoided likely limits the utility of MCB rates in the first place.

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A second major point of concern is possible exposure of low-income customers to real-time market prices. Customers may elect to sign up for new rates without an understanding of the risks or, because most loads are inelastic, with limited ability to react. This can result in extreme customer costs during extreme weather or other significant events.

2.3.3. Technical Feasibility

MCB rates also face several technical prerequisites that would need to be satisfied before implementation of an MCB rate. PCE faces some of the similar challenges as PG&E, including the lack of transmission and distribution marginal costs currently called for in the regulation. Assessing the hourly and locational costs is difficult to ascertain with reliable

methodologies. Consequently, there is no obvious data source to access hourly values to use as inputs to an MCB rate.

In addition, the hourly capacity costs are currently impossible to assess, because CPUC jurisdictional entities are transitioning to a new hourly capacity construct currently. The 24-hour slice-of-day framework will generate differential value of capacity in different hours. However, the CPUC has not finished implementing the slice-of-day methodology and several cost containment proposals remain unresolved. Over time, hourly capacity costs should be established by the market, but until LSEs develop expertise in trading hourly products over some years, it will be impossible to assess the capacity value in each hour.

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In addition, since PCE is not its own billing agent, additional prerequisites exist and remain to be resolved including access to billing quality daily-hourly data on a timely basis. This likely requires CPUC action to order PG&E to provide such data to PCE. PCE is an active participant in the DER Data Access proceeding at the CPUC (R.22-11-013) to assist the CPUC in making the requisite data available to enable the rates and programs PCE would like to implement.

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PCE strongly supports the goals of load shifting as a key cost-containment strategy, but there are a significant number of prerequisites that remain to be implemented on a usable, statewide basis.

2.3.4. Benefits to the Grid

If PG&E pilots are successful in shifting load to cheaper-to-serve times of day beyond what the TOU rates already achieve, this could provide marginal cost savings in the medium term. However, unpredictable customer behavior may actually impose costs on the grid as well.

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The changing nature of the grid supply may mean that this value will diminish as California shifts to a fully decarbonized grid. Variable energy resources vary strongly not just by hour, but seasonally. In PCE's modeling of achieving a fully decarbonized energy supply that meets PCE's load on an hourly basis with 100% renewable energy, the most important constraints on the grid are likely to shift from concerns about capacity during net peak load periods to daily energy constraints during seasons with low solar over a 24-hour cycle. These constraints will arise in winter months, during which lower solar production to charge storage will drive constraints in the early morning hours. A portfolio that has both sufficient generation and storage to be capable of meeting overnight winter loads with diminished generation will have considerable excess energy to serve peak load with zero marginal cost energy at other times of the year. What this means is that if storage is capable of meeting load whenever it occurs, then load shifting from one hour to another will deliver few if any grid benefits. In contrast, shifting load from one season to another would be far more significant, but it is difficult to conceive of how this might be

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accomplished and whether an MCB rate would incentivize investments in such technologies.

In addition, MCB rates may drive customer behavior in ways that force greater distribution costs. In particular, there are some indications that TOU rates have concentrated EV charging in hours immediately after the end of high TOU rate periods. This can actually increase the need for distribution investment to address new higher peak demands outside of TOU hours. If EV drivers move their charging to a small number of low-price hours in response to MCB rates, peak demand on the distribution circuits during those hours could spike. This would require significant distribution investments to accommodate new, higher peak demand. For example, if MCB rates send a signal to charge during solar hours based on CAISO wholesale market prices, that may drive very high loads on particular distribution circuits, triggering large-scale upgrades. Thus, responding to grid-level signals may drive high costs on specific circuits. Since the bulk of retail rates are made up of transmission and distribution charges, increasing these investments may swamp any benefit seen on energy generation costs. The interplay of these dynamics is difficult to predict, meaning that the net benefit to the grid from MCB rates is impossible to assess and may result in a net detriment to the grid.

In the medium term, the key analysis is the degree to which an MCB rate will shift load from expensive hours to cheaper ones. However, absent critical data on the hourly elasticity of electricity as described above, that analysis is currently not feasible to do.

2.3.5. Benefits to Customers

The benefits to participating customers depend on whether existing TOU rate differentials are greater or less than the hourly differences in marginal costs. In theory, if the difference between high-rate hours and low-rate hours is less than the hourly differences in marginal costs, then shifting to an MCB rate may save customers money if they can shift loads to relatively cheaper hours. Under a TOU rate, customers already save money by shifting load outside of the peak window. The benefit to customers then depends on whether customers would save even more money under an MCB rate, but that depends on the details of how the MCB and TOU rates compare in each hour and which hours customers shift usage to and from. Thus, determining whether customers would or would not realize rate benefits will depend on the actual rates by hour relative to existing TOU rates. Since the MCB rates are not currently feasible to develop, it is not possible to analyze the degree of benefits to customers currently.

3. Rate Identification Number

Since CCA bills are controlled and printed by the IOU billing agent (PG&E in this case), PCE has limited input on the design and placement of Rate Identification Numbers (RIN) on the customer billing statements. However, PCE is working with its third-party provider for data

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management and billing services, Calpine Energy Solutions (Calpine), and PG&E to comply with LMS requirements for RINs.

3.1. RINs and QR Codes on Customer Bills

PCE, Calpine, and PG&E have agreed to utilize the Electronic Data Interchange (EDI) 810 files to pass through RINs to PG&E for inclusion on the customer billing statements. The RINs are expected to be available to customers via billing statements and online customer accounts by April 2024.

Per PG&E's LMS Compliance Plan, the IOU will include the RIN and QR code on the customer billing statement in the rate schedule code section of the electric service agreement details page. PG&E has stated that it does not plan to include a QR code that links to a webpage.

3.2. Statewide RIN Access Tool

PCE has participated in CEC-led workshops on the development of the Statewide RIN Access Tool and provided input on the process, when able. However, PCE's involvement in the development of the tool is limited, as it has been with the design and placement of the RINs on the customer billing statements, which IOUs control. Nonetheless, PCE has been working with the other LSEs to design and implement the statewide RIN tool, pursuant to 20 Cal. Code Regs. § 1623(c). A proposed plan for the tool was submitted by a subset of LSEs to the CEC for review on October 1, 2024. We will continue to work with the other LSEs and the CEC to establish appropriate mechanisms for the implementation and maintenance of the statewide RIN tool in a timely manner subject to the tool's approval by the Commission.

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4. Load Flexibility Programs

4.1. Overview

In addition to the MCB rate approach above, PCE is also developing a series of programs that can become MCB signal-responsive programs to either supplement or serve in place of MCB rates in future years. PCE is also pursuing more cost-effective approaches of "right sizing" transportation and building electrification infrastructure to constrain costs and address peak loads

Load flexibility and grid reliability are key elements of PCE's decarbonization strategy. PCE has multiple offerings currently and is exploring a number of additional leading-edge options for its customers. These programs will likely play a central role in PCE's load-shifting strategy to meet the objective of the LMS.

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PCE has established the following objectives for its distributed resources programs:

- Provide grid benefits, especially peak shaving to reduce wholesale costs and carbon intensity, aiding further penetration of renewables.
- Enable resilience.
- Lower operating costs for customers.
- Make electrification more economically beneficial.
- Create scalable deployment through sustainable models.

PCE's approach includes a focus on avoiding unnecessary capacity increases which can result in added costs and reliability challenges. This includes guidelines for residential electrification within 100-amp service,[14] use of low-power charging in multi-family buildings, and fleet infrastructure planning.[15] In addition, PCE programs emphasize continuous load shaping, in contrast to event-driven curtailment, to maximize the benefits of load shaping for customers and the grid.

PCE has focused on developing a portfolio of flexible and effective load-shaping programs aimed at significantly reducing grid peak loads. PCE has also worked to innovate with technology and software providers to advance functionality that will allow for broad participation and help maximize potential resources, optimized for customer and grid needs. Multiple approaches are being continually assessed and PCE is learning from these initiatives to inform future program designs and the technology needed to scale adoption.

PCE currently offers a portfolio of load flexibility programs with a diversity of enabling technologies, and different tiers of engagement to provide options for customers. Following is a list of current and planned program offerings, including several pilots that are being tested for reliability, load reduction, and customer adoption.

4.1.1. Distributed Energy Resources Management System Deployment

In support of enabling automated responsiveness to any load flexibility signals, including MCB signals, PCE is planning on incorporating its load flexibility programs under a Distributed Energy Resource Management System (DERMS) platform. PCE published a request for proposals (RFP) for Customer Demand Flexibility Services in September 2024 and has selected a vendor for the development of its DERMS platform. PCE will evaluate the development of dynamic pricing signals under its DERMS platform by mid-2026.

[14] Blake Herrschaft, *Design Guidelines for Home Electrification*, 7-12 (2023), https://www.peninsulacleanenergy.com/wp-content/uploads/2023/04/Design-guidelines-for-home-electrification-v041223.pdf

[15] *San Carlos Case Study: EV chargers for your fleet, less is more*, Peninsula Clean Energy, https://www.peninsulacleanenergy.com/san-carlos-case-study-ev-chargers-for-your-fleet-less-is-more/; *Access to slow EV chargers could speed up EV adoption among renters*, Canary Media, https://www.canarymedia.com/articles/ev-charging/access-to-slow-ev-chargers-could-speed-up-ev-adoption-among-renters

Moved down [1]: <#>Electric Vehicle Managed Charging¶

Moved down [2]: <#> territory has one of the state's fastest adoption rates for EVs with over 45,000 EVs on the road today and EVs accounting for over one-third of new vehicle sales. Managing EV charging is a high priority for PCE with an emphasis on residential charging, where most evening charging is occurring, and shifting vehicle load daily out of the evening peak. In addition, minimizing the secondary midnight peak that can affect local distribution networks is also a priority. PCE has focused on leading-edge strategy by using vehicle telematics, which controls EV charging through the vehicle as opposed to charger-based load management. Because the installed base of smart chargers is very small and such chargers are expensive, the telematics approach holds greater promise because nearly all vehicles can participate without special equipment. ¶

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4.1.2. Solar and Storage for Public Buildings

Overview: Public agencies have significant interest in the deployment of solar and storage systems to reduce costs and provide resilience for power outages and emergencies. In addition, the Inflation Reduction Act's "direct pay" provisions allow public agencies to access the Investment Tax Credit without an intermediary, improving the economics of distributed generation systems. PCE operates an aggregate solar and storage program aimed at improving the economics of distributed solar and storage for public agencies. This program operates in cohorts in which PCE assumes the role of developer, providing upfront project development services, procurement, and financing under a PCE-supplied power purchase agreement (PPA) for the local government agency. Systems are then deployed by a construction firm under contract with PCE. PCE owns the systems and provides ongoing operations and maintenance support with a performance guarantee. The storage systems will provide backup power for outages and dispatch for grid peak load reduction.

Status: This program was launched in 2020 with significant legal and site development work to establish the program. Initial 12 systems with 1.7 MW of solar are nearing completion.[16] The second round of the program included 24 sites. Additional solar and storage sites are in development with as much as 6 MW of storage. Dispatch may be administered directly through a PCE distributed energy resource management system (DERMS), battery management systems, or contractually specified with service providers.

4.1.3. Residential Solar and Storage

Overview: Residential storage systems, typically paired with solar, are growing in popularity. Currently in PCE territory, there are approximately 34,000 systems with a total of 71.6 MW of storage.[17] With the state's adoption of the Net Billing Tariff, it is expected that residential solar and storage adoption will grow. PCE has had a residential solar and storage program since 2020. That program has provided outreach and incentives for customers to adopt solar and storage systems. The systems are installed by a competitively selected provider and the storage systems dispatch at the grid peak as specified under the contract between PCE and the provider.

Status: PCE's residential solar and storage program completed its enrollment phase between 2020 and 2023. Nearly 400 new system installations were completed, and an additional 200 existing systems were enrolled. (PCE is also enabling a further 200-300 systems at low-income customer sites, funded by a combination of the Self-Generation and Investment Tax Credit.) Under the agreement with the provider, the provider offers battery storage dispatch during the evening peak, and PCE purchases the rights to this

[16] *US climate law introduces billion-dollar 'game-changer' for nonprofits*, Canary Media https://www.canarymedia.com/articles/climatetech-finance/us-climate-law-introduces-billion-dollar-game-changer-for-nonprofits

[17] Q4 2023 PG&E Interconnection Data for Peninsula Clean Energy service territory

Deleted: Status: PCE recently completed its second phase pilot of managed charging. The first phase was a proof of concept executed in 2020 with 7 vehicles. The proof of concept successfully demonstrated curtailment of charging at peak while ensuring drivers received the charging necessary for their daily needs. Following a competitive solicitation, PCE launched its second-phase pilot demonstrating scaled operation of EV-managed charging. PCE selected EV.energy as its partner and engaged researchers at UC Davis to develop an experimental design to evaluate incentive structures and assess outcomes. About 700 vehicles participated in the second-phase pilot. Data collection has been completed and analysis is underway. PCE anticipates finalizing its ongoing program design and ramping up its recruitment in the coming months. Incentives to sign up are offered to EV purchasers through PCE's income-qualified used EV incentive in addition to direct marketing to customers. ¶

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capacity over a 10-year term. The dispatch capacity is factored into PCE's annual load forecast submitted to the CEC, and subsequently, the CEC reduces PCE's forecasted RA capacity as a result of a lower forecasted peak load. PCE is continually working with the provider to further optimize the dispatch schedule to maximize the grid value, such as by concentrating as much energy capacity into a narrower, 2-hour dispatch window. In addition, PCE anticipates developing a follow-on program that will again provide support to homeowners in deploying solar and storage systems, while also providing capacity services to the grid. Dispatch may be administered directly through a PCE DERMS or contractually specified with service providers.

4.1.4. FLEXmarket

Overview: PCE utilizes the innovative FLEXmarket program to provide incentives to project implementers based on the measured grid benefits. PCE is implementing this approach because most energy efficiency programs do not adequately target load-shaping benefits. In addition, incentives are not targeted based on grid benefits nor measure actual results. This program operates across all customer classes for permanent load shifting achieved by targeted energy efficiency and beneficial electrification. The program utilizes Normalized Metered Energy Consumption (NMEC) methodology to assess projects based on their actual performance weighed against grid benefits with the Avoided Cost Calculator (ACC). This is a CPUC-funded program.

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Status: PCE launched its FLEXmarket program in 2023 for both the commercial and residential sectors and has successfully enrolled projects in the first iteration of the program. Initial program emphasis has been on attracting service providers and proving the general model of the program. PCE anticipates continuing the program subject to CPUC approval.

4.1.5. Residential Electrification Direct Install

Overview: PCE operates an income-qualified direct install program for electric appliances – replacing aging, polluting methane gas systems. This program has upgraded approximately 300 homes with heat pump water heaters or other efficient electric measures. Under the program, PCE has piloted whole-home electrification of 5 single-family homes to assess costs and demonstrate electrification that minimizes grid impacts by fully electrifying within 100 amps.[18] Finally, PCE has also piloted an advanced load-shaping technology in space and water heating combo systems which can shift load in both applications through the thermal storage and advanced system logic.[19]

[18] *Yes, it's possible to electrify a home on just 100 amps*, Canary Media, https://www.canarymedia.com/articles/electrification/yes-its-possible-to-electrify-a-home-on-just-100-amps

[19] TRC / Rupam Singla, *Harvest Thermal Pilot: Measurement and Verification Report* (2023), https://www.peninsulacleanenergy.com/wp-content/uploads/2024/02/PCE-Harvest-Pilot-MV-Final-Report.pdf

Status: This program will be substantially expanded in 2024 to allow for whole-home electrification. Numerous innovations are envisioned to be incorporated into this program including electrification within 100 amps, as well as the potential use of advanced combo systems, and integration of load shaping for water heaters and thermostats, possibly through a PCE DERMS. Separate from this program, PCE currently provides incentives to customers for the installation of load-shaping combo systems.

4.1.6. GovEV

Overview: The GovEV program helps local municipal fleets plan for fleet electrification by providing technical assistance for vehicle replacement purchasing and the installation of EV chargers. As a component of this program, PCE produces a charging optimization plan, which outlines the cost potential of managed charging for their specific fleet. PCE is also making the ChargePilot charge management system by The Mobility House free for fleets, as part of the GovEV program for one year. The ChargePilot system (optional to fleets but recommended) will help shift more fleet charging to occur during off-peak hours and mitigate demand charges, as well as provide insights into EV charging metrics for fleet managers.

Status: The program is open, and 10 fleets are currently enrolled. Installation projects are expected to begin in Calendar Year (CY) 2025.

4.1.7. Electric Vehicle Managed Charging

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Overview: PCE ran an EV Managed Charging Pilot in collaboration with EV.energy and researchers at UC Davis but determined that the response was small and the program not cost-effective. PCE's territory has one of the state's fastest adoption rates for EVs with over 45,000 EVs on the road today and EVs accounting for over one-third of new vehicle sales. Managing EV charging is a high priority for PCE with an emphasis on residential charging, where most evening charging is occurring, and shifting vehicle load daily out of the evening peak. In addition, minimizing the secondary midnight peak that can affect local distribution networks is also a priority. PCE has focused on leading-edge strategy by using vehicle telematics, which controls EV charging through the vehicle as opposed to charger-based load management. Because the installed base of smart chargers is very small and such chargers are expensive, the telematics approach holds greater promise because nearly all vehicles can participate without special equipment.

Status: PCE recently completed and analyzed its second phase pilot of managed charging with EV.energy and researchers at UC Davis. The amount of load shift was minor, in large part because customers who opted to participate were more tech-savvy than typical and mostly already shaping their load. In light of the lackluster effectiveness of the pilot, PCE is not moving forward with this particular program design.

4.1.8. Program Design to Meet LMS Goals

Each of these programs is envisioned to incorporate remote dispatch DERMS or comparable technologies, which will enable all of these programs to become automated MCB signal responsive programs, as envisioned in 20 Cal. Code Regs. § 1623.1(a)(1)(B). The timeline and feasibility of the rollout of MCB signals to these load flexibility technologies will be evaluated in future development of PCE's DERMS platform.

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4.2. Evaluation

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PCE closely evaluates all programs it executes and anticipates that load-shaping programs will be evaluated with the following criteria:

- Amount of grid peak load reduction
- Consistency and reliability of load reduction
- Customer participation rate
- Cost of recruitment and operation
- Customer benefits, impacts, and satisfaction

4.2.1. Cost-Effectiveness

The costs associated with implementing a new load flexibility program include the following:

- Program development. This includes the costs associated with program design and setup, including integrating such programs with internal and external systems.
- Program administration. This involves ongoing costs to administer the program, including marketing, customer recruitment, customer education, development, and maintenance of customer tools, and any upfront or ongoing incentive payments that are part of the design.
- Technology and implementation costs. Each new load flexibility program requires significant investments in new technology platforms. These include external software systems that must be procured to communicate with and dispatch devices, as well as internal systems that must be developed and configured to integrate the external software.

PCE, as a CCA, may derive certain avoided cost value streams such as reduced RA costs and extreme event energy market costs. However, aside from CPUC-funded programs such as FLEXmarket, PCE does not have access to other value streams such as avoided distribution grid costs. Quantification of cost benefits is challenging and of limited confidence due to the volatile nature of the energy market, as described in the analysis of MCB rates above.

4.2.2. Equity

PCE has a major focus on equity across its programs. PCE's primary method of delivering equity benefits is in keeping generation rates low. Since inception, PCE has provided generation rates at least 5% below PG&E for all customers resulting in over $100 million in savings for the community since 2016. In 2024 PCE is currently keeping rates flat resulting in 10-15% savings for customers compared to PG&E for even greater savings. In addition, in December 2023 PCE provided customers in the income-qualified California Alternate Rates for Energy (CARE) / Family Electric Rate Assistance (FERA) programs each a rebate of $300.

PCE has numerous programs targeted at delivering additional equity benefits. These programs include an EV charging incentive and technical assistance for apartment buildings, income-qualified incentives for e-bikes and EVs, and the above-mentioned home direct-install program.

PCE offerings are geared towards ensuring financial benefits for customers and ensuring access to additional benefits such as functional appliances, etc. Load shaping provides a potential additional tool for reducing customer costs, helping ensure shiftable load is occurring under the most favorable rates. However, most loads in low-income households have little or no shifting capacity. It is essential that households are not penalized for inflexible loads. In addition, while some customer segments are interested in technology it is important that participation not introduce undue complexity, especially in this segment. Therefore, any technologies introduced need high reliability and effective passive operation with as little resident intervention as possible.

4.2.3. Technical Feasibility

Load shaping measures as described above have been technically demonstrated by PCE or other parties. PCE currently engages in a "direct control" approach with EVs (a type of DERMS but only for EVs), contractually based load shaping for its residential storage, and a market-based "shaped" incentive structure in FLEXmarket.

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However, real-time responsiveness introduces numerous added levels of complexity. Assets would need to be integrated through a DERMS as a management platform. However, the DERMS landscape is extremely fragmented. Currently, DERMS providers are only able to successfully dispatch a subset of deployed assets, even within an asset type (battery, vehicles, etc.). In addition, customers must retain override capabilities based on specific needs, particularly for batteries which may be needed for power outages in extreme weather, and vehicles for travel needs. Customers, service providers, and manufacturers in many cases can have competing objectives (e.g., backup vs. grid services) and interest in enrolling in competing programs. In principle, a portfolio approach could yield confidence that a predictable dispatch capacity can be achieved for an event-based program.

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However, PCE's approach of daily "permanent" load shift offers the advantage of high predictability for the customer and other parties.

Furthermore, for real-time programs, data integration for the price signals would need to be established reflecting real-time conditions and PG&E billing systems would need to be restructured to allow billing based on those prices. A price signal system must address common standards for calculation, availability of data on a real-time basis, high up-time platform for serving the data, mechanism for customer visibility, and other complexities. PG&E's billing system would require major updates of a platform already strained by high complexity, and billing information would need to be presented in a digestible manner for the customer with associated education and customer service support. Both of these areas are major barriers.

4.2.4. Benefits to the Grid

Load shaping provides several grid benefits including reducing costs, increasing reliability, and reducing emissions. Load shaping that is responsive to real-time conditions could potentially increase those benefits to the degree that responsive load shaping is able to provide additional load reductions, above that provided by permanent load shaping, at moments of grid strain.

However, different objectives would necessitate visibility to specific conditions. ISO-level load, transmission congestion, load aggregation points, and distribution circuit conditions each have distinct values that can contribute to the value of load shifting but are not necessarily easily evaluated in real-time by asset controllers, like PCE. Thus, PCE may be able to assess grid value at the level of generation costs but may have difficulty incorporating other grid benefits, except to the degree that data becomes available for other areas.

4.2.5. Benefits to Customers

Customer benefits of load shaping generally are assessed by PCE in relation to economic value. Specifically, cost reductions after considering customer installation costs and the change in operating costs. As noted above, PCE emphasizes permanent load shifting as a means of maximizing the operating cost benefits. Reliability is also an important benefit though this is difficult to quantify.

5. Conclusions

PCE strongly supports the goals of the LMS and is already working diligently to implement leading programs and approaches to deliver load flexibility in a cost-effective and technically feasible manner. Although load-flexibility technologies have many technical and policy prerequisites that must be satisfied before such approaches can deliver the full potential benefits, PCE is committed to deepening its current approaches and exploring

the feasibility of other approaches as they become available. PCE has committed to participate in the IOU HFP pilots to offer MCB rates to our customers. PCE anticipates receiving data on effectiveness and feasibility from that program going forward. While the IOU HFP pilots move forward, PCE is also moving forward on deploying a DERMS platform to enable MCB signal responsive programs as an alternative or supplement to MCB rates in coming years.

Load flexibility is a key tool for PCE's core objective to provide its customers with 100% renewable energy in all hours. Given PCE's goals, it anticipates working with the CEC to develop new approaches and to provide real-world, on-the-ground expertise from the lessons derived from this work going forward.

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PENINSULA CLEAN ENERGY

PENINSULA CLEAN ENERGY AUTHORITY
JPA Board Correspondence

DATE: March 21, 2025
MEETING DATE: April 24, 2025
VOTE REQUIRED: Majority Vote

TO: Honorable Peninsula Clean Energy Authority Board of Directors

FROM: Brianna Arroyo, Interim Board Clerk

SUBJECT: Approval of Minutes from the March 27, 2025 Board of Directors Meeting

RECOMMENDATION

Approval of Minutes from the March 27, 2025 Board of Directors Meeting

BACKGROUND

Approval of Minutes from the March 27, 2025 Board of Directors Meeting

ATTACHMENTS:
03-27-2025 BOD Draft Minutes.pdf

Regular Meeting of the Board of Directors of the Peninsula Clean Energy Authority (PCEA)
Minutes

Thursday, March 27, 2025
6:30 p.m.
Zoom Video Conference and Teleconference

CALL TO ORDER

Meeting was called to order at 6:31 p.m. in virtual teleconference, in the Peninsula Clean Energy Authority lobby, the Los Banos City Hall conference room A, and the Hotel at Oberlin, 10 East College Street, Oberlin, OH 44074.

SWEARING IN OF NEW BOARD MEMBER

Jennifer Stalzer, General Counsel, presided over a swearing-in ceremony for new Board Alternate Bob Nguyen from Millbrae.

ROLL CALL

Participating:

Effie Milionis Verducci, San Mateo County
Jackie Speier, San Mateo County
Rick DeGolia, Atherton
Tom McCune, Belmont
Coleen Mackin, Brisbane
Donna Colson, Burlingame, *Chair*
Roderick Daus-Magbual, Daly City, *participating remotely via AB 2449, arrived at 6:42 p.m.*
Carlos Romero, East Palo Alto
Stacy Jimenez, Foster City
Patrick Jonsson, Half Moon Bay
Leslie Ragsdale, Hillsborough, *participating remotely from Oberlin, OH*
Michael Amabile, Los Banos, *participating from Los Banos*
Betsy Nash, Menlo Park
Bob Nguyen, Millbrae
Greg Wright, Pacifica
Rebecca Flynn, Portola Valley
Elmer Martinez Saballos, Redwood City, *arrived at 7:57 p.m.*
Marty Medina, San Bruno, *Vice Chair*
Adam Loraine, San Mateo
James Coleman, South San Francisco, *arrived at 6:47 p.m.*
Hassan Aburish, Woodside

Absent:

Ken Gonzalez, Colma
John Dugan, San Carlos

A quorum was established.

PUBLIC COMMENT YouTube Home

James Tuleya, the Senior Energy Coach from Home Energy Analytics gave a public comment on the work being done by HEA in both San Mateo County and Los Banos.

ACTION TO SET THE AGENDA AND APPROVE REMAINING CONSENT AGENDA ITEMS YouTube Home

Nelly Wogberg, Board Clerk, noted an update to Agenda Item Number 3, "Approval of the Minutes for the February 27, 2025 Meeting" in an at-places memo.

Public Comment: None

MOTION: Director Medina moved, seconded by Director Romero to set the Agenda, and approve Agenda Item Numbers 1-3.

1. Approval of Two Funding Agreements for an EV Fleet Electrification Project with the City of East Palo Alto.

2. Approval of an Agreement with the Law Firm of Keyes & Fox LLP for Distributed Energy Resource Management System (DERMS) legal support in an Amount Not-to-Exceed $60,000 with a term of March 3, 2025 to August 30, 2025.

3. Approval of the Minutes for the February 27, 2025 Meeting.

MOTION PASSED: 18-0 (Absent: Colma, Daly City, Redwood City, San Carlos, South San Francisco)

JURISDICTION	BOARD MEMBER	YES	NO	ABSTAIN	ABSENT
San Mateo County	Director Milionis Verducci	X			
San Mateo County	Director Speier	X			
Atherton	Director DeGolia	x			
Belmont	Director McCune	X			
Brisbane	Director Mackin	X			
Burlingame	Director Colson	X			
Colma	Director Gonzalez				X
Daly City	Director Daus-Magbual				X
East Palo Alto	Director Romero	X			
Foster City	Director Jimenez	X			
Half Moon Bay	Director Jonsson	X			
Hillsborough	Director Ragsdale	X			
Los Banos	Director Amabile	X			
Menlo Park	Director Nash	X			
Millbrae	Director Nguyen	X			
Pacifica	Director Wright	X			
Portola Valley	Director Flynn	X			

Redwood City	Director Martinez Saballos				X
San Bruno	Director Medina	X			
San Carlos	Director Dugan				X
San Mateo	Director Loraine	X			
South San Francisco	Director Coleman				X
Woodside	Director Aburish	X			
	Total	18			5

REGULAR AGENDA

4. Chair Report. YouTube Home

Chair Colson gave a report pulling together a committee consisting of herself, Vice Chair Medina, and Director DeGolia for the CEO Annual Review Committee. She also noted the overlap between the C/CAG committee that a few directors sit, and mentioned Shalini Swaroop, Chief Operating Officer, and Rafael Reyes, Director of Community Programs will be working to create synergy between both committees.

5. CEO Report. YouTube Home

Shawn Marshall, Chief Executive Officer, gave a brief CEO Report including a legislative update, a timeline for the upcoming budget cycle and new strategic plan, and an update on the EV Ready Program.

6. Community Advisory Committee Report. YouTube Home

Jason Mendelson, Community Advisory Committee (CAC) Chair, provided an overview of the March 13, 2025 CAC meeting.

7. Selection of Board of Directors Chair and Vice Chair (Action). YouTube Home

Director DeGolia, Chair of the Nominating Committee, shared that the Committee, which includes Director Mackin and Director Taylor, received only one nomination for each role: Donna Colson for Chair and Marty Medina for Vice Chair.

Public Comment: None

MOTION: Director DeGolia moved, seconded by Director Aburish to nominate Director Colson to the position of Chair and Director Medina to the position of Vice Chair.

MOTION PASSED: 20-0 (Absent: Colma, Redwood City, San Carlos)

JURISDICTION	BOARD MEMBER	YES	NO	ABSTAIN	ABSENT
San Mateo County	Director Milionis Verducci	X			
San Mateo County	Director Speier	X			
Atherton	Director DeGolia	X			
Belmont	Director McCune	X			

Brisbane	Director Mackin	X			
Burlingame	Director Colson	X			
Colma	Director Gonzalez				X
Daly City	Director Daus-Magbual	X			
East Palo Alto	Director Romero	X			
Foster City	Director Jimenez	X			
Half Moon Bay	Director Jonsson	X			
Hillsborough	Director Ragsdale	X			
Los Banos	Director Amabile	X			
Menlo Park	Director Nash	X			
Millbrae	Director Nguyen	X			
Pacifica	Director Wright	X			
Portola Valley	Director Flynn	X			
Redwood City	Director Martinez Saballos				X
San Bruno	Director Medina	X			
San Carlos	Director Dugan				X
San Mateo	Director Loraine	X			
South San Francisco	Director Coleman	X			
Woodside	Director Aburish	X			
	Total	20			3

8. Study Sessions: 1. PCE Energy 101 and 2. Managing Volatility of Cost of Energy and the Power Charge Indifference Adjustment (PCIA) (Discussion). YouTube Home

Shawn Marshall, Chief Executive Officer, introduced the item, and Roy Xu, Senior Director or Power Resources, gave a presentation explaining how Peninsula Clean Energy procures energy in the California energy market. Justin Kudo, Associate Director, Strategic Analysis & Rates, and Nick Bijur, Chief Financial Officer, continued the presentation with the cost of energy and the Power Charge Indifference Adjustment (PCIA).

Public Comment: None

9. Board Members' Reports YouTube Home

Chair Colson noted a visit to Los Banos for a ribbon cutting on the Los Banos Community Center on March 28, 2025.

Director Loraine gave a report on the CA Energy Commission and Electrification Summit in Sacramento.

ADJOURNMENT

Meeting was adjourned at 8:40 p.m.

PENINSULA CLEAN ENERGY

PENINSULA CLEAN ENERGY AUTHORITY
JPA Board Correspondence

DATE: April 18, 2025
MEETING DATE: April 24, 2025
VOTE REQUIRED: None

TO: Honorable Peninsula Clean Energy Authority Board of Directors

FROM: Shawn Marshall, Chief Executive Officer

SUBJECT: CEO Report (Discussion)

BACKGROUND

This report is provided monthly to the Board of Directors and is informational only.

DISCUSSION

During the Board meeting, CEO Shawn Marshall will provide an update on a variety of PCE topics, including but not limited to: New Department of Innovation Strategy; CA Legislative update; Federal Administration Impacts; Wright BESS project update, and a few recent regulatory and program wins!

PCE In the Community - Thanks to our Team and Volunteers for Their Help with Earth Month!

April 24	Panel Careers for a Sustainable World, Virtual
April 26	Earth Day of Action and Pelican Fest, Pacifica
April 26	Love Our Earth Festival, Menlo Park
April 27	Eco Fest, Millbrae
April 27	Earth Day, Atherton
April 28	Ribbon Cutting, Los Banos
May 5th	Cinco De Mayo, East Palo Alto
May 8th	Multilingual Community Resource Fair, San Mateo
May 22 & 23	Pacheco High School Wax Museum, Los Banos

PCE Staffing Update

The deadline for four intern positions was April 15 and we have had very strong interest. Interns will be announced once selected and will work with PCE starting early June through the end of August.

There are no open positions posted at this time.

PENINSULA CLEAN ENERGY

PENINSULA CLEAN ENERGY AUTHORITY
JPA Board Correspondence

DATE: April 10, 2025
MEETING DATE: April 24, 2025
VOTE REQUIRED: None

TO: Honorable Peninsula Clean Energy Authority Board of Directors

FROM: Mike Mielke, Senior Manager of Legislative Policy

SUBJECT: Briefing on SB 540 (Becker) - Western Pathways Bill (Discussion)

RECOMMENDATION

This item is discussion only.

BACKGROUND

Overview

California's push to decarbonize its electricity grid is among the most ambitious in the world, with a legal mandate to achieve 100% zero carbon electricity of retail sales by 2045. California needs a massive amount of new clean energy and storage to reach this goal. However, doing this cost-effectively and reliably within California's borders alone presents significant challenges, especially given the limitations of in-state land, transmission, and resource diversity. Meanwhile, efforts to regionalize the western electricity grid have spanned more than two decades, with growing urgency as climate goals have become more ambitious. California has long operated its own Independent System Operator (CAISO), managing much of the state's electric grid. Over time, stakeholders in California and across the west have recognized the benefits of broader regional coordination to improve reliability, reduce costs, and integrate clean energy.

Core Challenge

The Western Interconnection spans multiple states, but it is highly fragmented: dozens of Balancing Area Authorities (BAAs) independently operate their own slices of the western grid. This fragmentation limits the ability to access and share low-cost, renewable resources across the broader region. Greater regional integration could help balance demand, reduce costs, and improve reliability, particularly as climate-driven extreme weather events become more common.

History of Regionalization Efforts in California

Efforts to regionalize the western grid have been considered for decades, with increased

momentum in recent years:

1990s-2000s: Federal Energy Regulatory Commission (FERC) promoted formation of Regional Transmission Organizations (RTOs), but the West (outside of CAISO) resisted full participation.

2015: SB 350 (2015) Senator Kevin de Leon (Clean Energy and Pollution Reduction Act). Primarily known for setting California's 50% Renewable Portfolio Standards (RPS) target and doubling energy efficiency goals, the bill originally included language to authorize CAISO regional expansion, but that section was removed from the final bill due to a lack of consensus around the governance structure.

2017-2018: Discussions began in earnest about transforming CAISO into a regional transmission organization (RTO). Legislation was introduced (e.g., AB 813 in 2017) which aimed to lay the legal groundwork for transforming CAISO into a multi-state RTO, with an independent governance structure separate from California state control, but failed due to labor, environmental, and political concerns over losing state control.

2023: Legislation was introduced, AB 538 (Holden), which again sought to lay the groundwork for transforming CAISO into a regional RTO. AB 538 failed similarly to AB 813 due mainly to issues of scope and governance.

History of PCE Engagement

The Peninsula Clean Energy (PCE) Board of Directors discussed AB 538 and regionalization in 2023 and expressed an interest in PCE participating in efforts that would lead to an expansion of the western grid while addressing the issues of concern that had been raised with AB 538.

In 2024, PCE adopted its 2024 Legislative and Regulatory Policy Platform to add paragraph c to Section VIII California Energy Market Structure so that the section now reads in relevant part:

b. Support policies that change California's market structures towards innovative models that reduce the costs of energy service and support the expansion of carbon free resources.

c. Engage in discussions and track policy efforts to create a multi-state regional transmission system to ensure that it increases supply availability and reliability for California energy customers, recognizes California's influence in its governance structure, and advances California's clean energy policies and goals.

In February 2025, in alignment with the Board approved legislative platform and concurrence by the Chair and Vice Chair, PCE took a position in support of SB 540 (Becker). Please also see attached letter dated 4/15/25 for a summary overview of why PCE supports the Pathways initiative.

DISCUSSION

Two speakers with expertise in California and western energy markets will brief the Board on this bill. Evelyn Kahl, Chief Policy Director and General Counsel at Cal-CCA and working group participant in the Pathways Initiative will speak in support. Loretta Lynch, attorney,

energy consultant, and former CPUC Commissioner from 2000-2005 will speak in opposition. This is a discussion item in response to a request from Board member Speier.

FISCAL IMPACT

None

STRATEGIC PLAN

Not Applicable

ATTACHMENTS:
SB 540.pdf
PCE Support Letter.pdf
SB 540 FAQ from CalCCA.pdf
SB 540 Pathways Factsheet.pdf
SB 540 Pathways Definitions.pdf
April 15 2025 Julian Lynch SB 540 Oppose letter.pdf
Laborers Boilermakers Ironworkers SB 540 Oppose letter.pdf
CBD_etal_SB540_Oppose.pdf
Preliminary Day-Ahead Market Impacts Study.pdf
SB 540 (Becker)_Joint IOU CalCCA Final Letter of Support (031225).pdf
CRP-SV-SB540-Suppport-Letter.pdf
SB 540_SUPPORT COALITION.pdf
SB 540 TURN OUA.pdf

AMENDED IN SENATE MARCH 24, 2025

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 amended, 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 *voluntary* 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 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 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.

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 *voluntary* 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 *unilateral* withdrawal by any participant with reasonable prior ~~notice.~~ *notice and without any further approvals.*

(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~~ *Except as provided in subdivision (a) with respect to managing energy markets as provided in this section, 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) (1) This section does not change any requirement related to the California Renewables Portfolio Standard Program as provided in Article 16 (commencing with Section 399.11).

(2) This section does not change the policy of the state to reach specified targets by specified dates for supplying eligible renewable energy resources and zero-carbon resources as provided in subdivision (a) of Section 454.53.

~~(e)~~

(f) 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)~~

(g) 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.

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.

O

April 9, 2025

The Honorable Josh Becker
Chair, Senate Energy, Utilities & Communications Committee
1021 O St., Suite 6520
Sacramento, CA 95814

Re: SB 540 (Becker) - SUPPORT

Dear Senator Becker,

On behalf of Peninsula Clean Energy Authority (PCE), a community choice aggregator (CCA) serving approximately 800,000 Californians in San Mateo County and the City of Los Banos in Merced County, we write in strong support of your SB 540, a bill that will help lower net total electricity system costs and promote a more efficient and affordable clean energy future for California.

Electricity affordability is central to Peninsula Clean Energy's mission. As a community-led energy provider, PCE is committed to delivering clean, reliable power at competitive rates to the residents and businesses we serve. Rising electricity costs, driven in part by system inefficiencies and increasing levels of renewables without corresponding system optimization, place a growing burden on ratepayers and pose challenges to achieving equitable climate goals across the state.

SB 540 would authorize California to participate in a regional organization (RO), subject to a robust governance and withdrawal framework. This participation enables more efficient dispatch of generation resources across a broader western footprint, integrating renewables more effectively and reducing system redundancies. According to analysis provided in support of SB 540, the state could realize up to $800 million in net annual savings by optimizing resource sharing across the western grid through a regional market. These cost savings can directly translate into lower bills for customers and allow for more reinvestment in clean energy innovation and reliability improvements.

Importantly, SB 540 maintains California's leadership on clean energy policy. The bill does not alter requirements under the state's Renewable Portfolio Standard (RPS), change the 100% clean electricity goals established by SB 100, or expand the jurisdiction of the Federal Energy Regulatory Commission (FERC) over California's energy markets. Instead, it strengthens the state's ability to meet its clean energy targets at lower cost and with greater reliability.

The bill also contains critical protections by establishing clear safeguards and governance principles for participation, including a process for California Independent System Operator (CAISO) withdrawal if that

becomes necessary. These provisions ensure that California's interests remain protected while accessing the economic and environmental benefits of regional collaboration.

Peninsula Clean Energy appreciates your leadership on this issue and strongly supports SB 540 as a responsible, forward-looking solution to support affordability, reliability, and environmental progress.

Sincerely,



Shawn Marshall
Chief Executive Officer

cc: The Honorable Members of the Senate Energy, Utilities & Communications Committee

SB 540 - Frequently Asked Questions (FAQ)

What is "regionalization?"

Regionalization generally means integrating elements of electricity markets across a particular region, such as the West, under the operation and management of a single Federal Energy Regulatory Commission (FERC) regulated regional entity. Energy markets, transmission planning, transmission system operation, reliability, and other elements can be regionalized individually or in combination.

How does the Pathways Initiative (Pathways) advance regional markets?

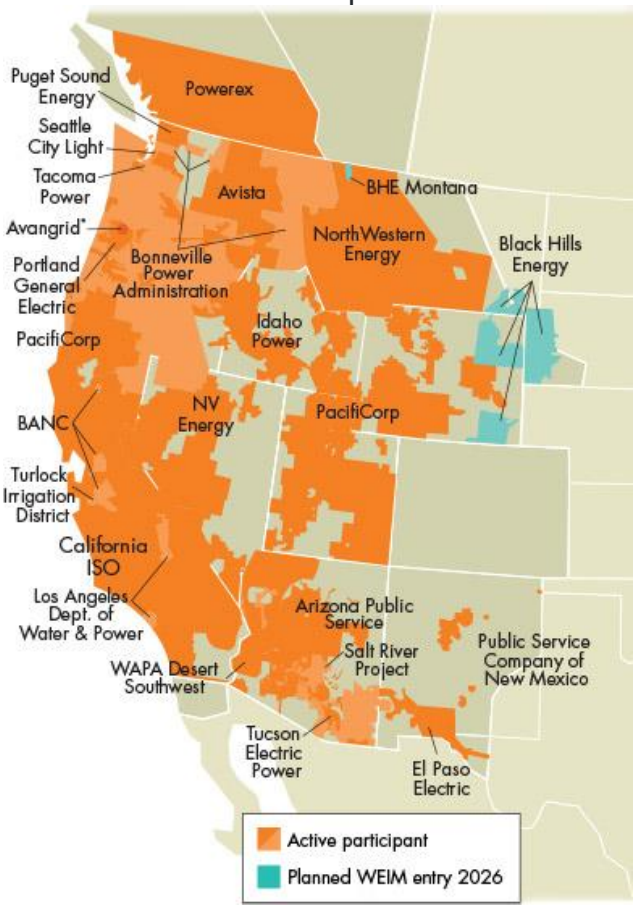
Pathways aims to expand participation across the West in the day-ahead and real-time energy markets currently managed by the California Independent System Operator (CAISO). It aims to support this expansion by creating a governance framework independent of any single state and overseen by a new regional organization (RO). This change recognizes that governance independence has long been a barrier to regionalization.

How does Pathways differ from prior efforts to regionalize?

Prior efforts attempted to remove the CAISO Governor-appointed board from oversight of all its existing functions. Pathways leaves the CAISO board intact; instead, it moves a single CAISO function—energy markets—to governance by a new regional organization (RO) and a board constituted from across the West. A diversity of stakeholders, including prior opponents, have coalesced around this new design.

What will change for CCAs?

The energy markets CCAs and other load-serving entities participate in today, both day-ahead and real-time, will no longer be under the governance of the CAISO's Governor-appointed board; the rules for these markets will be overseen by a new RO with an independent board from across the West. The shift is limited to governance, and the CAISO will continue to operate these markets under contract with the RO.



Map of Western Energy Imbalance Market participants. Credit: WEIM.

Are there elements of Western electricity markets that have already been regionalized?

Yes. The West is taking an incremental approach to regionalization in contrast to the East's holistic approach. The California Independent System Operator's (CAISO's) Energy Imbalance Market (EIM) and soon-to-be-implemented Extended Day Ahead

Market (EDAM) integrate resources and loads from several Western states. Likewise, compliance with federal and regional grid standards has also been regionalized, with the CAISO serving as the Reliability Coordinator for 25 Western balancing authorities and 39 transmission operators.

What are the potential benefits of Pathways?

Studies commissioned by the California Energy Commission from the Brattle Group and Stanford Climate & Energy Policy Program highlight the potential cost savings, enhanced grid reliability, and reduced air pollution that could result from implementing SB 540.

- **Enhanced Reliability.** Geographic and weather diversity in a broader regional market allows participants to draw on a much wider resource pool during unexpected or extreme events. The increased EDAM footprint could expand California's supply cushion by 25,000 MW, with most of this availability falling during the 10 tightest hours on the system.
- **Cost Savings.** California could achieve up to $800 million annually in lower net total system costs compared to baseline assumptions due *to:*
- *More efficient dispatch.* Pooling resources across a larger geographic area can lead to more efficient energy production and distribution, producing cost savings for consumers.
- *Renewable energy integration.* Today, consumers may pay twice for energy when excess renewable contracts are curtailed on the CAISO system: they must pay for both the curtailed energy and the energy they consume. Regionalization provides a broader market for California's solar and wind resources, reducing curtailment of existing resources and lowering customer costs.
- **Environmental Benefits.** By optimizing the use of renewable resources across the region, regionalization, as envisioned by Pathways, reduces

reliance on California's gas resource fleet by up to 31% relative to baseline assumptions, thereby reducing greenhouse gas emissions and offering other environmental co-benefits. Collaborative efforts can enhance the effectiveness of environmental policies across state lines.

Will regionalizing energy markets undermine California's achievement of key policy initiatives?

No. The crucial elements of reliability and climate policies will remain in the hands of California legislators and regulators. Resource adequacy, resource procurement, the Renewable Portfolio Standard, carbon reduction programs, retail rates, programs, and other functions will remain soundly within California's control.

Will Pathways expand FERC jurisdiction over energy markets serving California?

No. Today, FERC regulates the CAISO-managed wholesale energy markets, including EIM and EDAM, and transmission grid. Pathways simply shifts governance of the EIM and EDAM energy markets to a new FERC-regulated entity: the regional organization (RO). The key jurisdictional change is replacing the California Governor's unilateral right over CAISO board appointments with a regional board selection process.

If California were to find that participating in the RO market is undermining its fulfillment of key policy objectives, could it revert to today's CAISO status quo?

Yes. All regional operations, including the CAISO's EDAM and EIM markets, specify a process for withdrawal from the market. The RO will also have withdrawal provisions that would be available to and could be exercised by California participants. Even reinstatement of the status quo, however, could not avoid federal jurisdiction given that FERC regulates the CAISO markets today.

When would governance of energy markets shift from the CAISO to a new RO?

SB 540 does not specify an exact timeline for when the new regional energy market could become operational. CAISO must first demonstrate that the RO meets a number of statutory requirements before moving control of the market rules to the RO. The timeline would depend on how quickly the RO can meet the necessary requirements and how efficiently CAISO can complete the demonstration and authorization process. The process is likely to take several years.

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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Definitions

- **CPUC** California Public Utilities Commission, which regulates IOU rates and services and administers many of California's low-income, climate, and reliability programs.
- **CAISO** California Independent System Operator, the entity that today manages and operates the transmission grids of the state's three large IOUs and the day-ahead and real-time energy markets for most of California.
- **FERC** Federal Energy Regulatory Commission, the entity that holds jurisdiction over wholesale power markets and transmission systems and regulates CAISO today.
- **WEIM** Western Energy Imbalance Market, the "real time" regional energy market managed and operated by the CAISO.
- **EDAM** Extended Day Ahead Market, the day-ahead regional energy market that will be managed and operated by the CAISO when it launches in 2026.
- **GHG Emissions** Emissions of Greenhouse Gases (carbon dioxide) caused in the electricity sector by the combustion of fossil fuels (natural gas, coal).
- **kW, MW, GW** Measures of electric generating capacity: kilowatt, megawatt (1000 kW), gigawatt (1000 MW).

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April 15, 2025

Senator Josh Becker, Chair
Senate Committee on Energy, Utilities and Communications
1020 O Street, Room 3350
Sacramento, CA 95814

Re: Oppose SB 540 (Becker and Stern)

Chairman Becker:

We respectfully oppose Senate Bill 540 and urge a NO vote on the measure in the Energy Committee. SB 540 eliminates existing statutory requirements that assure accountability over California's electricity markets operator – the California Independent System Operator (CAISO) – by the people of California. SB 540's proposed new Pub. Util. Code section 345.6(a) specifically abrogates Pub. Util. Code section 345.5(b) by allowing the CAISO to "use energy markets" governed by a yet-to-be-formed out-of-state corporation (the Regional Operator or "RO") "in lieu of" Section 345.5(b), which details the CAISO's public interest responsibilities to the people of California. The "in lieu of" language:

- allows the RO to propose and operate our electricity markets under rules that no longer must be consistent with "applicable state law intended to protect the public's health or the environment" (section 345.5(b)(3) creating the troubling precedent of exempting electricity markets from the entirety of California's public health and environmental laws;
- eliminates the consumer protection obligation to "[reduce] to the extent possible, the overall economic cost to the state's consumers" (section 345.5(b)(2);
- eliminates the obligation to "make the most efficient use of available energy resources" (section 345.5(b)(1) including the state's abundant local solar, hydroelectric, geothermal and energy efficiency resources;
- eliminates the requirement that our electricity markets "maximize[e] availability of existing electric generation resources necessary to meet the needs of the state's consumers (section 345.5(b)(4).

SB 540 destroys the legal underpinning for California's renewable portfolio standard and its commitment to local renewable development and concomitant jobs established by Pub. Util. Code section 399.16. It opens the floodgates to massive inflows of coal- and gas-fired electric generation contrary to our laws and policies to minimize greenhouse gases. It makes California much more vulnerable to the attacks threatened by the Trump administrations on our carbon reduction programs.

The magnified vulnerability stems directly from the "in lieu of" language. Currently California law and policy completely aligns with the CAISO's FERC-approved tariff. The CAISO, acting through its Governor-appointed board, is precluded by section 345.5(b) from proposing to FERC to change the tariff in ways that violate the provisions of state law, because to do so would be illegal. Proposed Public Utilities Code section 345.6(a) permits the CAISO to depart from any and all state laws in its "use" of RO energy markets. Further, proposing market operator rules that move electricity market tariffs out of alignment with current California law would create legal vulnerabilities that aggressive private litigants could exploit, a pattern evident in other parts of the country.

A report prepared for the Energy Commission and released just prior to introduction of SB 540, and prior to the Trump Executive Orders. "Preliminary Day-Ahead Markets Impact Study," Presentation 1/24/25 https://www.energy.ca.gov/event/workshop/2025-01/iepr-commissioner-workshop-regional-electricity-markets-and-coordination ("Brattle Study") details the problems that SB 540 would create. This study forecasts energy flows (sources and sinks) and estimated production costs under the EDAM, a new experimental market proposed by the CAISO that will actually begin operation in 2026. The Brattle Study was published before the Trump Executive Orders promoting fossil fuels, attacking California's climate policies, and – crucially – ending FERC's independence from administration policies.

The Brattle Study predicts a net increase in GHG emissions throughout the West, and shows that any incremental supplies for California (a so-called reliability cushion) would be obtained primarily from coal- and gas-fired generation.

SB 540 purports to contain safeguards against any problems. The proponents argue that the "use" of the energy markets by CAISO is voluntary and CAISO's decision to "use" regional electricity markets must be predicated on a specified list of conditions precedent before the CAISO can vote to "use" the regional market operator without regard to current state law. The consumer, public health and environmental protections currently required by state law are replaced with suggestions, meaningless process and corporate governance documents, assurances that provide no legal or binding effect.

The loose and ambiguous drafting of proposed PU Code 345.6 (what does "use of energy markets" entail or mean?) and the legal uncertainties created by the interaction between the proposed section 345.6 and the operation of the Federal Power Act render the purported safeguards illusory, ineffective and unenforceable. For example, SB 540 would end our ability to course-correct if the Brattle Study's forecasts of increased CO2 emissions materialize.

Proponents claim that surrendering California's authority and incurring the severe environmental damage predicted by the Brattle Study would provide California with broader access to regional energy supplies and larger regional markets for exporting our local energy. Proponents claim that a broader market may help us gain control over runaway electricity prices. But California already has physical (through existing transmission) and commercial (both bi-lateral and multi-lateral contracts)

access to energy supplies throughout the West and Canada. Physically we gain nothing. The "incremental supplies" (misleadingly called a "reliability cushion") are all coal and gas, inconsistent with California's environmental laws.

Whether those out-of-state supplies would be priced affordably or provide any cost savings to California consumers depends on the bidding and pricing strategies of sellers, who are paid the highest price set by the CAISO algorithms regardless of their bids, and regardless of their costs. The single price auction mechanism used by the CAISO and other regional electricity markets creates a black hole of uncertainty for predicting future electricity market prices. The proponents rely on the Brattle Study's purported cost savings, which do not begin until 2032. But the Brattle Study inaccurately modeled future market prices by basing those prices on "production costs" and not the single price auction mechanism that actually sets electricity prices in RTO markets.

Proponents claim a second environmental benefit of avoided curtailments of solar and wind generation in California through regional sales. The rapid scaling up of storage in California, including battery storage and vehicle-based storage, and optimizing pumped storage and local hydroelectric resources, provide better approaches to managing California's solar surpluses than chasing below-cost or negative-priced sales. But even the Brattle Study's data shows that minimal to no lessening of solar curtailment will occur under the most likely Split Market scenario it modeled.

If the broader interstate market creates opportunities to build renewable supplies out-of-state for import in place of local supplies, California loses local jobs and economic development. Every study of the economic impact of the prior regionalization efforts has demonstrated significant job loss and economic damage. If SB 540 changes that job loss outcome, a new and independent study demonstrating that should be conducted. If a broader interstate market provides California electricity from out of state, California will experience substantial energy line losses attendant on long-distance transmission.

Although the March 24th amendments to SB 540 declare its intention to preserve California's Renewable Portfolio Standard (RPS) and its commitment to connection to the local grid, that declaration alone is legally inadequate to achieve that result. Proponents recognize that SB 540 in its current form makes California's RPS laws vulnerable to a Commerce Clause attack as they continue to draft amendments to try to "fix" the problem.

Proponents also recognize the substantial risks that SB 540 imposes on California because they argue that the CAISO's "use" of RO's markets can be stopped with carefully drawn withdrawal protections, if the threatened environmental damage, job losses or other negative consequences occur. But SB 540's withdrawal provisions have no legal precedent and little foundation in law or theory. As drafted, SB 540 has no legally enforceable "withdrawal" provisions. Better drafting might improve the chances of an enforceable withdrawal, including inclusion of simple and timely withdrawal permission in a FERC-approved tariff as a condition precedent to the "use" decision and including choice-of-law provisions that assure the participation of the California

Attorney General in the inevitable litigation. But all the pre-approved withdrawal conditions that can be imagined still remain legally controversial and experimental. Even if the FERC pre-approves withdrawal conditions in 2026, nothing exists to prevent a future FERC, once CAISO joins the regional energy markets, from disregarding a prior FERC's action and imposing onerous withdrawal conditions at the time the CAISO or a California utility seeks withdrawal.

SB 540 represents the fourth time efforts to eliminate the protections that were enacted to quell the 2000-01 Energy Crisis. (See Chapter 1, Stats. 2001 (First Extra Session, AB 5 Keeley); Ch. 847, Stats. 2002 (SB 1753 (Bowen)) In 2018 (AB 813, Holden) and 2023 (AB 538, Holden) the Legislature rejected similar efforts to repeal or abrogate Section 345.5's consumer and environmental protections. SB 540 transfers effective governance responsibilities – and crucial rights to interact with FERC under Federal Power Act section 205 – to unaccountable ("independent" in the Orwellian language of energy law) decision-makers and relieves the new regional corporation of any responsibility to follow California laws that protect the public's health, the environment and that require electricity markets to minimize costs and maximize electricity to California consumers

California faces a severe crisis in our electricity supply: the highest retail prices in the continental United States and increasingly fragile reliability that threatens homes and businesses. At the same time California has committed itself to addressing our climate challenges by fueling our economy with electricity. Given the massive uncertainties facing us – climate change; unparalleled shifts in federal energy policies; radical and untested shifts in the CAISO's operating and pricing procedures with the start of the EDAM in 2026; and changing international energy flows – this is not the time to decide that our electricity markets need not comply with California's public health or environmental laws or reduce costs to the maximum extent possible.

At the very least, the provisions of SB 540 that give the CAISO board the ability to abrogate the protections of current California law merely by adopting a resolution in 2027 should be stricken. Any final decision to "use" regional energy markets or to annul the statutory protections provided by Section 345.5(b) should be brought back to the Legislature for a vote in 2027.

Please VOTE NO on SB 540.

/s/
Loretta Lynch

/s/
Bill Julian

Cc: Committee Members

Senator Josh Becker, Chair

Senate Energy, Utilities and Communications Committee

1021 O Street, Suite 3350

Sacramento, California 95814

Re: SB 540

Dear Senator Becker,

On behalf of our organizations and the hundreds of thousands of workers we collectively represent, we write to express our current opposition to Senate Bill 540 due to its potential significant economic and employment consequences, particularly for middle-class, blue-collar workers. We urge this committee to slow down this process so that we can see how the current federal government is going to impact California's energy markets and determine the effect of this bill on in-state industrial jobs.

The hardworking men and women of the construction trades are the backbone of California's economy, delivering the critical infrastructure necessary to sustain our communities and industries. Our trades collectively represent tens of thousands of skilled workers essential in constructing and maintaining our energy infrastructure. Producing power in-state allows California to ensure that its high-road labor and environmental values are upheld as we work to meet the climate crisis and continue to power our state. We are committed to protecting our environment and the working-class families that drive California's economy.

Our trades were not consulted as this proposal was developed, so our members' concerns were not considered when developing this bill. With prior bills considering multistate markets and regionalization, robust job studies showed massive job losses to the industrial trades. We can all agree California is not in a position to afford to lose industrial jobs at this scale. Additionally, as of this week, we are seeing an attack on California's energy portfolio as the Trump administration is mounting an assault on our shared commitment to sustainable power generation and is also pressuring the Federal Energy Regulatory Commission (FERC) to implement the Administration's new energy directive. Additionally, the recently accepted CAISO tariff does not give California the ability to unilaterally rescind from any subsequent multi-state market-thus arguably giving FERC increased access to our energy markets. As SB 540 is not intended to take effect until 2027 at the earliest, and there is, therefore, no dire urgency, we ask that you allow time for the Federal policies to take shape so that we can determine the potential effect on Cali-

fornia and will enable us to also conduct an independent jobs study at a credible California institution and provide that report to the legislature. The legislature, rate-payers, and the blue-collar workers that power our state deserve this information before rash decisions about policy are made that could have such significant negative consequences.

We share the author's concerns about curtailed renewable power and urge this legislature to consider streamlining battery storage projects so that we can effectively and efficiently store California-made green power to independently power our state in accordance with our high road labor and environmental standards. At this moment in history, it would seem that collaborative efforts to bolster our energy independence would be well-spent.

On behalf of our hard-working members, thousands of whom power our state, we ask that you not rush into policy that might have a devastating effect on hundreds of thousands of industrial jobs and make our state more vulnerable to federal policy aimed at undermining decades of environmental policy in California. Please slow down the consideration of Senate Bill 540; as such, we oppose SB 540.

Thank you.

Keith Dunn
District Council of Iron Workers

Joseph Cruz
California State Counsel of Laborers

Erin Lehane
International Brotherhood of Boilermakers

April 15, 2025

SENATE ENERGY, UTILITIES,
AND COMMUNICATIONS COMMITTEE
1021 O Street, Suite 3350
Sacramento, CA 95814

RE: SB 540 (Becker, Stern) – OPPOSE

To the Honorable Members of the Senate Energy, Utilities and Communications Committee ~ Chair Becker, Vice Chair Ochoa Bogh, and Members Allen, Archuleta, Arreguín, Ashby, Caballero, Dahle, Gonzalez, Grove, Hurtado, Limón, McNerney, Rubio, Stern, Strickland, and Wahab:

The Center for Biological Diversity, California Alliance for Community Energy, Local Clean Energy Alliance, 350 Bay Area, The Protect Our Communities Foundation, the Reclaim Our Power Utility Justice Campaign, and the Environmental Working Group submit this letter opposing SB540. The bill would allow the California Independent System Operator (CAISO) and electrical corporations that own transmission systems that are operated by the CAISO to participate in unspecified energy markets governed by a Regional Organization (RO), and on or after January 2027, for CAISO to operate the energy markets governed by the RO, provided certain conditions, and "in lieu of" CAISO following its current state law mandates.

As currently drafted, SB540 still suffers the same flaws as its predecessors, in particular, ceding California's authority and oversight over energy policy. California must decide whether to risk ceding control over its energy and climate choices to other states who do not share California's commitment to clean energy or face the same crisis of affordability that plagues

California ratepayers. It is additionally concerning that SB540 would cede California controls over energy to FERC which is especially problematic in the wake of the recent announcement and Executive Orders to "unleash" fossil fuel, nuclear power and other polluting energy resources "through the removal of all illegitimate impediments" targeting State and local government energy regulations.[1]

Moreover, SB540 could likely worsen climate impacts and increase electricity bills in California even further.

I. SB540 Enables the Loss of California's Autonomy Over Energy Policy.

SB540 lacks specificity in outlining which "energy markets governed by" the RO that CAISO and transmission owners would be able to participate in. Nevertheless, despite this vagueness, which is of considerable concern, the CAISO's "use" of or participation in those markets is subject to 12 conditions. One of those conditions is:

> (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*.[2]

In other words, not only do we not know which markets are involved, but CAISO would then be subject to the RO's rules, "as accepted by" FERC.

And SB540 does not include sufficient safeguards. Participating in or operating the energy markets would also be "in lieu of . . . subdivision (b) of Section 345.5."[3] Yet Section 345.5(b) currently requires CAISO to run all electricity markets consistent with:

> (1) Making the most efficient use of available energy resources.
>
> (2) Reducing, to the extent possible, overall economic cost to the state's consumers.
>
> (3) Applicable state law intended to protect the public's health and the environment.
>
> (4) Maximizing availability of existing electric generation resources necessary to meet the needs of the state's electricity consumers.
>
> (5) Minimizing cost impact on ratepayers.
>
> (6) Communicating with all balancing area authorities in California to support electrical reliability.[4]

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[1] *See e.g.* White House, *Protecting American Energy from State Overreach* (April 8, 2025) *available at* https://www.whitehouse.gov/presidential-actions/2025/04/protecting-american-energy-from-state-overreach/

[2] Proposed Public Utilities Code § 345.6(a)(10) (emphasis added).

[3] Proposed Public Utilities Code § 345.6(a).

[4] Public Utilities Code § 345.5(b).

SB540 removes all of these energy market requirements for the new regional markets operator and for the CAISO. Then, on or after January 1, 2027, CAISO could operate the RO, subject to FERC oversight and conditions,[5] and with no requirement to continue to follow state *mandates* enumerated in Section 345.5(b).

II. SB540 Replacement Safeguards Are Either Unenforceable or Illusory.

A. SB540 Replaces Safeguard Laws with Policies and Advisory Groups.

SB540 then attempts to address the removal of these *statutory* safeguards with several provisions that are either unenforceable or illusory. The 12 conditions are replete with reference to public interest or environmental "policies,"[6] or advisory watchdog groups,[7] which is a far cry from adhering to the required "*laws* intended to protect the public's health and the environment" as currently required by Section 345.5(b).

SB540 also includes specific—but equally illusory—language designed to safeguard CAISO's current responsibilities with electricity markets:

> *Except as provided in subdivision (a) with respect to managing energy markets as provided in this section,* this section does not change the responsibilities of the Independent System Operator under Section 345.5.

Subdivision (a) as referenced, however, is Section 345.5(b). In which case, SB540 is clear that participation in energy markets **is not subject to the 6 above criteria CAISO currently must maintain consistency with to protect the environment, public health, and ratepayers**.

Furthermore, even assuming *arguendo* the effectiveness of the 12 conditions for participation in RO markets, SB540 **lacks any identifiable enforcement mechanism** for these critical commitments.

B. SB540 Threatens the RPS and Other California Climate Policy.

These concerns are extremely problematic for maintenance of California's Renewable Portfolio Standard. While the bill includes a recent amendment that tries to address this concern, it is similarly an illusory safeguard:

> (e) (1) This section does not change any requirement related to the California Renewables Portfolio Standard Program as provided in Article 16 (commencing with Section 399.11).

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[5] Proposed Public Utilities Code § 345.6(b).
[6] *See e.g.* Proposed Public Utilities Code § 345.6(a)(1) and (2).
[7] Proposed Public Utilities Code § 345.6(a)(8) (establishing a stakeholder process designed to provide *nonbinding advice* to the governing board of the RO).

Certainly, SB540 does not affect the RPS by the bill's terms, just like all of the prior versions of this bill proposing CAISO expansion, which similarly did not affect the RPS. Importantly, however, the regulatory structure that SB540 creates does not guard against future changes imposed or conditioned by the RO or by FERC. It also does not guard against future litigation to challenge the RPS and similar California environmental and climate laws based on federal preemption and the interstate commerce clause.

C. SB540 Withdrawal Provisions are Illusory.

Finally, the "escape" provision included in SB540 is also practically ineffective:

> (12) The independent regional organization provides a procedure for unilateral withdrawal by any participant with reasonable prior notice and without any further approvals.[8]

Prior versions of CAISO expansion legislative proposals included a 2 year notice limit for withdrawal, while SB540 leaves the length of the withdrawal period up to the yet-to-be-created RO. Moreover, SB540 gives the RO complete discretion to impose any condition it chooses for any withdrawal.

We emphasize that proponents of SB540 have provided no evidence of any member leaving any Regional Transmission Operator (RTO) successfully. FERC could also add additional onerous conditions of departing the RO, which the March 24, 2025 amendments cannot prevent, as California cannot limit FERC's ability to approve, or impose conditions on, any withdrawal from a FERC-approved market.

Overall, FERC could take future adverse actions to deny or disregard climate, environmental, biodiversity and public health impacts of continued fossil fuel and combustion pollution, undermining California's prioritization of renewable resources in favor of coal or gas-fired generation. Despite clarion calls from the world's leading scientific institutions that new fossil fuel projects are incompatible with maintaining a livable planet,[9] FERC continues to disregard the science and approve such projects.

California must avail itself of all available safeguards to limit the damage that could flow from FERC. For example, FERC could require the RO to devalue clean energy resources in favor of fossil fuels or other combustion resources and eliminate California's ability to apply critical environmental standards to imports. This includes the social costs of carbon pollution and protections for biodiversity. For instance, the RO could allow substantial imports of electricity from Western coal-fired generation to serve California residents, perpetuating those coal power plants' operation in other states. This would be problematic under any federal administration, but

[8] Proposed Public Utilities Code § 345.6(a)(12).
[9] *See e.g.* Oxford Open Climate Change, Volume 5, Issue 1, *Scientists' Warning on Fossil Fuels* (March 31, 2025) *available at* https://doi.org/10.1093/oxfclm/kgaf011.

it is particularly concerning given that the Trump Administration has "vow[ed] to ramp up U.S. production of "clean coal."[10]

Similarly for utility-scale renewables, California has supported land use planning to steer renewable development to areas where there are fewer on-the-ground impacts. Such policies include County planning and the Bureau of Land Management's Desert Renewable Energy Conservation Plan, which balances protection of irreplaceable desert habitats, plants, animals and ecological processes with the development of a significant amount of centralized renewable energy (from solar, wind and geothermal facilities) by focusing on areas with the least ecological impact. Out-of-state utility scale power from the same types of renewable resources may not have similar protections for biodiversity and the RO and FERC could well favor ecologically damaging resources over adequately sited energy generation in California.

III. SB540 Would Increase Climate Pollution.

In January 2025, Brattle produced a Preliminary Day-Ahead Market Impacts Study (Brattle 2025 Study) for the California Energy Commission. The Study examined four main scenarios for expanded western regional markets, including an analysis of projected impacts for each scenario.[11]

Each scenario includes a mix of participation (by utilities in California and neighboring states) in CAISO's Extended Day-Ahead Market (EDAM) and (by other utilities in the western U.S.) in different day-ahead markets (Markets+) that will not include California. The scenarios are: the Baseline Case (with already approved EDAM commitments); the Baseline+ Case (with projected likely EDAM commitments); the Expanded EDAM Case (which assumes maximum EDAM potential/commitments); and the Split Market Case (with projected likely participation in EDAM and Markets+).

"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."[12] The Expanded EDAM Scenario is extremely unlikely as several potential participants have already committed or indicated that they will join the Southwest Power Pool markets. Given existing commitments or expressed intentions to support, however, either the Baseline+ or Split Market Case are the most likely outcomes under SB540. In that case, expanding either CAISO's EDAM or Southwest Power Pool's Market+, would **increase total CO2 emissions from power plants** connected to the western U.S. grid. While California would see reduced CO2, notably, *increased CO2 in the western U.S. offset CO2 reductions in California*.[13]

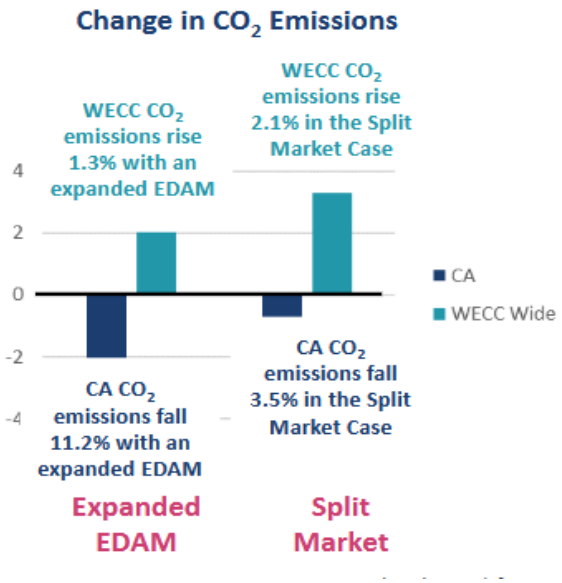
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[10] LA Times, *Trump vows to immediately ramp up U.S. production of 'beautiful, clean coal'* (March 18, 2025), *available at* https://www.latimes.com/environment/story/2025-03-18/trump-ramp-up-production-of-beautiful-clean-coal.

[11] Brattle 2025 Study, slide 3, *available at* https://www.brattle.com/wp-content/uploads/2025/02/Preliminary-Day-Ahead-Market-Impacts-Study-Impact-of-Market-Footprints-on-California-Customers.pdf.

[12] *Id.*, Slide 1.

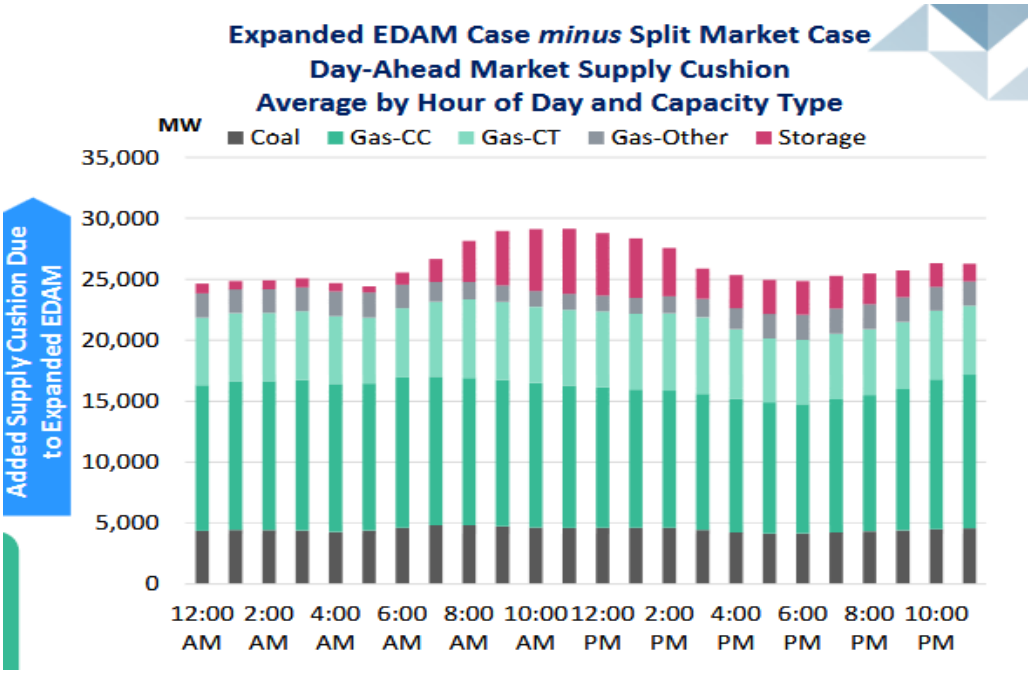
[13] *Id.*, Slide 6.



To put numbers on this net increase, in the most likely Split Market outcome under SB540, California emissions decrease by less than 1 million tons of CO2, *but* the Western region emissions increase by over 3 million tons, producing a net increase of over 2 million tons of CO2.[14] This is not progress but rather a step backwards for the climate.

Compounding this significant climate concern, although a claimed benefit of expanding integrated markets is improved reliability (through sharing surplus generation), the Brattle 2025 Study found that the vast majority of these "shared" or "extra surplus" generation would be fossil fuel power plants, including nearly 5,000MW of coal plants, as illustrated below.[15]

[14] *Id.*
[15] *Id.*, Slide 8.



Therefore, even without the substantial risks to our environment, public health, and rates imposed by FERC, even the studies upon which proponents of SB540 rely show that the bill would still jeopardize California's advancements as a Climate Leader, and our ability to tackle the climate emergency.

IV. In the Midst of an Affordability Crisis, SB540 Risks Increasing California Ratepayer Costs.

SB540 also fails to include any **mechanisms to ensure that California electricity rates do not increase** under the proposed RO structure. While the Brattle 2025 Study showed that costs for *power generation* may decrease, the costs for *power delivery*—which are substantial—have not been addressed and would likely fall on California ratepayers. The significant costs of power delivery (including transmission buildout, and associated wildfire mitigation or transmission maintenance) are also the two principal drivers of high electricity rates in the state.[16] Neither the Public Utilities Commission nor CAISO have yet conducted any studies to decipher how much the proposed RO and associated transmission buildout (which would also require wildfire mitigation costs) could increase rates.

Furthermore, given the Trump Administration's vows to increase electricity generation with "clean coal," it is possible that, as part of an RO, California residents would also have to begin paying for coal subsidies. There has similarly been no analysis about this potential, and substantial, impact.

* * *

[16] Senate Bill 695 Report to the Governor and Legislature on Actions to Limit Utility Cost and Rate Increases Pursuant to Public Utilities Code Section 913.1 (2022).

While we support coordination with other markets to tackle the state's energy challenges, there are ways to do so without resorting to increased reliance on potentially problematic out-of-state resources and without ceding state control over one of our most essential energy supplies. Many of these solutions are already in place, including the Energy Commission's Clean Energy Reliability Investment Plan, and the extent to which California eliminates barriers to and maximizes local energy supply resources. California should be focusing on reforming the state's investor-owned utilities, prioritizing local clean energy resources, and putting the consumer, not for-profit energy companies, at the center of all energy decision making.

For these reasons, we oppose SB540 and we urge the Committee to vote no and to protect California's authority over its clean energy policies, our environment, and the well-being of California residents and ratepayers.

Sincerely,

Roger Lin
Christina Scaringe
Center for Biological Diversity

Emi Yoko-Young
Reclaim Our Power

Malinda Dickenson
The Protect Our Communities Foundation

Barbara Stebbins
California Alliance for Community Energy

Claire Broome
350 Bay Area

Bernadette Del Chiaro
Environmental Working Group

Jessica Tovar
Local Clean Energy Alliance

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

PREPARED BY

John Tsoukalis
Kai Van Horn
Johannes Pfeifenberger
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

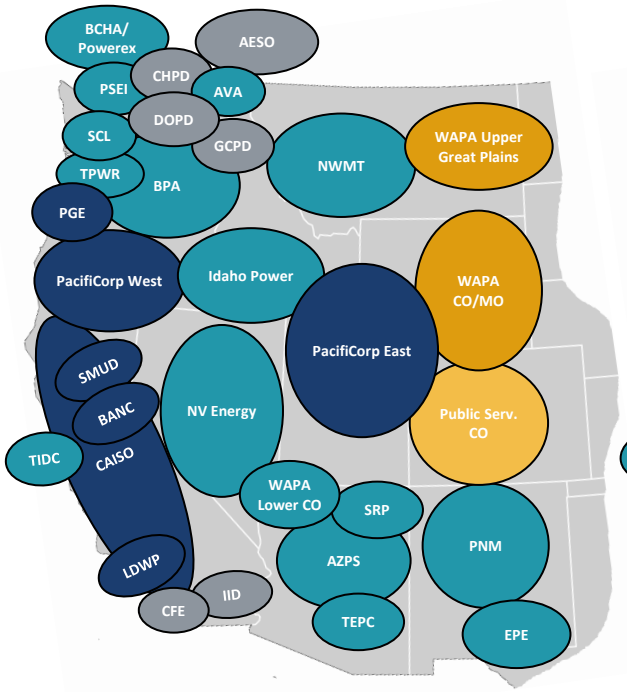
Larger and More Diverse Pool Transmission and Generation Resources	• **Shift from less efficient to more efficient resources, leading to production cost savings for customers.** ***Customer Cost Savings*** ↑ • **Emissions potentially decline due to shift to more efficient generation.** ***Potential Environmental 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

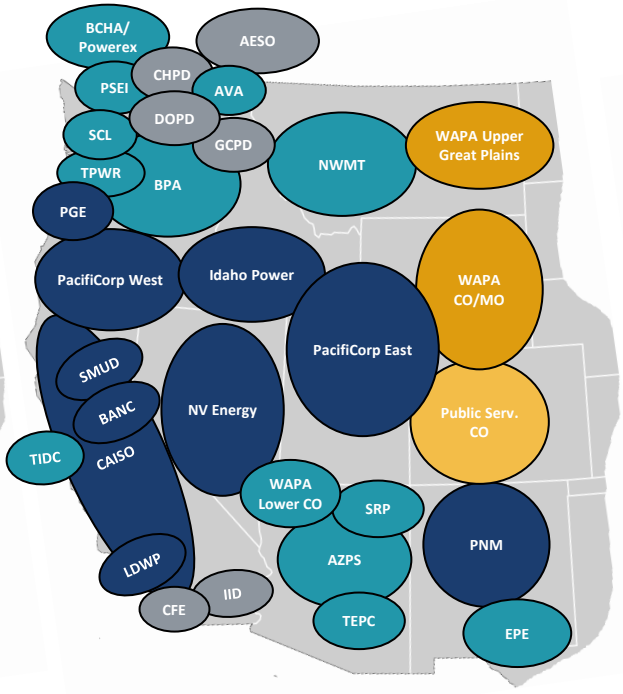
Markets+ (DA & RT)
EDAM (also in WEIM)
SPP RTO West (*co-optimizes w/ M+*)
WEIS
WEIM

To test the impacts for California DA market participation benefits of several potential DA market outcomes, we simulated four market footprints

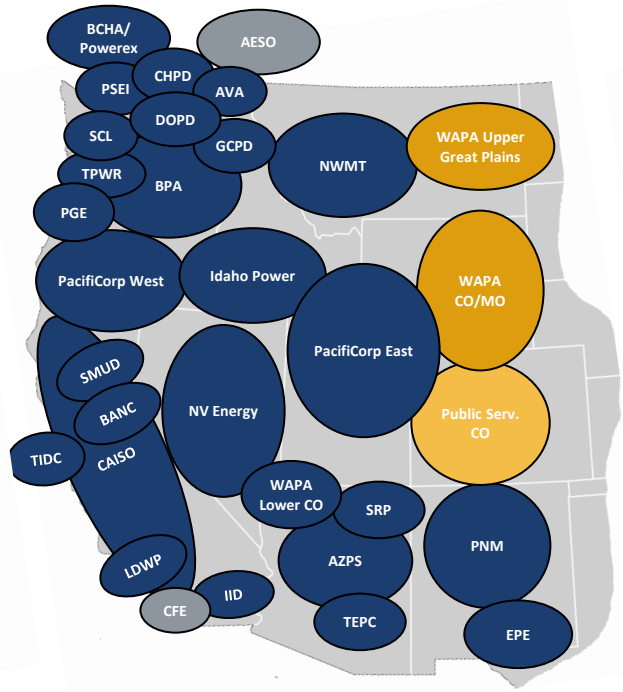
Baseline Case
(Approved EDAM Commitments)



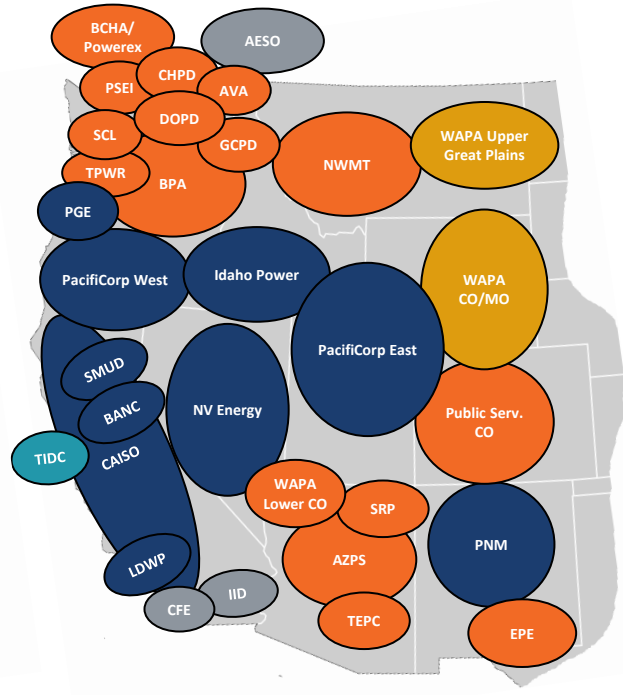
Baseline+ Case
(Likely EDAM Commitments)



Expanded EDAM Case
(Maximum EDAM Potential)



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

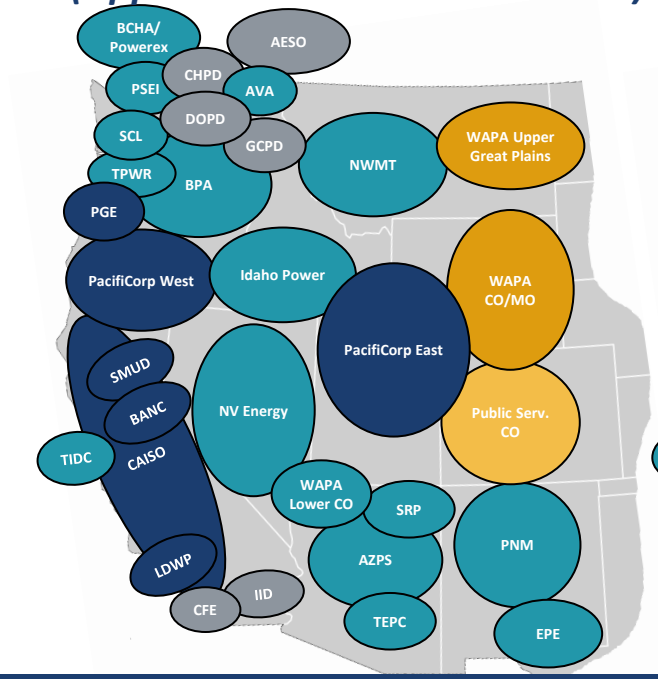


EDAM (also in WEIM)
SPP RTO West
WEIS
WEIM

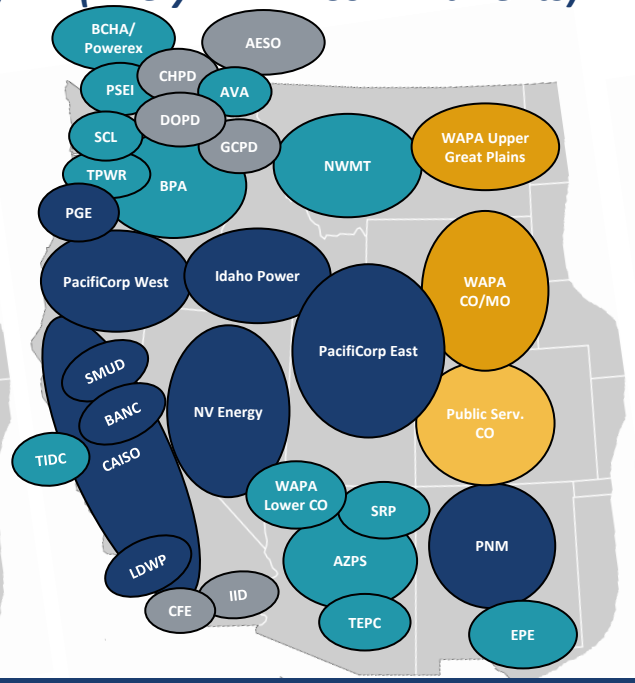
CA Customer Benefits Increase with the Size of the EDAM Footprint

Expansion of EDAM footprint could produce over $500 million/year in market benefits to CA customers

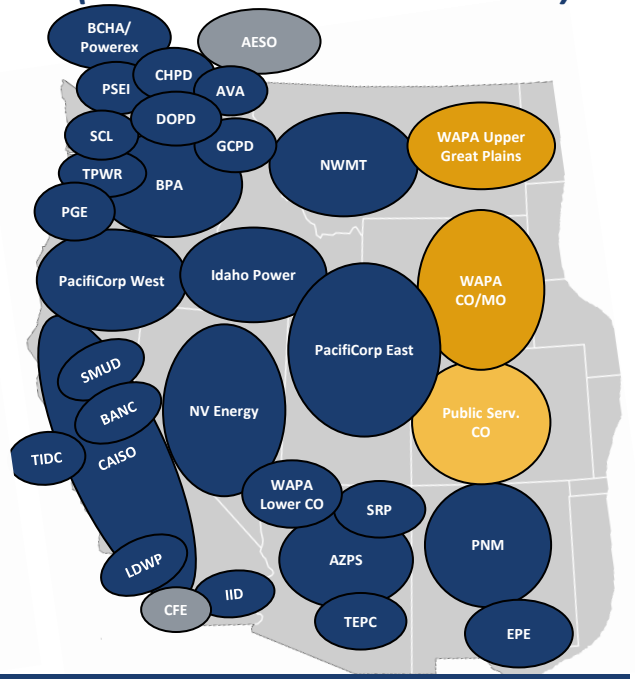
Baseline Case
(Approved EDAM Commitments)



Baseline+ Case
(Likely EDAM Commitments)



Expanded EDAM Case
(Maximum EDAM Potential)



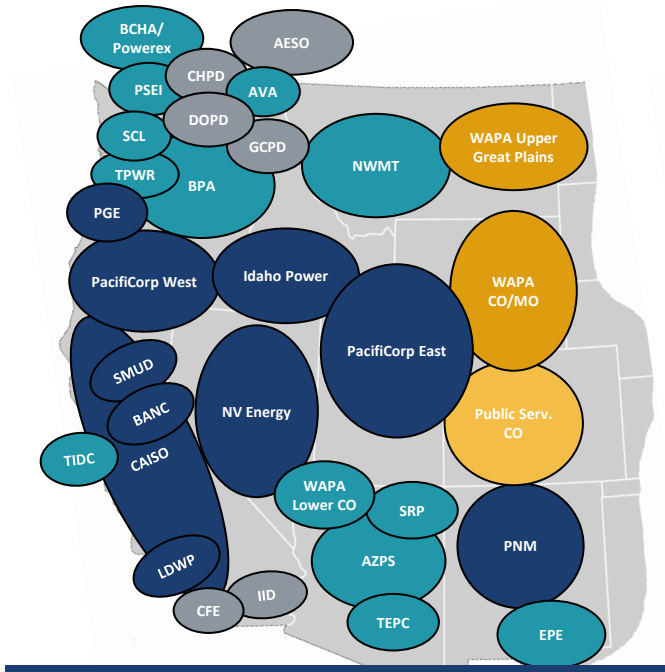
	Baseline Case	Baseline+ Case	Expanded EDAM Case
CA Total System Cost ($million per year)	$4,511	$4,399	$3,721
Δ to Baseline		$112	$790
Δ to Baseline+			$678

- 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"

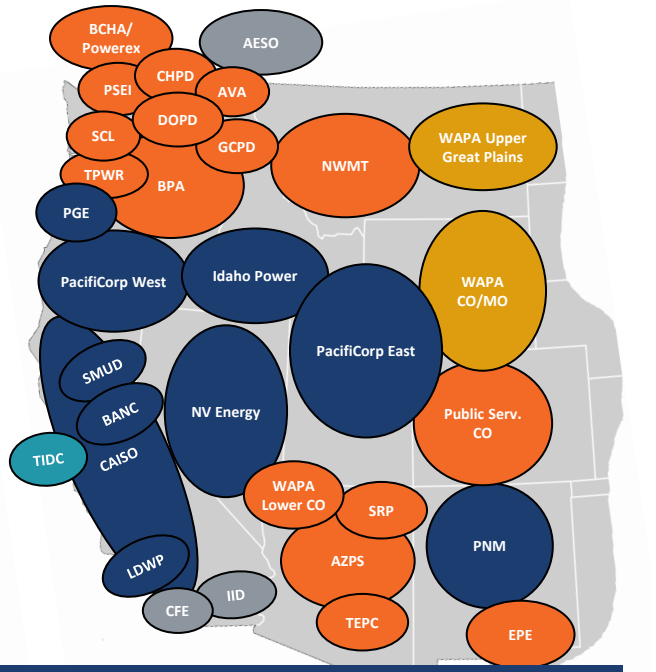
Markets+ (DA & RT)
EDAM (also in WEIM)
SPP RTO West
WEIS
WEIM

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.

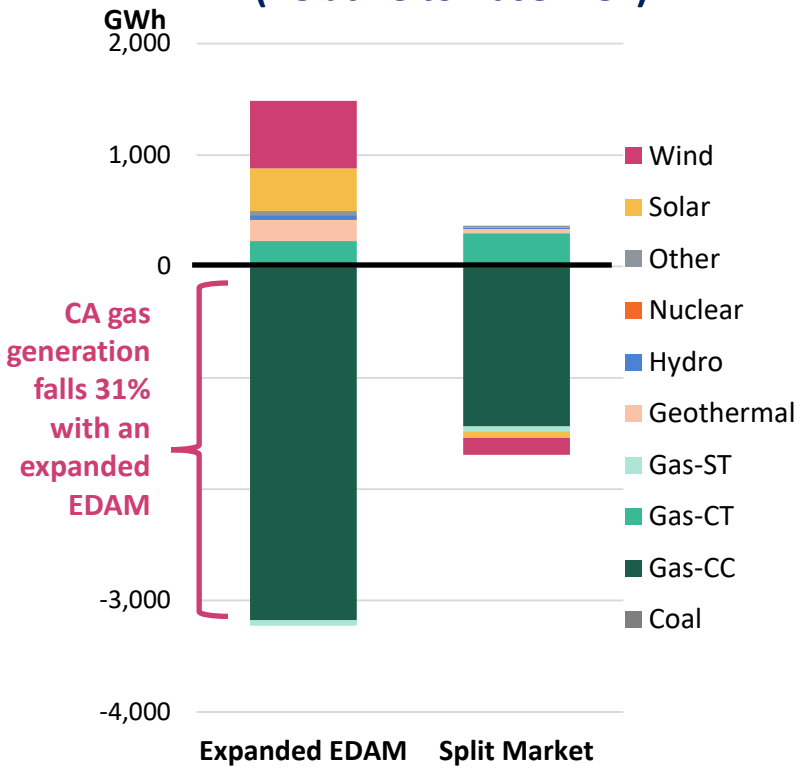
Several assumptions drive this result:

- 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.

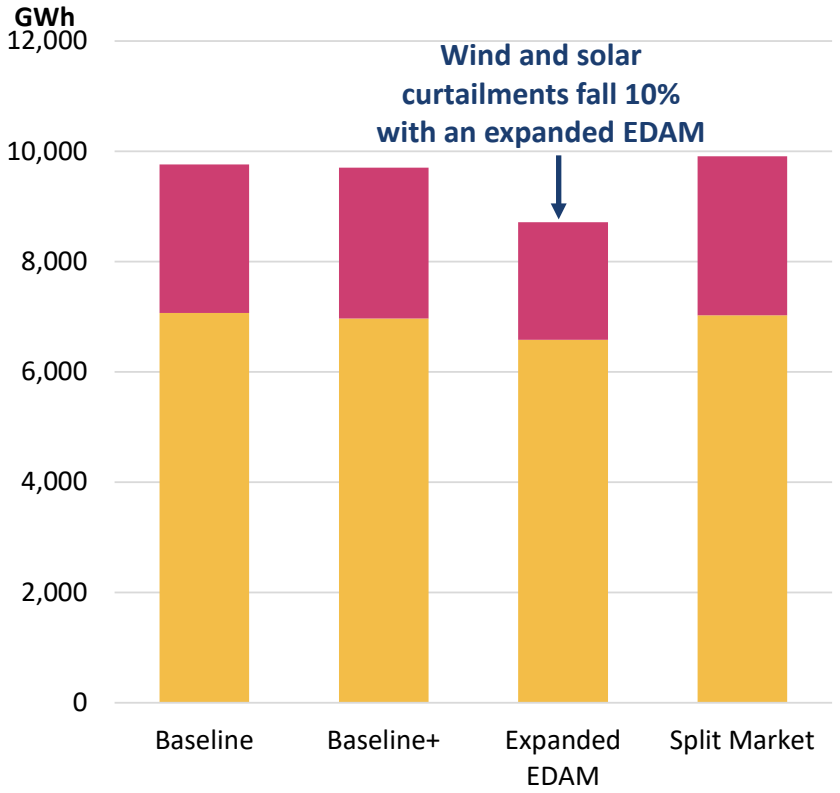
GHG Emissions Impacts

The expansion of EDAM reduces gas generation and the curtailment of wind and solar in California, resulting in lower GHG emissions in the state.

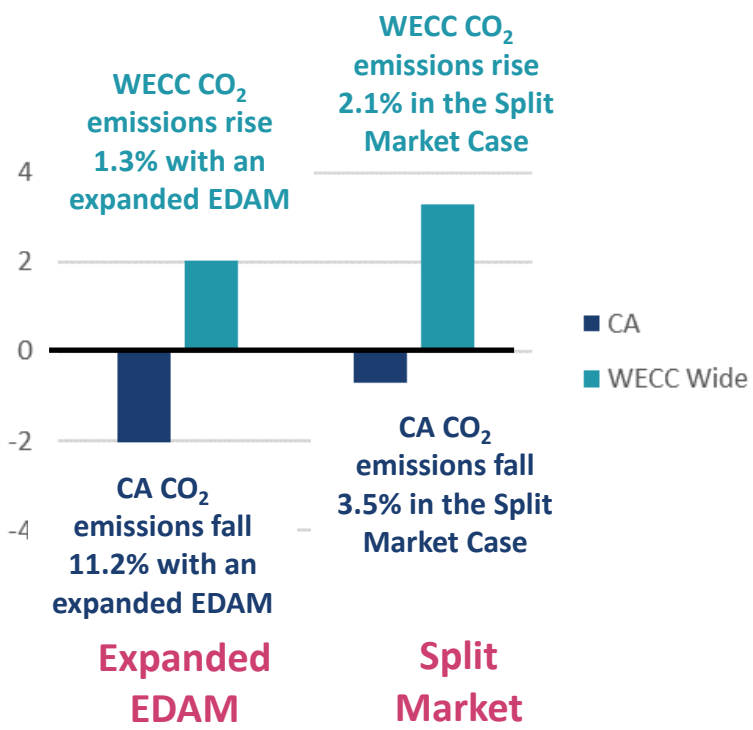
California-Wide Generation (Relative to Baseline+)



Total California Curtailments by Case



Change in CO_2 Emissions

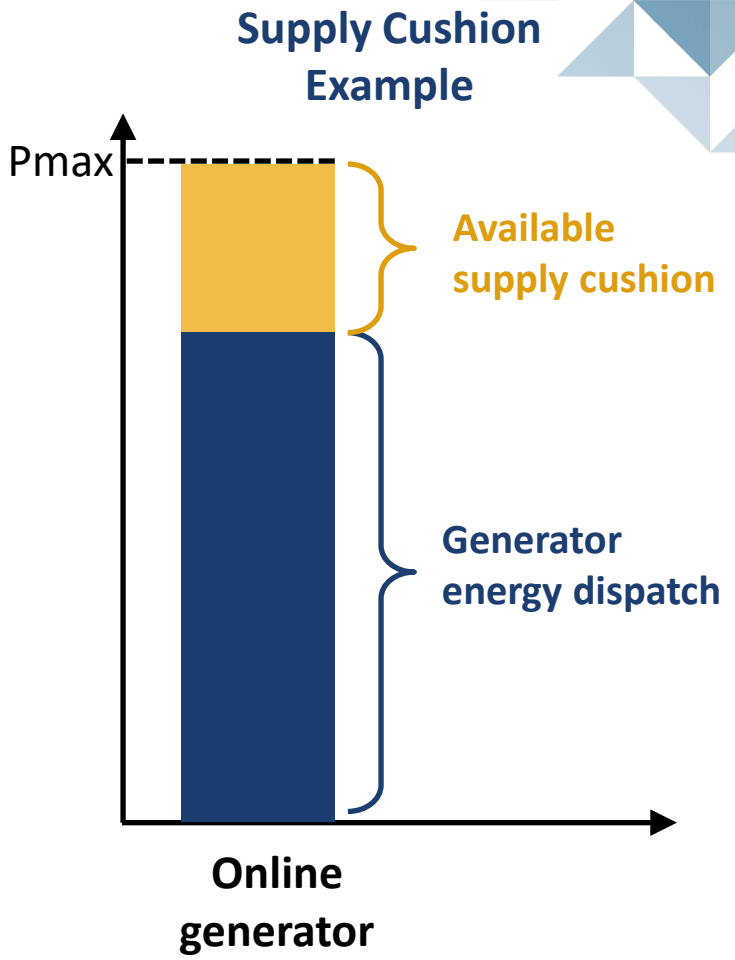


Market Supply Cushion Overview

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.

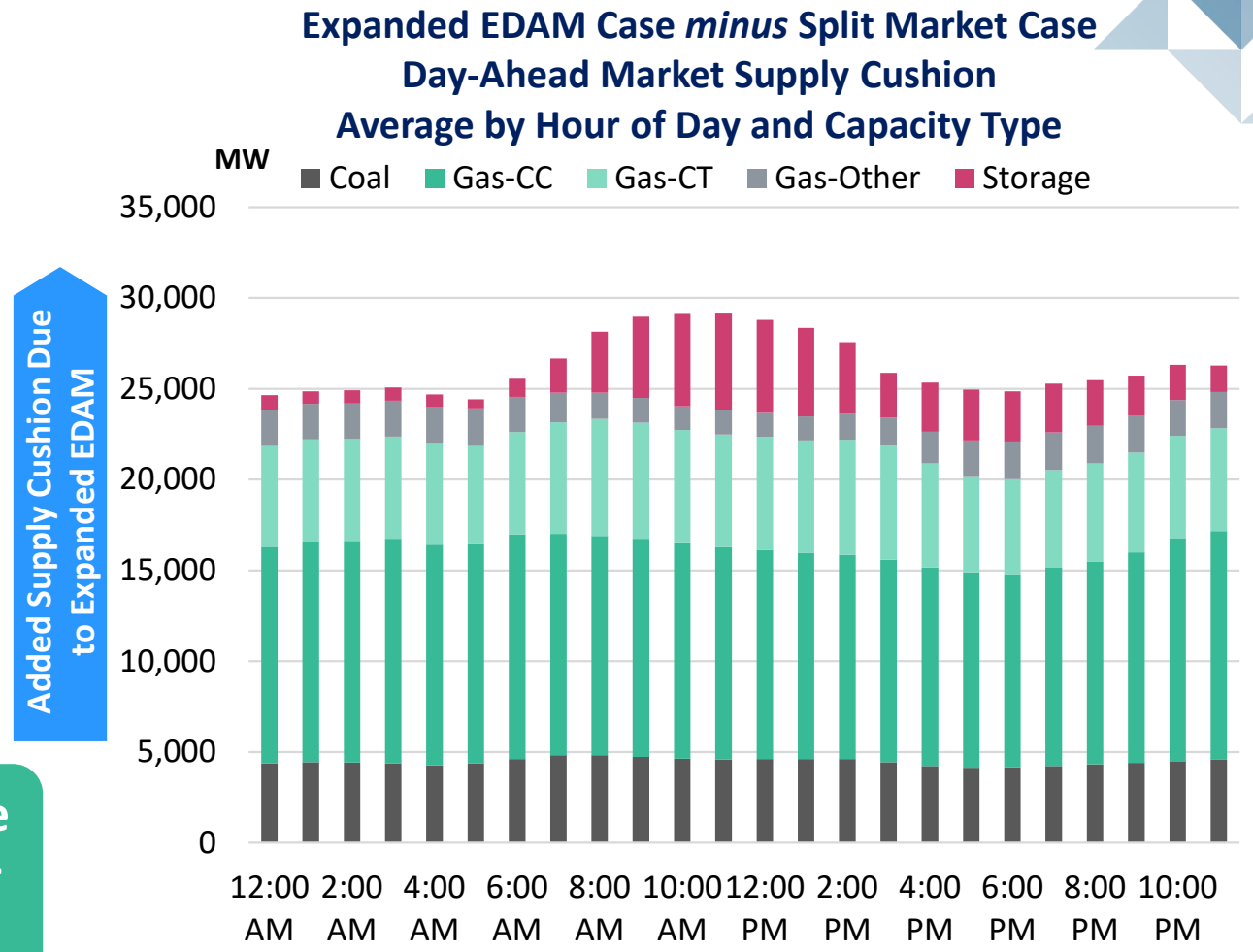
We use this metric as a proxy for the impacts of market footprint on access to capacity, especially during tight-supply periods with high risk of resource adequacy shortfalls.



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

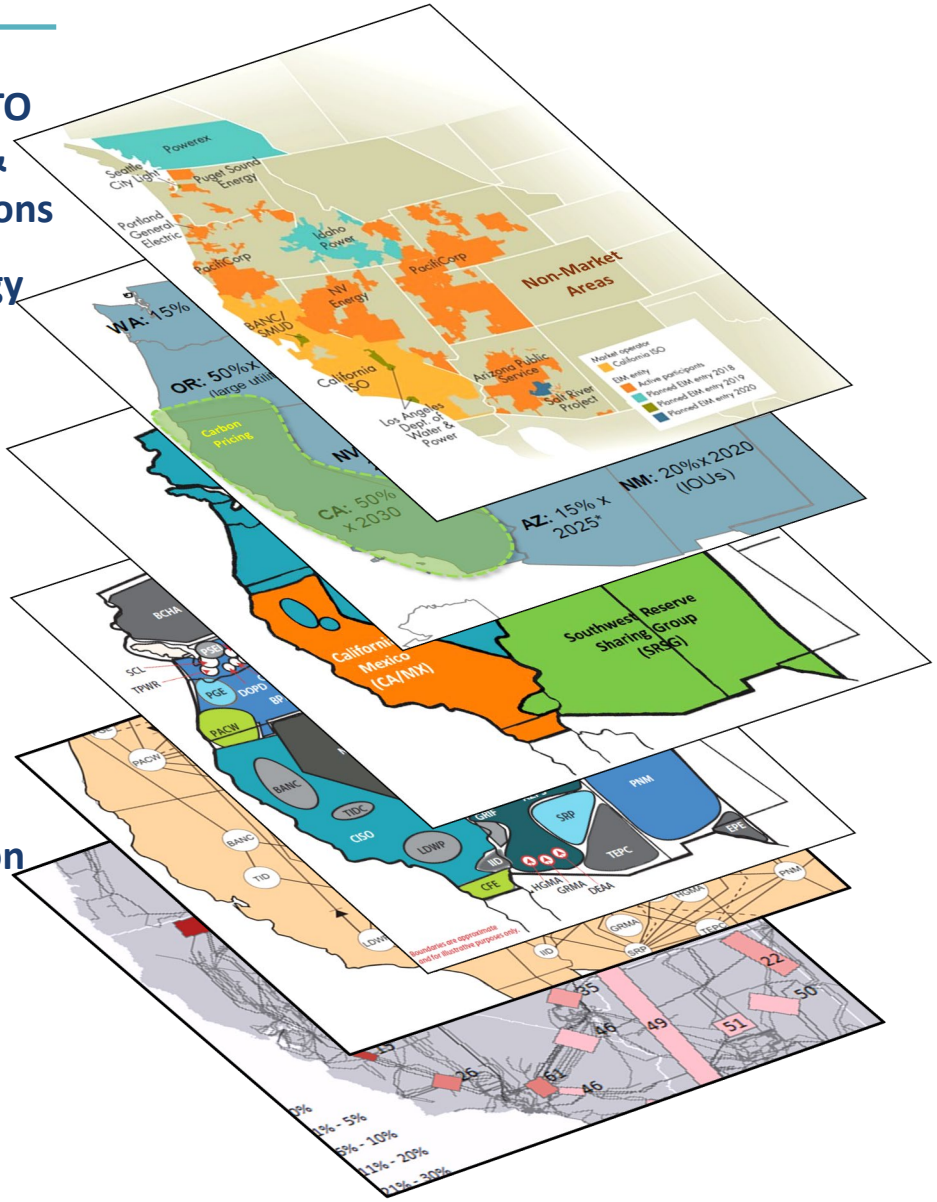
Clean Energy Policies

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

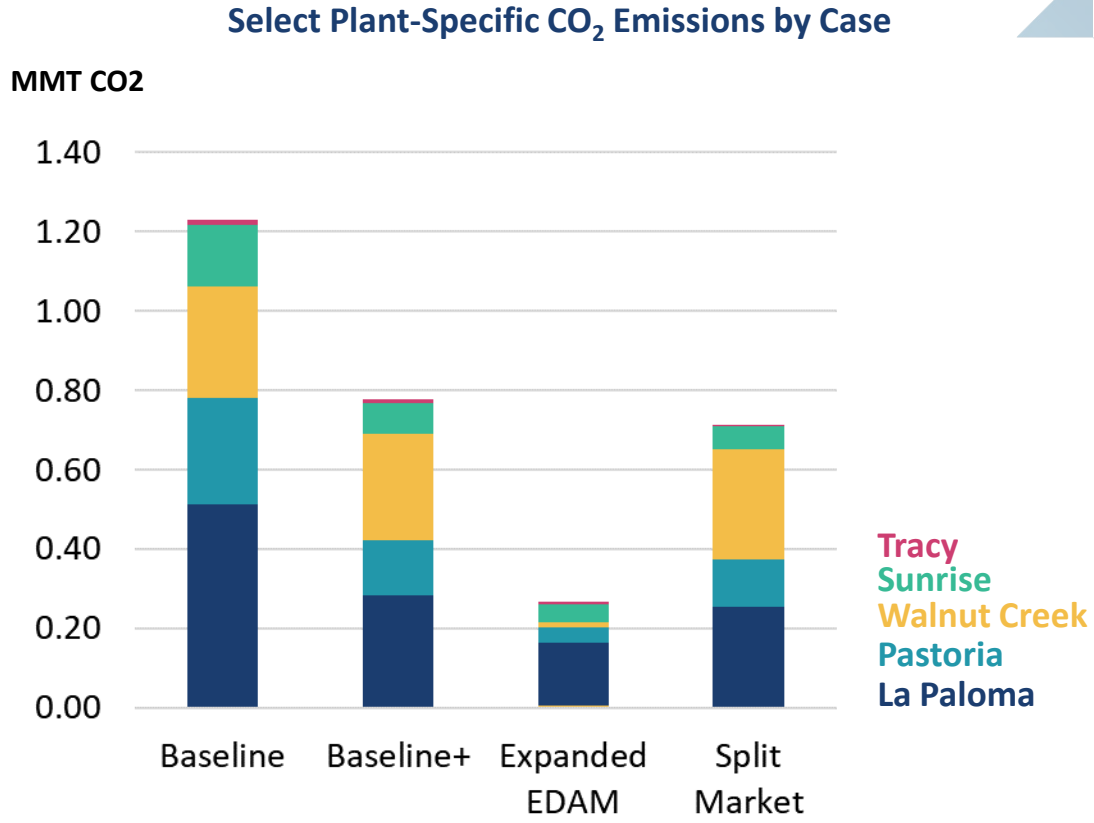
			GWh			$/MWh			Total ($1000s/Year)			
Cost Components			**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	**Baseline+**	**Split Market**	**Difference**	
Production Cost	(+)	[1]	344,267	342,887	**-1,379**	$4.18	$4.00	**-$0.19**	1,439,851	1,370,114	**-$69,737**	**(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.

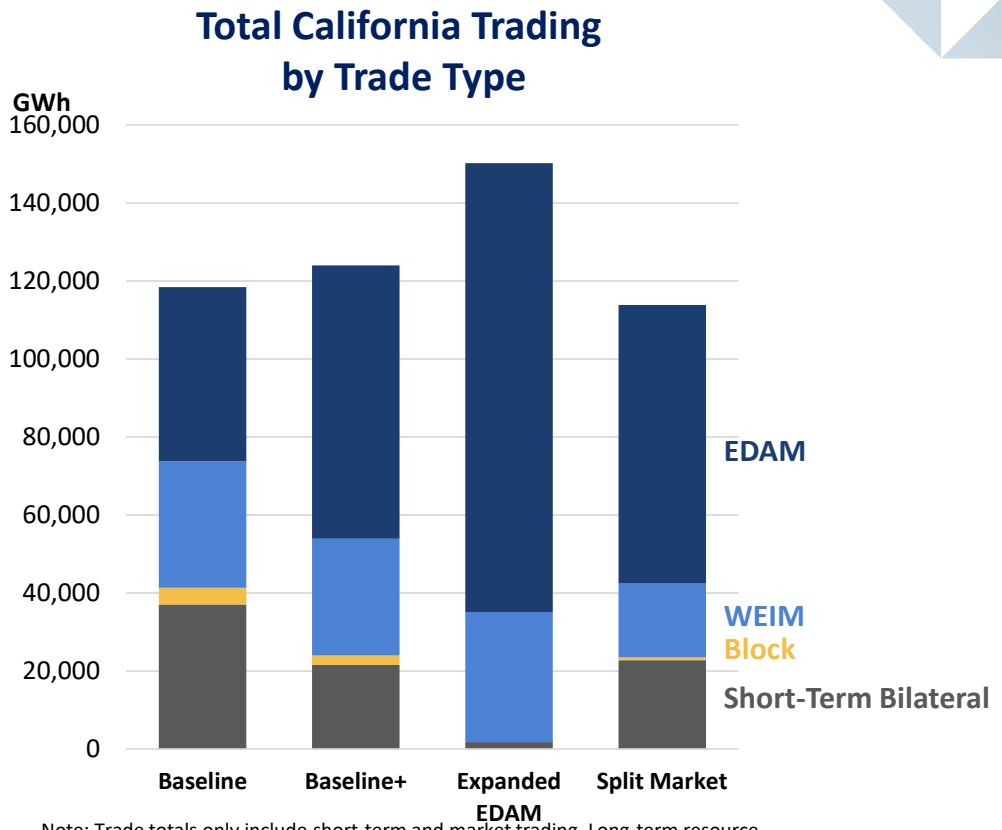
- Emissions from some of the larger gas plants in California fall across the board, but dramatically more in the Expanded EDAM case.
- The decline in gas generation in the Expanded EDAM case is broadly consistent across all areas of California.



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**

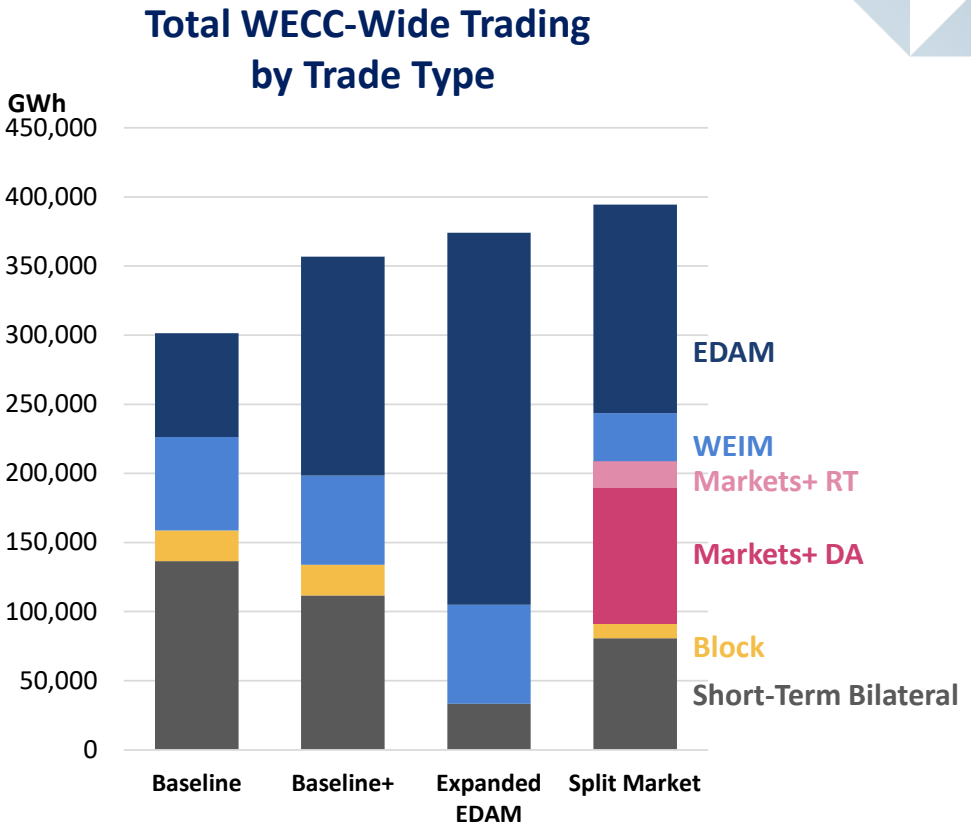


Note: Trade totals only include short-term and market trading. Long-term resource contracts are not included in these totals. Short-term bilateral trades include EDAM-Markets+ seam trades.

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



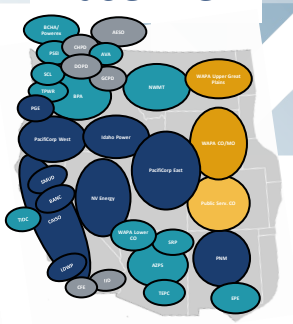
Note: Trade totals only include short-term and market trading. Long-term resource contracts are not included in these totals. Short-term bilateral trades include EDAM-Markets+ seam trades.

California Trading Changes: Baseline+ to Expanded EDAM

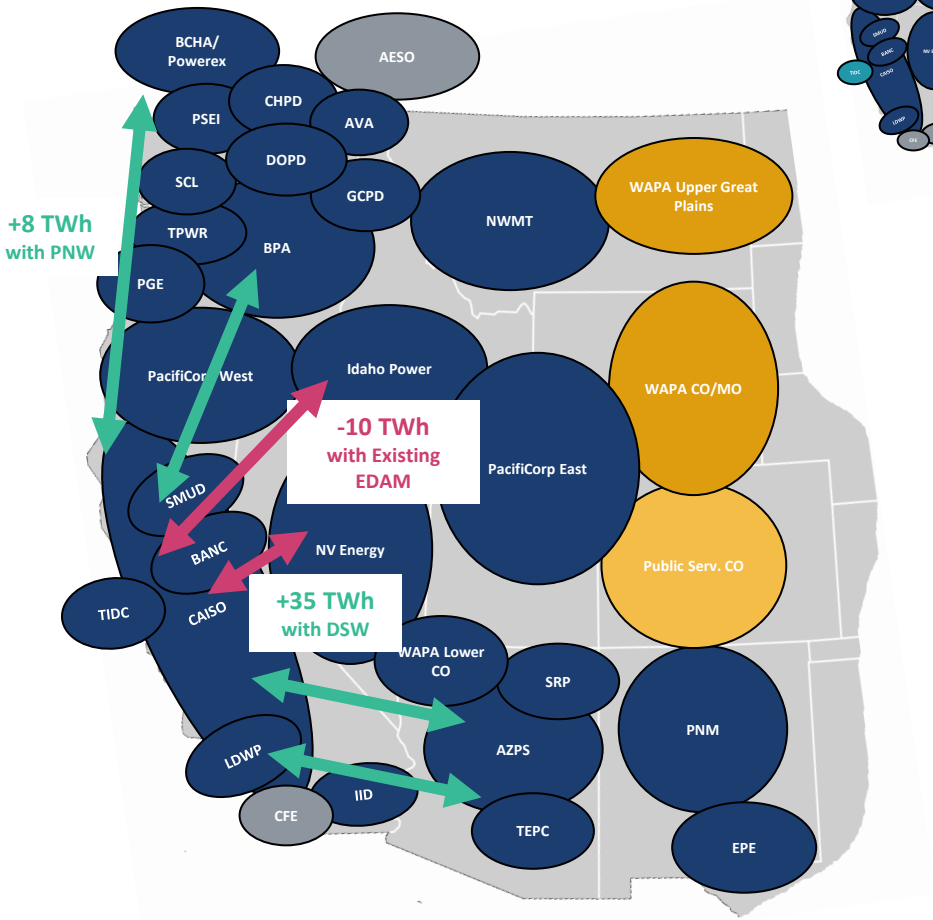
In the Expanded EDAM case, California trading increases with the new EDAM participants in the Desert Southwest and Pacific Northwest

- 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+



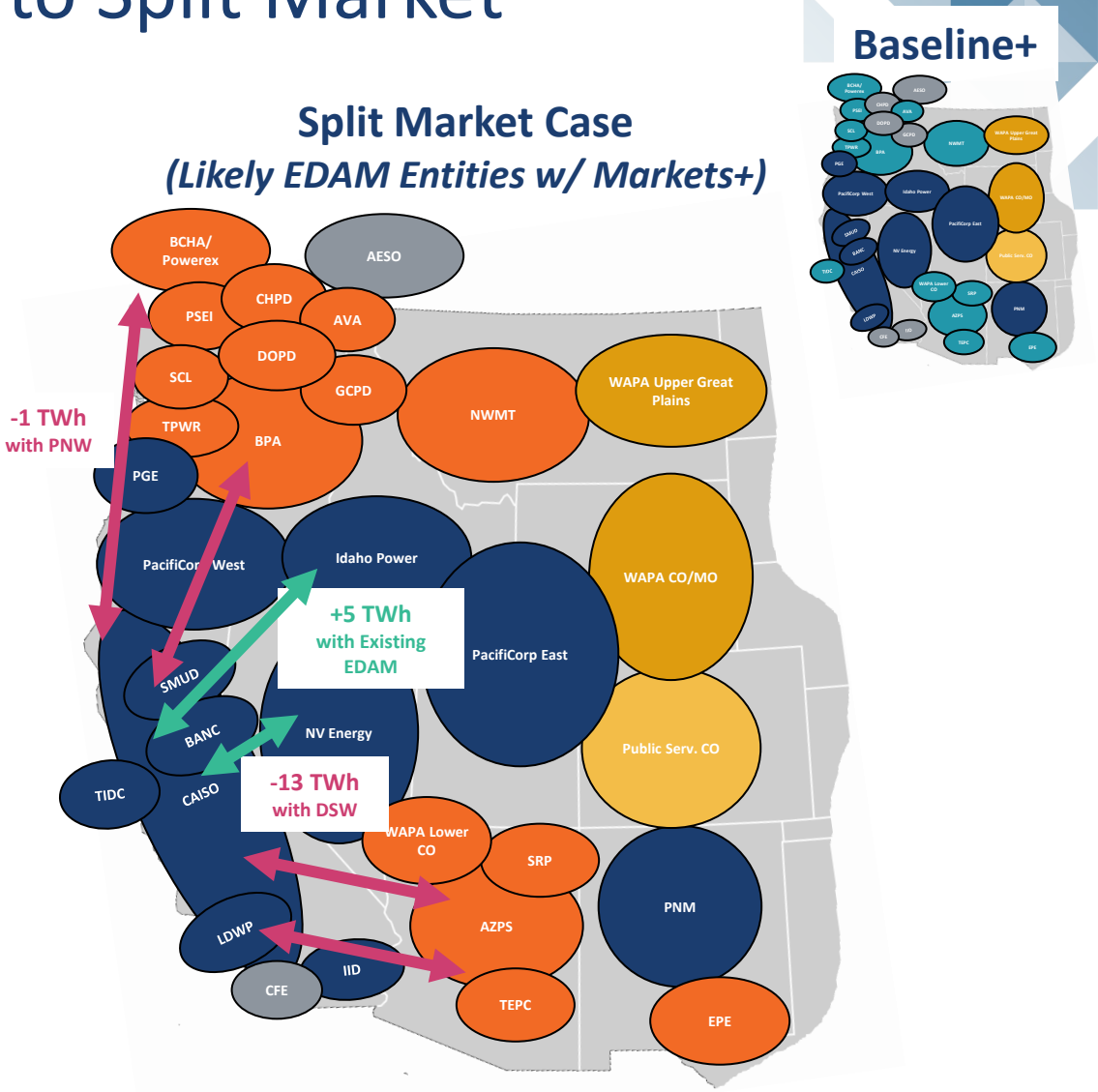
Expanded EDAM Case
(Maximum EDAM Potential)



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")

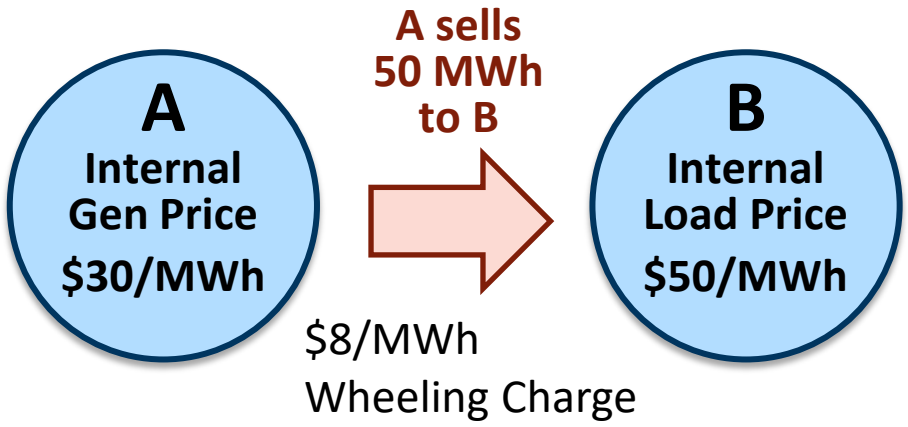
(–) Revenues from bilateral and market sales valued at the BAA's generation-weighted energy price ("Gen LMP")

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 <u>APC metric</u> only uses area-internal prices for purchase cost and sales revenues, which does not capture part of the value:

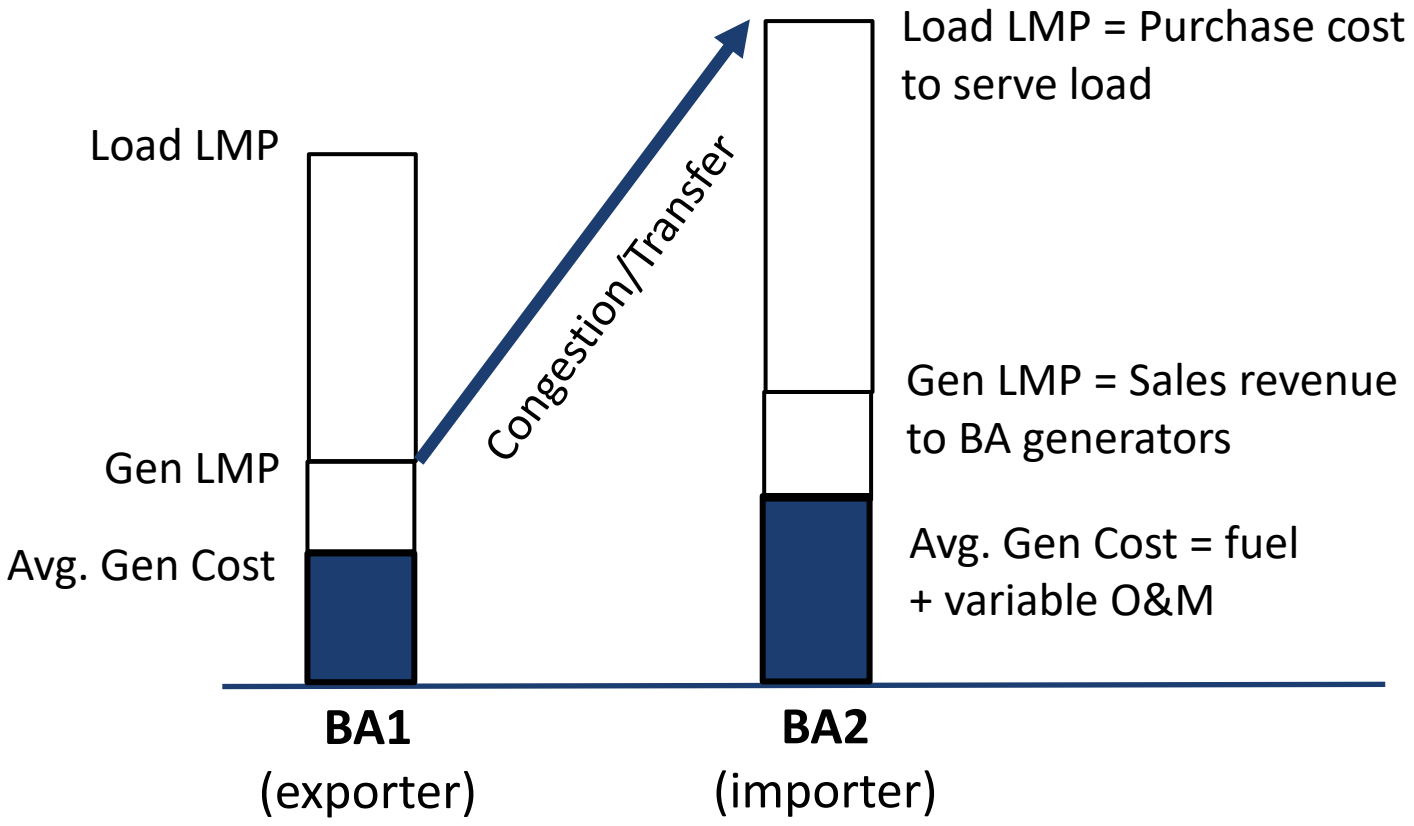
- A receives $30×50MWh=$1,500 in APC sales revenues
- B pays $50×50MWh=$2,500 in APC purchase costs

➔ $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

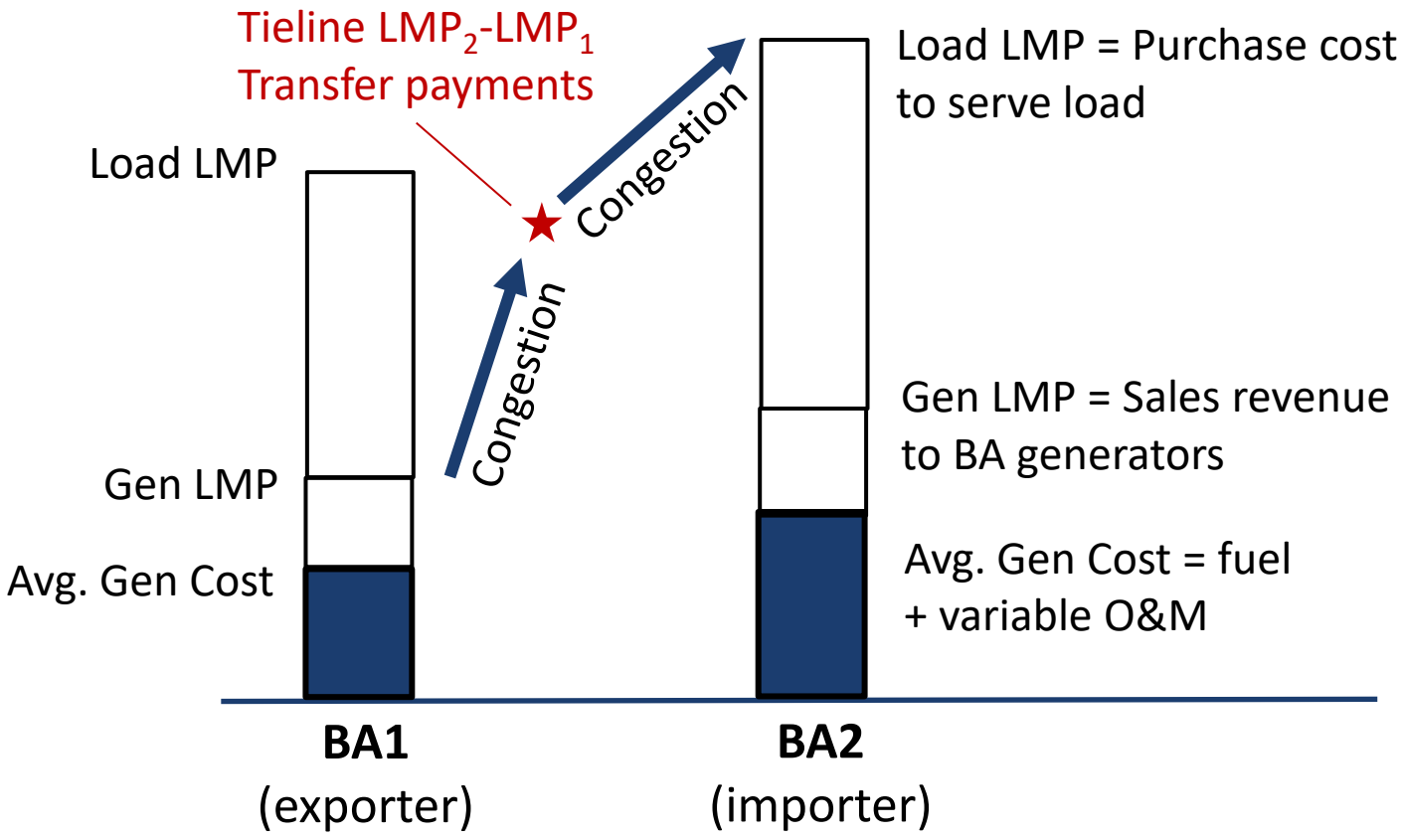
Illustration of Markets+ Congestion Revenues



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



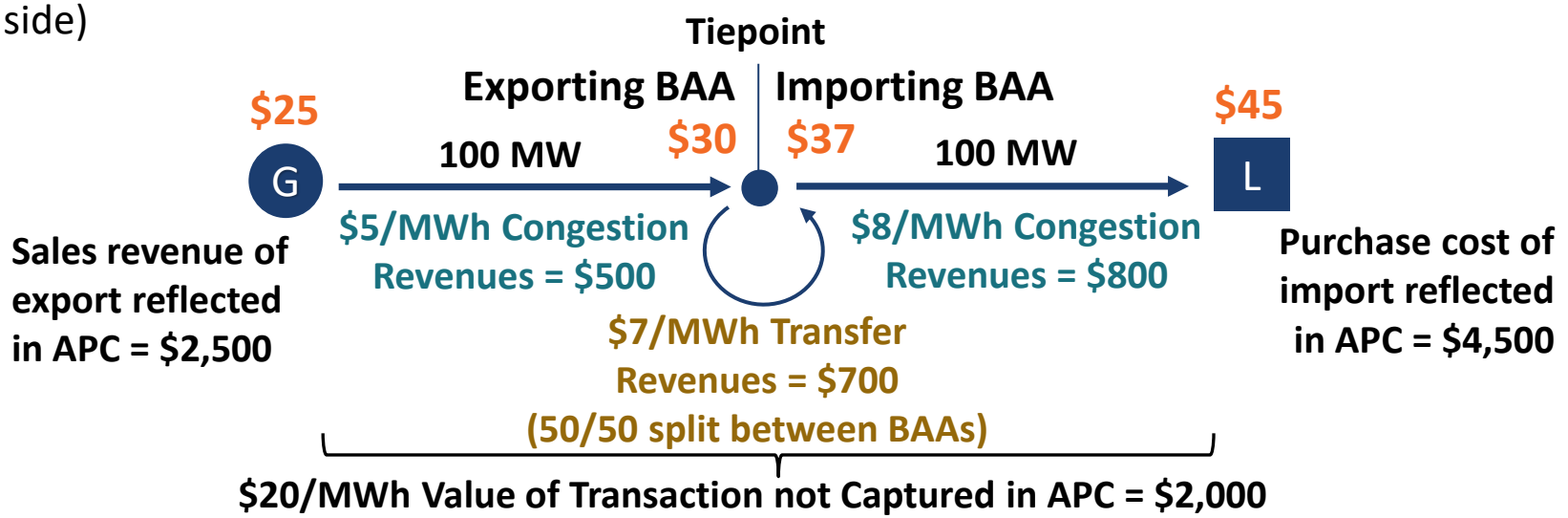
EDAM congestion and transfer revenues estimated based on individual tieline LMPs:

- **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

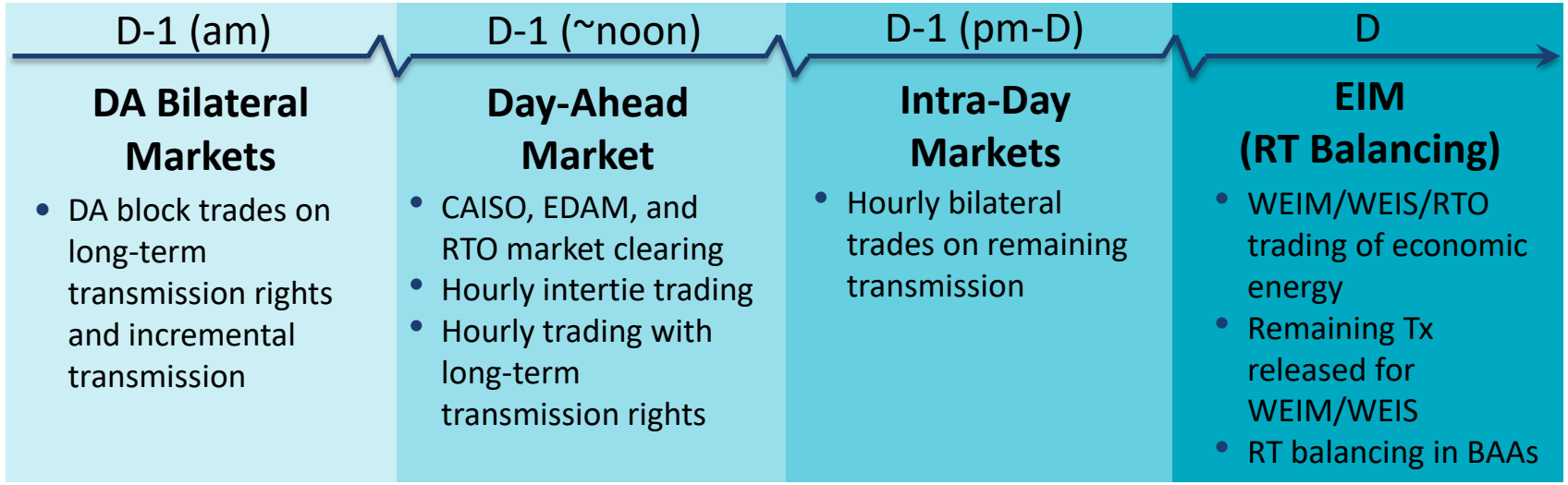
- Nodal mixed-integer model representing each load and generator bus in the WECC
- Licensed through Enelytix
- Detailed operating reserve and ancillary service product definition
- Detailed representation of the transmission system (both physical power flows and contract paths)
- Sub-hourly granularity (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.

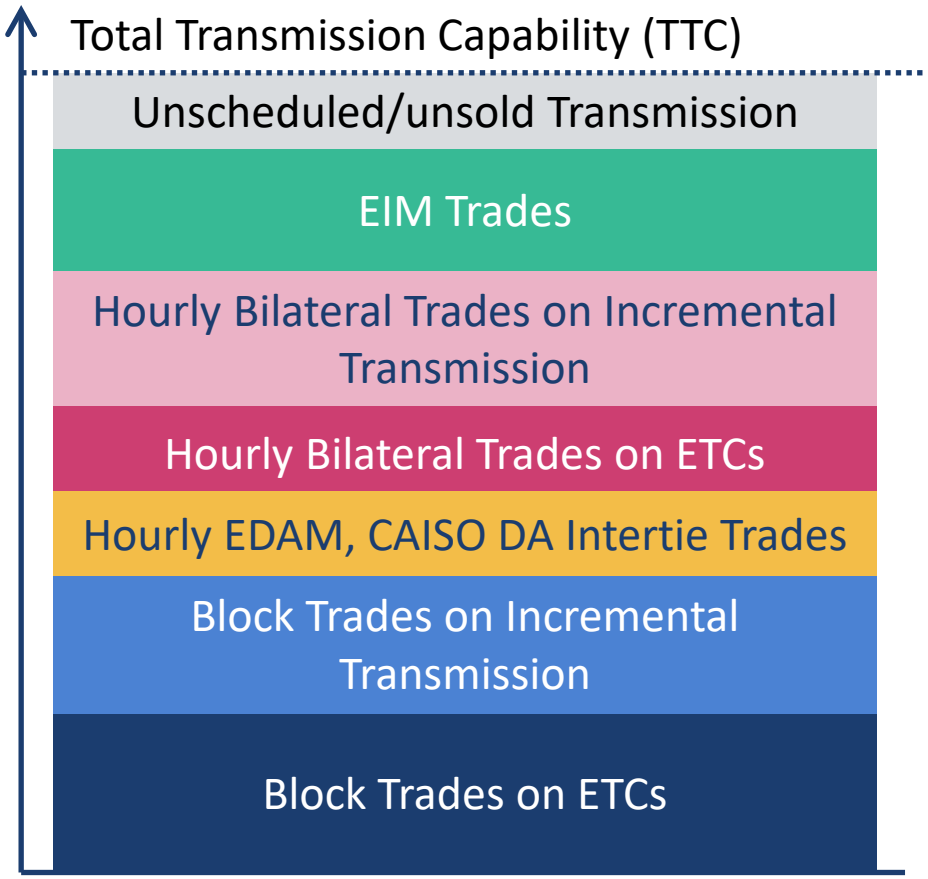
These cycles can take on different assumptions, depending on market structure. In a bilateral setting, all are set up to analyze utility-specific unit commitment and dispatch decisions, with each of them including hurdle rates and transmission fees that limit the amount of economic transactions that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

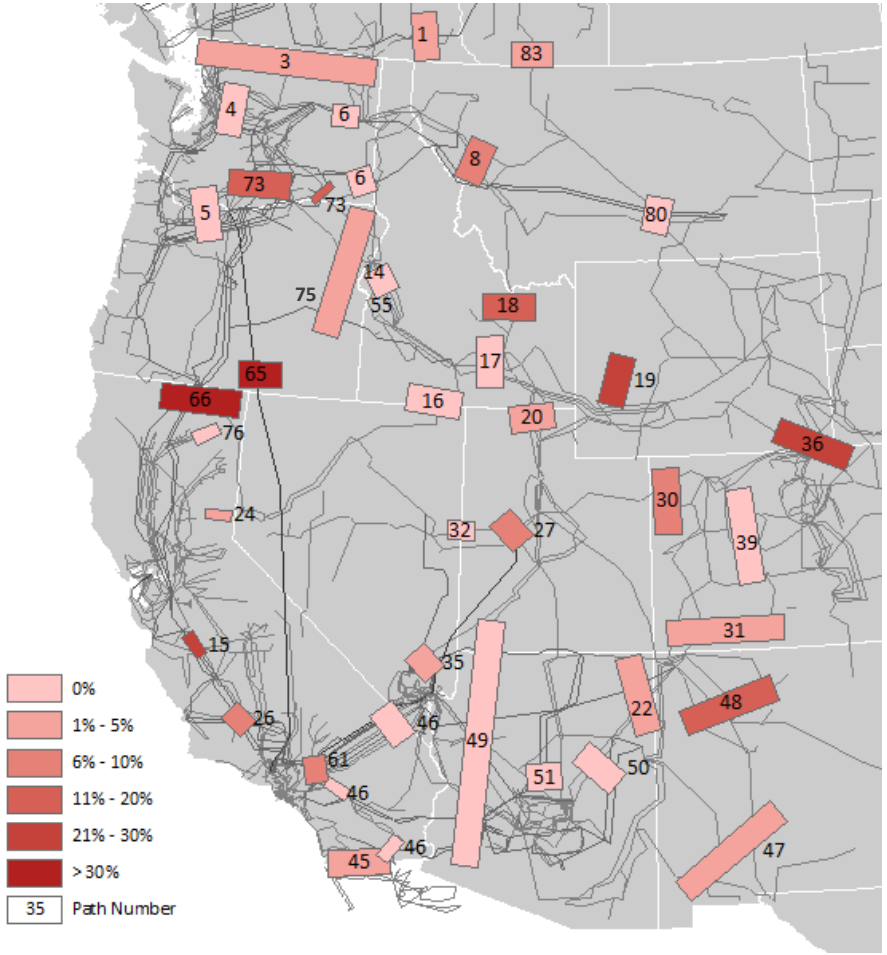
- Existing long-term transmission contracts (ETCs) and incrementally purchased transmission
- Total reservations on each contract path is limited by the total transfer capability (TTC)
- Trades are structured as blocks or hourly
- Bilateral trades between BAAs, at major hubs, or across CAISO interties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

March, 12th 2025

The Honorable Josh Becker
Chair, Senate Energy, Utilities and Communications Committee
1021 O Street, Suite 3350
Sacramento, CA 95814

RE: Joint-IOU and CalCCA Support for Senate Bill (SB) 540 – West-wide Governance Pathways Initiative

Dear Chair Becker,

Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and the California Community Choice Association (CalCCA) write in strong support of SB 540 (Pathways Initiative), which authorizes the California Independent System Operator (CAISO) and California Utilities to integrate into a broader regional energy market governed by an independent regional organization (RO), should it meet specific statutory requirements.

SB 540 Provides Savings and Reliability Benefits for Customers. SB 540 presents a unique opportunity to reduce energy costs and improve affordability. SB 540 provides entities throughout the Western Interconnection with increased confidence in the independent governance of an efficient and competitive regional energy market operated by the CAISO, thereby attracting broader participation. With a larger market footprint SB 540 supports optimized use of more generation, transmission, and storage assets than is currently the case. Optimization across a larger set of electrical assets increases efficiency and reduces overall electric costs for consumers. This optimization also allows for more effective pre-positioning of resources when grid conditions are tight, thereby enhancing reliability. A study by the California Energy Commission (CEC) estimates that an expanded market could save California ratepayers nearly $800 million per year by reducing reliance on expensive fossil-fuel generation and increasing access to lower-cost renewables from other states. A Stanford Woods Institute study found that under a regional market scenario, the California grid would experience 40% fewer hours of strain during extreme heat events, reducing the likelihood of costly emergency power procurement and ratepayer surcharges.

SB 540 Supports Clean Energy Investment. SB 540 will allow California to access a broader portfolio of clean energy resources and at a lower overall cost. For example, the bill has the effect of allowing California to export more excess renewable energy to neighboring states rather than curtailing their production, ensuring better utilization of clean energy investments. Conversely, when energy demand exceeds California's generation capacity, an expanded regional energy market will dispatch a larger pool of renewable resources with low marginal costs of operation to ensure we continue to reliably serve our customers as affordably as possible.

SB 540 Maintains California Regulations and Standards. Importantly, this bill retains California's control over key policy as it applies to the state -- including environmental regulations, procurement mandates, and reliability standards – and avoids interfering with the ability of other states to pursue policy initiatives applicable to those states. SB 540 ensures that an independent regional organization continues to remain aligned with the State's climate goals, without affecting the climate goals that other states may pursue. In addition, there are provisions for market withdrawal of California participants should participation no longer benefit California.

SB 540 provides a crucial framework for the evolution of an expanded regional electricity market by allowing the CAISO and participating California transmission owners to engage with an independent RO's governing board under clearly defined conditions. As noted herein, this framework will help enhance grid reliability, optimize resource utilization, and facilitate cost-effective decarbonization efforts while safeguarding California's energy policy priorities.

For these reasons, PG&E, SCE, SDG&E, and CalCCA strongly support SB 540. We urge your support and look forward to working with you to advance this critical legislation.

Sincerely,

Chris Patterson
Vice President, State Government Relations
Pacific Gas and Electric

Andrew Baldonado
Vice President, State Public Affairs
Southern California Edison

Kent Kauss
Regional Vice President, State Governmental Affairs
San Diego Gas & Electric

Beth Vaughan
Chief Executive Officer
California Community Choice Association

Date: April 4, 2025

Hon. Josh Becker
California State Senate
1021 O Street, Suite 6550
Sacramento, CA 95814
Position Letter Portal

Support SB 540: Independent System Operator: Independent regional organization

Dear Senator Becker,

The Climate Reality Project: Silicon Valley Chapter, 350 Humboldt, and 350 Sacramento are all-volunteer groups of California residents working to prevent the worst of climate change in our communities and the world. We advocate for science-based solutions to the climate crisis that will carry us forward into a cleaner, healthier, more prosperous future. We support this bill, because the Pathways Initiative to create a Western-grid-wide day-ahead market (EDAM) will further our efforts to achieve these goals. Not only for California, but for the entire Western United States.

A Western RO, Why Would We Do This?

We've been experimenting with Western grid integration for 10 years with the Western Energy Imbalance Market (WEIM), and the results are extremely positive. So far, WEIM participants have saved $6.62B in total energy costs and avoided 1,043,034 metric tons of CO2 emissions[1]. That's with just the real-time market in place that covers only 1-3% of wholesale energy sales. The inter-state coordination enabled by the WEIM has also saved California and other participants from grid emergencies that otherwise would have resulted in blackouts.

The Pathways Initiative to expand the current CAISO day-ahead market to serve the West-wide grid enhances these benefits to make the Western grid cleaner, cheaper, and more resilient. How will it do this?

- Decarbonize the grid faster for California and the West with more renewables and less curtailment
- Save California up to $800M annually in wholesale energy costs, reducing California rate payer bills[2]

[1] https://www.westerneim.com/Documents/iso-western-energy-imbalance-market-benefits-report-q4-2024.pdf
[2] Brattle CEC study: https://efiling.energy.ca.gov/GetDocument.aspx?tn=261300&DocumentContentId=97632

- Significantly increase the reliability of the grid and quickly address emergencies such as the early Sept 2022 heat wave, both here in California and across the Western grid[3]
- Provide a larger market for California solar power that today goes unused at its peak and displace dirtier energy in doing so
- Create a better investment environment for new solar, wind, and storage facilities, leading to the build-out of more clean power sooner
- Put coal plants out of business by making them compete with cheaper solar and wind power

If we don't do this, others will:

- The Southwest Power Pool (SPP), an RTO based in Arkansas, is moving in to fill the gap with a market called Markets+
- Arizona Public Service, Bonneville Power Administration, NV Energy, Puget Sound Energy, and the Salt River Project and others are considering SPP already
- The WEIM's current California-only governance is very reasonably not OK with other Western states. If we don't fix it, they will simply join SPP Markets+ instead.

Failing to allow for shared governance of the EDAM and WEIM will not preserve the status quo. It will lead to our neighbors leaving the WEIM to join SPP Markets+. As the biggest source of demand in the West, this will leave California more vulnerable to power outages and price spikes, simply because we won't be a part of an automated market that draws from a wide range of power plants.

Being the biggest player in the West makes us more, not less, dependent on our neighbors in times of grid stress. Texas and its grid operator, ERCOT, are well-known for the large size of their electrical demand (about 60% higher peak demand than CAISO today), and are now infamous for the ERCOT grid failure during Winter Storm Uri that was avoided by the nearby SPP and MISO grids that were able to import power from their neighbors.[4]

A Western-grid RO managing the EDAM and WEIM will make it easier and cheaper for California to achieve its clean energy goals. It does not replace the important policy mechanisms that are driving decarbonization in California, for example the Cap and Trade system or Renewable Portfolio Standards. It does make it more likely that these policy mechanisms will succeed in driving us to meet our goals at a reasonable cost and without grid outages that could set us back for years.

What Are We Afraid Of?

A Western-grid RO to run the EDAM and WEIM requires a state-independent board. Today, the CAISO board is appointed by the California governor and legislature. A Western-grid RO serves all of the Western states, and those states are not OK leaving California solely in charge. Of course, some of those states are Wyoming and Utah, where coal interests still rule.

---

[3] Michael Wara study:
https://efiling.energy.ca.gov/GetDocument.aspx?tn=261263&DocumentContentId=97631
[4] https://sustainableferc.org/the-texas-storm-that-proved-the-need-for-grid-investments/

California's Clean Energy Goals at Risk?

Could an independent Western-grid RO subvert California's clean energy goals? Fortunately, no:

- From the NREL ACR-188 report about evolving CAISO into a Western-grid RTO: "Expanding CAISO to become a multistate regional transmission organization (RTO) is an option that ACR 188 calls out specifically. The literature affirms that such a scenario would not remove the jurisdiction of California (or any other state) over its retail rates, resource planning, resource siting, transmission siting, renewable energy policies, or emissions reduction policies. However, the literature also suggests strongly that such a move would require changes to CAISO's governance[5]."
- The RO will only be responsible for managing the day-ahead market and the real-time market. It will not be responsible for energy and climate policy. The CPUC, CEC, and CARB will remain in charge of implementing California's clean energy policies.

California's Renewable Portfolio Standards at Risk?

Will the Western-grid RO put California's Renewable Portfolio Standards (RPS) at risk? Again, the answer is no. California's RPS law requires our utilities to contract for power from renewable power plants. It's not about what they buy in the day-ahead market or the real-time market. Here's the relevant bit from the law[6]:

> (1) Not less than 50 percent for the compliance period ending December 31, 2013, 65 percent for the compliance period ending December 31, 2016, and 75 percent for each compliance period thereafter, of the eligible renewable energy resource electricity products associated with contracts executed after June 1, 2010, shall meet the product content requirements of paragraph (1) of subdivision (b).

This is a state law concerning requirements for utilities regulated by our state regulator (the CPUC). FERC's approval needed for rules for our day-ahead and real-time markets has no bearing here.

Our RPS laws also require that much of this power come from in-state generators, generators connected directly to the in-state grid, or generators with dedicated grid capacity to deliver their power to the in-state grid. Here's that portion of the same law as above:

> (1) Eligible renewable energy resource electricity products that meet either of the following criteria:
>
> (A) Have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source. The use of another source to provide real-time ancillary services required to maintain an hourly or subhourly import schedule into a California balancing authority shall

[5] http://www.caiso.com/Documents/Expanded-Regional-Cooperation-ACR-188-Final-Report-Feb2023.pdf

[6] https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=399.16.&nodeTreePath=2.1.5.19&lawCode=PUC

be permitted, but only the fraction of the schedule actually generated by the eligible renewable energy resource shall count toward this portfolio content category.

(B) Have an agreement to dynamically transfer electricity to a California balancing authority.

Opponents of SB 540 make the argument that the geographic area applied to our RPS rules will expand to the entire West. In previous grid regionalization proposals, the idea was to extend CAISO to be an RTO that would form a single Balancing Authority (BA) for the entire West. That got people very worried about the "Have a first point of interconnection with a California balancing authority ... " part of (b)(1)(a) now meaning anywhere in the West rather than just in California. Of course, the Pathways Initiative creators fully understand this, and that's why with SB 540 and Pathways the CAISO BA remains unchanged. SB 540 only authorizes CAISO to move the market function, not its Balancing Authority functions, to the new market RO entity.

Control of the new RO by the Federal Energy Regulatory Commission

Will a Western-grid RO be controlled by a Federal Energy Regulatory Commission (FERC) board full of Trump-appointed climate deniers?

- Maybe, but no more than CAISO is today. Despite being California's ISO, CAISO was created under FERC regulations and abides by all FERC rules. This applies to both California-internal and Western-grid management.
- From the Yale Law School's Environmental Protection Clinic report about this: "The key takeaway is that a move to a regional ISO would not expand FERC's authority over California's electricity system, because FERC already has jurisdiction over CAISO[7]."
- Even the Hughes v. Talen Energy case, so often thrown out as proof that FERC will interfere with California reaching its clean energy goals, is a narrow ruling preventing states from interfering in wholesale energy price markets. The ruling itself lists many ways for states to support clean energy development without FERC interference.[8] Given how often this case is referenced by the opposition, I recommend that people simply read it. It is remarkably clear and well-written.
- RO/RTO board members are power-industry technocrats, not political flunkies. They are nominated by the RTO members, and they are approved by the other board members. Look at the boards of PJM[9] and MISO[10] for good examples of RTOs with a mix of clean energy and coal/oil/gas-oriented territory.

[7] https://law.yale.edu/sites/default/files/area/clinic/document/yaleepc_enhanced_western_grid_integration_may_2017.pdf

[8] https://www.law.cornell.edu/supremecourt/text/14-614

[9] https://www.pjm.com/about-pjm/who-we-are/pjm-board

[10] https://www.misoenergy.org/meet-miso/leadership/

FERC requires that “the RTO must have a decision-making process that is independent of control by any market participant or class of participants.”[11] That will apply to California, but it will also apply to Wyoming and Utah.

So, What Do We Do?

California is leading the West into a clean energy future. We have great partners such as Washington and Oregon, and we have reluctant partners such as Wyoming and Utah. Unified Western-grid markets will help all of us to decarbonize, lower prices, and increase the reliability of our electric service. Meeting our clean energy goals is going to be difficult. It is in California’s best interest to partner with our neighboring states in ways that benefit all of us, whether any given state’s interest lies in lower electricity prices, higher grid reliability, or clean energy. Doing so requires letting go of California’s sole governance of the Western-grid energy markets and sharing it with the states we are partnering with. The alternative of becoming an energy island like Texas as our neighbors partner with an SPP market managed from Arkansas is a path to nowhere that will make our clean energy transition more expensive and less reliable. With a Western-grid RO to manage the EDAM and WEIM markets, we still keep our policy-making agencies, CARB, CPUC, CEC, and the non-market functions of CAISO, and their ability to set policy for California does not seem to be at risk here.

The opportunity in front of us today is to build a West-wide energy market that will benefit Californians for decades to come. The fears about actions of the Trump administration impacting the new RO, that won’t even start until 2028 at the earliest, are short-sighted and missing the point. We take this opportunity to collaborate with our neighbors today, or we lose it for the foreseeable future. 10 years of success with the WEIM already show us that this is the right path forward for California. Let’s not let this opportunity slip away.

Thank you for introducing this measure. We urge AYE votes in the Energy, Utilities, and Communications committee and all subsequent votes.

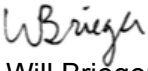
Sincerely,



Adam Sweeney
Chapter Chair, The Climate Reality Project: Silicon Valley Chapter



Dan Chandler, Ph.D.
Steering Committee Member
350 Humboldt



Will Brieger, Chair
350 Sacramento Legislative Team

[11] From the FERC rule governing RTOs:
https://www.govinfo.gov/content/pkg/FR-2000-01-06/html/00-2.htm

Resources

Next10 report on regionalization: https://www.next10.org/publications/regional-grid

The ACR 188 Final Report from NREL:
http://www.caiso.com/Documents/Expanded-Regional-Cooperation-ACR-188-Final-Report-Feb2023.pdf

The Yale Law School's Environmental Protection Clinic study on CAISO Western grid RTO regulation exposures:
https://law.yale.edu/sites/default/files/area/clinic/document/yaleepc_enhanced_western_grid_integration_may_2017.pdf

Senate Bill 350 Study on economic impacts of regionalization:
https://www.caiso.com/documents/sb350study-volume8economicimpacts.pdf

Supreme Court ruling in Hughes v. Talen Energy (a surprisingly easy read):
https://www.law.cornell.edu/supremecourt/text/14-614



CCUE Coalition of California Utility Employees

CSAEW California & Nevada State Association of Electrical Workers

NRDC

Environmental Defense Fund

Google

WESTERN STATES COUNCIL SHEET METAL | AIR | RAIL | TRANSPORTATION SMART California - Arizona - Nevada - Hawaii

CalChamber

Microsoft

amazon

CEBA Clean Energy Buyers Association

Union of Concerned Scientists

RIVIAN

E2

CLECA CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

Ceres

ADVANCED ENERGY UNITED™

SEIA Solar Energy Industries Association®

CALCCA ADVANCING LOCAL ENERGY CHOICE

CALIFORNIA ENVIRONMENTAL VOTERS

SAN DIEGO COMMUNITY POWER

SVLG SILICON VALLEY LEADERSHIP GROUP

edp Renewables

Pattern

MITSUBISHI CEMENT CORPORATION

IEPA

MCE

WESTERN FREEDOM

SILICON VALLEY CLEAN ENERGY

SIERRA NEVADA

WPTF WESTERN POWER TRADING FORUM

AMERICAN CLEAN POWER CALIFORNIA

PSG PACIFIC STEEL GROUP

Western Resource Advocates wra

leap

March 7, 2025

The Honorable Senator Becker
Chairman, Senate Utilities, Energy, and Communications Committee
1021 O Street, Suite 3350
Sacramento, CA 95814

RE: SUPPORT - SB 540 (Becker, Stern) – as introduced February 20, 2025

Dear Senator Becker,

We are writing to express our strong support for SB 540. This bill provides the statutory authorization necessary to implement the Pathways Proposal which would make electricity more affordable for California consumers while protecting California's procurement, environmental, reliability, and other public interest policies.

Developed by a large and diverse set of stakeholders, the Proposal would create a new, independent regional organization that would be solely responsible for setting energy market rules. The California Independent System Operator (CAISO) would continue to operate the markets as it does today, as well as continuing its role in operating the transmission system, transmission system planning, and balancing authority functions. SB 540 ensures the expertise and infrastructure that the CAISO has built is maintained, further protecting investments in current energy markets.

Creating an independent organization responsible for energy market rules would enable more utilities across the West to participate in consolidated electricity markets, making electricity in California more affordable and reliable while also reducing emissions in California.

SB 540 Provides More Affordable Electricity

This legislation, and the consolidated electricity markets it enables, would provide much needed energy affordability benefits to Californians. A new analysis conducted for the California Energy Commission (CEC) determined a West-wide day-ahead market could produce nearly $800 million in annual cost savings for California customers.[1]

SB 540 Improves Electric Reliability

The legislation would enhance the reliability of California's power grid by enabling more efficient and coordinated management of energy supply and demand across the Western region. With better access to shared resources, grid operators will be better equipped to draw on a wider resource pool during peak demand periods, reduce the likelihood of blackouts, and support the

[1] John Tsoukalis, et al., Brattle Group, "Preliminary Day-Ahead Market Impact Study: Impact of Market Footprints on California Customers" (Prepared for California Energy Commission, January 24, 2025).

resilience of the grid in the face of growing challenges such as extreme weather events and climate-driven disruptions.[2]

SB 540 Increases Use of Clean Energy

A consolidated western energy market will maximize use of existing clean energy generation and enable a faster, more affordable clean energy future. SB 540 makes more clean energy available both in California and around the West by reducing curtailment (deliberately reducing output below what could have been produced), a growing problem for solar and wind power generators in California. The CEC study determined the expanded market would reduce wind and solar curtailment by 10 percent. This improvement would reduce air pollution by displacing other less efficient emitting resources and enhance the financial foundation for clean energy investment and jobs by enabling California to use and sell more of its clean energy.[3]

With 80% of energy customers in the West now served by utilities with net-zero carbon energy mandates, the demand for clean energy resources will continue to grow. Maximizing use of existing clean generation is the fastest, most affordable way to reduce emissions.

SB 540 Protects Consumers and California Energy Policy

SB 540 would permit CAISO and California investor-owned utilities to participate in the independently governed energy markets only if the new regional organization meets guardrails designed to protect consumers and ensure that California can continue to set its own procurement, environmental, reliability, and other public interest policies. These protections include:

- public interest protections in the corporate documents;
- specific roles and engagement with state regulators and consumer advocate offices including access to market data;
- transparent and accessible operations including an office of public participation;
- independent market analysis and monitoring to protect consumers;
- engagement with states, local power authorities, and federal power marketing agencies to evaluate potential impacts of proposed market rule and tariff changes to state, local, and federal policies; and
- retention of the right to withdraw from the energy markets governed by the new regional organization if participation were no longer in the interests of their customers.

The diverse set of signatories on this letter represent an unprecedented coalition of consumer advocates, organized labor, environmental advocates, clean energy developers, investor-owned

[2] See Tsoukalis, et al. and Michael Wara, et al., Stanford Climate & Energy Policy Program, "Grid Regionalization in the West: Reliability Benefits from Increased Cooperation in Electricity Markets and Operations"(Prepared for California Energy Commission, January 24, 2025).
[3] John Tsoukalis, et al., Brattle Group, "Preliminary Day-Ahead Market Impact Study: Impact of Market Footprints on California Customers" (Prepared for California Energy Commission, January 24, 2025).

utilities, public power, and large customers who strongly support SB 540. For all of the above reasons, we support this legislation and request your support.

Sincerely,

Advanced Energy United (AEU)
Amazon
American Clean Power – California (ACP)
CA & NV State Association of Electrical Workers (IBEW)
CalCCA
California Chamber of Commerce
California Environmental Voters
California Large Energy Consumers Association (CLECA)
California State Pipe Trades Council
Ceres
Clean Energy Buyers Association (CEBA)
Coalition of California Utility Employees (CCUE)
E2 | Environmental Entrepreneurs
EDP Renewables
Environmental Defense Fund (EDF)
Google
Independent Energy Producers Association (IEPA)
Leap
MCE Community Choice Energy
Microsoft
Mitsubishi Cement Corporation
Natural Resources Defense Council (NRDC)
Pacific Steel Group (PSG)
Pattern Energy
Rivian
San Diego Community Power
Sierra Nevada Brewing Co.
Silicon Valley Leadership Group (SVLG)
Silicon Valley Clean Energy
Solar Energy Industries Association (SEIA)
Union of Concerned Scientists (UCS)
Western Freedom
Western Power Trading Forum (WPTF)
Western Resource Advocates (WRA)
Western States SMART Council

CC: Senator Henry Stern, Co-Author
Members, Senate Utilities, Energy, and Communications Committee
Nidia Bautista, Chief Consultant
Kerry Yoshida, Republican Caucus Consultant

Edson Perez
Senior Principal
Advanced Energy United (AEU)

Nate Hill
Head of Energy Policy
Amazon

Alexander L. Jackson
Executive Director
American Clean Power – California (ACP)

John Doherty
Secretary/Treasurer
CA & NV State Association of Electrical Workers (IBEW)

Beth Vaughan
Chief Executive Officer
CalCCA

Jonathan Kendrick
Policy Advocate
California Chamber of Commerce

Melissa Romero
Policy Advocacy Director
California Environmental Voters

Christian Lenci
Chair
California Large Energy Consumers Association (CLECA)

Mike Hartley
Executive Director
California State Pipe Trades Council

Kelly Trombley
Director, State Policy, West
Ceres

Priya Barua
Senior Director of Market & Policy Innovation
Clean Energy Buyers Association (CEBA)

Hunter Stern
Chair
Coalition of California Utility Employees (CCUE)

Susan Nedell
Senior Western Advocate
E2 | Environmental Entrepreneurs

Jack Wadleigh
Regulatory Affairs and Market Development Manager, Western Region
EDP Renewables

Katelyn Roedner Sutter
California State Director
Environmental Defense Fund (EDF)

Dylan Sullivan
Head of Energy Market Development, US-West
Google

Jan Smutny-Jones, Esq.
Chief Executive Officer, General Counsel
Independent Energy Producers Association (IEPA)

Collin Smith
Regulatory Affairs Manager
Leap

Dawn Weisz
Chief Executive Officer
MCE Community Choice Energy

Robyn Hines
Sr. Director Government Affairs
Microsoft

Austin Marshall
President/C.O.O.
Mitsubishi Cement Corporation

Victoria Rome
CA Government Affairs Director
Natural Resources Defense Council (NRDC)

Mark Olson
Vice President of Mill Operations
Pacific Steel Group (PSG)

Varner Seaman
Director of Government Affairs
Pattern Energy

Coley Girouard
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Rivian

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San Diego Community Power

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Sustainability & Social Impact Officer
Sierra Nevada Brewing Co.

Monica V. Padilla
Chief Executive Officer
Silicon Valley Clean Energy

Laura Wilkinson
SVP, Strategy & External Affairs
Silicon Valley Leadership Group (SVLG)

Stephanie Doyle
California State Affairs Director
Solar Energy Industries Association (SEIA)

Daniel Barad
Western States Policy Manager
Union of Concerned Scientists (UCS)

Kathleen Staks
Executive Director
Western Freedom

Scott Miller
Executive Director
Western Power Trading Forum (WPTF)

Vijay Satyal
Deputy Director, Regional Markets and Transmission
Western Resource Advocates (WRA)

Dion Abril
Executive Administrator
Western States SMART Council

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Oakland, CA 94610

415-929-8876 • www.turn.org

April 15, 2025

Senator Josh Becker
Chair, Senate Committee on Energy, Utilities and Communications
1021 O Street, Room 3350
Sacramento, CA 95814

Re: SB 540 (Becker) – OPPOSE UNLESS AMENDED
Senate Energy, Utilities and Communication Committee – April 21, 2025

Dear Senator Becker,

The Utility Reform Network (TURN), a consumer advocacy organization that has fought on behalf of California residential utility customers for more than 50 years, opposes SB 540 (Becker) unless amended. This bill would authorize the California Independent System Operator (CAISO) to rely on voluntary wholesale energy markets governed by an independent Regional Organization (RO). This authorization would represent a significant shift in control over energy markets along with a broadening of the market actors participating in a single regional market that includes California utilities and other California load serving entities. This shift may expose California customers to new risks that could prove difficult to mitigate.

TURN was strongly opposed to legislation in prior years that would have transformed CAISO into a Regional Transmission Organization by eliminating the Governor-appointed, Senate-confirmed board and merging the individual balancing authority areas associated with all the participating transmission owners. By preserving CAISO's governance structure and its role as a balancing authority, SB 540 represents a different, and more cautious, approach to the development of regional energy markets. Despite the incremental nature of this new approach, TURN remains concerned that SB 540 currently contains insufficient safeguards to protect California consumers if the RO adopts market rules that frustrate key state environmental, resource planning, reliability or other public interest policies. These adverse outcomes have become more likely given recent announcements by the Trump administration indicating an intention to prioritize

coal-fired generation[1], devalue production from clean energy resources, and challenge the legitimacy of state climate policies.[2]

TURN has been working with the author of SB 540 on various concerns relating to the RO and hopes that they can be addressed through amendments. Specifically, TURN recommends amendments to accomplish the following:

- Clarify that the RO's tariffs must permit California to withdraw its utilities from the regional market without penalties or any need for additional approvals by the Federal Energy Regulatory Commission (FERC). This element of the RO tariff must be approved by FERC prior to CAISO agreeing to cede its governance of these markets. The Legislature may wish to consider a requirement that a joint concurrent resolution be enacted after FERC approves the relevant tariff but prior to the transition.

- The RO must be prohibited from establishing any requirements relating to resource adequacy, reserve margins or reliability. Further the RO must not be allowed to rely on a centralized capacity market or separate energy markets for dispatchable, firm and intermittent resources. These prohibitions are necessary because the Trump administration has indicated its intent to intervene in wholesale markets for purposes of favoring coal and gas generation and marginalizing renewable energy resources. Successful federal intervention would be far more likely if the RO managed requirements, policies or markets that go beyond the proposed Extended Day Ahead Market (EDAM).

- Authorize the California Public Utilities Commission to direct the Investor Owned Utilities (IOUs) to withdraw from the RO if there are any violations of the obligations laid out in SB 540 or changes to RO-governed markets that harm California consumers or frustrate California resource planning, procurement, environmental, reliability or other public interest policies.

- Require California IOUs and Publicly Owned Utilities (POUs) to withdraw from the RO if legal challenges result in a court ruling that any California resource planning policy (including the Renewables Portfolio Standard (RPS)) impermissibility discriminates against out-of-state resources. This protection is necessary in light of the increased risk that participation in the RO, combined with strict delivery requirements to the CAISO

[1] https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/
[2] https://www.whitehouse.gov/presidential-actions/2025/04/protecting-american-energy-from-state-overreach/

balancing authority area, could embolden various market participants to pursue legal challenges to California's resource planning and RPS rules.

- Require California IOUs and Publicly Owned Utilities (POUs) to withdraw from the RO if actions taken by the federal government force California consumers to subsidize out-of-state fossil generating resources under Section 202 of the Federal Power Act. President Trump has already indicated an intention to use Section 202 to force all participants in energy markets to subsidize fossil generation at risk of retirement.

- Require California IOUs and POUs to withdraw from the RO if a Joint Concurrent resolution is passed by the State Assembly and State Senate.

- Clarify that the RPS requirements relating to energy delivery from resources outside of a California Balancing Authority must satisfy strict standards including the use of dynamic scheduling, pseudo ties, or firm transmission rights. These clarifications are needed in light of changes to energy market rules and practices under EDAM.

The adoption of amendments responsive to these concerns would allow TURN to remove our opposition. While we recognize the potential benefits of an efficiently administered regional energy market, the risk of adverse outcomes to California consumers and California policy leadership must be fully addressed in this bill.

For more information about TURN's position, please contact the Hernandez Strategy Group at (916) 447-9719.

Sincerely,



Matthew Freedman
Staff Attorney

Cc: Members, Senate Energy, Utilities and Communications Committee
Senator Josh Becker

PENINSULA CLEAN ENERGY

PENINSULA CLEAN ENERGY AUTHORITY
JPA Board Correspondence

DATE: April 15, 2025
MEETING DATE: April 24, 2025
VOTE REQUIRED: Majority Vote

TO: Honorable Peninsula Clean Energy Authority Board of Directors

FROM: Shelby Bush, Energy Efficiency Programs Manager

SUBJECT: Approval of the Program Plan for California Public Utilities Commission (CPUC) FLEXmarket Program (Action)

RECOMMENDATION

Approve the Program Plan for the California Public Utilities Commission (CPUC) FLEXmarket Program.

BACKGROUND

Peninsula Clean Energy's mission is to reduce greenhouse gas emissions by expanding access to sustainable and affordable energy solutions. Achieving this goal requires shifting uses of methane gas and petroleum to electric power (electrification) and encouraging alignment between power demand and renewable supply.

To support these objectives, in November 2021, the Board approved a Program Plan for FLEXmarket, a novel energy efficiency initiative sponsored by the CPUC. Peninsula Clean Energy's plan was granted approval by the CPUC for full cost recovery over a three-year period, beginning in May 2022 and concluding in May 2025. Peninsula Clean Energy has been among the early adopters of this market-driven approach, aligning its program with similar efforts launched by other load-serving entities/CCAs in the state. This first three-year phase piloted the program and the lessons learned are informing PCE's next steps as discussed below.

FLEXmarket is an innovative "pay-for-performance" energy efficiency program that assigns an hourly price to measured, behind-the-meter energy load reductions. Energy companies deliver efficiency and load-shifting projects and receive payments based on verified outcomes. Unlike traditional energy efficiency programs that provide incentives for specific installed measures, FLEXmarket features a robust measurement and verification (M&V) framework that leverages smart meter data across Peninsula Clean Energy's entire service area. This approach ensures more precise and cost-effective impact measurement.

The intent of the FLEXmarket structure is to implement energy efficiency in a way that "shapes load" to benefit the grid. In addition, because the program uses a market approach that

rewards outcomes, allowing any technology or method that delivers benefits, it is highly adaptable to changing market conditions. It allows the top-level program administrator (PCE) to focus on managing to end performance, leaving the specific approach (customer segment, technology, marketing) to the implementers, referred to as “aggregators.”

Program Impacts

Through the FLEXmarket program, Peninsula Clean Energy seeks to achieve the following outcomes:

- Peak load reduction benefits
- Customer utility bill savings
- Energy savings

Through the first phase of the program, a total of 11 commercial projects were implemented, primarily at medium-sized commercial sites, including big box retailers, car dealerships, and discount variety store chains. The most significant savings were achieved through lighting retrofits and refrigeration controls. In addition, the program supported 13 residential customers who installed heat pumps. While these projects contributed to decarbonization goals, including residential projects made it more challenging for the program to meet overall cost-effectiveness standards as required by the CPUC. The program works well for larger, commercial sized projects so that component will continue. However, PCE will continue to explore targeted strategies to support residential participation in future phases of the program.

Overall, the first phase of the program achieved the following outcomes:

- **Peak Load Reduction Benefits**: The program has contributed to a 10% reduction in summer peak energy usage across the implemented projects, helping to alleviate grid demand during critical periods. This reduction in peak load supports grid stability and aligns with Peninsula Clean Energy's goal of reducing system strain during high-demand times.

- **Customer Utility Bill Savings**: While the financial incentives were distributed to aggregators, participants in the program benefited from financial support for energy-efficient upgrades. The energy savings from these upgrades will lead to ongoing reductions in customer utility bills, furthering Peninsula Clean Energy's goal of providing cost savings and energy efficiency to residents and businesses.

- **Energy Savings and Project Scope**: The program has achieved a forecasted 1,239,437 kWh in energy savings, with projects exceeding initial savings projections by 30%.

Lessons Learned

- **Price Signal Design**: Early in implementation, Peninsula Clean Energy set the price signal at a relatively high level to help jumpstart market participation—a common strategy in energy efficiency programs. While this successfully drove early engagement, adjustments to the incentive level did not happen quickly enough, which negatively impacted CPUC cost-effectiveness test. Going forward, PCE has refined its approach by running more frequent market tests and calibrating price signals to optimize both participation and cost-effectiveness.

- **Regulatory Learning Curve**: PCE has gained a deeper understanding of CPUC reporting requirements, documentation standards, and overall program compliance. Navigating this regulatory landscape has informed internal processes and strengthened PCE's ability to manage future programs under CPUC oversight.

- **Program Operations and Contracts**: PCE has also improved the design and structure of contracts and incentives to better align implementer performance with program outcomes. These operational refinements position us to run the next phase of the program more efficiently and effectively.

Next Phase and Regulatory Approvals
PCE's FLEXmarket program is an example of an CPUC's "Elect to Administer" pathway for Energy Efficiency ("EE") program, or "ETA program." Under California statute, CCAs have a statutory right to administer EE programs through the ETA pathway. The ETA pathway allows CCAs to design and run energy efficiency programs serving CCA customers tailored to local community needs, rather than relying on traditional utility-administered offerings. These programs must still meet CPUC energy savings and cost-effectiveness requirements. Additionally, ETA programs are funded using dedicated energy efficiency funds collected through distribution charges (i.e., on the investor-owned utility side of the electric bill), rather than the CCA's own generation revenue.

CPUC authorization under the ETA Pathway requires CCA Program Plan approval by their Board for each cycle before the request is submitted to the CPUC. The CPUC authorizes ETA Programs in three-year budget increments.

The current FLEXmarket program will conclude on May 4, 2025. To maintain continuity, the next phase is expected to launch in September 2025, following ETA approval. This phase will run through 2028, at which point it will transition into a broader energy efficiency program portfolio that is forthcoming.

In the first funding cycle, the FLEXmarket program has been heavily weighted toward commercial customers, with strong participation from large businesses pursuing energy efficiency and load reduction projects. PCE anticipates that the second phase of the program will continue to focus on commercial customers while also exploring opportunities to potentially extend participation to targeted residential customer segments in the 2025-2028 funding cycle.

DISCUSSION

PCE plans to submit a request for to renew its ETA FLEXmarket program from 2025 through 2028 after the PCE Board of Directors approves the Program Plan. The attached draft Program Plan is substantively the same as the original version approved by the PCE Board in November 2021.

The current CPUC-funded budget period will close this May, and the program will be paused until the new budget period is authorized by the CPUC. PCE anticipates that approval from the CPUC will occur sometime in **Q3 2025**, at which point the program will be relaunched.

PCE is requesting approval of the attached near-final Program Plan to submit to the CPUC. The Program Plan is largely the same as the PCE's current FLEXmarket Program Plan. The

major features are:

- An open market that service providers can participate in across all solutions including energy efficiency, smart controls of all kinds, and batteries.
- Inclusion of commercial customer segments with opportunity to explore residential offerings where there is potential and overlap with existing programs is limited.
- Setting price points based on the state-wide “Avoided Cost Calculator” which provides a formal methodology for valuation of avoided costs such as generation, transmission, distribution, greenhouse gas mitigation and other factors.
- PCE providing payments to service providers according to those price points and recouping those funds from the CPUC.
- Partnering with implementation firms to deliver the FLEXmarket.
- Providing formal measurement and verification, as well as auditing, to the CPUC consistent with CPUC requirements.
- Coordinating with PG&E and other providers on program details to ensure resources provided are not double-counted in local and state programs.
- Delivering demand reduction benefits during periods of grid stress during the summer period.

Of note, PCE’s billing data provider Calpine Energy Solutions is providing program admin services through an M&V technology firm called Recurve, and PCE will onboard additional support services for reporting and other administration as needed. Specific contracts that may be considered under this program would come to the Board at a future date.

PCE’s ETA FLEXmarket program is part of a longer-term strategy to expand the energy efficiency programs PCE can offer without relying on its generation revenue. In addition to the ETA pathway, CCAs also have a statutory right to administer EE programs through what is referred to as the Apply to Administer (“ATA”) pathway. In February 2026, PCE plans to submit an application to the CPUC under the ATA pathway to launch an expanded portfolio of EE programs in January 2028. PCE is pursuing a new three-year ETA in order to maintain its FLEXmarket program until it can be rolled into the larger ATA portfolio beginning in 2028.

The Apply to Administer (“ATA”) pathway provides an alternative to the Elect to Administer (“ETA”) approach, offering CCAs the opportunity to pursue larger budgets for energy efficiency programs. Unlike ETA, which features a streamlined, automatic approval process but comes with a limited budget, ATA requires CCAs to submit a detailed application to the CPUC. This application must demonstrate how the proposed programs will meet the same standards investor-owned utilities must follow, including energy savings goals, cost-effectiveness requirements, and other regulatory benchmarks. While ATA offers significantly greater funding potential, it involves a more rigorous approval process and ongoing reporting and compliance obligations, making it a more resource-intensive pathway for CCAs. PCE's Board will receive additional details on the ATA plan later this year as the plans advance.

On April 14, 2025, PCE staff presented the FlexMarket Program Plan to the Executive Committee. Following discussion and questions, the Committee voted unanimously to recommend that the Board of Directors approve the Program Plan.

FISCAL IMPACT

Approval of the Draft Program Plan has no immediate fiscal impact. If the plan is approved by the CPUC and implemented by PCE it will result in expenditures that will be fully recovered from Public Purpose funds. Specific contracts that will be considered under this program will come to the Board for approval at a future date.

ATTACHMENTS:
2025.04.15 BOD Programs FLEXMarket_Program Plan DRAFT.docx

RESOLUTION NO. _____

PENINSULA CLEAN ENERGY AUTHORITY, COUNTY OF SAN MATEO, STATE OF CALIFORNIA

APPROVAL OF THE PROGRAM PLAN FOR CALIFORNIA PUBLIC UTILITIES COMMISSION (CPUC) FLEXMARKET PROGRAM (ACTION)

RESOLVED, by the Peninsula Clean Energy Authority of the County of San Mateo, State of California, that

WHEREAS, PCE was formed on February 29, 2016; and

WHEREAS, Peninsula Clean Energy's mission is to reduce greenhouse gas emissions by expanding access to sustainable and affordable energy solutions; and

WHEREAS, reducing and shifting electricity demand to better align with renewable energy supply is a key strategy in support of that mission; and

WHEREAS, PCE has implemented FLEXmarket, a pay-for-performance energy efficiency program funded by the California Public Utilities Commission, since May 2022, which has achieved measurable peak load reduction and energy savings, and is set to conclude in May 2025; and

WHEREAS, under California statute, Community Choice Aggregators such as PCE are authorized to design and administer energy efficiency programs through the California Public Utilities Commission's Elect to Administer (ETA) pathway, using dedicated public purpose funds; and

WHEREAS, continuing FLEXmarket through the CPUC's ETA pathway supports PCE's strategic goal of diversifying funding sources for customer programs, by utilizing fully reimbursable public purpose funds; and

WHEREAS, PCE seeks to continue its FLEXmarket program through 2028 under the ETA pathway, and has developed a Draft Program Plan that aligns with CPUC requirements and builds on lessons learned from the initial implementation; and

NOW, THEREFORE, IT IS HEREBY DETERMINED AND ORDERED that the Board of Directors hereby approves the Program Plan for the CPUC funded FLEXmarket Program (2025–2028) and delegates authority to the Chief Executive Officer to finalize and submit the plan to the CPUC for approval.

PENINSULA CLEAN ENERGY

Peninsula Clean Energy (PCE) Demand FLEXmarket Program Implementation Plan Program Manual Measurement & Verification Plan PCE01

March 27, 2025

Version 3

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1. Program Overview

The PCE Demand FLEXmarket program offers aggregators a performance-based pathway to deliver energy efficiency and demand flexibility solutions. Using a price-driven NMEC model, aggregators are compensated based on verified energy savings and Total System Benefits (TSB) achieved. This approach reduces transaction costs, prioritizes high-value customers, and maximizes energy savings and grid benefits while ensuring sector-specific evaluation and reporting.

Program Budget and Savings

Table 1: Program Budget and Savings		
1	Program Name	FLEXMarket
2	Program ID number	PCE01
3	Program Implementer	TBD
4	Portfolio Administrator	Peninsula Clean Energy
5	Program Implementer Type (IOU Core, Third-Party Solicited, REN/CCA)	REN/CCA
6	Portfolio Segment (Resource Acquisition, Equity, Market Support, or Codes and Standards)[1]	Resource Acquisition
7	Total Program Budget	$2,974,493.93
8	Program Budget by Year	$991,497.98
9	Program Duration (Start Date - End Date)	August 1, 2025 – July 31, 2028
10	Total System Benefit (TSB) (Total Program TSB and TSB by Program Year)	Total: $4,607,511.22 2025: $0.00 2026: $1,978,834.52 2027: $2,544,725.50 2028: $83,951.21

[1] D.21-05-031 Ordering Paragraph 2

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Table 1: Program Budget and Savings		
11	CO_2 (Lifecycle, First Year, Net, Gross)	Lifecycle Gross CO_2: 22,527 Lifecycle Net CO_2: 21,401 First Year Gross CO_2: 2,311 First Year Net CO_2: 2,195
12	KW (First Year, Net, Gross)	First Year Net kW: 1,938 First Year Gross kW: 2,040
12	KWh (Lifecycle, First Year, Net, Gross)	Lifecycle Gross KWh: 86,928,000 Lifecycle Net KWh: 82,581,600 First Year Gross KWh: 7,074,000 First Year Net KWh: 6,720,300
13	Therms (Lifecycle, First Year, Net, Gross)	Lifecycle Gross Therms: 0 Lifecycle Net Therms: 0 First Year Gross Therms: 0 First Year Net Therms: 0
14	Program Cost Effectiveness: Total Resource Cost (TRC): (Total TRC and TRC by Year)	Total TRC: 1.13 2025: N/A 2026: 1.15 2027: 1.11 2028: 1.19

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Table 1: Program Budget and Savings		
15	Program Cost Effectiveness: Program Administrator Cost (PAC): (Total PAC and PAC by Year)	Total PAC: 1.76 2025: N/A 2026: 1.87 2027: 1.84 2028: 1.92
16	Market Sector(s) (i.e., residential, commercial, industrial, agricultural, public or cross-cutting) If multi-sector, provide estimated % of the total budget for each sector)	Commercial 90%, Residential 10%
17	Program Type (i.e., Non-resource, Resource)	Resource
18	Delivery Type(s) (i.e., Upstream-Manufactured, Midstream-Distributor, Midstream-Retail, Downstream, Downstream - Direct Install,[2] Codes & Standards)[3]	Downstream
19	Intervention Strategies (e.g., Strategic Energy Management (SEM), Market Access Program (MAP), Direct Install, Incentive, Finance, Audit, Technical Assistance, Advocacy, Training, Marketing and Outreach, etc.)	Incentive
20	M&V Methods (e.g., Deemed, Custom, NMEC – Population, NMEC – Site, SEM M&V, Randomized Controlled Trial (RCT), Other (if applicable, describe Other M&V method))	NMEC – Population

2. Implementation Plan Narrative

Program Description:

The PCE Demand FLEXmarket program will offer a flexible path for aggregators[4] of commercial & residential customers to bridge the gap of customer needs, PCE's energy efficiency (EE) resource needs, and grid reliability. A price-based population Normalized Metered Energy Consumption (NMEC) program design

[2] https://cedars.sound-data.com/deer-resources/deemed-measure-packages/guidance/
[3] Database for Energy Efficiency Resources (DEER) 2026 Delivery Types
[4] Aggregators are participating vendors or program partners who generate energy efficiency and/or demand savings for an aggregated group of customers.

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will support the delivery of cost-effective savings (and potential decarbonization) to help meet PCE's goals and optimize energy usage for commercial & residential customers. Performance incentives and payment structures will push aggregators to deliver maximum savings and optimized load shapes that maximize system benefits.

PCE will leverage Recurve as an M&V partner. Recurve is tasked with providing software for project processing ,determining customer eligibility, analytics, determining payments to aggregators and more.

PCE will contract with a firm or potentially bring in house, aggregator relationship management, Project processing and other tasks.

Under the program, all aggregator payments are tied to the delivery of savings. Aggregators will leverage capital upfront to deliver the savings and will be compensated for the total program value delivered (Total System Benefit after programmatic adjustments described in the M&V plan), net of the marketplace management fees and non-energy private investment for their projects. Marketplace management costs include general and administrative (G&A) overhead, direct implementation non-incentive (DINI), M&V, and marketing, education and outreach. These management costs are forecasted at 25% of the total program budget.

The relationship management team will recruit and contract with multiple qualified aggregators and will support them directly with eligibility and prioritization analytics to identify and engage the highest value customers based on the aggregators' business model. Aggregators recruit customers and install projects. Recurve will then track the NMEC verified impacts in the Recurve Platform. PCE will pay aggregators quarterly, based on the impacts achieved and the auditable record of performance for each aggregator's portfolio. Portfolios are categorized by market sector and by the Program years, meaning an aggregator will only have a Commercial Portfolio if they submit projects to the Commercial FLEXmarket and a Residential Portfolio if they submit projects to the Residential FLEXmarket. This separation ensures sector-specific evaluation and reporting. The core objectives of this program are as follows:

- Pay aggregators on measured savings performance and total program value delivered (Total System Benefits (TSB) after adjustments detailed in the accompanied M&V plan), incentivizing aggregators to pursue projects and measures that produce the most savings.
- Reducing transaction costs for aggregators, PCE, and end customers.

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- Improving diversity in the vendor pool that provides demand flexibility services.
- Customer prioritization to drive outsized savings impacts.

See flow diagram in Supporting Documents Section, Process Flow for more detail.

Pricing, payments and incentives are included in Supporting Documents, Program Plan.

Performance Tracking:

The core strategy of this program is to enable a market-driven, performance-based approach to energy efficiency. As a FLEXmarket program, it is designed to be measure-agnostic, allowing aggregators to develop and implement the most effective solutions based on real-world performance rather than predetermined project types. Rather than dictating specific technologies or energy savings thresholds, the program relies on Total System Benefit (TSB) and adherence to the NMEC Rulebook[5] as the primary indicators of success.

	Metric	Target
1	Total System Benefit (TSB)	$4,607,511.22
4	Fraction of Completed Customer Survey	70%

By focusing on TSB and NMEC Rulebook adherence, this program ensures that energy savings are measurable, verifiable, and aligned with cost-effectiveness and grid benefit goals. Given that savings during summer peak hours provide the greatest value, aggregators will naturally be drawn to projects that optimize reductions during these periods. This approach maximizes benefits while maintaining the flexibility needed to encourage innovative and high-impact energy efficiency solutions. We will consider including additional metrics in future contracting opportunities.

Program Delivery and Customer Services:

The core strategy of this program is simplification and flexibility. Qualified aggregators will have the flexibility to meet commercial & residential customers

[5] Rulebook for Programs and Projects Based on Normalized Metered Energy Consumption, January 7, 2020 https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/n/6442463694-nmec-rulebook2-0.pdf

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in terms of energy needs, technology fit, and project cost. Rather than a prescriptive set of program offerings, aggregators will develop their offerings around a core set of targeted solutions (e.g., HVAC, Lighting, Heat Pumps, Water Heaters, Building Shell, Refrigeration, and controls) and optimize the meter-based performance to maximize benefits to PCE, the grid and the customer.

The range of services, products and tools that are provided by the aggregators to customers is diverse. They will have full flexibility to propose services, tools, or interventions (as defined in the "Eligibility" and "Qualifying Measures" section in the attached M&V plan) to customers to encourage adoption, effectuate consumption changes, and manage energy. Recurve will provide core services and tools to PCE and aggregators in the form of an operational platform to identify, enroll, track, and settle the energy efficiency resources delivered through this program.

This program is not specifically designed to address hard-to-reach customer segments, but it is flexible and is a viable program concept for doing so. If aggregators have a business model that can serve hard-to-reach customers effectively, they will be highly valuable participants in the Marketplace.

This program cannot be combined with other PA programs or incentives, as all M&V tracking and incentive payments are measured at the meter. Allowing multiple incentives would result in double payments, as there is no way to exclude those savings from FLEXmarket calculations.

Program Design and Best Practices:

The key program strategies and tactics to reduce barriers for program participation for targeted customers are:

Reduce technical and administrative barriers associated with traditional deemed, custom, and site-specific NMEC project development pathways. These delivery pathways are not only burdensome for aggregators and contractors, but also for customers.

Matching customers with aggregators who are best-equipped to meet their needs and tying those needs to grid-optimized solutions (as valued in the avoided cost calculator (ACC) adopted by the Commission).

Leveraging a key benefit of population-level NMEC programs - the inclusion of to-code savings opportunities and thereby reducing so-called "stranded" savings opportunities, while simultaneously removing the administrative challenges of excluding to-code impacts.

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The program anticipates that a specific set of technologies will be best suited to maximizing the avoided costs, but their adoption (and appropriate incentive levels) will be a function of the customer needs, financing requirements, and other funding mechanisms available to the aggregator to promote adoption through financing options or shared costs.

The Demand FLEXmarket is adopting three key best practices. The first is focusing on market design rather than program or project design to draw in the maximum number of solutions from aggregators. The second is setting the price for energy savings based on the total program value delivered net of marketplace management cost. And third, managing risk by only paying aggregators for the value delivered. Program value is defined as TSB after any programmatic adjustments defined in the M&V plan. This strategy protects the rate-payer risk of investing in programs that may not deliver value and creates the proper incentives for aggregators to mobilize and deliver the maximum benefit possible.

The Recurve platform is critical to the strategy, administration and implementation of the Demand FLEXmarket program. It provides the necessary analytic tools to bridge the flow of information between PCE, aggregators, and evaluators. The primary elements of Recurve's platform to be leveraged are outlined below.

The Resource Planner module will help identify end customers with the highest potential for savings. Using Resource Planner, Recurve computes a suite of customer usage characteristics or "features", based exclusively on pre-program consumption data. These features are calculated for every customer and range from simple summations (e.g. total annual MWh usage) to normalized metrics (e.g. the percentage of usage from cooling) to more complex load characteristics (e.g. baseload, evening ramp).

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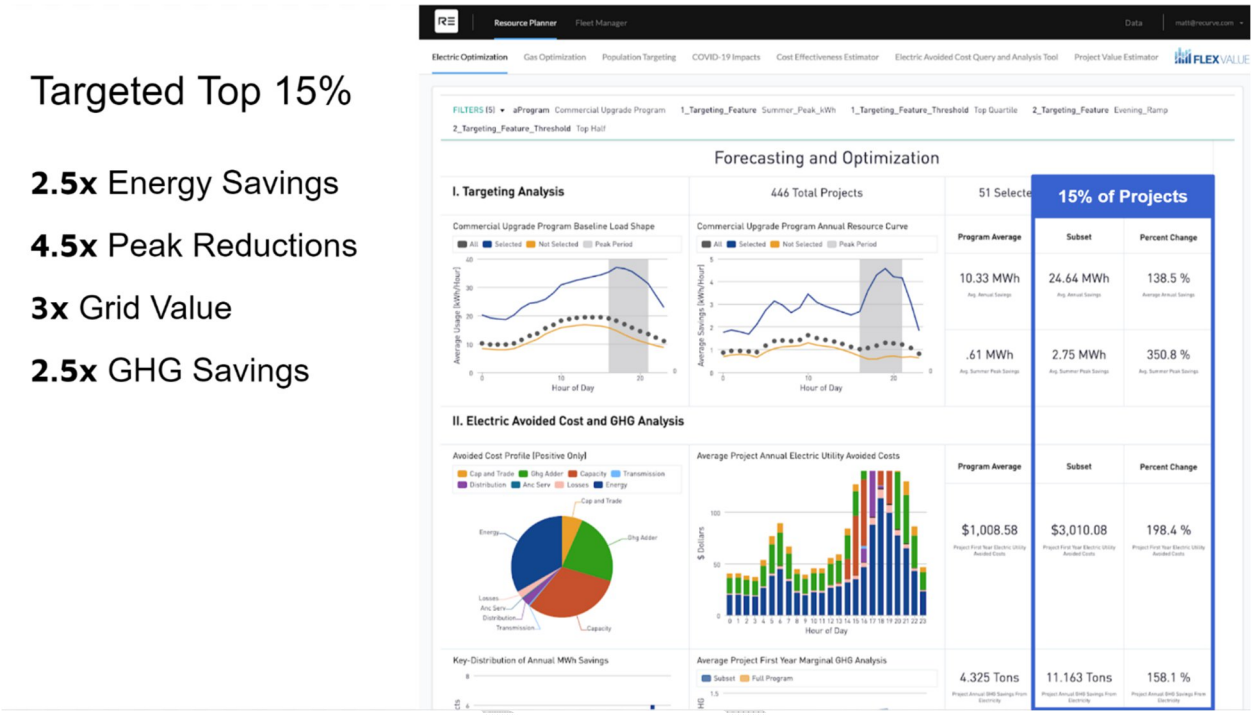


Figure 1: Resource Planner Module - Prioritization Analysis

Recurve will segment the PCE service area by load shape and develop a customer and usage analysis. Some customers may have little potential for savings from a particular measure, while others present a significant opportunity. The relationship management team will work with aggregators to identify high priority customers within the segments they serve and the solutions they are capable of providing.

The program team may also provide an analysis to qualified aggregators of projects they implemented within PCE's service area in previous program years. This analysis would generate the information required for aggregators to know which of their interventions at specific customer types deliver maximum grid benefits.

The Fleet Manager module provides ongoing tracking of building-level energy savings and is the foundation of automated M&V. Each demand-side asset (e.g, energy efficiency participant) is tracked for savings using open-source, replicable methods. Savings will be updated on a monthly basis as new data is ingested.

Fleet Manager provides some key features including:

- CalTRACK savings tracking for the duration of the program term
- Continually updated savings values for kWh and therm values

- Tracking and access to all of the data and savings results at an individual meter/project level
- The ability to define and assess relevant cohorts6 for which data are available
- The ability to view savings performance at a portfolio, cohort, and individual project level
- API functionality to allow for accessing data for any desired additional analysis

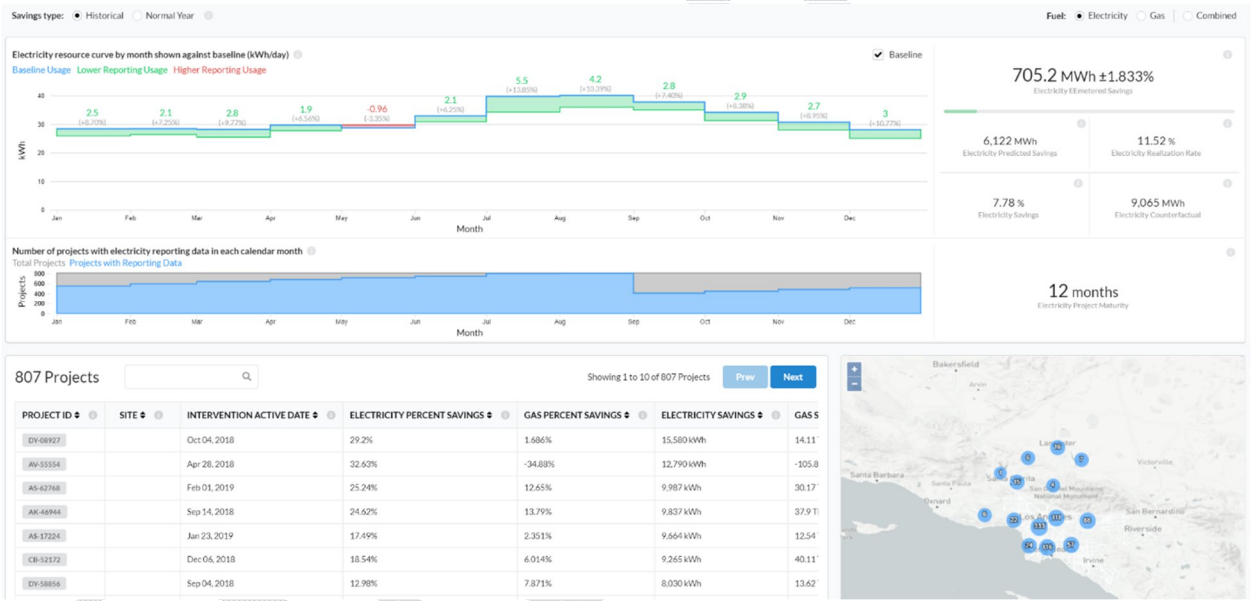


Figure 2: Program and Portfolio Savings Tracking in Fleet Manager

The Ledger module turns metered savings into transactions. With the savings calculations serving as a basis of payment for aggregators, a system of record is needed to record savings and payments to third parties in an auditable, transparent fashion. The Ledger supports payment invoicing and regulatory filings backed by a full audit trail of all historical transactions as visualized in Figure 3 below.

The Flex Ledger provides for:

- Custom Portfolio Valuation Functions
- Custom Eligibility Rules
- Custom Configurations

[6] Cohorts are defined as portfolios of projects grouped by various metadata (such as aggregator, measure type, installation month, etc.)

- Non-Routine Event Tracking
- Full Auditability of Transaction Records
- Regulatory Reporting

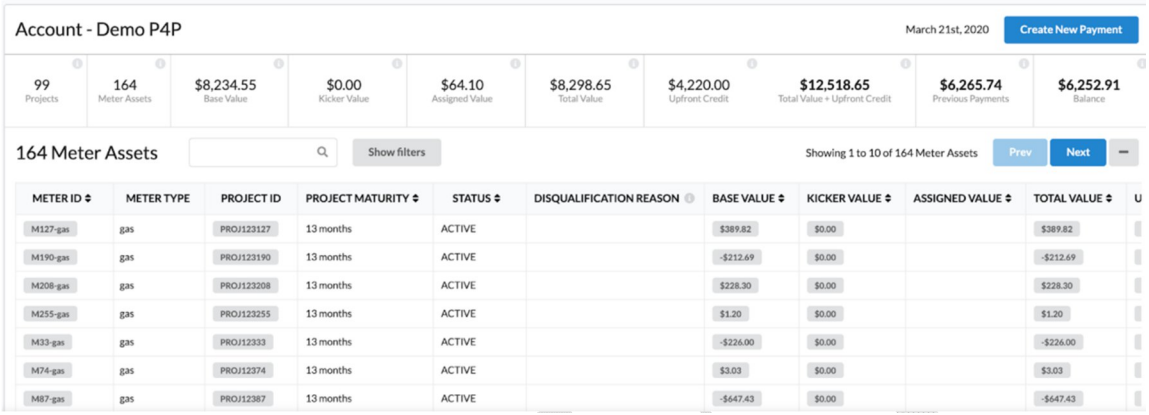


Figure 3: Flex Ledger Module Tracking Incentive Payments Owed and Due

Innovation:

The primary objective of this program is to simplify the path for PCE to translate allocated budgets for energy efficiency into actual results in the most streamlined and scalable manner possible. FLEXmarket does so by:

1. Combining pay-for-performance with an aggregator marketplace designed to deliver savings impacts with an upfront price signal;
2. Consistent, transparent meter-based quantification of impacts, and;
3. An auditable performance payment structure.

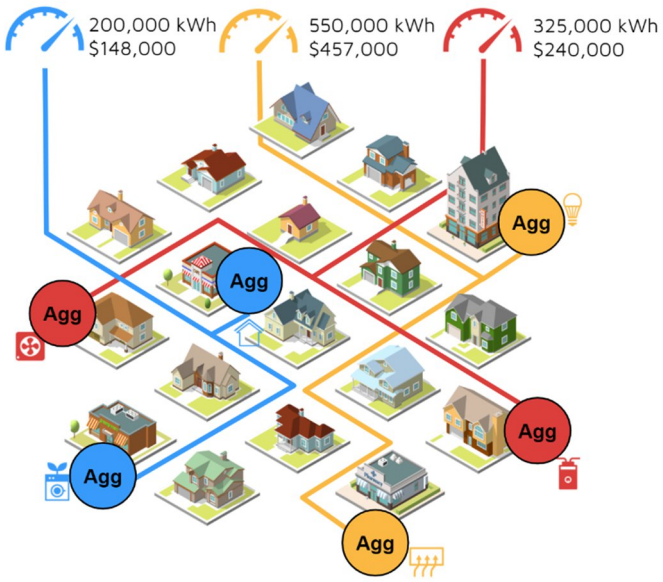


Figure 4: Demand FLEXmarket Concept

The innovation in this model involves overcoming the barriers of entry for qualified aggregators, ensuring that the program pays only for grid benefits delivered, and validating the impacts for both customers and the grid. This will enable a tighter connection of energy efficiency program investments with the grid impacts that drive significant value in increasing reliability, meeting climate goals, and improving the lives and livelihoods in the communities they serve.

The core innovation principles of the Demand FLEXmarket program are simplification, flexibility and scale and have been designed specifically to deploy resources in this grid reliability emergency rapidly.

The program brings simplification by reducing or eliminating common technical and administrative barriers associated with traditional prescriptive EE programs. These delivery pathways are not only burdensome for aggregators, but also for end customers. With the Demand FLEXmarket delivery model, project and customer enrollment are streamlined while still retaining the necessary quality assurance/ quality control (QA/QC) checks on paperwork. The program reduces transaction costs and administrative burden by measuring savings at the meter after project installation and paying only for delivered value, rather than burdening aggregators with administrative bottlenecks and extensive reviews up front to receive a rebate.

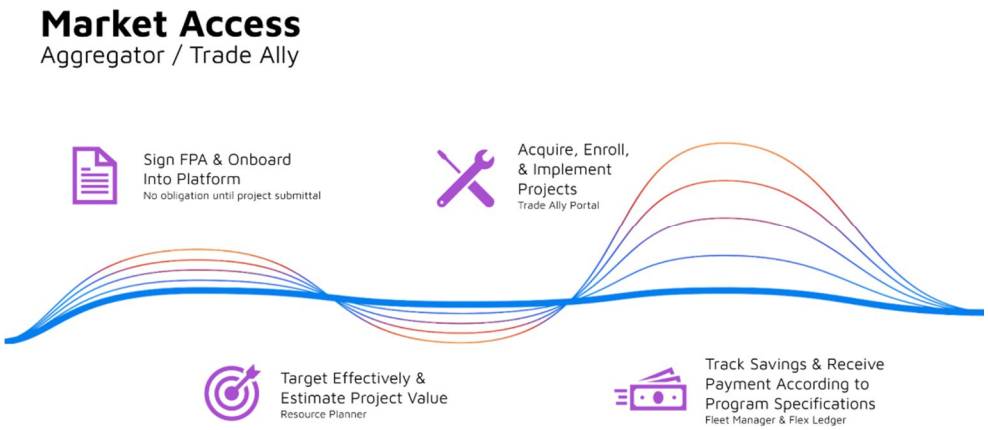


Figure 5: General Aggregator Process for Demand FLEXmarket

The Demand FLEXmarket program brings flexibility by allowing qualified aggregators to meet the individual needs of end customers in terms of energy savings, comfort, technology fit, and project cost. Rather than a prescriptive set of program offerings, aggregators will deliver solutions oriented around peak savings and TSB delivered. By leaving the solution set open-ended but fixing the price to savings delivered and providing consistency in tracking impacts, the range of possible solutions is determined by optimizing between cost and benefits, rather than prescribing a fixed program solution to a customer.

The program achieves scale by leveraging the growing number of aggregators participating in the Marketplace. Qualified aggregators can join any Marketplace after signing a Flexibility Purchase Agreement and agreeing to program rules. This increases competition and vendor diversity that will create scale in the marketplace to ensure the program addresses stranded opportunities and realizes efficiency potential.

The other key innovation is that payments to aggregators will be based on the TSB (after adjustments described in the M&V plan) of the portfolio of projects they deliver, net of the marketplace management costs and non-energy private investment. Marketplace management costs include general and administrative (G&A) overhead, direct implementation non-incentive (DINI), M&V, and marketing, education and outreach. These management costs are forecasted at 25% of the total program budget. Aggregators will target customers and optimize their budget by increasing savings impacts and finding the right shared cost point for customers to "say yes" to a project. It is in the hands of the aggregator to maximize their performance payments across their portfolio by achieving the greatest benefits (savings and demand impacts).

By focusing on the total program value delivered (both as presented through analytics and motivated through price), aggregators will have the tools and resources to improve their portfolio over time, manage risk, and be paid for the actual value delivered to PCE. Underperformance by an aggregator will likewise signal either modifications to their delivery model or exit from the Marketplace with no additional risk to ratepayers.

Pilots:

This section is not applicable to this program.

Workforce Education and Training:[7]

The Demand FLEXmarket program does not have a direct component for workforce education and training.

Workforce Standards:[8]

Aggregators that join the Demand FLEXmarket program will adhere to all requirements for workforce standards established by the Commission.[9] As part of the intake and review process, aggregators will provide all necessary qualifications and licensure to perform the proposed work.

Disadvantaged Worker Plan:[10]

The Demand FLEXmarket program does not have a direct component for targeting disadvantaged workers

Market Access Programs:

This section is not applicable.

Additional information:

This section is forthcoming… "Describe additional information required by CPUC decision, resolution, or ruling, as applicable. Indicate decision, resolution, or ruling and page numbers."

[7] D.18-05-041, pages 20-21 and Ordering Paragraph 7
[8] D.18-10-008, Ordering Paragraph 1-2 and Attachment B, Section A-B, page B-1
[9] D.18-10-008
[10] D.18-10-008, Attachment B, Section D, page B-9

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Supporting Documents

Program Manuals and Program Rules

A program manual containing rules for participation is provided with this implementation plan and is also integrated into the Demand FLEXmarket web page, found at www.demandflexmarket.com.

Program Theory and Program Logic Model

The essence of the program theory for the Demand FLEXmarket program is price signaling. The program establishes a flexible structure (i.e., a market design) by which aggregators can offer direct value from energy efficiency investments, and PCE can then purchase that value directly.

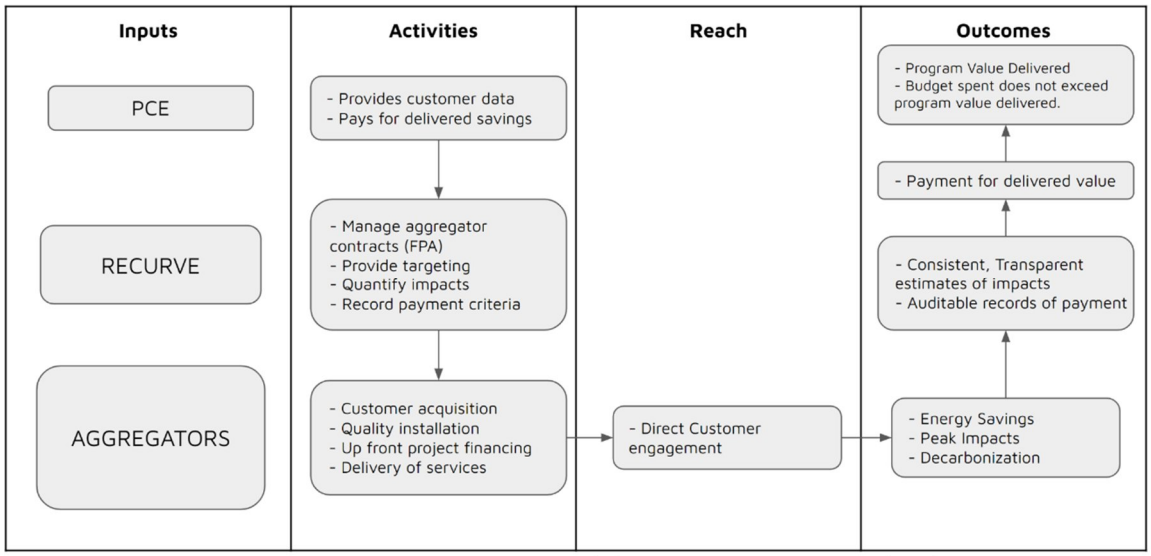
Unlike a traditional program, PCE is not buying the service, but the commodity - a stream of net benefits - from the aggregator. Historic barriers to program implementation have included rigid program designs with fixed technology incentives and pre-payment for program services which risked program savings delivered. In the Marketplace model, the program theory holds that the aggregators will act to optimize the value they can deliver, based on the price offered.

Aggregators are typically already familiar with the barriers for their targeted customer groups and have the flexibility to devise solutions to address those barriers for the customer groups that are likely to adopt similar technologies offered by the aggregators.

PCE gets the benefit of the value delivered at a price aligned with the Commission's Avoided Costs Calculator and with a protection against exceeding spending thresholds by only paying for value delivered above and beyond the Marketplace management costs.

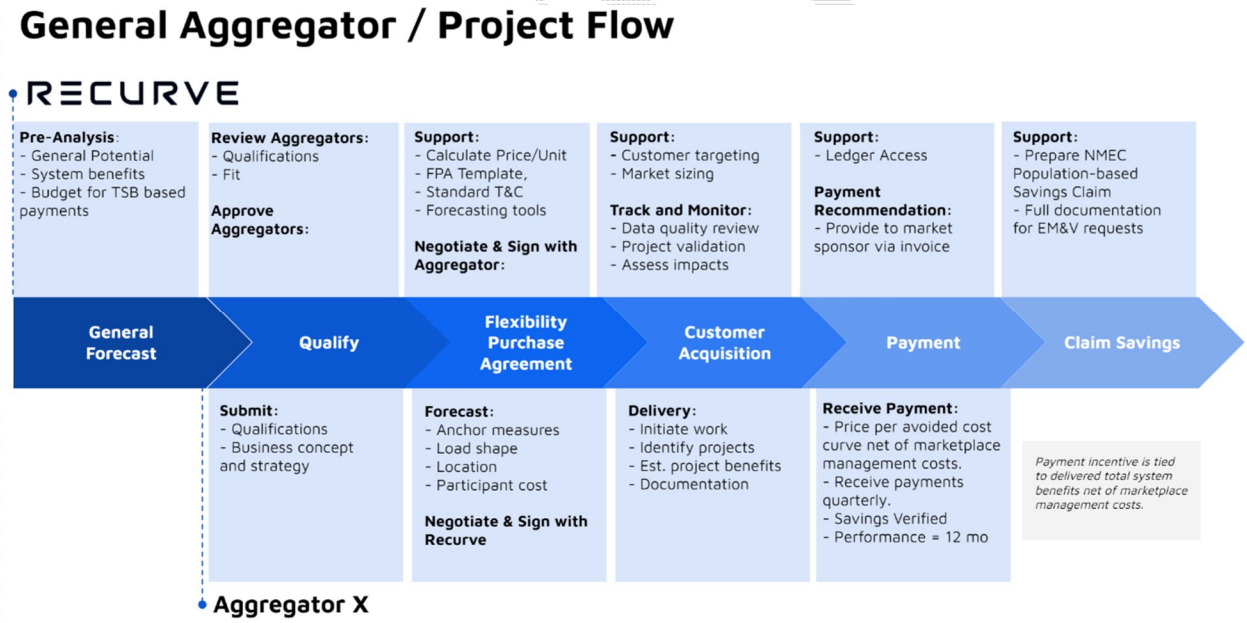
Marketplace Logic Model

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Process Flow Chart

The following graphic illustrates the process flow for Demand FLEXmarket projects and portfolios.



Incentive Tables, Workpapers, Software Tools

The Demand FLEXmarket program is a population-level NMEC program and does not have fixed measures or incentives. Workpapers or deemed savings values are not part of the program plan, but may be used for initial forecasts. The program's M&V plan describes the approach and associated software tools for calculating actual payable and claimable savings.

Savings estimates from aggregators will be reviewed by program staff. Since savings forecasts are not foundational to the Aggregator payments, reviews are focused on ensuring customers are getting reasonable estimates of savings potential, aggregators are appropriately applying EULs as agreed upon in the M&V plan, and that PCE can have confidence in forecasted impacts and manage performance payment budgets.

For payable savings, the value per unit of energy is grounded in the climate zone of the project, the metered load shape, ACC adjustments such as capacity smoothing, program multipliers applied to incent specific interventions or customer groups, and the Effective Useful Life appropriate for the primary measure (based on historic savings claims).

Incentives and costs presented to the customer are at the discretion of the aggregator. For program claims, the participant contribution will be net of non-energy private investment. Past approved program portfolios illustrate that measure costs can account for a large portion of the total resource costs. Programs that leverage incentives to encourage a high degree of private investment are often best able to achieve savings goals and policy objectives at the lowest ratepayer cost.
Based on the suite of best available evaluation research, net non-energy private investment will be utilized for claimed impacts.[11, 12, 13, 14, 15, 16]

Quantitative Program Targets

During program years 2025-2028, PCE anticipates this program will deliver a total savings of 7,074,000 in gross kWh. The estimated incentives for the program are $$2,230,300.42, and PCE projects that over 10 aggregators will be active by the end of 2028. The program has a goal of 2,040 kW in cumulative peak impact (gross) by the end of 2028.

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[11] The Commission as recognized this model as being low risk to rate payers. *". . . this type of program is very low risk to ratepayers regardless of cost-effectiveness score, because actual energy savings are measures based on NMEC methods, payments to aggregators are made based on performance, and spending is limited by the TSB actually achieved."* D.21-12-011 at p.26
[12] PG&E Advice Letter 2019 - Advice Letter 4011-G/5375-E - 2019
[13] PY2013-2014 California Statewide Residential and Nonresidential Spillover Study, Opinion Dynamics and Itron, Inc., 2017. CALMAC ID: CPU0186.01; see figure 3. noting that "internal motivators" drive participant action to "do more".
[14] Energy Upgrade California – Home Upgrade Program Process Evaluation 2014-2015, EMI Consulting, 2015. CALMAC ID: PGE0389.01; *Figure 4-10 shows equal weight (between 4-5 on a 5 point scale) of the importance given to energy savings among other considerations.* AND SBW Consulting. (2013). and 2010-2012 PG&E Whole House Retrofit Program Phase II Process Evaluation Study - Methods and Findings - PGE0302.06. Bellevue, WA. *Table 2, shows that the top motivations for participants are comfort, saving money, the incentives available and reducing their environmental impact.*
[15] PG&E Whole House Program: Marketing and Targeting Analysis. Opinion Dynamics Corporation, 2014. CALMAC ID: PGE0302.05 20 Energy Upgrade California – Home Upgrade Pro; see figure 3; reasons for participation. and:
[16] *Cost-Effectiveness of Energy Efficiency Financing Programs - Methodology & Strategic Issues, December 2016* documents the influence of other value drivers for participating in the financing programs.

Diagram of Program

Program Lifecycle Flow

	Eligibility	Qualification	Enrollment		Performance Tracking	Quality Assurance
			Pre-Intervention	Post-Intervention		
Program Implementer	Identify eligible customers for program. Engage customers to participate in the program.	Review baseline analysis for eligible customers to determine appropriate measures. Make notes on project. Group projects by contractor cohort	Review recently scheduled projects	Review recently completed projects	Monitor ongoing portfolio performance after update to ensure on track to meet savings goals. Download KPIs for reporting.	Periodically examine disqualifed projects and look for outliers which may negatively effect portfolio peformance.
Recurve Platform	Pull authorized customer, site and historical meter data into platform. Verify eligibility w/meta data.	Create placeholder-project for each eligible customer. Batch customers and ETL to complete baseline analysis for each.	Update project intervention date and status to scheduled. Remove customer from eligibility table.	Update project intervention date and status to completed.	Batch completed projects/new data to ETL and run meters at set frequency e.g. monthly.	Use portfolio settings to detect NRE's and identify outliers.
Program Channel		View cohort of eligible projects to see suggested measures and info for each customer. Use list for customer outreach.	Sell intervention to customer. Use enrollment form to update project with scheduled intervention date and set status to scheduled. Upload required contracts & info.	Complete intervention. Use enrollment form to update project with actual intervention date and set status to completed.	Examine program performance to see if projects performed as expected.	Identify outliers and examine their meta data to understand how to improve performance.

Evaluation, Measurement & Verification (EM&V)

At this time, there are no plans for implementing a process evaluation or other evaluation effort for this program. This program employs a robust embedded M&V strategy (as described in the M&V plan below).

Normalized Metered Energy Consumption (NMEC)

The Demand FLEXmarket Population NMEC M&V Plan is provided with this implementation plan.

PCE Demand FLEXmarket Program Manual

1. How the PCE Demand FLEXmarket Works

Any aggregator[17] who has agreed to the Terms and Conditions as detailed in the Flexibility Purchase Agreement (FPA) and signed Peninsula Clean Energy's Terms and

[17] Aggregators are participating vendors or program partners who generate energy efficiency and/or demand savings for an aggregated group of customers.

Conditions, both provided by Program Staff, is allowed to participate in PCE's Demand FLEXmarket.

Commercial Enrollment

The PCE Commercial Demand FLEXmarket enrolls projects in a two-stage process (Initial Enrollment and Project Completion). Through the FLEXmarket portal, project information is collected from aggregators along with an estimated incentive value, as well as various permissions and acknowledgments to complete a formal project enrollment. A "Reservation Letter" will be issued to the aggregator, providing details of the proposed incentive reservation and serve as a reservation confirmation to the aggregator for the project's installation. Upon installation, if there have been changes to the scope of work that affect the forecasted value of the project, values from the project reservation letter will change upon final project review and reflected in the issue of the "Project Completion Confirmation" letter. Submissions are checked for eligibility and completion prior to official enrollment into the Commercial Market and can be subject to additional documentation and review (as per the terms in the "Engineering Review Trigger" section). Unless otherwise agreed upon, a project's official "Start Tracking Date" will correspond with the date of project installation completion, noted on the final Project Completion Paperwork submitted by aggregator.

Commercial Efficiency Market incentive payments are paid based on performance of an aggregator's portfolio of projects and occur on a quarterly basis. Each project within a portfolio has its performance calculated quarterly, for the previous quarter, and an aggregator's collective portfolio performance for that quarter will be paid out. To prevent under- or over-performance due to seasonality, 10% is withheld from each quarterly portfolio payment and will be returned if performance holds. If a project performs as expected, 100% of its estimated incentive value will be paid out. The reservation of 120% of the forecasted project value ensures that incentive funding will be available for overperforming aggregator portfolios. Value that accrues in excess of this amount will be paid based on program funds availability; this availability will be assessed in order of project maturity following the end of the Commercial Program Portfolio[18] performance periods.

Projects can increase their value by increasing savings volume and delivering load shape impacts that are more valuable than the CPUC's deemed average resource cost curve (greater $/kWh saved), especially during summer peak and net peak hours. The Commercial Efficiency Market is agnostic to measures and business models, however,

[18] PCE Commercial Program Portfolio is defined as a single portfolio across all Commercial Program 2025-2028 years, inclusive of all participating aggregator portfolios.

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the expected useful life of the measures being implemented affects the magnitude of the incentive.

Recurve tracks savings for every project in an aggregator's portfolio and provide aggregators M&V for all projects through the Fleet Manager portal. Recurve also tracks payment recommendations through the Flex Ledger. Both of these tools are available to aggregators that have successfully enrolled a project in the Commercial Efficiency Market to monitor their portfolios.

Residential Enrollment

The PCE Demand FLEXmarket enrolls projects in a single-stage process; bypassing the "Initial Enrollment" and moving directly to the "Project Completion" stage. Through the FLEXmarket portal,[19] project information is collected from aggregators, as well as various permissions and acknowledgments to complete a formal project enrollment. Submissions will be checked for eligibility and completion prior to official enrollment into the Demand FLEXmarket and can be subject to additional documentation and review (as per the terms in the "Engineering Review Trigger" section).

Once projects are officially approved and enrolled into the Demand FLEXmarket, a "Project Completion Confirmation Letter" will be issued for the project. The letter represents PCEs commitment to paying the aggregator for the grid value to be delivered by a project. Unless otherwise agreed upon, a project's official "Start Tracking Date" will correspond with the date of project installation completion, noted on the final Project Completion Paperwork submitted by aggregator. The Project Reservation is calculated at 120% of the estimated incentive value (submitted through the enrollment process) from the program budget to account for the possibility of the project overperforming, exceeding its savings forecast.

Demand FLEXmarket incentive payments are paid based on performance of an aggregator's portfolio of projects and occur on a quarterly basis. As soon as a project's value generated exceeds the upfront incentives paid and the initial associated Marketplace management costs, portfolios become "active for payment". Accurate forecasting is inherent to the program design: over forecasting may lead to unnecessarily high marketplace management costs attributed to the project, while under forecasting may result in an insufficient budget reservation. Each project within a portfolio will have its performance calculated quarterly, for the previous quarter, and an aggregator's collective portfolio performance for that quarter will be paid out. To prevent under- or

[19] The FLEXmarket portal can be found at https://www.demandflexmarket.com

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over-performance due to seasonality, a Safety Factor will be withheld from each portfolio quarterly payment and will be returned if performance holds. If a project performs as expected, 100% of its estimated incentive value will be paid out. The reservation of 120% of the forecasted project value ensures that incentive funding will be available for overperforming portfolios. Savings that accrue in excess of this amount will be paid based on program funds availability; this availability will be assessed in order of project maturity following the end of the Residential program portfolio[20] performance period.

Projects can increase their value by increasing savings volume and delivering load shape impacts that are more valuable than the CPUC's deemed average resource cost curve (greater $/kWh saved), especially during summer peak and net peak hours. The Demand FLEXmarket is agnostic to measures and business models, however, the expected useful life of the measures being implemented will affect the magnitude of the incentive.

Recurve will track savings for every project in an aggregator's portfolio and provide aggregators M&V for all projects through the **Fleet Manager** portal. Recurve will also track payment recommendations through the **Ledger**. Both of these tools are available to aggregators that have successfully enrolled a project in the Demand FLEXmarket to monitor their portfolios.

2. Eligibility Requirements

Aggregator Eligibility

Any organization that can meet the requirements as listed in the FPA can participate in the PCE Demand FLEXmarket. Aggregators are participating vendors or program partners who generate energy efficiency and/or demand savings for an aggregated group of customers.

If an organization can meet these listed requirements, it must sign the Flexibility Purchase Agreement and Peninsula Clean Energy's Terms and Conditions to officially submit and enroll projects.

Project and Customer Eligibility

Recurve will utilize CalTRACK modeling to qualify customers based on data sufficiency and baseline model fit in addition to other usage characteristics.[21]

[20] Residential Program's Portfolio is defined as a single portfolio across all Residential 2023 - 2025 Program years, inclusive of all participating aggregator portfolios.

[21] Project qualifications based on data sufficiency and model fit may only apply to the type of savings being measured (electric or gas).

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General customer eligibility requirements include but are not limited to:

- Commercial site or Residential customer (single-family);
- Project site must be located in PCE's service area;[22]
- Unbundled (i.e., receiving electric generation service from PCE) customer;
- Site is not currently participating, and has not participated in the past 12 months, in a CPUC ratepayer-funded energy efficiency program;
- 12 consecutive months of energy usage data is available;
- Model fit needs to be < 1.0 Coefficient of the Variation of the Root Mean Square Error (CVRMSE) and site must pass CalTRACK data sufficiency analysis (Recurve will conduct analysis at intake);
- If the customer has onsite solar system, installation of the system must have been completed at least 12 months prior to the EE intervention.
- Projects can only enroll in the Market if they were installed and completed following the Program's elect to administer date.
- Qualifying residential projects subject to cost-effectiveness requirements set forth by the Program
- Commercial and Residential projects must be installed and project completion paperwork submitted to Recurve by no later than August 30, 2028.

More requirements for eligible customers are detailed in the program M&V plan.

Qualifying Measures

The Demand FLEXmarket will promote a wide range of measures including, but is not limited to, the following interventions: lighting, HVAC, water heating, building envelope, refrigeration, and controls-based technologies. The types of measures that are installed will be documented in the course of program deployment and be included in the metadata (see Data Collection section).

Projects with a primary measure (as defined in the M&V plan) of controls or behavioral interventions will default to a 1-year EUL (with the option to re-enroll) unless otherwise supported with documentation such as CPUC approved work papers or eTRM data (see the "Effective Useful Life" section of the M&V plan for more detail). Solar PV and other electricity generation are not eligible for incentives from the Demand FLEXmarket.

[22] https://www.PCEcleanenergy.org/member-communities/

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3. Project Enrollment Process

Pre-Enrollment

Prior to enrolling a customer, the program recommends that aggregators use the "Data Sufficiency and Eligibility Tool"[23] to check if a customer is eligible for program enrollment. To operate this tool, an aggregator must receive the SAID (Service Agreement Identifier) for a customer. Please note, this is different from the Account ID and Service Point ID numbers. Once an aggregator has an SAID, they simply enter it into the Data Sufficiency and Eligibility Tool. Outputs include but are not limited to:

1. If there is sufficient baseline data (12 months consecutively)
2. CalTRACK model fit (< 1.0 CVRMSE for eligibility)
3. Address
4. If the site has participated in a CPUC funded program within the past 12 months (as data provided by PCE)
5. Customer prioritization metrics

Customers with SAIDs that do not pass the data sufficiency check are not eligible to participate in the Demand FLEXmarket. Customers that have other factors contributing to ineligibility will have those listed in the Tool. For a full list of eligibility criteria, please see the Eligibility Requirements section above. Only aggregators that have signed the Flexibility Purchase Agreement are given access to the Data Sufficiency Tool.

Enrollment

Aggregators enroll projects under the Demand FLEXmarket via the FLEXMarket Portal[24]. Aggregators submitting projects must include the following:

1. Contact information for their company;
2. Contact information for the customer being enrolled;
3. Project information (such as forecasted savings) for electric and gas (if applicable).
4. Final scope of work;
5. Final project invoice;
6. Customer signed Data Authorization form;
7. Customer signed Project Completion form.

Upon completion of the project enrollment form, Recurve will review and verify that the enrollment is complete. The review is focused on ensuring that customers are receiving reasonable estimates of savings potential, aggregators are appropriately applying EULs,

[23] The Data Sufficiency and Eligibility tool can be found at https://www.demandflexmarket.com
[24] The FLEXmarket portal can be found at https://www.demandflexmarket.com

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and that PCE can have confidence in forecasted impacts and manage performance payment budgets. If the review is not passed, Recurve will review the results with the Aggregator to resolve any issues identified.

Projects will also be reviewed to see if a Third-Party Engineering Review is required. While the table below outlines the general parameters for a Third-Party Engineering Review, Recurve and PCE maintain the right to subject any project to additional engineering review.

Engineering Review Thresholds

Category	Threshold
New Aggregator Submission	First 3 projects in the market
% Savings (Annual Usage)	> 20%
Forecasted Aggregator Incentive	> $200,000[25]

Once installed, projects may be inspected on-site per the terms of the program's Quality Assurance Plan found in the program M&V plan. If an installed project does not pass a QA inspection, the Aggregator will be alerted by a program representative and will be expected to rectify the issue as specified in the Flexibility Purchase Agreement.

Approval

Commercial FLEXmarket Approval

Once projects are officially approved and enrolled into the Commercial Efficiency Market, a "Project Reservation" letter is issued for the project. The letter represents PCE's commitment to reserve funds required to pay the aggregator for the grid value to be delivered by a project, should the project be installed at the customer site. The Project Reservation is calculated at 120% of the forecasted incentive value (submitted through the enrollment process) from the program budget to account for the possibility of the project exceeding its forecasted value. Once projects are installed and completed, a "Project Completion Confirmation" letter is issued for the project with updated information and tracking start date, as well as the final amount of funding reserved, based on the completed scope of work, to pay the aggregator for any grid value

[25] If aggregators routinely underperform relative to project forecast, engineering review thresholds may be lowered.

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delivered by the project. Unless otherwise agreed upon, a project's official "Start Tracking Date" will correspond with the date of project installation completion, noted on the final Project Completion Paperwork submitted by aggregator.

Residential FLEXmarket Approval

Projects approved by the program will be issued a "Project Completion Confirmation Letter". Aggregators will be alerted when projects are rejected or are subject to additional review.

Approved projects will have 120% of their estimated incentive value reserved from the program budget for aggregator payments for the delivered value. Unless otherwise agreed upon, a project's official "Start Tracking Date" will correspond with the date of project installation completion, noted on the final Project Completion Paperwork submitted by aggregator.

Approved projects will be added to the submitting aggregator's portfolio of projects within their Recurve Platform Instance, where project performance will be monitored (using the Fleet Manager tool) and incentive tracking will be calculated (using the Ledger tool).

4. Incentive Payments

Upfront Incentives

Commercial projects are eligible for an upfront payment equaling 20% of the Forecasted Aggregator Incentive, while Residential Projects are eligible for an upfront incentive payment equaling 50%[26] of the forecasted Total System Benefit (TSB) grid value which will be processed for payment in the month after the "Project Completion Confirmation" letter was issued. The upfront incentive will be debited against the aggregators portfolio and the aggregator must deliver value beyond this debit prior to receiving additional payments.

How Incentives are Calculated

In general, incentives are calculated based on the total grid value from savings achieved in an aggregator's portfolio applied to the hourly grid value as defined by the Avoided Cost Curve, weighted EUL, adjustment factors (e.g., NTG, comparison groups) and participant costs. Individual projects are evaluated over a 12-month period but receive the full benefit of the weighted EUL of the project. 75% of the delivered grid value is allocated to the aggregator. 25% of the delivered grid value is

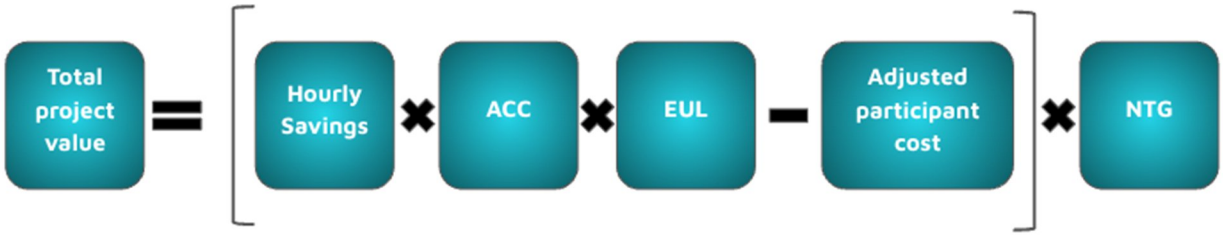
26 Upfront incentives are capped at $40,000. An aggregator with a project with a forecasted value of greater than $200,000 must submit the project with ICP certification to receive an upfront incentive beyond $40,000.

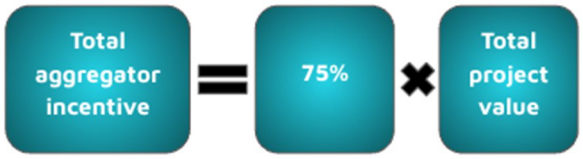
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allocated to program management fees, which include administration, marketing and outreach, and direct implementation non-incentive (DINI) costs.

The total project value is calculated in three steps. First, hourly energy savings are multiplied by the hourly value dictated by the ACC for the duration of the EUL. Second, an adjusted participant cost is subtracted from the resulting value.[27] Finally, this total is multiplied by the net-to-gross ratio, which is pre-determined to 0.95 for all commercial projects and 0.85 for all residential projects.

The aggregators receive 75% of the total project value.





Aggregators are able to receive payments quarterly for value delivered at the portfolio level. Further detail on this process can be found in the "Payments and Incentives" section of the M&V plan. A project value estimation tool and further detail on the Avoided Cost Curve can be found at https://www.demandflexmarket.com.

How Payments Are Made

Aggregator incentive payments for this population-level program will be made based on payable savings determinations using NMEC methods described in the gross and net

27 Only 50% of the participant costs are included in the equation to reflect that customers make efficiency investments for non-energy reasons. The incentive equation does not factor in non-energy benefits, so the costs are reduced accordingly for symmetrical accounting of costs and benefits.

sections of the M&V plan. Payments for the program will be made quarterly during the 12-month measurement period for active projects in the aggregator portfolio.

The quarterly measurement periods are:

- January-March
- April-June
- July-September
- October-December

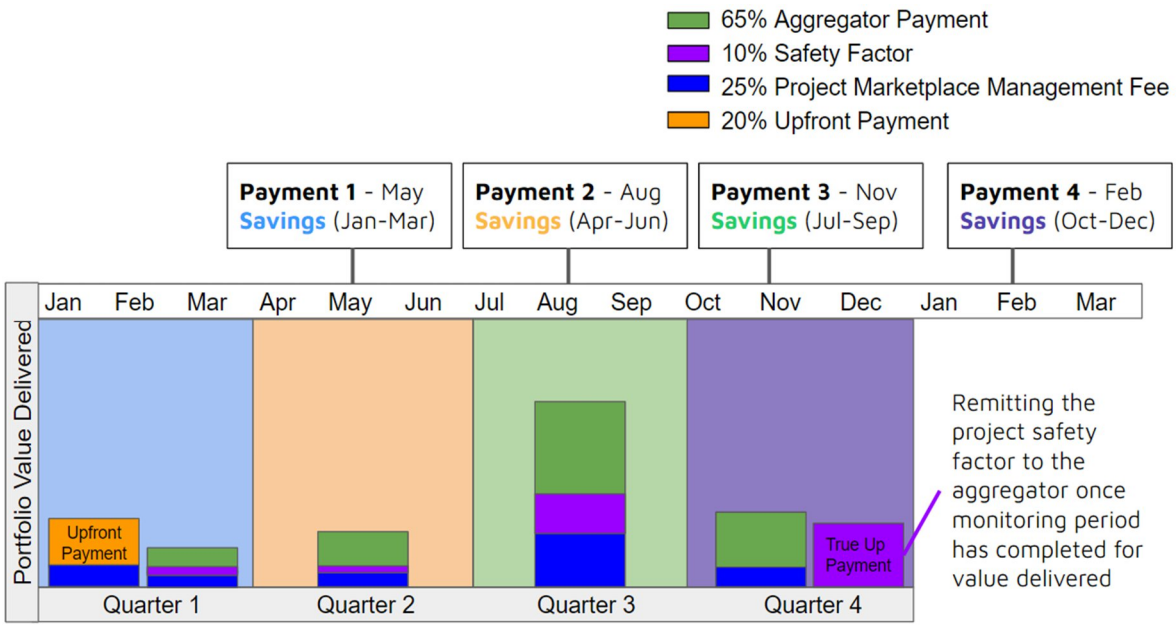
Payments are expected to be made within 60 days from the end of the previous measurement period. For example, payments for Q1 (January through March) will be made by May 30. Aggregators will be alerted if there's a deviation from this timeline.

The quarterly incentive payment is based on the total program value net of program management costs of projects in the portfolio and non-energy private investment. Aggregators will be paid for their portfolio value achieved based on metered savings from active projects achieved during the most recent measurement quarter. Aggregators are not eligible for a quarterly incentive payment if the net benefits from their projects do not exceed upfront incentives and the associated initial market management costs. In other words, the portfolio becomes active for a quarterly incentive payment after the value generated exceeds the upfront incentives and applicable participant costs for the projects. Marketplace management costs include general and administrative (G&A) overhead, direct implementation non-incentive (DINI), M&V, and marketing, education, and outreach. These management costs are calculated at 25% of the total program value delivered quarterly.

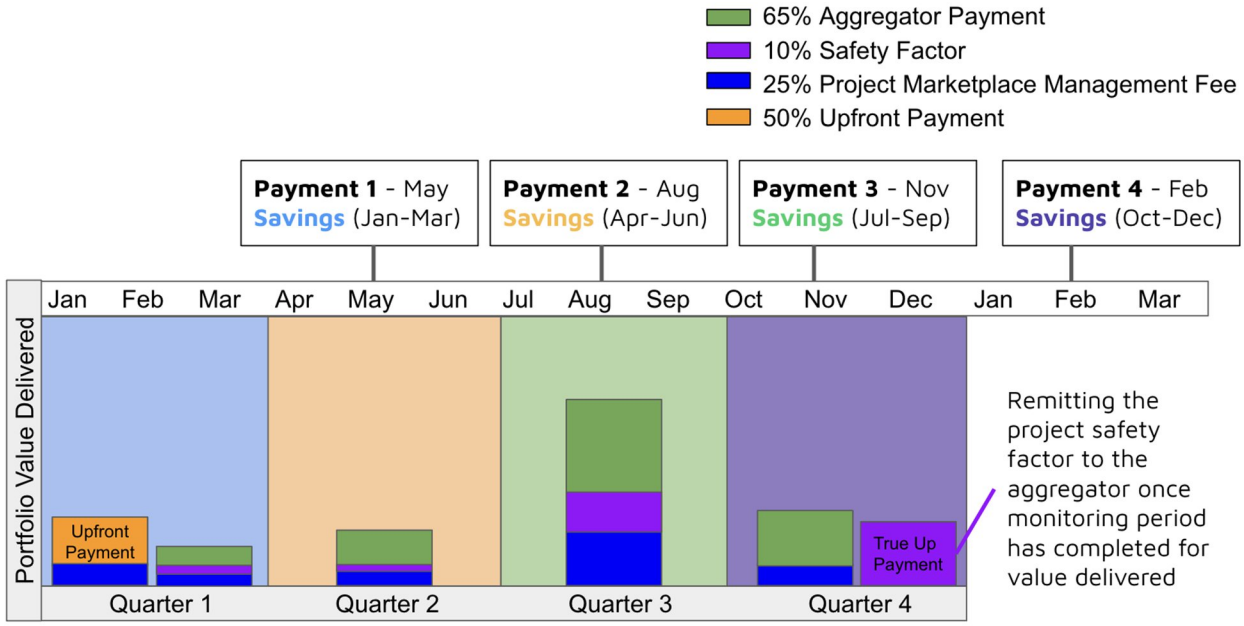
In addition, a Safety Factor is withheld each quarter to provide a buffer in regards to seasonality and/or project performance. As projects complete the full 12 month measurement period, aggregators will be compensated with a "true-up" payment in the following quarterly payment cycle that will release owed funds. The safety factor percentage defaults at 10% of measured project value. At the end of the portfolio year, each aggregator's safety factor will be re-evaluated based on the performance of their portfolio relative to their forecast (realization rate). A visualization of payment cadences and safety factor evaluation is shown in the figures below.

Commercial:

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Residential:



Aggregators with realization rates less than 30% will be evaluated regarding their participation in the next year of the Market. This evaluation may impact the Safety Factor applied as well as the Aggregator's eligibility for Upfront Payments.

The reservation of 120% of the forecasted project value ensures that incentive funding will be available for installed projects. Values that accrue in excess of this amount will be paid based on program funds availability and assessed once the portfolio tracking period has completed.

In the case that aggregator portfolio performance exceeds the reserved budget for the portfolio, a "scale back factor" will be calculated for the portfolio and applied uniformly to each meter, reducing the payment equally across all meters, resulting in a total portfolio payment equal to the reserved funds.

Scale back factor = Aggregator's Reserved Portfolio Incentive Funds / Aggregator's Earned Portfolio Incentive (Before Any Holdback or Scale back)]

Recurve will document in an electronic, revenue-grade, auditable ledger the recommended payments to support aggregator invoices to PCE after each quarterly measurement period. The electronic ledger will track all stages of a project, including non-routine adjustments. Invoice payment recommendations will be based on CalTRACK payable savings results. Claimable results to the CPUC will be derived from the ledger for compliance with reporting requirements.

Invoicing and Payment

Recurve's Ledger tracks all stages of the project and converts it into value, including non-routine adjustments. Invoice payment recommendations will be provided to PCE based on CalTRACK payable savings results. PCE will issue payments based on Recurve's payment recommendation.

Please see the Measurement & Verification Plan for the details of payment calculations, timelines, and non-routine event adjustments.

5. Additional Services

Co-Branding

PCE offers co-branded marketing as a free service to aggregators as an opportunity to showcase their organization's offerings and benefits to their potential residential customers within PCE's service area. PCE must approve in advance any use of PCE's logo.

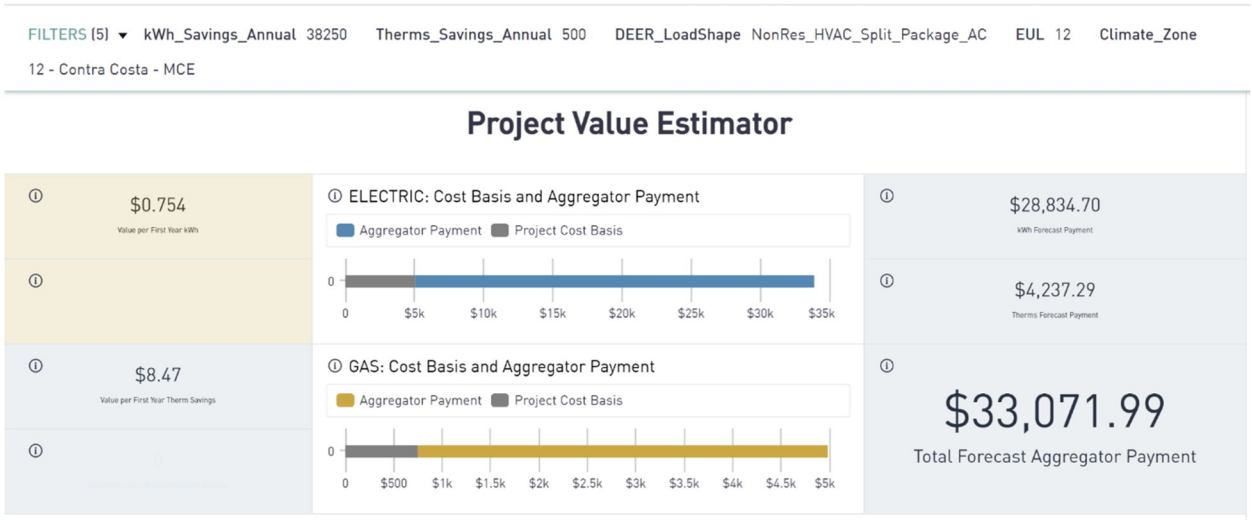
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Exploring Project Value: How much is your project worth?

As program incentives shift from deemed rebates or fixed performance rates to meter-based incentives that pay for grid value delivered, it can be difficult to understand how to estimate how a particular project earns value. As incentives begin to value temporal benefits over sheer volume of installations, understanding how load shapes impact performance is crucial.

Estimating and Forecasting Value

Aggregators have access to a Project Value Estimator and FLEXvalue[28] tools via the program webpage. These tools give aggregators the ability to estimate their projects' value through the PCE Demand FLEXmarket. The Project Value Estimator dashboard requires basic project inputs to estimate the available Aggregator Incentive Payment value.



Customer Optimization to Maximize Value

Aggregators have an incentive to both increase the volume of total savings and maximize the value of the resource curve (savings load shape) to maximize project value. We encourage all aggregators to take time using the Project Value Calculator to understand these interactive effects to develop a model that maximizes grid impacts and customer offerings.

One primary tactic in the Demand FLEXmarket is the ability to work with Recurve tools to identify customers with the highest potential for savings. Aggregators are encouraged to

[28] https://colab.research.google.com/github/recurve-methods/flexvalue/blob/master/notebooks/colab.ipynb#scrollTo=7da3bd62

pursue opportunities with customers whose consumption profiles suggest greater savings potential, especially those with high usage during the summer peak and net peak hours.

Program tools can also be used to identify the buildings that offer flexibility opportunities during summer evening ramp, leading to much more valuable avoided cost savings. Recurve will work with aggregators to identify the attributes of high-potential customers. These attributes are then used to prioritize customer segments that are the most likely to have cost-effective outcomes for all parties involved.

For example, an aggregator targeting residential Air Conditioner savings would have the greatest potential impact by focusing on the customers with the greatest AC usage during the grid peak periods when savings are worth the most. These customers are most likely in need of help, and will have dramatically higher bill savings and grid benefits.

Aggregators also have the freedom to optimize their offerings toward the most beneficial mixes of technologies, develop innovative customer engagement strategies, or explore automation. Aggregators will be given maximum flexibility to determine their own business models, and customer value propositions.

Understanding Avoided Cost

The cost of energy is not static and fluctuates based on the time of use. The CPUC Avoided Cost Calculator (ACC) provides a set of 8760 marginal hourly values for the California grid, forecasting the cost of energy for each hour of the day. For the purpose of this program, the ACC has been adjusted, as outlined in the M&V plan, to provide a more stable compensation structure and adequately value summer peak hours. This data set is used to value energy savings or demand flexibility in the Marketplace. This data feeds into the Project Value Estimator, where aggregators have direct access to derive incentives in the PCE Demand FLEXmarket, estimating the avoided cost value of the project in order to forecast potential cash flows

Audits

No pre-or post-on-site audits are required. PCE may, as part of the quality assurance framework, select a random sample of projects to confirm technologies were installed. Audit of data quality and eligibility of participants will be conducted by Recurve.

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6. Sub-Program Quality Assurance Provisions

Quality Assurance Plan

PCE maintains the integrity of the Demand FLEXmarket through an independent Standards and Quality Assurance Team who manages the quality assurance system for the Market.

The quality assurance (QA) system has several components, including a review of qualifications and credentials, paperwork audits, the establishment of program standards, and field and photo inspections. QA inspections involve verification of the contracted scope of work, accuracy of site analysis, comparison of installation to submitted designs. Recurve, PCE, or its representatives may make a reasonable number of visits to the customer site before, during, and/or after installation of efficiency measures to assess overall compliance.

Aggregator Roles and Responsibilities

The program relies on aggregators to provide complete turnkey services for qualified energy efficiency improvements to customers. Aggregator roles and responsibilities include:

- Aggregator and/or their subcontractors hold the agreement (contract) with the customer
- Responsible for performance, including subcontractors
- Receives incentive payments and determines customer incentives
- Agrees to terms of the Flexibility Purchase Agreement
- Agrees to PCE's terms and conditions
- Agrees to terms of the M&V agreement
- Accountable for resolution of customer complaints
- Responsible for installation, warranties, and product guarantees

Selecting Completed Projects for Inspection

The purpose of the QA inspection is to provide PCE an opportunity to evaluate the accuracy of the site analysis and design documents and verify that building components and equipment are installed according to Program requirements. The QA inspection also includes selected health and safety and performance items.

PCE reserves the right to select any project for inspection. Selections may include consideration of the following criteria:

- Low savings realization rates
- High CVRMSE or CVRMSE change

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- High variance

PCE reserves the right to conduct both field and photo inspections based on the following sampling rates:

- 10% photographic
- 2-4% onsite inspection

PCE may select any completed project for inspection based upon customer complaints, warranty-related issues, or as part of the review of a contractor under status review or Program disciplinary action.

Field Inspections Process and Scope

The purpose of a field inspection is to confirm measures are installed per manufacturer instructions and as outlined by the aggregator in the customer agreement, and in the project documentation provided to Recurve. QA field inspections are scheduled at the customer's convenience. Customers are encouraged to allow the contractor to attend the inspection to answer questions. If the customer agrees, the contractor will be notified by email between 5 to 14 days before the inspection. Every effort will be made to accommodate the contractor's schedule, but the customer's convenience takes precedence.

Customers have the right to request that the contractor not attend the QA field inspection. In these situations, the contractor will not be notified of the scheduled inspection but will receive the report from the QA team within 15 business days of the inspection.

Photo Inspections

The contractor is required to take construction photos for each measure installed, which describe the existing conditions as well as the replacement product or measure. PCE expects contractors to take photos throughout the installation process to ensure that each measure completed is supported with photographic documentation. PCE may request construction photos for purposes of conducting a photo inspection at any time, and failure to provide the requested photos may result in higher onsite inspection rates. Taking multiple pictures of each installed measure will help ensure a smooth photo inspection process.

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QA Inspection Report

The QA inspection report will provide a summary of all evaluated elements of the project and list any non-conformances identified during the inspection. The report will provide an overall score of the project and identify it as a pass or fail. Scoring criteria is further described below in the program M&V plan.

The report will be provided to the contractor approximately 15 days after the inspection, following an internal review and scoring by the QA Team. The report will be made available to the customer upon a direct request to PCE.

7. Other Program Metrics

N/A

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Population-level NMEC M&V Plan

Program Name: PCE Demand FLEXmarket
Program Administrator: PCE
Market Implementer: Recurve

1. Summary

This is a Program-Level Measurement and Verification (M&V) Plan for the PCE Demand FLEXmarket. The program is eligible for, and complies with, the population-level Normalized Meter Energy Consumption (NMEC) requirements defined in the CPUC NMEC Rulebook v.2.[29] Based on the definitions provided by the CPUC, population-level NMEC is used when savings claims are made for a portfolio of projects using fixed, standardized, verifiable measurement methods established before the program starts and that are uniformly applied to all sites in the group.[30] All NMEC approaches are based on pre- and post-intervention energy usage data observed at the meter.

The program implementation plan[31] for the Demand FLEXmarket provides the details for how the program shall be implemented. The population-level NMEC M&V approach is appropriate for this program because it meets all required program design criteria, including those related to expected savings and permissible project types related to building-type similarity.

The Demand FLEXmarket, implemented by Recurve will utilize independent, transparent measurement and continual tracking of changes in pre- and post-intervention energy usage observed at the meter. Standardized, open-source methods and tools are the foundation of this M&V plan. The remainder of this document details compliance with the CPUC NMEC Rulebook 2.0 requirements for the program-level M&V Plan for Population NMEC, which must be included in any implementation plan.

2. Analytical Methods and Calculation Software Selection

This Demand FLEXmarket is designed for the commercial & residential sector within PCE's service area. Targeted building types, including consumption trends, existing equipment, and likely impact of the interventions, will be reasonably consistent for each aggregator within the program. Qualified aggregators will mostly focus on installing a primary

[29] Rulebook for Programs and Projects Based on Normalized Metered Energy Consumption, January 7, 2020 https://www.cpuc.ca.gov/General.aspx?id=6442456320

[30] CPUC's full definition: "*Population-level NMEC is an energy savings calculation approach in which results are based on pre- and post-intervention energy usage data observed at the meter and calculated across a group of sites, rather than a modeled engineering forecast or deemed value (or a Site-level metered savings calculation). For Population-level NMEC, measurement methods are fixed before the program starts and apply to all sites in the group in a uniform fashion, as opposed to Site-level NMEC measurement methods which may differ on a site-by-site basis.*" Rulebook p. 24

[31] Templates for implementation plans can be found here: https://www.caeecc.org/implementation-plan-guidance

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technology across a similar sub-section of the market, but the implementation plan does not pre-define the measures nor the targeted sub-set of the market.

Initial savings forecasts from aggregators will be reviewed and validated by Recurve. Since aggregator payments are based on metered impacts, not calculated estimates, reviews are utilized to ensure estimates are reasonable and based on industry best practice. This review process will help ensure customers receive reliable estimates of savings potential, aggregators are appropriately applying EULs, and that PCE can have confidence in forecasted impacts and effectively manage performance payment budgets.

Approach	Project Documentation from Aggregator
Actuarial *Meter-based past performance*	Past evaluation report, third party evaluation or engineering assessment of a similar projects' past performance utilizing whole building IPMVP Option C methods; e.g. CalTRACK/OpenEEmeter or ECam
Modeled *Building simulation projection*	Results of a building simulation model like Energy Plus, EQuest, or other similar IPMVP Option D modeling tool. Models calibrated with actual usage data are preferred.
Deemed *Pre-approved standardized measure-specific savings*	Citation of a CPUC-approved or archived work paper, or other DEER value. Measure-specific savings estimates from CalTF via the eTRM may also be appropriate but should be calibrated for to and through code performance.
Bottom-Up *Multiple approved and standardized measure-specific savings*	Citation of a suite of deemed values (see above) combined to estimate the whole impacts of a project. Interactions between measures should be considered in the estimate.

Figure 1: Pre-Installation Verification of Savings Estimation Options if Engineering Review Threshold Exceeded

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Payable Savings

Payable savings constitute the basis of payments between PCE and aggregator(s). The public, open-source CalTRACK 2.0 methods,[32] executed via the OpenEEmeter[33] for the calculation of baseline models and counterfactuals, GRIDmeter for comparison group sampling and savings adjustment, and FLEXvalue for the calculation of grid value based on the measured hourly savings impact and the CPUC's avoided cost calculator have been chosen as the analytical method(s) and calculation software for payable savings for this program. A wide range of building types may be part of the program and a threshold baseline model fit will be a precursor for project acceptance. The open-source methods and codebase can collectively be called the FLEXmeter. The FLEXmeter methods and code will be used for quantifying energy efficiency and demand response impacts and can be used to disaggregate EE and DR impacts as applicable. Background on development of CalTRACK and the OpenEEmeter can be accessed through www.caltrack.org. The GRIDmeter methods and code are available publicly at gridmeter.recurve.com and FLEXmeter tools and code are found at flexvalue.recurve.com. References to technical specifics are provided throughout this M&V plan.

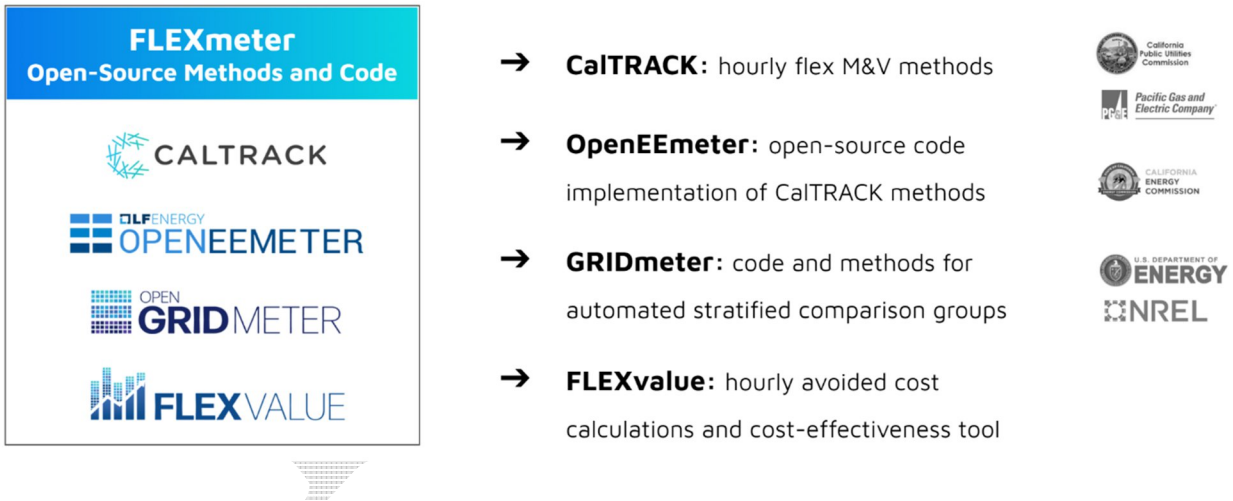


Figure 2: FLEXmeter Methods and Codebase

The CalTRACK methods are based on industry guidelines established by The American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE Guideline 14)[34]

[32] The current v. 2.0 CalTRACK methods documentation and technical appendix are available at http://docs.caltrack.org/en/latest/methods.html

[33] The python code base for the OpenEEmeter (eemeter and eeweather) can be downloaded from Github at: https://github.com/openeemeter; Code and methods to accommodate special cases like PV, EV, and batteries may be included in updates to openEEmeter.

[34] ASHRAE Guideline 14-2014 –Published guideline. Supersedes ASHRAE Guideline 14-2002. Measurement of Energy, Demand and Water Savings https://www.ashrae.org/technical-resources/standards-and-guidelines/titles-purposes-and-scopes

and the Uniform Methods Project (Chapter 8 - Whole Building Methods)[35] and meet all International Performance Measurement and Verification Protocol (IPMVP Option C[36]) requirements. These methods are an appropriate match for this program given it is targeting a range of commercial & residential buildings and combination of interventions. Hourly methods have demonstrated appropriate fit based on historic applications and technical review, and discrete project baseline fit review. Additionally, tests conducted by the Efficiency Valuation Organization (EVO) demonstrate that the OpenEEmeter 2.6.0 CalTRACK hourly methods, performs on par with the LBNL Time of Week Temperature (TOWT) model, and comparably with all other models tested, including more complex machine learning models that are based on decision trees and genetic programming.[37]

Payable savings will be adjusted for free ridership using the approved deemed net to gross ratio of 0.95 for Commercial and 0.85 for Residential Single-Family NMEC. Payable savings will also be adjusted via a comparison group adhering to the protocols and recommendations described in the report ***Comparison Groups for the COVID Era and Beyond.***[38] The GRIDmeter methods were developed in partnership with the United States Department of Energy and in consultation with a working group of industry experts. Comparison groups are described further below.

The CPUC has specified criteria for "Tools, Methods, Analytical Approaches, and Calculation Software" in the NMEC 2.0 rulebook. FLEXmeter compliance with each of the criteria is provided in Attachment A in table format.

Claimable Savings

Demand FLEXmarket claimable savings will be based on the payable savings (calculated with CalTRACK and the OpenEEmeter), including adjustment for free ridership using the approved deemed net to gross ratio of 0.95 for Commercial NMEC and 0.85 for Single-Family Residential NMEC. The October 12, 2019 DEER Resolution allows for alternative approaches for net adjustment, but, for this program, the traditional application of the net to gross ratio will be combined with the comparison group adjustment to gross savings impacts.[39]

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[35] *The Uniform Methods Project: Methods for Determining Energy Efficiency Savings for Specific Measures*, National Renewable Energy Laboratory, https://www.energy.gov/eere/about-us/ump-protocols

[36] International Performance Measurement & Verification Protocol: Concepts and Options for Determining Energy and Water Savings, Volume I, Revised March 2002 DOE/GO-102002-1554, International Performance Measurement & Verification Protocol Committee https://evo-world.org/en/products-services-mainmenu-en/protocols/ipmvp

[37] EVO's testing portal <http://mvportal.evo-world.org/ > allows users to compare Advanced M&V implementations and methods against each other using a single standardized dataset comprised of one year of hourly electricity data and outdoor temperature from 367 buildings from different regions in North America.

[38] Report available at: https://gridmeter.recurve.com/uploads/8/6/5/0/8650231/doe_sampling_v2.pdf

[39] Resolution E-4952. Approval of the Database for Energy-Efficient Resources updates for 2020 and revised version 2019 in Compliance with D.15-10-028, D.16-08-019, and Resolution E-4818. See p. A-45 for table of NMEC NTG ratios. http://docs.cpuc.ca.gov/publisheddocs/published/g000/m232/k459/232459122.pdf

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Other fields required for claimed savings include the estimated useful life (EUL), load shape, and costs. These parameters of claimed savings will be handled in accordance with CPUC reporting requirements. Aggregator portfolios of reasonably consistent measures will utilize an EUL matching the primary measure or technology installed in accordance with the requirement outlined in in accordance with the requirement outlined in the "Effective Useful Life" section. Savings will be claimed using the actual measured load shape. Actual project costs, including participant contributions and information on the key value drivers, will be collected during program implementation to support savings claims to the CPUC. Savings will be claimed based on forecasted savings and savings load shapes for each project, and after the 12 month measurement period will be revised based on actual measured savings during a "true-up" process.

3. Calculation of Gross and Net Savings

Gross Savings

The basic calculation process for gross savings is conducted in four parts using the FLEXmeter calculation methods after data collection and sufficiency checks (see Data Plan section D. for more detail). The first is establishing the baseline calculation or model fit (see CalTRACK Section 3(b): Modeling - Hourly Methods). The second is normalization of weather and occupancy (section 3.8 and 3.9). The third is computing the results of the avoided energy use (sections 3.10-3.12) and the fourth is the formation of comparison groups and adjustment to savings via the difference of differences calculation (Chapters 3 and 4 of *Comparison Groups for the COVID Era and Beyond*).

Baseline Calculation

The CalTRACK Hourly model draws from 365 days of pre-intervention data in order to deliver a fully specified baseline model for a weather-normalized savings calculation. Customer AMI data for a full year prior to program enrollment, customer location (address or latitude/longitude coordinates), initial project intervention date, and blackout period that encompasses the duration of project installation are minimal requirements to fully specify the CalTRACK model and assess savings. Aggregators will report project installation and completion dates in addition to various project metadata, which will enable Recurve to assign baseline, blackout, and reporting periods and to create project cohorts that can be tracked separately.

Normalization for Weather and Other Factors

The CalTRACK Hourly methods normalize for weather and occupancy, as described in detail in section 3.8 and 3.9 of CalTRACK technical documentation.

For occupancy, the sensitivity of building energy use to temperature may vary depending on the "occupancy" status. This is handled by segmenting the hours-of-week into periods of high load and low load (also referred to as occupied/unoccupied,

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although the states may not necessarily correspond to specific occupancy changes). The segmentation is accomplished using the residuals of a linear HDD-CDD model fit at an earlier stage.

For weather normalization, for each data point (hour) in the baseline dataset, the outdoor dry bulb air temperature is used to calculate up to 7 temperature bins (<30, 30-45, 45-55, 55-65, 65-75, 75-90, >90). These bin endpoints are validated for each model by counting the number of hours with temperatures within these bins. Bins with fewer than 20 hours are combined with the next closest bin by dropping the larger bin endpoint, except for the largest bin, where the lower endpoint is dropped. The ? valid bin endpoints are then used to develop the binned temperature features.

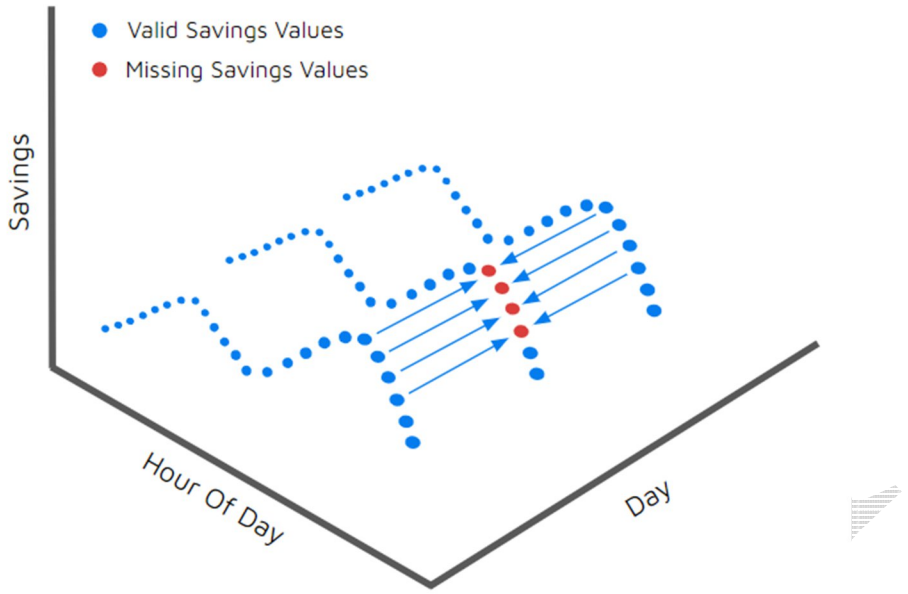
These methods have been tested and demonstrate that they yield an appropriate model fit for most building types in California (as measured by the coefficient of variation of the root-mean-squared error, CVRMSE).

Interpolation of Missing Savings

Using the savings calculation methods described in this M&V plan, there are still around 2-3% of values missing on average. Missing values occur if the treatment meter or all matched comparison group meters have experienced missing; weather data or observed meter reads. These dropped meter reads have the potential to substantially impact on the payments being made to aggregators.

In the case that there are missing values, Interpolation will be performed via an 8 moving average window that surrounds the missing value and fills them with the average of surrounding days for counterfactual, observed and savings values. For hourly electricity data, the missing hour will be filled with the average of surrounding days for that same hour of day.

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Adjusted Gross and Net Savings

For the Demand FLEXmarket, the site-specific gross savings will be adjusted to quantify the relative grid impacts of the program interventions using a comparison group and adjusted for free ridership using a fixed net to gross value. More detail can be found in the demand response disaggregation section. All adjustments will be reflected in the payable savings to aggregators and in the claimable savings to the CPUC.

Comparison groups will be maintained for gross savings adjustments. The same savings calculation as described in the "gross savings" section including method and software will be applied to understand participant and comparison group changes in energy consumption. The calculated incremental impact of the program over the non-participant population will adjust both payable and claimable savings for the portfolio. The adjusted gross savings[40] will be the difference of differences, calculated on a percentage basis and then applied to the treatment group counterfactual.

Comparison groups used in meter-based programs have the unique challenge of needing to quantify impacts in the midst of implementation as well as address dissimilar responses to exogenous factors, unpredictable exogenous events, and limited data for assigning buildings to cohorts. As such, the comparison group selection process in meter-

[40] "Adjusted gross" is, in this context, net of other activity on the grid, whereas the final "net" adjustment is considering free ridership alone.

based programs needs to utilize a more standardized and consistent methodology than what might be found in traditional impact evaluations.

The methodological approach that will be used for establishing comparison groups in the Demand FLEXmarket was developed in an intensive, collaborative research project led by Recurve and funded by DOE in the summer of 2020. More detail on the research informing this method is described in a comprehensive working group report funded by the Department of Energy and peer-reviewed by industry leaders.[41] The comparison group analytic approach comports with best practices in the Department of Energy Uniform Methods Project on Estimating Net Savings[42], and is an evolution of standardized approaches for developing matched comparison groups documented by the Energy Trust of Oregon.[43] This method has been expanded to Demand Response applications and is compliant with the FERC-approved tariff for comparison group settlement used by the California Independent System Operator.[44]

Comparison Group Method Synopsis

Comparison group selection can be summarized as follows:

1. Identify program-eligible participants
    a. The eligibility rules for this program are included in the program plans. These classifications will guide the classification of comparable customers.
2. Limit comparison pool to eligible non-participating customers that meet program requirements.
    a. Fit a CalTRACK 2.0 model on all eligible program participants prior to program launch. This model will uncover incomplete or missing data as well as erratic energy consumption patterns.
    b. Remove customers with insufficient baseline data, defined in the CalTRACK methods to be < 328 days for the specification of annual baselines. For the measurement of demand response or seasonal savings shorter baseline periods may be utilized if needed.
    c. Remove customers with CalTRACK Daily baseline CVRMSE values in excess of 1.0[45].

[41] *Comparison Groups for the COVID Era and Beyond*, Recurve, 2020 https://gridmeter.recurve.com/uploads/8/6/5/0/8650231/doe_sampling_v2.pdf
[42] *Chapter 21: Estimating Net Savings – Common Practices* https://www.nrel.gov/docs/fy17osti/68578.pdf
[43] *Comparison Group Identification for Impact Evaluation*, OpenEE, for Energy Trust of Oregon, 10/2018 https://www.energytrust.org/documents/open-ee-technical-report-comparison-group-identification-for-impact-evaluation/openee-technical-report-comparison-group-identification-methods-final-wsr/
[44] See *Demand Response Advanced Measurement Methodology: Analysis of Open-Source Baseline and Comparison Group Methods to Enable CAISO Demand Response Resource Performance Evaluation,* CAISO -Recurve, 2021 http://www.caiso.com/Documents/DemandResponseAdvancedMeasurementMethodology.pdf
[45] Given the focus on peak savings that can only be measured with an hourly model, there may be a recommendation to incorporate an hourly CVRMSE threshold.

d. Remove any remaining customers failing to meet program eligibility criteria

3. Selection of Comparison Group from within Sample of Sub-Population

a. Segment treatment customers by climate zone, solar status, and sector. For the measurement of efficiency savings in the commercial sector also segment customers by business type using NAICS Group mapping as was done in the GRIDmeter report as applicable.

b. For a comparison pool meter to be sampled into the comparison group for a specific categorical segment of the treatment group, the customer must share all criteria listed in 3.a.

c. With categorical segmentation completed, conduct individual meter selection on the basis of Euclidean distance (least sum of squares) matching with each treatment meter on the basis of seasonal hour-of-week baseline modeled consumption as described in Chapter 3 of the GRIDmeter report. For shorter-term baselines such as those used to gauge demand response impacts, the Euclidean distance matching may be performed on a single (non-seasonal) modeled hour-of-week basis as described in the CAISO report[46] . For non-residential programs that serve a small number of customers or serve very large customers, the stratified sampling methods also described in chapter 3 of the GRIDmeter report may be more appropriate and thus utilized as applicable.

4. Creation of Comparison Group Vintages and Difference of Differences

a. Once a comparison group has been created, the baseline period of the comparison group must be aligned temporally with the baseline period of the participating customers.

b. Where programs enroll customers over a period of time longer than 30 days, the comparison group savings calculation must be rebaselined for each month of enrollment and a new vintage created that is assigned to a monthly cohort of enrolled participants.

c. For each monthly cohort of participants, calculate a difference of differences of percentage savings between the treated customers and the associated vintage of the comparison group.

[46] See *Demand Response Advanced Measurement Methodology: Analysis of Open-Source Baseline and Comparison Group Methods to Enable CAISO Demand Response Resource Performance Evaluation*, CAISO -Recurve, 2021 http://www.caiso.com/Documents/DemandResponseAdvancedMeasurementMethodology.pdf

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d. The fractional difference of differences is then multiplied by the treatment group counterfactual on an aggregated basis for each segment established in 3a. More detail is provided in Chapter 4 of the GRIDmeter[47] report on conducting the difference of differences savings calculations as well as in the CAISO report.

For payable and claimable net savings, Recurve will apply 0.95 default net to gross ratio for Commercial and 0.85 default net to gross ratio for Single-Family Residential NMEC programs as specified in the October 12, 2019 DEER Resolution[48] to account for free ridership.

Outlier Site & Non-Routine Event Identification

This section of the M&V plan augments generic qualification criteria for participants with specific considerations regarding project eligibility criteria, screening, and handling of non-routine events to ensure that the savings from the program are reflective of the impacts of the program intervention.[49] The process includes pre-screening, event detection, and handling adjustments as described in the sections below. The following diagram illustrates the 4 step process:

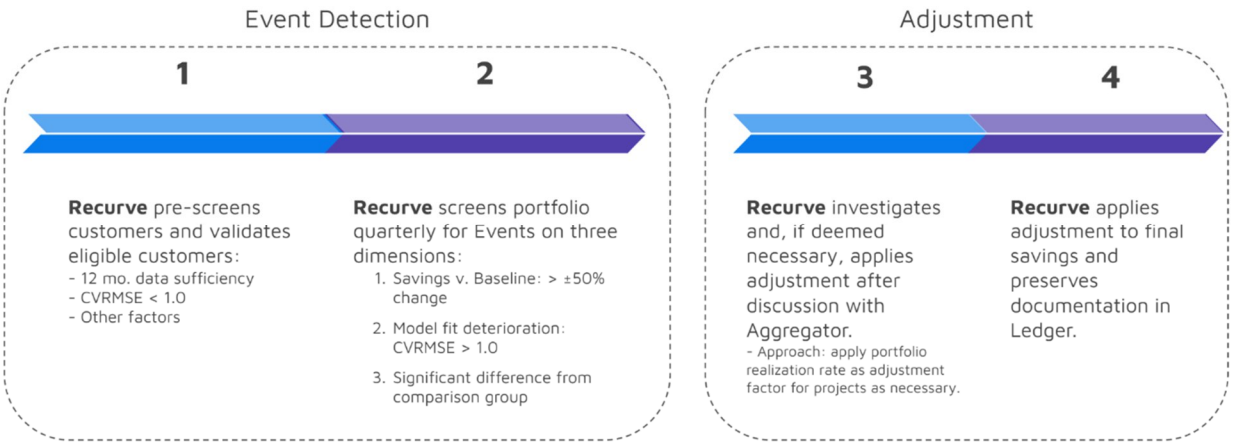


Figure 4: Eligibility Criteria and Screening

Eligibility Criteria and Screening

[47] *Comparison Groups for the COVID Era and Beyond*, Recurve, 2020
https://gridmeter.recurve.com/uploads/8/6/5/0/8650231/doe_sampling_v2.pdf

[48] Resolution E-4952. Approval of the Database for Energy-Efficient Resources updates for 2020 and revised version 2019 in Compliance with D.15-10-028, D.16-08-019, and Resolution E-4818. See p. A-45 for table of NMEC NTG ratios.
http://docs.cpuc.ca.gov/publisheddocs/published/g000/m232/k459/232459122.pdf

[49] This approach is preliminary and any adjustment to it will be made in consultation with the Market Sponsor (Program Administrator)

STEP 1. As described above, Recurve will utilize CalTRACK modeling to pre-screen the population to identify qualifying customers that have data sufficiency and baseline model fit, which will ensure savings are measurable in the performance period. Customers who experience a baseline non-routine event or erratic energy consumption that exceeds the prescribed threshold during the baseline period may be excluded from the program. Some scenarios in which they may remain include:

(i) the impacted metered consumption can be excluded from the analysis without violating minimum data sufficiency standards.

(ii) the NRE can be adequately controlled by comparing customer energy consumption to a matched nonparticipant comparison group. Aggregators will be able to check potential projects against this pre-screened list.

(iii) the NRE is determined to not materially impact the project and portfolio savings.

In the process of customer acquisition, aggregators will verify with customers that they do not plan to install major new load additions or subtractions, solar PV, or EV charging in the reporting year (post-program implementation). In addition, aggregators will work with Recurve and PCE to ensure that customers are not participating in another energy efficiency program, have not installed an EV charging system, or solar PV or battery storage within the baseline year. PCE will be responsible for providing past energy efficiency program participation data to ensure accurate monthly program forecasting. If data is not provided in a timely fashion and sites are enrolled that have participated within the previous year, project reservations, tracking, and payments to aggregators will be maintained.

Non-Routine Events and Treatment

STEP 2. Once projects have been initiated, Recurve shall regularly conduct screening of all projects in the aggregators' portfolios for possible non-routine events in three dimensions:

- Savings relative to comparison group-adjusted counterfactual consumption: Recalculate savings as a percentage of comparison group-adjusted counterfactual consumption for all participating projects on a quarterly basis. Flag any projects with savings exceeding ±50 percent annual savings.
- Deterioration in normalization model goodness of fit: Fit CalTRACK model to the Year 1 post-retrofit consumption data and recalculate CVRMSE, prior to a savings claim. If the Year 1 model has a CVRMSE of greater than 1.0, then the Project will be flagged as a non-routine event.

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- Significant difference from comparison group: If a treatment site does not have a sufficient comparison group to adjust for exogenous impacts, the Project will be flagged as a non-routine event.

STEP 3 & 4. If it has been determined that metered savings results are invalid, for instance due to the project being flagged as a savings outlier, insufficient reporting period data, or poor (CVRMSE > 1) reporting period CalTRACK daily model fit, the project savings will be estimated using a consistent adjustment applied uniformly to all disqualified projects. Assigned savings values will be based on the average savings or realization rate for the other qualified projects in the aggregators' portfolio.[50] Assigned savings for disqualified projects will be applied on a monthly basis and paid out on an ongoing quarterly basis by applying the current aggregator portfolio realization rate at the time of savings calculation. Aggregators whose entire portfolios are subject to an NRE, or assigned savings, will not receive ongoing assigned savings but rather a single payment at the end of the project's 12-month performance period; at that time, the assigned savings payment will be calculated by applying the Program Portfolio's current realization rate to the projects forecasted savings.

Aggregator Self-Reported NRE Notification

The Aggregator is required to notify the Lead Implementer of any situation in which a building enrolled in the Program has a non-program related material change in energy usage, or an NRE. Examples of NREs may include material changes in the following:

- Changes to building size;
- Additions of heating and cooling loads in the building;
- Addition of load such as computers or data processing equipment;
- Longer, or shorter operating hours, or material schedule changes; and/or
- Changes in building usage such as converting lab space to office space.

The Aggregator shall notify the Lead Implementer of NREs as soon as supporting information can be assembled and submitted. For all NREs, Aggregators shall submit to the Lead Implementer a detailed narrative describing the changes that occurred and the duration of the NRE including the following:

- Describe the change and its impact on energy usage;
- Identify the date the change occurred and expected length;
- Describe the systems that are likely impacted by the change;
- If changing equipment, either adding or subtracting, note the load (kW) of the existing equipment, and the new equipment, if appropriate.

[50] If an entire aggregator's portfolio is subject to an NRE, the aggregator's portfolio will receive the program's realization rate at the time of Program Portfolio maturity and the aggregator's participation will be reviewed.

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Estimated Savings = Realization Rate * Predicted Annual Project Savings

Where:

Estimated Savings = Annual non-routine-adjusted savings to calculate performance payments

Realization Rate = Aggregators total portfolio actual savings divided by total predicted portfolio savings;

$$\sum S / \sum P$$

Where:

S = Actual annual project savings in kWh or therms as calculated in Recurve platform

P = Predicted annual project savings in kWh or therms as reported by the Aggregator during Project submission to Recurve, aligned with the load shape forecasted for the purposes of determining project value.

This standard approach for the identification and treatment of non-routine events will be included as part of an aggregator's contract with Recurve. Systematic and predictable treatment of non-routine events tied to overall portfolio performance to manage risk comports with the Population-NMEC expectation of consistent calculations and treatment of projects across the portfolio. Any custom calculations for non-routine adjustments will be reviewed and approved in collaboration with the market sponsor for this program.

4. Hourly Load Shape and Peak Impact Calculations

CalTRACK V.2.0 hourly methods quantify savings for each hour in the reporting period. The GRIDmeter methods adjust these results for exogenous factors also at an hourly level. The hourly tracking of savings enables valuation of savings and marginal greenhouse gas (GHG) impacts.[51,52] For gas savings, if applicable, the CalTRACK V.2.0 Daily methods will

[51] A careful study of the CPUC's 2019 Avoided Cost Calculator reveals that over-generation and renewables curtailment is forecast for 25% of all hours in 2025 with the majority of these hours occurring during mid-day time periods and mild shoulder months.

[52] Golden, M., A. Scheer and C. Best. 2019. "*Decarbonization of Electricity Requires Market-Based Demand Flexibility*". The Electricity Journal. Vol 32. Issue 7 (August-September).

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be used and comparison adjustments and non-routine event tracking and adjustments will be made as described above.[53]

At this time, actual load shape impacts cannot be reported to the CPUC via CEDARS - Cost-Effectiveness Tool.[54] Deemed load shapes or proportional deemed load shapes are used to mirror the impacts of meter-based programs. For the Demand FLEXmarket, actual load shapes will be submitted through FLEXvalue. If actual load shapes are not accepted, a proportional multi-deemed load shape that is the closest reflection of the actual load shape achieved by the program may be used.

Peak impact calculations will leverage the hourly data to estimate the peak impacts achieved by the program during the peak periods defined in the October 11, 2019, DEER Resolution.[55] Timing of peak load is 4:00 p.m. to 9:00 p.m over a three consecutive weekday "heatwave" that occurs between June 1st and September 30th, does not include weekends or holidays, has the highest value for the sum of the average temperature over the three-day period, plus the average temperature from noon to 6 p.m. over the three day period, plus the peak temperature over the three-day period.

5. Data Collection

Data Security

Data security and customer privacy are paramount for effective, trustworthy customer programs. Recurve has implemented rigorous data security procedures and protocols at every step of data transfer, analysis, and reporting for handling AMI data and customer information. Recurve data tools and systems are built on modern industry standards and have undergone the auditing process to achieve SOC 2 compliance, which ensures best in class security and data management practices that meet the required "trust service principles" as defined by the AICPA. Security agreements with PCE and aggregators are available to the CPUC upon request.

Data Collection

The availability and quality of hourly consumption data for proper baselines is fundamental to identifying and qualifying NMEC program participants. CalTRACK details necessary data and sufficiency requirements for the establishment of appropriate baselines in Section 2. Data Management.

Aggregators will collect the site and meter information required for proper weather station matching project start and end dates needed for the identification of baseline,

[53] Gas data is generally available but hourly gas data is only available in part of the state.

[54] Recurve is hopeful functionality to submit actual load shapes will be available by the time savings can be reported for this program.

[55] http://docs.cpuc.ca.gov/publisheddocs/published/g000/m232/k459/232459122.pdf

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blackout, and reporting periods to meet the CalTRACK with the specification. Aggregators will collect relevant project and site metadata as specified in the aggregator's Flexibility Purchase Agreement. These data will include participant, location, meter id, date of installation, technology installed, and project costs. Any or all of these data will be utilized for more granular cohort (program subgroup) tracking and management and could be used to facilitate future EM&V studies.

For developing a comparison group, a sample of non-participant customers will be identified to perform accurate matching and comprise a reliable comparison group from non-participant data.

Data must be delivered in a clean readable format. Any duplicated data will be thrown out. Any overlaps in meter datasets will resolve to the dataset with the largest time period.

6. Monitoring and Documentation QA/QC Over Reporting Period

The CalTRACK modeling process specifies quality assurance and quality control procedures. Recurve will maintain quality data management and monitoring throughout the program life to ensure the reporting period results generate an accurate representation of the savings impacts. As part of this M&V plan, Recurve will provide a fully auditable and verifiable record to track each meter that is modeled and its fate over the course of the program.

7. M&V Related Plans for Project Types, Design, Payments, Measures and Cost Effectiveness

Permissible Project Types

As noted in the implementation plan, the Demand FLEXmarket may consist of several aggregators targeting a range of measures. For any given aggregator, participating customers are reasonably expected to have similar types of equipment and drivers in energy consumption. During the aggregator qualification process, Recurve will ensure that factors that impact consumption and energy savings will be relatively similar across the population.

In addition, the Demand FLEXmarket will leverage insights from multiple recent studies[56,57,58,59] which have shown that recruiting customers based on insights from AMI data analytics can effectively identify stranded potential and substantially enhance the metered savings and cost-effectiveness of energy efficiency programs. These analyses

[56] *Customer Targeting for Residential Energy Efficiency Programs: Enhancing Electricity Savings at the Meter*, A.M. Scheer, S. Borgeson, K. Rosendo, 2017

[57] *Energy Efficiency Program Targeting: Using AMI Data Analysis to Improve At-the-Meter Savings for Small and Medium Businesses*, S. Borgeson, A.M. Scheer, R. Kasman et. al. 2018

[58] *Customer Targeting via Usage Data Analytics to Enhance Metered Savings*, 2018 ACEEE Summer Study, A.M. Scheer, S. Borgeson, R. Kasman et al.

[59] PG&E's Energy Efficiency Business Plan 2018 – 2025, Residential Appendix D

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will be conducted by Recurve in partnership with qualified aggregators to find populations that may have similar characteristics of usage prior to intervention and that will be predictive of impacts of the intervention.

8. Program Design Criteria and Fractional Savings Uncertainty (FSU)

Program Design Criteria

The Demand FLEXmarket has been designed to meet the CPUC criteria for population-level NMEC programs. Recurve is currently forecasting over 5,000 projects in PCE's service area that encompass lighting, HVAC, water heating, building envelope, controls, and refrigeration. The program will be measuring FSU for this program portfolio, and based on past program experience with this number of projects and savings depth, the program does not foresee any issue in remaining below the 25% guideline for Population NMEC.

Fractional Savings Uncertainty

Calculation of FSU used in this plan complies with industry best practice and specifically reflects Section 4.3 of the CalTRACK methods. The two key metrics for uncertainty are the Coefficient of Variation of the Root Mean Square Error (CVRMSE) and Fractional Savings Uncertainty (FSU). The FSU depends on a number of interactive factors, several of which have non-linear dependencies. In general, driving deeper savings, recruiting customers with good model fit, and serving a large number of customers will improve FSU at a given confidence interval. FSU at an individual site level is defined by the following equation:

$$FSU_i = \frac{\Delta U_{save,Qi}}{U_{save,Qi}} = \frac{t(aM^2 + bM + d)CV(RMSE) * \sqrt{\frac{P}{P'}(1 + \frac{2}{P'})\frac{1}{Q}})}{F}$$

where

t is the t-statistic and a, b, and d are empirical coefficients described further in the online CalTRACK documentation

M is the number of months in the reporting period

Q is the number of periods in the reporting period (days or billing periods for example)

F is the savings fraction defined as the savings divided by the counterfactual baseline usage

CVRMSE is the coefficient of variation of the root-mean-squared error and provides a measurement of the quality of model fit (lower CVRMSE equates to better model fit) and is defined as follows:

$$CV(RMSE) = \frac{\sqrt{\frac{\sum_{p=1}^{P}(U_p - \hat{U}_p)^2}{P-c}}}{\overline{U}}$$

where

U_P is the total energy use during period P

Uhat is the predicted energy use during period p

Ubar is the mean energy use during the baseline period

P is the total number of periods

c is the number of explanatory variables in the model

Fractional savings uncertainty at an aggregated (portfolio) level is calculated via the following equation:

$$FSU_{portfolio} = \frac{\sqrt{\sum_{i=1}^{N}(\Delta U_{save,Qi})^2}}{\sum_{i=1}^{N} U_{save,Qi}}$$

For the Demand FLEXmarket, the CalTRACK methods described above were applied to a sample of buildings similar to those that are likely to be targeted as part of the program. Assumptions about the forecasted average savings and savings depth as a percentage of the baseline were derived from past project experience and combinations of DEER technology savings and load shapes (lighting, HVAC, water heating, building envelope, controls, and refrigeration) that will be deployed as part of the program. Recurve has estimated the rough number of projects needed to capture savings under projected budgets; and discrete business plans from Aggregators will further refine these estimates.

The CalTRACK methods model each site individually before aggregating to the portfolio level with savings uncertainty reported as a first-class output. Savings uncertainty, as opposed to savings depth, is the ultimate parameter of concern (e.g. savings of 4+/-1% may be acceptable, but savings of 10+/-3% may be unacceptable). Aggregating results to a portfolio mitigates issues related to model noise and increases confidence in savings estimates. An extensive discussion of model uncertainty is included in CalTRACK documentation and was leveraged for this analysis.[60]

[60] See CalTRACK issue: https://github.com/energy-market-methods/caltrack/issues/71.

Based on assumptions, if the Demand FLEXmarket is able to achieve the forecasted installations of the planned technologies, and achieve the forecasted average savings, FSU will fall well within the bounds of the CPUC requirements. Recurve expects to achieve the CPUC's stated desired FSU of +/- 25% at the 90% confidence level by recruiting a sufficient number of projects, supporting aggregators in recruiting customers with a reasonable CVRMSE (generally less than 0.75), monitoring savings for a sufficient number of days (FSU will be calculated with the CalTRACK daily model), and delivering a reasonable savings depth measured from existing conditions baseline.

Payments and Incentives

Aggregators are eligible for an upfront incentive payment of 20% of the forecasted aggregator incentive for installed commercial projects[61] and 50% of the forecasted grid value for installed residential projects. The remaining incentive depends on the performance of their portfolio. There are no predetermined customer payments or rebates set by the program- customer rebates are determined by participating aggregators, and are expected to be variable depending on business models, cost of service etc. Aggregators will be required to report any incentive payments passed on to the customer. This payment structure is designed to incentivize maximum performance around net benefits, as well as peak and net-peak impacts. The incentive payment is designed to pay directly on the value of delivered metered net savings.

In calculating the net benefits (avoided costs), Recurve will take the full measured 8,760 electric savings resource curve and multiply by the appropriate hourly avoided cost profile of the CPUC's Electric Avoided Cost Calculator (ACC) for the duration of the Effective Useful Life of the measure.

However, for the purposes of program payment, a smoothing process for generation capacity, transmission, and distribution values will be applied as follows:

- Evenly distribute the average gross peak values across gross peak hours (4-7 PM)
- Evenly distribute the average net peak values across net peak hours (7-9 PM)
- Evenly distribute the average off-peak values across the off-peak hours.

The purpose of this smoothing process is to account for sporadic capacity peaks distributed throughout the original avoided cost curve. As illustrated in the figure below, the majority of capacity value is concentrated in a small number of days throughout the year. While this may be logical to facilitate simulations, it creates enormous risk to aggregators and creates the potential for gaming. Since actual critical peak demand days are unknown ahead of time, the programmatic approach is to take the gross and net peak capacity value and distribute it evenly across gross and net peak hours. This provides a more consistent price curve and value signal for program participants to plan

[61] Upfront incentives are capped at $40,000. An aggregator with a project with a forecasted value of greater than $200,000 must submit the project with ICP certification to receive an upfront incentive beyond $40,000.

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around while staying anchored within the original avoided cost curve. Throughout this smoothing process, the "total 8760 value" of the avoided cost curve is kept completely consistent.

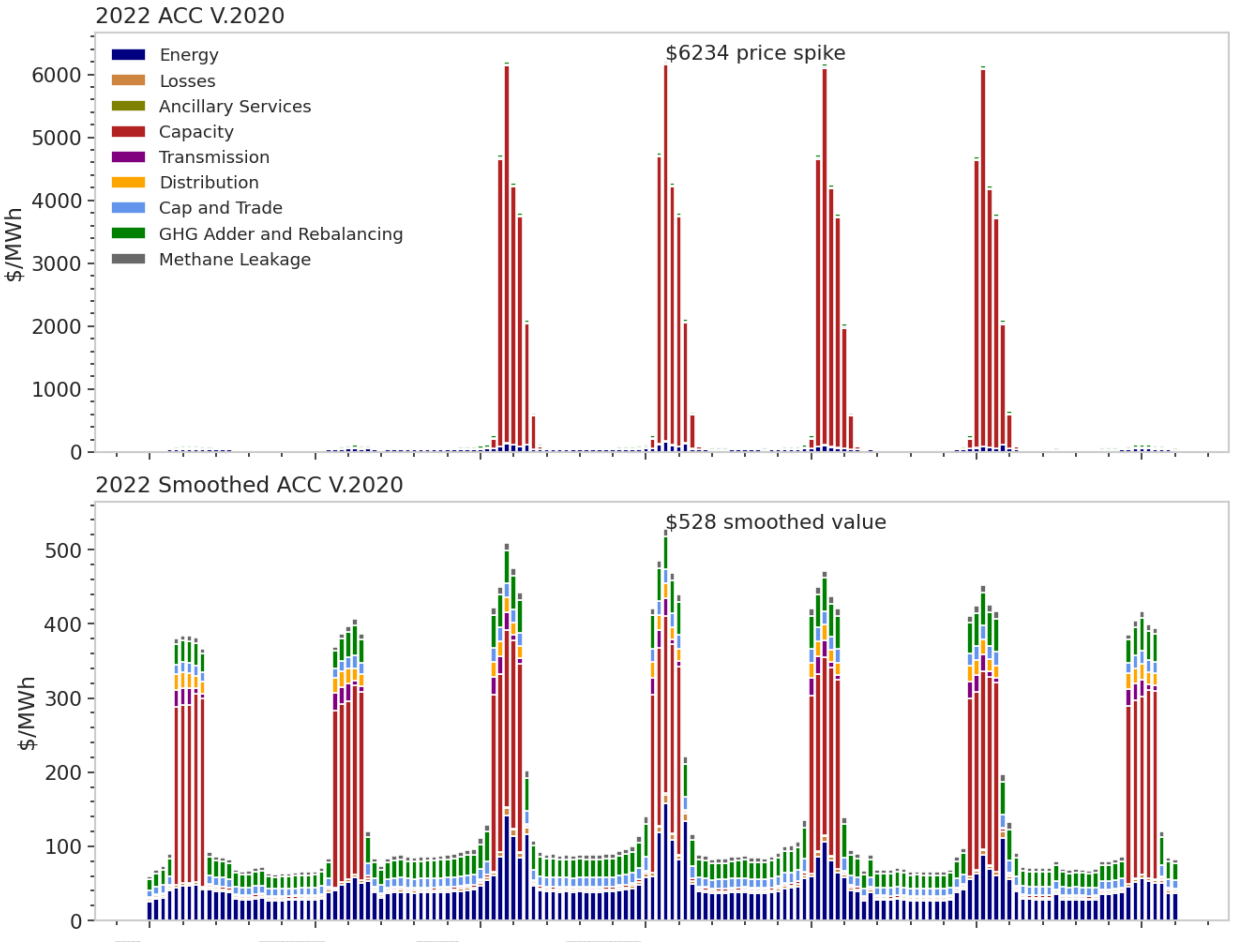


Figure 4: Smoothing Capacity Value

The gas benefits will be paid based on the lifetime therm savings based on the measured annual savings, effective useful life, and the forecasted value per therm. The forecasted therms value is derived from the CPUC's Gas Avoided Cost Calculator.

For this program, the hourly avoided cost profile is adjusted as described below to provide a more accurate TSB value where measured savings are aligned to the correct Hour of Year on the ACC.

The ACC used with FLEXValue tend to align with weekdays of all years such that the first day of each year is the same day. For example, in the 2020 California Avoided Cost Calculator, January 1, 2020 was a Wednesday. This means that all subsequent years in the ACC are all modeled as if they start on a Wednesday.

In measured savings, we have real savings that occur on a real date (for example January 1st, 2021). To properly match the days of the week of the ACC to the actual day savings occurred, the ACC is shifted to the hour of year based on the year that the savings were measured, depicted below.

Year	First Day of Year	First Day of Year to Align To	Hour of Year Shift
2021	Friday	Wednesday	-48

Hour of Year (Real Life)	Year (Real Life)	Hour of Year Shift	Wednesday Aligned Hour of Year
0	2021	-48	8712
1	2021	-48	8713
2	2021	-48	8714
3	2021	-48	8715
4	2021	-48	8716
5	2021	-48	8717
...	...	...	...
8754	2021	-48	8706
8755	2021	-48	8707
8756	2021	-48	8708
8757	2021	-48	8709
8758	2021	-48	8710
8759	2021	-48	8711

Savings are essentially shifted 48 hours "backwards", wrapping around at the end of the year.

Most projects in the Commercial Efficiency Market are tracked across multiple calendar years. For example, a project that completed January 1, 2021 will have measured savings spanning both 2021 and 2022, but these years have different ACC Hour of Year shift requirements.

An illustration of this is below:

Year	First Day of Year	First Day of Year to Align To	Hour of Year Shift
2021	Friday	Wednesday	-48
2022	Saturday	Wednesday	-72

Hour of Year (Real Life)	Year (Real Life)	Hour of Year Shift	Wednesday Aligned Hour of Year
72	2021	-48	24
73	2021	-48	25
74	2021	-48	26
...	...	...	...
8736	2021	-48	8688
8737	2021	-48	8689
8738	2021	-48	8690
...	...	...	...
0	2022	-72	8688
1	2022	-72	8689
2	2022	-72	8690
...	...	...	...



Shifting across multiple years results in:

- 24 hours that are not assigned to any "Wednesday aligned" Hour of Year.
- 24 hours that are duplicative, assigned to the same "Wednesday aligned" Hour of Year.
- The gap/duplication comes from the delta between the hour of year shifts (i.e. 72-48=24)

Recurve's Metering+ software allows the duplicate/dropped assignments to happen, and after FLEXValue runs, it realigns the hourly value outputs back to the real life hour of years.

For duplicate hour of year assignments, we store savings for each real life hour such that we can disaagregate value back to real life hours after FLEXValue has ran.

PCE payments for this population-level program will be made based on payable savings determinations using NMEC methods described in the gross and net sections of this plan.

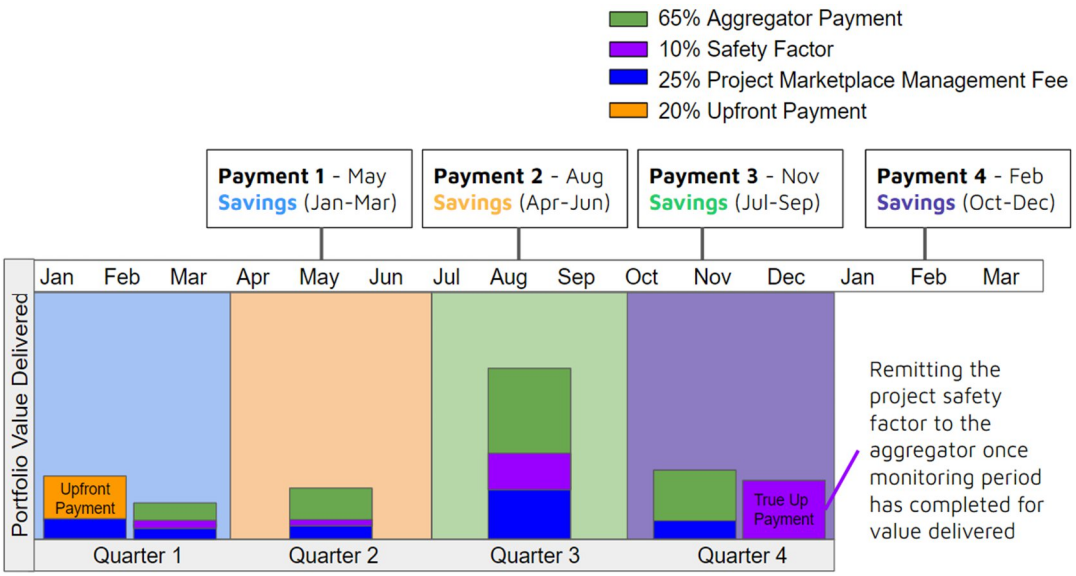
Payments for the program will be made quarterly during the 12-month measurement period for active projects in the aggregator portfolio. The quarterly measurement periods are fixed before program start, and aggregators will be paid based on portfolio savings for active projects during the measurement period.

The quarterly incentive payment is based on the total program value (adjusted avoided cost benefits as described above) net of market management costs and non-energy private investment. Marketplace management costs include general and administrative (G&A) overhead, direct implementation non-incentive (DINI), M&V, and marketing, education and outreach. These management costs account for 25% of the total program budget. Aggregators will be paid for their portfolio value achieved based on metered savings from active projects achieved during the most recent measurement quarter. The Aggregator is not eligible for a quarterly incentive payment if the net benefits from their portfolio does not exceed the upfront payments.Portfolios become "active for payment" after the value generated exceeds the upfront incentives paid and associated marketplace management costs. Payments will be made at fixed quarterly intervals established in the program manual and are based on each aggregator's project portfolio that is "active for payment". Payments will be made based on the latest data received at the time of measurement, and payment for missing time periods of data will move to the following payment cycle. Once data is received for the end of the monitoring of the market , no further updates to measurements will occur.

In addition, a Safety Factor is withheld each quarter to provide a buffer in regard to seasonality and/or portfolio performance. As the portfolio completes the full 12 month measurement period, aggregators are compensated with a "true-up" payment in the following quarterly payment cycle that will release owed funds. The safety factor defaults at 10% of measured portfolio value. At the end of the portfolio year, each aggregators' Safety Factor will be re-evaluated based on the performance of their portfolio relative to their forecast (realization rate). A visualization of payment cadences and safety factor evaluation is shown in the figures below.

Commercial:

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Residential:

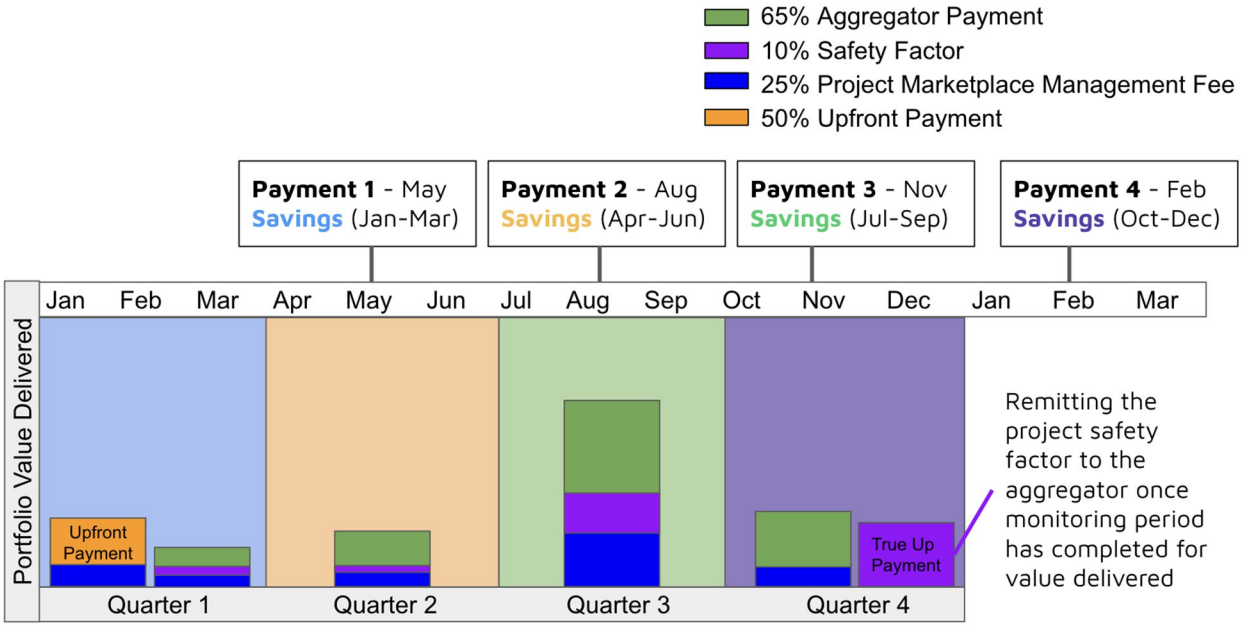


Figure 7: Aggregator Payments Based on Active Projects within the Measurement Period

Aggregators with realization rates less than 30% will be evaluated regarding their participation in the next year of the Market. This evaluation may impact the Safety Factor applied as well as the Aggregator's eligibility for Upfront Payments.

Recurve will document in an electronic, revenue-grade, auditable ledger the recommended payments to support aggregator invoices to PCE after each quarterly measurement period. The electronic ledger will track all stages of an NMEC project in a program, including non-routine adjustments. Invoice payment recommendations will be based on CalTRACK payable savings results. Claimable results to the CPUC will be derived from the ledger for compliance with reporting requirements.

Payments for eligible projects involving solar in the baseline or reporting year will only be eligible for an annual payment, further described in the eligibility section below.

Qualifying Measures

The Demand FLEXmarket will promote a wide range of measures including, but is not limited to, the following interventions: lighting, HVAC, water heating, building envelope, refrigeration, and controls-based technologies. The types of measures that are installed will be documented in the course of program deployment and be included in the metadata (see Data Collection section).

Projects with a primary anchor measure of controls or behavioral interventions will default to a 1-year EUL (with an option for re-enrollment) unless otherwise supported with documentation such as work papers or eTRM data (see the "Effective Useful Life" section of the M&V plan for more detail). Solar PV and other electricity generation are not eligible for incentives from the Demand FLEXmarket.

Cost Effectiveness

The Demand FLEXmarket was designed for compliance with all of the Commission's current cost-effectiveness rules. All data needed to calculate cost-effectiveness for this program are included in this plan.

9. Eligibility Criteria

See Section b. Calculation of Gross and Net Savings/Eligibility Criteria and Screening

Recurve will utilize CalTRACK modeling to qualify customers based on data sufficiency and baseline model fit in addition to other usage characteristics.[62]

General customer eligibility requirements include but are not limited to:

- Commercial site or Residential customer (single-family);
- Project site must be located in PCE's service area;[63]
- Unbundled (i.e., receiving electric generation service from PCE) customer;

[62] Project qualifications based on data sufficiency and model fit may only apply to the type of savings being measured (electric or gas).
[63] https://www.PCEcleanenergy.org/member-communities/

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- Site is not currently participating, and has not participated in the past 12 months, in a CPUC ratepayer-funded energy efficiency program;
- 12 consecutive months of energy usage data is available;
- Model fit needs to be < 1.0 Coefficient of the Variation of the Root Mean Square Error (CVRMSE) and site must pass CalTRACK data sufficiency analysis (Recurve will conduct analysis at intake);
- If the customer has an onsite solar system, installation of the system must have been completed at least 12 months prior to the EE intervention.
- Projects can only enroll in the Market if they were installed and completed following the Program's elect to administer date.
- Qualifying residential projects subject to cost-effectiveness requirements set forth by the Program
- Commercial and Residential projects must be installed and project completion paperwork submitted to Recurve by no later than April 30, 2025

Aggregators will verify with customers that they do not plan to install major new load additions or subtractions, solar PV, or EV charging in the reporting year (post-program implementation). In addition, Recurve will assess if a site has participated in another energy efficiency program, installed an EV charging system, or installed solar PV or battery storage within the baseline year. Past program participation data will be used as received to ensure that savings claims will not be duplicated for measures by cross-referencing known participants in other programs and not allowing them to participate. If data is not provided in a timely fashion and sites are enrolled that have participated within the previous year, project reservations, tracking, and payments to aggregators will be maintained.

Customer sites with existing solar installations within the baseline period are ineligible for participation in the Market due to solar generation's temperature independence. However, the Market will allow aggregators to enroll sites in the program at a future date to be announced with 30 days of notice to aggregators, and provided certain minimum criteria are met, including but not exclusive to:

1. Aggregator will take the risk of site eligibility until after the project is paid and the impacts analyzed.
2. Aggregator must provide submeter from the PV system for the baseline and reporting years in the format the Market specifies to assess impacts.
3. The Demand FLEXmarket aggregator completes the onboarding process for submeter data submittal, demonstrating ability to provide the Demand FLEXmarket program with submeter data required in the specified format. This must be completed before any sites with solar installations are enrolled.

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Sites with PV generation will only be eligible for an annual payment within four months of final data receipt from both the meter data from PCE and the PV submeter data from the Aggregator in the specified format.

In addition, solar PV and other electricity generation are not eligible for incentives from the Demand FLEXmarket. If a PV system or other generation capacity is installed/activated as part of an on-site intervention, the aggregator must adhere to the conditions listed above and must include a peak load reduction component, such as battery storage or efficiency upgrades.

Tracking grid impacts from a battery-system submeter, based on the charge/discharge of the system is currently ineligible for participation in the Market. However, given the state of emergency, the Market will allow aggregators to enroll battery submeters in the program at a future date to be announced with 30 days of notice to aggregators, and provided minimum criteria are met, including but not exclusive to:

1. Storage system must have been installed after January 1st, 2018
2. Aggregator must provide submeter data from the storage in the format the Market specifies for the period required by the Market administrator.
3. Aggregator completes the onboarding process for submeter data submittal, demonstrating ability to provide the program with submeter data required in the specified format. This must be completed before any sites with storage installations are enrolled.

Sites tracking against the charge/discharge of the battery system as opposed to the whole-building analysis of CalTRACK will only eligible for an annual payment after final data receipt of both the meter data from MCE and the battery submeter data from the aggregator in the specified format.

Projects consisting solely of 1-year (or less) EUL controls or behavioral measures will be eligible to re-enroll in the program for up to 2 additional years while utilizing the counterfactual model developed upon the date of initial enrollment and has otherwise maintained eligibility and data sufficiency status. The number of years for re-enrollment while utilizing the existing counterfactual model may be expanded in future plans.

10. Effective Useful Life (EUL)

The FLEXmarket includes, but is not limited to, the following interventions: lighting, HVAC, water heating, building envelope, refrigeration, and controls-based technologies. The measures listed in the following table will be utilized to assign EUL values to primary and secondary measures for each project as applicable. The EULs listed combined with the default DEER loadshapes (based on past program claims) will be used to calculate the Forecasted Program Value for submitted interventions and for savings claims. The program is technology agnostic and a wide array of measures may be installed to meet

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the savings and demand impact targets. Primary and secondary anchor measures are identified and appropriate EULs will be applied as part of the final claimable savings calculations. This table is the list of EULs and savings load shapes that are used for primary and secondary anchor measures for this program. This table is based on best available research from eTRM measure packages and 2020 program claims. Default load shapes are used for forecasting purposes only. The tables below shall be referenced for all primary and secondary measure EULs. If the proposed primary or secondary measure does not conform into one of the categories listed, then a justification for another EUL or Load Shapes may be submitted to the program for review in the form of CPUC approved work papers or eTRM data. All EULs will be reviewed and confirmed by Recurve during project enrollment.

Technology / Intervention	Sector	Effective Useful Life	Default DEER Load Shape for Forecasting
Lighting	Com	12	DEER: NonRes_Indoor_CFL_Ltg
HVAC Retrofit	Com	15	DEER: NonRes_HVAC_Split_Package_AC
Heat Pump Retrofit	Com	15	DEER: NonRes_HVAC_Split_Package_HP
HVAC Maintenance	Com	3	DEER:HVAC_Split-Package_AC
Chillers	Com	20	DEER:NonRes_HVAC_Chillers
Refrigeration	Com	12	DEER: NonRes_HVAC_Chillers
Building Envelope	Com	20	DEER:NonRes_HVAC_Split_Package_AC
Pumps/Motors/Drives	Com	15	DEER: NonRes_Indoor_CFL_Ltg
Storage Water Heater	Com	15	DEER: NonRes_Indoor_CFL_Ltg
Heat Pump Water Heater	Com	10	DEER: NonRes_Indoor_CFL_Ltg
Controls or Behavior		Default is 1-year EUL unless otherwise supported through	By default match the

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Based Interventions (Including Storage)	Com	work papers or eTRM data and approved by market sponsor. (Eligible for re-enrollment)	anchor measure load shape that controls are influencing.
Lighting	Res	12	DEER:Res_Indoor_CFL_Ltg
HVAC Retrofit	Res	15	DEER:Res_HVAC_Eff_AC
Heat Pump Retrofit	Res	15	DEER:Res_HVAC_Eff_HP
HVAC Maintenance	Res	3	DEER:Res_HVAC_Eff_AC
Refrigeration	Res	12	DEER:Res_Indoor_CFL_Ltg
Building Envelope	Res	20	DEER:Res_BldgShell_Ins
Pumps/Motors/Drives	Res	10	DEER:Res_Indoor_CFL_Ltg
Smart Thermostat (New Install Only)	Res	9	DEER:Res_HVAC_Eff_AC
Heat Pump Water Heater	Res	10	DEER:Res_HVAC_Eff_HP
Controls or Behavior Based Interventions (Including Storage)	Res	Default is 1-year EUL unless otherwise supported through work papers or eTRM data and approved by market sponsor. (Eligible for re-enrollment)	N/A

In the case of an add-on equipment measure, the guidelines outlined in Resolution E-4818 will be followed. Retrofit add-on equipment measures will have an EUL that is "equal to the lower of the RUL of the modified system or equipment or the EUL of the add-on component."[64] In such cases, the program will apply the ⅓ rule for the EUL of the parent system as described in the EE policy manual.[65] The program will require aggregators to attest if their measure is an add-on to an existing system and will work to provide consistent messaging on which measures are likely to be considered add-ons: VFDs and VSDs being an example measure type.

[64] https://www.caetrm.com/media/reference-documents/CPUC_Resolution_E-4807_December_2016.PDF
[65] https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/e/6442465683-eepolicymanualrevised-march-20-2020-b.pdf

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In preparing savings claims, this program will develop combined measure claims In accordance with the CPUC's guidance on "Weighted Average Expected Useful Life/Net to Gross Method.[66] Since the outputs of the calculator are dependent on the savings achieved, the projected EUL for this program is not yet known.

11. Methods, Payment Terms, and Risk

Methods for Payable and Claimable Savings

See section a. Analytical Methods and Calculation Software Selection and section b. Calculation of Gross and Net Savings for detail on methods and the expected difference between payable and claimable savings.

Payment Terms

Recurve and qualified aggregators will establish the payment terms in their contract based on the net metered savings in the portfolio and corresponding project EULs, net of marketplace management costs. Value is directly related to the benefit stream in the adjusted hourly avoided cost calculator for the service area and climate zone.

These payment terms are designed in accordance with the NMEC Rulebook 2.0 guidance and all known Commission directives related to terms and conditions. Compliance on payment terms for this M&V plan is described in *Section f. Payments and Incentives.*

Risk Mitigation

The Demand FLEXmarket has a fundamentally different risk profile from the rest of the energy efficiency portfolio. The Commission noted the limited risk to ratepayers of this program model in D.21-12-011 in their justification to suspend the cost-effectiveness rules:

> *". . . this type of program is very low risk to ratepayers regardless of cost-effectiveness score, because actual energy savings are measures based on NMEC methods, payments to aggregators are made based on performance, and spending is limited by the TSB actually achieved. Therefore, it is reasonable to suspend cost-effectiveness rules for this purpose for this unforeseen emergency situation in response to the Governor's Proclamation."* [67]

One-hundred percent of the payment to the aggregator is based on the annual net savings achieved at the meter. The aggregator takes on the upfront risk, and arranges financing, to deliver impacts. This risk is within their power to mitigate with successful program implementation, innovative financing, insurance, and with general support provided by the program administrator. The Demand FLEXmarket represents minimal risk

[66] Rolling Portfolio Program Guidance; Weighted Average Expected Useful Life/Net to Gross Method. Excel Spreadsheet titled "Combining_Measures_Claims-DRAFT". The spreadsheet calculator has not been updated to reflect new DEER values; so can only be used with respect to the proposed method. https://www.cpuc.ca.gov/General.aspx?id=6442456320

[67] See D.21-12-011 at p. 26

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for PCE or ratepayers, especially when compared to deemed program models given that the program administrator will only pay for savings achieved at the meter and by design will meet minimum cost effectiveness criteria.

The Demand FLEXmarket will further mitigate risk of settlement dispute by using a consistent, transparent means of tracking the impacts for settling payable savings as described in this M&V plan. Payment to the aggregator is completely based on savings delivered at the meter and will be made on a quarterly basis.

The Demand FLEXmarket is designed to minimize risk to program administrators, moderate risk for project developers with a portfolio pricing scheme, and decouple interest in the savings from the entity calculating the savings. PCE makes incremental payments by portfolio rather than committing to full project or program costs. The majority of payments to external entities are dependent on identifying projects and the performance of those projects. In the worst-case scenario: PCE pays its administrative cost (internal and/or external staff); no projects come forward, and no savings are achieved, which would still represent a very small portion of the total allocated budget.

An easy way to visualize the risk is looking at a three point table as has been done in other papers on understanding risk in pay for performance programs:[68]

<table>
<tr><td colspan="2">(Market Sponsor) PCE / RATEPAYERS

Upfront: Administrative cost
If projects materialize: Portion of the forecasted benefits for monitoring and tracking
If savings materialize: Payment for kWh or therms, net of marketplace management costs</td></tr>
<tr><td>CUSTOMERS / PARTICIPANTS

Upfront: Contribution to project

If savings materialize: Enough savings to generate value for the customer in addition to other value provided by the project.</td><td>PROJECT DEVELOPERS / AGGREGATORS

Upfront: Forecasting, business plans, customer recruitment, project development, financing, etc.

If projects materialize: Payment needs to be enough to cover costs and generate margin.

If savings materialize: Ineligibility risk will fall on developers (manage risk with portfolio), that installations will deliver expected savings and load shapes.</td></tr>
</table>

[68] Where's the Risk with Pay for Performance? Rob Hansen, ACEEE paper 2018

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12. To Code Savings Compliance

The Demand FLEXmarket is targeting to-code savings as described in the implementation plan. Compliance with D. 17-11-006 Ordering Paragraph 2 is met in Section 6 of the implementation plan.

The M&V plan described herein will quantify the savings achieved compared to an existing conditions baseline as authorized in AB802, SB350, and detailed in the methods sections of this M&V plan.

13. Bid M&V Plan

The Demand FLEXmarket will not conduct a bidding process for this program. It will utilize an aggregator qualification approach that reduces barriers to entry. Bid M&V plans will not exist.

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ATTACHMENT A. Tools, Methods, Analytical Approaches and Software Criteria

In the NMEC Rulebook V. 2.0 (p. 17) the CPUC outlines specific criteria for the approaches and calculation software allowable and preferable for NMEC population-level M&V. The following table itemizes the criteria in the left hand column and how the proposed tools, methods, analytical approaches, and calculation software in this M&V plan meet these criteria.

Tools, Methods, Analytical Approaches and Calculation Software - CPUC Criteria	Compliance demonstrated in this M&V plan
Savings Calculations: All analytical methods, including tools, algorithms and software used in savings and incentive or compensation payment calculations, must be made available to Commission staff and its consultants upon request.	The proposed analytical methods (FLEXmeter) (CalTRACK) and calculation software (OpenEEmeter) are open source and publicly available. Comparison group methods (GRIDMeter) are publicly available. A certificate of compliance with the CalTRACK methods will be provided to the PA, CPUC, and Evaluators. All data will be readily accessible and made available upon request.
Measurement Period: Savings determinations must be made by comparing at least 12 months of post-intervention energy consumption to at least 12 months of pre-intervention energy consumption.	CalTRACK data handling (see Section 2 of the technical specification) will be followed which screens for pre-intervention baseline data criteria: "2.2.1.1. Consumption and temperature data should be sufficient to allow for a 365-day baseline period" Interim savings determinations will be

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	assessed on an ongoing basis but reported annually and based on the Commission guidelines.
Transparency: Data, methods and calculations must be made available to the PAs well as the Commission and its impact evaluators.	The proposed analytical methods (FLEXmeter) (CalTRACK) (GRIDMeter) and calculation software (OpenEEmeter) are open source and publicly available. Certification of compliance will be provided to PAs, the CPUC and impact evaluators in addition to access to all data methods and calculations.
Documentation and Replicability: The methods used to calculate savings for NMEC programs must be documented in the program-level M&V Plan sufficiently such that savings calculations are able to be replicated by the PAs as well as the Commission and its impact evaluators. Upon request, the underlying participant consumption data and other data inputs must be made available to the PAs well as the Commission and its impact evaluators such that savings calculations can be replicated to reach the same result.	The methods used to calculate savings are referenced in the program-level M&V plan and the details for savings calculation, including data handling, and weather station selection are documented in the CalTRACK 2.0 Technical Specification. Comparison group methods for quantifying net impacts to the grid are documented in GRIDMeter. The OpenEEmeter is a Python code base which enables replication of the CalTRACK methods. The FLEXmeter methods and code base documents demand response savings calculations. All data will be made available. In addition, documentation of data handling, and calculations will be documented and provided to PA, CPUC

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	and evaluators to quickly isolate any differences in results using the same data.
Consistent, Pre-Set Method: For Population-level NMEC programs, the specific measurement method(s) and calculation software must be determined before the program begins and applied uniformly to all sites in the program.	The FLEXmeter, CalTRACK, and GRIDMeter methods and OpenEEmeter code base have been pre-determined for this program; and will be applied uniformly to all sites in the program. Certification of compliance and documentation of data handling will validate uniform application to all sites in the program.

DRAFT

PENINSULA CLEAN ENERGY

PENINSULA CLEAN ENERGY AUTHORITY
JPA Board Correspondence

DATE: April 14, 2025
MEETING DATE: April 24, 2025
VOTE REQUIRED: None

TO: Honorable Peninsula Clean Energy Authority Board of Directors

FROM: Rafael Reyes, Senior Director of Energy Programs; Jana Kopyciok-Lande, Associate Director of Innovation Strategy; and Peter Levitt, Senior Manager of Distributed Energy Programs

SUBJECT: Discussion of the Distributed Energy Resources Framework 2025 - 2030 (Discussion)

RECOMMENDATION

Information and discussion only

BACKGROUND

Peninsula Clean Energy's mission is to reduce greenhouse gas emissions by expanding access to sustainable and affordable energy solutions. In 2018, PCE initiated community programs, which have been developed within three major pillars: Building decarbonization, Transportation decarbonization and Distributed Resources.

In September 2021, the Board adopted a new aspirational target supporting the region in reaching 100% decarbonization in buildings and transportation by 2035 and directed staff to analyze the feasibility of that target and return with an assessment and plan. The detailed analysis was delivered to the Board in September 2022 and assessed current market conditions, funding and financing availability, economics, and policy status. The plan also provided guidance on strategies to deliver significant emissions reductions within a scope that the agency is well positioned to affect.

The core strategy was defined as follows: To decarbonize buildings and transportation, align energy use with renewables, and deliver community benefits in segments PCE is best positioned to influence - progressively developing and adapting programs that evolve customer preference, innovation, and policy. In addition, to demonstrate scalable, sustainable business models and mobilize market forces state-wide. PCE has developed a portfolio of decarbonization programs aligned with the plan including reach codes, existing building decarbonization focused primarily on the residential sector, and transportation programs focused on private vehicles (EVs, ebikes, EV charging), with significant elements aimed at underserved communities. PCE programs are setting critical benchmarks for the state including:

1. **Building codes** for clean buildings and comprehensive EV readiness in multi-family buildings: Initiated in 2019, the reach code work of local governments with PCE technical assistance has played a major role in state building codes. CEC has recently reported that 80% of new home construction is now all-electric.
2. **Cost-effective upgrades**: PCE's "right-sizing" strategy to avoid unnecessary service upgrades is resulting in major cost avoidance and increased scale, including apartment EV charging at 80% lower cost than state and utility programs.
3. **Innovative strategies**: Including novel business models such as PCE power purchase agreements to deploy solar and storage systems on municipal facilities.

However, the Decarbonization Plan also identified major barriers in scaling decarbonization and a special need to develop new business models to achieve scalability. Subsequent to the decarbonization plan, the Board directed staff to develop a Distributed Energy Resources (DER) Plan to complement the Decarbonization Plan. As with the decarbonization programs, DER programs have been ongoing and details of the existing approach for those DER programs were presented to the Board as "Part 1" in May 2024. Staff will provide a brief recap of Part 1 during the Board meeting to set the stage for the rest of the Plan as outlined below.

The need for a more comprehensive plan on how to foster DER development in PCE's service area was also confirmed during the recent discussions for PCE's Strategic Plan for 2026 - 2030. As part of the new strategic planning process, PCE examined whether it should expand any existing, or develop any new, lines of business. All involved stakeholders (staff, Board and community partners) agreed that PCE should continue focusing on – and expand – its work on DERs. The following DER Strategic Policy was developed and presented to the Board in January 2025:

Over the next five years, PCE will prioritize efforts to accelerate the development of carbon-free distributed energy resources (DERs) in order to support further innovation and market transformation of distributed energy technologies, accelerate greenhouse gas (GHG) reductions, and provide customer and community resilience.

The following strategies were identified to foster the growth of DERs:

1. DER project development: For example, by growing PCE's Virtual Power Plant (VPP) or developing community solar + storage or microgrid projects
2. Financial services: increasing customer access to capital via scalable and sustainable business models
3. Consulting & technical assistance for both residential and commercial customers
4. Advocacy: drive policy to increase the value and reduce the hurdles of DER deployment

In the following section, staff outlines specific Goals for the next 5 years to address each of these strategies in more detail.

DISCUSSION

This DER Framework for 2025 – 2030 has three core components: (1) Align around an updated definition of DERs that reflects the breadth and scale of DERs in today's energy environment; (2) Provide context on the benefits, barriers and status of DERs in PCE's service area today and; (3) Outline specific Goals, including programmatic and policy initiatives, to foster DERs over the next 5 years.

DER Definitions

Historically, PCE has largely focused on DERs as behind-the-meter (BTM) distributed generation and storage technologies such as solar + storage. Moving forwards, PCE will use a broader definition of DERs that also includes local front-of-the- meter (FTM) resources, as well as non-generation BTM technologies that can shift load, such as electric vehicles (EVs), heat pump water heaters (HPWHs), smart control thermostats (SCT) and other energy efficiency measures (defined jointly as "**Load Flexibility Technologies** "). PCE will use the following definition of DERs moving forwards:

Distributed Energy Resources (DERs) *are assets on the distribution grid, either on the consumer's side of the energy meter (behind-the-meter (BTM)) or in front of the customer meter connected to the distribution grid (front- of-the-meter (FTM)). They can be used individually or in aggregate to provide value to the grid and individual customers. Importantly, PCE will focus on "clean" DERs, which do not emit greenhouse gases (GHGs) in their operations.*

PCE will aggregate BTM DERs under a so called "**Virtual Power Plant**" which is a collection of load flexibility technologies that are located at a customer site that can be aggregated together and flexibly managed to modify load in order to meet grid needs.

FTM DERs are typically 1-10 MW in size and are interconnected directly to the California Independent System Owner (CAISO) market. They do not offset customer load and are often referred to as the "missing middle" as they neither fall under the scope of work of the Power Resources team (who focuses on the procurement of large-scale, centralized FTM energy resources) nor the Energy Program team (who focus on BTM solutions at customer site). Examples of FTM DERs include community solar + storage facilities and multi-customer, community-scale microgrids.

Context: Status, Benefits and Barriers

To establish a baseline for its future work on DERs, PCE staff analyzed the **status** of DERs in its service area, as well as the associated benefits and barriers. PCE's customers have one of the highest adoption rates of BTM DERs in the United States. There are roughly 40,000 solar systems, 6,500 storage systems[1], 60,000 zero emission vehicles (ZEVs)[2], 440 HPWHs and 1,500 heat pump HVAC systems[3] in PCE's service area. Unfortunately, the same success has not been seen for FTM DERs to date. Over the past 20 years, only 26 MW of FTM DERs have been interconnected into PG&E's distribution system in San Mateo and Merced counties. 433 MW have been withdrawn, which reflects the large challenges facing these types of resources. 126 MW are currently in project development.[4]

DERs provide **benefits** to customers, the load serving entity (LSE) and the grid and society at large. For customers, DERs can reduce energy costs in several ways. For example, residential customers often see immediate savings between the cost for energy of the new solar + storage system versus purchasing energy from the grid. Non-residential customers can reduce demand charges with DERs. And all customers can save on electricity costs when using their load flexibility technologies to move energy consumption out of peak times (i.e., 4 PM - 9 PM) into non-peak times. In addition, solar and storage systems can mitigate any increase in electricity consumption due to electrification measures, thereby supporting a customer's transition to electrifying their home. Last but not least, distributed storage systems

provide backup power for customers in the event of grid outages (so called “energy resilience”).

For PCE, customer-sited renewables can complement large-scale, centralized renewable deployment in meeting PCE’s renewable energy goals. BTM DERs can also function as a flexible load resource that can support PCE’s 24/7 renewable energy matching goal. More specifically, BTM DERs can provide quantifiable financial benefits to the LSE by reducing its need to procure energy during high-priced hours and by reducing its resource adequacy (RA) obligations. They are also a means for PCE to engage with its customers, to deepen our understanding and relationship of customers, and to retain them as PCE customers. In theory, DERs can also help reduce grid costs by deferring or avoiding the need for upgrades to the distribution grid. However, there is currently no pathway for LSEs to take advantage of this value stream in California. Last but not least, developing DERs in PCE’s service area contributes to the local economy similar to other construction projects.

Despite the many benefits of DERs, it can be challenging to develop both BTM and FTM DERs in PCE’s service area. These **barriers** vary by technology and market segment but can generally be summarized into 5 categories. First, it can be challenging to engage customers in new and emerging technology areas (customer adoption barrier). Second, DERs can carry significant added costs and financing is not always readily available. Third, not all potential benefits and value streams of DERs are accessible to the customer or the LSE, largely due to regulatory constraints. Fourth, the market landscape for DERs can be fragmented and complex, making it hard for customers and stakeholders to engage. Fifth, deployment timelines for certain DERs can be extended by slow and onerous permitting and interconnection processes.

Goals for 2025 - 2030

PCE has developed the following **Goals** to foster the development of DERs in its service area under a customer-centric approach during the 2025 – 2030 timeframe:

1. Grow PCE’s behind-the-meter “Local Power” Portfolio by 15 MW of solar and 35 MWh of storage leveraging scalable and self-sustaining financing solutions
2. Move towards a Whole-Home Energy Approach by integrating electrification, solar + storage, and EV offerings in a streamlined manner in major PCE programs
3. Develop a Virtual Power Plant (VPP) that aggregates 10 MW of dispatchable capacity from customer-sited resources in PCE’s service area to the benefit of the customer, PCE and the grid
4. Explore business models to foster the development of front-of-the-meter Distribution Resources in PCE’s service area
5. Investigate additional behind-the-meter DER ownership models to scale DER growth
6. Make PCE DER programs more accessible to customers through technical assistance services
7. Engage in policy advocacy on DER value maximization and value stacking

Under **Goal 1**, PCE will expand its BTM Local Power [5] portfolio by 15 MW of solar and 35 MWh of storage via two core initiatives – (1) developing a General Market Residential Solar + Storage Program and (2) expanding PCE’s Solar + Storage for Public Buildings Program (GovPV). Scalable and self-sustaining financial solutions are central to this Goal.

Under **Goal 2**, PCE will initially strive towards integrating additional DERs such as solar + storage and EV readiness under PCE's existing residential electrification program, the Home Upgrade Program. In a second step, PCE will also work towards providing integrated program offerings across the breadth of DERs to local government and commercial customers.

Under **Goal 3**, PCE is already working on procuring a Distributed Energy Resource Management System (DERMS) that monitors, controls, and optimizes BTM DERs for PCE's VPP under an ongoing request for proposal (RFP) for Customer Demand Flexibility Services . PCE staff is planning on discussing the details of the DERMS platform, as well as the contract with the selected vendor, during the May Executive Committee and May Board meeting. The DERMS RFP was also discussed with the Programs subcommittee on January 7, 2025.

Under **Goal 4**, PCE will undertake both programmatic and policy initiatives to explore new business models for FTM distribution resources such as community solar + storage projects and microgrids. As mentioned above, these resources face several challenges in their deployment, mostly related to cost and uncertain value streams. PCE will pursue public funding opportunities and engage in policy advocacy to identify business models that can foster the deployment of FTM distribution resources.

As described under Goal 1, PCE is already engaged in developing scalable financing models for BTM DERs, including where PCE is the owner of the resource. Over the next 5 years, PCE will investigate if similar ownership models should also be expanded to other BTM DERs such as EV charging equipment and electrification measures under **Goal 5**. In doing so, PCE can potentially unlock more equitable access to DERs (e.g., via reduced charging rates for EVs) and/or significantly scale the deployment of DERs (e.g. of electrification measures for local government customers).

Under **Goal 6**, PCE will expand its existing, in-house technical assistance currently offered for building electrification to other DERs such as solar + storage and transportation electrification. For residential customers, technical assistance will be offered free of charge through the existing call line and engineering support, called the "Concierge Service." For commercial customers, an enhanced service will be developed with an equitable fee structure that is low or no-cost for small businesses and a reasonable fee for large commercial customers.

Under **Goal 7**, PCE will engage in policy advocacy to reduce barriers to DER deployment and unlock DER value stacking. Potential initiatives will include, but are not limited to, accessing RA value and distribution upgrade deferral value for DERs, reducing interconnection timelines, and enabling vehicle-to-grid (V2G) integration.

[1] Per California Distributed Generation Statistics at https://www.californiadgstats.ca.gov/downloads/

[2] Per the California Energy Commission's light duty vehicle count at https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics-collection/light

[3] Per the TECH Clean California program at https://techcleanca.com/

[4] Per PG&E's Wholesale Distribution Access Tariff (WDAT) interconnection queue. See here: https://www.pge.com/assets/pge/docs/about/doing-business-with-pge/PublicQueueInterconnection.xlsx

[5] "Local Power" refers to any DER – both BTM and FTM - located in PCE's service area

PENINSULA CLEAN ENERGY

PENINSULA CLEAN ENERGY AUTHORITY
JPA Board Correspondence

DATE: April 11, 2025
MEETING DATE: April 24, 2025
VOTE REQUIRED: Majority Vote

TO: Honorable Peninsula Clean Energy Authority Board of Directors

FROM: Justin Pine, Senior Manager of Strategic Accounts and Masha Doubrovskaia, Account Services Analyst

SUBJECT: Approval of the Budget Billing Program for Peninsula Clean Energy Customers (Action)

RECOMMENDATION

PCE Staff recommend that the Board approve implementation of the proposed Budget Billing Program.

BACKGROUND

Residential monthly energy costs can vary widely throughout the year depending on both weather and seasonal rates. In hot climate zones where air conditioning is used for space cooling in the summer, customers can experience a summer month bill two to three times the amount paid in non-summer months. Customers in colder climate zones can see similar trends during winter months, when space heating is used to keep homes warm. In either case, variability in monthly energy costs can create hardship for customers with fixed incomes and tight budgets. To help manage seasonal spikes in energy costs, customers can enroll in the PG&E administered Budget Billing Program (BBP), previously also known as a Balanced Payment Plan. The BBP, available in some form to PG&E customers since 1982, averages the customer's PG&E energy costs over the previous 12 months to determine the Budget Billing amount due each month. Importantly, the BBP does not lower energy costs for enrolled participants and instead results in levelized charges due over a 12-month period.

Currently, Community Choice Aggregation (CCA) customers enrolled in PG&E's BBP only receive the benefit of average billing for the PG&E electric distribution charges, and when applicable, PG&E gas charges. Prior to this year, PG&E's BBP program could recalibrate a customer's BBP charge up to three times per year, but would only do so if certain threshold requirements were met. Since PG&E was unable to communicate these BBP programmatic details to CCAs, PCE was unable to offer a reciprocal program for PCE charges which could align with the intent of the program. PG&E however modified the program in December 2024 to regularly recalibrate the average charge on a monthly basis, making it possible for CCAs to offer complementary programs. In addition, PG&E has reprioritized marketing of its BPP program to customers in 2025. For these reasons, Peninsula Clean Energy staff is requesting

the Board's approval to proceed with the development of a PCE Budget Billing Program to provide levelized generation charges which align with the existing BBP offered by PG&E.

DISCUSSION

Coinciding with PG&E's modification to the BBP described above, PG&E shared with PCE its plans for a direct marketing campaign to occur in 2025. The campaign's goal is to more than double participation in the program across their service territory, and in January of 2025, PG&E sent emails to 1.8 million eligible customers encouraging enrollment in BBP.

Peninsula Clean Energy currently has 7,654 customers enrolled with PG&E's BBP, which has added over 600 accounts (9%) since January 2025. While only 2.4% of eligible PCE customers are currently enrolled in PG&E's BBP, the program can help vulnerable customers manage unpredictable energy costs. Should PCE not provide a complimentary Budget Billing Program, customers who have enrolled in the BBP with PG&E will continue to see levelized costs only for PG&E charges while PCE generation charges will continue to fluctuate. Staff do not see a high risk of opt out due to the absence of a PCE Budget Billing Program, but instead expect greater customer satisfaction among the enrolled group. Below are more details on the benefits of the program to customers, as well as the details of implementation.

Customer Impact

The benefits of Budget Billing vary depending on a customer's climate zone and usage profile. In the Peninsula Clean Energy service territory, the high temperatures experienced in summer in the Central Valley can cause Los Banos customers to have increased seasonal volatility in energy costs compared with San Mateo County customers. For this reason, Staff is providing analysis of the impact of Budget Billing on typical Los Banos and San Mateo County households.

The typical San Mateo County household would see an estimated $7 reduction in PCE charges on their highest monthly bills between November and January (Figure 1). More significantly, the typical Los Banos household would see a $90 reduction in PCE charges on their peak summer bills (Figure 2). While the impact for the average San Mateo County customer may appear relatively small, this benefit is compounded with the benefit they see for PG&E delivery and gas charges. Additionally, customers with electrified space and water heating may experience greater winter peaks.

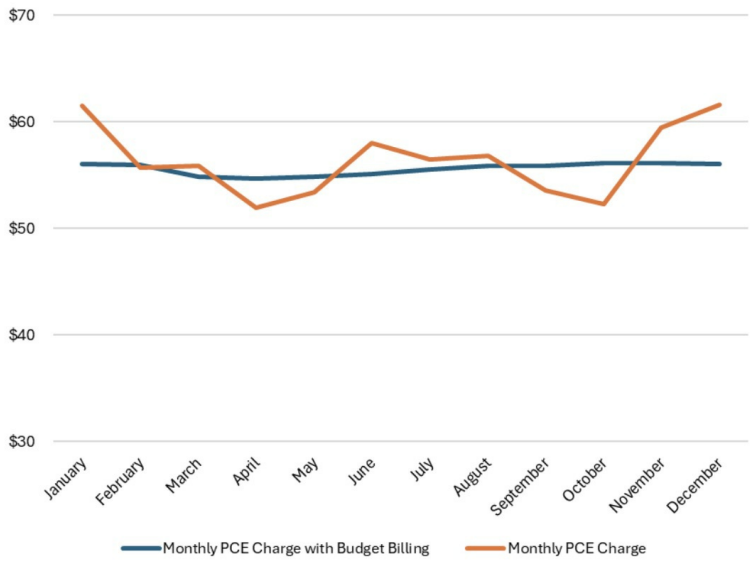


Figure 1: Impact of BBP on Average San Mateo County Customer

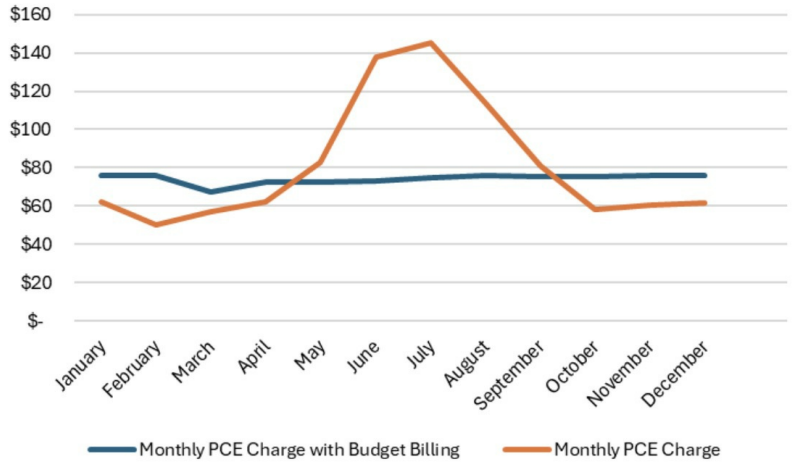


Figure 2: Impact of BBP on Average Los Banos Customer

Enrollment

Enrollment would mirror enrollment in PG&E's BBP. To qualify for BBP, customers must:

1. be a residential or small business customer on a non-NEM rate plan
2. have a history of on-time, complete bill payments
3. not be on a payment plan or have a history of partial or late payments Staff proposes auto-enrolling all customers that have enrolled into PG&E's BBP once PCE's BBP is operational.

Thereafter, customers will manage BBP enrollment with PG&E, similar to how customers manage their rate selections. Customers cannot enroll in PCE's program without enrolling in PG&E's.

Implementation and Timeline

Offering a BBP to customers requires billing system changes and development by PCE's

back-office provider, Calpine Energy Solutions (Calpine). Calpine has communicated that the program will be included in their billing system upgrade scheduled for CY2025 Q2-Q3, and that PCE should be able to enroll customers by Q3 or Q4 of CY2025.

Marketing

Staff do not plan to market the PCE BBP heavily, as the program is already being marketed by PG&E and customers must enroll through PG&E to participate. Information will be added to PCE's website, and other collateral will be considered as needed.

FISCAL IMPACT

BBP creates some nominal cashflow risks due to the deferral of charges on customer bills during peak months. Current enrollment levels would result in deferrals of up to $37,438 in charges, potentially growing to $74,876 if the program grows consistent with PG&E enrollment targets, representing a deferred revenue of up to 0.2% as described in Table 1.

Table 1: Cashflow impact of Budget Billing Program compared to revenues

Month	Impact to PCE Revenue if all Budget Billing Plan Customers Enroll (Approx. 7,500)	Grows 200% (Approx. 15,000 Customers)	Total Billed (2024) Revenue	Impact to PCE Budget if 7,500 Budget Billing Plan Customers Enrol	Impact if Enrollment grows by 200%
January	$ (36,580)	$ (73,160)	$ 39,719,130	**-0.09%**	**-0.18%**
February	$ 7,279	$ 14,558	$ 34,240,334	0.02%	0.04%
March	$ (4,749)	$ (9,498)	$ 33,795,484	**-0.01%**	**-0.03%**
April	$ 21,912	$ 43,823	$ 31,029,423	0.07%	0.14%
May	$ 8,544	$ 17,088	$ 39,128,345	0.02%	0.04%
June	$ (35,400)	$ (70,800)	$ 44,005,582	**-0.08%**	**-0.16%**
July	$ (22,763)	$ (45,525)	$ 47,389,107	**-0.05%**	**-0.10%**
August	$ (15,334)	$ (30,669)	$ 45,889,329	**-0.03%**	**-0.07%**
September	$ 15,781	$ 31,562	$ 38,622,195	0.04%	0.08%
October	$ 31,803	$ 63,605	$ 38,008,954	0.08%	0.17%
November	$ (35,526)	$ (71,052)	$ 34,344,184	**-0.10%**	**-0.21%**
December	$ (37,438)	$ (74,876)	$ 38,884,586	**-0.10%**	**-0.19%**

There is also a nominal risk of increased non-payment of bills when customers close their accounts during certain months, if the customer fails to pay their final bill (Figure 3). Staff will monitor program performance and recommend changes if necessary.

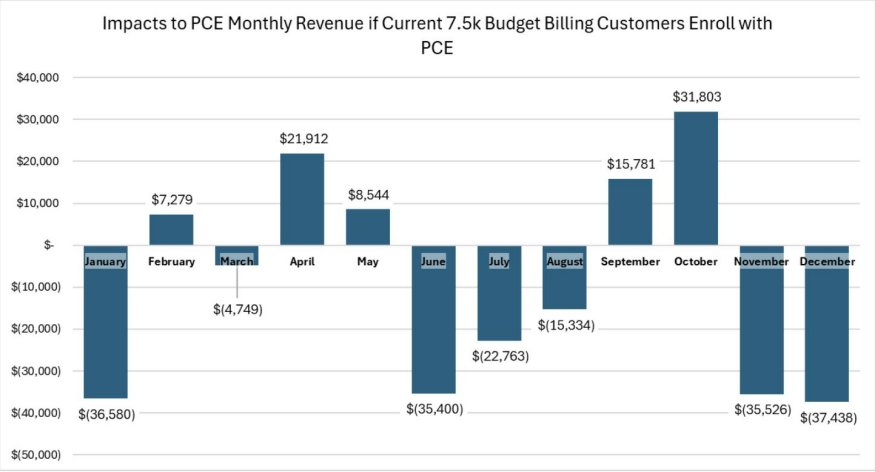


Figure 3: Seasonal impacts on cashflow operating a Budget Billing Program

RESOLUTION NO. _____

PENINSULA CLEAN ENERGY AUTHORITY, COUNTY OF SAN MATEO, STATE OF CALIFORNIA

APPROVAL OF THE BUDGET BILLING PROGRAM FOR PENINSULA CLEAN ENERGY CUSTOMERS (ACTION)

RESOLVED, by the Peninsula Clean Energy Authority of the County of San Mateo, State of California, that

WHEREAS, Peninsula Clean Energy (PCE) was formed on February 29, 2016; and

WHEREAS, maintaining affordability and retaining customers are organizational priorities for PCE; and

WHEREAS, the Budget Billing Program is a program administered by PG&E meant to reduce the seasonal bill variation to better help customers budget for their bills; and

WHEREAS, by offering the Budget Billing Program for PCE generation costs, PCE can enable its customers to fully participate in the program without needing to opt out of PCE, helping to offset unexpected bill spikes due to higher seasonal usage;

NOW, THEREFORE, IT IS HEREBY DETERMINED AND ORDERED that the Board approves the implementation of a PCE Budget Billing Program.

PENINSULA CLEAN ENERGY

PENINSULA CLEAN ENERGY AUTHORITY
JPA Board Correspondence

DATE: April 11, 2025
MEETING DATE: April 24, 2025
VOTE REQUIRED: None

TO: Honorable Peninsula Clean Energy Authority Board of Directors

FROM: Rafael Reyes, Senior Director of Energy Programs

SUBJECT: Community Energy Programs Quarterly Report

BACKGROUND

The following programs are in progress, key metrics are provided in the table here and detailed information is provided below.

Buildings	
Home Upgrade Rebates (Appliance Rebates)	4,620 measures rebated (+156 M/M); 922 loans issued (+37 M/M)
Home Upgrade Full-Service Installations	2021-2014 phase (old): 305 homes completed. Closed. 2024- phase (new): 2 homes completed; 41 more registered and in-progress.
Home Upgrade Personalized Support	24 support calls completed 10 have been scheduled for Full-Service assessments
GovBE	5 proposals selected for funding, $1M in incentives and $1.6M in loans. 1 project completed.
Reach Codes	5 agencies have adopted new “energy performance” codes post-Ninth Circuit ruling. Planning 2025 cycle in-progress, exploring retrofit codes for existing buildings.
Distributed Resources	
Residential Solar + Storage	409 applications pre-qualified. 67 battery-only projects received approval for an SGIP rebate, others pending. 597 installs under prior general market program. Enrollment is currently closed.
FLEXmarket	13 residential building electrification projects being tracked, 11 commercial energy efficiency projects being tracked

GovPV	Round 1: 12 sites, 1.7MW solar. 7 sites operational, 4 complete construction, 1 in construction. Round 2: 24 sites, 3.5 MW solar, 2 started construction Round 3: 12 sites, 6+MW solar, 10+MWh storage.
Green Access (DAC-GT)	First PCE community solar project – and one of the first in the state - is now online. 3MW project. 2,500 low-income customers subscribed and receiving bill discounts.
Transportation	
EV Charging	Ports to date: 1,533 (+173 in Q1 25). Pipeline: 3,500+
Used EV	819 EVs since 2021. (+~30 M/M)
E-Bikes	Total 1,070, 271 e-bikes in 2024. Reopening in April.
GovEV (fleets)	11 agencies enrolled. Multiple projects expected in CY 25.

DISCUSSION

1. Building and EV Reach Codes

Background: In 2018 the Board approved a building "reach code" initiative to support local governments in adopting enhancements to the building code for low-carbon and EV ready buildings. The initiative is a joint project with Silicon Valley Clean Energy (SVCE). The program includes no-cost technical assistance, model codes and other tools. The tools and model code language are available on the project website (www.BayAreaReachCodes.org).

In addition, in January 2020 the Board approved an extension of the reach code technical assistance plus additional elements – Education and training for developers and contractors, and consumer education program on the benefits of all-electric buildings. This technical assistance is publicly available at www.AllElectricDesign.org. In December 2020, the Board approved to extend the contract with TRC Engineers include technical assistance for developing policy for existing buildings. In February 2022 the Board extended the initiative for another two years.

Status

- **2025 Update:** Many cities considering adoption of reach codes for the 2025 building code cycle are likely to adopt in the 2025 calendar year to align with overall building code adoption ahead of the January 1st, 2026 implementation date.
- **City Progress**: County of San Mateo, East Palo Alto, Menlo Park, Brisbane, Burlingame, and City of San Mateo adopted a post-Ninth Circuit building code
- **State Code:** The new triennial state code cycle (going into effect on January 1st, 2026) built on the local reach codes implementing an EV charger or outlet for every new multi-family residence with an assigned parking space. Code also requires heat pump water and space heating in the proscriptive path.

For more information, please visit https://bayareareachcodes.org/

2. Buildings Programs

2.1 Home Upgrade Rebates and Zero Percent Loans

Background: Approved by the Board in May 2020, Peninsula Clean Energy launched the heat pump water heater (HPWH) rebates in January 2021. Additionally, in August 2021, the Board approved an On-Bill Financing program (referred to as the Zero Percent Loan). The program offers qualified residential customers a 0% interest loan up to $10,000 to fund the cost of eligible electrification upgrades. The Zero Percent Loan program launched in October 2022.

Updates to the rebate and loan programs have been instituted a few times, no more than annually, over the past years. Primarily changes include adjusting rebate amounts based on uptake and state and federal rebate landscape for those upgrades, and shortening the loan term to 5 years from the initial 10 years to establish a more sustainable "revolving fund".

Status: The summary table below summarizes the number of rebates and loans issued per year.

Measure Type	**2021**	**2022**	**2023**	**2024**	**2025**
Heat Pump HVAC Rebate		10	948	1221	298
Heat Pump Water Heater Rebate	149	172	588	521	165
Electrical Panel Rebate	19	34	177	202	56
0% Loan		1	342	449	130

PCE is moving to use the umbrella name "Home Upgrade" for all services for residential home electrification, including the rebates and loans. The Home Upgrade Full-Service Installation service is described in more detail below. For more information, please visit https://pencleanenergy.com/all-electric-homes

2.2 Home Upgrade Full-Service Installation (includes Low-Income Direct-Install)

Background: In May 2020, the Board approved implementing a direct-install low-income home upgrade program to offer minor home repair, energy efficiency, and electrification measures to income-qualified homeowners at no cost to them. The measures implemented in each home varied depending on the home's needs but included at least one electrification measure. The program launched on September 2021. The Board extended the program through June 30, 2024. The program served 305 homes, including 9 homes who received whole home electrification as part of a pilot within the program.

Following a competitive selection process, the Board approved the $26M contract with Franklin Energy on February 22, 2024 for the next phase of the program, which will include a scaling-up the number of low-income homes served with whole home electrification upgrades at no-cost to these residents, offering full-service electrification installation services to non-income qualified residents at a low cost, and launching an emergency heat pump water heater replacement service. Silicon Valley Clean Energy (SVCE) also contracted with Franklin for the joint program.

Status: PCE and SVCE jointly worked with Franklin on program design and start up tasks. PCE soft launched the low-income no-cost electrification segment of the program in late August by contacting a waitlist of customers collected in the previous phase of the program. In November 2024, PCE opened up the program to all customers (i.e. including those that do not qualify for no-cost installation) but it is not yet widely promoting it. General promotion will be initiated when process improvements learned from the early participants are incorporated,

anticipated to be in early summer. As of April 9, 2025, 88 home assessments have been completed; 43 customers have signed on to move forward with installations; and 2 installations have been completed. In addition to these homes through full-service installation, 2 homes have had heat pump water heaters installed through the emergency water heater replacement service.

For more information, please visit https://www.peninsulacleanenergy.com/homeupgrade/

2.3 Local Government Building Electrification Program (GovBE)

Background: In August 2023, the Board approved a local government building electrification program to help fund building electrification at local government facilities. The program will offer roughly $1 million per year in incentives and creates a $10 million dollar revolving loan fund. Incentives are based on therms saved at a given facility. Incentives and loan are capped at $600k per jurisdiction per year, each. The program requires a 25% cost-share from non-PCE funds, and will have a streamlined, annual application process.

Status: Five project applications have been selected for funding for the current year, totaling $1 million in incentives and $1.6 million in loans. Projects include:

- A pool heating electrification project in Brisbane,
- Portfolio-wide municipal decarbonization for Half Moon Bay
- Portfolio-wide HVAC electrification for Los Banos
- A project installing seven HPHW across multiple facilities at East Palo Alto
- A project electrifying HVAC at a child development center for Menlo Park

A separate $5 million from the surplus funds were allocated for schools however, no schools submitted for funding in this round. PCE plans to re-open the application for schools in the upcoming months and is in discussions with the San Mateo County Office of Education on rollout.

For more information, please visit https://www.peninsulacleanenergy.com/public-organization/govbe-program-electrification-for-public-buildings/

2.4 Personalized Support Services (Concierge)

Background: In March 2023, the Programs Team presented the Building Electrification Strategy to the BOD as a discussion item. The Building Electrification Strategy included a “hotline” provided electrification planning and technical support. In July 2024, Peninsula Clean Energy hired a new building electrification expert to provide customized support to Peninsula Clean Energy customers.

Status: The service launched on February 24, 2025. As of April 10, 2025, 24 support calls have been conducted and 15 additional calls are scheduled.

More info at https://www.peninsulacleanenergy.com/residential/home-electrification/personalized-support/

3. Distributed Energy Programs

Peninsula Clean Energy is advancing distributed energy resources to provide resilience, lower

decarbonization costs, provide load shaping to support our strategic goal for 24/7 renewables. The projects described below are efforts towards meeting both of these goals.

3.1 Solar and Storage for Public Buildings ("GovPV")

Background: The Solar and Storage for Public Buildings / GovPV Program is aimed at aggregating local government facilities into a group procurement of solar and optionally storage systems. Peninsula Clean Energy provides no-cost site assessments and preliminary designs as well as manages the procurement process. Participating sites have systems installed as part of power purchase agreements directly with Peninsula Clean Energy. Initial site scoping and up to $8 million in capital was approved by the Board in October 2020 for the first round, known as "GovPV1." At the January 2023 Board Meeting, the Board of Directors approved the installation contract and power purchase agreements with 10 jurisdictions in the first round for a total of 12 sites yielding 1.7 MW solar. Battery storage systems are planned for 3 of the sites but will not move forward until after the solar systems are operational due to NEM2 grandfathering rules.

Round 2 - or GovPV2 - was approved by the Board in January 2024. This portfolio includes 24 sites and totals 3.5MW. McMillan Electric, a local union firm, is providing construction services on round 2 and most of round 1 (round 1 was transitioned from a prior provider due to financial difficulties the firm encountered during the pandemic). In February 2025, the Board approved an expanded scope with McMillan to build battery storage and EV chargers at GovPV sites. PCE's contract with McMillan is for up to $30 million for their EPC services. All projects in rounds 1 and 2 are being pursued as NEM 2 projects, and are slated to become operational by April 2026.

Round 3 – or GovPV3 – is under development and includes much larger project sites that necessitate the direct pairing of battery storage. In order to fund the capital required to build these projects, PCE is beginning to explore external financing options.

Status

As of April 10, 2025, 7 systems are operational (Brisbane Mission Blue Center, San Carlos Youth Center, Millbrae Recreation Center, San Mateo County Health Services Administration, Hillsborough Corp Yard, and Los Banos Community Center). Four are substantially complete but awaiting PG&E to complete upgrades and/or inspections to its system it deemed necessary during the interconnection process. One is in construction with substantial completion expected by end of the month. Some sites have been waiting over 1 year on PG&E, and we have no control over their timeline. Staff expects this to be a continual challenge with distributed generation projects.

For Round 2, 13 agencies with a total of 24 facilities are in advanced development. All projects have executed Power Purchase Agreements (PPAs) and construction drawings are in development. McMillian Electric is currently working on construction plans for the first tranche of projects that will be ready for construction and four building permits have been issued. Two projects, Brisbane Library and Woodside Town Hall commenced construction the week of April 7th. All other projects are expected to begin construction throughout 2025 and will be commissioned by late 2025 / early 2026.

For Round 3, staff is currently in early consultancy with agencies and conducted interviews in Q1 with four prospective developers that were shortlisted after an extensive RFP process.

Proposal evaluations are continuing. Staff has also created internal solar + storage financial models which inform optimized energy storage dispatch strategies and impacts to customer financials. Staff forecasts that this portfolio could include 12 sites with a total of >5MW of solar and >10MWh of battery storage. The previous portfolios have been funded directly with Peninsula Clean Energy capital. In order to fund this much larger portfolio, staff is evaluating external financing solutions that will allow us to utilize a low cost of capital or a third party PPA structure.

For more information, please visit https://pencleanenergy.com/government-programs

3.2 Residential Solar + Battery Backup

Background: Peninsula Clean Energy's programs for residential solar are split up into two customer segments: general market and low income. The general market program is referred to as Residential Solar + Battery Backup, and is currently closed for new enrollments. The low-income program is referred to as the Solar plus Battery Savings, detailed below.

The Residential Solar+ Battery Backup program utilizes batteries that were deployed by Sunrun and provide backup power to each home. These batteries are discharged daily to reduce PCE's peak load. PCE will receive >1.5MW of daily peak load reduction through 2032. Enrollment in the program closed in 2022 and PCE has been developing a successor program.

Separately, PCE developed a program to help low-income single-family homeowners access the State of California's Self-Generation Incentive Program (SGIP). SGIP provides behind-the-meter (BTM) storage or solar + storage systems to eligible low-income single-family homeowners to deliver bill savings and resilience benefits. The program will leverage state SGIP incentives which are expected to mostly or fully fund the installation of systems for income qualified customers. PCE is targeting 200 total installations at low-income customer sites, most of which we expect will be fully funded by the State. This would result in approximately 1MW of solar and 2.5MWh of battery storage. In October, the Board approved the contract with the competitively selected developer Haven Energy to manage installation of the systems.

Status: PCE opened the program to help customers access SGIP funds in August 2024. Applications were closed to new applicants on December 31. PCE has pre-qualified 398 customers. Based on regulatory filings, we anticipate state SGIP funding applications may open in May 20, 2025 (at the earliest), at which point solar + storage projects will be submitted. In the meantime, Haven Energy has already begun submitting battery-only projects utilizing different SGIP budgets.

3.3 FLEXmarket

Background: In November 2021 the Board approved a program plan for the establishment of an innovative "virtual power plant" using what is known as FLEXmarket. FLEXmarket is a market-based program structure that provides incentives to program "aggregators" to implement programs for energy efficiency and load shaping. The novel elements of the structure include a "pay-for-performance" approach which only provides incentives on confirmed performance using meter data. This novel structure was innovated by MCE and has also been implemented by Sonoma Clean Power. In addition, the program plan was developed for submission to the CPUC to allow Peninsula Clean Energy to run the program

with fully reimbursed funding through the CPUC. Peninsula Clean Energy's billing data services provider Calpine has entered into a strategic partnership with the firm Recurve to provide FLEXmarket services through a streamlined structure. Providers of energy efficiency and building electrification equipment can apply for incentives through this program.

Staff developed the commercial version of the program and launched the market in July 2023. Like the residential version, providers of commercial energy efficiency and building electrification equipment, as well as aggregators of these projects, can pursue incentives through the Commercial FLEXmarket.

Status: The FLEXMarket Program has achieved approximately $1.7 million in total system benefits to date.

In Q4, the program temporarily paused new project submissions to address a budgeting issue with the California Public Utilities Commission (CPUC). This issue resolved early February, and we reopened enrollments in with approximately $322,000 in remaining funding, which must be utilized by May 2025, as the current funding cycle for the program is set to expire in early May 2025. Looking ahead, we are preparing a new funding request for a three-year cycle spanning calendar years 2025-2028. This submission is planned for early May after board approval of the program plan.

For more information, please visit https://pencleanenergy.com/flexmarket

3.4 Green Access Community Solar (DAC-GT)

Background: The Disadvantaged Communities Green Tariff program ("DAC-GT") and associated Community Solar Green Tariff ("CSGT") are community solar programs developed by the California Public Utilities Commission (CPUC) to enable residents in eligible census tracts to participate in renewable energy projects, and to promote development of renewable projects in DACs. Participating customers will receive a 20% discount on their full electric bill (PG&E and Peninsula Clean Energy charges). Peninsula Clean Energy administers these programs on behalf of its customers.

Peninsula Clean Energy began enrolling DAC-GT customers in San Mateo County in January 2022 and customers in Los Banos in April 2022. Those customers are currently served by an interim resource procured from Marin Clean Energy pending Peninsula Clean Energy's procurement of a new renewable resource for the program.

Status: The program, publicly known as Green Access, is currently serving approximately 2,500 customers. Peninsula Clean Energy signed a PPA with Renewable America, LLC for a 3MW solar resource located in Dos Palos, CA, approximately 15 miles southeast of the City of Los Banos. This project is operational as of March 2025. 1,200 additional customers were subscribed with the new system, each receiving a 20% discount on their electricity bill.

For more information, please visit www.peninsulacleanenergy.com/greenaccess

4 Transportation Programs

4.1 Used Electric Vehicle (EV)

Background: Originally launched in March 2019, the Used EV Rebate Program currently

provides a $2,000 rebate to income-qualified residents. Customers can seamlessly combine the PCE rebate and federal rebate at the point of sale, providing up to $6,000 in downpayment assistance.

Status: 819 rebates have been provided throughout the program history and Grid Alternatives has been assisting with "EV Advisor" services, helping customers navigate various rebate programs they may qualify for, in addition to PCE's rebate, and providing general EV adoption outreach assistance. This service will transition to our in-house call center starting in May. Staff is actively training the call center reps to serve as EV Advisors.

For more information, please visit https://pencleanenergy.com/usedev/

4.2 "EV Ready" Charging Design Assistance & Incentives

Background: In December 2018, the Board approved the EV Ready program, consisting of EV charging infrastructure incentives and technical assistance. The program is open and available to multi-family housing, affordable housing, workplace charging, and general public-access sites, through there is a general focus on multi-family housing, which has been a historically underserved population in state EV charging programs.

PCE offers free project design assistance, facilitated through CLEAResult. There are currently 300+ active projects receiving this assistance and, on average, projects receiving assistance more than double the overall size of their EV charging projects.

Status: The program has helped the community install over 1,500 chargers (70%+ at multi-family housing) with more than 3,500 additional chargers in progress. . The EV Ready program was an award winner at the 2024 CalCCA conference and is a statewide model with installation costs well below other similar programs. Key elements of the program are being replicated by a number of other programs. PCE staff presented at a number of upcoming state and national events and were featured in a recent CleanTechnica podcast.

Some of the largest multi-family EV charging projects in the nation are occurring currently in the EV Ready program. This includes the installation 92 chargers installed in East Palo Alto, 144 chargers in Millbrae/Burlingame, ~140 chargers in Daly City, and over 200 chargers in South San Francisco, the single largest retrofit multi-family EV charging project in the nation.

To address EV charging affordability issues, PCE is also currently leading an innovation grant opportunity. This will develop new EV charging systems that can be submeter to a multi-family residential unit, even though the charger is connected to a separate meter, reducing or eliminating price markups experienced by EV drivers that utilize third-party charging systems. Orange Charger has been awarded this innovation grant and work has begun.

For more information, please visit https://pencleanenergy.com/ev-ready/

4.3 E-Bike Rebate Program

Background: The Board originally approved the income-qualified E-Bikes Rebate program in July 2020 and has run in annual cycles to provide rebates to residents with low to moderate incomes. The program has provided over 1,000 rebates since 2021. Customers can use the rebate either at qualifying bike shops for a point-of-sale discount. with several participating bike shops in San Mateo County and Merced County (for Los Banos-based customers).

Status: The program will be relaunching in April and is expected to be offered year-round, making it the only e-bike rebate program in the county to have ongoing availability.

For more information, please visit https://www.pencleanenergy.com/ebikes

4.4 Public EV Fleet Program (GovEV)

Background: The Board approved the GovEV Fleet Program in November 2020. This program is comprised of three components to help local agencies begin their fleet electrification efforts: hands-on technical assistance, gap funding, and a vehicle to building resiliency demonstration that will assess the costs and benefits of utilizing fleet EVs as backup power resources for agencies in grid failures and other emergencies. In August 2022, the Board of Directors approved a contract with Optony to assist in the administration of this program and further approved an extension with Optony in March 2024.

Status: 11 cities have enrolled, including: Menlo Park, Burlingame, San Mateo, South San Francisco, Daly City, San Carlos, Foster City, Millbrae, Brisbane, San Bruno, and East Palo Alto are now receiving technical assistance. Menlo Park plans to install 30+ charging stations for fleet vehicles at the City Hall, Police Department, and Corporation Yard, Burlingame is moving forward with 8 chargers at their Corporation Yard, Millbrae is currently installing 24 chargers at their Corporation Yard and City Hall, and San Mateo will be installing 12 chargers at their City Hall. Other projects are expected in FY 26.

Staff are developing guidance on resiliency options for EV fleets, to be published shortly.

For more information, please visit https://www.peninsulacleanenergy.com/public-organization/govev-program-public-fleet-electrification/

4.5 EV Managed Charging Pilot

Background: Peninsula Clean Energy extensively tested “managed charging” systems over multiple pilot phases, including a proof-of-concept with FlexCharging and a phase 2 pilot with ev.energy with a larger set of vehicles. In October of 2021, the Board approved a contract up to $220,000 with the University of California, Davis’ Energy Economics Program (DEEP) to develop and advise on an incentive structure experiment. In November, the Board approved a contract up to $220,000 with ev.energy as the platform provider for EV managed charging services.

Status: Results of the phase 2 pilot with ev.energy yielded very limited results. Recruitment was a major challenge. In addition, self-selection bias among those that did enroll provided less than expected load shift potential as the type of people who joined were mostly already charging their EVs off peak. Staff have decided to not extend the managed charging pilot into a full program due to poor cost-effectiveness and will instead focus on targeted behavioral outreach.

The final report is available at https://www.peninsulacleanenergy.com/wp-content/uploads/2025/03/PCE-EV-Mgd-Charging-Final-Report.pdf

PENINSULA CLEAN ENERGY

PENINSULA CLEAN ENERGY AUTHORITY
JPA Board Correspondence

DATE: April 15, 2025
MEETING DATE: April 24, 2025
VOTE REQUIRED: None

TO: Honorable Peninsula Clean Energy Authority Board of Directors

FROM: Gwen Rose, Director of Marketing

SUBJECT: Marketing, Outreach Activities, and Media Relations Quarterly Report

BACKGROUND

The Marketing & Community Relations Teams is responsible for enhancing Peninsula Clean Energy's brand reputation, educating and engaging customers, driving participation in programs, and ensuring customer satisfaction and retention. Tactics include community outreach, content creation and storytelling through owned (e.g. online, social media), earned (e.g. public relations), and paid media (advertising), and school engagement programs.

DISCUSSION

The following is a quarterly update of activities taking place from January to March 2025. Please refer to the "Strategic Plan" section below for further information/explanation as to how these activities support Peninsula Clean Energy's (PCE) strategic plan objectives.

Brand

We launched the new website on January 22, 2025 after months of extensive user input and quality assurance testing. Key features of this new website include:

- Simplified Navigation: Tailored to meet diverse customer needs.
- Streamlined Access: Clear pathways to eligibility criteria and program applications.
- Search Functionality: Enabling residential customers to easily find applicable discounts, rebates, and incentives.
- Brand Integration: Reflecting PCE's updated brand strategy and messaging platform to reinforce our identity and mission.

Designed to showcase the breadth of PCE's work, the website emphasizes storytelling and building emotional connections with our customers. The platform is scalable, allowing it to grow alongside PCE's decarbonization ambitions, and prioritizes accessibility to ensure all customers—regardless of income or familiarity with clean energy—can confidently access and benefit from our services. Over 2025, Marketing will continue enhancing the customer experience.

To ensure our website continues to meet customer needs and support organizational goals,

we rely on ongoing analysis of user behavior. By examining how visitors arrive at our site and navigate through it using tools like Google Analytics, we gain insight into their pathways and interests. Heatmaps help us understand how customers engage with content—where they scroll, pause, and spend time—revealing which information resonates. Conversion tracking further tells us whether users are taking intended actions such as filling out forms or downloading resources. These insights directly inform improvements to our channel mix, customer journey design, website structure and functionality, and the development of new content and storytelling approaches. This data-driven approach allows us to evolve our site in ways that enhance the user experience and increase impact.

Program Marketing

Marketing efforts focused on promoting electrification and EV adoption via email, paid search and online advertising. Programs we are actively promoting include the Zero Percent Loan Program, appliance rebates, Used Electric Vehicle (EV) rebates.

Following the soft launch of the Home Upgrade Services program, we promoted no cost upgrades for income qualifying customers in Menlo Park through flyers, emails, and social ads.

Events

In Q1, the Community Relations team participated in 23 community events, including electrification workshops and green career days, reaching 870 attendees.

Outreach Grants

Peninsula Clean Energy has awarded $500,000 in grants for diverse and innovative efforts across San Mateo County to educate the public about energy bill discounts, and the benefits of clean energy, electric appliances, and electric vehicles. The grants awarded to 16 local community organizations include outreach in Spanish, Chinese and Tagalog to help customers receive assistance in meeting their energy needs. It will also support creative local partnerships, such as showcasing electric vehicles at the Redwood City Day of the Dead event. Community Relations onboarded the outreach grantees through a half-day training, and conducted Spanish-speaking trainings for outreach workers and Promotoras.

Schools and Youth Program

Our school outreach activities this quarter supported student engagement, educator collaboration, and career pathway development in clean energy. Highlights include presenting to the Youth Climate Ambassadors at their Mid-Year Retreat and supporting their Community Impact Projects with energy-focused ideas. We conducted site visits to Metro Ed and Evergreen Valley College as part of the EV Collaborative to explore EV career education opportunities in Santa Clara County. We also advanced our community college partnerships with interactive energy exhibits (to be finalized by April) and prepared for the Sustainable Career Fair and additional EV site visits. Staff also participated in school events such as an Electricity Career Panel at Skyline College, Earth Day at Carlmont High School, Canada College's Earth Fest, and a Careers for a Sustainable World Panel.

Los Banos Update

Los Banos Mayor Michael Amabile and other city leaders joined Peninsula Clean Energy at a March 28 ribbon cutting for new solar carports at the Los Banos Community Center. The carports are expected to save Los Banos more than $1 million over their lifetime. They were installed as part of Peninsula Clean Energy's GovPV program, which required no upfront costs to the city and used union labor for construction. The new system not only provides parking lot

shading. The solar power generated will offset 95 percent of energy usage for the Community Center. Others gathered at the ribbon cutting included Interim City Manager Gary Brizzee, Community and Economic Development Director Stacy Souza Elms, Director of Parks and Recreation Joe Heim and representatives for U.S. Rep. Adam Gray and California Assemblymember Esmeralda Soria. With the ribbon cutting celebration and 8 other community events, 278 attendees were reached in Los Banos.

News & Media

Media Relations focuses on enhancing Peninsula Clean Energy's reputation and leadership position by garnering earned media attention. Full coverage of Peninsula Clean Energy in the news can be found on our News & Media webpage. Highlights from the last quarter include:

- **Community Outreach Grants Announcement:** We announced awarding $500,000 in our latest round of annual community outreach grants.
- **Rate Reduction Announcement:** We announced the approval by the Board of Directors to lower electric generation charges for at least the first six months of 2025.
- **CalGreen Special Recognition Announcement:** We announced the special recognition at Sustainable San Mateo County's April 3 Annual Sustainability Awards highlighting community-wide efforts to develop and enact pioneering local and statewide building reach codes. We worked in coordination with Sustainable San Mateo County on issuing our release simultaneously with their broader release on the awards ceremony.
- **Los Banos Ribbon Cutting:** We issued a media advisory and press release regarding the March 28 ribbon cutting of the solar carport at the Los Banos Community Center.
- **Newsletters:** PCE updates were included in newsletters for the cities of Menlo Park, Millbrae, East Palo Alto, Burlingame, Foster City, Brisbane, Belmont, San Mateo, Portola Valley and Woodside. PCE also had mentions of our EV Ready webinar in several chambers of commerce newsletters, including the Coastside Chamber, Brisbane Chamber, South San Francisco Chamber and San Mateo Area Chamber. The Brisbane Luminary newsletter featured an item from us highlighting San Mateo County's history of building electrification leadership that was showcased at the Sustainable San Mateo County awards. The spring CalCCA newsletter also featured several recent announcements dating back to last October.
- **Moody's Rating Announcement:** PCE announced that Moody's has upgraded our credit rating to A3, placing us in the top-rated category among California community energy providers. California Energy Markets wrote about the ratings upgrade.

Other Media

- Streamlined regional energy market in works, San Mateo Daily Journal
- Peninsula Clean Energy lowers 2025 electricity rates, Patch.com
- Menlo Park may expand home electrification program, The Almanac
- Switch from gas to electric off to a slow start, Palo Alto Daily Post
- Los Banos City Council March 19 meeting recap, Los Banos Enterprise
- San Carlos sees progress toward emission goals, San Mateo Daily Journal
- Menlo Park hosts first college and career day, The Almanac
- Is "sustainable development" pushing residents to drive more?, San Mateo Daily Journal
- Powering the world: Sustainability generates economic growth, Scot Scoop

- San Mateo County Board of Supervisors to bid farewell to Slocum and Pine , San Mateo Daily Journal
- Two CCAs gain credit rating upgrades, California Energy Markets

FISCAL IMPACT

None

STRATEGIC PLAN

This section describes how the above Marketing and Community Outreach activities relate to the overall goal and objectives laid out in the strategic plan.

The strategic goal for Marketing and Customer Care is: Develop a strong brand reputation that drives participation in Peninsula Clean Energy's programs and ensures customer satisfaction and retention.

Brand

- Objective A, KT3: Tell the story of Peninsula Clean Energy through diverse channels
- Objective A, KT5: Identify and address gaps between perception and desired brand identity

Program Marketing

- Objective B, KT5: Provide inspirational and informative content that spurs action to reduce emissions
- Objective B, KT6: Promote programs and services, community energy programs and premium energy services

Events

- Objective A, KT4: Engage community through participation in local events

Outreach Grants

- Objective A, KT4: Engage community through participation in local events
- Objective B, KT1: Foster relationships with community-based, faith-based, and non-profit organizations programs focused on energy

School and Youth Programs

- Objective A, KT4: Engage community through participation in local events
- Objective B, KT2: Continue to support schools-based literacy

Los Banos Update

- KT4: Engage community through participation in local events
- Objective B, KT1: Foster relationships with community-based, faith-based, and non-profit organizations
- Objective B, KT3: Enhance relationships with municipal and county staff and elected

officials

News & Media

- Objective A, KT1: Position leadership as experts on CCAs and the industry
- Objective A, KT2: Cultivate relationships with industry media and influencers
- Objective A, KT3: Tell the story of Peninsula Clean Energy through diverse channels

PENINSULA CLEAN ENERGY

PENINSULA CLEAN ENERGY AUTHORITY
JPA Board Correspondence

DATE: March 31, 2025
MEETING DATE: April 24, 2025
VOTE REQUIRED: None

TO: Honorable Peninsula Clean Energy Authority Board of Directors

FROM: Marc Hershman, Director of Government Affairs and Mike MIelke, Senior Manager of Legislative Policy

SUBJECT: Legislative Update

RECOMMENDATION

Informational

BACKGROUND

Sacramento Summary – the 2025-26 Legislative Session

At the time of preparation of this report, the legislature's Spring Recess is taking place. Legislators will return to Sacramento on April 21. It will then be a sprint to conclude hearings in policy committees. The deadline for policy committees in the first house (the house of the Legislature where the bill was introduced) to meet and hear bills with a fiscal impact is May 2. The deadline for bills that do not have a fiscal component is May 9. Many bills are referred to more than one committee for a hearing. However, the number of committee referrals does not change these deadlines.

May 23 is the last day for the fiscal committees to meet and report bills to the floor. This includes both houses' Committee on Appropriations and their "Suspense Calendars." Between June 2 and June 6, legislative committees do not meet because that week is reserved for floor sessions. It is the point at which bills are voted on by the full body and those that pass are referred to the other house.

We are pleased to share a recent success for our Programs and Policy teams.

Last fall, after the end of the legislative session, PCE staff went to Sacramento and met with some of the legislative staff of Assemblymembers who comprised the Select Committee on Electric Vehicles and Charging Infrastructure. Our team shared PCE's approach and the many benefits to right-sizing EV charging infrastructure, including lower costs for customers and the grid. We highlighted PCE's successes and the cost-effective solution provided by the installation of Level 1 chargers at individual parking stalls in multi-family developments.

The Chair of the Select Committee, Assemblymember Jacqui Irwin of Thousand Oaks, took a particular interest in the issue. She authored a sign-on letter that went out this week to the California Energy Commission in which the Assemblymembers asked the CEC to reconsider and lift its current restrictions on funding for Level 1 chargers in dedicated parking spaces in multi-family developments. A copy of that letter is provided with this Legislative Update.

Notably, the 9 Assemblymember signatories to the letter included the Chair of the Assembly Committee on Utilities and Energy, Cottie Petrie-Norris, and PCE-area legislators, Marc Berman, Diane Papan and Catherine Stefani.

Members of the PCE programs and policy teams will be following up with the CEC to advance this issue.

Also attached to this Legislative Update is a copy of the March 25, 2025, Assembly sign-on letter, led by the Chair of the Assembly Committee on Utilities and Energy, Cottie Petrie-Norris, in which legislators ask the California Public Utilities Commission to reject the recent requested increase of the Investor-Owned Utilities for an increase in their Return on Equity citing the impact this increase would have on energy rates.

DISCUSSION

2025 California State Budget

California budget watchers have sounded the alarm that the state coffers could be impacted by the recent tariffs imposed by Washington DC. The state's funds are closely linked to taxes generated from capital gains on the sale of stock. With the recent downturn in the markets after the imposition of higher tariffs it is very possible that the state will see smaller than anticipated revenues.

The possibility of higher tariffs resulting in lower revenues was anticipated by the Governor when he submitted his initial budget in January, however the details of the tariffs were unknown at that time.

It is expected that the Governor's budget revisions (May Revise) will be released on or before May 14.

Legislation of Interest

While energy affordability was the focus of the legislature in 2024, much has changed in the intervening months. Responses to wildfires in Southern California and to the new Administration in Washington have been a key focus of the Governor and many state Legislators.

PCE has also observed a significant increase in the number of energy bills introduced in 2025 as compared to prior years. Please refer to the attached Bill Matrix for a compendium of some of the legislation being followed closely by Peninsula Clean Energy and CalCCA. This is not a complete list of the bills we are following. More than 100 bills of interest have been introduced.

Peninsula Clean Energy Policy 1 delegates authority by the Board of Directors to the CEO to timely engage and position the organization on public policy matters, including legislative and

regulatory issues.

Some of the bills we are actively engaged on and/or closely watching currently include:

SB 540 (Josh Becker, D-Menlo Park and Henry Stern, D-Calabasas)

SB 540, authored by Senators Josh Becker and Henry Stern, would allow the formation of a regional transmission organization to operate regional energy markets with other western states. Currently the California Independent System Operator (CAISO), the authority that manages the transmission grid in California, is only permitted to use energy from markets outside the state on a limited basis.

Proponents of **SB 540** believe that regional energy markets are a critical solution to bring down electricity costs as energy islanding is inefficient and expensive. Allowing California to trade energy across the west would enable carbon reduction through increasing access to complementary renewable energy like hydro and wind, while reducing solar curtailment. This also helps with reliability by allowing California to more easily import energy from other states during times of grid stress.

An informational hearing was held by the Senate Committee on Energy, Utilities and Communications on March 12 in Sacramento under the title Regional Expansion of Wholesale Electricity Markets: Overview of the West-Wide Governance Pathways Initiative. At this hearing, Senators heard arguments for and against the West-Wide Governance Pathways Initiative, with some lawmakers voicing concerns about guardrails against market manipulation and what the effort means for the state's autonomy to set its own policies. At the informational hearing in Sacramento, Peninsula Clean Energy staff Mike Mielke voiced support for the Pathways Process. Mike spoke to the fact that this process would expand renewable energy supply and help achieve California's ambitious climate change goals, help make electricity more available and affordable for the consumers and businesses in our service territory, while also ensuring that California retains control over critical functions such as transmission planning, procurement, and other critical policies.

In addition to Peninsula Clean Energy and CalCCA, CCA support for **SB 540** includes MCE, Silicon Valley Clean Energy, and San Diego Community Power.

Support for **SB 540** from labor, business and environmental groups includes CA & NV State Association of Electrical Workers (IBEW), California Chamber of Commerce, California Environmental Voters, Coalition of California Utility Employees (CCUE), Environmental Defense Fund, Natural Resources Defense Council (NRDC), Silicon Valley Leadership Group (SVLG), and Union of Concerned Scientists.

Voicing opposition at the March 12 hearing was former CPUC Commissioner and President Loretta Lynch and a representative from the Indivisible California Green Team. Consumer Watchdog has also come out with opposition to **SB 540**.

As a result of the information received at the March 12 hearing SB 540 has been amended. The bill now states that a participant in the Regional Organization may *withdraw unilaterally* without further approval needed and that state policies to reach renewable energy targets are not changed by the legislation.

This legislation has been referred to the Senate Committee on Energy, Utilities and

Communications where it is set to be heard on April 21 and the Senate Committee on the Judiciary where it is set to be heard on April 29.

Peninsula Clean Energy has scheduled further discussion on this legislation for the April meeting of the Board of Directors. A copy of PCE's letter is support of SB 540 is attached to this Legislative Update. Further background information about SB 540 can be found attached to the report provided to the Board of Directors' in support of the Board discussion.

SB 330 (Steve Padilla, D-Chula Vista)

SB 330 would enable the Governor to establish one or more pilot projects to develop, finance, or operate electrical transmission infrastructure that meet certain criteria, including: being identified by the California Independent System Operator (CAISO) in its transmission planning process, provides a significant reduction in cost, and is implemented under a Project Labor Agreement (PLA). It authorizes the Governor to designate existing state agencies, local public agencies, tribal organizations, or joint powers authorities to implement the pilot projects.

The bill could be seen as an important tool to promote a robust and cost-effective transmission network in the CAISO footprint. CCA projects rely on transmission in the CAISO system for deliverability. Transmission is key to meeting 100% renewable/clean energy objectives. There is no transition without transmission. At the same time, as referenced above, transmission costs are expected to rise and create additional cost pressures on ratepayers.

SB 330 addresses these concerns by saying California needs more transmission, but it should be done in a more cost-effective way: through public financing or ownership. The bill currently focuses on a pilot program approach. The sponsor’s hope is to create support for the general concept of public financing and to refine the bill further down the road.

The bill has been referred to both the Senate Energy, Utilities and Communications and Environmental Quality Committees and is awaiting a hearing.

AB 303 (Dawn Addis, D–Monterey) would make it much more difficult to get a Battery Energy Storage System (BESS) licensed in California. Not only would the permitting process be more difficult, but the bill seeks to limit the locations in which a BESS can be placed.

BESS facilities are viewed as an essential tool needed for the state to reach its clean energy goals that employ new technologies and features that make them much safer than the infrastructure at Moss Landing.

CalCCA has taken an oppose position on **AB 303**. The bill has been triple referred, meaning it must move through 3 policy committees. The first stop is the Assembly Committee on Utilities and Energy; however, it has not yet been heard by that committee. It is also referred to the Committees on Natural Resources, and Local Government.

In addition to Asm. Addis, the Moss Landing area is represented in the Legislature by state **Senator John Laird (D-Monterey)**, who has filed a spot bill, **SB 283**. Senator Laird has so far emphasized his intention to take a more cautious approach to this issue. His bill focuses on fire safety standards for BESS. SB 283 seeks to ensure that BESS facilities develop emergency response plans, hold regular safety drills, and document maintenance and incidents. SB 283 does not address the location of BESS facilities.

A third bill to address BESS facilities was introduced at the filing deadline. **AB 1285** is a committee bill whose authorship includes a bipartisan group of six of the seven Assemblymembers comprising the Assembly's Committee on Emergency Management.

AB 1285 centers on developing state-wide specific fire safety guidance for lithium-ion batteries, the type which were in use at Moss Landing.

AB 306 (Nick Schultz, D–Burbank)

Introduced by Assemblymember Schultz and part of a package of bills sponsored by **Assembly Speaker Robert Rivas (D-Salinas),** whose stated goal is to support the rebuild of Southern California and advance home building in the state, **AB 306** would place a 6-year moratorium on reach codes and any other local government efforts to modify building codes on new construction throughout the state, not just in the fire-effected areas. It would also impact existing building modifications.

Peninsula Clean Energy and other CCAs have shared our concerns with the authors and CalCCA has taken an oppose position on the bill. Among the concerns expressed by the CCAs is the fact that electrifying new buildings helps local jurisdictions implement their Climate Action Plans and supports the state's goal of reducing Greenhouse Gas Emissions while creating clean energy jobs. In addition, energy efficiency measures in reach codes help improve building performance while also reducing energy costs and increasing grid reliability.

A letter of concern was submitted by Peninsula Clean Energy prior to the hearing on AB 306. That letter was attached to the March 2025 Board packet.

AB 306 passed out of the Assembly Committee on Housing and Community Development on March 12 by a vote of 12-0 and was re-referred to the Committee on Appropriations where it was also voted out. Designated as an urgency bill, **AB 306** needed a 2/3 vote to pass the state Assembly. It was passed off the floor of the Assembly by a vote of 71-0.

AB 1372 (Papan – San Mateo)

This bill, sponsored by Caltrain, would direct the California Public Utilities Commission to add regenerative braking to those energy sources that would receive compensation under Net Billing Tariff (NBT) and in turn require that Caltrain receive compensation for regenerative braking from PCE and other energy providers.

Peninsula Clean Energy has had extensive conversations with Caltrain and with Asm. Papan's staff on this bill and have shared concerns that as written the legislation infringes upon CCA rate setting autonomy.

Discussions are ongoing and we anticipate bringing this issue to the Board of Directors in the coming months with a request to provide credit to Caltrain for regenerative braking and thereby alleviate any concerns raised by the legislation through an adjustment to PCE's Caltrain tariff.

AB 942 (Calderon – City of Industry)

AB 942 would transition NEM 1.0 and 2.0 solar contracts to NBT after they have been in effect for 10 years. Of particular concern to PCE is how this bill, if it becomes law, would impact on

the GovPV program that places solar infrastructure on government buildings.

This bill has been referred to the Assembly Committee on Utilities and Energy where it is set to be heard on April 30.

Federal Developments of Interest

Peninsula Clean Energy continues to closely monitor the many Executive Orders and legislative actions emanating from the Nation's Capital for their impact on energy policy and Peninsula Clean Energy. This includes the President's recent Executive Order seeking to halt state enforcement of state environmental laws.

As noted in the March Legislative Update, there was an encouraging development on March 9th. A letter was signed by 21 members of the Republican Conference, and addressed to the Chair of the House of Representatives Way and Means Committee, the tax writing committee in that chamber. The letter voiced support for the continuation of "sector-wide energy tax credits" that have led to major investments in "domestic energy production and infrastructure for traditional and renewable energy sources alike." In recent weeks a similar effort in support of energy tax credits was initiated by four U.S. Senators.

During the week of March 31, 2025, PCE staff member Mike Mielke participated in a Washington, D.C. federal advocacy trip organized by LEAN Energy US (Local Energy Aggregation Network). Members of various CCAs from across the U.S., including five California CCAs, held a series of meetings with key federal agencies, congressional staff, and trade associations to assess federal energy policy trends, identify risks and opportunities for CCAs, and align on strategies going forward. These conversations focused heavily on the evolving landscape for tax credits, permitting reform, clean energy funding, and CCA engagement at both the state and federal levels.

The key takeaways from the meetings in Washington are that IRA tax credits are at risk and tax credit defense remains the top priority across stakeholders.

In the short time since the federal advocacy meetings, the President has unveiled significant tariffs. We continue to review the President's proposal and the status of the tariffs for implications on energy markets, California, CCAs and Peninsula Clean Energy.

(Public Policy Objective B, Key Tactic 1)

FISCAL IMPACT

None

ATTACHMENTS:
Asm. Irwin - Level 1 Chargers in Multifamily Housing.pdf
Assembly to CPUC - Reject IOU COC - 03.25.2025 copy.pdf
April 2025 Bill Matrix.docx
LOS - SB 540- SEUC 4.9.25.docx

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Assembly
California Legislature

JACQUI IRWIN
ASSEMBLYMEMBER, FORTY-SECOND DISTRICT

COMMITTEES
AGRICULTURE
BUDGET (1st EX.)
BUSINESS & PROFESSIONS
PRIVACY & CONSUMER PROTECTION
RULES (1st EX.)
RULES
UTILITIES & ENERGY

JOINT COMMITTEES
CHAIR: CLIMATE CHANGE POLICIES

SELECT COMMITTEES
CHAIR: CYBERSECURITY

March 25th, 2025

The Honorable Nancy Skinner
Commissioner
California Energy Commission
715 P Street
Sacramento, California 95814

Hannon Rasool
Director, Fuels and Transportation Division
California Energy Commission
715 P Street
Sacramento, California 95814

Re: CEC EV Charging Infrastructure and Multi-Family Housing

Dear Commissioner Skinner and Director Rasool,

We, the undersigned legislators, write to address the California Energy Commission's (CEC) approach to serving multi-family building residents with electric vehicle (EV) charging. With the State's ambitious climate and EV goals, we are concerned that charging infrastructure serving multi-family housing is falling behind partially due to the restrictions on the Communities in Charge CALeVIP program. By only allowing Level 2 chargers in multi-family housing and only in shared parking stalls, the CEC may have inadvertently limited the pool of tenants or owners that would switch to EVs. Further, these rules may have limited more cost effective solutions that are better suited for a multifamily residents.

While California has made progress on expanding the number of EV charging stations deployed throughout the state, only 150,000 public and private EV chargers have been installed.[1] In order to reach the state's 2035 clean transportation goals, the CEC has found that California needs at least 1 million additional chargers within the next five years. [2] It is urgent to accelerate efforts that will support the millions of EVs needed to reach transportation emissions targets especially in multifamily settings.

We acknowledge that much of the state's non-residential EV charging infrastructure will need to be served by Level 2 and fast chargers. However, Level 1 smart chargers, particularly in assigned parking spots, present a solution to the multi-family dwelling deployment challenge. Providing residents of multi-family housing with access to EV charging is a necessary component of an inclusive and equitable transition to zero-emissions transportation. According to the CEC's latest AB 2127 Staff Report (Revised January 2024[3]), nearly 600,000 EV chargers will be needed at multi-family housing.

Although Level 2 chargers are authorized by the CALeVIP program, the installation and energization process is costly and time consuming. The average cost of installation is about $12,500 each[4], according to current CALeVIP averages. Level 2 charger installation also often triggers time-consuming service upgrades, making it difficult for multi-family property owners to view EV charging as an investment. An analysis commissioned by the CPUC found that it takes 237 business days on average for the state's

[1] https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics-collection/electric
[2] https://www.energy.ca.gov/data-reports/reports/electric-vehicle-charging-infrastructure-assessment-ab-2127
[3] https://efiling.energy.ca.gov/GetDocument.aspx?tn=254161
[4] https://calevip.org/rebate-statistics

three large investor-owned utilities to fulfill an energization request.[5] These limitations will continue to hinder California's ability to increase EV adoption.

Charging needs at multi-family housing differ from those co-located at grocery stores, parking lots, and other convenient sites. Based on census data analyzed by Peninsula Clean Energy, a community choice aggregator (CCA) that provides rebates for Level 1 charging, most drivers park their cars for at least 12 hours per day.[6] When EVs are plugged into Level 2 chargers at multi-family housing, the cars remain parked in the charger parking spot all night but may only use electricity for less than three hours. Level 1 smart chargers help reduce demand and stabilize the grid by consistently drawing low levels of energy over a longer period of time. With the cost of Level 2 charger installation and energization, right-sizing is a practical way to meet appropriate charging needs at multi-family sites.

In order to install the necessary amount of chargers, partnership on smart Level 1 charging at the state level will be crucial. The Clean Transportation Program's CALeVIP block grant of $400 million is one of California's largest investments in light-duty EV charging. Despite its focus on multi-family buildings, CALeVIP has deployed only 2,000 EV chargers at these sites. The CALeVIP program rules only allow Level 2 EV charging stations that "must be shared and not assigned or otherwise allocated to any one individual,"[7] posing a significant impediment and limiting the deployment at multi-unit housing.

The mandate that CALeVIP program funds cannot be used for an individual customer is not consistent with the state's other clean transportation programs. Individual customers can receive state incentives (e.g. CARB Clean Cars for All Program) to *purchase* an electric vehicle. To make EV usage as convenient as possible, the state must consider smart Level 1 charging solutions for drivers in multifamily settings. Right-sizing EV charging will help California reach its clean transportation goals more efficiently and cost-effectively.

We respectfully request that the CEC update the CALeVIP program to allow for Level 1 smart chargers in assigned parking spots as it is sorely needed in order to expand access to EV charging at multi-family buildings.

Sincerely,

JACQUI IRWIN
Assemblymember, 42nd District

DIANE PAPAN
Assemblymember, 21st District

PILAR SCHIAVO
Assemblymember, 40th District

JUAN CARRILLO
Assemblymember, 39th District

CHRIS ROGERS
Assemblymember, 2nd District

CHRIS WARD
Assemblymember, 78th District

[5] https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M540/K719/540719251.PDF
[6] https://www.peninsulacleanenergy.com/wp-content/uploads/2021/09/Determining-the-Appropriate-Level-of-Power-Sharing-for-EV-Charging-in-Multifamily-Properties-1.pdf.
[7] https://thecommunitiesincharge.org/wp-content/uploads/2024/11/Communities-in-Charge-Implementation-Manual-Funding-Wave-3-ADA.pdf

CATHERINE STEFANI
Assemblymember, 19th District

COTTIE PETRIE-NORRIS
Assemblymember, 79th District

MARC BERMAN
Assemblymember, 23rd District

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Assembly
California Legislature

COTTIE PETRIE-NORRIS
ASSEMBLYWOMAN, SEVENTY-THIRD DISTRICT

March 25, 2025

The Honorable Alice Reynolds
President, California Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102

Subject: Urge Rejection of Utility Cost of Capital Applications

Dear President Reynolds,

We urge you to reject the March 20, 2025, applications of Pacific Gas and Electric (PG&E), Southern California Edison (SCE), Southern California Gas (SoCalGas), and San Diego Gas and Electric (SDG&E) as they relate to requested increases to their cost of capital, and specifically by approximately 1% in 2026 to the return on equity (ROE) portion.[1] As academic literature has shown, an increase by one percentage point of the ROE leads to a 3-4% increase in capital assets.[2] These capital assets have a larger cumulative impact on rates, as capital costs are recovered over a longer time horizon during which the higher ROE may be collected. The impact of approving such utility rate requests will be an increase to customer bills throughout the state. Nationwide, these excess costs have resulted in approximately $7 billion per year to the U.S. consumer.[3]

Californians are facing enormous strain at the kitchen table, and specifically with their electric and natural gas bills. The CPUC has long recognized this in its annual *SB 695 Report*, noting electricity rates have increased faster than inflation for customers of California's electric investor-owned utilities (IOUs).[4] Nearly 1 in 5 electric IOU customers are behind on their bills, with the average amount owed approximately $821.[5] This trend is unsustainable. Yet little action has occurred to date. Continuing a business-as-usual approach, and approving these IOU requests to increase their profit structure, will inflict harm on an already pained system.

[1] PG&E ROE = 10.28% in Jan 1, 2025 (D.24-10-008) requesting 11.3%; SCE ROE = 10.33% requesting 11.75%; SoCalGas ROE = 10.08% requesting 11%; and SDG&E ROE = 10.23% requesting 11.25%
[2] Werner, K. D. and Jarvis, S.; "Rate of Return Regulation Revisited;" *Energy Institute WP 329R*; Energy Institute at Haas, University California at Berkeley; *Revised* September 2024.
[3] *Ibid.*
[4] CPUC; *2024 Senate Bill 695 Report*; July 2024; https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/office-of-governmental-affairs-division/reports/2024/2024-sb-695-report.pdf
[5] California Public Advocates Office Q3 2024 Report; December 2024; https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/241205-public-advocates-office-q3-2024-rates-report.pdf

The utility sector is a capital-intensive industry, and utilities need investors to pay for the significant new investment needed to modernize the grid and decarbonize our economy. It is in all our interests that California's utilities are healthy – any increase to their cost of borrowing or decrease to their credit rating results in higher costs to ratepayers, who shoulder the cost of utility financing.[6] However the need for utilities to bring forward significant new capital investments must be balanced with our clear mandate to keep costs low. The IOUs' proposals to increase their ROE does not strike an appropriate balance, and the CPUC should push back firmly.

In striking the right balance, we instead propose a *pivot*; in other words, a change in strategy without a change in vision. We have observed the CPUC traditionally employs a mix of analytical models and subjective judgement to set the ROE, seeking an ROE value that "is necessary to attract capital." However such subjectivity has been found to introduce bias.[7] And the traditional approach of benchmarking against other U.S. utilities, while sometimes advantageous, can cause rates to update very slowly when market conditions change.[8] We urge a change in strategy:

1) **The CPUC should conduct its own independent analysis of ROE.** The CPUC should then center that analysis – which should optimize for customer affordability – as the starting point of the discussion, not the IOUs' applications. In rate cases, the utilities are most knowledgeable about the future needs of their systems, workforce, and equipment. However, is the IOU insight into wider market forces or general investor sentiment (all necessary considerations for ROE) unique? The CPUC should lead the discussion of IOU cost of capital, not be a passive recipient of the IOUs' wishes.

2) **The CPUC should pursue alternative financing options in its evaluation of future capital needs.** The IOUs cite increased wildfire risk, and the potential depletion of the state's Wildfire Fund, as justification for their request for increased ROE.[9] As PG&E notes, "investors have choices where to put their money, and customers will be adversely impacted if PG&E has to curtail its infrastructure…because we cannot obtain the funding…"[10] It is in this atmosphere that the CPUC should more actively partner with the Legislature to explore alternative financing options to attract investment, outside of increases to IOU ROE. These can include securitized financing orders, partnerships with nonprofits, or even state revenue bonds to offset utility cost of borrowing. Both the Legislature and the CPUC should explore these additional tools, and bear them in mind when considering IOU ROE, rather than solely viewing IOU cost of capital as the only tool available to attract investment.

Californians are suffering at the increasing cost of their goods and services, including electric and natural gas bills. It is imperative we bear this reality in mind when evaluating any policy that may impact rates. Achieving a reasonable ROE is a critical regulatory task, one that must balance attracting new investment while keeping consumer costs down. We propose the CPUC adopt the two strategies above in order to strike this balance.

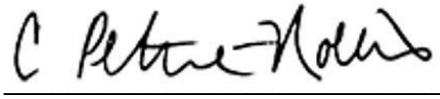
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[6] Pg. 8, John Quackenbush, USAID, *Cost of Capital and Capital Markets: A Primer for Utility Regulators;* December 2019.
[7] Rode, D. C., and Paul Fischbeck; "Regulated equity returns: A puzzle;" *Energy Policy* 133 (October): 110891; 2019. https://doi.org/10.1016/j.enpol.2019.110891.
[8] Pg. 10 Werner, K. D. and Jarvis, S.; "Rate of Return Regulation Revisited;" *Energy Institute WP 329R*; Energy Institute at Haas, University California at Berkeley; *Revised* September 2024.
[9] See applications of PG&E, SCE, and SDG&E
[10] Pg. 1-4; *Pacific Gas and Electric Company Cost of Capital 2026 Prepared Testimony*; March 20, 2025.

Our energy sector is in a period of transformational change; our regulatory structures must transform alongside it. The Legislature stands ready to partner with you in this effort. And we urge you, as a first step, to reject the current IOU applications.

We look forward to receiving a response to our request.

Sincerely,



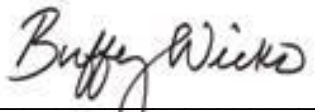
Cottie Petrie-Norris, 73rd Assembly District
Chair, Assembly Committee on Utilities & Energy



Rebecca Bauer-Kahan, 16th Assembly District



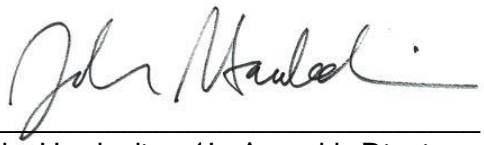
Joe Patterson, 5th Assembly District
Vice-Chair, Assembly Committee on Utilities & Energy



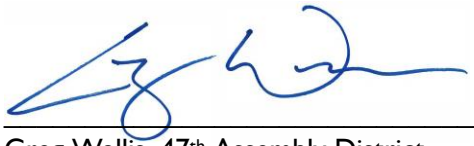
Buffy Wicks, 14th Assembly District



Tri Ta, 70th Assembly District



John Harabedian, 41st Assembly District



Greg Wallis, 47th Assembly District



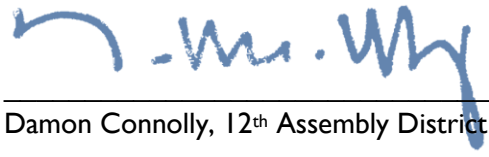
Catherine Stefani, 19th Assembly District



Pilar Schiavo, 40th Assembly District



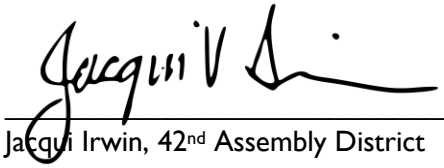
Darshana Patel, 76th Assembly District



Damon Connolly, 12th Assembly District



Chris Rogers, 2nd Assembly District



Jacqui Irwin, 42nd Assembly District



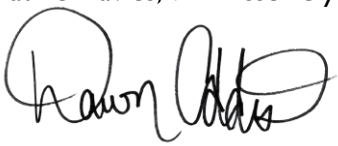
Marc Berman, 23rd Assembly District



Laurie Davies, 74th Assembly District



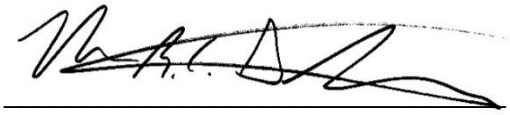
Sharon Quirk-Silva, 67th Assembly District



Dawn Addis, 30th Assembly District



Tina McKinnor, 61st Assembly District



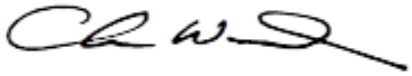
Nick Shultz, 44th Assembly District



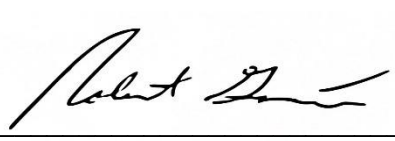
Gail Pellerin, 28th Assembly District



Phillip Chen, 59th Assembly District



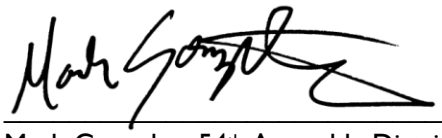
Chris Ward, 78th Assembly District



Robert Garcia, 50th Assembly District



Celeste Rodriguez, 43rd Assembly District



Mark Gonzalez, 54th Assembly District



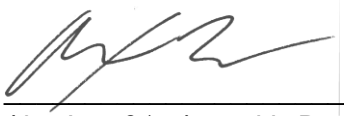
Matt Haney, 17th Assembly District



Liz Ortega, 20th Assembly District



Diane Papan, 21st Assembly District



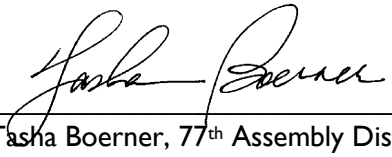
Alex Lee, 24th Assembly District



Steve Bennett, 38th Assembly District



Ash Kalra, 25th Assembly District



Tasha Boerner, 77th Assembly District



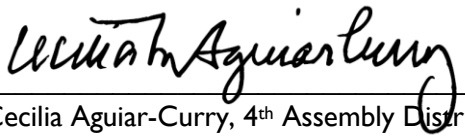
Lisa Calderon, 56th Assembly District



Gregg Hart, 37th Assembly District



Esmeralda Soria, 27th Assembly District



Cecilia Aguiar-Curry, 4th Assembly District
Assembly Majority Leader



Sade Elhawary, 57th Assembly District



Rhodesia Ransom, 13th Assembly District

Cc: Commissioner Darcie Houck, California Public Utilities Commission
Commissioner John Reynolds, California Public Utilities Commission
Commissioner Karen Douglas, California Public Utilities Commission
Commissioner Matthew Baker, California Public Utilities Commission

Status of 2025 Legislative Session Bills
As of April 11, 2025
With Peninsula Clean Energy and CalCCA Adopted Positions

Bill	Summary	Status	PCE Position	CalCCA Position	Comments
AB 259 (B. Rubio) Brown Act Exemption: Remote Participation	This bill would remove the January 1, 2026, sunset that allows members of a local legislative body to appear remotely, under certain circumstances, without having to provide their location and other requirements of the Brown Act.	Awaiting vote on the Assembly Floor. Passed the Assembly Committee on Local Government			This is a simple sunset removal to extend the policy first enacted by AB 2449, the bill Asm. Rubio authored in 2022. The bill is sponsored by the CA Special Districts Assn.
AB 303 (Addis) Battery Energy Storage Facilities	Existing law, until June 30, 2029, authorizes a person proposing an eligible facility, including an energy storage system capable of storing 200 megawatt hours or more of energy, to submit an application for certification with the State Energy Resources Conservation and Development Commission of the site and related facility. Existing law specifies that the issuance by the commission of the certificate is in lieu of any permit, certificate, or similar document required by any state, local, or regional agency, or federal agency to the extent permitted by federal law, except as provided. Existing law establishes the procedures by which the commission is to review the application. This bill would specify that energy	Awaiting hearing in the Assembly Committee on Utilities & Energy. Bill was pulled from the April 2 hearing in the Assembly Committee on Utilities & Energy. The bill is also referred to Assembly Natural Resources and		Oppose	

Bill	Summary	Status	PCE Position	CalCCA Position	Comments
	storage systems do not include battery energy storage systems for the above-described purposes. This bill contains other related provisions and other existing laws.	Local Government Committees.			
AB 306 (Schultz) Building Regulations: state building standards	Existing law authorizes any city or county to make changes to building standards that are published in the code, including to green building standards. Existing law requires the governing body of a city or county, before making modifications or changes to those green building standards, to make an express finding that those modifications or changes are reasonably necessary because of local climatic, geological, or topographical conditions. 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.	Awaiting Committee Referral in the Senate. Passed the Assembly on a 71-0 vote.	Concern	Oppose Unless Amended	

Status of 2025 Legislative Session Bills
As of April 11, 2025
With Peninsula Clean Energy and CalCCA Adopted Positions

Bill	Summary	Status	PCE Position	CalCCA Position	Comments
AB 526 (Papan) Geothermal Energy Generation	This bill would require the Energy Commission, in coordination with the PUC, Air Resources Board, and other state agencies, to develop a strategic plan for the development of new in-state geothermal energy. The bill would also 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	Scheduled for April 21 hearing in Assembly Committee on Utilities & Energy	Moving to Support	Support	This bill is sponsored by Sonoma Clean Power.
AB 527 (Papan) CEQA: Geothermal Exploratory Projects	This bill proposes to create a categorical exemption from CEQA for geothermal exploratory wells.	Scheduled for April 21 hearing in Assembly Committee on Utilities & Energy		Support	This bill is sponsored by Sonoma Clean Power.
AB 531 (Rogers) Environmental Leadership Development Projects: Geothermal	This bill would expand the types of facilities eligible to be certified as environmental leadership development projects by the Energy Commission, which enjoy CEQA streamlining benefits, to include geothermal powerplants and geothermal field development projects	Referred to Assembly Committee on Natural Resources Passed Assembly Committee on Utilities & Energy on Consent		Support	This bill is sponsored by Sonoma Clean Power and co-authored by Asm. Papan

Status of 2025 Legislative Session Bills
As of April 11, 2025
With Peninsula Clean Energy and CalCCA Adopted Positions

Bill	Summary	Status	PCE Position	CalCCA Position	Comments
AB 915 (Petrie-Norris) Clean Energy Reliability Investment Plan	This bill would appropriate the remaining $900 million to the Clean Energy Reliability Investment Plan contained in SB 846 (Dodd, 2022)	Awaiting committee referral			
AB 941 (Zbur) CEQA: Electrical Infrastructure Projects.	This bill would require the PUC 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.	Referred to Assembly Committee on Natural Resources Passed Assembly Committee on Utilities & Energy		Support	
SB 57 (Padilla) Data Centers: Special Rates	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.	Referred to the Senate Committee on Appropriations Passed the Senate Committee Energy, Utilities & Communications			
SB 239 (Arreguín)	This bill would authorize a subsidiary body, defined as one that serves exclusively in an advisory capacity and has no final decision-	Referred to the Senate Committee on Judiciary			A very similar bill was attempted in the last session as

Bill	Summary	Status	PCE Position	CalCCA Position	Comments
Brown Act Exemption: Subsidiary Bodies	making authority, to use similar alternative teleconferencing provisions and would impose requirements for notice, agenda, and public participation, as prescribed. To use teleconferencing pursuant to this act, the bill would require the legislative body that established the subsidiary body by charter, ordinance, resolution, or other formal action to make specific findings by 2/3 vote before the subsidiary body uses teleconferencing for the first time and every 12 months thereafter.	Passed the Senate Committee on Local Government			AB 817 (Pacheco). That bill failed to pass the Senate Local Government Committee as the author refused to accept certain amendments.
SB 254 (Becker) FERA Customers	Existing law requires the PUC, by March 1, 2025, and each year thereafter, to require the state's 3 largest IOUs to report on their efforts to enroll customers in the FERA program and to review those reports to ensure the IOUs have made reasonable efforts to enroll eligible households in the FERA program. If the commission, in its review of a report, determines an IOU has not made reasonable efforts to enroll eligible households in the FERA program, the PUC shall require the IOU to develop a strategy and plan to sufficiently enroll eligible households within 3 years of the adoption of the strategy and plan. This bill would additionally require each electrical corporation's report to provide a breakdown of the number of eligible	Referred to the Senate Committee Energy, Utilities & Communications	Moving to Support		

Bill	Summary	Status	PCE Position	CalCCA Position	Comments
	households and FERA program enrollment by disadvantaged community, as defined by the PUC. The bill would also require the above-described strategy and plan to include strategies to reach households in disadvantaged communities.				
SB 282 (Wiener) Residential Heat Pump Systems: Water Heaters and HVAC: Permit Streamlining	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 HVAC systems to obtain a heat pump installation certification. The bill would authorize a licensed contractor with a heat pump system installation certification described above to self-certify that the installation of a residential heat pump water heater or heat pump HVAC system meets all relevant code requirements without any requirement that an inspector be present for the installation, and would require a city, including a charter city, county, or city and county to accept the certification for those purposes, as specified.	Referred to the Senate Committee on Local Government Passed the Senate Committee on Energy, Utilities & Communications			This bill is co-sponsored by SPUR, Bay Area Air District, and Building Decarb Coalition
SB 283 (Laird) Battery Energy Storage Facilities: Emergency	Existing law requires the State Fire Marshal, before the next triennial edition of the California Building Standards Code adopted after January 1, 2025, to propose to the Building Standards Commission (commission) updates to	Scheduled for April 21 hearing in Senate Committee on Energy, Utilities & Communications		Support if Amended	

Bill	Summary	Status	PCE Position	CalCCA Position	Comments
Response Plans and Emergency Action Plans	the fire standards relating to requirements for lithium-based battery systems, as provided. This bill would require the commission and the Office of the State Fire Marshal to review and consider the most recently published edition of the National Fire Protection Association (NFPA) 855, Standard for the Installation of Stationary Energy Storage Systems, for incorporation into the next update of the California Building Standards Code adopted after July 1, 2026. This bill contains other related provisions and other existing laws.				
SB 302 (Padilla) County Sealers: EV Chargers	This bill would align California's tax code with provisions in the Inflation Reduction Act that expand financing options for clean energy developers. In other states, developers may exclude, when reporting their gross income, earnings from the sale of clean energy tax credits, which accrue under the law once projects are up and running.	Referred to the Senate Appropriations Committee Suspense File		Support	
SB 314 (Padilla) Electric Vehicle Supply Equipment: Weights & Measures	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	Scheduled for the April 28 hearing in the Senate Committee on Business, Profession, &			

Bill	Summary	Status	PCE Position	CalCCA Position	Comments
	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.	Economic Development			
SB 330 (Padilla) Transmission Infrastructure Financing	Enables the Governor to establish one or more pilot projects to develop, finance, or operate electrical transmission infrastructure that meet certain criteria, including: being identified by the ISO in its transmission planning process, provides a significant reduction in cost, and is implemented under a PLA. Authorizes the Governor to designate existing state agencies, local public agencies, tribal organizations, or joint powers authorities to implement the pilot projects	Scheduled for April 29 hearing in Senate Committee on Energy, Utilities & Communications		Support	
SB 332 (Wahab) PUC Commissioners	Would require the Energy Commission, in coordination with the public advisor and the PUC, on or before March 31, 2026, to issue a request for proposals for a team to undertake a study to (1) conduct a historical energy justice assessment of IOU operations and impacts, (2)	Scheduled for April 21 hearing in Senate Committee on Energy, Utilities & Communications			

Bill	Summary	Status	PCE Position	CalCCA Position	Comments
	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 IOU model, create a justice-centered implementation plan for managing the transition. The bill would require the Energy Commission to hold a public proceeding and submit a report of the study team's findings and recommendations to the Legislature no later than 24 months after selecting the study team for the feasibility portion of the study, and no later than 36 months after selecting the study team for the implementation plan portion of the study, as specified.	Scheduled for April 21 hearing in Senate Committee on Judiciary			
SB 540 (Becker) Western Regional Organization	This bill codifies the West-Wide Pathways recommendation to authorize CAISO to relinquish its singular control of the Western Energy Imbalance Market (EIM) and Western Enhanced Day Ahead Market (EDAM) so that those two markets could be governed by an independent western regional organization	Scheduled for the April 21 hearing in Senate Committee on Energy, Utilities & Communications Scheduled for the April 29 hearing in Senate Committee on Judiciary	Support	Support	This is the effort to create a new western regional organization that is an interim step to the full western regionalization grid

Status of 2025 Legislative Session Bills
As of April 11, 2025
With Peninsula Clean Energy and CalCCA Adopted Positions

Bill	Summary	Status	PCE Position	CalCCA Position	Comments
SB 541 (Becker) Load Shifting: Dynamic Pricing	Existing law requires the CEC to adopt a biennial integrated energy policy report (IEPR). Existing law requires the CEC, in consultation with the PUC and the ISO, to adopt a goal for load shifting to reduce net peak electrical demand and adjust this target in each biennial IEPR. This bill would require the CEC, as part of each IEPR, to allocate the incremental load shifting needed to reach the above-described load-shifting goal, including biennial adjustments to the goal, to each retail supplier. The bill would require the CEC to establish rules for evaluating the effectiveness of the various load-shifting strategies for the purpose of determining how much credit a retail supplier should get for each type of load flexibility effort it undertakes, as specified.	Scheduled for the April 21 hearing in Senate Committee on Energy, Utilities & Communications			CalCCA and individual CCAs have engaged with Sen. Becker's staff to explain concerns and there has been acknowledgement to work together to address those concerns.
SB 707 (Durazo) Open Meetings: Brown Act Requirements	This bill is an omnibus proposal for exemptions to the Brown Act for local public meetings including extending until 1/1/30 the AB 2449 sunset, authorizing virtual meetings for subsidiary bodies, neighborhood councils, and multijurisdictional bodies. For multijurisdictional bodies, an in-person quorum must be established, each remote attending member must be identified in the agenda, a member receiving compensation must participate from a	Scheduled for April 22 hearing in theSenate Committee on Judiciary Passed the Senate Committee on Local Government			

Bill	Summary	Status	PCE Position	CalCCA Position	Comments
	physical location accessible to the public, the remote participating members must be at least 20 miles round trip from the in-person meeting location.				

PENINSULA CLEAN ENERGY

San Mateo County | Atherton | Belmont | Brisbane | Burlingame | Colma | Daly City | East Palo Alto | Foster City
Half Moon Bay | Hillsborough | Los Banos | Millbrae | Menlo Park | Pacifica | Portola Valley | Redwood City | San Bruno |
San Carlos San Mateo | South San Francisco | Woodside

April 9, 2025

The Honorable Josh Becker
Chair, Senate Energy, Utilities & Communications Committee
1021 O St., Suite 6520
Sacramento, CA 95814

Re: SB 540 (Becker) - SUPPORT

Dear Senator Becker,

On behalf of Peninsula Clean Energy Authority (PCE), a community choice aggregator (CCA) serving approximately 800,000 Californians in San Mateo County and the City of Los Banos in Merced County, we write in strong support of your SB 540, a bill that will help lower net total electricity system costs and promote a more efficient and affordable clean energy future for California.

Electricity affordability is central to Peninsula Clean Energy's mission. As a community-led energy provider, PCE is committed to delivering clean, reliable power at competitive rates to the residents and businesses we serve. Rising electricity costs, driven in part by system inefficiencies and increasing levels of renewables without corresponding system optimization, place a growing burden on ratepayers and pose challenges to achieving equitable climate goals across the state.

SB 540 would authorize California to participate in a regional organization (RO), subject to a robust governance and withdrawal framework. This participation enables more efficient dispatch of generation resources across a broader western footprint, integrating renewables more effectively and reducing system redundancies. According to analysis provided in support of SB 540, the state could realize up to $800 million in net annual savings by optimizing resource sharing across the western grid through a regional market. These cost savings can directly translate into lower bills for customers and allow for more reinvestment in clean energy innovation and reliability improvements.

Importantly, SB 540 maintains California's leadership on clean energy policy. The bill does not alter requirements under the state's Renewable Portfolio Standard (RPS), change the 100% clean electricity goals established by SB 100, or expand the jurisdiction of the Federal Energy Regulatory Commission (FERC) over California's energy markets. Instead, it strengthens the state's ability to meet its clean energy targets at lower cost and with greater reliability.

The bill also contains critical protections by establishing clear safeguards and governance principles for participation, including a process for California Independent System Operator (CAISO) withdrawal if that

becomes necessary. These provisions ensure that California's interests remain protected while accessing the economic and environmental benefits of regional collaboration.

Peninsula Clean Energy appreciates your leadership on this issue and strongly supports SB 540 as a responsible, forward-looking solution to support affordability, reliability, and environmental progress.

Sincerely,

Shawn Marshall
Chief Executive Officer

cc: The Honorable Members of the Senate Energy, Utilities & Communications Committee

PENINSULA CLEAN ENERGY

PENINSULA CLEAN ENERGY AUTHORITY
JPA Board Correspondence

DATE: April 18, 2025
MEETING DATE: April 24, 2025
VOTE REQUIRED: None

TO: Honorable Peninsula Clean Energy Authority Board of Directors

FROM: Nelly Wogberg, Board Clerk

SUBJECT: Report on California Community Power (CCP) Joint Powers Authority

ATTACHMENTS:
CC Power Board Report for March 19 2025.pdf

California Community Power

901 H St, Ste 120 PMB 157, Sacramento, CA 95814 | cacommunitypower.org

TO: CC Power Board of Directors and Alternates **DATE:** 3/26/25
FROM: Alex Morris – General Manager
SUBJECT: **Report on CC Power Regular Board of Directors Meeting – March 19, 2025**

The CC Power Board of Directors held its December Board Meeting on March 19, 2025, via Zoom. Details on the Board packet, presentation materials, and public comment letters can be found under the Meetings tab at the CC Power website: Meetings and Agendas – ca community power

Highlights of the meeting included the following:

- **Matters subsequent to posting the Agenda.** None.
- **Public Comment.** None.
- **Consent Agenda** - The Board approved the following items:
  - Minutes of the Regular Board Meeting held on January 22, 2025.
- **Regular Agenda Items**:
  - **Work-Planning and Budget *Ad Hoc* Committee Update*:*** Chair Lori Mitchell (SJCE) shared about timelines and approaches to establishing the 2025-2026 CC Power budget. By April, a draft budget will be available. Board consideration is expected in April or May. The *Ad Hoc* Committee includes Chair Mitchell, Treasurer Mitch Sears (VCE), Monica Padilla (SVCE), and Shawn Marshall (PCE)
  - **General Manager Report:** the General Manager provided updates to the Board, including on current work to explore wind and energy storage projects for member consideration, dates and target locations for the Fall Forum annual event, and on the member-survey for work-planning. Market conditions for power projects are showing higher uncertainty due to tariffs and Federal positions on certain resource-types and permitting.
  - **Discussion on Coordinated Operations Agreement:** CC Power's Tumbleweed energy storage project is scheduled to come online in April 2026 (13-months). Pursuant to CC Power's established contracts, CC Power must work with members to develop a Coordinated Operations Agreement (COA) under which operating decisions for power projects are made, including how participating members can provide input on power project operations, such as outage management, bidding strategies, etc. CC Power staff shared potential approaches and feedback from member-staff to date, notifying the Board that a draft-final COA will be brought for Board Consideration in April.

PENINSULA CLEAN ENERGY

PENINSULA CLEAN ENERGY AUTHORITY
JPA Board Correspondence

DATE: April 18, 2025
MEETING DATE: April 24, 2025
VOTE REQUIRED: None

TO: Honorable Peninsula Clean Energy Authority Board of Directors

FROM: Brianna Arroyo, Administrative Assistant

SUBJECT: Social Media FAQ's

ATTACHMENTS:
PCE_ How to handle comments on Nextdoor.pdf
PCE_Social media talking points.pdf

How to handle comments on Nextdoor

What qualifies as an incendiary comment?

- The post contains aggressive or accusatory language.
- The post spreads misinformation about PCE's programs, services, or billing—or about clean energy.
- The post escalates negativity within the Nextdoor community, even if the original post is not negative.

How do I know if PCE should respond?

- ☐ Does the comment contain misinformation that could harm PCE's reputation?
- ☐ Is the comment receiving significant, negative attention (likes, replies, etc.)?
- ☐ Does responding to the post align with PCE's values and commitment to candor, transparency, and community support?
- ☐ Is someone asking a question related to PCE's billing or services?

It may be helpful to respond proactively, even if the original comment isn't particularly negative. This early intervention can help prevent misinformation and keep the community conversation on track.

I found an incendiary comment. What should I do next?

1. **Notify the Marketing team.**
   Send an email with the subject line: "Nextdoor comment for review" with a direct link to the post and any necessary screenshots to the following PCE team members:

   - Aleisha Juarez, ajuarez@peninsulacleanenergy.com
   - Kerstin Grune (cc'd), kgrune@peninsulacleanenergy.com
   - Gwen Rose (cc'd), grose@peninsulacleanenergy.com
   - Kirsten Andrews-Schwind (cc'd), kandrews-schwind@peninsulacleanenergy.com
   - Jayden Hanan (cc'd), jhanan@peninsulacleanenergy.com

2. **Be prepared to take action.**
   Given Nextdoor's limited access, we may ask you to respond via your personal profile. If the Marketing team confirms that a response is necessary, we will provide you with the appropriate post copy.

Helpful reminders

- When you see a negative Nextdoor comment, be a calm observer and collect details for escalation.
- Do not engage with incendiary comments, unless the Marketing team provides you with post copy.
- Responses on behalf of PCE should always reflect the organization's values.
- Stay ahead of the negativity: Responding to questions early can help keep the tone positive and prevent the situation from escalating.

PENINSULA CLEAN ENERGY

Social media FAQs

Here are some helpful tips for responding to frequently asked questions about Peninsula Clean Energy (PCE) on social media. Frame your response in a way that is accurate, concise, and friendly—all while staying true to PCE's mission and values. Feel free to adapt these prompts to your own voice, keeping it casual, personable, and polite.

Depending on the social media platform, your response could also encourage people to contact PCE Support for more information at info@peninsulacleanenergy.com or 1-866-966-0110.

What is Peninsula Clean Energy (PCE)? How is PCE different from PG&E?
PCE is your local, not-for-profit electricity provider. PCE provides the majority of the electricity supply—97% in fact—for San Mateo County and Los Banos.

PCE provides you with clean electricity, while PG&E delivers it to you through their wires. It's kind of like ordering takeout from your favorite restaurant (PCE) and having a food delivery service (PG&E) deliver it to your door.

Does PCE cost more than PG&E?
No! PCE's rates are competitive with or even lower than PG&E's, so you save money with PCE. You can compare PCE's and PG&E's rates here:
https://www.pge.com/assets/pge/docs/account/alternate-energy-providers/pce-sm_rateclasscomparison.pdf

Why was I automatically enrolled?
Your city or county voted to join PCE to bring cleaner, affordable energy to your community.

Can I opt out of PCE?
Yes, you can opt out. However, PCE's rates are typically lower than PG&E's, so opting out of PCE will make your electricity bill go up.

I opted out of PCE and my bill went down.
When you opted out of PCE, PG&E put you on a special temporary rate (TBCC) for six months. Recently, this rate has been lower than PCE's, which is probably why your bill went down. However, after six months, you'll be switched back to PG&E's regular rates, which are at least 5% higher than PCE's. So, even though it seems like you're saving money now, your bill will likely go up in the long term.

What clean energy options do I have?
You are automatically enrolled in ECOplus, which is 100% clean, 50% from renewable sources, and cheaper than PG&E. If you want to do even more good for the environment, you can upgrade to ECO100, which is 100% renewable energy for a small additional cost.

I have solar power. Why do I still have fees?
PCE only charges for the electricity you use beyond what your solar panels generate. If your panels produce less energy than your household needs, you'll see charges for the extra electricity you pulled from the grid. However, if your solar panels generate more energy than you use, PCE gives you a credit!

Why did my bill go up after switching to PCE?
Your bill increase is likely due to PG&E's delivery rates, not PCE. In fact, PCE has frozen rates multiple times to keep costs stable and put savings back in customers' pockets.

PENINSULA CLEAN ENERGY

PENINSULA CLEAN ENERGY AUTHORITY
JPA Board Correspondence

DATE: April 18, 2025
MEETING DATE: April 24, 2025
VOTE REQUIRED: None

TO: Honorable Peninsula Clean Energy Authority Executive Committee

FROM: Nelly Wogberg, Board Clerk

SUBJECT: Acronym List

ATTACHMENTS:
ACRONYMS - as of 02-01-2024.pdf

PENINSULA CLEAN ENERGY

COMMONLY USED ACRONYMS AND KEY TERMS

AB xx – Assembly Bill xx
ALJ – Administrative Law Judge
AMP - Arrears Management Plans
Apple Valley Choice Energy
AQM – Air Quality Management
Ava – Formally East Bay Community Energy
BAAQMD – Bay Area Air Quality Management District
BLPTA – Buyer Liability Pass Through Agreement
CAC – Citizens Advisory Committee
CAISO – California Independent System Operator
CalCCA – California Community Choice Association
CAM – Cost Allocation Mechanism
CAP – Climate Action Plan
CAPP – California Arrearage Payment Program
CARB – California Air Resources Board, or California ARB
CARE - California Alternative Rates for Energy Program
CBA – California Balancing Authority
3CE- Central Coast Community Energy (Formerly Monterey Bay Community Power-MBCP)
CCA – Community Choice Aggregation (aka Community Choice Programs (CCP) or
CCE – Community Choice Energy (CCE)
CCCFA – California Community Choice Financing Authority
CC Power – California Community Power
CEC – California Energy Commission
Clean Energy Alliance – CCA in
CPA – Clean Power Alliance
Clean Power SF
CPP - Critical Peak Pricing
CPSF – Clean Power San Francisco
CPUC – California Public Utility Commission (Regulator for state utilities) (Also PUC)
CSD – California Department of Community Services and Development
CSGT - Community Solar Green Tariff
Customer Centricity - culture, framework and business strategy based on providing a positive customer experience and building long-term relationships
DA – Direct Access
DAC-GT - Disadvantaged Communities Green Tariff
DER – Distributed Energy Resources
Desert Community Energy
DG – Distributed Generation
DOE – Department of Energy
DR – Demand Response
DRP – Demand Response Provider
DRP/IDER – Distribution Resources Planning / Integrated Distributed Energy Resources
EBCE – East Bay Community Energy now known as Ava Community Energy
ECOplus – PCE's default electricity product, 50% renewable and 50% carbon-free (in 2021)
ECO100 – PCE's 100% renewable energy product

EDR – Economic Development Rate
EE – Energy Efficiency
EEI – Edison Electric Institute; Standard contract to procure energy & RA
EIR – Environmental Impact Report
ELCC – Effective Load Carrying Capability
EPIC – Energy for Palmdale's independent Choice
ESP – Electric Service Provider
ESS – Energy Storage Systems
ESSA – Energy Storage Services Agreement
ERRA – Energy Resource Recovery Account
EV – Electric Vehicle
EVSE – Electric Vehicle Supply Equipment (Charging Station)
FERA- Family Electric Rate Assistance Program
FERC – Federal Energy Regulatory Commission
FFS – Franchise Fee Surcharge
GHG – Greenhouse gas
GHG-Free – Greenhouse gas free
GTSR – Green Tariff Shared Renewables
GWh – Gigawatt Hours (Energy) = 1000 MWh
Heavy Duty Vehicle – large vehicles such as busses and long-haul trucks
HPWH – Heat Pump Water Heater
HP HVAC – Heat Pump Heating, Ventilation, and Air Conditioning
HR xx – House of Representatives Bill xx
IDER – Integrated Distributed Energy Resources
IGFC – Income Graduated Fixed Charge
IOU – Investor-Owned Utility (e.g. PG&E, SCE, SDG&E)
IIJA – Infrastructure Investment and Jobs Act
IRA – Inflation Reduction Act
IRP – Integrated Resource Plan
IVR – Interactive Voice Response
ITC – Investment Tax Credit (it's a solar tax credit)
JCC – Joint Cost Comparison
JPA – Joint Powers Authority
JRC – Joint Rate Comparison
JRM – Joint Rate Mailer
kW – kilowatt (Power)
kWh – Kilowatt-hour (Energy)
Lancaster Energy
Light Duty Vehicle - passenger vehicles such as cars and small pickup trucks
LDS – Long Duration Storage
LDES – Long Duration Energy Storage
LIHEAP- Low Income Home Energy Assistance Program
Load Shaping – changing when grid energy is used
LSE – Load Serving Entity
MCE – Marin Clean Energy
Methane Gas - formerly known as 'natural gas'
Microgrid – building or community energy system
Mid Duty Vehicle – vehicles such as passenger vans
MW – Megawatt (Power) = 1000 kW
MWh – Megawatt-hour (Energy) = 1000 kWh

MTR – Mid-Term Reliability
MUD – Multi-unit Dwelling
NBCs – non-bypassable charges
NBT – Net Billing Tariff
NEM – Net Energy Metering
NERC – North American Electric Reliability Corporation
NDA – Non-Disclosure Agreement
NG – Natural Gas
OBF – On-bill Financing
OBR – On-bill Repayment
OCPA – Orange County Power Authority
OES – Office of Emergency Services
OIR – Order Instituting Rulemaking
PACE – Property Assessed Clean Energy
PCC – Portfolio Content Category (aka "buckets") – categories for RPS compliance
PCC1 – Portfolio Content Category 1 REC (also called bucket 1 REC)
PCC2 – Portfolio Content Category 2 REC (also called bucket 2 REC)
PCC3 – Portfolio Content Category 3 REC (also called bucket 3 REC or unbundled REC)
PCEA – Peninsula Clean Energy Authority
PCIA – Power Charge Indifference Adjustment
PCL – Power Content Label
Pioneer Community Energy
PLA – Project Labor Agreement
POU – Publicly Owned Utility
Pomona Choice Energy
PPA – Power Purchase Agreement
PPSA – Project Participation Share Agreement (CC Power)
PRIME – Pico Rivera innovative Municipal Energy
PSPS – Public Safety Power Shutoff
PV – Photovoltaics (solar panels)
Rancho Mirage Energy Authority
RA – Resource Adequacy
RE – Renewable Energy
REC – Renewable Energy Credit/Certificate
Redwood Coast Energy Authority
RICAPS - Regionally Integrated Climate Action Planning Suite
RPS – California Renewable Portfolio Standard
S xx – US Senate Bill xx
SB xx – CA Senate Bill xx
Santa Barbara Clean Energy
SBP – Solar Billing Plan
SCP – Sonoma Clean Power
SDCP – San Diego Community Power
SJCE – San Jose Clean Energy
San Jacinto Power
SJVAPCD - San Joaquin Valley Air Pollution Control District
SMD – Share My Data, interval meter data
SQMD – Settlement Quality Meter Data
SVCE – Silicon Valley Clean Energy
TOB – Tariff on Bill

TOU Rates – Time of Use Rates
Valley Clean Energy
VGI – Vehicle-Grid Integration
V2G – Vehicle-to-Grid
VPP – Virtual Power Plant
WECC – Western Energy Coordinating Council
WREGIS – Western Renewable Energy Generation Information System
WSPP – Western Systems Power Pool; standard contract to procure energy and RA
WWGPI - West-Wide Governance Pathways Initiative