BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U-902-E) to Extend and Modify The Power Your Drive Pilot Approved By Decision 16-01-045.	Application 19-10-012 (Issued October 28, 2019)

DIRECT TESTIMONY OF PAUL L. CHERNICK & JOHN WILSON ON BEHALF OF SMALL BUSINESS UTILITY ADVOCATES

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May 18, 2020

SBUA Small Business Utility Advocates

TABLE OF CONTENTS

ATTACHMENTS

I. Identification & Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: My name is Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a Bachelor of Science degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and a Master of Science degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, conservation program design, estimation of avoided costs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Attachment-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over three hundred and fifty times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-seven states and six Canadian provinces, and three U.S. federal agencies. This previous testimony has included planning and ratemaking for distributed resources, distributed resource planning, the benefits of load reduction on the distribution and transmission systems, utility planning, marginal costs, and related issues.

I have filed testimony in five California PUC proceedings since June 2018.

Q: Mr. Wilson, please state your name, occupation, and business address.

A: I am John D. Wilson. I am the research director of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a BA degree from Rice University in 1990, with majors in physics and history, and an MPP degree from the Harvard Kennedy School of Government with an emphasis in energy and environmental policy, and economic and analytic methods.

I was deputy director of regulatory policy at the Southern Alliance for Clean Energy for more than twelve years, where I was the senior staff member responsible for SACE's utility regulatory research and advocacy, as well as energy resource analysis. I engaged with southeastern utilities through regulatory proceedings, formal workgroups, informal consultations, and research-driven advocacy.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, conservation program design, ratemaking and cost recovery for utility efficiency programs, allocation of costs of service between rate classes and jurisdictions, design of retail rates, and performance-based ratemaking for electric utilities.

My professional qualifications are further summarized in Attachment-2.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than a dozen times before utility regulators in the Southeast U.S. and Nova Scotia, and appeared numerous additional times before various regulatory and legislative bodies.

II. Introduction

Q: On whose behalf are you testifying?

A: We are testifying on behalf of Small Business Utility Advocates.

Q: What is the scope of your testimony?

A: We review the application of San Diego Gas & Electric (SDG&E or the Company) for the Power Your Drive Extension.

Q: What issues do you address?

A: We address three aspects of SDG&E's proposed extension:

- Budget controls.
- Ensuring that utility-installed chargers advance California's goal for electric vehicles.
- Outreach to small business customers.

Our focus is primarily on workplace charging, although some of our comments address multi-unit dwellings (MUDs) and disadvantaged communities (DACs).

Q: What are your conclusions regarding the SDG&E application?

A: SDG&E's Power Your Drive (PYD) extension addresses a well-established market need to achieve California's electric transportation goals. Overall, the PYD pilot appears to have achieved significant learning with respect to site host engagement and the construction process.

The overall objective of PYD and other transportation electrification programs is to transform the transportation market by reducing the barriers to EV ownership. As SDG&E states, the availability of chargers "will send a signal to drivers that owning and operating an EV is within reach."[1]

While SDG&E makes a strong case that it has succeeded in deploying over 3,000 charging ports and implementing an innovative Vehicle Grid Integrated rate ("VGI rate"), it is less certain whether the "signal to drivers" has been successfully received. We believe that some modest adjustments to SDG&E's program could strengthen that signal, and better measure the response. These improvements would expand the information that can be learned from the pilot and better position SDG&E to develop a broader transportation electrification program.

Q: What do you recommend?

A: In order to strengthen the "signal to drivers," we recommend approaches that would stretch the program budget further, by limiting the cost per port and increasing customer cost participation. We also suggest that SDG&E strive

[1] SDG&E, Application Ch. 1, p. BAS-5 at 16-17.

towards limiting the cost based on the number of drivers served who do not have alternative regular access to charging facilities, as well as the number of new EVs acquired due to the additional charging facilities. SDG&E does not currently have the necessary data to associate drivers or EV purchases with specific charging facilities; it is timely for SDG&E to prepare for those analyses.

In order to better measure the effectiveness of the charging-access signal, we recommend several steps:

- Consider expanding utility ownership of electric vehicle service equipment (EVSE), rather than shifting to make-ready only at workplaces.
- Enhance evaluation, measurement and verification (EM&V) with a third-party report, similar to those conducted for energy efficiency programs.
- Increase the focus of the program (and EM&V) reporting requirements on increasing EV adoption rates and supporting drivers "who otherwise might not have access to regular charging facilities."[2]
- Enhance the outreach strategy to address market barriers faced by small businesses.

III. Budget Controls.

Q: What is SDG&E's budget for the Power Your Drive (PYD) extension?

A: SDG&E proposes $58.4 million in total capital and O&M expenditures to install approximately 2,000 ports at 200 sites.[3] Because SDG&E is proposing

[2] SDG&E, Application Ch. 1, p. BAS-10 at 1-2.

[3] SDG&E, Application Ch. 2, Table 2-1, p. RS-2; Ch. 3, Table 3-6, p. JB-6.

a two-way balancing account, if the actual revenue requirement is exceeded, SDG&E is requesting that those costs be put into rates and collected from ratepayers.

In other words, SDG&E is not proposing a minimum number of charger ports or sites, nor is it proposing a budget cap. The revenue requirement is only constrained by SDG&E's best practices that it has developed to control costs.

Q: What was the cost per port in the PYD Pilot?

A: For Level 2 chargers, the average total cost per port (including installation and interconnection costs) was about $22,900.[4] This value does not change significantly whether the charging installation is in a parking lot or a structure, or whether it is at a workplace or multi-unit dwelling. This cost is roughly double what SDG&E estimated in its original filing.[5]

Q: What is SDG&E's current cost-effectiveness requirement?

A: SDG&E does not have a specific cost per site or cost per port threshold.[6] SDG&E lists "Estimated cost for infrastructure and EV charging station installation" as one of ten factors it considers "when evaluating and prioritizing the interested sites for installation."[7]

During SDG&E's technical webinar, program staff described a number of best practices that have been developed during the pilot program that will

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[4] SDG&E Response to Cal PA DR-02, Question 2, A.19-10-012 (February 17, 2020).

[5] SDG&E, Electric Vehicle Integrated Pilot Program (Power Your Drive) Semi-Annual Report of SDG&E (Corrected Version, September 2019), Figure 10, p. 11.

[6] Confirmed during Q&A period of SDG&E's Power Your Drive Extension Program Technical Workshop (May 13, 2020).

[7] SDG&E, Application Ch. 2, pp. RS-8 at 16 to RS-9 at 9.

"Prevent unnecessary expenditure of resources and funds" and "Reduce excess materials and equipment."[8]

Q: What other budget control mechanisms does SDG&E propose?

A: SDG&E describes several other budget control mechanisms for the PYD Extension, but these would not differ significantly from those in the PYD Pilot.[9] SDG&E expects site hosts to provide land and otherwise facilitate the project. SDG&E will also seek non-utility sources of funding.

The funding of the EVSEs would vary between MUD and workplace sites. SDG&E is proposing to pay for facilities with MUD hosts, charging the Non-DAC MUD sites a very small participation payment ($350 per port, less than 2% of the typical cost per port).[10] For workplace sites, the customer would be responsible for purchasing, installing and energizing the EVSE. SDG&E would provide a rebate to cover the equipment purchase price up to $3,000 per port, which was SDG&E's actual equipment cost per EVSE port during the pilot.[11] SDG&E is likely to wind up paying nearly all costs for workplace installations.

Q: Do sites with more ports cost less per port?

A: To a degree, yes. As explained below, there is a weak downward trend in cost as a function of the number of ports per site, but the number of ports at a site does not explain most of the differences in costs.

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[8] SDG&E, Power Your Drive Extension Program Technical Workshop (May 13, 2020).

[9] SDG&E, Application, Ch. 2, pp. RS-14 at 12 through RS-15 at 21.

[10] DAC MUD sites would not be required to contribute a participation payment.

[11] SDG&E Response to Cal Advocates DR-01, Question 3.

Costs varied widely among project sites. As shown in Figure 1, SDG&E's typical cost per port was around $25,000 for up to 10 ports, declining to $20,000 for 30 ports or more. Regressing cost against a 2nd-order polynomial function of cost suggests that the number of ports per site explains only about 15% of cost variability, as measured by the R^2. Differentiating the data for parking location (structure or lot) and customer type (MUD versus workplace) did not change the results of the regression substantially. SDG&E seems to agree that site conditions (e.g., distance from the transformer to the chargers, subsurface infrastructure, parking structure design) matter more than any economy of scale associated with the number of ports, or the type of location or customer.[12]

In fact, as shown in Figure 1, a large number of the lower-cost projects had 10 or fewer ports.[13]

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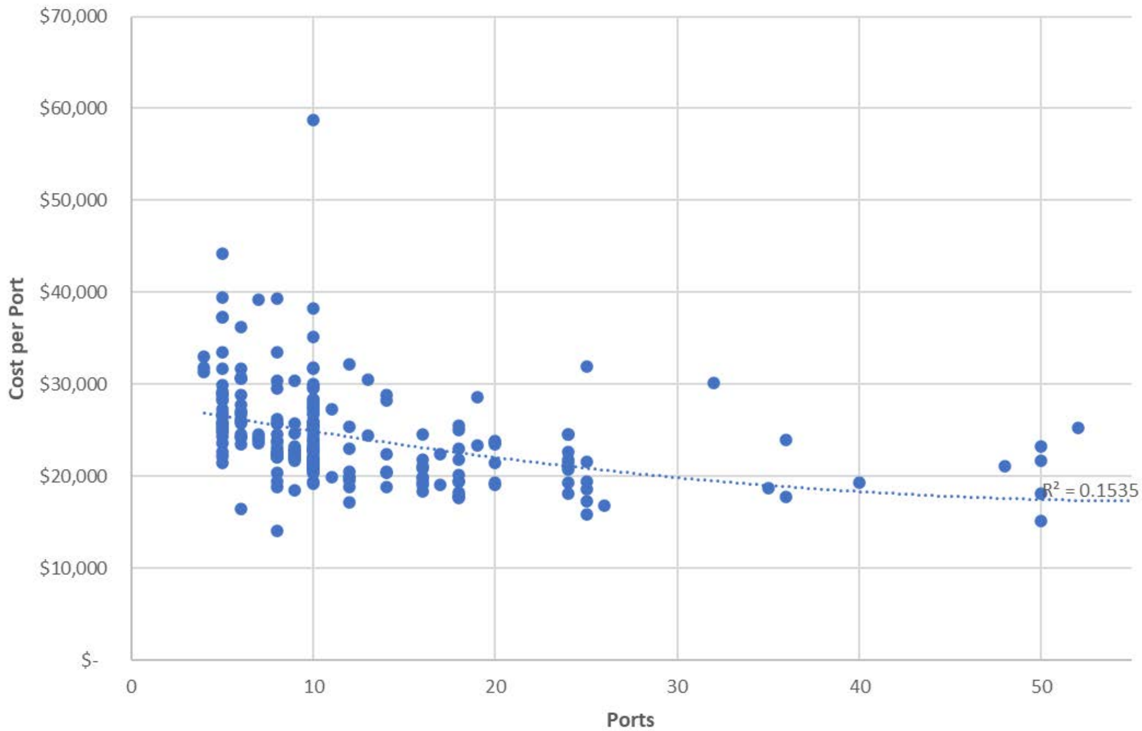
[12] SDG&E Response to TURN DR-02, Question 1.

[13] Analysis based on SDG&E Response to TURN DR-01, Question 1 and cost data provided by SDG&E Response to Cal PA DR-02, Question 2.

Figure 1: Cost per Port, PYD Pilot



Q: The other IOUs have minimum requirements for the number of ports at a site in order to be eligible. Do you recommend that PYD have a minimum port requirement?

A: No. Because costs vary widely for projects with the same number of ports, requiring projects to have a minimum number of ports, as has been the practice for the IOU's Level 2 charger programs, does not appear to be necessary to improve cost-effectiveness. That requirement would also limit the equity of the program, by excluding smaller installations and hence smaller customers, who may not have enough employees or other users to justify many ports.

Q: Should the PYD Extension have additional budget controls?

A: Yes. While we do not oppose the two-way balancing account, we do believe that the Commission should direct SDG&E to achieve the highest possible program impact for approximately the amount suggested in its application. We suggest measures to limit the cost per port and increase customer cost participation. Although not yet practicable, we suggest that SDG&E strive towards limiting the cost based on the number of drivers served without other regular access to charging facilities and encouraging new adoption of EVs.

Q: How do you suggest that the cost per port be limited?

A: We suggest that SDG&E implement a flexible participation payment or rebate. SDG&E would cover up to $20,000 per port, plus 80% of costs above that amount. Furthermore, if the cost per port is estimated to exceed $25,000 and SDG&E determines that approval of the site would nonetheless be desirable, SDG&E should negotiate with the site host to cover a substantial portion of the excess amount.[14]

For sites located in DACs, all or part of the participation payment could be waived, depending on SDG&E's assessment of the customer's need for a waiver.[15] We also suggest that similar discretion be authorized for sites that primarily serve small businesses.

We also suggest that after six months, SDG&E be authorized to adjust these terms in either direction, depending on customer response and updated estimates of average costs.[16] If response is strong or costs appear to be lower than forecast, SDG&E could lower the $20,000, $25,000 or 80% parameters.

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[14] SDG&E should aspire to shift at least half of the excess to the site host, although the host share will need to vary with the host's financial constraints and incentive.

[15] A chain store in a DAC, serving customers from a wide area, may be able to easily cover its small share of the costs under SDG&E's standard cost contribution.

[16] SDG&E has not conducted any market research on willingness to pay for EVSE costs. SDG&E Response to NDC DR-02, Questions 1 and 2.

And if customers are not proceeding as expected, SDG&E could increase those values.

Our suggested approach could help SDG&E stretch the proposed budget further and supply more customers with EV charging stations. For example, if SDG&E had achieved an average cost of $20,000 per port in the PYD Pilot, it would have been able to increase the number of ports installed by more than 10%, while staying within the same budget.

It is worth noting that other state programs have provided substantially smaller incentives per port. The California Energy Commission averaged $8,700 per Level 2 charging station, with workplace chargers incentives averaging less than $5,000 per port, and CALeVIP provides $5,000-7,500 incentives per Level 2 EVSE installed as of 2019.[17] We note that these incentives may have been combined with utility or other incentive opportunities, so the values may not be entirely comparable.

Q: Why don't you recommend a firm cost per charger port cap?

A: We do not believe that the cost per charger port is the best measure of program cost-effectiveness. The goal of the program should not be for the utility to install any particular number of charger ports (although many are needed), but rather to facilitate rapid progress towards California's goal of five million ZEVs on the road by 2030.

With that goal in mind, ideally SDG&E would be focused on (a) the number of drivers served without other regular access to charging facilities and (b) new adoptions of EVs. However, as we explain below, it is not yet practicable to anticipate those outcomes when reviewing prospective sites.

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[17] California Energy Commission, *Final 2019 Integrated Energy Policy Report*, CEC-100-2019-001-CMF (January 2020), pp. 97-98. Attachment-3.

If a firm cost per charger cap were applied, it could be counterproductive to those goals. As we discuss below, many sites appear to result in no new adoptions of EVs. Even if those sites are very cost-effective per port, they are not contributing to the most challenging goal of assisting customers adopt EVs. Likewise, a site that appears very likely to result in customer adoption of EVs might be somewhat more expensive per port.

In order to emphasize the more important goal of supporting widespread adoption of EVs, we believe that a firm cost per charger cap should not be adopted at this time. With additional experience and data, it may be possible to adopt such a firm cost cap in the future.

IV. Utility ownership of EVSE.

Q: Why does SDG&E propose that workplace site hosts own EVSE?

A: In the PYD Pilot, SDG&E owned all EVSE, which has been provided by ChargePoint and Greenlots. For the PYD Extension, SDG&E proposes to require the site host to provide the EVSE. SDG&E states that its proposal is "in response to stakeholder feedback in the Commission TE proceedings."[18]

In comments on the Transportation Electrification Framework (TEF), SDG&E described a Utility-Side EV Infrastructure Tariff, in which the utility would "design, install, own and maintain the make-ready infrastructure upstream of the customer meter." SDG&E explains that this model "is supported by numerous parties" and "would provide a level playing field for private investment."[19]

[18] SDG&E, Application Ch. 2, p. RS-9 at 13-15.

[19] SDG&E, Comments on Energy Staff Proposal, R. 18-12-006 (March 6, 2020), p. 17.

In contrast to the PYD Extension, SDG&E suggests that customers participating in an EV Infrastructure Tariff "would be responsible for and commit to procuring all customer-side equipment necessary to provide EV charging service at EV Infrastructure Tariff sites, in the absence of another utility TE program." This customer-side equipment would include underground conduit, signage, parking space treatment, and EVSE. The PYD Extension would continue to install the underground conduit, but it is not clear whether SDG&E would also cover signage and parking space treatment.

Q: What could be the advantages of 3rd party ownership of EVSE?

A: The primary concern expressed by parties to transportation electrification proceedings is, as expressed by UCAN, "no one wants a regulated monopoly to prevent the creation of a competitive market for EV charging infrastructure and services."[20] A competitive market could advance new amenities and drive down costs. Site hosts might also be able to better align the EVSE, parking space treatment, and signage with property conditions than if the utility handles those matters.

Q: What could be the advantages of utility ownership of EVSE?

A: The utility may provide better maintenance, lower risk of project abandonment, offer rates that are better aligned with grid utilization, and collect data that informs future program development.

Q: Please explain how utility ownership of EVSE might lead to better maintenance.

A: With respect to better maintenance, SDG&E makes the following comments:

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[20] UCAN, Comments on Energy Division's Staff Proposal, R.18-12-006 (March 6, 2020), p. 15.

> SDG&E is responsible for the maintenance and reliability of charging stations owned by the utility in their various TE programs. Money has been budgeted for maintenance, and processes and procedures are in place to monitor the charging stations owned by the utility and to dispatch maintenance personnel when the stations have operational issues.
>
> There is less utility and CPUC oversight of 3rd party-owned charging stations. Many site hosts are conscientious and perform the monitoring, maintenance and repair functions when necessary, but the Plugshare.com website has plenty of examples of driver comments about 3rd party owned charging stations that are not operational or well-maintained.
>
> … the site host has to get much more involved in the aspect of purchasing, and managing the installation and operation of the charging stations. The site host has to pay for the stations, hire project management to design and install the charging stations, perform operational functions, manage the billing, monitor the charging station performance, and schedule and pay for maintenance and repairs. Some site hosts are okay with this role, but during the PYD Pilot many site hosts told SDG&E that charging stations are not their core business and they preferred that SDG&E manage the installation, operation, and maintenance of the stations.[21]

However, SDG&E does not provide any research to support its suggestion that utility-owned charging stations are better maintained than 3rd party owned stations.

Q: Please explain how utility ownership of EVSE might lead to lower risk of project abandonment.

A: With both the utility and the site host being responsible for construction work, there is a risk that the project could be abandoned after the utility's make-ready work is completed. If the site host's construction does not begin until the utility has completed work up to the customer meter, then there is a risk that unforeseen construction issues could be identified.

According to SDG&E program staff, projects frequently encounter unforeseen construction issues – mainly subsurface issues, such as water lines,

[21] SDG&E Response to UCAN DR-01, Question 6.

that are an obstacle to installing underground conduits.[22] In contrast, if the utility is conducting all underground conduit installation on both sides of the meter, it would be likely to identify any unforeseen subsurface obstacles relatively early in the construction process, either avoiding the obstacles or abandoning the project before additional costs are incurred.

We do not know how important this issue may be, because SDG&E has not collected the relevant data. In response to a question during the technical webinar, SDG&E program staff were unable to state whether unexpected subsurface issues encountered during construction were likely to occur in the segment between the customer meter and the EVSE.[23] Nor did SDG&E "track costs based on which side of the utility meter the infrastructure is on."[24] The lack of information regarding the construction process on the customer side of the meter suggests that the risks of shifting responsibility for this work to the site host are not well understood.

Q: Please explain how utility ownership of EVSE might affect the alignment of workplace charging with grid utilization.

A: The PYD Pilot sought to use the VGI hourly dynamic rate to provide an economic signal to drivers to avoid charging during periods of high grid utilization. However, workplaces will no longer have the option to offer the VGI hourly dynamic rate as a Rate to Driver option. Instead, all workplace customers will be billed as Rate to Host. When billed as Rate to Host, the site host is not required to pass on the VGI rate to the driver, and may elect to take

[22] SDG&E, Power Your Drive Extension Program Technical Workshop (May 13, 2020).

[23] SDG&E, Power Your Drive Extension Program Technical Workshop (May 13, 2020).

[24] SDG&E Response to TURN DR-04, Question 1.

service under other C&I TOU rates.[25] Thus, drivers may not see the economic signal to avoid charging during periods of high grid utilization.

SDG&E explained that it cannot offer the Rate to Driver option where the site host selects the EVSE since the utility "will not have access to the charging station internal meters, won't be able to verify the accuracy of the billing data …, and can't effectively respond to customer inquiries …"[26] The utility was not definitive on whether a site host would be able to offer a rate that approximates Rate to Driver.[27]

There is some evidence that the Rate to Driver option has an impact on aligning the timing of workplace charging with grid utilization. SDG&E stated that drivers charging on Rate to Driver appeared to "save more per [money per] kWh … likely due to customers' responsiveness to pricing signals."[28] SDG&E further concluded that the VGI rate used during the PYD Pilot encouraged workplace "EV charging during periods of lower grid utilization."[29] SDG&E finds that the average electric rate when the direct-billed drivers took power to be 18¢/kWh, while drivers who did not get the time-of-use signals (because the charger hosts were billed) charged when electricity cost an average of 24¢/kWh.

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[25] SDG&E intends to require site hosts to submit a load management plan, but it is not clear whether SDG&E would have the ability to enforce that plan in perpetuity. SDG&E, Application Ch. 2, p. RS-17 at 7-12.

[26] SDG&E Response to Cal Advocates DR-02 ,Question 3.

[27] SDG&E Response to NDC DR-04, Question 6.

[28] SDG&E Response to NDC DR-04, Question 5.

[29] SDG&E, Electric Vehicle Integrated Pilot Program (Power Your Drive) Semi-Annual Report of SDG&E (Corrected Version, January 2020), p. 8.

Our review of SDG&E's semi-annual reports suggest that the VGI rate reduces demand during high priced hours. The effect appears relatively small, since workplace charging occurs primarily before 11 am, and is already relatively low after that, during hours that can be high priced during July and August.

Also, SDG&E shared evidence that some drivers are relying exclusively on workplace charging.[30] The economic signal to reduce charging during high priced hours is not as effective for drivers who rely exclusively on workplace charging and cannot complete charging before the prices increase. Unfortunately, SDG&E does not have data that would allow this hypothesis to be tested.

Q: Please explain how utility ownership of EVSE might assist with the collection of data that informs future program development.

A: Currently, SDG&E is able to obtain session data, including the start and end times of charging used to calculate the average cost of electricity for charging sessions. The utility is also able to identify vehicles that are new to charging at the site. SDG&E's opportunity to obtain these data is due to its contractual relationship and performance requirements. According to program staff, these performance requirements are a major reason that only two EVSE vendors qualified for the PYD Pilot, and there was significant work required to meet the utility's standards for sharing these data.[31]

If SDG&E does not own the EVSE, then "SDG&E may only be able to report on workplace charging data in the Program from the aggregated utility

[30] SDG&E, Power Your Drive Extension Program Technical Workshop (May 13, 2020).

[31] SDG&E, Power Your Drive Extension Program Technical Workshop (May 13, 2020).

meter level,"[32] and will be "unable to receive charging session data, port consumption data, and driver data for customer-owned EVSEs."[33] SDG&E will lose the capability to evaluate whether drivers are responding to the site host's load management program (discussed above) and will not be able to identify "incremental EVs" (discussed below). Without these data, load management and EV adoption goals will be more difficult to achieve.

Q: What do you recommend with respect to EVSE ownership?

A: While we favor a broader EVSE market, we are also convinced that developing that market will come with some sacrifices. Below, we discuss our recommendations for enhanced EM&V during the PYD Extension. The opportunity to learn from the PYD Extension will be reduced if the EM&V contractor lacks access to session data and vehicle adoption rates. Thus, we recommend that at least some utility ownership of EVSE should be maintained during the PYD Extension.

We recommend that the Commission consider three options:

1. Direct SDG&E to continue the existing utility ownership model. This will maximize the benefits of utility ownership, as discussed above, but will not expand the EVSE marketplace.
2. Direct SDG&E to randomly select approximately half of workplace sites to be utility owned, with the remaining half of site hosts being required to select an EVSE vendor. This will provide a statistically valid comparison between the two ownership models for analysis of issues such as maintenance, construction cost, grid utilization pattern, and EV adoption.

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[32] SDG&E, Application Ch. 2, p. RS-20 at 10-12.

[33] SDG&E Response to NDC DR-04, Question 10.

3. Direct SDG&E to allow site hosts to self-select whether the EVSE should be provided by the utility, or procured from the marketplace. The two samples could be different sizes, and the self-selection will mean that the comparisons will be less statistically valid. However, this approach provides a higher degree of market freedom.

We currently have some preference for option 2 above, but will be interested to see if other parties bring perspectives to this issue that we have not considered.

V. Reporting Requirements, Including EM&V.

Q: What is SDG&E's monitoring and reporting plan?

A: SDG&E plans to report semi-annually based on the latest Energy Division reporting templates. Reporting on workplace charging data will be at the aggregated utility meter level if the EVSE is owned by site hosts.[34]

SDG&E also conducted a survey of PYD customers. Two slides with the results of this survey were shared with the Program Advisory Council on April 7, 2020.[35] We presume that SDG&E intends to conduct additional high-level surveys from time to time.

Q: Is SDG&E's monitoring and reporting plan sufficient?

A: No. There are many unanswered questions that would inform future program development. At least for the PYD Extension, a more extensive EM&V plan should be required.

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[34] SDG&E, Application Ch. 2, p. RS-20 at 4-12.

[35] SDG&E Response to SBUA DR-01, Question 2.

Some examples of unanswered questions are discussed above. SDG&E's analysis of the impact of the VGI rate indicates some level of positive effect, but the analysis does not provide a quantitative result. SDG&E concludes that its workplace charging is supporting drivers who lack access to other charging options, but is not able to estimate the number of such drivers. SDG&E lacks data on construction costs and construction problems that distinguish between the utility side and customer side of the meter.

SDG&E has also not completed research on several topics identified in its PYD Pilot data collection and monitoring plan. For example, the utility has not estimated the percentage of EV purchases related to the PYD Pilot.[36]

Other examples of unanswered questions occur throughout SDG&E's responses to data requests in this proceeding.

- Market research on site host willingness to pay for EVSE costs.[37]
- Property type, business size, or charging infrastructure sharing.[38]
- Site characteristics influencing new driver adoption.[39]
- Site-specific distribution system upgrade costs.[40]
- Location of PYD workplace driver's residences.[41]

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[36] SDG&E, Electric Vehicle-Grid Integration Pilot Program ("Power Your Drive") Semi-Annual Report of SDG&E (March 15, 2017), p. 19.

[37] SDG&E Response to NDC DR-02, Questions 1 and 2.

[38] SDG&E Response to SBUA DR-01, Question 1.

[39] SDG&E Response to SBUA DR-01, Question 2.

[40] SDG&E Response to TURN DR-01, Question 9.

[41] SDG&E Response to TURN DR-01, Question 18.

- Percentage of charging at PYD workplace sites compared to residential charging.[42]
- Vehicle type and ownership.[43]
- Number of drivers who charged at a PYD workplace site who did not previously have access to charging.[44]
- Potential impact of Direct Current Fast Charging (DCFC) stations on charging at PYD stations.[45]

As can be seen from this list, parties had significant interest in data about the PYD Pilot driver participants, their off-site charging practices, and whether the PYD Pilot influenced their adoption of EVs. Also of interest is information about the site host participants, construction costs, and willingness to pay.

Q: Earlier you discussed SDG&E's ability to identify "incremental EVs." Please describe why this is important.

A: SDG&E has suggested a tentative definition of "incremental EVs," which is a measure of EV adoption influenced by the PYD Pilot. Incremental EVs are estimated from the number of new EVs charging at each location.[46] On

[42] SDG&E Response to TURN DR-02, Question 8.

[43] SDG&E Response to TURN DR-02, Question 9 and to NDC DR-04, Question 3. Program staff were also asked if they were able to distinguish between commuters and other workplace charging users (e.g., business-owned vehicles), which they stated the were not able to do. SDG&E, Power Your Drive Extension Program Technical Workshop (May 13, 2020).

[44] SDG&E Response to TURN DR-04, Question 9.

[45] SDG&E Response to UCAN DR-01, Question 5.

[46] "The calculation for incremental drivers is determined by counting the number of drivers whose first charge occurred 90 days after the site was available for use. The count of incremental drivers provided is as of December 1, 2019." SDG&E Response to TURN DR-01, Question 1. Calculations in this section also rely on cost data provided by SDG&E,Response to Cal PA DR-02, Question 2.

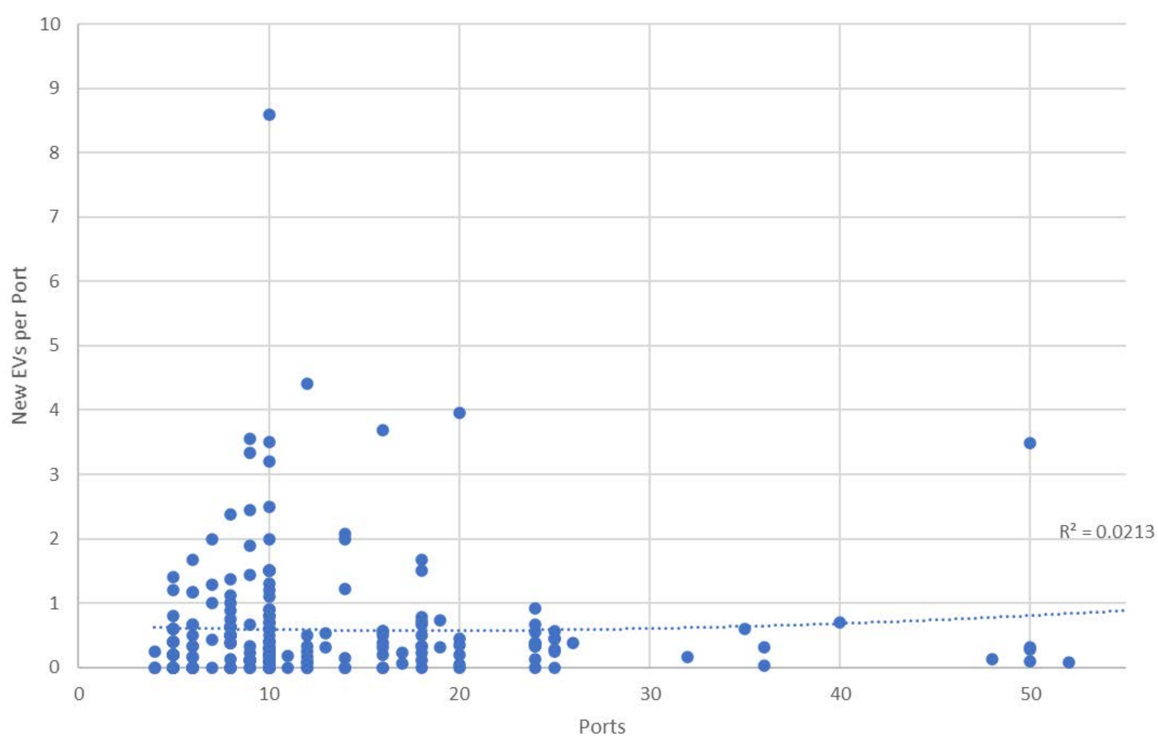
average, 7 incremental EVs were observed for every 10 ports installed by the PYD Pilot.

If SDG&E (and other IOUs) can identify what site characteristics tend to be associated with a higher number of incremental EVs per port, then the utility can prioritize sites likely to drive EV adoption. As discussed above, we would recommend this approach to improving cost-effectiveness rather than a focus on cost per port.

Q: Does the number of ports at a PYD Pilot site influence EV adoption rates?

A: No. As shown in Figure 2, the number of incremental EVs per port is not closely related to the number of ports installed. There is no apparent difference between smaller and larger sites in terms of encouraging EV adoption.

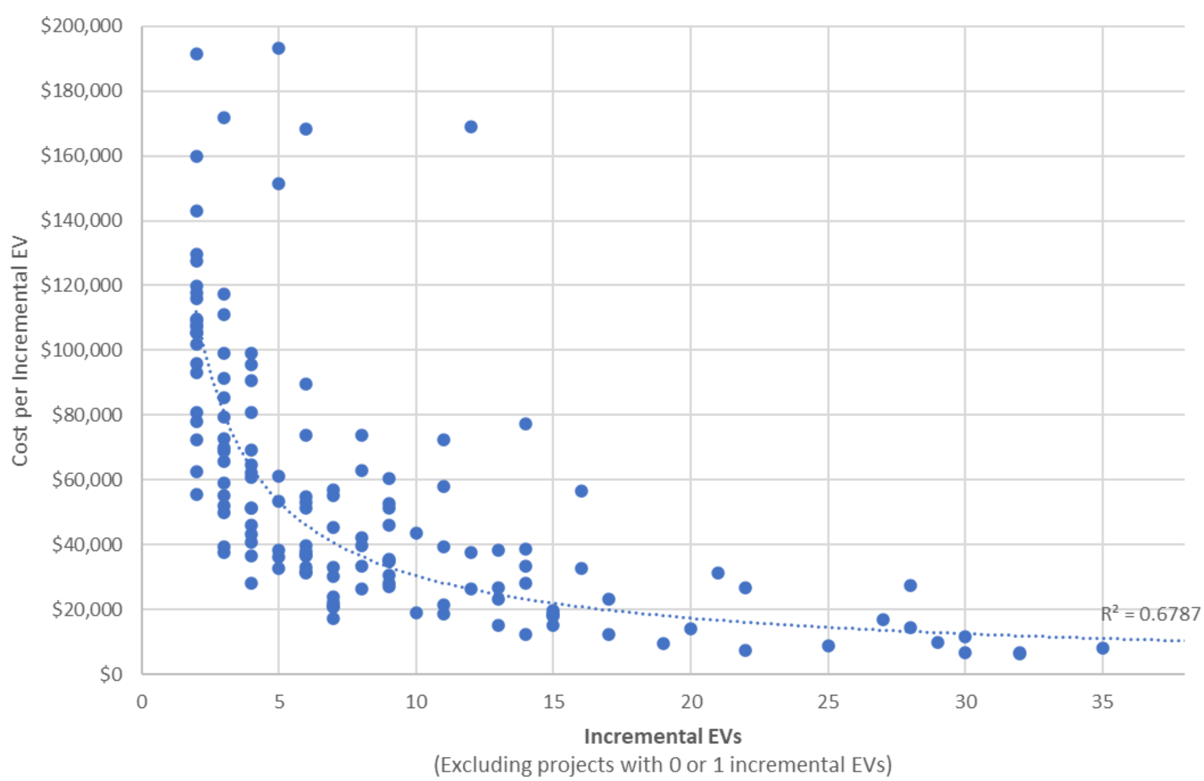
Figure 2: New EVs per Port, PYD Pilot



Q: Are sites with a large number of incremental EVs more cost-effective?

A: Yes. There *is* a strong relationship between the cost per incremental EV and the number of incremental EVs. As shown in Figure 3, many projects that resulted in less than five incremental EVs had a cost per incremental EV of over $80,000. (In fact, SDG&E reported 0 or 1 incremental EVs for a substantial number of projects.) If the IOUs or an independent evaluator could identify a method for reliably predicting the number of incremental EVs, then the resulting criteria could be used to set a cap on the cost per incremental EV. An effective cap on the cost per incremental EV would help increase adoption of EVs by drivers with access to PYD sites because the program budget could go further.

Figure 3: Cost per Incremental EV, PYD Pilot



Q: What steps could SDG&E take to better understand how site and project characteristics drive EV adoption rates?

A: We recommend that SDG&E be required to hire an independent evaluator to conduct research on both the PYD Pilot sites and the PYD Extension sites (if an extension is approved). SDG&E should give the independent evaluator maximum possible access to existing data, and the independent evaluator should be permitted to gather further data from site hosts, EVSE suppliers, and PYD participating drivers who agree to participate in the study.

The independent evaluator should be charged with validating SDG&E's initial findings from the PYD Pilot (e.g., regarding charging response to the VGI rate) as well as investigating other questions suggested in our testimony, as well as other relevant issues identified by parties, SDG&E, or in the Transportation Electrification Framework proceeding. The independent evaluator should be encouraged to conduct measurements in a manner consistent with existing practices in California, but should have the flexibility to adopt other methods for good cause.

Q: Hasn't SDG&E's program staff identified best practices already?

A: Yes, but the best practices identified by SDG&E program staff relate mainly to customer engagement and the construction process. For example, when asked what makes a good site host, program staff stated that they are looking for a "constructible" site, with good Wi-Fi connectivity, avoiding subterranean parking lots, avoiding deeded parking, obvious challenges to trenching, and the engagement and interest level from drivers and site hosts.[47] With the

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[47] SDG&E, Power Your Drive Extension Program Technical Workshop (May 13, 2020).

exception of the last point, none of these site characteristics are likely to be associated with EV adoption rates.

The program staff did mention that during the PYD Extension, they plan to capture additional information about potential and accepted sites for future analysis. On the other hand, if the PYD Extension does not include SDG&E ownership of EVSE at workplaces, it is likely that SDG&E will have less opportunity to collect data about drivers participating in PYD and thus less opportunity to relate those site data to EV adoption outcomes.

VI. Outreach to Small Businesses.

Q: What is SDG&E's plan to conduct outreach to small businesses?

A: Neither the PYD Extension testimony nor the semi-annual PYD Pilot reports discuss any specific considerations related to small businesses. In response to a data request, SDG&E stated that, "approximately 80% of the businesses in SDG&E's service territory are considered small businesses based on energy demand, therefore the marketing and outreach plan for the pilot extension will have a focus on reaching small businesses."[48] We do not see any evidence that SDG&E has given specific consideration to small business concerns in its marking and outreach plans.

As discussed in our comments on the draft *Transportation Electrification Framework*, most IOU transportation electrification programs that potentially serve small businesses appear to be more relevant and accessible to larger businesses.[49] In our review of utility program reports and recent testimony, we

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[48] SDG&E Response to SBUA DR-01, Question 3.

[49] SBUA, Reply Comments of Small Business Utility Advocates to the Draft *Transportation Electrification Framework*, R.18-12-006 (April 27, 2020), pp. 12-25.

found only two examples of a utility's attention to small business concerns. SCE's rebuttal testimony in the Charge Ready 2 program application acknowledged that the 5- or 10-port minimum requirement was a barrier for small businesses,[50] and SDG&E's settlement in its MD/HD EV Infrastructure program included agreements to collect data on the size of participating businesses and dedicate 15 percent of the approved education budget to small business education.[51]

Neither SCE's Charge Ready pilot program nor PG&E's EV Charge Network, which install Level 2 chargers, appeared to have identified responses from or outreach and marketing directed towards small businesses. We do not know how many of the IOUs' workplace EV charging sites are at shopping centers or multi-tenant office buildings that might enable some participation by small businesses in these programs.

Q: Is it important to include small businesses in transportation electrification programs?

A: Yes. SBUA is concerned about the total cost of transportation electrification programs as well as the potential for some customers to receive large benefits that are not readily available to others. We note that UCAN usefully highlighted that the CPUC should focus subsidizes to situations in which market barriers to EV infrastructure can be identified.[52] Market barriers for large commercial fleets may be eased more quickly than for small business

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[50] SCE, Amended Rebuttal Testimony, A.18-06-015 (January 22, 2019), p. 22.

[51] Settling Parties, Settlement Agreement, A.18-01-012 (November 5, 2018), p. 7.

[52] UCAN, Opening Comments on the Draft *Transportation Electrification Framework*, R.18-12-006, p. 21.

fleets. The unique challenges that face small businesses may justify targeted program design, both in terms of technical assistance and financing.

Various small businesses depend on passenger vehicles, light duty commercial trucks, and/or medium- or heavy-duty vehicles. Unfortunately, there are limited data regarding the use of vehicles by small businesses, as discussed in our comments on the draft *Transportation Electrification Framework*.[53]

Compared to larger businesses, the vehicles operated by small businesses probably tend to skew toward smaller vehicles, in size ranges for which manufacturers are currently supplying a greater variety of electric vehicle models. Small businesses such as construction, trades, and landscaping depend on light duty commercial trucks. While some vehicle sizes are determined by their task (e.g., furniture delivery may require a medium or large truck, regardless of the size of the store), the smaller volumes handled by typical small businesses are likely to result in their using smaller vehicles.[54] As a result, small businesses are likely to have greater near-term capability of adopting electric vehicles than would larger businesses. The importance of small fleets to California's carbon emission reduction goals is potentially significant.

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[53] SBUA, Reply Comments of Small Business Utility Advocates to the Draft *Transportation Electrification Framework*, R.18-12-006 (April 27, 2020), pp. 20-21.

[54] The Vehicle Inventory and Use Survey of the 1997 Economic Census (the latest for which data have been released) indicates that 87% of California light trucks (pickups, panels, vans and SUVs) were part of fleets of less than 6 trucks, while 39% of heavier trucks were in fleets of 25 or more vehicles. (www2.census.gov/library/publications/economic-census/1997/vehicle-inventory-and-use-survey/97tv-us.pdf) About 75% of heavy-duty trucks are operated as part of large fleets. (www.scag.ca.gov/committees/CommitteeDocLibrary/mtf012319_CAVIUS.pdf)

Q: Is it more costly to install charger ports at small business locations?

A: No. As discussed above, the cost per charger port can be just as low at sites with few ports as it is at sites with many ports (see Figure 1).

Q: What needs to be done to conduct marketing and outreach to small businesses?

A: First, SDG&E needs to better understand its PYD site hosts and drivers. As discussed above, we recommend a more extensive EM&V plan than SDG&E has conducted during the PYD Pilot. This is foundational to all of our additional recommendations.

The EM&V report should consider questions specific to small businesses. For example, do small businesses pay more than large businesses for charging through the PYD program? Small businesses may be dependent on rates set by site hosts, especially if the site hosts control rates as proposed in the PYD Extension. Larger businesses can self-supply and obtain rates directly from the utility for their business needs.

Building on that research, to encourage more small business participation in PYD and its successors, SDG&E needs to identify and address the specific challenges faced by small businesses, who are a critical part of the market that California intends to transform to electric vehicle use. Our research suggests that IOUs should address five characteristics when designing transportation electrification programs:

- Tenancy
- Space constraints
- Planning uncertainty
- Technology uncertainty
- Financing needs

Q: Please discuss how SDG&E should address small business tenancy issues in the PYD Extension.

A: Many small businesses located in office buildings or shopping centers may have tenancy issues. The make-ready infrastructure needs to be installed to support the existing business, but the small business may also need to secure the approval of a landlord, who may be a passive property investor. SDG&E should seek out opportunities to gain experience with such arrangements, as it has with managers of multiple commercial office buildings.

Q: Please discuss how SDG&E should address small business space constraints in the PYD Extension.

A: Retail installations typically reduce the number of available parking spaces, which may be at a premium. Private charging installations may be difficult to locate safely, due to loading docks, garbage service, or other property uses. Ongoing utility engagement in these issues will develop experience and capability to efficiently assist small business customers in identifying opportunities to install charging infrastructure.

Q: Please discuss how SDG&E should address small business planning uncertainty in the PYD Extension.

A: Generally lacking a fleet manager, small businesses will need easy-to-use tools to assist them in deciding what infrastructure to install based on business practices and financial options. These tools will need to accommodate a wide range of business practices, but not require sophisticated technical skills to operate a model.

Some categories of small businesses (e.g., landscapers, tree services, construction firms, dry cleaners, and many retailers doing home delivery) would have limited opportunity to charge their own vehicles during midday hours when abundant solar generation is available, since the vehicles will typically be on the road or at worksites, rather than the garage.[55] If they need to charge their vehicles outside of daytime business hours and are not able to install onsite charging, this will require their vehicles to be parked at an employee's home or at a public charging facility, potentially overnight. There may be a complementary opportunity for small businesses to offer public charging stations during the day and then utilize those stations for overnight charging of their service vehicles.[56]

Small business receptivity to public fast charging will depend not only on cost and location, but customer experience. For those small businesses that charge during the daytime, demand response events at public chargers could be very disruptive to a small business and discourage EV adoption.[57]

We also note that in order to charge during high-solar, low-cost hours, small businesses without onsite charging may require fast charging capabilities. While this is beyond the scope of the PYD Extension, any research conducted for an EM&V report should seek to investigate this topic for future program development purposes.

[55] Some restaurants and caterers, in contrast, may do most of their pickups (and some breakfast catering) in the early morning, lunch deliveries in the late morning, and dinner deliveries after the peak solar hours, allowing for some mid-day charging.

[56] Security and access issues would vary among customers and may need to be addressed in some situations.

[57] EVgo, Opening Comments on the Draft *Transportation Electrification Framework*, R.18-12-006, p. 2.

Q: Please discuss how SDG&E should address small-business technology uncertainty in the PYD Extension.

A: Small businesses will not be able to anticipate what make and model they will acquire in future years, much less the charging capabilities. Financing decisions depend on an assessment of vehicle resale values, which small businesses will find difficult to assess. Small businesses may also need assistance in understanding any implications of TE infrastructure decisions for future vehicle procurement, such as whether today's charging equipment will be suitable for tomorrow's vehicles?

Q: Please discuss how SDG&E should address small-business financing needs in the PYD Extension.

A: As shown above (see Figure 1 and Figure 3), it is not necessarily the case that the cost per charging port or incremental vehicle is higher at smaller sites appropriate to small businesses. Nonetheless, those costs will be significant, and small businesses may find it difficult to finance charging infrastructure and a new vehicle simultaneously. Furthermore, without business expertise in costing out such projects, they may find it difficult to convince a loan officer to finance their project without utility participation.

Q: What do you recommend to address your concerns about small business outreach and marketing?

A: We recommend that SDG&E commit to address the five issues we have outlined above in its outreach and marketing program, report on its progress to its Program Advisory Council, and utilize lessons learned in the development of future transportation electrification programs.

Q: Does this conclude your testimony?

A: Yes.

ATTACHMENT - 1

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SUMMARY OF PROFESSIONAL EXPERIENCE

1986–Present **President, Resource Insight, Inc.** Consults and testifies in utility and insurance economics. Reviews utility supply-planning processes and outcomes: assesses prudence of prior power planning investment decisions, identifies excess generating capacity, analyzes effects of power-pool-pricing rules on equity and utility incentives. Reviews electric-utility rate design. Estimates magnitude and cost of future load growth. Designs and evaluates conservation programs for electric, natural-gas, and water utilities, including hook-up charges and conservation cost recovery mechanisms. Determines avoided costs due to cogenerators. Evaluates cogeneration rate risk. Negotiates cogeneration contracts. Reviews management and pricing of district heating systems. Determines fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determines profitability of transportation services. Advises regulatory commissions in least-cost planning, rate design, and cost allocation.

1981–86 **Research Associate, Analysis and Inference, Inc.** (Consultant, 1980–81). Researched, advised, and testified in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions. Consulted on utility rate-design issues, including small-power-producer rates; retail natural-gas rates; public-agency electric rates, and comprehensive electric-rate design for a regional power agency. Developed electricity cost allocations between customer classes. Reviewed district-heating-system efficiency. Proposed power-plant performance standards. Analyzed auto-insurance profit requirements. Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

1977–81 **Utility Rate Analyst, Massachusetts Attorney General.** Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination, and briefing. Provided extensive expert testimony before various regulatory agencies. Topics included demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power-pool operations, nuclear-power cost projections, power-plant cost-benefit analysis, energy conservation, and alternative-energy development.

EDUCATION

SM, Technology and Policy Program, Massachusetts Institute of Technology, February 1978.

SB, Civil Engineering Department, Massachusetts Institute of Technology, June 1974.

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

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“Report on the Adequacy of Ontario Hydro’s Estimates of Externality Costs Associated with Electricity Exports” (with Emily Caverhill), January 1991.

“Comments on the 1991–1992 Annual and Long Range Demand-Side-Management Plans of the Major Electric Utilities,” (with John Plunkett et al.), September 1990. Filed in NY PSC Case No. 28223 in re New York utilities’ DSM plans.

“Power by Efficiency: An Assessment of Improving Electrical Efficiency to Meet Jamaica’s Power Needs,” (with Conservation Law Foundation, et al.), June 1990.

"Analysis of Fuel Substitution as an Electric Conservation Option," (with Ian Goodman and Eric Espenhorst), Boston Gas Company, December 22 1989.

"The Development of Consistent Estimates of Avoided Costs for Boston Gas Company, Boston Edison Company, and Massachusetts Electric Company" (with Eric Espenhorst), Boston Gas Company, December 22 1989.

"The Valuation of Externalities from Energy Production, Delivery, and Use: Fall 1989 Update" (with Emily Caverhill), Boston Gas Company, December 22 1989.

"Conservation Potential in the State of Minnesota," (with Ian Goodman) Minnesota Department of Public Service, June 16 1988.

"Review of NEPOOL Performance Incentive Program," Massachusetts Energy Facilities Siting Council, April 12 1988.

"Application of the DPU's Used-and-Useful Standard to Pilgrim 1" (With C. Wills and M. Meyer), Massachusetts Executive Office of Energy Resources, October 1987.

"Constructing a Supply Curve for Conservation: An Initial Examination of Issues and Methods," Massachusetts Energy Facilities Siting Council, June 1985.

"Final Report: Rate Design Analysis," Pacific Northwest Electric Power and Conservation Planning Council, December 18 1981.

PRESENTATIONS

"Rethinking Utility Rate Design—Retail Demand and Energy Charges," Solar Power PV Conference, Boston MA, February 24, 2016.

"Residential Demand Charges - Load Effects, Fairness & Rate Design Implications." Web seminar sponsored by the NixTheFix Forum. September 2015.

"The Value of Demand Reduction Induced Price Effects." With Chris Neme. Web seminar sponsored by the Regulatory Assistance Project. March 2015.

"Adding Transmission into New York City: Needs, Benefits, and Obstacles." Presentation to FERC and the New York ISO on behalf of the City of New York. October 2004.

"Plugging Into a Municipal Light Plant." With Peter Enrich and Ken Barna. Panel presentation as part of the 2004 Annual Meeting of the Massachusetts Municipal Association. January 2004.

"Distributed Utility Planning." With Steve Litkovitz. Presentation to the Vermont Distributed-Utility-Planning Collaborative. November 1999.

"The Economic and Environmental Benefits of Gas IRP: FERC 636 and Beyond." Presentation as part of the Ohio Office of Energy Efficiency's seminar, "Gas Utility Integrated Resource Planning," April 1994.

"Cost Recovery and Utility Incentives." Day-long presentation as part of the Demand-Side-Management Training Institute's workshop, "DSM for Public Interest Groups," October 1993.

"Cost Allocation for Utility Ratemaking." With Susan Geller. Day-long workshop for the staff of the Connecticut Department of Public Utility Control, October 1993.

"Comparing and Integrating DSM with Supply." Day-long presentation as part of the Demand-Side-Management Training Institute's workshop, "DSM for Public Interest Groups," October 1993.

"DSM Cost Recovery and Rate Impacts." Presentation as part of "Effective DSM Collaborative Processes," a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August 1993.

"Cost-Effectiveness Analysis." Presentation as part of "Effective DSM Collaborative Processes," a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August 1993.

"Environmental Externalities: Current Approaches and Potential Implications for District Heating and Cooling" (with R. Brailove), International District Heating and Cooling Association 84th Annual Conference. June 1993.

"Using the Costs of Required Controls to Incorporate the Costs of Environmental Externalities in Non-Environmental Decision-Making." Presentation at the American Planning Association 1992 National Planning Conference; presentation cosponsored by the Edison Electric Institute. May 1992.

"Cost Recovery and Decoupling" and "The Clean Air Act and Externalities in Utility Resource Planning" panels (session leader), DSM Advocacy Workshop. April 15 1992.

"Overview of Integrated Resources Planning Procedures in South Carolina and Critique of South Carolina Demand Side Management Programs," Energy Planning Workshops; Columbia, S.C. October 21 1991.

"Least Cost Planning and Gas Utilities." Demand-Side Management and the Global Environment Conference; Washington, D.C. April 22 1991.

Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28 1991.

"Least-Cost Planning in a Multi-Fuel Context." NARUC Forum on Gas Integrated Resource Planning; Washington, D.C., February 24 1991.

"Accounting for Externalities: Why, Which and How?" Understanding Massachusetts' New Integrated Resource Management Rules. Needham, Massachusetts, November 9 1990.

New England Gas Association Gas Utility Managers' Conference. Woodstock, Vermont, September 10 1990.

"Quantifying and Valuing Environmental Externalities." Presentation at the Lawrence Berkeley Laboratory Training Program for Regulatory Staff, sponsored by the U.S. Department of Energy's Least-Cost Utility Planning Program; Berkeley, California, February 2 1990;

"Conservation in the Future of Natural Gas Local Distribution Companies." District of Columbia Natural Gas Seminar; Washington, D.C. May 23 1989.

"Conservation and Load Management for Natural Gas Utilities," Massachusetts Natural Gas Council; Newton, Massachusetts. April 3 1989.

New England Conference of Public Utilities Commissioners, Environmental Externalities Workshop. Portsmouth, New Hampshire, January 22–23 1989.

"Assessment and Valuation of External Environmental Damages." New England Utility Rate Forum. Plymouth, Massachusetts, October 11 1985; "Lessons from Massachusetts on Long Term Rates for QFs".

"Reviewing Utility Supply Plans." Massachusetts Energy Facilities Siting Council; Boston, Massachusetts. May 30 1985.

"Power Plant Performance.," National Association of State Utility Consumer Advocates; Williamstown, Massachusetts. August 13 1984.

"Utility Rate Shock," National Conference of State Legislatures; Boston, Massachusetts, August 6 1984.

"Review and Modification of Regulatory and Rate Making Policy," National Governors' Association Working Group on Nuclear Power Cost Overruns; Washington, D.C., June 20 1984.

"Review and Modification of Regulatory and Rate Making Policy," Annual Meeting of the American Association for the Advancement of Science, Session on Monitoring for Risk Management; Detroit, Michigan, May 27 1983.

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

District of Columbia Public Service Commission, Docket No. 834, Phase II; Least-cost planning procedures and goals. August 1987 to March 1988.

Connecticut Department of Public Utility Control, Docket No. 87-07-01, Phase 2; Rate design and cost allocations. March 1988 to June 1989.

Austin City Council, Austin Energy Rates, March to June 2012.

Puerto Rico Energy Commission, Puerto Rico Electric Power Authority, rate design issues, September 2015 to present.

EXPERT TESTIMONY

1. **Mass. EFSC** 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General. June 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with Susan C. Geller.

2. **Mass. EFSC** 78-17, Northeast Utilities 1978 forecast; Massachusetts Attorney General. September 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. **Mass. EFSC** 78-33, Eastern Utilities Associates 1978 forecast; Massachusetts Attorney General. November 1978.

   Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. **Mass. DPU** 19494, Phase II; Boston Edison Company construction program; Massachusetts Attorney General. April 1979.

   Review of numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with Susan Geller.

5. **Mass. DPU** 19494, Phase II; Boston Edison Company construction program; Massachusetts Attorney General. April 1979.

   Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. **U.S. ASLB** NRC 50-471, Pilgrim Unit 2; Commonwealth of Massachusetts. June 1979.

   Review of the Oak Ridge National Laboratory and NEPOOL demand forecast models; cost-effectiveness of oil displacement; nuclear economics. Joint testimony with Susan Geller.

7. **Mass. DPU** 19845, Boston Edison time-of-use-rate case; Massachusetts Attorney General. December 1979.

   Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with Susan Geller.

8. **Mass. DPU** 20055, petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G. & E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General. January 1980.

Review of demand forecasts of three utilities purchasing Seabrook shares; Seabrook power costs, including construction cost, completion date, capacity factor, O&M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal conversion.

9. **Mass. DPU** 20248, petition of Massachusetts Municipal Wholesale Electric Company to purchase additional share of Seabrook Nuclear Plant; Massachusetts Attorney General. June 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. **Mass. DPU** 200, Massachusetts Electric Company rate case; Massachusetts Attorney General. June 1980.

    Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. **Mass. EFSC** 79-33, Eastern Utilities Associates 1979 forecast; Massachusetts Attorney General. July 1980.

    Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

12. **Mass. DPU** 243, Eastern Edison Company rate case; Massachusetts Attorney General. August 1980.

    Rate design: declining blocks, promotional rates, alternative energy, master metering.

13. **Texas PUC** 3298, Gulf States Utilities rates; East Texas Legal Services. August 1980.

    Inter-class revenue allocations, including production plant in-service, O&M, CWIP, nuclear fuel in progress, amortization of canceled plant residential rate design; interruptible rates; off-peak rates. Joint testimony with M. B. Meyer.

14. **Mass. EFSC** 79-1, Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General. November 1980.

    Cost comparison methodology; nuclear cost estimates; cost of conservation, cogeneration, and solar.

15. **Mass. DPU** 472, recovery of residential conservation-service expenses; Massachusetts Attorney General. December 1980.

    Conservation as an energy source; advantages of per-kWh allocation over per-customer-month allocation.

16. **Mass. DPU** 535; regulations to carry out Section 210 of PURPA; Massachusetts Attorney General. January 1981 and February 1981.

    Filing requirements, certification, qualifying-facility status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of qualifying facilities in specific areas; wheeling; standardization of fees and charges.

17. **Mass. EFSC** 80-17, Northeast Utilities 1980 forecast; Massachusetts Attorney General. March 1981.

    Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecasts and wholesale forecast.

18. **Mass. DPU** 558, Western Massachusetts Electric Company rate case; Massachusetts Attorney General. May 1981.

    Rate design including declining blocks, marginal cost conservation impacts, and promotional rates. Conservation, including terms and conditions limiting renewable, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. **Mass. DPU** 1048, Boston Edison plant performance standards; Massachusetts Attorney General. May 1982.

    Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.

20. **DC PSC** FC785, Potomac Electric Power rate case; DC Peoples Counsel. July 1982.

    Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O&M classification; distribution and service allocators. Marginal cost estimation, including losses.

21. **N.H. PSC** DE 81-312, Public Service of New Hampshire supply and demand; Conservation Law Foundation et al. October 1982.

    Conservation program design, ratemaking, and effectiveness. Cost of power from Seabrook nuclear plant, including construction cost and duration, capacity factor, O&M, replacements, insurance, and decommissioning.

22. **Mass. Division of Insurance,** hearing to fix and establish 1983 automobile insurance rates; Massachusetts Attorney General. October 1982.

    Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

23. **Ill. CC** 82-0026, Commonwealth Edison rate case; Illinois Attorney General. October 1982.

Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O&M, capital additions, useful like, capacity factor), risks, discount rates, evaluation techniques.

24. **N.M. PSC** 1794, Public Service of New Mexico application for certification; New Mexico Attorney General. May 1983.

    Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking proposal.

25. **Conn. DPUC** 830301, United Illuminating rate case; Connecticut Consumers Counsel. June 17 1983.

    Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O&M, capital additions, insurance and decommissioning.

26. **Mass. DPU** 1509, Boston Edison plant performance standards; Massachusetts Attorney General. July 15 1983.

    Critique of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. **Mass. Division of Insurance,** hearing to fix and establish 1984 automobile-insurance rates; Massachusetts Attorney General. October 1983.

    Profit margin calculations, including methodology, interest rates.

28. **Conn. DPUC** 83-07-15, Connecticut Light and Power rate case; Alloy Foundry. October 3 1983.

    Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand versus energy charges.

29. **Mass. EFSC** 83-24, New England Electric System forecast of electric resources and requirements; Massachusetts Attorney General. November 14 1983, Rebuttal, February 2 1984.

    Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. **Mich. PSC** U-7775, Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan. February 21 1984.

    Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. **Mass. DPU** 84-25, Western Massachusetts Electric Company rate case; Massachusetts Attorney General. April 6 1984.

Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. **Mass. DPU** 84-49 and 84-50, Fitchburg Gas & Electric financing case; Massachusetts Attorney General. April 13 1984.

    Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. **Mich. PSC** U-7785, Consumers Power fuel-cost-recovery plan; Public Interest Research Group in Michigan. April 16 1984.

    Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative policy.

34. **FERC** ER81-749-000 and ER82-325-000, Montaup Electric rate cases; Massachusetts Attorney General. April 27 1984.

    Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the Utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. **Maine PUC** 84-113, Seabrook-1 investigation; Maine Public Advocate. September 13 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. **Mass. DPU** 84-145, Fitchburg Gas and Electric rate case; Massachusetts Attorney General. November 6 1984.

    Prudence of Fitchburg and Public Service of New Hampshire in decision regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

37. **Penn. PUC** R-842651, Pennsylvania Power and Light rate case; Pennsylvania Consumer Advocate. November 1984.

    Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. **N.H. PSC** 84-200, Seabrook Unit-1 investigation; New Hampshire Consumer Advocate. November 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

39. **Mass. Division of Insurance,** hearing to fix and establish 1986 automobile insurance rates; Massachusetts Attorney General. November 1984.

    Profit-margin calculations, including methodology and implementation.

40. **Mass. DPU** 84-152, Seabrook Unit 1 investigation; Massachusetts Attorney General. December 1984.

    Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

41. **Maine PUC** 84-120; Central Maine Power rate case; Maine PUC Staff. December 1984.

    Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

42. **Maine PUC** 84-113, Seabrook 2 investigation; Maine PUC Staff. December 1984.

    Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

43. **Mass. DPU** 1627, Massachusetts Municipal Wholesale Electric Company financing case; Massachusetts Executive Office of Energy Resources. January 1985.

    Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

44. **Vt. PSB** 4936, Millstone 3 costs and in-service date; Vermont Department of Public Service. January 1985.

    Construction schedule and cost of completing Millstone Unit 3.

45. **Mass. DPU** 84-276, rules governing rates for utility purchases of power from qualifying facilities; Massachusetts Attorney General. March 1985 and October 1985.

Institutional and technological advantages of Qualifying Facilities. Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

46. **Mass. DPU** 85-121, investigation of the Reading Municipal Light Department; Wilmington (Mass.) Chamber of Commerce. November 1985.

    Calculation on return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in street-lighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. **Mass. Division of Insurance,** hearing to fix and establish 1986 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. November 1985.

    Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

48. **N.M. PSC** 1833, Phase II; El Paso Electric rate case; New Mexico Attorney General. December 1985.

    Nuclear decommissioning fund design. Internal and external funds; risk and return; fund accumulation, recommendations. Interim performance standard for Palo Verde nuclear plant.

49. **Penn. PUC** R-850152, Philadelphia Electric rate case; Utility Users Committee and University of Pennsylvania. January 1986.

    Limerick-1 rate effects. Capacity benefits, fuel savings, operating costs, capacity factors, and net benefits to ratepayers. Design of phase-in proposals.

50. **Mass. DPU** 85-270;, Western Massachusetts Electric rate case; Massachusetts Attorney General. March 1986.

    Prudence of Northeast Utilities in generation planning related to Millstone 3 construction: decisions to start and continue construction, failure to reduce ownership share, failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

51. **Penn. PUC** R-850290, Philadelphia Electric auxiliary service rates; Albert Einstein Medical Center, University of Pennsylvania, and Amtrak. March 1986.

    Review of utility proposals for supplementary and backup rates for small power producers and cogenerators. Load diversity, cost of peaking capacity, value of generation, price signals, and incentives. Formulation of alternative supplementary rate.

52. **N.M. PSC** 2004, Public Service of New Mexico Palo Verde issues; New Mexico Attorney General. May 1986.

    Recommendations for power-plant performance standards for Palo Verde nuclear units 1, 2, and 3.

53. **Ill. CC** 86-0325, Iowa-Illinois Gas and Electric Co. rate investigation; Illinois Office of Public Counsel. August 1986.

    Determination of excess capacity based on reliability and economic concerns. Identification of specific units associated with excess capacity. Required reserve margins.

54. **N.M. PSC** 2009, El Paso Electric rate moderation program; New Mexico Attorney General. August 1986.

    Prudence of EPE in generation planning related to Palo Verde nuclear construction, including failure to reduce ownership share and failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

    Recommendation for rate-base treatment; proposal of power plant performance standards.

55. **City of Boston Public Improvements Commission,** transfer of Boston Edison district heating steam system to Boston Thermal Corporation; Boston Housing Authority. December 1986.

    History and economics of steam system; possible motives of Boston Edison in seeking sale; problems facing Boston Thermal; information and assurances required prior to Commission approval of transfer.

56. **Mass. Division of Insurance,** hearing to fix and establish 1987 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. December 1986 and January 1987.

    Profit margin calculations, including methodology, implementation, derivation of cash flows, installment income, income tax status, and return to shareholders.

57. **Mass. DPU** 87-19, petition for adjudication of development facilitation program; Hull (Mass.) Municipal Light Plant. January 1987.

    Estimation of potential load growth; cost of generation, transmission, and distribution additions. Determination of hook-up charges. Development of residential load estimation procedure reflecting appliance ownership, dwelling size.

58. **N.M. PSC** 2004, Public Service of New Mexico nuclear decommissioning fund; New Mexico Attorney General. February 1987.

    Decommissioning cost and likely operating life of nuclear plants. Review of utility funding proposal. Development of alternative proposal. Ratemaking treatment.

59. **Mass. DPU** 86-280, Western Massachusetts Electric rate case; Massachusetts Energy Office. March 1987.

Marginal cost rate design issues. Superiority of long-run marginal cost over short-run marginal cost as basis for rate design. Relationship of Consumer reaction, utility planning process, and regulatory structure to rate design approach. Implementation of short-run and long-run rate designs. Demand versus energy charges, economic development rates, spot pricing.

60. **Mass. Division of Insurance** 87-9, 1987 Workers' Compensation rate filing; State Rating Bureau. May 1987.

Profit-margin calculations, including methodology, implementation, surplus requirements, investment income, and effects of 1986 Tax Reform Act.

61. **Texas PUC** 6184, economic viability of South Texas Nuclear Plant #2; Committee for Consumer Rate Relief. August 1987.

Nuclear plant operating parameter projections; capacity factor, O&M, capital additions, decommissioning, useful life. STNP-2 cost and schedule projections. Potential for conservation.

62. **Minn. PUC** ER-015/GR-87-223, Minnesota Power rate case; Minnesota Department of Public Service. August 1987.

Excess capacity on MP system; historical, current, and projected. Review of MP planning prudence prior to and during excess; efforts to sell capacity. Cost of excess capacity. Recommendations for ratemaking treatment.

63. **Mass. Division of Insurance** 87-27, 1988 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. September 2 1987. Rebuttal October 1987.

Underwriting profit margins. Effect of 1986 Tax Reform Act. Biases in calculation of average margins.

64. **Mass. DPU** 88-19, power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric. November 1987.

Comparison of risk from QF contract and utility avoided-cost sources. Risk of oil dependence. Discounting cash flows to reflect risk.

65. **Mass. Division of Insurance** 87-53, 1987 Workers' Compensation rate refiling; State Rating Bureau. December 1987.

Profit-margin calculations including updating of data, compliance with Commissioner's order, treatment of surplus and risk, interest rate calculation, and investment tax rate calculation.

66. **Mass. Division of Insurance,** 1987 and 1988 automobile insurance remand rates; Massachusetts Attorney General and State Rating Bureau. February 1988.

    Underwriting profit margins. Provisions for income taxes on finance charges. Relationships between allowed and achieved margins, between statewide and nationwide data, and between profit allowances and cost projections.

67. **Mass. DPU** 86-36, investigation into the pricing and ratemaking treatment to be afforded new electric generating facilities which are not qualifying facilities; Conservation Law Foundation. May 1988.

    Cost recovery for utility conservation programs. Compensating for lost revenues. Utility incentive structures.

68. **Mass. DPU** 88-123, petition of Riverside Steam & Electric; Riverside Steam and Electric Company. May 1988 and November 1988.

    Estimation of avoided costs of Western Massachusetts Electric Company. Nuclear capacity factor projections and effects on avoided costs. Avoided cost of energy interchange and power plant life extensions. Differences between median and expected oil prices. Salvage value of cogeneration facility. Off-system energy purchase projections. Reconciliation of avoided cost projection.

69. **Mass. DPU** 88-67, Boston Gas Company; Boston Housing Authority. June 1988.

    Estimation of annual avoidable costs, 1988 to 2005, and levelized avoided costs. Determination of cost recovery and carrying costs for conservation investments. Standards for assessing conservation cost-effectiveness. Evaluation of cost-effectiveness of utility funding of proposed natural gas conservation measures.

70. **R.I. PUC** 1900, Providence Water Supply Board tariff filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island. June 1988.

    Estimation of avoidable water supply costs. Determination of costs of water conservation. Conservation cost-benefit analysis.

71. **Mass. Division of Insurance** 88-22, 1989 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau; Profit Issues, August 1988, supplemented August 1988; Losses and Expenses, September 1988.

    Underwriting profit margins. Effects of 1986 Tax Reform Act. Taxation of common stocks. Lag in tax payments. Modeling risk and return over time. Treatment of finance charges. Comparison of projected and achieved investment returns.

72. **Vt. PSB** 5270 Module 6, investigation into least-cost investments, energy efficiency, conservation, and the management of demand for energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group. September 1988.

    Cost recovery for utility conservation programs. Compensation of utilities for revenue losses and timing differences. Incentive for utility participation.

73. **Vt. House of Representatives, Natural Resources Committee,** House Act 130; "Economic Analysis of Vermont Yankee Retirement"; Vermont Public Interest Research Group. February 1989.

    Projection of capacity factors, operating and maintenance expense, capital additions, overhead, replacement power costs, and net costs of Vermont Yankee.

74. **Mass. DPU** 88-67 Phase II, Boston Gas company conservation program and rate design; Boston Gas Company. March 1989.

    Estimation of avoided gas cost; treatment of non-price factors; estimation of externalities; identification of cost-effective conservation.

75. **Vt. PSB** 5270, status conference on conservation and load management policy settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service. May 1989.

    Cost-benefit test for utility conservation programs. Role of externalities. Cost recovery concepts and mechanisms. Resource allocations, cost allocations, and equity considerations. Guidelines for conservation preapproval mechanisms. Incentive mechanisms and recovery of lost revenues.

76. **Boston Housing Authority Court** 05099, Gallivan Boulevard Task Force vs. Boston Housing Authority, et al.; Boston Housing Authority. June 1989.

    Effect of master-metering on consumption of natural gas and electricity. Legislative and regulatory mandates regarding conservation.

77. **Mass. DPU** 89-100, Boston Edison rates; Massachusetts Energy Office. June 1989.

    Prudence of decision to spend $400 million from 1986–88 to return Pilgrim nuclear plant to service. Projections of nuclear capacity factors, O&M, capital additions, and overhead. Review of decommissioning cost, tax effect of abandonment, replacement power cost, and plant useful life estimates. Requirements for prudence and used-and-useful analyses.

78. **Mass. DPU** 88-123, petition of Riverside Steam and Electric Company; Riverside Steam and Electric. July 1989. Rebuttal, October 1989.

Reasonableness of Northeast Utilities' 1987 avoided cost estimates. Projections of nuclear capacity factors, economy purchases, and power plant operating life. Treatment of avoidable energy and capacity costs and of off-system sales. Expected versus reference fuel prices.

79. **Mass. DPU** 89-72, Statewide Towing Association police-ordered towing rates; Massachusetts Automobile Rating Bureau. September 1989.

Review of study supporting proposed increase in towing rates. Critique of study sample and methodology. Comparison to competitive rates. Supply of towing services. Effects of joint products and joint sales on profitability of police-ordered towing. Joint testimony with I. Goodman.

80. **Vt. PSB** 5330, application of Vermont utilities for approval of a firm power and energy contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group. December 1989. Surrebuttal February 1990.

Analysis of a proposed 20-year power purchase. Comparison to efficiency investment. Critique of conservation potential analysis. Analysis of Vermont electric energy supply. Planning risk of large supply additions. Valuation of environmental externalities. Identification of possible improvements to proposed contract.

81. **Mass. DPU** 89-239, inclusion of externalities in energy-supply planning, acquisition, and dispatch for Massachusetts utilities. Boston Gas Company. December 1989; April 1990; May 1990.

Critique of Division of Energy Resources report on externalities. Methodology for evaluating external costs. Proposed values for environmental and economic externalities of fuel supply and use.

82. **California PUC,** incorporation of environmental externalities in utility planning and pricing; Coalition of Energy Efficient and Renewable Technologies. February 1990.

Approaches for valuing externalities for inclusion in setting power purchase rates. Effect of uncertainty on assessing externality values.

83. **Ill. CC** 90-0038, proceeding to adopt a least-cost electric-energy plan for Commonwealth Edison Company; City of Chicago. May 25 1990. Joint rebuttal testimony with David Birr, August 1990.

Problems in Commonwealth Edison's approach to demand-side management. Potential for cost-effective conservation. Valuing externalities in least-cost planning.

84. **Md. PSC** 8278, adequacy of Baltimore Gas & Electric's integrated resource plan; Maryland Office of People's Counsel. September 1990.

Rationale for demand-side management. BG&E's problems in approach to DSM planning. Potential for cost-effective conservation. Valuation of environmental externalities. Recommendations for short-term DSM program priorities.

85. **Ind. URC,** integrated-resource-planning docket; Indiana Office of Utility Consumer Counselor. November 1990.

Integrated resource planning process and methodology, including externalities and screening tools. Incentives, screening, and evaluation of demand-side management. Potential of resource bidding in Indiana.

86. **Mass. DPU** 89-141, 90-73, 90-141, 90-194, 90-270; preliminary review of utility treatment of environmental externalities in October qualifying-facilities filings; Boston Gas Company. November 1990.

Generic and specific problems in Massachusetts utilities' RFPs with regard to externality valuation requirements. Recommendations for corrections.

87. **Mass. EFSC** 90-12/90-12A, adequacy of Boston Edison proposal to build combined-cycle plant; Conservation Law Foundation. December 1990.

Problems in Boston Edison's treatment of demand-side management, supply option analysis, and resource planning. Recommendations of mitigation options.

88. **Maine PUC** 90-286, adequacy of conservation program of Bangor Hydro Electric; Penobscot River Coalition. February 1991.

Role of utility-sponsored DSM in least-cost planning. Bangor Hydro's potential for cost-effective conservation. Problems with Bangor Hydro's assumptions about customer investment in energy efficiency measures.

89. **Va. SCC** PUE900070, commission investigation; Southern Environmental Law Center. March 1991.

Role of utilities in promoting energy efficiency. Least-cost planning objectives of and resource acquisition guidelines for DSM. Ratemaking considerations for DSM investments.

90. **Mass. DPU** 90-261-A, economics and role of fuel-switching in the DSM program of the Massachusetts Electric Company; Boston Gas Company. April 1991.

Role of fuel-switching in utility DSM programs and specifically in Massachusetts Electric's. Establishing comparable avoided costs and comparison of electric and gas system costs. Updated externality values.

91. **Private arbitration,** Massachusetts Refusetech Contractual Request for Adjustment to Service Fee; Massachusetts Refusetech. May 1991.

NEPCo rates for power purchases from the New England Solid Waste Compact plant. Fuel price and avoided cost projections vs. realities.

92. **Vt. PSB** 5491, cost-effectiveness of Central Vermont's commitment to Hydro Quebec purchases; Conservation Law Foundation. July 1991.

Changes in load forecasts and resale markets since approval of HQ purchases. Effect of HQ purchase on DSM.

93. **S.C. PSC** 91-216-E, cost recovery of Duke Power's DSM expenditures; South Carolina Department of Consumer Affairs. Direct, September 13 1991; Surrebuttal October 1991.

Problems with conservation plans of Duke Power, including load building, cream skimming, and inappropriate rate designs.

94. **Md. PSC** 8241 Phase II, review of Baltimore Gas & Electric's avoided costs; Maryland Office of People's Counsel. September 1991.

Development of direct avoided costs for DSM. Problems with BG&E's avoided costs and DSM screening. Incorporation of environmental externalities.

95. **Bucksport (Maine) Planning Board,** AES/Harriman Cove shoreland zoning application; Conservation Law Foundation and Natural Resources Council of Maine. October 1991.

New England's power surplus. Costs of bringing AES/Harriman Cove on line to back out existing generation. Alternatives.

96. **Mass. DPU** 91-131, update of externalities values adopted in Docket 89-239; Boston Gas Company. October 1991. Rebuttal, December 1991.

Updates on pollutant externality values. Addition of values for chlorofluorocarbons, air toxics, thermal pollution, and oil import premium. Review of state regulatory actions regarding externalities.

97. **Fla. PSC** 910759, petition of Florida Power Corporation for determination of need for proposed electrical power plant and related facilities; Floridians for Responsible Utility Growth. October 1991.

Florida Power's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

98. **Fla. PSC** 910833-EI, petition of Tampa Electric Company for a determination of need for proposed electrical power plant and related facilities; Floridians for Responsible Utility Growth. October 1991.

    Obligation to pursue integrated resource planning, failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

99. **Penn. PUC** I-900005, R-901880; investigation into demand-side management by electric utilities; Pennsylvania Energy Office. January 1992.

    Appropriate cost recovery mechanism for Pennsylvania utilities. Purpose and scope of direct cost recovery, lost revenue recovery, and incentives.

100. **S.C. PSC** 91-606-E, petition of South Carolina Electric and Gas for a certificate of public convenience and necessity for a coal-fired plant; South Carolina Department of Consumer Affairs. January 1992.

    Justification of plant certification under integrated resource planning. Failures in SCE&G's DSM planning and company potential for demand-side savings.

101. **Mass. DPU** 92-92, adequacy of Boston Edison's street-lighting options; Town of Lexington. June 1992.

    Efficiency and quality of street-lighting options. Boston Edison's treatment of high-quality street lighting. Corrected rate proposal for the Daylux lamp. Ownership of public street lighting.

102. **S.C. PSC** 92-208-E, integrated-resource plan of Duke Power Company; South Carolina Department of Consumer Affairs. August 1992.

    Problems with Duke Power's DSM screening process, estimation of avoided cost, DSM program design, and integration of demand-side and supply-side planning.

103. **N.C. UC** E-100 Sub 64, integrated-resource-planning docket; Southern Environmental Law Center. September 1992.

    General principles of integrated resource planning, DSM screening, and program design. Review of the IRPs of Duke Power Company, Carolina Power & Light Company, and North Carolina Power.

104. **Ont. EAB** Ontario Hydro Demand/Supply Plan Hearings, *Environmental Externalities Valuation and Ontario Hydro's Resource Planning* (3 vols.); Coalition of Environmental Groups. October 1992.

    Valuation of environmental externalities from fossil fuel combustion and the nuclear fuel cycle. Application to Ontario Hydro's supply and demand planning.

105. **Texas PUC** 110000, application of Houston Lighting and Power company for a certificate of convenience and necessity for the DuPont Project; Destec Energy, Inc. September 1992.

Valuation of environmental externalities from fossil fuel combustion and the application to the evaluation of proposed cogeneration facility.

106. **Maine BEP,** in the matter of the Basin Mills Hydroelectric Project application; Conservation Intervenors. November 1992.

Economic and environmental effects of generation by proposed hydro-electric project.

107. **Md. PSC** 8473, review of the power sales agreement of Baltimore Gas and Electric with AES Northside; Maryland Office of People's Counsel. November 1992.

Non-price scoring and unquantified benefits; DSM potential as alternative; environmental costs; cost and benefit estimates.

108. **N.C. UC** E-100 Sub 64, analysis and investigation of least cost integrated resource planning in North Carolina; Southern Environmental Law Center. November 1992.

Demand-side management cost recovery and incentive mechanisms.

109. **S.C. PSC** 92-209-E, in re Carolina Power & Light Company; South Carolina Department of Consumer Affairs. November 1992.

Demand-side-management planning: objectives, process, cost-effectiveness test, comprehensiveness, lost opportunities. Deficiencies in CP&L's portfolio. Need for economic evaluation of load building.

110 **Fla. DER** hearings on the Power Plant Siting Act; Legal Environmental Assistance Foundation. December 1992.

Externality valuation and application in power-plant siting. DSM potential, cost-benefit test, and program designs.

111. **Md. PSC** 8487, Baltimore Gas and Electric Company electric rate case. Direct January 1993; rebuttal February 1993.

Class allocation of production plant and O&M; transmission, distribution, and general plant; administrative and general expenses. Marginal cost and rate design.

112. **Md. PSC** 8179, Approval of amendment to Potomac Edison purchase agreement with AES Warrior Run; Maryland Office of People's Counsel. January 29 1993.

Economic analysis of proposed coal-fired cogeneration facility.

113. **Mich. PSC** U-10102, Detroit Edison rate case; Michigan United Conservation Clubs. February 17 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

114. **Ohio PUC** 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP; Cincinnati Gas and Electric demand-management programs; City of Cincinnati. April 1993.

Demand-side-management planning, program designs, potential savings, and avoided costs.

115. **Mich. PSC** U-10335, Consumers Power rate case; Michigan United Conservation Clubs. October 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

116. **Ill. CC** 92-0268, electric-energy plan for Commonwealth Edison; City of Chicago. Direct, February 1 1994; rebuttal, September 1994.

Cost-effectiveness screening of demand-side management programs and measures; estimates by Commonwealth Edison of costs avoided by DSM and of future cost, capacity, and performance of supply resources.

117. **FERC** 2422 et al., application of James River–New Hampshire Electric, Public Service of New Hampshire, for licensing of hydro power; Conservation Law Foundation; 1993.

Cost-effective energy conservation available to the Public Service of New Hampshire; power-supply options; affidavit.

118. **Vt. PSB** 5270-CV-1,-3, and 5686; Central Vermont Public Service fuel-switching and DSM program design, on behalf of the Vermont Department of Public Service. Direct, April 1994; rebuttal, June 1994.

Avoided costs and screening of controlled water-heating measures; risk, rate impacts, participant costs, externalities, space- and water-heating load, benefit-cost tests.

119. **Fla. PSC** 930548-EG–930551-EG, conservation goals for Florida electric utilities; Legal Environmental Assistance Foundation, Inc. April 1994.

Integrated resource planning, avoided costs, rate impacts, analysis of conservation goals of Florida electric utilities.

120. **Vt. PSB** 5724, Central Vermont Public Service Corporation rate request; Vermont Department of Public Service. Joint surrebuttal testimony with John Plunkett. August 1994.

Costs avoided by DSM programs; Costs and benefits of deferring DSM programs.

121. **Mass. DPU** 94-49, Boston Edison integrated-resource-management plan; Massachusetts Attorney General. August 1994.

Least-cost planning, modeling, and treatment of risk.

122. **Mich. PSC** U-10554, Consumers Power Company DSM program and incentive; Michigan Conservation Clubs. November 1994.

Critique of proposed reductions in DSM programs; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

123. **Mich. PSC** U-10702, Detroit Edison Company cost recovery, on behalf of the Residential Ratepayers Consortium. December 1994.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

124. **N.J. BRC** EM92030359, environmental costs of proposed cogeneration; Freehold Cogeneration Associates. November 1994.

Comparison of potential externalities from the Freehold cogeneration project with that from three coal technologies; support for the study "The Externalities of Four Power Plants."

125. **Mich. PSC** U-10671, Detroit Edison Company DSM programs; Michigan United Conservation Clubs. January 1995.

Critique of proposal to scale back DSM efforts in light of potential for competition. Loss of savings, increase of customer costs, and decrease of competitiveness. Discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

126. **Mich. PSC** U-10710, power-supply-cost-recovery plan of Consumers Power Company; Residential Ratepayers Consortium. January 1995.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

127. **FERC** 2458 and 2572, Bowater–Great Northern Paper hydropower licensing; Conservation Law Foundation. February 1995.

Comments on draft environmental impact statement relating to new licenses for two hydropower projects in Maine. Applicant has not adequately considered how energy conservation can replace energy lost due to habitat-protection or -enhancement measures.

128. **N.C. UC** E-100 Sub 74, Duke Power and Carolina Power & Light avoided costs; Hydro-Electric–Power Producer's Group. February 1995.

Critique and proposed revision of avoided costs offered to small hydro-power producers by Duke Power and Carolina Power and Light.

129. **New Orleans City Council** UD-92-2A and -2B, least-cost IRP for New Orleans Public Service and Louisiana Power & Light; Alliance for Affordable Energy. Direct, February 1995; rebuttal, April 1995.

Critique of proposal to scale back DSM efforts in light of potential competition.

130. **D.C. PSC** FC917 II, prudence of DSM expenditures of Potomac Electric Power Company; Potomac Electric Power Company. Rebuttal testimony, February 1995.

Prudence of utility DSM investment; prudence standards for DSM programs of the Potomac Electric Power Company.

131. **Ont. Energy Board** EBRO 490, DSM cost recovery and lost-revenue–adjustment mechanism for Consumers Gas Company; Green Energy Coalition. April 1995.

Demand-side-management cost recovery. Lost-revenue–adjustment mechanism for Consumers Gas Company.

132. **New Orleans City Council** CD-85-1, New Orleans Public Service rate increase; Alliance for Affordable Energy. Rebuttal, May 1995.

Allocation of costs and benefits to rate classes.

133. **Mass. DPU** Docket DPU-95-40, Mass. Electric cost-allocation; Massachusetts Attorney General. June 1995.

Allocation of costs to rate classes. Critique of cost-of-service study. Implications for industry restructuring.

134. **Md. PSC** 8697, Baltimore Gas & Electric gas rate increase; Maryland Office of People's Counsel. July 1995.

Rate design, cost-of-service study, and revenue allocation.

135. **N.C. UC** E-2 Sub 669. December 1995.

Need for new capacity. Energy-conservation potential and model programs.

136. **Arizona CC** U-1933-95-317, Tucson Electric Power rate increase; Residential Utility Consumer Office. January 1996.

Review of proposed rate settlement. Used-and-usefulness of plant. Rate design. DSM potential.

137. **Ohio PUC** 95-203-EL-FOR; Campaign for an Energy-Efficient Ohio. February 1996

Long-term forecast of Cincinnati Gas and Electric Company, especially its DSM portfolio. Opportunities for further cost-effective DSM savings. Tests of cost effectiveness. Role of DSM in light of industry restructuring; alternatives to traditional utility DSM.

138 **Vt. PSB** 5835, Central Vermont Public Service Company rates; Vermont Department of Public Service. February 1996.

Design of load-management rates of Central Vermont Public Service Company.

139. **Md. PSC** 8720, Washington Gas Light DSM; Maryland Office of People's Counsel. May 1996.

Avoided costs of Washington Gas Light Company; integrated least-cost planning.

140. **Mass. DPU** 96-100, Massachusetts Utilities' Stranded Costs; Massachusetts Attorney General. Oral testimony in support of "estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities," July 1996.

Stranded costs. Calculation of loss or gain. Valuation of utility assets.

141. **Mass. DPU** 96-70, Essex County Gas Company rates; Massachusetts Attorney General. July 1996.

Market-based allocation of gas-supply costs of Essex County Gas Company.

142. **Mass. DPU** 96-60, Fall River Gas Company rates; Massachusetts Attorney General. Direct, July 1996; surrebuttal, August 1996.

Market-based allocation of gas-supply costs of Fall River Gas Company.

143. **Md. PSC** 8725, Maryland electric-utilities merger; Maryland Office of People's Counsel. July 1996.

Proposed merger of Baltimore Gas & Electric Company, Potomac Electric Power Company, and Constellation Energy. Cost allocation of merger benefits and rate reductions.

144. **N.H. PUC** DR 96-150, Public Service Company of New Hampshire stranded costs; New Hampshire Office of Consumer Advocate. December 1996.

Market price of capacity and energy; value of generation plant; restructuring gain and stranded investment; legal status of PSNH acquisition premium; interim stranded-cost charges.

145. **Ont. Energy Board** EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas; Green Energy Coalition. March 1997.

LRAM and incentive mechanisms in rates for the Consumers Gas Company.

146. **New York PSC** 96-E-0897, Consolidated Edison restructuring plan; City of New York. April 1997.

Electric-utility competition and restructuring; critique of proposed settlement of Consolidated Edison Company; stranded costs; market power; rates; market access.

147. **Vt. PSB** 5980, proposed statewide energy plan; Vermont Department of Public Service. Direct, August 1997; rebuttal, December 1997.

Justification for and estimation of statewide avoided costs; guidelines for distributed IRP.

148. **Mass. DPU** 96-23, Boston Edison restructuring settlement; Utility Workers Union of America. September 1997.

Performance incentives proposed for the Boston Edison company.

149. **Vt. PSB** 5983, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, October 1997; rebuttal, December 1997.

In three separate pieces of prefiled testimony, addressed the Green Mountain Power Corporation's (1) distributed-utility-planning efforts, (2) avoided costs, and (3) prudence of decisions relating to a power purchase from Hydro-Quebec.

150. **Mass. DPU** 97-63, Boston Edison proposed reorganization; Utility Workers Union of America. October 1997.

Increased costs and risks to ratepayers and shareholders from proposed reorganization; risks of diversification; diversion of capital from regulated to unregulated affiliates; reduction in Commission authority.

151. **Mass. DTE** 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Jonathan Wallach, January 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

152. **N.H. PUC** Docket DR 97-241, Connecticut Valley Electric fuel and purchased-power adjustments; City of Claremont, N.H. February 1998.

Prudence of continued power purchase from affiliate; market cost of power; prudence disallowances and cost-of-service ratemaking.

153. **Md. PSC** 8774, APS-DQE merger; Maryland Office of People's Counsel. February 1998.

Proposed power-supply arrangements between APS's potential operating subsidiaries; power-supply savings; market power.

154. **Vt. PSB** 6018, Central Vermont Public Service Co. rate increase; Vermont Department of Public Service. February 1998.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Reasonableness of avoided-cost estimates. Quality of DU planning.

155. **Maine PUC** 97-580, Central Maine Power restructuring and rates; Maine Office of Public Advocate. May 1998; Surrebuttal, August 1998.

Determination of stranded costs; gains from sales of fossil, hydro, and biomass plant; treatment of deferred taxes; incentives for stranded-cost mitigation; rate design.

156. **Mass. DTE** 98-89, purchase of Boston Edison municipal street lighting; Towns of Lexington and Acton. Affidavit, August 1998.

Valuation of municipal streetlighting; depreciation; applicability of unbundled rate.

157. **Vt. PSB** 6107, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, September 1998; Surrebuttal drafted but not filed, November 2000.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Least-cost planning and prudence. Quality of DU planning.

158. **Mass. DTE** 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Jonathan Wallach, October 1998. Joint surrebuttal with Jonathan Wallach, January 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

159. **Md. PSC** 8794 and 8804, BG&E restructuring and rates; Maryland Office of People's Counsel. Direct, December 1998; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

160. **Md. PSC** 8795; Delmarva Power & Light restructuring and rates; Maryland Office of People's Counsel. December 1998.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

161. **Md. PSC** 8797, Potomac Edison Company restructuring and rates; Maryland Office of People's Counsel. Direct, January 1999; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

162. **Conn. DPUC** 99-02-05, Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear and non-nuclear assets from comparable-sales and cash-flow analyses.

163. **Conn. DPUC** 99-03-04, United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear assets from comparable-sales and cash-flow analyses.

164. **Wash. UTC** UE-981627, PacifiCorp–Scottish Power merger, Office of the Attorney General. June 1999.

Review of proposed performance standards and valuation of performance. Review of proposed low-income assistance.

165. **Utah PSC** 98-2035-04, PacifiCorp–Scottish Power merger, Utah Committee of Consumer Services. June 1999.

Review of proposed performance standards and valuation of performance.

166. **Conn. DPUC** 99-03-35, United Illuminating Company proposed standard offer; Connecticut Office of Consumer Counsel. July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost

167. **Conn. DPUC** 99-03-36, Connecticut Light and Power Company proposed standard offer; Connecticut Office of Consumer Counsel. Direct, July 1999; supplemental, July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost.

168. **W. Va. PSC** 98-0452-E-GI, electric-industry restructuring, West Virginia Consumer Advocate. July 1999.

Market value of generating assets of, and restructuring gain for, Potomac Edison, Monongahela Power, and Appalachian Power. Comparable-sales and cash-flow analyses.

169. **Ont. Energy Board** RP-1999-0034, Ontario performance-based rates; Green Energy Coalition. September 1999.

Rate design. Recovery of demand-side-management costs under PBR. Incremental costs.

170. **Conn. DPUC** 99-08-01, standards for utility restructuring; Connecticut Office of Consumer Counsel. Direct, November 1999; supplemental, January 2000.

Appropriate role of regulation. T&D reliability and service quality. Performance standards and customer guarantees. Assessing generation adequacy in a competitive market.

171. **Conn. Superior Court** CV 99-049-7239, Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. Affidavit, December 1999.

Errors of the Conn. DPUC in deriving discounted-cash-flow valuations for Millstone and Seabrook, and in setting minimum bid price.

172. **Conn. Superior Court** CV 99-049-7597, United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. December 1999.

Errors of the Conn. DPUC, in its discounted-cash-flow computations, in selecting performance assumptions for Seabrook, and in setting minimum bid price.

173. **Ont. Energy Board** RP-1999-0044, Ontario Hydro transmission-cost allocation and rate design; Green Energy Coalition. January 2000.

Cost allocation and rate design. Net vs. gross load billing. Export and wheeling-through transactions. Environmental implications of utility proposals.

174. **Utah PSC** 99-2035-03, PacifiCorp Sale of Centralia plant, mine, and related facilities; Utah Committee of Consumer Services. January 2000.

Prudence of sale and management of auction. Benefits to ratepayers. Allocation and rate treatment of gain.

175. **Conn. DPUC** 99-09-12, Nuclear Divestiture by Connecticut Light & Power and United Illuminating; Connecticut Office of Consumer Counsel. January 2000.

Market for nuclear assets. Optimal structure of auctions. Value of minority rights. Timing of divestiture.

176. **Ont. Energy Board** RP-1999-0017, Union Gas PBR proposal; Green Energy Coalition. March 2000.

Lost-revenue-adjustment and shared-savings incentive mechanisms for Union Gas DSM programs. Standards for review of targets and achievements, computation of lost revenues. Need for DSM expenditure true-up mechanism.

177. **N.Y. PSC** 99-S-1621, Consolidated Edison steam rates; City of New York. April 2000.

Allocation of costs of former cogeneration plants, and of net proceeds of asset sale. Economic justification for steam-supply plans. Depreciation rates. Weather normalization and other rate adjustments.

178. **Maine PUC** 99-666, Central Maine Power alternative rate plan; Maine Public Advocate. Direct, May 2000; Surrebuttal, August 2000.

Likely merger savings. Savings and rate reductions from recent mergers. Implications for rates.

179. **Mass. EFSB** 97-4, Massachusetts Municipal Wholesale Electric Company gas-pipeline proposal; Town of Wilbraham, Mass. June 2000.

Economic justification for natural-gas pipeline. Role and jurisdiction of EFSB.

180. **Conn. DPUC** 99-09-03; Connecticut Natural Gas Corporation merger and rate plan; Connecticut office of Consumer Counsel. September 2000.

Performance-based ratemaking in light of mergers. Allocation of savings from merger. Earnings-sharing mechanism.

181. **Conn. DPUC** 99-09-12RE01, Proposed Millstone sale; Connecticut Office of Consumer Counsel. November 2000.

Requirements for review of auction of generation assets. Allocation of proceeds between units.

182. **Mass. DTE** 01-25, Purchase of streetlights from Commonwealth Electric; Cape Light Compact. January 2001

Municipal purchase of streetlights; Calculation of purchase price under state law; Determination of accumulated depreciation by asset.

183. **Conn. DPUC** 00-12-01 and 99-09-12RE03, Connecticut Light & Power rate design and standard offer; Connecticut Office of Consumer Counsel. March 2001.

Rate design and standard offer under restructuring law; Future rate impacts; Transition to restructured regime; Comparison of Connecticut and California restructuring challenges.

184. **Vt. PSB** 6460 & 6120, Central Vermont Public Service rates; Vermont Department of Public Service. Direct, March 2001; Surrebuttal, April 2001.

Review of decision in early 1990s to commit to long-term uneconomic purchase from Hydro Québec. Calculation of present damages from imprudence.

185. **N.J. BPU** EM00020106, Atlantic City Electric Company sale of fossil plants; New Jersey Ratepayer Advocate. Affidavit, May 2001.

Comparison of power-supply contracts. Comparison of plant costs to replacement power cost. Allocation of sales proceeds between subsidiaries.

186. N.J. BPU GM00080564, Public Service Electric and Gas transfer of gas supply contracts; New Jersey Ratepayer Advocate. Direct, May 2001.

Transfer of gas transportation contracts to unregulated affiliate. Potential for market power in wholesale gas supply and electric generation. Importance of reliable gas supply. Valuation of contracts. Effect of proposed requirements contract on rates. Regulation and design of standard-offer service.

187. Conn. DPUC 99-04-18 Phase 3, 99-09-03 Phase 2; Southern Connecticut Natural Gas and Connecticut Natural Gas rates and charges; Connecticut Office of Consumer Counsel. Direct, June 2001; supplemental, July 2001.

Identifying, quantifying, and allocating merger-related gas-supply savings between ratepayers and shareholders. Establishing baselines. Allocations between affiliates. Unaccounted-for gas.

188. N.J. BPU EX01050303, New Jersey electric companies' procurement of basic supply; New Jersey Ratepayer Advocate. August 2001.

Review of proposed statewide auction for purchase of power requirements. Market power. Risks to ratepayers of proposed auction.

189. N.Y. PSC 00-E-1208, Consolidated Edison rates; City of New York. October 2001.

Geographic allocation of stranded costs. Locational and postage-stamp rates. Causation of stranded costs. Relationship between market prices for power and stranded costs.

190. Mass. DTE 01-56, Berkshire Gas Company; Massachusetts Attorney General. October 2001.

Allocation of gas costs by load shape and season. Competition and cost allocation.

191. N.J. BPU EM00020106, Atlantic City Electric proposed sale of fossil plants; New Jersey Ratepayer Advocate. December 2001.

Current market value of generating plants vs. proposed purchase price.

192. Vt. PSB 6545, Vermont Yankee proposed sale; Vermont Department of Public Service. January 2002.

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Review of auction manager's valuation of bids.

193. Conn. Siting Council 217, Connecticut Light & Power proposed transmission line from Plumtree to Norwalk; Connecticut Office of Consumer Counsel. March 2002.

Nature of transmission problems. Potential for conservation and distributed resources to defer, reduce or avoid transmission investment. CL&P transmission planning process. Joint testimony with John Plunkett.

194. **Vt. PSB** 6596, Citizens Utilities rates; Vermont Department of Public Service. Direct, March 2002; rebuttal, May 2002.

Review of 1991 decision to commit to long-term uneconomic purchase from Hydro Québec. Alternatives; role of transmission constraints. Calculation of present damages from imprudence.

195. **Conn. DPUC** 01-10-10, United Illuminating rate plan; Connecticut Office of Consumer Counsel. April 2002

Allocation of excess earnings between shareholders and ratepayers. Asymmetry in treatment of over- and under-earning. Accelerated amortization of stranded costs. Effects of power-supply developments on ratepayer risks. Effect of proposed rate plan on utility risks and required return.

196. **Conn. DPUC** 01-12-13RE01, Seabrook proposed sale; Connecticut Office of Consumer Counsel. July 2002

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Assessment of valuation of purchased-power contracts.

197. **Ont. Energy Board** RP-2002-0120, review of transmission-system code; Green Energy Coalition. October 2002.

Cost allocation. Transmission charges. Societal cost-effectiveness. Environmental externalities.

198. **N.J. BPU** ER02080507, Jersey Central Power & Light rates; N.J. Division of the Ratepayer Advocate. Phase I December 2002; Phase II (oral) July 2003.

Prudence of procurement of electrical supply. Documentation of procurement decisions. Comparison of costs for subsidiaries with fixed versus flow-through cost recovery.

199. **Conn. DPUC** 03-07-02, CL&P rates; AARP. October 2003

Proposed distribution investments, including prudence of prior management of distribution system and utility's failure to make investments previously funded in rates. Cost controls. Application of rate cap. Legislative intent.

200. **Conn. DPUC** 03-07-01, CL&P transitional standard offer; AARP. November 2003.

Application of rate cap. Legislative intent.

201. **Vt. PSB** 6596, Vermont Electric Power Company and Green Mountain Power Northwest Reliability transmission plan; Conservation Law Foundation. December 2003.

Inadequacies of proposed transmission plan. Failure of to perform least-cost planning. Distributed resources.

202. **Ohio PUC** 03-2144-EL-ATA, Ohio Edison, Cleveland Electric, and Toledo Edison Cos. rates and transition charges; Green Mountain Energy Co. February 2004.

Pricing of standard-offer service in competitive markets. Critique of anticompetitive features of proposed standard-offer supply, including non-bypassable charges.

203. **N.Y. PSC** 03-G-1671 & 03-S-1672, Consolidated Edison company steam and gas rates; City of New York. Direct March 2004; rebuttal April 2004; settlement June 2004.

Prudence and cost allocation for the East River Repowering Project. Gas and steam energy conservation. Opportunities for cogeneration at existing steam plants.

204. **N.Y. PSC** 04-E-0572, Consolidated Edison rates and performance; City of New York. Direct, September 2004; rebuttal, October 2004.

Consolidated Edison's role in promoting adequate supply and demand resources. Integrated resource and T&D planning. Performance-based ratemaking and streetlighting.

205. **Ont. Energy Board** RP 2004-0188, cost recovery and DSM for Ontario electric-distribution utilities; Green Energy Coalition. Exhibit, December 2004.

Differences in ratemaking requirements for customer-side conservation and demand management versus utility-side efficiency improvements. Recovery of lost revenues or incentives. Reconciliation mechanism.

206. **Mass. DTE** 04-65, Cambridge Electric Light Co. streetlighting; City of Cambridge. Direct, October 2004; supplemental, January 2005.

Calculation of purchase price of street lights by the City of Cambridge.

207. **N.Y. PSC** 04-W-1221, rates, rules, charges, and regulations of United Water New Rochelle; Town of Eastchester and City of New Rochelle. Direct, February 2005.

Size and financing of proposed interconnection. Rate design. Water-mains replacement and related cost recovery. Lost and unaccounted-for water.

208. **N.Y. PSC** 05-M-0090, system-benefits charge; City of New York. Comments, March 2005.

Assessment and scope of, and potential for, New York system-benefits charges.

209. **Md. PSC** 9036, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, August 2005.

Allocation of costs. Design of rates. Interruptible and firm rates.

210. **B.C. UC** 3698388, British Columbia Hydro resource-acquisition plan; British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter. September 2005.

Renewable energy and DSM. Economic tests of cost-effectiveness. Costs avoided by DSM.

211. **Conn. DPUC** 05-07-18, financial effect of long-term power contracts; Connecticut Office of Consumer Counsel. September 2005.

Assessment of effect of DSM, distributed generation, and capacity purchases on financial condition of utilities.

212. **Conn. DPUC** 03-07-01RE03 & 03-07-15RE02, incentives for power procurement; Connecticut Office of Consumer Counsel. Direct, September 2005; Additional, April 2006.

Utility obligations for generation procurement. Application of standards for utility incentives. Identification and quantification of effects of timing, load characteristics, and product definition.

213. **Conn. DPUC** Docket 05-10-03, Connecticut L&P; time-of-use, interruptible, and seasonal rates; Connecticut Office of Consumer Counsel. Direct and Supplemental Testimony February 2006.

Seasonal and time-of-use differentiation of generation, congestion, transmission and distribution costs; fixed and variable peak-period timing; identification of pricing seasons and seasonal peak periods; cost-effectiveness of time-of-use rates.

214. **Ont. Energy Board** Case EB-2005-0520, Union Gas rates; School Energy Coalition. Evidence, April 2006.

Rate design related to splitting commercial rate class into two classes. New break point, cost allocation, customer charges, commodity rate blocks.

215. **Ont. Energy Board** EB-2006-0021, Natural-gas demand-side-management generic issues proceeding; School Energy Coalition. Evidence, June 2006.

Multi-year planning and budgeting; lost-revenue adjustment mechanism; determining savings for incentives; oversight; program screening.

216. **Ind. URC** 42943 and 43046, Vectren Energy DSM proceedings; Citizens Action Coalition. Direct, June 2006.

Rate decoupling and energy-efficiency goals.

217. **Penn. PUC** 00061346, Duquesne Lighting; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; benefits of time-dependent pricing; appropriate metering technology; real-time rate design and customer information

218. **Penn. PUC** R-00061366 et al., rate-transition-plan proceedings of Metropolitan Edison and Pennsylvania Electric; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; appropriate metering technology; real-time rate design and customer information.

219. **Conn. DPUC** 06-01-08, Connecticut L&P procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly since September 2006 to October 2013.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

220. **Conn. DPUC** 06-01-08, United Illuminating procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly August 2006 to October 2013.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

221. **N.Y. PSC** 06-M-1017, policies, practices, and procedures for utility commodity supply service; City of New York. Comments, November and December 2006.

Multi-year contracts, long-term planning, new resources, procurement by utilities and other entities, cost recovery.

222. **Conn. DPUC** 06-01-08, procurement of power for standard service and last-resort service, lessons learned; Connecticut Office Of Consumer Counsel. Comments and Technical Conferences December 2006 and January 2007.

Sharing of data and sources; benchmark prices; need for predictability, transparency and adequate review; utility-owned resources; long-term firm contracts.

223. **Ohio PUC** PUCO 05-1444-GA-UNC, recovery of conservation costs, decoupling, and rate-adjustment mechanisms for Vectren Energy Delivery of Ohio; Ohio Consumers' Counsel. February 2007.

Assessing cost-effectiveness of natural-gas energy-efficiency programs. Calculation of avoided costs. Impact on rates. System benefits of DSM.

224. **N.Y. PSC** 06-G-1332, Consolidated Edison Rates and Regulations; City of New York. March 2007.

Gas energy efficiency: benefits to customers, scope of cost-effective programs, revenue decoupling, shareholder incentives.

225. **Alb. EUB** 1500878, ATCo Electric rates; Association of Municipal Districts & Counties and Alberta Federation of Rural Electrical Associations. May 2007.

Direct assignment of distribution costs to street lighting. Cost causation and cost allocation. Minimum-system and zero-intercept classification.

226. **Conn. DPUC** 07-04-24, review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), June 2007.

Assessment of proposed capacity contracts for new combined-cycle, peakers and DSM. Evaluation of contracts for differences, modeling of energy, capacity and forward-reserve markets. Corrections of errors in computation of costs, valuation of energy-price effects of peakers, market-driven expansion plans and retirements, market response to contracted resource additions, DSM proposal evaluation.

227. **N.Y. PSC** 07-E-0524, Consolidated Edison electric rates; City of New York. September 2007.

Energy-efficiency planning. Recovery of DSM costs. Decoupling of rates from sales. Company incentives for DSM. Advanced metering. Resource planning.

228. **Man. PUB** 136-07, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. February 2008.

Revenue allocation, rate design, and demand-side management. Estimation of marginal costs and export revenues.

229. **Mass. EFSB** 07-7, DPU 07-58 & -59; proposed Brockton Power Company plant; Alliance Against Power Plant Location. March 2008

Regional supply and demand conditions. Effects of plant construction and operation on regional power supply and emissions.

230. **Conn. DPUC** 08-01-01, peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

231. **Ont. Energy Board** 2007-0905, Ontario Power Generation payments; Green Energy Coalition. April 2008.

Cost of capital for Hydro and nuclear investments. Financial risks of nuclear power.

232. **Utah** PSC 07-035-93, Rocky Mountain Power Rates; Utah Committee of Consumer Services. July 2008

Cost allocation and rate design. Cost of service. Correct classification of generation, transmission, and purchases.

233. **Ont. Energy Board** 2007-0707, Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Jonathan Wallach and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

234. **N.Y. PSC** 08-E-0596, Consolidated Edison electric rates; City of New York. September 2008.

Estimated bills, automated meter reading, and advanced metering. Aggregation of building data. Targeted DSM program design. Using distributed generation to defer T&D investments.

235. **Conn. DPUC** 08-07-01, Integrated resource plan; Connecticut Office of Consumer Counsel. September 2008.

Integrated resource planning scope and purpose. Review of modeling and assumptions. Review of energy efficiency, peakers, demand response, nuclear, and renewables. Structuring of procurement contracts.

236. **Man. PUB** 2008 MH EIIR, Manitoba Hydro intensive industrial rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. November 2008.

Marginal costs. Rate design. Time-of-use rates.

237. **Md. PSC** 9036, Columbia Gas rates; Maryland Office of People's Counsel. January 2009.

Cost allocation and rate design. Critique of cost-of-service studies.

238. **Vt. PSB** 7440, extension of authority to operate Vermont Yankee; Conservation Law Foundation and Vermont Public Interest Research Group. Direct, February 2009; Surrebuttal, May 2009.

Adequacy of decommissioning funding. Potential benefits to Vermont of revenue-sharing provision. Risks to Vermont of underfunding decommissioning fund.

239. **N.S. UARB** M01439, Nova Scotia Power DSM and cost recovery; Nova Scotia Consumer Advocate. May 2009.

Recovery of demand-side-management costs and lost revenue.

240. **N.S. UARB** M01496, proposed biomass project; Nova Scotia Consumer Advocate. June 2009.

Procedural, planning, and risk issues with proposed power-purchase contract. Biomass price index. Nova Scotia Power's management of other renewable contracts.

241. **Conn. Siting Council** 370A, Connecticut Light & Power transmission projects; Connecticut Office of Consumer Counsel. July 2009. Also filed and presented in **MA EFSB** 08-02, February 2010.

Need for transmission projects. Modeling of transmission system. Realistic modeling of operator responses to contingencies

242. **Mass. DPU** 09-39, NGrid rates; Mass. Department of Energy Resources. August 2009.

Revenue-decoupling mechanism. Automatic rate adjustments.

243. **Utah PSC** 09-035-23, Rocky Mountain Power rates; Utah Office of Consumer Services. Direct, October 2009; rebuttal, November 2009.

Cost-of-service study. Cost allocators for generation, transmission, and substation.

244. **Utah PSC** 09-035-15, Rocky Mountain Power energy-cost-adjustment mechanism; Utah Office of Consumer Services. Direct, November 2009; surrebuttal, January 2010.

Automatic cost-adjustment mechanisms. Net power costs and related risks. Effects of energy-cost-adjustment mechanisms on utility performance.

245. **Penn. PUC** R-2009-2139884, Philadelphia Gas Works energy efficiency and cost recovery; Philadelphia Gas Works. December 2009.

Avoided gas costs. Recovery of efficiency-program costs and lost revenues. Rate impacts of DSM.

246. **B.C. UC** 3698573, British Columbia Hydro rates; British Columbia Sustainable Energy Association and Sierra Club British Columbia. February 2010.

Rate design and energy efficiency.

247. **Ark. PSC** 09-084-U, Entergy Arkansas rates; National Audubon Society and Audubon Arkansas. Direct, February 2010; surrebuttal, April 2010.

Recovery of revenues lost to efficiency programs. Determination of lost revenues. Incentive and recovery mechanisms.

248. **Ark. PSC** 10-010-U, Energy efficiency; National Audubon Society and Audubon Arkansas. Direct, March 2010; reply, April 2010.

Regulatory framework for utility energy-efficiency programs. Fuel-switching programs. Program administration, oversight, and coordination. Rationale for commercial and industrial efficiency programs. Benefit of energy efficiency.

249. **Ark. PSC** 08-137-U, Generic rate-making; National Audubon Society and Audubon Arkansas. Direct, March 2010; supplemental, October 2010; reply, October 2010.

Calculation of avoided costs. Recovery of utility energy-efficiency-program costs and lost revenues. Shareholder incentives for efficiency-program performance.

250. **Plymouth, Mass., Superior Court** Civil Action No. PLCV2006-00651-B (Hingham Municipal Lighting Plant v. Gas Recovery Systems LLC et al.), Breach of agreement; defendants. Affidavit, May 2010.

Contract interpretation. Meaning of capacity measures. Standard practices in capacity agreements. Power-pool rules and practices. Power planning and procurement.

251. **N.S. UARB** M02961, Port Hawkesbury biomass project; Nova Scotia Consumer Advocate. June 2010.

Least-cost planning and renewable-energy requirements. Feasibility versus alternatives. Unknown or poorly estimated costs.

252. **Mass. DPU** 10-54, NGrid purchase of long-term power from Cape Wind; Natural Resources Defense Council et al. July 2010.

Effects of renewable-energy projects on gas and electric market prices. Impacts on system reliability and peak loads. Importance of PPAs to renewable development. Effectiveness of proposed contracts as price edges.

253. **Md. PSC** 9230, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, July 2010; rebuttal, surrebuttal, August 2010.

Allocation of gas- and electric-distribution costs. Critique of minimum-system analyses and direct assignment of shared plant. Allocation of environmental compliance costs. Allocation of revenue increases among rate classes.

254. **Ont. Energy Board** 2010-0008, Ontario Power Generation facilities charges; Green Energy Coalition. Evidence, August 2010.

Critique of including a return on CWIP in current rates. Setting cost of capital by business segment.

255. **N.S. UARB** 03454, Heritage Gas rates; Nova Scotia Consumer Advocate. October 2010.

Cost allocation. Cost of capital. Effect on rates of growth in sales.

256. **Man. PUB** 17/10, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. December 2010.

Revenue-allocation and rate design. DSM program.

257. **N.S. UARB** M03665, Nova Scotia Power depreciation rates; Nova Scotia Consumer Advocate. February 2011.

Depreciation and rates.

258. **New Orleans City Council** UD-08-02, Entergy IRP rules; Alliance for Affordable Energy. December 2010.

Integrated resource planning: Purpose, screening, cost recovery, and generation planning.

259. **N.S. UARB** M03665, depreciation rates of Nova Scotia Power; Nova Scotia Consumer Advocate. February 2011.

Steam-plant retirement dates, post-retirement use, timing of decommissioning and removal costs.

260. **N.S. UARB M**03632, renewable-energy community-based feed-in tariffs; Nova Scotia Consumer Advocate. March 2011.

Adjustments to estimate of cost-based feed-in tariffs. Rate effects of feed-in tariffs.

261. **Mass. EFSB** 10-2/**DPU** 10-131, 10-132; NStar transmission; Town of Sandwich, Mass. Direct, May 2011; Surrebuttal, June 2011.

Need for new transmission; errors in load forecasting; probability of power outages.

262. **Utah PSC** 10-035-124, Rocky Mountain Power rate case; Utah Office of Consumer Services. June 2011.

Load data, allocation of generation plants, scrubbers, power purchases, and service drops. Marginal cost study: inclusion of all load-related transmission projects, critique of minimum- and zero-intercept methods for distribution. Residential rate design.

263. **N.S. UARB** M04104; Nova Scotia Power general rate application; Nova Scotia Consumer Advocate. August 2011.

Cost allocation: allocation of costs of wind power and substations. Rate design: marginal-cost-based rates, demand charges, time-of-use rates.

264. **N.S. UARB** M04175, Load-retention tariff; Nova Scotia Consumer Advocate. August 2011.

Marginal cost of serving very large industrial electric loads; risk, incentives and rate design.

265. **Ark. PSC** 10-101-R, Rulemaking re self-directed energy efficiency for large customers; National Audubon Society and Audubon Arkansas. July 2011.

Structuring energy-efficiency programs for large customers.

266. Okla. CC PUD 201100077, current and pending federal regulations and legislation affecting Oklahoma utilities; Sierra Club. Comments July, October 2011; presentation July 2011.

Challenges facing Oklahoma coal plants; efficiency, renewable and conventional resources available to replace existing coal plants; integrated environmental compliance planning.

267. Nevada PUC 11-08019, integrated analysis of resource acquisition, Sierra Club. Comments, September 2011; hearing, October 2011.

Scoping of integrated review of cost-effectiveness of continued operation of Reid Gardner 1–3 coal units.

268. La. PSC R-30021, Louisiana integrated-resource-planning rules; Alliance for Affordable Energy. Comments, October 2011.

Scoping of integrated review of cost-effectiveness of continued operation of Reid Gardner 1–3 coal units.

269. Okla. CC PUD 201100087, Oklahoma Gas and Electric Company electric rates; Sierra Club. November 2011.

Resource monitoring and acquisition. Benefits to ratepayers of energy conservation and renewables. Supply planning

270. Ky. PSC 2011-00375, Kentucky utilities' purchase and construction of power plants; Sierra Club and National Resources Defense Council. December 2011.

Assessment of resources, especially renewables. Treatment of risk. Treatment of future environmental costs.

271. N.S. UARB M04819, demand-side-management plan of Efficiency Nova Scotia; Nova Scotia Consumer Advocate. May 2012.

Avoided costs. Allocation of costs. Reporting of bill effects.

272. Kansas CC 12-GIMX-337-GIV, utility energy-efficiency programs; The Climate and Energy Project. June 2012.

Cost-benefit tests for energy-efficiency programs. Collaborative program design.

273. N.S. UARB M04862, Port Hawksbury load-retention mechanism; Nova Scotia Consumer Advocate. June 2012.

Effect on ratepayers of proposed load-retention tariff. Incremental capital costs, renewable-energy costs, and costs of operating biomass cogeneration plant.

274. Utah PSC 11-035-200, Rocky Mountain Power Rates; Utah Office of Consumer Council. June 2012.

Cost allocation. Estimation of marginal customer costs.

275. **Ark. PSC** 12-008-U, environmental controls at Southwestern Electric Power Company's Flint Creek plant; Sierra Club. Direct, June 2012; rebuttal, August 2012; further, March 2013.

Costs and benefits of environmental retrofit to permit continued operation of coal plant, versus other options including purchased gas generation, efficiency, and wind. Fuel-price projections. Need for transmission upgrades.

276. **U.S. EPA** EPA-R09-OAR-2012-0021, air-quality implementation plan; Sierra Club. September 2012.

Costs, financing, and rate effects of Apache coal-plant scrubbers. Relative incomes in service territories of Arizona Coop and other utilities.

277. **Arkansas PSC** Docket No. 07-016-U; Entergy Arkansas' integrated resource plan; Audubon Arkansas. Comments, September 2012.

Estimation of future gas prices. Estimation of energy-efficiency potential. Screening of resource decisions. Wind costs.

278. **Vt. PSB** 7862, Entergy Nuclear Vermont and Entergy Nuclear Operations petition to operate Vermont Yankee; Conservation Law Foundation. October 2012.

Effect of continued operation on market prices. Value of revenue-sharing agreement. Risks of underfunding decommissioning fund.

279. **Man. PUB** 2012–13 GRA, Manitoba Hydro rates; Green Action Centre. November 2012.

Estimation of marginal costs. Fuel switching.

280. **N.S. UARB** M05339, Capital Plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.

Economic and financial modeling of investment. Treatment of AFUDC.

281. **N.S. UARB** M05416, South Canoe wind project of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.

Revenue requirements. Allocation of tax benefits. Ratemaking.

282. **N.S. UARB** 05419; Maritime Link transmission project and related contracts, Nova Scotia Consumer Advocate and Small Business Advocate. Direct, April 2013; supplemental (with Seth Parker), November 2013.

Load forecast, including treatment of economy energy sales. Wind power cost forecasts. Cost effectiveness and risk of proposed project. Opportunities for improving economics of project.

283. **Ont. Energy Board** 2012-0451/0433/0074, Enbridge Gas Greater Toronto Area project; Green Energy Coalition. June 2013, revised August 2013.

Estimating gas pipeline and distribution costs avoidable through gas DSM and curtailment of electric generation. Integrating DSM and pipeline planning.

284. **N.S. UARB** 05092, tidal-energy feed-in-tariff rate; Nova Scotia Consumer Advocate. August 2013.

Purchase rate for test and demonstration projects. Maximizing benefits under rate-impact caps. Pricing to maximize provincial advantage as a hub for emerging tidal-power industry.

285. **N.S. UARB** 05473, Nova Scotia Power 2013 cost-of-service study; Nova Scotia Consumer Advocate. October 2013.

Cost-allocation and rate design.

286. **B.C. UC** 3698715 & 3698719; performance-based ratemaking plan for FortisBC companies; British Columbia Sustainable Energy Association and Sierra Club British Columbia. Direct (with John Plunkett), December 2013.

Rationale for enhanced gas and electric DSM portfolios. Correction of utility estimates of electric avoided costs. Errors in program screening. Program potential. Recommended program ramp-up rates.

287. **Conn. PURA** Docket No. 14-01-01, Connecticut Light and Power Procurement of Standard Service and Last-Resort Service. July and October 2014.

Proxy for review of bids. Oversight of procurement and selection process.

288. **Conn. PURA** Docket No. 14-01-02, United Illuminating Procurement of Standard Service and Last-Resort Service. January, April, July, and October 2014.

Proxy for review of bids. Oversight of procurement and selection process.

289. **Man. PUB** 2014, need for and alternatives to proposed hydro-electric facilities; Green Action Centre. Evidence (with Wesley Stevens) February 2014.

Potential for fuel switching, DSM, and wind to meet future demand.

290. **Utah PSC** 13-035-184, Rocky Mountain Power Rates; Utah Office of Consumer Services. May 2014.

Class cost allocation. Classification and allocation of generation plant and purchased power. Principles of cost-causation. Design of backup rates.

291. **Minn. PSC** E002/GR-13-868, Northern States Power rates; Clean Energy Intervenors. Direct, June 2014; rebuttal, July 2014; surrebuttal, August 2014.

Inclining-block residential rate design. Rationale for minimizing customer charges.

292. **Cal. PUC** Rulemaking 12-06-013, electric rates and rate structures; Natural Resources Defense Council. September 2014.

Redesigning residential rates to simplify tier structure while maintaining efficiency and conservation incentives. Effect of marginal price on energy consumption. Realistic modeling of consumer price response. Benefits of minimizing customer charges.

293. **Md. PSC** 9361, proposed merger of PEPCo Holdings into Exelon; Sierra Club and Chesapeake Climate Action Network. Direct, December 2014; surrebuttal, January 2015.

Effect of proposed merger on Consumer bills, renewable energy, energy efficiency, and climate goals.

294. **N.S. UARB** M06514, 2015 capital-expenditure plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2015.

Economic evaluation of proposed projects. Treatment of AFUDC, overheads, and replacement costs of lost generation. Computation of rate effects of spending plan.

295. **Md. PSC** 9153 et al., Maryland energy-efficiency programs; Maryland Office of People's Counsel. January 2015.

Costs avoided by demand-side management. Demand-reduction-induced price effects.

296. **Québec Régie de L'énergie** R-3867-2013 phase 1, Gaz Métro cost allocation and rate structure; ROEÉ. February 2015

Classification of the area-spanning system; minimum system and more realistic approaches. Allocation of overhead, energy-efficiency, gas-supply, engineering-and-planning, and billing costs.

297. **Conn. PURA** Docket No. 15-01-01, Connecticut Light and Power Procurement of Standard Service and Last-Resort Service. February and July 2015.

Proxy for review of bids. Oversight of procurement and selection process.

298. **Conn. PURA** Docket No. 15-01-02, United Illuminating Procurement of Standard Service and Last-Resort Service. February, July, and October 2015.

Proxy for review of bids. Oversight of procurement and selection process.

299. **Ky. PSC** 2014-00371, Kentucky Utilities electric rates; Sierra Club. March 2015.

Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.

300. **Ky. PSC** 2014-00372, Louisville Gas and Electric electric rates; Sierra Club. March 2015.

Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.

301. **Mich. PSC** U-17767, DTE Electric Company rates; Michigan Environmental Council, Sierra Club, and Natural Resource Defense Council. May 2015.

Cost effectiveness of pollution-control retrofits versus retirements. Market prices. Costs of alternatives.

302. **N.S. UARB** M06733, supply agreement between Efficiency One and Nova Scotia Power; Nova Scotia Consumer Advocate. June 2015.

Avoided costs. Cost-effectiveness screening of DSM. Portfolio design. Affordability and bill effects.

303. **Penn. PUC** P-2014-2459362, Philadelphia Gas Works DSM, universal-service, and energy-conservation plans; Philadelphia Gas Works. Direct, May 2015; Rebuttal, July 2015.

Avoided costs. Recovery of lost margin.

304. **Ont. Energy Board** EB-2015-0029/0049, 2015–2020 DSM Plans Of Enbridge Gas Distribution and Union Gas, Green Energy Coalition. Evidence July 31, 2015, Corrected August 12, 2015.

Avoided costs: price mitigation, carbon prices, marginal gas supply costs, avoidable distribution costs, avoidable upstream costs (including utility-owned pipeline facilities).

305. **PUC Ohio** 14-1693-EL-RDR, AEP Ohio Affiliate purchased-power agreement, Sierra Club. September 2015.

Economics of proposed PPA, market energy and capacity projections. Risk shifting. Lack of price stability and reliability benefits. Market viability of PPA units.

306. **N.S. UARB** M06214, NS Power Renewable-to-Retail rate, Nova Scotia Consumer Advocate. November 2015.

Review of proposed design of rate for third-party sales of renewable energy to retail customers. Distribution, transmission and generation charges.

307. **PUC Texas** Docket No. 44941, El Paso Electric rates; Energy Freedom Coalition of America. December 2015.

Cost allocation and rate design. Effect of proposed DG rate on solar customers. Load shapes of residential customers with and without solar. Problems with demand charges.

308. **N.S. UARB** M07176, NS Power 2016 Capital Expenditures Plan, Nova Scotia Consumer Advocate. February 2016.

Economic evaluation of proposed projects, including replacement energy costs and modeling of equipment failures. Treatment of capitalized overheads and depreciation cash flow in computation of rate effects of spending plan.

309. **Md. PSC** 9406, BGE Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct February 2016, Rebuttal March 2016, Surrebuttal March 2016.

Assessment of benefits of Smart Meter programs for energy revenue, load reductions and price mitigation; capacity load reductions and price mitigation; free riders and load shifting in peak-time rebate (PTR) program; cost of PTR participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

310. **City of Austin TX**, Austin Energy 2016 Rate Review, Sierra Club and Public Citizen. May 2016

Allocation of generation costs. Residential rate design. Geographical rate differentials. Recognition of coal-plant retirement costs.

311. **Manitoba PUB**, Manitoba Hydro Cost of Service Methodology Review, Green Action Centre. June 2016, reply August 2016.

Allocation of generation costs. Identifying generation-related transmission assets. Treatment of subtransmission. Classification of distribution lines. Allocation of distribution substations and lines. Customer allocators. Shared service drops.

312. **Md. PSC** 9418, PEPCo Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct July 2016, Rebuttal August 2016, Surrebuttal September 2016.

Assessment of benefits of Smart Meter programs for energy revenue, load reductions and price mitigation; load reductions in dynamic-pricing (DP) program; cost of DP participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

313. **Md. PSC** 9424, Delmarva P&L Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct September 2016, Rebuttal October 2016, Surrebuttal October 2016.

Estimation of effects of Smart Meter programs—dynamic pricing (DP), conservation voltage reduction and an informational program—on wholesale revenues, wholesale prices and avoided costs; estimating load reductions from the DP program; cost of DP participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

314. **N.H. PUC** Docket No. DE 16-576, Alternative Net Metering Tariffs, Conservation Law Foundation. Direct October 2016, Reply December 2016.

Framework for evaluating rates for distributed generation. Costs avoided and imposed by distributed solar. Rate design for distributed generation.

315. **Puerto Rico Energy Commission** CEPR-AP-2015-0001, Puerto Rico Electric Power Authority rate proceeding, PR Energy Commission. Report December 2016.

Comprehensive review of structure of electric utility, cost causation, load data, cost allocation, revenue allocation, marginal costs, retail rate designs, identification and treatment of customer subsidies, structuring rate riders, and rates for distributed generation and net metering.

316. **N.S. UARB** M07745, NS Power 2017 Capital Expenditures Plan, Nova Scotia Consumer Advocate. January 2017.

Computation and presentation of rate effects. Consistency of assumed plant operation and replacement power costs. Control of total cost of small projects. Coordination of information-technology investments. Investments in biomass plant with uncertain future.

317. **N.S. UARB** M07746, NS Power Enterprise Resource Planning project, Nova Scotia Consumer Advocate. February 2017.

Estimated software project costs. Costs of internal and contractor labor. Affiliate cost allocation.

318. **N.S. UARB** M07767, NS Power Advanced Metering Infrastructure projects, Nova Scotia Consumer Advocate. February 2017.

Design and goals of the AMI pilot program. Procurement. Coordination with information-technology and software projects.

319. **Québec Régie de l'énergie** R-3867-2013 phase 3A; Gaz Métro estimates of marginal O&M costs; ROEÉ. March 2017.

Estimation of one-time, continuing and periodic customer-related operating and maintenance cost. Costs related to loads and revenues. Dealing with lumpy costs.

320. **N.S. UARB** M07718, NS Power Maritime Link Cost Recovery, Nova Scotia Consumer Advocate. April 2017.

Usefulness of transmission interconnection prior to operation of the associated power plant.

321. **Mass. DPU** 17-05, Eversource Rate Case, Cape Light Compact. Direct April 2017, Rebuttal May 2017.

Critique of proposed performance-based ratemaking mechanism. Proposal for improvements.

322. **PUCO** 16-1852, AEP Ohio Electric Security Plan, Natural Resources Defense Council. May 2017.

Residential customer charge. Cost causation. Effect of rate design on consumption.

323. **Iowa Utilities Board** RPU-2017-0001, Interstate Power and Light rate case, Natural Resources Defense Council. Direct August 2017, Reply September 2017.

Critique of proposed demand-charge pilot rates for residential and small commercial customers. Defects of demand rates and shortcomings of IPL experimental proposal design.

324. **N.S. UARB** M08087, NS Power 2017 Load Forecast, Nova Scotia Consumer Advocate. Direct August 2017.

Review of forecast methodology, including extrapolation of drivers of commercial load from US national data; treatment of non-firm and competitive loads; behind-the-meter generation and controlling peak-load growth.

325. **Québec Régie de l'énergie** R-3867-2013 phase 3B; Gaz Métro line-extension policy; ROEÉ. September 2017.

The costs of adding new load. Estimating the durability of revenues from line extensions.

326. **Mass. EFSB** 17-02; Eversource proposed Hudson-Sudbury transmission line; Town of Sudbury. October 2017.

Accuracy of ISO New England regional load forecasts. Potential for distributed solar, storage and demand response.

327. **Manitoba PUB**, Manitoba 2017/18 & 2018/19 General Rate Application; Green Action Coalition. October 2017.

Marginal costs. Rate design. Affordability rate design for low-income and electric-heating customers. Design of residential inclining blocks. Problems with demand charges and demand ratchets. Cost-of-service study improvements.

328. **N.S. UARB** M08383, NS Power 2018 Annually Adjusted Rates; Consumer Advocate. January 2018.

Projection of incremental dispatch cost. Computing administrative charges. Methodological issues.

329. **N.S. UARB** M08349, NS Power's Advanced Metering Infrastructure Proposal; Consumer Advocate. January 2018.

Estimation of AMI benefits: load balancing among feeders, critical peak pricing, avoided costs of meters for distributed generation. NS Power's claims of benefits from accounting credits (AFUDC, overheads, and converting write-offs to reduced revenue) and shifting costs to customers (earlier billing, higher recorded usage). Realistic AMI meter life. Excessive charge for customers who opt out of AMI.

330. **N.S. UARB** M08350, NS Power 2018 Annual Capital Expenditures Plan; Consumer Advocate. February 2018.

Overlap between ACE projects and AMI project. Hydro project planning and valuation of lost hydro energy output.

331. **Conn. PURA** Docket No. 08-01-01RE05, Proposed Amendment to Peaker Contracts; Connecticut Consumers Counsel. May 2018.

Dividing increased revenues from ISO-NE's Pay-for-Performance mechanism between contract generators and ratepayers.

332. **Kansas CC** Docket No. 18-WSEE-328-RTS, Westar Rate Case; Sierra Club. Direct June 2018. Rebuttal June 2018. Supplement July 2018.

Costs and benefits of running Westar coal plants. Costs of renewables and other alternatives. Recommendation regarding planning, coal retirement schedule, and acquisition of leased capacity.

333. **Cal. PUC** Application 17-09-006; Pacific Gas and Electric Gas Cost Allocation Proceeding; Small Business Utility Advocates. Direct June 2018.

Allocation of gas distribution system costs. Allocation of costs of energy-efficiency programs.

334. **N.S. UARB** M08670, NS Power 2018 Load Forecast, Nova Scotia Consumer Advocate. Direct July 2018.

Review of forecast methodology, including treatment of future energy-efficiency programs, treatment of third-party supply and behind-the-meter generation.

335. **Iowa Utilities Board** RPU-2018-0003, MidAmerican Energy Request for Approval of Ratemaking Principles for Wind XII; Sierra Club. Direct August 2018.

Cost and benefits of continued operation of six MidAmerican coal-fired units.

336. **Cal. PUC** A.18-02-016, 03-001, 03-002; 2018 Energy Storage Plans; Small Business Utility Advocates. Direct, Rebuttal and Supplement, August 2018.

Reliance on substation-sited storage. Need for increased emphasis on customer-sited and shared storage. Maximizing benefits, total and for small business. Oversized SDG&E proposed projects. Cost recovery. Storage technology diversity.

337. **La. PSC** U-34794; Cleco Corp Purchase of NRG Assets and Contracts; Sierra Club. Direct, September 2018.

Economics of NRG generation resources, Cleco Power coal plants and wholesale sales contracts. Risks of the proposed transaction.

338. **Cal. PUC** A.18-11-005; Southern California Gas Demand-Response Proposal; Small Business Utility Advocates. Direct March 2019, Rebuttal April 2019.

Potential benefits of gas demand response and SoCalGas failure to identify potential benefits from its programs. Program design. Cost allocation.

339. **Cal. PUC** A.18-11-003; Pacific Gas & Electric Electric Vehicle Rate; Small Business Utility Advocates. Direct April 2019, Rebuttal May 2019.

Critique of subscription demand charge. Time-of-use periods. Outreach to small business. Time-of-use price differentials.

340. **Cal. PUC** A.18-07-024; Southern California Gas and San Diego Gas & Electric Triennial Cost Allocation Proceeding; Small Business Utility Advocates. Direct April 2019.

Core commercial declining blocks. Computation of customer charges. Embedded versus marginal cost allocation. Marginal cost computation. Allocation of self-generation incentives.

341. **Vt. PUC** 19-0397-PET; Screening Values for Energy-Efficiency Measures; Conservation Law Foundation. Direct May 2019.

Conceptual basis for including price-suppression benefits to consumers. Avoided T&D costs. Avoided externalities with a renewable energy standard. Risk mitigation.

342. **N.S. UARB** M09096; EfficiencyOne Application for 2020–2022 DSM Plan; Consumer Advocate. May 2019

Evaluate NS Power critique of EfficiencyOne proposal. Comparability of efficiency budgets. Affordability. Energy-efficiency programs and resource planning.

343. **N.S. UARB** M09191; NS Power 2019 Load Forecast Report; Consumer Advocate. July 2019.

Review load-forecast treatment of energy efficiency, fuel switching, electric vehicles, behind-the-meter solar, AMI-enabled programs, and the changing trend in lighting efficiency.

344. **Iowa Utilities Board** RPU-2019-001; Interstate Power and Light Rate Case; Sierra Club. Direct August 2019; Rebuttal September 2019.

Economics of continued operation of five coal units: fuel, O&M, capital additions, overheads, market revenues, and cost of renewable resources. Recommend retirement of all units.

345. **Maine PUC** 2019-00101; Unitil Precedent Agreement for Westbrook Xpress, Conservation Law Foundation. August 2019.

The role of fuel convserions in Unitil's load forecast. Mandates for reducing greenhouse gas emissions. Efficient electric end uses as alternatives to gas system expansion. Risks of and alternatives to new pipeline supply.

346. **Maine PUC** 2019-00105; Bangor Natural Gas Precedent Agreement for Westbrook Xpress, Conservation Law Foundation. August 2019.

Mandates for reducing greenhouse gas emissions. Efficient electric end uses as alternatives to gas system expansion. Risks of and alternatives to new pipeline supply.

347. **Wisconsin PSC 6690-UR-126**; Wisconsin Public Service Corporation 2020 Rate Case, Sierra Club. Direct August 2019, Surrebuttal October 2019.

Economics of continued operation of four coal units: fuel, O&M, capital additions, overheads, market revenues, and cost of renewable resources. Recommend retirement of uneconomic units.

348. **Wisconsin PSC 05-UR-109**; Wisconsin Electric Power Company2020 Rate Case; Sierra Club. Direct August 2019, Surrebuttal October 2019

Economics of continued operation of six coal units: fuel, O&M, capital additions, overheads, market revenues, and cost of renewable resources. Recommend retirement of uneconomic units.

349 **N.S. UARB M09277**; NS Power Maritime Link Cost Recovery, Nova Scotia Consumer Advocate. August 2019.

Benefits of the Maritime Link transmission line prior to operation of associated power supply and connecting transmission facilties.

350. **N.H. PUC** DG 17-198; Liberty Utilities Petition to Approve Firm Supply, Transportation Agreements, and the Granite Bridge Project; Conservation Law Foundation. September 2019.

Need for transportation contracts and new pipeline. Alternative of switching oil and propane to efficient electric end uses. Limited life of gas infrastructure and effect on ratepayer costs.

351. **Colorado PUC** 19AL-0268E; Public Service of Colorado Rate Case; Sierra Club. September 2019.

Prudence of management of superheater tube failures. Unfavorable economics of coal plants nationally. Need for continuing review of coal-plant economics and benefits of retirement.

352. **N.H. PUC** DG 17-152; Liberty Utilities Least Cost Integrated Resource Plan; Conservation Law Foundation. September 2019.
Integrated planning for gas utilities in an era of carbon constraints. Heat pump electrification versus gas conversion of oil-fired space and water heating.

353. **N.S. UARB** M09420; NS Power Application for an Extra-Large Industrial Active Demand Control Tariff; Nova Scotia Consumer Advocate. December 2019.

Estimating incremental costs, including lost wheeling revenues, variable O&M, and variable capital cost; updating and reconciliation of incremental costs.

354. **Cal. PUC** A.19-07-006; San Diego Gas & Electric Fast-Charging and Heavy-Duty Electric Vehicle Proposal; Small Business Utility Advocates. Direct January 2020, Rebuttal February 2020.

Interim rate proposal. Critique of subscription and demand charges. Time-of-use periods. Recovery of lost revenues.

N.S. UARB M09519; NS Power Smart Grid Application; Nova Scotia Consumer Advocate. February 2020.

Differentiating capital costs from expenses. Inclusion of decommissioning costs in project plan. Selection of the Distributed Energy Resources Management System.

N.S. UARB M09499; NS Power 2020 Annual Capital Expenditure Plan; Nova Scotia Consumer Advocate. February 2020.

Planning for hydro life extension or retirement. Appropriate levels of contingency in project budgets. Aggregation of multi-year capital programs. Cost-control efforts.

Cal. PUC A.19-03-002; San Diego Gas & Electric General Rate Application, Phase 2; Small Business Utility Advocates. Direct March 2020

Problems with proposed increases in the Monthly Service Fees and reliance on demand charges in for medium non-residential customers. Improving hours for the TOU periods.

ACRONYMS AND INITIALISMS

APS	Alleghany Power System
ASLB	Atomic Safety and Licensing Board
BEP	Board of Environmental Protection
BPU	Board of Public Utilities
BRC	Board of Regulatory Commissioners
CC	Corporation Commission
CMP	Central Maine Power
DER	Department of Environmental Regulation
DPS	Department of Public Service
DQE	Duquesne Light
DPUC	Department of Public Utilities Control
DSM	Demand-Side Management
DTE	Department of Telecommunications and Energy
EAB	Environmental Assessment Board
EFSB	Energy Facilities Siting Board
EFSC	Energy Facilities Siting Council
EUB	Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
LRAM	Lost-Revenue-Adjustment Mechanism
NARUC	National Association of Regulatory Utility Commissioners
NEPOOL	New England Power Pool
NRC	Nuclear Regulatory Commission
OCA	Office of Consumer Advocate
PSB	Public Service Board
PBR	Performance-based Regulation
PSC	Public Service Commission
PUC	Public Utility Commission
PUB	Public Utilities Board
PURA	Public Utility Regulatory Authority
PURPA	Public Utility Regulatory Policy Act
ROEÉ	Regroupement des organismes environnementaux en énergie
SCC	State Corporation Commission
UARB	Utility and Review Board
USAEE	U.S. Association of Energy Economists
UC	Utilities Commission
URC	Utility Regulatory Commission
UTC	Utilities and Transportation Commission

PLC 4/27/2020

ATTACHMENT - 2

JOHN D. WILSON

Resource Insight, Inc.
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Arlington, Massachusetts 02476

SUMMARY OF PROFESSIONAL EXPERIENCE

2019–Present **Research Director, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, and regulation. Reviews electric-utility rate design. Designs and evaluates conservation programs for electric utilities, including conservation cost recovery mechanisms and performance incentives. Evaluates performance of renewable resources and designs performance evaluation systems for procurement. Designs and assesses resource planning and procurement strategies for regulated and competitive markets.

2007-19 **Deputy Director for Regulatory Policy, Southern Alliance for Clean Energy.** Managed regulatory policy, including supervision of experts in areas of energy efficiency, renewable energy, and market data. Provided expert witness testimony on topics of resource planning, renewable energy, energy efficiency to utility regulators. Directed litigation activities, including support of expert witnesses in the areas of rate design, resource planning, renewable energy, energy efficiency, and resource procurement. Conducted supporting research and policy development. Represented SACE on numerous legislative, utility, and private committees across a wide range of climate and energy related topics.

2001–06 **Executive Director, Galveston-Houston Association for Smog Prevention.** Directed advocacy and regulatory policy related to air pollution reduction, including ozone, air toxics, and other related pollutants in the industrial, utility, and transportation sectors. Served on the Regional Air Quality Planning Committee, Transportation Policy Technical Advisory Committee, and Steering Committee of the TCEQ Interim Science Committee.

2000–01 **Senior Associate, The Goodman Corporation.** Provided transportation and urban planning consultant services to cities and business districts across Texas.

1997–99 **Senior Legislative Analyst and Technology Projects Coordinator, Office of Program Policy Analysis and Government Accountability, Florida Legislature.** Author or team member for reports on water supply policy, environmental permitting, community development corporations, school district financial management and other issues – most recommendations implemented by the 1998 and 1999 Florida Legislatures. Edited statewide government accountability newsletter and coordinated online and internal technical projects.

1997 **Environmental Management Consultant, Florida State University.** Project staff for Florida Assessment of Coastal Trends.

1992-96 **Research Associate, Center for Global Studies, Houston Advanced Research Center.** Coordinated and led research for projects assessing environmental and resource issues in the Rio Grande / Rio Bravo river basin and across the Greater Houston region. Coordinated task force and edited book on climate change in Texas.

EDUCATION

BA, Physics (with honors) and history, Rice University, 1990.

MPP, John F. Kennedy School of Government, Harvard University, 1992. Concentration areas: Environment, negotiation, economic and analytic methods.

PUBLICATIONS

“Urban Areas,” with Judith Clarkson and Wolfgang Roeseler, in Gerald R. North, Jurgen Schmandt and Judith Clarkson, *The Impact of Global Warming on Texas: A Report of the Task Force on Climate Change in Texas*, 1995.

“Quality of Life and Comparative Risk in Houston,” with Janet E. Kohlhase and Sabrina Strawn, *Urban Ecosystems*, Vol. 3, Issue 2, July 1999.

“Seeking Consistency in Performance Incentives for Utility Energy Efficiency Programs,” with Tom Franks and J. Richard Hornby, *2010 American Council for an Energy-Efficient Economy Summer Study on Energy Efficiency in Buildings*, August 2010.

REPORTS

“Policy Options: Responding to Climate Change in Texas,” Houston Advanced Research Center, US EPA and Texas Water Commission, October 1993.

Houston Environmental Foresight Science Panel, *Houston Environment 1995*, Houston Advanced Research Center, 1996.

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Office of Program Policy Analysis and Government Accountability, *Best Financial Management Practices for Florida School Districts*, Report No. 97-08, October 1997.

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Office of Program Policy Analysis and Government Accountability, *Review of the Expedited Permitting Process Coordinated by the Governor’s Office of Tourism, Trade, and Economic Development,* Report No. 98-17, October 1998.

Office of Program Policy Analysis and Government Accountability, *Florida Water Policy: Discouraging Competing Applications for Water Permits; Encouraging Cost-Effective Water Development,* Report No. 99-06, August 1999.

"Smoke in the Water: Air Pollution Hidden in the Water Vapor from Cooling Towers – Agencies Fail to Enforce Against Polluters," Galveston Houston Association for Smog Prevention, February 2004.

"Reducing Air Pollution from Houston-Area School Buses," Galveston Houston Association for Smog Prevention, March 2004.

"Who's Counting: The Systematic Underreporting of Toxic Air Emissions," Environmental Integrity Project and Galveston Houston Association for Smog Prevention, June 2004.

"Mercury in Galveston and Houston Fish: Contamination by Neurotoxin Places Children at Risk," Galveston Houston Association for Smog Prevention, October 2004.

"Exceeding the Limit: Industry Violations of New Rule Almost Slid Under State's Radar," Galveston Houston Association for Smog Prevention, January 2006.

"Whiners Matter! Citizen Complaints Lead to Improved Regional Air Quality Control," Galveston Houston Association for Smog Prevention, June 2006.

"Bringing Clean Energy to the Southeastern United States: Achieving the Federal Renewable Energy Standard," Southern Alliance for Clean Energy, February 2008.

"Cornerstones: Building a Secure Foundation for North Carolina's Energy Future," Southern Alliance for Clean Energy, May 2008.

"Yes We Can: Southern Solutions for a National Renewable Energy Standard," Southern Alliance for Clean Energy, February 2009.

"Green in the Grid: Renewable Electricity Opportunities in the Southeast United States," with Dennis Creech, Eliot Metzger, and Samantha Putt Del Pino, World Resources Institute Issue Briefs, April 2009.

"Local Clean Power," with Dennis Creech, Eliot Metzger, and Samantha Putt Del Pino, World Resources Institute Issue Briefs, April 2009.

"Energy Efficiency Program Impacts and Policies in the Southeast," Southern Alliance for Clean Energy, May 2009.

"Recommendations for Feed-In-Tariff Program Implementation In The Southeast Region To Accelerate Renewable Energy Development," Southern Alliance for Clean Energy, March 2011.

"Renewable Energy Standard Offer: A Tennessee Valley Authority Case Study," Southern Alliance for Clean Energy, November 2012.

"Increased Levels of Renewable Energy Will Be Compatible with Reliable Electric Service in the Southeast," Southern Alliance for Clean Energy, November 2014.

“Cleaner Energy for Southern Company: Finding a Low Cost Path to Clean Power Plan Compliance,” Southern Alliance for Clean Energy, July 2015.

“Analysis of Solar Capacity Equivalent Values for Duke Energy Carolinas and Duke Energy Progress Systems,” prepared for and filed by Southern Alliance for Clean Energy, Natural Resources Defense Council, and Sierra Club in North Carolina NCUC Docket No. E-100, Sub 147, February 17, 2017.

“Seasonal Electric Demand in the Southeastern United States,” Southern Alliance for Clean Energy, March 2017.

“Analysis of Solar Capacity Equivalent Values for the South Carolina Electric and Gas System,” Southern Alliance for Clean Energy, March 2017.

“Solar in the Southeast, 2017 Annual Report,” with Bryan Jacob, Southern Alliance for Clean Energy, February 2018.

“Energy Efficiency in the Southeast, 2018 Annual Report,” with Forest Bradley-Wright, Southern Alliance for Clean Energy, December 2018.

“Solar in the Southeast, 2018 Annual Report,” with Bryan Jacob, Southern Alliance for Clean Energy, April 2018.

“Tracking Decarbonization in the Southeast, 2019 Generation and CO_2 Emissions Report,” with Heather Pohnan and Maggie Shober, Southern Alliance for Clean Energy, August 2019.

“Seasonal Electric Demand in the Southeastern United States,” with Maggie Shober, Southern Alliance for Clean Energy, April 2020.

“Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement,” with Mike O’Boyle, Ron Lehr, and Mark Detsky, Energy Innovation Policy & Technology LLC and Southern Alliance for Clean Energy, April 2020.

PRESENTATIONS

“Clean Energy Solutions for Western North Carolina,” presentation to Progress Energy Carolinas WNC Community Energy Advisory Council, February 7, 2008.

“Energy Efficiency: Regulating Cost-Effectiveness,” Florida Public Service Commission undocketed workshop, April 25, 2008.

“Utility-Scale Renewable Energy,” presentation on behalf of Southern Alliance for Clean Energy to the Board of the Tennessee Valley Authority, March 5, 2008.

“An Advocates Perspective on the Duke Save-a-Watt Approach,” ACEEE 5th National Conference on Energy Efficiency as a Resource, September 2009.

“Building the Energy Efficiency Resource for the TVA Region,” presentation on behalf of Southern Alliance for Clean Energy to the Tennessee Valley Authority Integrated Resource Planning Stakeholder Review Group, December 10, 2009.

"Florida Energy Policy Discussion," testimony before Energy & Utilities Policy Committee, Florida House of Representatives, January 2010.

"The Changing Face of Energy Supply in Florida (and the Southeast)," 37th Annual PURC Conference, February 2010.

"Bringing Energy Efficiency to Southerners," Environmental and Energy Study Institute panel on "Energy Efficiency in the South," April 10, 2010.

"Energy Efficiency: The Southeast Considers its Options," NAESCO Southeast Regional Workshop, September 2010.

"Energy Efficiency Delivers Growth and Savings for Florida," testimony before Energy & Utilities Subcommittee, Florida House of Representatives, February 2011.

"Rates vs. Energy Efficiency," 2013 ACEEE National Conference on Energy Efficiency as a Resource, September 2013.

"TVA IRP Update," TenneSEIA Annual Meeting, November 19, 2014.

"Views on TVA EE Modeling Approach," Presentation with Natalie Mims to Tennessee Valley Authority's Evaluating Energy Efficiency in Utility Resource Planning Meeting, February 10, 2015.

"The Clean Power Plan Can Be Implemented While Maintaining Reliable Electric Service in the Southeast," Presentation to FERC Eastern Region Technical Conference on EPA's Clean Power Plan Proposed Rule, March 11, 2015.

"Renewable Energy & Reliability," Presentation to 5th Annual Southeast Clean Power Summit, EUCI, March 2016.

"Challenges to a Southeast Carbon Market," Presentation to 5th Annual Southeast Clean Power Summit, EUCI, March 2016.

"Solar Capacity Value: Preview of Analysis to Date," Florida Alliance for Accelerating Solar and Storage Technology Readiness (FAASSTeR) meeting, Orlando, FL, November 2017.

EXPERT TESTIMONY

2008 **South Carolina PSC** Docket No. 2007-358-E, surrebuttal testimony on behalf of Environmental Defense, the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy and the Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

2009 **North Carolina NCUC** Docket No. E-7, Sub 831, direct testimony on behalf of Environmental Defense Fund, Natural Resources Defense Council, Southern Alliance for Clean Energy, and Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

Florida PSC Docket Nos. 080407-EG through 080413-EG, direct testimony on behalf of Southern Alliance for Clean Energy and the Natural Resources Defense Council. Energy efficiency potential and utility program goals.

South Carolina PSC Docket No. 2009-226-E, direct testimony in general rate case on behalf of Environmental Defense, the Natural Resources Defense Council, the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy and the Southern Environmental Law Center. Cost recovery mechanism for energy efficiency, including shareholder incentive and lost revenue adjustment mechanism.

2010 **North Carolina NCUC** Docket No. E-100, Sub 124, direct testimony on behalf of Environmental Defense Fund, the Sierra Club, Southern Alliance for Clean Energy, and Southern Environmental Law Center. Adequacy of consideration of energy efficiency in Duke Energy Carolinas and Progress Energy Carolinas' 2009 integrated resource plans.

Georgia PSC Docket No. 31081, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2010 integrated resource plan, including cost effectiveness, rate and bill impacts, and lost revenues.

Georgia PSC Docket No. 31082, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2010 demand side management plan, including program revisions, planning process, stakeholder engagement, and shareholder incentive mechanism.

2011 **South Carolina PSC** Docket No. 2011-09-E, allowable ex parte briefing on behalf of Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever. Adequacy of South Carolina Electric & Gas's 2011 integrated resource plan, including resource mix, sensitivity analysis, alternative supply and demand side options, and load growth scenarios.

South Carolina PSC Docket Nos. 2011-08-E and 2011-10-E, allowable ex parte briefing on behalf of Southern Alliance for Clean Energy, South Carolina Coastal Conservation League, and Upstate Forever. Adequacy of Progress Energy Carolinas and Duke Energy Carolinas' 2011 integrated resource plans, including resource mix, sensitivity analysis, alternative supply and demand side options, cost escalation, uncertainty of nuclear and economic impact modeling.

2013 **Georgia PSC** Docket No. 36498, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of energy efficiency in Georgia Power's 2013 integrated resource plan, including cost effectiveness, rate and bill impacts, and lost revenues, economics of fuel switching and renewable resources.

South Carolina PSC Docket No. 2013-392-E, direct testimony with Hamilton Davis in Duke Energy Carolinas need certification case on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Need for capacity, adequacy of energy efficiency and renewable energy alternatives, and use of solar power as an energy resource.

2014 **South Carolina PSC** Docket No. 2014-246-E, direct testimony generic proceeding on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. Methods for calculating dependable capacity credit for renewable resources and application to determination of avoided cost.

2015 **Florida PSC** Docket No. 150196-EI, direct testimony in Florida Power & Light need certification case on behalf of Southern Alliance for Clean Energy. Appropriate reserve margin and system reliability need.

2016 **Georgia PSC** Docket No. 40161, direct testimony on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of renewable energy in Georgia Power's 2016 integrated resource plan, including portfolio diversity, operational and implementation risk, analysis of project-specific costs and benefits (including location and technology considerations), and methods for calculating dependable capacity credit for renewable resources.

2019 **Georgia PSC** Docket Nos. 42310 and 42311, direct testimony with Bryan A. Jacob in Georgia Power's 2019 integrated resource plan and demand side management plan on behalf of Southern Alliance for Clean Energy. Adequacy of consideration of renewable energy in IRP, retirement of uneconomic plants, and use of all-source procurement process. Shareholder incentive mechanism for both renewable energy and DSM plan.

2020 **Nova Scotia UARB** Matter No. M09519, direct testimony with Paul Chernick in Nova Scotia Power's application for approval of the Smart Grid Nova Scotia Project on behalf of the Nova Scotia Consumer Advocate. Cost classification, decommissioning costs, justification for software vendor selection, and suggested changes to project scope.

Nova Scotia UARB Matter No. M09499, direct testimony with Paul Chernick in Nova Scotia Power's 2020 annual capital expenditure plan on behalf of the Nova Scotia Consumer Advocate. Potential to decommission hydroelectric systems, review of annually recurring capital projects, use of project contingencies, and cost minimization practices.

ATTACHMENT - 3

DOCKETED	
Docket Number:	19-IEPR-01
Project Title:	General/Scope
TN #:	232922
Document Title:	Adopted 2019 Integrated Energy Policy Report
Description:	Final 2019 Integrated Energy Policy Report including errata adopted at the February 20, 2020 Business Meeting
Filer:	Stephanie Bailey
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	5/6/2020 3:17:58 PM
Docketed Date:	5/6/2020

CALIFORNIA ENERGY COMMISSION

California Energy Commission

COMMISSION REPORT

Final 2019 Integrated Energy Policy Report

Gavin Newsom, Governor

February 2020 | CEC-100-2019-001-CMF

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PREFACE

Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002), as amended, requires the California Energy Commission to prepare a biennial integrated energy policy report that assesses major energy trends and issues facing the state's electricity, natural gas, and transportation fuel sectors and provides policy recommendations to conserve resources; protect the environment; ensure reliable, secure, and diverse energy supplies; enhance the state's economy; and protect public health and safety (Public Resources Code § 25301[a]). The Energy Commission prepares updates to these assessments and associated policy recommendations in alternate years (Public Resources Code § 25302[d[). Preparation of the *Integrated Energy Policy Report* involves close collaboration with federal, state, and local agencies and a wide variety of stakeholders in an extensive public process to identify critical energy issues and develop strategies to address those issues.

ABSTRACT

The *2019 Integrated Energy Policy Report* provides the results of the California Energy Commission's assessments of a variety of energy issues facing California. Many of these issues will require action if the state is to meet its climate, clean energy, air quality, and other environmental goals while maintaining reliability and controlling costs.

The *2019 Integrated Energy Policy Report* covers a broad range of topics, including decarbonizing buildings, integrating renewables, energy efficiency, energy equity, integrating renewable energy, updates on Southern California electricity reliability, climate adaptation activities for the energy sector, natural gas assessment, transportation energy demand forecast, and the California Energy Demand Forecast.

Keywords: California Energy Commission, decarbonizing buildings, energy efficiency, energy equity, electricity demand forecast, natural gas assessment, climate adaptation and resiliency, Southern California reliability, transportation electrification, integrated resource plans, Assembly Bill 1257

Please use the following citation for this report:

California Energy Commission staff. 2020. *Final 2019 Integrated Energy Policy Report*. California Energy Commission. Publication Number: CEC-100-2019-001-CMF.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

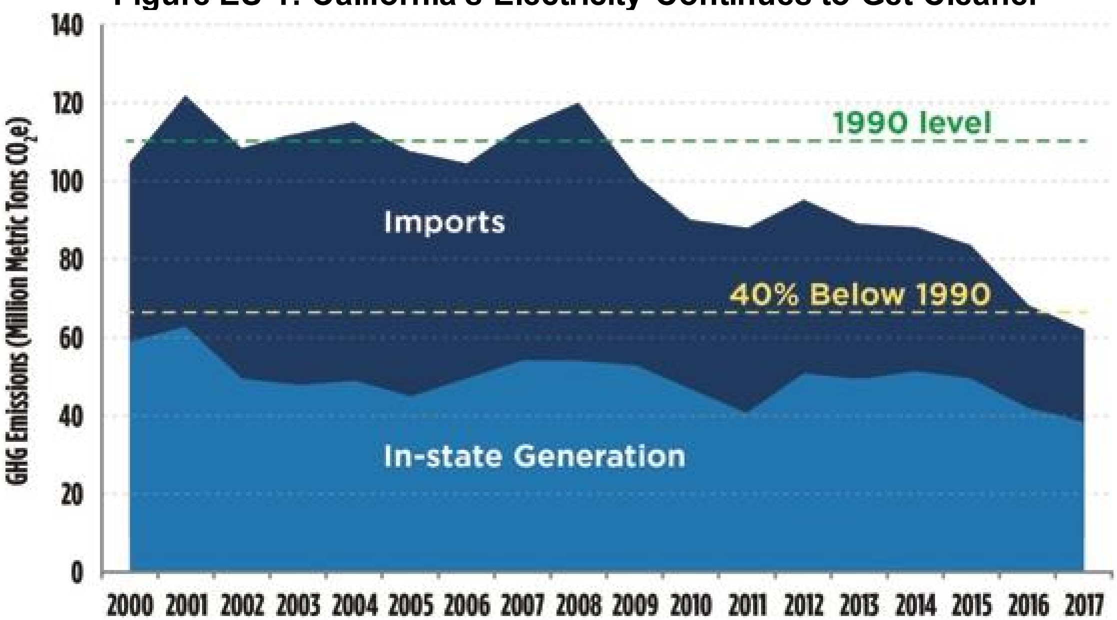
Page

EXECUTIVE SUMMARY

California is working to make sweeping changes in its energy system to address climate change, improve air quality, and make sure that all Californians share in the benefits of the state's clean energy future. In 2018, California furthered its national and international leadership in energy policy with the enactment of Senate Bill 100 (De León, Chapter 312, Statutes of 2018), which calls for California's electricity system to become 100 percent zero-carbon by 2045. The California Energy Commission (CEC), California Public Utilities Commission (CPUC), and the California Air Resources Board (CARB) are working together to identify pathways to deeply decarbonize the state's electricity system in response to SB 100. The aim is to leverage California's clean electricity system to decarbonize, or remove carbon from, other portions of the state's energy system.

The electricity sector led the way in California meeting its 2020 goal to reduce GHG emissions to 1990 levels, four years ahead of schedule. In 2017, GHG emissions from the electricity sector were 40 percent below 1990 levels. Although impressive, meeting the SB 100 goal of zero-carbon by 2045 requires more work.

Figure ES-1: California's Electricity Continues to Get Cleaner



Source: CEC using data from CARB

Landmark California Initiatives to Reduce GHG Emissions

SB 100 builds on the state's goals to reduce greenhouse gases (GHGs) to 1990 levels by 2020 and GHG emissions 40 percent below 1990 levels by 2030 (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006 and Senate Bill 32, Pavley, Chapter 249, Statutes of 2016). In 2018, Executive Order B-55-18 set a longer-term goal of statewide carbon neutrality as soon as possible and no later than 2045, with net negative GHG emissions thereafter. The targets laid out in Executive Order B-55-18 and SB 100 are consistent with international goals to reduce GHG emissions enough to avoid catastrophic climate change.

Renewable resources such as solar and wind account for about 34 percent of California's electricity use in 2018. SB 100 requires an increase to 60 percent by 2030, making renewables one of the main driving forces in reducing the state's GHG emissions. Other factors include the sharp decline in the import of coal-fired electricity over the last decade, which is expected to drop to zero by 2025, and the beginning of a waning dependence on natural gas for electricity generation. The goal is to cut emissions from the electricity sector to zero while meeting an increasing demand and maintaining energy reliability, controlling costs, and ensuring that benefits reach all Californians.

California's Evolving Electricity System

California's electricity sector is rapidly evolving in response to climate policy and market changes. Customers are generating their own power from rooftop solar and other distributed generation. In 2019, the state met its goal for a million solar roofs set by former Governor Arnold Schwarzenegger. Soon distributed solar will be a mainstay for new homes given that on January 1, 2020, California's building standards began to require new homes include solar. During the last decade, installed renewable capacity in the state increased from 9,313 megawatts (MW) in 2009 to 23,313 MW in 2018. The variable nature of renewable resources, which change as the sun rises and sets and as winds blow, requires shifts in how the system is managed. Flexibility with fast responsiveness is needed to accommodate morning and late-afternoon changes (termed *ramps*) in the *net load* (total load minus solar and wind generation) to prevent surpluses or shortages on the electricity grid.

Although several tools are available to rapidly adjust supply or demand or both to meet flexibility needs, natural gas power plants provide about 75 percent of the available flexible capacity (the ability to quickly ramp energy production up or down as needed to match supply and demand). For the near term, natural gas generation will continue to play an important role in integrating renewable resources and ensuring reliability. As the electricity market grows regionally and resources such as energy storage and demand management grow to help integrate renewables, natural gas generation will decrease further.

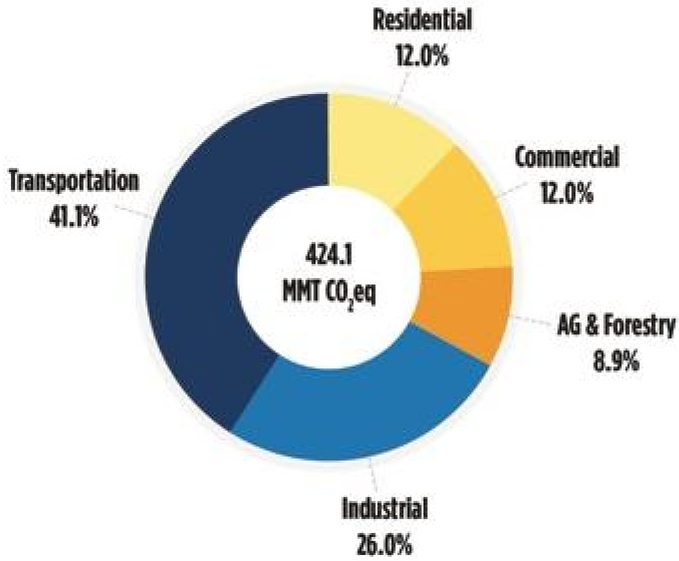
Customers face increasing choices over their sources and suppliers of electricity. Communities are opting to make their own electric resource choices through community choice aggregation (CCA) to develop innovative ways of providing cleaner energy resources. Residential and commercial retail customers are increasingly departing from investor-owned utilities (IOUs) and moving to CCA. Large commercial and industrial customers are buying their electricity directly from renewable generators, as well as from private direct access providers when allowed. Furthermore, utilities face financial uncertainties with the looming liability associated with California's devastating wildfires, with one utility in bankruptcy. Historically, the state has used its regulatory authority over the fairly centralized electricity market to help deliver GHG reductions and achieve other environmental and policy goals. These structural changes present uncertainty as well as opportunities for achieving clean energy goals.

California's electricity system planning approach has also changed with the development of integrated resources plans (IRPs) as called for in Senate Bill 350 (De León, Chapter 547, Statutes of 2015). IRPs are long-term planning documents that outline how load-serving entities, including investor- and publicly owned utilities, community choice aggregators, and private electricity suppliers, will meet demand reliably and cost-effectively while achieving state policy goals and mandates. These plans show steady progress in achieving the state's renewable procurement requirements, including the increased Renewables Portfolio Standard of 60 percent renewables by 2030 called for in SB 100. They also meet GHG emissions reduction targets established by CARB, in consultation with the CEC and CPUC, in accordance with SB 350. A large share of the resource additions identified in the plans are from solar resources.

Buildings Are Part of the Solution

In 2017, the most recent data available, the state's building stock accounted for almost a quarter of statewide GHG emissions, including fossil fuel consumed onsite (for example, gas or propane for heating) and electricity consumption (for example, for lighting, appliances, and cooling). (See Figure ES-2.) Under Assembly Bill 3232 (Friedman, Chapter 373, Statutes of 2018), the CEC must assess the feasibility of reducing GHG emissions in residential and commercial buildings 40 percent below 1990 levels by January 1, 2030. Leveraging the decarbonization of the electricity system by transitioning space and water heating in buildings toward highly efficient electric appliances, coupled with strategies to enable greater ability to shift when energy is consumed, will be key to reducing emissions from buildings. Under Senate Bill 1477 (Senate Bill 1477, Stern, Chapter 378, Statutes of 2018), the CPUC and CEC are establishing two five-year incentive programs to enable greater penetration of these building decarbonization technologies.

ES-2: 2017 GHG Emissions by Sector (Percentage of Carbon Dioxide Equivalent)



Source: CEC using data from CARB

The increased digitization of the grid presents new to enhance the operational flexibility of buildings. Launching efficient technologies that can communicate with the grid can help shift the timing of energy use in buildings. At a large-enough scale, such *smart* technologies can adjust electricity consumption to maximize the use of renewable generation and help manage morning and afternoon ramps without compromising comfort or function. In this way, buildings can be a resource that helps maintain the reliability of evolving energy systems.

Further, maximizing energy efficiency savings will reduce the costs of achieving the state's climate goals, in part by opening new possibilities for meeting greater electricity demand from electrification. In late 2019, the CEC adopted the *2019 California Energy Efficiency Action Plan*, which lays out strategies for achieving deep savings through energy efficiency and reducing GHG emissions from buildings. The action plan addresses legislative requirements to update strategies that increase energy efficiency in existing buildings and, more broadly, to achieve a statewide doubling of energy efficiency savings from electricity and natural gas end uses by 2030 (Assembly Bill 758 [Skinner, Chapter 470, Statutes of 2009] and SB 350).

Zero-Emission Vehicles are Critical

Eliminating emissions from the transportation sector is critical to the state's clean air goals—roughly 50 percent of in-state GHG emissions come from this sector when including refinery emissions from the industrial sector, along with the vast majority of criteria pollutants (such as nitrogen oxide and diesel particulate matter). Unfortunately, despite the overall reduction in statewide GHG emissions from 2013 through 2017, emissions from the transportation sector actually increased by 6 percent. A statewide shift from the use of vehicles that run on fossil fuels to those that run on electricity (referred to as "transportation electrification"), whether in the form of battery-electric vehicles, plug-in hybrid electric vehicles, or fuel cell electric vehicles, is essential for reducing emissions. Thus, California has set ambitious goals of achieving 1.5 million zero-emission vehicles (ZEVs) by 2025 and 5 million by 2030 as established in former Governor Edmund G. Brown Jr's Executive Order B-16-2012.

California is aggressively pursuing the deployment of ZEVs through regulations administered by CARB (for example, the Advanced Clean Cars rulemaking and the Innovative Clean Transit Regulation) and incentives (such as the Clean Vehicle Rebate Project and the Low Carbon Transportation Program). The CEC's Clean Transportation Program is investing tens of millions of dollars in charging infrastructure and hydrogen refueling stations statewide. The CPUC has also directed IOUs to file applications for transportation electrification projects. Finally, the state's settlement agreement with Volkswagen for the company's violations of state and federal law in regard to emission tests will support the implementation of zero-emission transit and fleet vehicles, as well as plug-in electric vehicle recharging around the state.

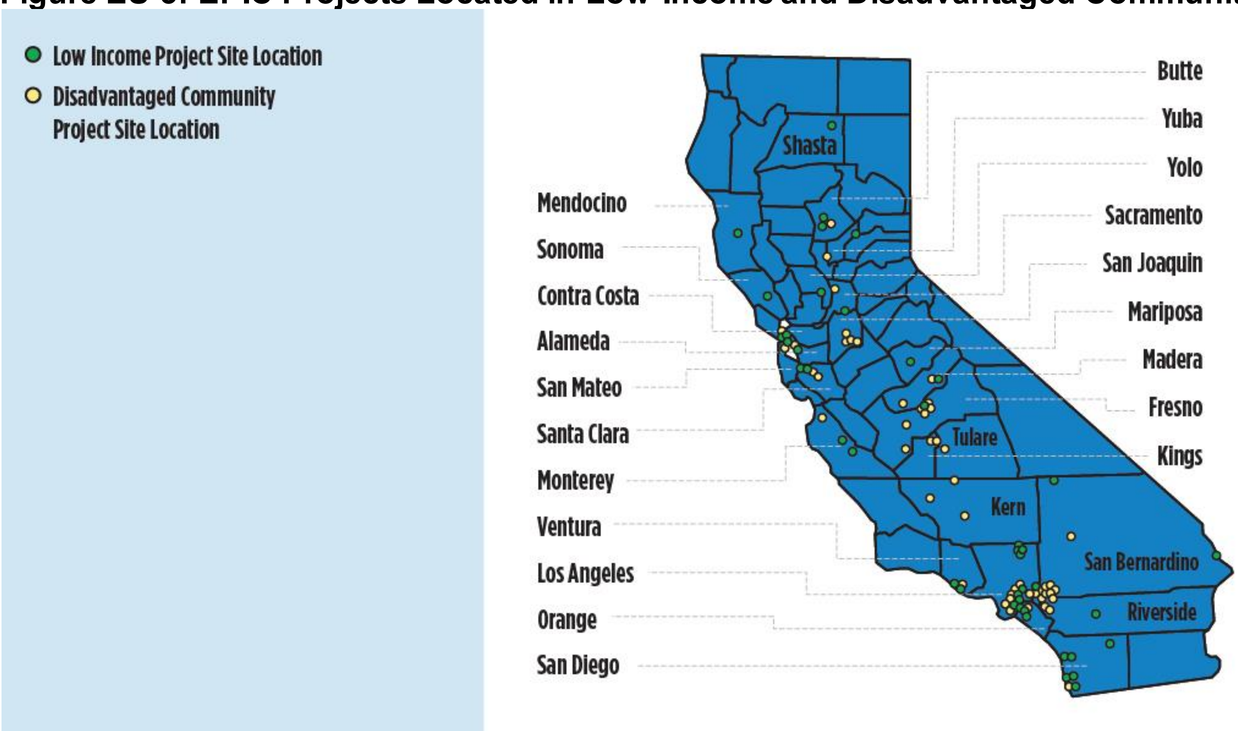
These efforts have helped California become the largest ZEV market in the nation with more than 650,000 ZEVs on the road and nearly half of the U.S. annual sales. Plug-in electric vehicles accounted for nearly 8 percent of California's vehicle sales in 2018, compared to 2 percent nationally. However, ZEV sales are expected to accelerate worldwide in response to technological advancements and government policies. Battery pack prices have declined by upward of 85 percent from 2010 to 2018, with the potential for additional reductions through 2030. Investments in electrification, as well as autonomous and shared vehicle technologies, continue to grow dramatically. Globally, auto manufacturers may be selling upward of 15 million plug-in electric vehicles per year by 2025, given the anticipated effects of existing regulatory sales requirements.

To support California's growing ZEV population, the state will need to drastically increase the availability of refueling infrastructure. Executive Order B-48-18 set a target of 250,000 shared charging infrastructure connections, including 10,000 direct-current fast charging stations by 2025. (The same executive order also set a target of 200 hydrogen refueling stations by 2025.) Assembly Bill 2127 (Ting, Chapter 365, Statutes of 2018) subsequently required the CEC to assess the number and type of charging infrastructure necessary for California to meet its goal of 5 million ZEVs by 2030. The CEC's first charging infrastructure assessment is expected at the end of 2020. The CEC is also updating the state's Vehicle Grid Integration Roadmap, which will outline key steps in the implementation of technologies that can lower the costs for plug-in electric vehicle drivers, recharging station owners, and utility customers in general.

All Californians Must Benefit From the Clean Energy Future

California's clean energy future must create an inclusive clean energy economy in which the benefits are equitably distributed. SB 350 put California's clean energy targets into law and took steps to ensure that all Californians realize the benefits of clean energy. In response to SB 350, the CEC published the *Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities* (Barriers Study Part A) and, in 2018, CARB published the *Low-Income Barriers Study, Part B: Overcoming Barriers to Clean Transportation Access for Low-Income Residents* (Barriers Study Part B). California's agencies have made significant progress toward accomplishing the recommendations in the barriers studies. For example, the CEC's Electric Program Investment Charge (EPIC) program exceeded the goal set in Assembly Bill 523 (Reyes, Chapter 551, Statutes of 2017) for at least 25 percent of the technology demonstration and deployment funds to be allocated to projects in and benefitting disadvantaged communities, and at least 10 percent allocated to projects in and benefitting low-income communities. As of July 2019, the CEC's EPIC program invested about 31 percent of funds to projects in disadvantaged communities and an additional 34 percent to projects in communities that are low-income but not considered disadvantaged. (See Figure ES-3.)

Figure ES-3: EPIC Projects Located in Low-Income and Disadvantaged Communities



Source: Joint agency presentation by at the July 30, 2019, workshop on Advancing Energy Equity

Going forward, California must look for new opportunities to advance clean energy equity in disadvantaged and low-income communities, tribes, and rural communities. Areas for further work include developing attainable opportunities to finance energy upgrades, developing one-stop shops to increase access to clean technologies, advancing retrofits in low-income multifamily housing, training and dedicating staff to community outreach, and providing direct support to community based organizations.

Planning for the Future

It is critical that the state's planning efforts reflect and account for rapid changes in energy markets, such as the deployment of solar photovoltaic and energy storage technologies, migration of load from IOUs to community choice aggregators, climate change impacts on supply and demand, and declining reliance on natural gas. The *2019 IEPR* puts forward new 10-year forecasts for electricity and natural gas use, as well as for transportation fuels. The forecasts for electricity and natural gas demand inform planning for resource procurement and transmission investments in the CPUC's Integrated Resource Planning process and the California Independent System Operator's (California ISO's) Transmission Planning Process, respectively. In addition, the CEC provides monthly peak demand forecasts in coordination with the California ISO and the CPUC for evaluating resource adequacy.

The transportation forecast aims to capture changes in consumer preferences influenced by clean vehicle policies, technology investments, and global market pressures. The findings from the transportation forecast are also inputs into the electricity and natural gas forecast. Staff continues to refine the electricity and natural gas forecast to better reflect hourly data for factors such as rooftop solar, energy efficiency, electricity storage, demand response (to reliably and quickly ramp energy load up or down in response to price signals), climate change, and electric vehicle charging. California's planning efforts continue to evolve as its historically siloed sectors such as buildings, electricity, and transportation are becoming increasingly intertwined.

Investing in technology innovation is also necessary to help the state decarbonize its energy system in ways that are clean, safe, affordable, accessible, and reliable. The CEC is conducting research that ranges from identifying pathways to achieve deep GHG reductions, to developing technological solutions such as low- and no-carbon alternatives for space heating, water heating, and cooking in buildings, to identifying solutions to better integrate electric vehicles into the grid.

In light of California's climate change policies, difficult decisions about replacing aging gas infrastructure and managing investments to maintain energy reliability are needed. In Southern California, maintaining energy reliability remains challenging, and concerns in recent years are primarily due to breakdowns in the aging natural gas infrastructure in the region. Following a massive leak at the Aliso Canyon natural gas storage facility in 2015, the state has limited the use of the facility, which has historically helped balance natural gas supply and demand. Further, multiyear outages of natural gas pipelines that serve the region greatly add to the risk of disruptions in energy reliability. The CEC, CPUC, California ISO, and the Los Angeles Department of Water and Power continue to work closely together to monitor the situation and implement solutions, with an emphasis on using preferred resources such as storage, demand response, and renewables.

Adapting to Climate Change

As California pursues its clean energy future, it must plan for and adapt to a changing environment that will affect the demands on and capabilities of the system. A warmer climate increases the need for indoor cooling, while extreme heat compromises the performance of generation, transmission, and distribution infrastructure. Reduced spring snowpack reduces hydroelectric supplies during summer months when hydropower has historically provided an important, zero-emission resource for meeting peak demand. Wildfires have had tragic consequences in recent years in terms of loss of life and property. During weather associated with extreme wildfire risk, planned power shutoffs intended to protect public safety were used in unprecedented levels in October 2019. The shutoffs affected an estimated 2 million people.

California's investments in research and development are one of the most important tools for reaching long-term decarbonization in a resilient and cost-effective manner. Planning for the effects of climate change in the energy sector, identifying pathways to achieve deep decarbonization of energy use, and developing innovative solutions to these complex issues must be rooted in a science-based understanding. Further, climate science must be actionable on a local level, and the state must prioritize research and actions that support climate-resilience for California's communities that are most vulnerable to climate change.

Taking Up the Challenge

California must boldly face the challenge of decarbonizing its energy system to dramatically cut GHG emissions while maintaining energy reliability, controlling costs, increasing its resiliency to climate change, and improving the equity of how clean energy benefits are realized. Addressing this challenge will require the engagement of state and local governments, industry, environmental groups, nongovernmental organizations, and Californians throughout the state. California is the fifth largest economy in the world, a state rich with renewable resources, the home of technological innovations that have spread throughout the world, and a leader in clean energy policies. California has the resources, talent, and political will to achieve its clean energy goals and be an example to others striving for a similarly sustainable future.

CHAPTER 1: Electricity Sector

Introduction

California's electricity system is facing rapid and sweeping changes as California continues to lead the way in achieving greenhouse gas (GHG) reductions. In 2017, GHG emissions in the electricity sector dropped to more than 40 percent below 1990 levels, helping to ensure the state is on its way to achieving the 2030 statewide GHG reduction target set by Senate Bill 32 (Pavley, Chapter 249, Statutes of 2016). California's Renewables Portfolio Standard (RPS) calls for 33 percent of the retail sales to be served with renewable resources by 2020. In 2018, the state achieved an estimated 34 percent.[1]

The state's path to deeper GHG reductions in the electricity sector is delineated in Senate Bill 100 (De León, Chapter 312, Statutes of 2018), which calls for a 100 percent zero-carbon electricity system by 2045. SB 100 also establishes an ambitious 60 percent RPS by 2030, increased from the previous 50 percent established by Senate Bill 350 (De León, Chapter 547, Statutes of 2015). Also in 2018, Executive Order B-55-18 set a goal of statewide carbon neutrality as soon as possible (no later than 2045), with net negative GHG emissions thereafter.

Over the last decade, the electricity resource mix has changed significantly as new renewable resources have come on-line. By 2025, reliance on out-of-state coal generation will be eliminated from the state's resource mix altogether and the system is shifting to decreased reliance on fossil natural gas.

In the near term to mid-term, fossil natural gas generation plays a critical role in ensuring reliability and integrating renewable energy resources. Increased coordination and the evolution of markets in the western region are already helping to better integrate renewables. Resources such as energy storage and demand management are also helping to integrate renewables and ensure reliability.

Changes are also underway as customers face increasing choices over their sources and suppliers of electricity. Many customers are generating their own power from rooftop solar and

1 California Energy Commission, Tracking Progress, Renewable Energy, December 2018, https://www.energy.ca.gov/sites/default/files/2019-05/renewable.pdf.

other distributed generation, decreasing demand on the electricity grid. Further, California is the first state to require photovoltaic (PV) generation for all new low-rise homes under new building standards that went into effect on January 1, 2020. Many communities are deciding to make their own electric resource procurement choices by forming community choice aggregators to develop innovative ways of providing cleaner energy resources. As of 2019, roughly 20 percent of customers have moved from service provided by an investor-owned utility (IOU) to service provided by a community choice aggregator. Large commercial and industrial customers are buying their electricity directly from renewable generators, as well as from private direct access providers.

These changes challenge the regulatory framework that has ensured reliable and affordable power for California Public Utilities Commission (CPUC) jurisdictional entities representing nearly 80 percent of the electricity grid. As responsibility for resource procurement and resource adequacy becomes more disaggregated, one of the state's primary mechanisms for delivering GHG reductions and achieving other environmental and policy goals in the electricity sector is fragmenting. Further, utilities face financial uncertainties with the looming liability associated with California's devastating wildfires, with one utility in bankruptcy.

California energy agencies, in collaboration with the California Independent System Operator (California ISO) and other California balancing authority areas, continue to work together to address questions about how to ensure reliability, achieve clean energy goals, and provide affordable electricity in this evolving environment. This chapter provides an overview of emerging trends in the electricity sector.

Review of Major Trends in the Electricity Sector

Electricity Sector Leads California's Efforts to Reduce GHG Emissions

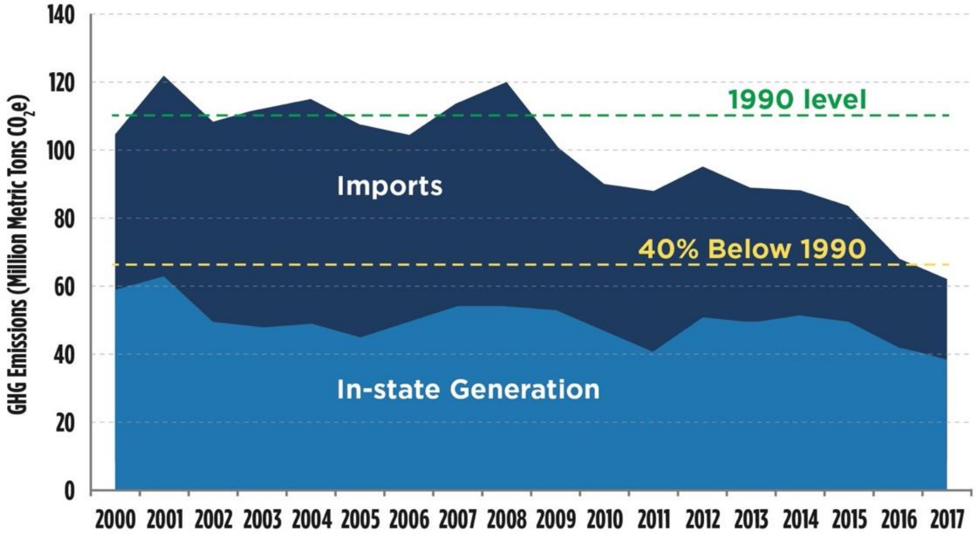
California's electricity sector continues to make steady progress toward its energy and environmental goals and is leading California's efforts to reduce GHG emissions. GHG emissions from the electricity sector declined by 9 percent in 2017, compared with 2016, as shown in Figure 1.[2] In 2017, 52 percent of total electricity generation, including in-state generation and imported power, came from zero-carbon generation sources.[3] Total GHG

2 CARB, 2019 Edition, California Greenhouse Gas Emissions Inventory: 2000–2017 https://www.arb.ca.gov/cc/inventory/pubs/reports/2000_2017/ghg_inventory_trends_00-17.pdf.

3 For the inventory, CARB includes solar, wind, large and small hydro, and nuclear as zero-GHG-emission generation sources.

emissions attributed to the electricity sector decreased by 6 million metric tons carbon dioxide equivalents (MMT CO_2e), from 68 MMT CO_2e in 2016 to 62 MMT CO_2e in 2017.

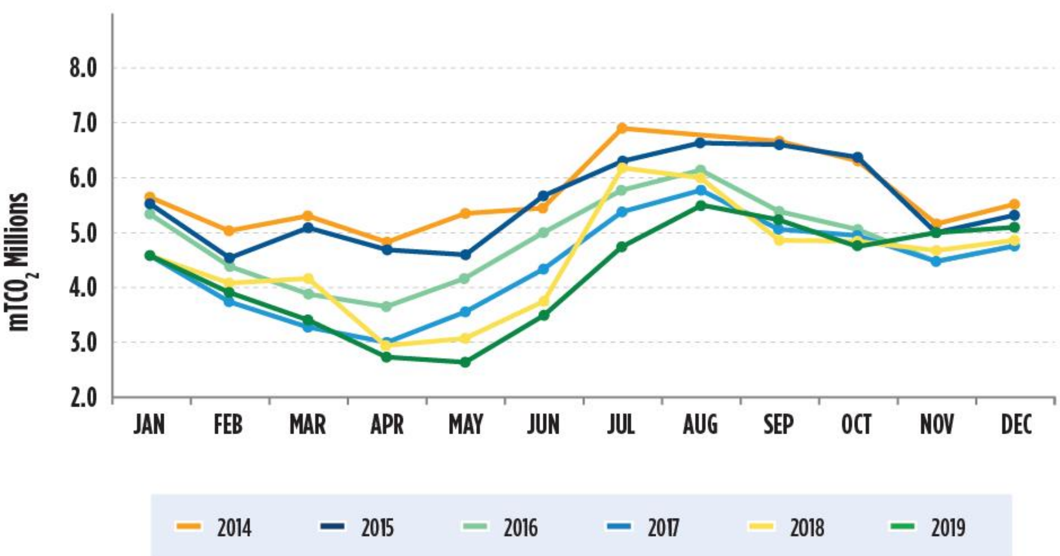
Figure 1: GHG Emissions From California's Electricity Sector Continue to Decline



Source: CEC using data from the California Air Resources Board (CARB)

More current and granular GHG emissions data are available for the portion of California load served by the California ISO. As shown in Figure 2, GHG emissions continue to decline annually, with most months showing downward trends.

Figure 2: Total GHG Emissions to Serve California ISO Load

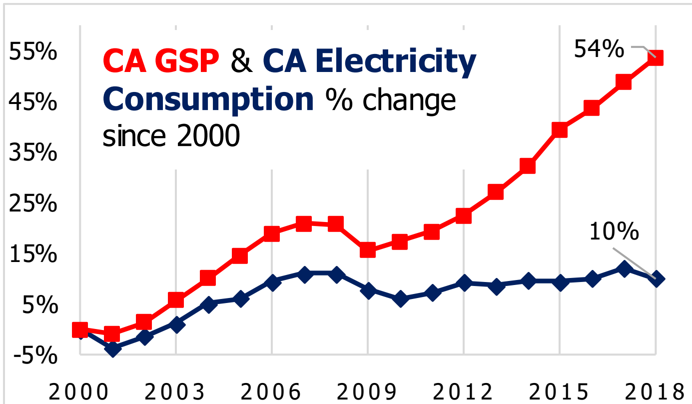


Source: California ISO, [GHG Emission Tracking Report– December 2019](http://www.caiso.com/Documents/GreenhouseGasEmissions-TrackingReport-Dec2019.pdf), http://www.caiso.com/Documents/GreenhouseGasEmissions-TrackingReport-Dec2019.pdf.

Changes in Fossil Natural Gas-Fired Electricity Generation

California is beginning a transition away from fossil natural gas as a primary fuel source for electric generation. To meet air quality, climate, and other environmental goals, fossil generation is being replaced by resources including renewables, transmission upgrades, energy storage, energy efficiency, and demand response.

California's Economic Growth Outpaces Electricity Consumption



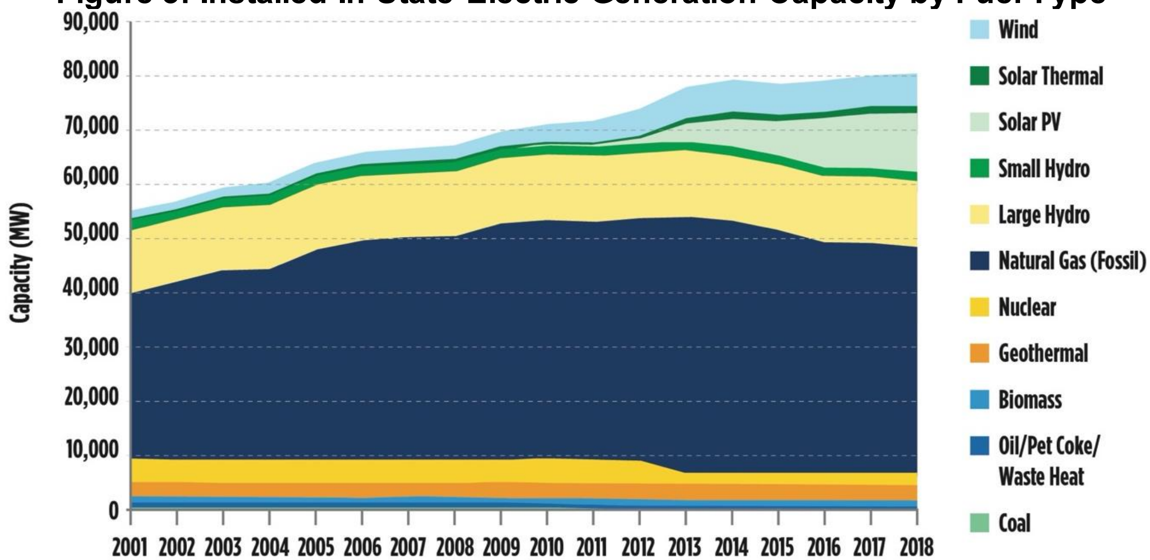
California continues to demonstrate that it is possible for economic growth to outpace energy consumption. Between 2000 and 2018, California's gross state product (GSP) grew by almost 54 percent while electricity consumption grew by about 10 percent—the state's economy grew five times faster than electricity consumption. Meanwhile, the state's population grew roughly 17 percent from about 34 million in 2000 to almost 40 million in 2018.

Sources: Jobs data are from the Employment Development Department and reflect civilian employment growth, June 2019. Gross state product data are from U.S. Bureau of Economic Analysis and Moody's Analytics, June 2019. Population data are from California Department of Finance, December 2018.

Over the last decade, the portfolio of resources in California's electric system has significantly changed. The amount of generation from fossil natural gas plants has decreased by roughly 22 percent, from 117 gigawatt-hours (GWh) in 2009 to 91 GWh in 2018. Large amounts of renewable generation have been added to the system, driven primarily by California's Renewables Portfolio Standard (RPS) and the California Solar Initiative. Installed renewable capacity in the state increased from 9,313 megawatts (MW) in 2009 to 23,313 MW in 2018, as shown in Figure 3. Over the last decade, renewable generation, including rooftop solar PV, has also more than doubled, from 33 GWh in 2009 to 77 GWh in 2018, as shown in Figure 4. Further changes in the state's resource mix result from reduced reliance on imported out-of-state coal resources and nuclear generation. By 2025, out-of-state coal imports will be eliminated from the resource mix and the last remaining nuclear power plant in the state, Diablo Canyon Power Plant, is slated to retire.[4]

California is also retiring aging coastal fossil natural gas plants that use ocean water for cooling (once-through cooling), with only a portion of that capacity being replaced by gas-fired generation. Between 2009 and 2018, California retired more than 8,100 MW of fossil natural gas power plants using once-through cooling. By 2020, another 5,300 MW is expected to retire, and by 2029, an additional 1,600 MW will retire.[5] See Chapter 6 for more information.

Figure 3: Installed In-State Electric Generation Capacity by Fuel Type



Source: CEC Quarterly Fuels and Energy Note: One natural gas-fired power plant, Grayson, uses renewable natural gas (RNG) as a secondary fuel for two operational units. The combined units account for 88 MW, and the RNG share as a secondary fuel (fossil

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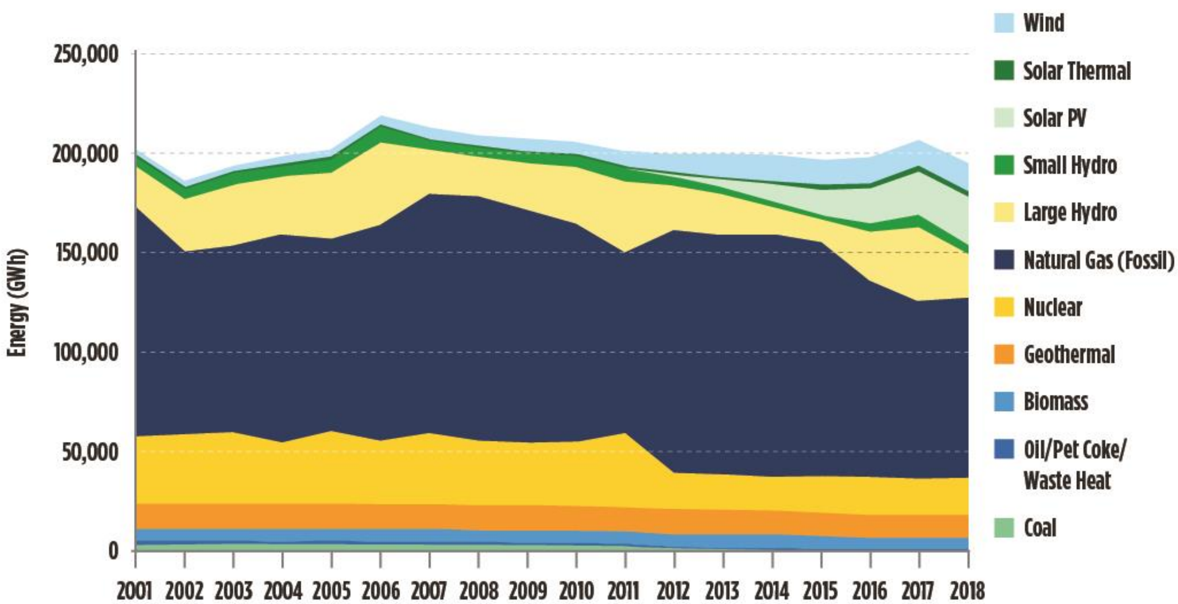
4 Several of the state's publicly owned utilities have long-term contracts with out-of-state nuclear generation from the Palo Verde Nuclear Generating Station located in Arizona that extend beyond 2030.

5 The Statewide Advisory Committee on Cooling Water Intake Structures is considering an extension of the once-through cooling compliance date of Alamitos units 3, 4, and 5 to December 31, 2022, because of the delay of the Mesa Loop-in transmission upgrade, Report of the Statewide Advisory Committee on Cooling Water Intake Structures draft report
https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/sccwintrpt.pdf.

natural gas being the primary fuel) is 15 percent of total fuel usage for the two units in 2018. This is not shown in the figure.

Figure 4: In-State Electric Generation by Fuel Type



Source: CEC Quarterly Fuels and Energy Note: On natural gas-fired power plant, Grayson, uses RNG as a secondary fuel for two operational units. The units (combined) account for 120 GWh, and the RNG share as a secondary fuel (fossil natural gas being the primary fuel) is 15 percent of total fuel usage for the two units in 2018. This is not shown in the figure.

Historically, fossil natural gas power plants have had the lowest operating costs, or marginal costs, so they were the first resources called on, or dispatched, to meet electricity demand. However, the lower overall operating costs of renewable resources means that when the sun is shining or the wind is blowing these resources are being called on instead of fossil natural gas plants.[6] The use of these resources is leading to an overall reduction in the amount of fossil natural gas used for electricity generation. In addition, fossil natural gas generation has

6 For example, in the California ISO market, resources with the lowest marginal costs are called on first to meet load, which is also referred to as "economic dispatch." Solar has essentially zero marginal costs, while wind has very low marginal costs when compared with fossil natural gas generation.

typically been the swing generation to make up for loss of hydro resources during droughts, but in 2016, renewable generation began to serve that purpose. Still, as discussed below, fossil natural gas plants are needed to meet load during periods when renewable resources are varying or not generating and to provide grid services to ensure system and local reliability.

Fossil natural gas power plants provide about 75 percent of the flexible capacity available to meet system needs. This flexible capacity means that some gas plants that were designed to operate as baseload resources, primarily combined-cycle power plants, are being operated more like peaking resources, running fewer hours. In recent years, peaking gas plants have been added, which run less of the time—in most cases only a few hours on the hottest days—and make up a portion of the once-through cooling plant retirements.[7] Some fossil natural gas plants are adding on-site energy storage to increase flexibility. Fossil natural gas plants with low capacity factors may retire early, as they may not be economic to run if they are called on only infrequently. For the near term, fossil natural gas generation will continue to play a key role in integrating renewable resources and ensuring reliability.

Integrating Increasing Amounts of Renewables and Storage

The integration of increasing amounts of renewable resources is changing the way the grid is operated. With the growth in intermittent renewables, system operators need additional generators with flexible capabilities to balance supply and demand.

With the addition of solar and wind generation on the system, electricity demand in the state is being served by record levels of renewables. As of December 20, 2019, the most recent solar peak of 11,473 MW occurred on the California ISO system on July 2, 2019. The most recent wind generation peak of 5,309 MW on the California ISO system was set on May 8, 2019. A new overall renewable generation penetration peak for the California ISO system was recorded on May 15, 2019, with 80 percent of instantaneous load served by all renewables.[8] As solar penetration continues to increase on the customer side of the meter and on the grid, the net load[9] shows steep afternoon ramps as demand remains high or increases, while solar generation subsides as the sun sets. These ramps, managed by the California ISO and other

7 For example, the Carlsbad Energy Center is a 500 MW peaker plant that replaced the 946 MW Encina combined-cycle power plant.

8 Letter from Steve Berberich (President and Chief Executive Officer of California ISO) to ISO Board of Governors. *CEO Report*. July 17, 2019. Memorandum to ISO Board of Governors from Steve Berberich, president and CEO http://www.caiso.com/Documents/CEOReport-Jul2019.pdf.

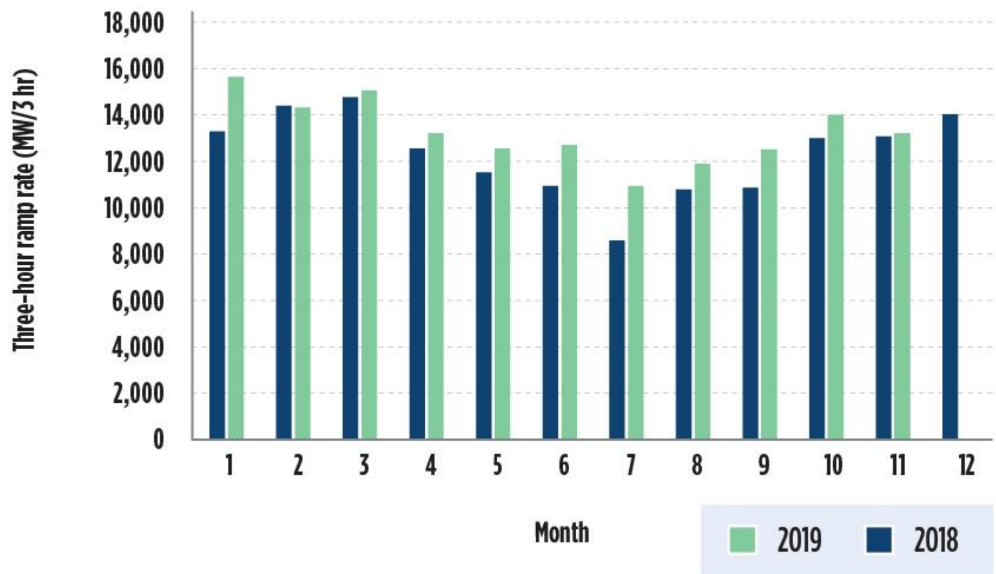
9 *Net load* is the amount of energy that must be provided net of wind and solar generation.

balancing authorities, are becoming steeper, as shown in Figure 5. These three-hour ramp rates far exceed predictions by the California ISO several years ago, when the maximum ramp rate on a typical spring day in 2020 was predicted to be 13,000 MW in three hours.[10] In January 2019, the three-hour ramp was almost 16,000 MW.

Similarly, the minimum net load is lower than predicted, as shown in Figure 6. Several years ago, the California ISO predicted that the net load would not reach a minimum of 12,000 MW until 2020 for the worst case of a typical spring day when load is low and renewable generation (primarily wind and solar) is high. However, the California ISO reaches that level nearly every month of the year, and well below it on spring days—as low as 5,439 MW in May 2019. Although the California ISO has identified reliability concerns with minimum loads below 12,000 MW, the California ISO grid has remained stable.

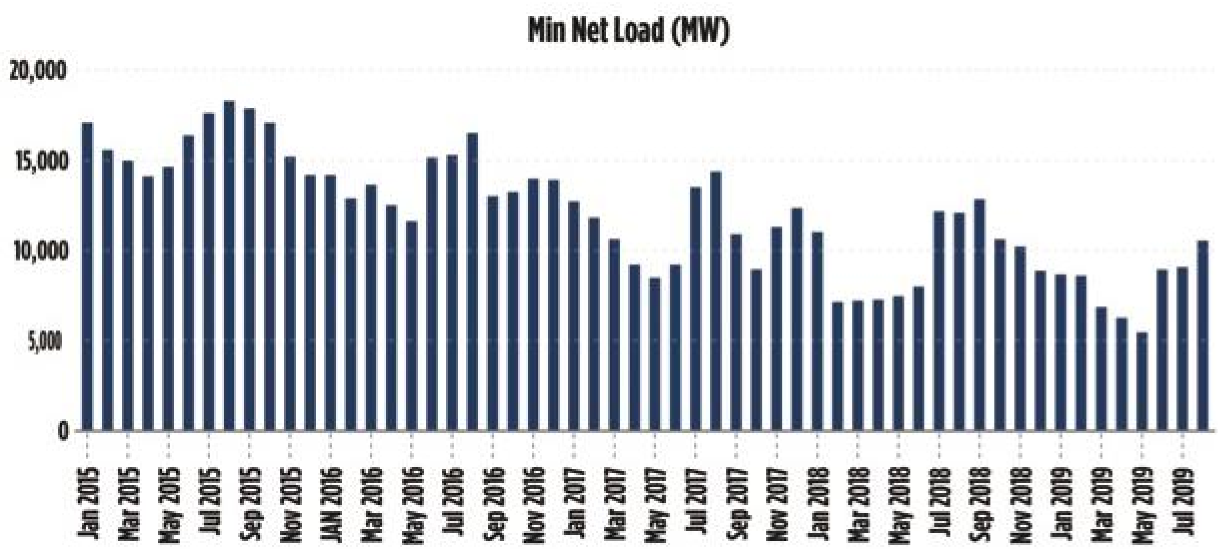
10 California ISO. "Fast Facts: What the Duck Curve Tells Us About Managing a Green Grid." 2016. Fact sheet on the "duck curve" by the California ISO http://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf#search=what%20the%20duck%20curve%20tells%20us.

Figure 5: California ISO Maximum Three-Hour Ramp Rate by Month



Source: Based on data obtained from the California ISO, available at [Link to past Monthly Renewables Performance Reports on the California ISO website](http://www.caiso.com/market/Pages/ReportsBulletins/RenewablesReporting.aspx#MonthlyRenewables) http://www.caiso.com/market/Pages/ReportsBulletins/RenewablesReporting.aspx#MonthlyRenewables.

Figure 6: California ISO Monthly Minimum Net Load (January 2015–November 2019)



Source: California ISO, [Monthly Renewables Performance Report for November 2019 on California ISO's website](http://www.caiso.com/Documents/MonthlyRenewablesPerformanceReport-Nov2019.html) http://www.caiso.com/Documents/MonthlyRenewablesPerformanceReport-Nov2019.html.

The *2018 IEPR Update*[11] further described the challenges and opportunities associated with the need to increase flexibility in the electricity system to integrate more renewable energy. Progress is being made in developing performance standards for inverter-connected solar and wind power plants that will help improve reliability and increase services to the grid. There is an increasing need for energy storage that can absorb excess energy and reinject it into the grid when needed, and California is seeing an emerging trend toward hybrid resources, such as solar-plus-storage projects.

The California ISO is receiving an increasing number of inquiries from generation developers interested in pairing energy storage with either existing or proposed generation (conventional or renewable). As of July 3, 2019, the California ISO's Generator Interconnection Queue included 35,341 MW of hybrid resources seeking interconnection, or a little more than 40 percent of the total requested. Based on the number of interconnection requests and strong interest by developers and stakeholders, the California ISO anticipates the installed capacity of hybrid resources will grow significantly in coming years.[12]

In response to this trend, the California ISO launched a new stakeholder process to address issues associated with market participation of hybrid resources. The initiative will explore how such hybrid generation resources can be registered and configured to operate within the California ISO markets and will assess new operational and forecasting challenges hybrid resources will likely present. In the meantime, the California ISO will allow existing solar facilities to colocate new storage with an expedited material modification assessment process so the additional storage does not need to resubmit into the California ISO interconnection queue.[13]

The CEC received comments on the draft *2019 IEPR* from the Governor's Office of Business and Economic Development,[14] the California Hydrogen Business Council,[15] and other hydrogen

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11 CEC staff. 2018. *2018 Integrated Energy Policy Report Update, Volume II*. CEC. Publication Number: 100-2018-001-V2-CMF. (p. 197) Link to 2018 IEPR Update on the CEC's website https://www.energy.ca.gov/2018publications/CEC-100-2018-001/CEC-100-2018-001-V2-CMF.pdf.

12 California ISO. *Hybrid Resources Issue Paper*. July 18, 2019. Copy of California ISO's Hybrid Resources Issue Paper http://www.caiso.com/Documents/IssuePaper-HybridResources.pdf.

13 California ISO. See Attachment A, http://www.caiso.com/Documents/Oct2-2019-Comments-ReliabilityProcurementProposedDecision-IRP-R16-02-007.pdf.

14 Tyson Eckerle. Office of Business and Economic Development. December 18, 2019. TN# 2316450. Tyson Eckerle. Office of Business and Economic Development. January 23, 2020. TN# 231649. https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-01.

stakeholders and experts that highlight the role hydrogen and fuel cells can play in helping integrate renewable resources, providing long term energy storage, and adding resilience to the grid.[16] These comments also provide useful data for further consideration about hydrogen as a possible decarbonized resource for industrial energy and building heat and power.

Addressing Short-Term Resource Adequacy Concerns

The California ISO submitted a system resource adequacy and operational analysis[17] for 2021–2022 as part of the comments it filed in the CPUC integrated resource plan proceeding. (See Chapter 10 for more information on integrated resource plans.) The analysis identified capacity shortfalls starting in 2020 and challenges meeting summer evening peak load. The state is facing these short-term resource adequacy gaps, the California ISO explained, because the peak demand it serves has shifted from the afternoon to the early evening (within hour ending at 5:00 p.m. [17 Pacific Standard Time] [PST] in 2020 and 2021, and 6:00 p.m. [18 PST] in 2022), which is when solar production is significantly reduced or not available.[18]

The California ISO resource adequacy analysis shows a 500 MW system resource adequacy deficiency in 2020, which increases to 2,300 MW and 2,200 MW in 2021 and 2022, respectively.[19] The analysis also shows operational deficiencies reaching maximums of 2,300 MW, 4,400 MW, and 4,700 MW in 2020, 2021, and 2022, as shown in Figures 7, 8, and 9, respectively.[20] In Figure 7, the 2020 analysis shows an operational gap starting at 6:00 p.m.

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15 California Hydrogen Business Council. November 27, 2019. CBHC Comments on the 2019 Draft IEPR. https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-01. TN# 230880.

16 Bloom Energy. December 6, 2019. Comments on the Draft 2019 IEPR. https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-01. TN# 231012.

17 The California ISO's complementary operational analysis reflects the capability of the projected resource adequacy fleet to serve load after the gross peak hour based on operational performance rather than static capacity values. The California ISO's energy-based analysis focuses on hours 4:00 p.m. to 9:00 p.m. PDT.

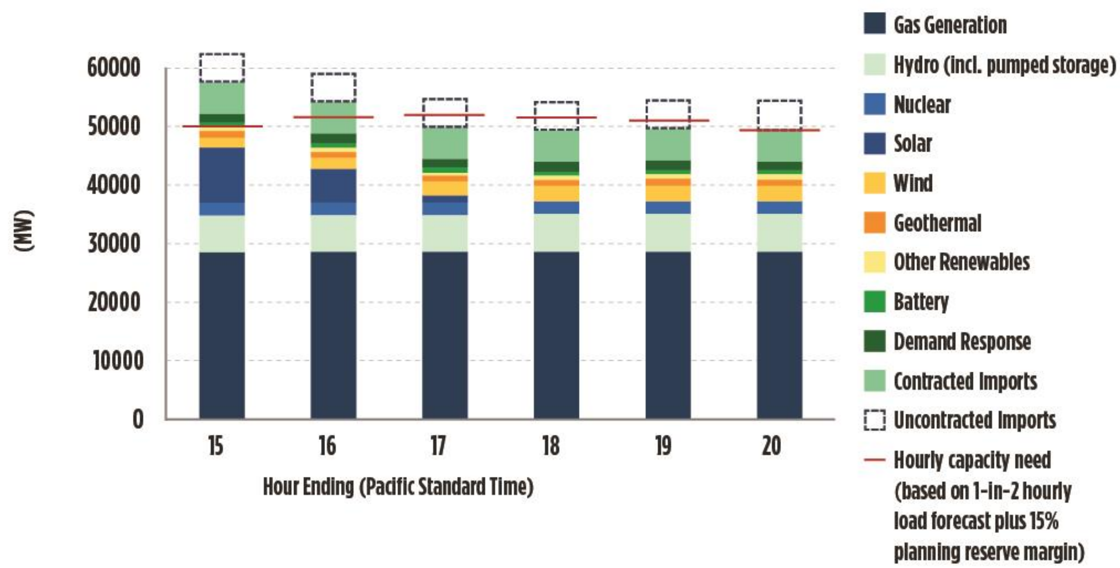
18 California ISO briefing on post 2020 operational outlook, September 18, 2019, Board of Governors Meeting General Session, p. 4, http://www.caiso.com/Documents/Briefing-Post-2020-GridOperationalOutlook-Presentation-Sep2019.pdf.

19 Reply Comments of the California ISO, August 12, 2019, CPUC Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements, p. 2, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M311/K582/311582922.PDF.

20 Ibid., p. 2.

Pacific Daylight Time (PDT) (in hour ending in 17 PST) and in the two hours immediately after.[21] Figure 8 shows that in 2021, the reliability gap expands to four hours, from 6:00 p.m. through 9:59 p.m. PDT (hour ending 17 through 20 PST).[22] In 2022 (Figure 9), the reliability gap continues from 6:00 p.m. through 9:59 p.m. PDT (to cover hours ending in 17 through 20 PST), but the peak hour shifts from 6:00 p.m. to 7:00 p.m. PDT (hour ending in 18 PST).[23]

Figure 7: 2020 Projected Energy Production From Resource Adequacy Fleet



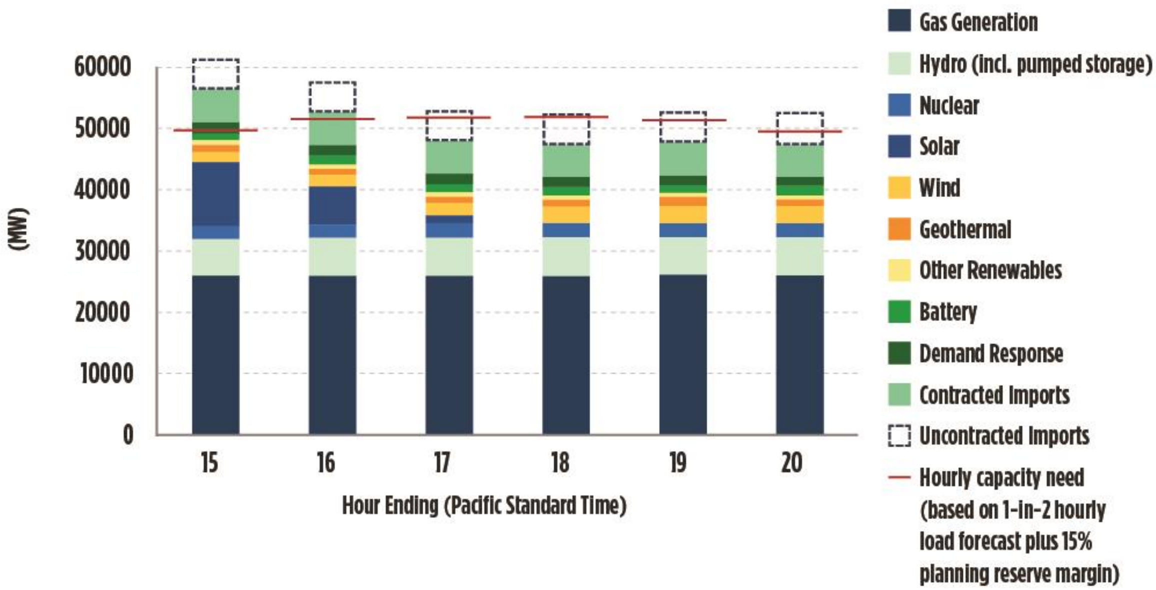
Source: California ISO

21 Ibid., p. 11.

22 Ibid.

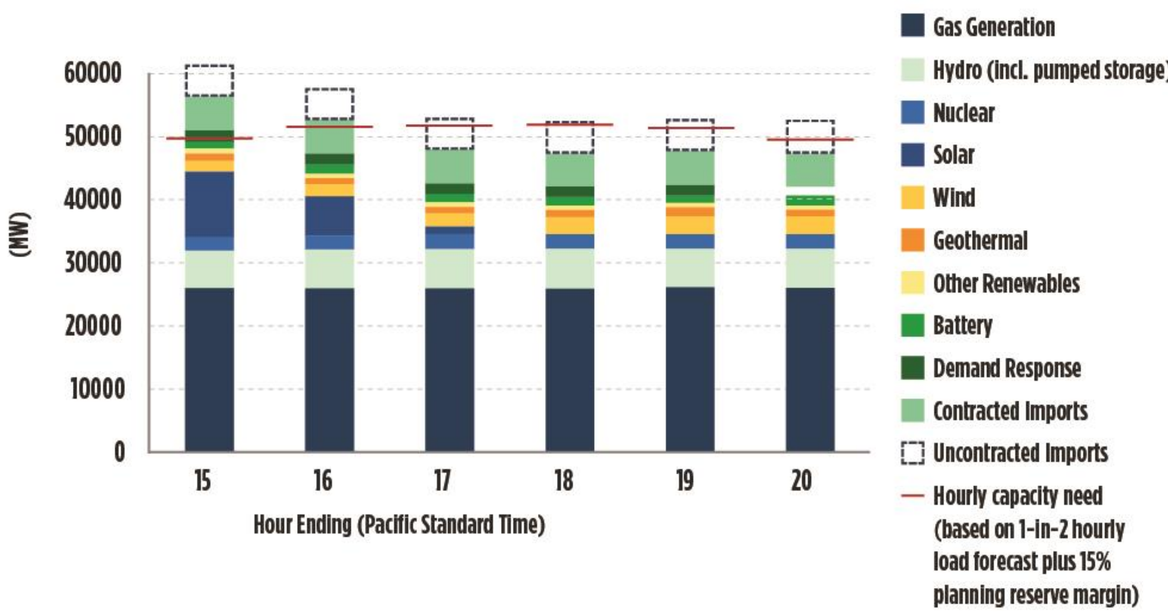
23 Ibid.

Figure 8: 2021 Projected Energy Production from Resource Adequacy Fleet



Source: California ISO

Figure 9: 2022 Projected Energy Production from Resource Adequacy Fleet



Source: California ISO

The California ISO explained that there are several challenges to addressing these short-term resource adequacy concerns, including energy capacity decreasing because of net retirement of 4,000 MW of OTC natural gas-fired plants, increasing load, thermal resource retirements and increasing renewable integration needs outside California along with potential changes in hydro resource conditions in California and the West.[24]

As part of the CPUC integrated resource plan proceeding, the CPUC has issued a decision to address the electricity system resource adequacy shortages beginning in 2021.[25] Specifically, the decision recommends that the State Water Resources Control Board extend the OTC compliance deadlines for gas-fired plants required to retire by December 31, 2020.[26] In addition, the decision requires incremental procurement of system-level resource adequacy capacity of 3,300 MW by all load-serving entities (LSEs) serving load within the California ISO balancing authority area.[27]

Western States Coordination and Collaboration

Increased regional coordination is important to supporting policies, objectives, and efficient and reliable operations of the changing energy system. Coordination offers significant potential to ease importation and integration of additional renewable energy facilities in regions where resource attributes match or complement California's seasonal and daily operational needs.

The Western EIM is a real-time wholesale energy trading market that enables participants anywhere in the West to buy and sell energy when needed. It has proven successful in producing cost savings, reducing renewables curtailment, and reducing GHG emissions. The existing Western EIM has nine member entities (including the California ISO).[28] Eleven additional entities plan to join by 2022.[29] The Bonneville Power Administration (BPA) has

24 California ISO briefing on post 2020 operational outlook, September 18, 2019, Board of Governors Meeting General Session, p. 7, http://www.caiso.com/Documents/Briefing-Post-2020-GridOperationalOutlook-Presentation-Sep2019.pdf.

25 CPUC Decision Requiring Electric System Reliability for 2021-2023, R. 16-02-007, released November 7, 2019 http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=318169119.

26 Ibid., p. 2, pp. 16–24.

27 Ibid., p. 3, pp. 28–33.

28 The entities and their dates of entry include the following: PacifiCorp (2014), NV Energy (2015), Arizona Public Service (2016), Puget Sound Energy (2016), Portland General Electric (2017), Idaho Power (2018), Powerex (2018), and the Balancing Authority of Northern California/Sacramento Municipal Utility District (2019).

29 Entities and their planned dates of entry include Seattle City Light (2020), Salt River Project (2020), Los Angeles Department of Water and Power (2021), Northwestern Energy (2021), Turlock Irrigation District (2021), Public Service Company of New Mexico (2021), Balancing Authority of Northern California Phase 2 [Modesto Irrigation District, City of Redding, and City of Roseville] (2021), Western Area Power Administration–Sierra Nevada Region (2021), Avista Utilities (2022), Tucson Electric Power (2022), and Tacoma Power (2022).

signed an implementation agreement that positions it to join the Western EIM in 2022.[30] Assuming all these entities join as noted, in 2022 the balancing authorities participating in the Western EIM will account for more than 77 percent of the load in the Western Electricity Coordinating Council.[31]

There is also growing interest in extending the day-ahead market to include Western EIM entities. To that end, the California ISO launched its Extended Day-Ahead Market Initiative on October 10, 2019, with an issue paper.[32] The paper outlines the major topics to be addressed in the Extended Day-Ahead Market Initiative, including transmission provisions, distribution of congestion rents, resource sufficiency evaluations, ancillary services, and accounting for GHG costs. The aim is to enable current and future Western EIM entities to participate in a day-ahead market using a framework similar to the existing Western EIM real-time market, rather than requiring full integration into the California ISO balancing area.

As participation in the Western EIM increases and opportunities for expanding the market services offered to participants are considered, Western EIM governance issues are being addressed in various forums. The CEC is engaged with several regional entities that have roles related to reliability, transmission planning, market development, and other issues of interest to states and provinces in the West.

Also, the California ISO is taking on a new role in the western United States as the reliability coordinator (RC) in its control area and has extended these services to other western balancing authorities.[33] After more than a year of planning and stakeholder input, the new service, RC West, launched operations July 1, 2019, providing reliability coordinator services for balancing authorities and transmission for most of California and one entity in Mexico,

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30 BPA is a nonprofit federal power marketer that markets wholesale electrical power from 31 federal hydroelectric projects in the Northwest, one nonfederal nuclear plant, and several small nonfederal power plants. Joining the Western EIM is part of BPA's overall grid modernization program that positions BPA and its customers to benefit from new technology and emerging market opportunities. BPA Grid Modernization Program website https://www.bpa.gov/Projects/Initiatives/Grid-Modernization/Pages/Grid-Modernization.aspx.

31 The Western Electricity Coordinating Council promotes bulk electric system reliability in the Western Interconnection and is the regional entity responsible for compliance monitoring and enforcement.

32 Link to Extended Day-Ahead Market Initiative information on the California ISO's Web page http://www.caiso.com/informed/Pages/StakeholderProcesses/ExtendedDay-AheadMarket.aspx.

33 A reliability coordinator (RC) has the highest level of authority and responsibility for the reliable operation of the power grid, and has a wide-area view of the bulk electricity system. It is required to comply with federal and regional grid standards, and can authorize measures to prevent or address system emergencies in day-ahead or real-time operations. The RC also provides leadership in system restorations following major events.

Centro Nacional de Control de Energía. In early November 2019, following additional certifications by North American Electric Reliability Corporation and Western Electricity Coordinating Council, the California ISO anticipates that RC West will become the reliability coordinator for another 23 entities in the Western Interconnection, overseeing 87 percent of load in the western United States.[34]

As the Western EIM expands, the California ISO continues to work with participants, as well as adjacent balancing authorities and transmission operators, to establish critical telemetry and operating procedures that minimize, or preclude, the impacts of Western EIM operations on adjacent, affected systems. This visibility into Western EIM participant systems and adjacent, affected systems delivers significant economic and operational benefits.

Decarbonizing the State's Electricity Sector

Senate Bill 100 Sets the Framework to Decarbonize the Electricity Sector

SB 100 establishes 2045 targets for renewable and zero-carbon energy procurement equal to 100 percent of retail sales to consumers and 100 percent of electricity procured to serve state agencies. It also requires all state agencies to incorporate these targets into their relevant planning, including in the CEC's Integrated Energy Policy Report (IEPR) process. The bill also increases the state's RPS to 60 percent of retail sales by December 31, 2030, and raises interim procurement requirements by amounts consistent with this increase. SB 100 requires the CPUC, CEC, and CARB to use programs authorized under existing statutes to achieve this policy.

SB 100 requires a joint report prepared by the CEC, CARB, and CPUC, in consultation with the state's balancing authorities, to the Legislature by January 1, 2021, and every four years thereafter.[35] The report will address the implementation of the policy including a review focused on technologies, forecasts, existing transmission, maintaining safety, environmental pollution, affordability, and system and local reliability. The report will include an evaluation of the potential benefits and impacts on the system, any anticipated financial costs and benefits

34 Information on the California ISO's role as reliability coordinator
http://www.caiso.com/informed/Pages/RCWest/Default.aspx.

35 A *balancing authority* is responsible for continuously balancing supply and demand for electricity within its areas and among other balancing authorities and for maintaining adequate reserves to ensure reliable operation. Balancing authorities include the California Independent System Operator, the Balancing Authority of Northern California, the Los Angeles Department of Water and Power, the Imperial Irrigation District, the Turlock Irrigation District, and several others that connect to California.

to utilities including customer rate impacts and benefits, barriers to achieving the policy, and alternative scenarios to achieve the policy and the associated costs and benefits.

On September 5, 2019, the CEC, CARB, and CPUC publicly kicked off a collaboration to implement SB 100 with a workshop that included participation from the Governor's Office, the Secretary of Natural Resources, and leadership from each of the agencies. At the workshop, policy leaders stressed that the benefits of California's clean energy future must reach low-income and disadvantaged communities. To help engage a wide variety of perspectives on the scope of the joint agency report, the collaboration held a series of three workshops in Northern California, Central California, and Southern California. Additional SB 100 workshops are anticipated in spring 2020 to address issues related to environmental and land-use impacts, equity, affordability, reliability, climate resilience, and others.[36]

Research Is Needed to Support California's Transition to Clean Energy in a Changing Climate

California's clean energy future and environmental goals can be fully realized only by remaining at the forefront of clean energy research. Making the leap to a clean, modern energy system supporting continued growth in the world's fifth-largest economy demands a sustained, directed, equitable, and vigorous public-interest research investment program. With SB 100 as a north star, the CEC is investing in ideas and approaches to unlock the promise of the clean-energy, low-carbon future for all Californians.

Achieving and sustaining this future require thoughtful, vigorous, benefit-focused investment through CEC programs like the Electric Program Investment Charge (EPIC). EPIC invests more than $130 million annually to unleash innovation and drive refinement in areas like energy efficiency, energy generation, storage, grid resiliency, renewable integration, electrified transportation, and bring breakthroughs from the lab to the market. EPIC offers researchers and entrepreneurs something the market often cannot: sustained, reliable, and sufficient funding to do their work, minimizing risks that can derail progress or delay market adoption, all with strong oversight.

Climate Science Requires Focus on All Sectors, Including Electricity

California met its goal of reducing statewide GHG emissions to 1990 levels in 2016—four years ahead of schedule.[37] The 2017 *Climate Change Scoping Plan*[38] laid out a cost-effective and

36 For additional information and to participate in the Senate Bill 100 proceeding, see https://www.energy.ca.gov/sb100.

37 In 2016, statewide GHG emissions were 429 MMT CO_2e, 2 MMT CO_2e below the 2020 GHG limit of 431 MMT

achievable path to meet the state's goal to further reduce statewide GHG emissions to 40 percent below 1990 levels by 2030. In 2017, GHG emissions in the electricity sector alone dropped more than 40 percent below the 1990 level;[39] however, there is still work to do in all sectors to meet the statewide 2030 target.

The state also faces the challenge of meeting midcentury targets to achieve the state's climate change goals. As discussed above, SB 100 established a 100 percent zero-carbon electricity goal by 2045. Furthermore, state policy calls for economywide GHG emissions reductions of 80 percent below 1990 levels by 2050[40] and carbon neutrality by 2045, with net-negative emissions thereafter.[41] These aggressive goals are consistent with the Paris Agreement, which calls for limiting global warming to well below 2 degrees Celsius and pursuing efforts to limit warming to 1.5 degrees.[42]

Effectively integrating 100 percent zero-carbon electricity and achieving carbon neutrality in the state by 2045 will require rigorous analysis of various scenarios and pathways, as well as coordinated planning across state agencies, local governments, utilities, and community choice aggregators. This planning must also include developing strategies to increase the resiliency of California's electricity system to the effects of climate change. (See Chapter 5.) Although California is ahead of schedule in meeting its 33 percent renewable energy target by 2020 and on track to achieve 60 percent renewable energy by 2030, completely decarbonizing the electricity sector to meet climate change objectives will dramatically change the state's electric system, and focused attention is needed to maintain reliability.

CO_2e. GHG emissions have continued to decline since 2016. In 2017, statewide GHG emissions were 424 MMT CO_2e, 7 MMT CO_2e below the 2020 limit. CARB, 2019 Edition, California Greenhouse Gas Emissions Inventory: 2000–2017 (pp. 1-2), https://www.arb.ca.gov/cc/inventory/pubs/reports/2000_2017/ghg_inventory_trends_00-17.pdf.

38 See CARB. 2017. California's 2017 Climate Change Scoping Plan, https://ww3.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf.

39 CARB, *California Greenhouse Gas 2000-2017 Emissions Trends and Indicators Report*, 2019 Edition https://gcc01.safelinks.protection.outlook.com/?url=https%3A%2F%2Fwww.arb.ca.gov%2Fghg-inventory-data&data=01%7C01%7C%7C5f66deca36974c01cd5708d750d1423e%7Cac3a124413f44ef68d1bbaa27148194e%7C0&sdata=nWKlrXWmEo%2Bj7jIAtOvaFnrnSZ3NyWAmqZGIF3M%2BUnY%3D&reserved=0.

40 Executive Order S-03-55.

41 Executive Order B-55-18.

42 IPCC, Special Report Global Warming of 1.5°C, https://www.ipcc.ch/sr15/.

Initial Considerations for Near-Zero Carbon Electricity

On September 24, 2019, the CEC hosted an IEPR workshop on Near-Zero Carbon Electricity. The objective of the workshop was to explore existing decarbonization scenarios and pathways and highlight some practical considerations that could help inform policy makers working to achieve 2045 and 2050 clean energy and carbon-neutral goals. The IEPR workshop, while complementary, is separate from the ongoing workshops being held to inform the SB 100 proceeding.

The workshop began with a brief overview of the CARB Climate Scoping Plan. The scoping plan describes the approach California will take to reduce GHG emissions to achieve its goals. Dr. Maureen Hand, an air resources engineer at CARB, noted that CARB's "thinking about how to approach climate challenge is evolving," and "the concept of carbon neutrality is gaining importance."[43] The Intergovernmental Panel on Climate Change (IPCC) Special Report on Global Warming of 1.5 Degrees Celsius, released in 2018, finds that to limit global warming to 1.5 degrees Celsius, GHG emissions must be reduced and carbon must be removed from the atmosphere.[44] Consistent with these findings, the executive order on carbon neutrality introduces the concept of balancing carbon emissions and carbon sequestration within the state.[45]

The workshop then moved to a discussion of two key studies containing in-depth analyses of decarbonization pathways. Dr. Zack Subin, a senior consultant at Energy+ Environment Economics (E3), and Melanie Kenderdine, a principal at Energy Futures Initiative (EFI), presented high-level synopses of their studies on decarbonization scenarios in California. Each study looked at various scenarios and developed pathways based on distinct inputs. These studies provide viewpoints, pathways, and potential strategies to decarbonize California's energy system. Both studies find that even in a deep decarbonization future, the gas system will still play a critical role. While there are still many unknowns, these studies provide insight into some of the challenges the state may face as it moves to decarbonize the energy sector.

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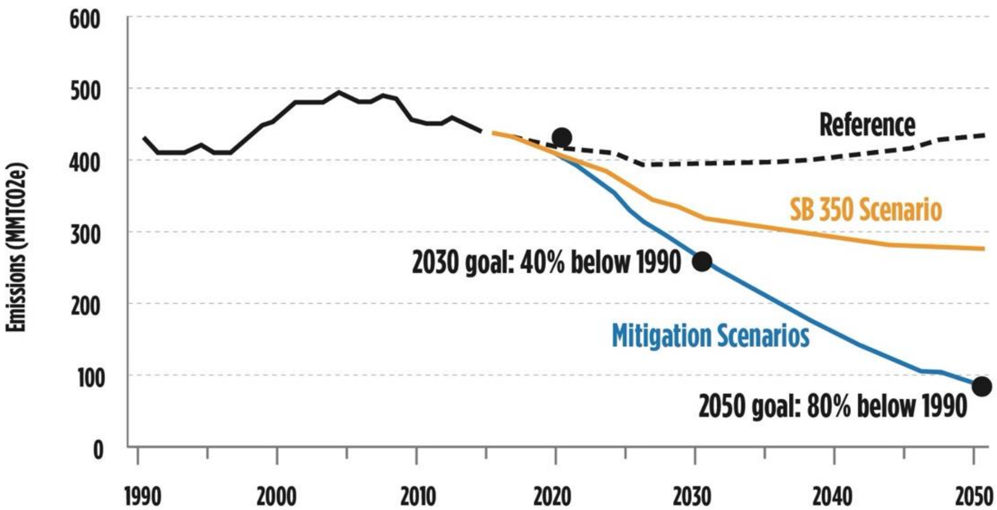
43 Transcript of September 24, 2019, IEPR Lead Commissioner Workshop on Near-Zero Carbon Electricity, p. 31, https://gcc01.safelinks.protection.outlook.com/?url=https%3A%2F%2Fefiling.energy.ca.gov%2FGetDocument.aspx%3Ftn%3D230529%26DocumentContentId%3D62099&data=01%7C01%7C%7Ca5a959d59e7743960a3208d763ce2326%7Cac3a124413f44ef68d1bbaa27148194e%7C0&sdata=veAVcyBq05aqBtCd37GO%2FR2uvwGQTD2PPV7rIa5xm1E%3D&reserved=0.

44 IPCC, *Special Report Global Warming of 1.5ºC*, https://www.ipcc.ch/sr15/.

45 See Executive Order B-55-18.

E3's 2018 study *Deep Decarbonization in a High Renewables Future* analyzed a reference scenario, SB 350 scenario, and 10 mitigation scenarios to assess GHG emissions reductions required to meet the state's 2030 and 2050 goals.[46] As shown in Figure 10, the E3 study found that all the mitigation scenarios, including the high-electrification scenario, meet the state's GHG emissions reduction goals.[47] The study focuses on the high-electrification scenario, which E3 found to be relatively lower cost and lower risk compared to other mitigation scenarios.[48] This scenario uses a combination of existing technologies and includes high levels of energy efficiency and conservation, renewable electricity, and electrification of buildings and transportation.[49]

Figure 10: California GHG Emissions by Scenario



Source: E3, 2019

When summarizing this study at the workshop, Dr. Subin stated that "electrification is the lynchpin for decarbonizing the energy system."[50] As shown in Figure 11, the E3 study indicates

46 Energy+ Environment Economics (E3), *Deep Decarbonization in a High Renewables Future*, June 2018, pp. 28-29 https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf.

47 Ibid.

48 Ibid., p.2.

49 Ibid., pp. 2-3.

50 Transcript of September 24, 2019, IEPR Lead Commissioner Workshop on Near-Zero Carbon Electricity, p. 48, https://gcc01.safelinks.protection.outlook.com/?url=https%3A%2F%2Ffiling.energy.ca.gov%2FGetDocument.as

that in 2050, under the high-electrification scenario, emissions from buildings and light-duty vehicles are nearly eliminated.[51] Dr. Subin explained that this near elimination is accomplished by reaching 100 percent sales of electric building appliances and electric light-duty vehicles by about 2035 to 2040.[52] He also noted that "this leaves room for emission reductions in the most challenging sectors, such as industry, off-road transportation, waste, and agriculture."[53] According to the E3 study, biofuels should be targeted toward high-value uses that are difficult to electrify or substitute, supplemented by electrolytic fuels or carbon capture and sequestration or both (for example, aviation, trucking, industrial heating, and backup thermal electricity generation).[54]

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px%3Ftn%3D230529%26DocumentContentId%3D62099&data=01%7C01%7C%7Ca5a959d59e7743960a3208d763ce2326%7Cac3a124413f44ef68d1bbaa27148194e%7C0&sdata=veAVcyBq05aqBtCd37GO%2FR2uvwGQTD2PPV7rIa5xm1E%3D&reserved=0.

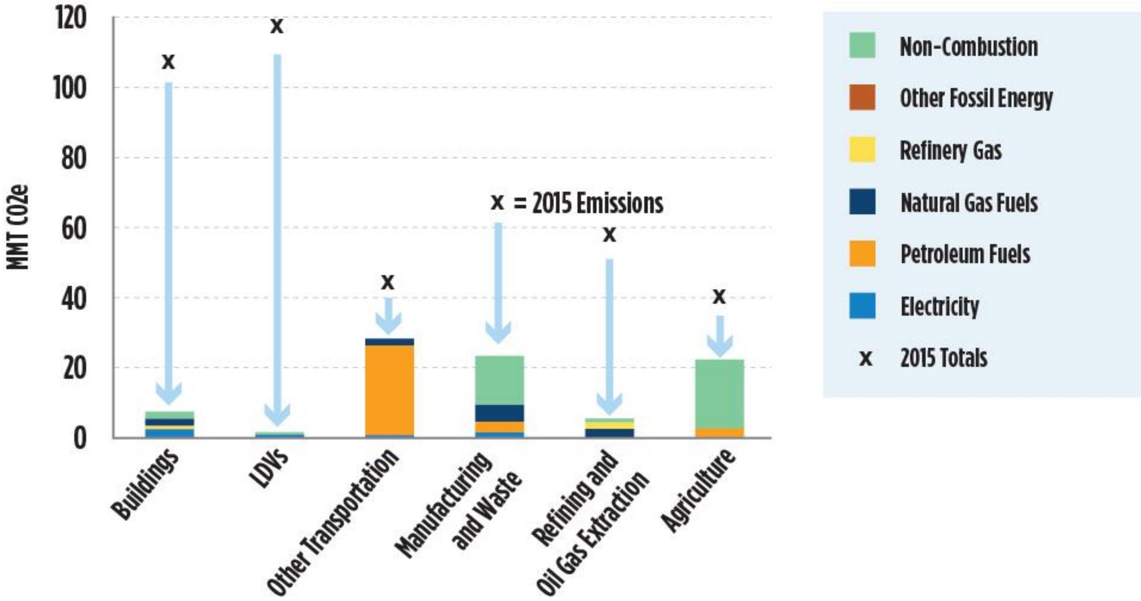
51 E3 Presentation for September 24, 2019, IEPR Lead Commissioner Workshop on Near-Zero Carbon Electricity, The Role of Electricity in Decarbonizing CA's Energy System, p.5, https://efiling.energy.ca.gov/GetDocument.aspx?tn=229820&DocumentContentId=61266.

52 Transcript of September 24, 2019, IEPR Lead Commissioner Workshop on Near-Zero Carbon Electricity, p. 45, https://gcc01.safelinks.protection.outlook.com/?url=https%3A%2F%2Fefiling.energy.ca.gov%2FGetDocument.aspx%3Ftn%3D230529%26DocumentContentId%3D62099&data=01%7C01%7C%7Ca5a959d59e7743960a3208d763ce2326%7Cac3a124413f44ef68d1bbaa27148194e%7C0&sdata=veAVcyBq05aqBtCd37GO%2FR2uvwGQTD2PPV7rIa5xm1E%3D&reserved=0. The E3 study did not evaluate scenarios to achieve carbon neutrality by 2045, which will require accelerating these measures further or identifying additional measures.

53 E3 Presentation for September 24, 2019, IEPR Lead Commissioner Workshop on Near-Zero Carbon Electricity, The Role of Electricity in Decarbonizing CA's Energy System, p.5, https://efiling.energy.ca.gov/GetDocument.aspx?tn=229820&DocumentContentId=61266.

54 Ibid., p. 11.

Figure 11: California 2050 GHGs High Electrification Scenario (86 MMT CO_2e)



Source: E3, 2019

E3's high electrification scenario relies on current strategies to decarbonize electricity (for example, wind, solar, flexible loads, and storage).[55] However, Dr. Subin explained that simply scaling up these strategies would not, by themselves, ensure the state fully achieves zero-emission electricity by 2050.[56] In fact, the E3 study found that only 90 to 95 percent decarbonized electricity is achievable by scaling up current approaches.[57]

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55 Ibid., p. 11.

56 Transcript of September 24, 2019, IEPR Lead Commissioner Workshop on Near-Zero Carbon Electricity, p. 48, https://gcc01.safelinks.protection.outlook.com/?url=https%3A%2F%2Fefiling.energy.ca.gov%2FGetDocument.aspx%3Ftn%3D230529%26DocumentContentId%3D62099&data=01%7C01%7C%7Ca5a959d59e7743960a3208d763ce2326%7Cac3a124413f44ef68d1bbaa27148194e%7C0&sdata=veAVcyBq05aqBtCd37GO%2FR2uvwGQTD2PPV7rIa5xm1E%3D&reserved=0.

57 E3 Presentation for September 24, 2019, IEPR Lead Commissioner Workshop on Near-Zero Carbon Electricity, The Role of Electricity in Decarbonizing CA's Energy System, p.5, https://efiling.energy.ca.gov/GetDocument.aspx?tn=229820&DocumentContentId=61266.

According to E3, completely decarbonizing electricity will require an additional option to provide firm capacity and long-duration energy storage.[58] Dr. Subin noted, "that could be one of any number of options, including using biomethane or hydrogen in gas turbines, it could be nuclear or CCS, or it could be advanced duration … multiday storage."[59] The E3 study concluded that until any of these additional options are available, maintaining sufficient firm capacity is critical.[60] Dr. Subin stated that this likely means "keeping most of the existing gas generation fleet around in California."[61] Lastly, the E3 study notes that because electrification is consumer-facing, California must prioritize affordable, reliable electricity. SCE filed comments on the *Draft 2019 IEPR* and noted that its 2045 Pathway analysis "estimates that a small number of gas generators will still be necessary in the future" to meet the state's decarbonization goals.[62]

The workshop also delved into EFI's 2019 study Optionality, Flexibility, and Innovation, Pathways for Deep Decarbonization.[63] The EFI study uses a portfolio approach to present a wide range of options to achieve deep decarbonization in California. In particular, the study identifies GHG emissions reduction potential and sector-specific pathways for meeting the state's 2030 and 2050 targets.

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58 Ibid.

59 Transcript of September 24, 2019, IEPR Lead Commissioner Workshop on Near-Zero Carbon Electricity, p. 49, https://gcc01.safelinks.protection.outlook.com/?url=https%3A%2F%2Fefiling.energy.ca.gov%2FGetDocument.aspx%3Ftn%3D230529%26DocumentContentId%3D62099&data=01%7C01%7C%7Ca5a959d59e7743960a3208d763ce2326%7Cac3a124413f44ef68d1bbaa27148194e%7C0&sdata=veAVcyBq05aqBtCd37GO%2FR2uvwGQTD2PPV7rIa5xm1E%3D&reserved=0.

60 E3 Presentation for September 24, 2019, IEPR Lead Commissioner Workshop on Near-Zero Carbon Electricity, The Role of Electricity in Decarbonizing CA's Energy System, p.5, https://efiling.energy.ca.gov/GetDocument.aspx?tn=229820&DocumentContentId=61266.

61 Transcript of September 24, 2019, IEPR Lead Commissioner Workshop on Near-Zero Carbon Electricity, p. 49, https://gcc01.safelinks.protection.outlook.com/?url=https%3A%2F%2Fefiling.energy.ca.gov%2FGetDocument.aspx%3Ftn%3D230529%26DocumentContentId%3D62099&data=01%7C01%7C%7Ca5a959d59e7743960a3208d763ce2326%7Cac3a124413f44ef68d1bbaa27148194e%7C0&sdata=veAVcyBq05aqBtCd37GO%2FR2uvwGQTD2PPV7rIa5xm1E%3D&reserved=0.

62 Southern California Edison Company Comments on draft 2019 IEPR, p. 2, https://efiling.energy.ca.gov/GetDocument.aspx?tn=230898&DocumentContentId=62533.

63 Energy Futures Initiative (EFI), May 2019, *Optionality, Flexibility, and Innovation, Pathways for Deep Decarbonization in California*, https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5ced6fc515fcc0b190b60cd2/1559064542876/EFI_CA_Decarbonization_Full.pdf.

The EFI and E3 studies use different inputs. Melanie Kenderdine, the project director of the report, explained that EFI used a 2016 baseline for GHG emissions reductions rather than the California 1990 baseline to account for changes in the technology space since 1990.[64] Ms. Kenderdine also noted that although total GHG emissions in 2016 are almost the same as in 1990, the emissions within each sector differ.[65]

The EFI study examines emissions reductions of 40 percent below 2016 levels by 2030 and 80 percent below 2016 levels by 2050 on a per sector basis (assuming each sector must reduce by 40 percent and 80 percent below 2016 emission levels). Figure 12 shows EFI's approach for determining emissions reductions needed to meet the economywide targets by sector.[66] According to EFI, in the electricity sector alone, 55 MMT CO_2e reductions are needed to meet the 2050 target.[67]

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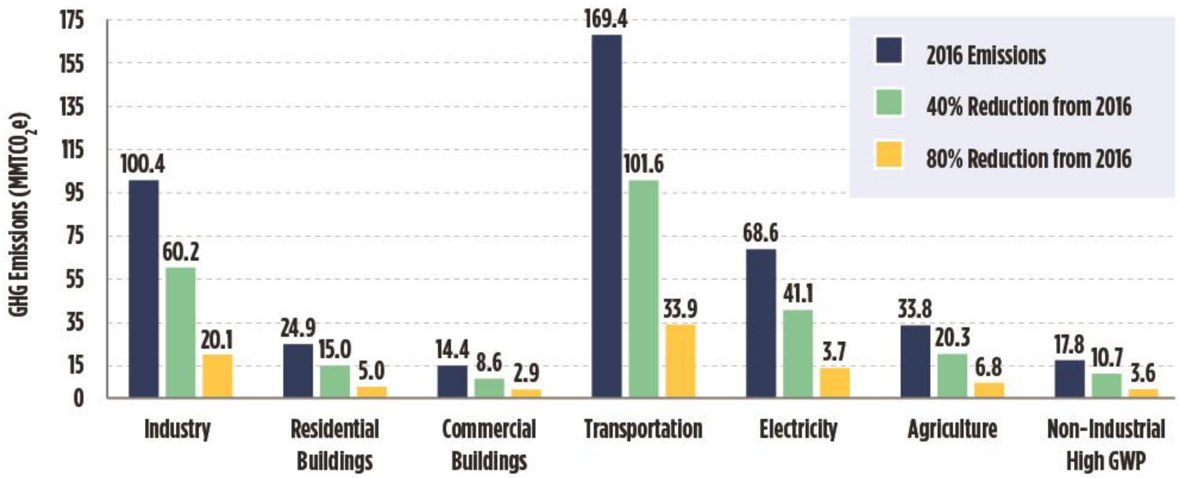
64 Transcript of September 24, 2019, IEPR Lead Commissioner Workshop on Near-Zero Carbon Electricity, p. 74, https://gcc01.safelinks.protection.outlook.com/?url=https%3A%2F%2Fefiling.energy.ca.gov%2FGetDocument.aspx%3Ftn%3D230529%26DocumentContentId%3D62099&data=01%7C01%7C%7Ca5a959d59e7743960a3208d763ce2326%7Cac3a124413f44ef68d1bbaa27148194e%7C0&sdata=veAVcyBq05aqBtCd37GO%2FR2uvwGQTD2PPV7rIa5xm1E%3D&reserved=0.

65 Ibid.

66 EFI, May 2019, *Optionality, Flexibility, and Innovation, Pathways for Deep Decarbonization in California*, https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5ced6fc515fcc0b190b60cd2/1559064542876/EFI_CA_Decarbonization_Full.pdf.

67 Transcript of September 24, 2019, IEPR Lead Commissioner Workshop on Near-Zero Carbon Electricity, p. 78, https://gcc01.safelinks.protection.outlook.com/?url=https%3A%2F%2Fefiling.energy.ca.gov%2FGetDocument.aspx%3Ftn%3D230529%26DocumentContentId%3D62099&data=01%7C01%7C%7Ca5a959d59e7743960a3208d763ce2326%7Cac3a124413f44ef68d1bbaa27148194e%7C0&sdata=veAVcyBq05aqBtCd37GO%2FR2uvwGQTD2PPV7rIa5xm1E%3D&reserved=0.

Figure 12: Study Approach: 2030 and 2050 Emission Reduction Targets by Sector From 2016 Baseline (MMT CO_2e)



Source: Energy Futures Initiative, 2019. Compiled using data from CARB, 2018.

The EFI study also looked at the different types of technologies needed to achieve the GHG emissions reductions for each sector. Figure 13 shows estimated emissions reduction potential for each pathway by sector based on an attempt to meet the state's target of 40 percent emissions reduction from the 1990 (or 2016 as assessed by EFI) levels by 2030.[68] EFI's scenarios envision that in the electricity sector, the largest emissions reduction by 2030 comes from fossil natural gas combined-cycle with carbon sequestration (NGCC).[69] The EFI study

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68 EFI, May 2019, *Optionality, Flexibility, and Innovation, Pathways for Deep Decarbonization in California*, https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5ced6fc515fcc0b190b60cd2/1559064542876/EFI_CA_Decarbonization_Full.pdf.

69 Ibid.

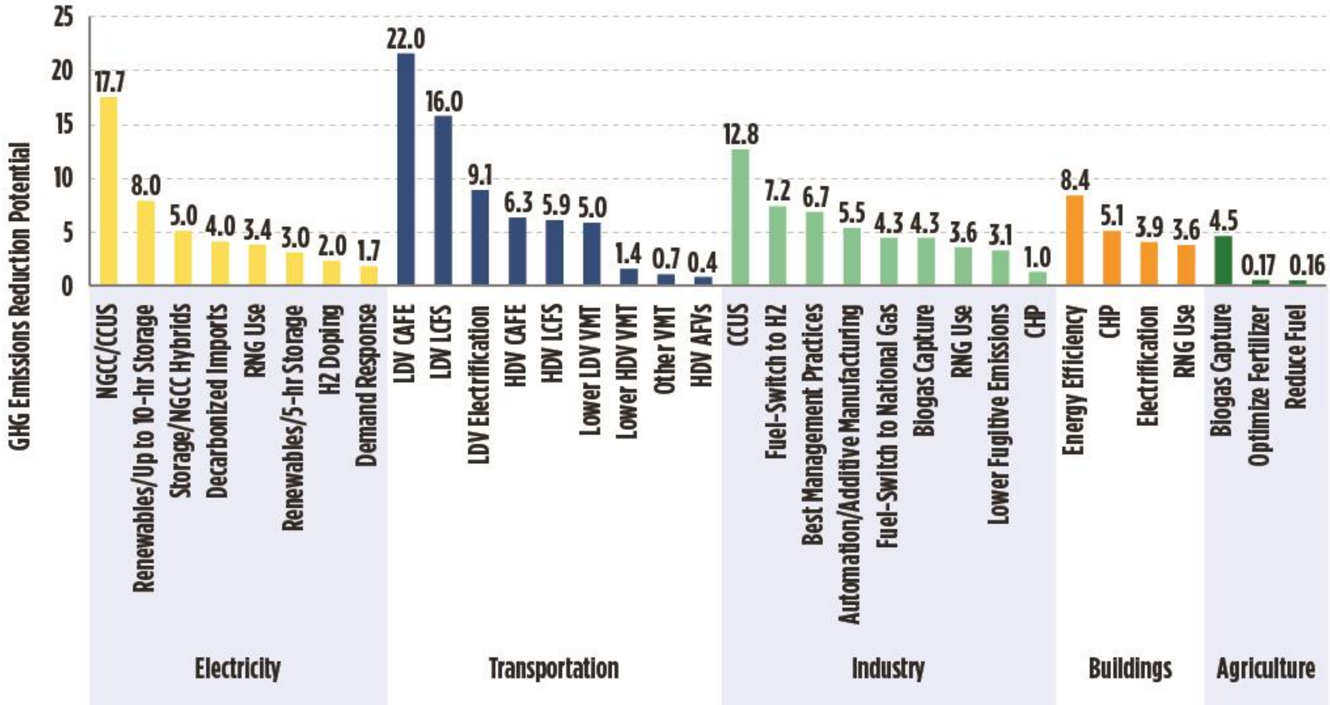
Transcript of September 24, 2019, IEPR Lead Commissioner Workshop on Near-Zero Carbon Electricity, p. 82, https://gcc01.safelinks.protection.outlook.com/?url=https%3A%2F%2Fefiling.energy.ca.gov%2FGetDocument.aspx%3Ftn%3D230529%26DocumentContentId%3D62099&data=01%7C01%7C%7Ca5a959d59e7743960a3208d763ce2326%7Cac3a124413f44ef68d1bbaa27148194e%7C0&sdata=veAVcyBq05aqBtCd37GO%2FR2uvwGQTD2PPV7rIa5xm1E%3D&reserved=0.

indicates that the state could achieve 17.7 MMT in reductions from NGCC (nearly 50 percent of in-state generation comes from fossil natural gas-powered plants), and about 8 MMT could come from renewables with up to 10 hours of energy storage.[70] These two top pathways, Ms. Kenderdine explained, could help achieve the reductions in the electricity sector that EFI found are needed by 2030.[71]

70 Energy Futures Initiative (EFI), May 2019, *Optionality, Flexibility, and Innovation, Pathways for Deep Decarbonization in California*, https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5ced6fc515fcc0b190b60cd2/1559064542876/EFI_CA_Decarbonization_Full.pdf.

71 Transcript of September 24, 2019, IEPR Lead Commissioner Workshop on Near-Zero Carbon Electricity, p. 82, https://gcc01.safelinks.protection.outlook.com/?url=https%3A%2F%2Fefiling.energy.ca.gov%2FGetDocument.aspx%3Ftn%3D230529%26DocumentContentId%3D62099&data=01%7C01%7C%7Ca5a959d59e7743960a3208d763ce2326%7Cac3a124413f44ef68d1bbaa27148194e%7C0&sdata=veAVcyBq05aqBtCd37GO%2FR2uvwGQTD2PPV7rIa5xm1E%3D&reserved=0. The E3 study did not evaluate scenarios to achieve carbon neutrality by 2045, which will require accelerating these measures further or identifying additional measures.

Figure 13: Identified Emissions Reduction Potential of Sector-Specific Pathways for Meeting the 2030 Targets



Source: Energy Futures Initiative

However, EFI does not believe that storage for 10 days stretches with no wind will be available by 2030.[72] At the workshop, Ms. Kenderdine explained that fossil natural gas fuel is needed to run the system reliably with a lot of wind and solar on the electric system.[73] Further, she noted that hydrogen made from renewables could substitute fossil natural gas and serve as the fuel needed to run the system.[74] Yet it is unclear the extent to which existing infrastructure can be used for hydrogen in time to meet the 2030 and 2050 targets. Ms. Kenderdine recommended that hydrogen be the focus of innovation in the 2050 time frame.[75]

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72 Ibid., pp. 79, 85.

73 Ibid., p. 86.

74 Ibid.

75 Ibid., p. 110.

The EFI and E3 scenarios and pathways provide useful data points for decision makers to consider as the state transitions to a 100 percent clean energy standard and works toward a carbon-neutral economy. No matter which strategies are selected to achieve the 2030 and 2050 GHG emissions reduction goals, there are some practical considerations for policy makers to keep in mind (for example, the multiple days in a row of low or no wind and solar to meet demand).

At the September 24 workshop, Ms. Debra Lew, an energy consultant to the Western Interconnection Regional Advisory Body, illuminated some of these considerations. She stated that "100 percent clean energy is possible with today's technology … but it might be very expensive," if not implemented in a smart way with costs in mind.[76] Ms. Lew highlighted three challenges to grid reliability as the amount of intermittent resources increases: system stability, system balancing, and resource adequacy. Concerning system balancing, she noted the importance of controlling both sides of the supply/demand balance and suggested that this may be addressed with controllable or price-sensitive signals on both sides of the supply-and-demand balance.[77] For instance, Ms. Lew explained, time-of-use rates could replace the need for a four-hour battery, and coincident peak demand charges could replace the need for more system peakers.[78]

However, Ms. Lew noted that time-of-use prices alone are not enough to balance supply and demand; chasing time-of-use rates can make system balancing worse by causing large step changes.[79] She suggested that dispatching demand can smooth this problem and noted that we must start thinking of demand response, not as a generator, but more as demand that is price elastic.[80] This would mean that demand would be determined by who is willing to pay at a moment in time.[81] Ms. Lew explained that as California electrifies inherently flexible sectors, such as transportation and building heating, such significant new price-elastic demand will cause the loss-of-load concept to lose relevance (hours or days for which generation is insufficient to meet demand).[82] In response to CEC Commissioner Andrew McAllister's

76 Ibid., p. 61.

77 Ibid., p. 63.

78 Ibid.

79 Ibid., p. 64.

80 Ibid., p. 65.

81 Ibid., p. 66.

82 Ibid.

questions on how and who can implement price-responsive load shaping, Ms. Lew explained, “we must expose more loads to more price volatility.”[83] One way would be to develop more plug-and-play infrastructure through codes and standards such that aggregators can use control standardized, scalable protocols to communicate with and aggregate loads, including electric water heaters and other appliances.[84]

Regarding system stability, Ms. Lew discussed the challenge caused by high penetration of inverter-based resources (such as solar and wind) in the electric system.[85] Inverters read the system voltage and frequency and respond by continuously modulating current appropriately.[86] That is, all inverters on the grid are grid-following, and they require normal system operating conditions to operate reliably and stably.[87] Ms. Lew explained that for the system to work properly, grid-following inverters cannot control 100 percent of the electricity flowing within; there would be no independent reference signal.[88] To help address this challenge, Ms. Lew noted, states must begin exploring options available, including fine-tuning and coordinating controller settings, installing synchronous condensers to provide grid inertia, building more transmission to alleviate weak grid issues, and developing or requiring grid-forming invertor technologies.[89]

83 Ibid., pp. 101-102.

84 Ibid., p. 103.

85 Ibid., pp. 66-67.

86 Debra Lew Presentation for September 24, 2019, IEPR Lead Commissioner Workshop on Near-Zero Carbon Electricity, Maintaining Reliability in a Near-Zero carbon Grid, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-07.

87 Ibid.

88 Transcript of September 24, 2019, IEPR Lead Commissioner Workshop on Near-Zero Carbon Electricity, p. 67, https://gcc01.safelinks.protection.outlook.com/?url=https%3A%2F%2Fefiling.energy.ca.gov%2FGetDocument.aspx%3Ftn%3D230529%26DocumentContentId%3D62099&data=01%7C01%7C%7Ca5a959d59e7743960a3208d763ce2326%7Cac3a124413f44ef68d1bbaa27148194e%7C0&sdata=veAVcyBq05aqBtCd37GO%2FR2uvwGQTD2PPV7rIa5xm1E%3D&reserved=0.

89 Ibid., pp. 69-69

Debra Lew Presentation for September 24, 2019, IEPR Lead Commissioner Workshop on Near-Zero Carbon Electricity, Maintaining Reliability in a Near-Zero carbon Grid, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-07.

Changes Related to Load-Serving Entities

Adding to the complexity of planning for and implementing the changes needed in California's electricity system are shifts and uncertainty in the business models for load-serving entities. Traditionally, load-serving entities have been the primary mechanism for implementing state energy policies.

IOU Financial Uncertainty and Fire Liability

Facing up to $30 billion in liability associated with the deadly fires in the northern portions of the state in the last few years, Pacific Gas and Electric Company (PG&E) filed voluntary petitions under Chapter 11 of the U.S. Bankruptcy Code on January 29, 2019. PG&E was able to secure financing to ensure that during the bankruptcy process, it would be able to deliver safe and reliable electricity and fossil natural gas to its customers. The bankruptcy court provided PG&E with the authority to continue existing customer programs, including energy efficiency and other programs that support adoption of clean energy. In response to the Chapter 11 filing, Governor Gavin Newsom issued the following statement:

> "PG&E today filed for reorganization in federal bankruptcy court. That was PG&E's choice, but it does not change my focus, which remains protecting the best interests of the people of California. My administration will continue working to ensure that Californians have access to safe, reliable, and affordable service, that victims and employees are treated fairly, and that California continues to make forward progress on our climate change goals."[90]

In June 2019, the judge overseeing the bankruptcy proceeding ruled that the bankruptcy court, not the Federal Energy Regulatory Commission (FERC), has final jurisdiction over whether the utility can cancel and amend up to $42 billion in power purchase agreements, including for renewable projects to meet the state RPS requirements. This ruling raises concerns over what action the court will ultimately take on the RPS contracts and how that might affect the state's progress in meeting RPS goals and reducing GHG emissions.

Fires in Southern California similarly pose large potential liability for Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E). In response to the PG&E bankruptcy filing, the credit of all utilities was downgraded. However, financial conditions have improved somewhat

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90 Governor Newsom statement on PG&E bankruptcy filing https://www.gov.ca.gov/2019/01/29/pge-bankruptcy-filing/.

with the IOUs showing profits during the second quarter of last year.[91] Energy companies credited Governor Newsom and state lawmakers with creating a new wildfire liability insurance fund for utilities earlier this summer, saying it will ease the risk of fires that undermine their financial stability.[92]

In response to instability in the energy sector and PG&E's decision to file for bankruptcy, Governor Newsom created a strike force in February 2019 to coordinate the state's efforts relating to the safety, reliability, and affordability of energy and achieving the state's climate commitments.[93] In October 2019, widespread public safety power shutoffs in response to wildfire risk further amplified the need to address fire risks. (For more information, see Chapter 5 on Climate Adaptation.) Millions of Californians lost power for days at a time. Governor Newsom stated, "Far too many households and businesses were without power for seven days straight. This cannot—and will not—be the new normal."[94] Reducing the use of public safety power shutoffs will be a priority in long-term planning efforts.

Emergence of Community Choice Aggregators and the Evolving Role of IOUs

The movement toward community choice aggregators, along with growth in customer-installed resources (primarily rooftop solar PV), has transformed what was once a vertically integrated industry to one in which responsibility for resource procurement and resource adequacy is fragmented among a diverse set of entities. Community choice aggregators are formed by local jurisdictions or through joint powers authorities to purchase power for their customers. Their governing bodies are composed mostly of city and county officials representing districts within the community choice aggregator and have staffs that are usually separate from municipality or county staff.

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91 For example on July 31, 2019, Moody's Investor Services upgraded SDG&E from a negative outlook to a positive outlook based on improved fire safety programs and AB 1054 establishing a new utility wildfire insurance fund. SDG&E media statement on Moody's upgrading SDG&E's financial outlook https://sdgenews.com/article/sdge-media-statement-moodys-upgrading-sdges-financial-outlook.

92 *California Current*, August 5, 2019.

93 Governor Newsom's Strike Force. *Wildfires and Climate Change: California's Energy Future*. April 12, 2019. *Wildfires and Climate Change: California's Energy Future* report https://www.gov.ca.gov/wp-content/uploads/2019/04/Wildfires-and-Climate-Change-California's-Energy-Future.pdf.

94 Governor Newsom Outlines State Efforts to Fight Wildefires, Protect Vulnerable Californians and Ensure that Going Forward, All Californians have Save, Affordable, Reliable and Clean Power, November 1, 2019, https://www.gov.ca.gov/2019/11/01/governor-newsom-outlines-state-efforts-to-fight-wildfires-protect-vulnerable-californians-and-ensure-that-going-forward-all-californians-have-safe-affordable-reliable-and-clean-power/.

When a community choice aggregator is established, IOU customers in the service area are automatically enrolled in the community choice aggregator and must opt out of the community choice aggregator if they choose to remain with the IOU. The community choice aggregator is responsible for procuring power, while the IOU is responsible for distribution, metering, billing and collection, and customer service. In 2019, community choice aggregators are expected to account for more than 20 percent of total load in the IOUs' service territories and are expected to grow over the next few years.[95] In fact, 26 local jurisdictions have filed statements of intent or implementation plans or both with the CPUC to establish a community choice aggregator.

The rapid emergence of community choice aggregators over the last few years prompted the CPUC to undertake a comprehensive assessment of the impacts of community choice aggregators and increased customer choice. In particular, the CPUC assessed how this trend affects California's ability to achieve policy objectives related to affordability, decarbonization, and reliability. Community choice aggregators are an exciting new model that brings benefits to customers in different ways than IOUs.[96] Addressing global warming requires action from myriad players, and it is important that all power providers are working together collaboratively and strategically to ensure the state meets its climate-related goals.

Recommendations

The *2017 IEPR* and the *2018 IEPR Update* focused extensively on the challenges and opportunities associated with increasing the flexibility and resilience of the electricity system. These *IEPRs* included a wide range of recommendations to meet these challenges while also maintaining a reliable, sustainable electricity sector that will support continuing decarbonization of the transportation and building sectors. Recommendations included improvements needed in rate design, forecasting, demand response, energy storage,

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95 Final data for 2019 are not available until the end of the first quarter of 2020. As of November 2019, community choice aggregators are expected to account for 36 percent of load in Pacific Gas and Electric's (PG&E's) transmission access charge area and roughly 52 percent of load in the PG&E service territory. See PG&E's November 27, 2019, Comments on the Draft 2019 Integrated Energy Policy Report, https://www.energy.ca.gov/2019_energypolicy/documents/draft_2019_report_comments.php. Community choice aggregators in 2019 account for12.4 percent for Southern California Edison (SCE). San Diego Gas & Electric (SDG&E) has less than 1 percent of load met by community choice aggregators. However, the City of San Diego developed a business plan for forming a community choice aggregator that would encompass 30 percent of SDG&E's load and could begin service in 2021.

96 Information about community choice aggregation on the California Community Choice Association website https://cal-cca.org/cca-impact/.

expansion of western electricity markets and regional coordination, and research and development for transportation electrification, smart inverters, and electric vehicle chargers.

While progress has been made in many of these areas, California must continue developing the tools needed to ensure a reliable grid as load is added and the state brings more variable renewable resources on-line. The following are recommendations to further advance California's electric system:

- **Develop a plan that identifies the appropriate amount and mix of resources and technologies to ensure reliability in the near term to midterm while promoting the longer-term transition to a zero-carbon electricity system called for in Senate Bill 100.** The California Energy Commission (CEC) should continue to work with the California Public Utilities Commission (CPUC), the California Air Resources Board, and the California Independent System Operator (California ISO) to develop an orderly plan for using new clean technologies to ensure a reliable zero-carbon grid in 2045. The plan for the near term to midterm should account for plant retirements; identify critical, strategically located gas generation needed for reliability where deferring retirements may be appropriate; and ensure that new and emerging technologies are employed to fill the role of these plants. This plan will allow for the retirement of fossil natural gas generation and provide a reliable and resilient grid in the long term.
- **Continue to support research to improve forecasting of load and renewable generation.** The CEC should continue to support research that improves forecasting capabilities that allow grid operators to predict more accurately the amount of generation that will be needed to meet the net load and support more frequent bidding of solar generators into short-term markets.
- **Accelerate research, development, and use of smart inverters.** The CEC, CPUC, and the California ISO should accelerate research, development, and launch of smart inverters with advanced capabilities for inverter-based resources to enhance power quality, decrease grid disturbances, and participate in ancillary service markets.[97]

97 "Ancillary services" refer to the functions that help grid operators maintain a reliable electricity system. Ancillary service maintain the proper flow and direction of electricity, address imbalances between supply and demand, and help the system recover after a power system event.

CHAPTER 2: Building Decarbonization and Energy Efficiency

Introduction

Expanding on California's decades-long leadership on climate change, the state is working to double the energy efficiency of, and decrease the greenhouse gas (GHG) emissions from, existing buildings. The transformation of buildings from carbon emitters to a clean distributed energy resource will require support of stakeholders, regular and sustained state guidance, creative incentive programs, market transformation, and new technologies. This approach includes clean energy resources, electrification, increased energy efficiency, and demand flexibility. It will also require the balance of other state goals and challenges, such as increasing energy equity, reducing costs, and managing increased levels of energy demand with clean electricity sources.

In 2019, the California Energy Commission (CEC) developed the *California 2019 Energy Efficiency Action Plan* (2019 Action Plan) that will serve as the state's policy map for improving, increasing, and targeting energy efficiency. The CEC adopted the 2019 Action Plan[98] on December 11, 2019. The 2019 Action Plan is built around three goals:

- Achieving a doubling of energy efficiency savings by 2030
- Reducing the barriers to energy efficiency in low-income, disadvantaged, and rural communities, as well as developing metrics to track progress for these communities
- Reducing GHG emissions from the built environment

The CEC gathered public input on the 2019 Action Plan through five workshops from April to May 2019.[99] The proposed 2019 Action Plan includes background and recommendations on energy programs and efficiency targets. It also addresses financing mechanisms, resiliency,

98 Kenney, Michael, Heather Bird, and Heriberto Rosales. 2019. *2019 California Energy Efficiency Action Plan*. California Energy Commission. Publication Number: CEC-400-2019-010-SF. https://www.energy.ca.gov/business_meetings/2019_packets/2019-12-11/Item_06_2019%20California%20Energy%20Efficiency%20Action%20Plan%20(19-IEPR-06).pdf.

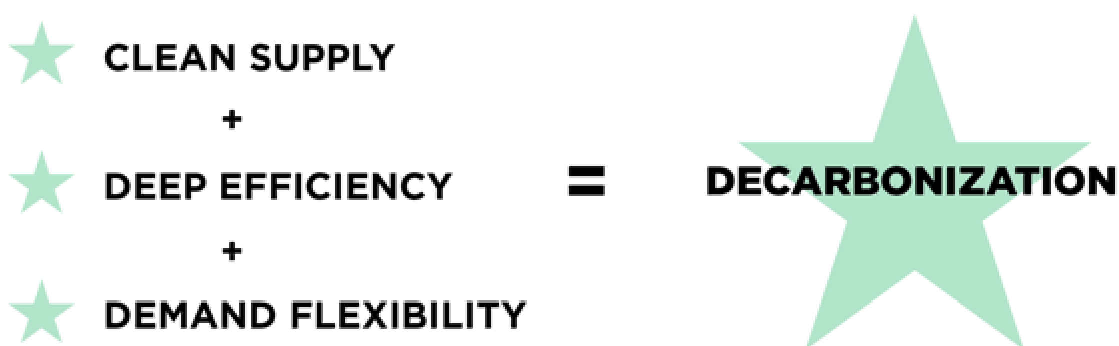
99 The CEC held workshops in San Francisco, Redding, Fresno, Los Angeles, and San Diego. Link to information on workshops under the 2019 IEPR proceeding on the CEC's website https://www.energy.ca.gov/2019_energypolicy/documents/.

multifamily building energy efficiency, building decarbonization, industrial and agricultural energy efficiency, use of energy data to better design and target efficiency, demand response measures, and barriers and opportunities to expand low-income and rural residents' access to energy efficiency and renewable energy.

The CEC's Energy Research and Development Division is assessing pathways to decarbonizing the energy system. The division funded a study by E3 to evaluate deep decarbonization scenarios in California for the 2030 and 2050 time frames.[100] All scenarios for meeting California's decarbonization targets show reduced natural gas demand at the distribution level, negative impacts on gas system reliability as throughputs decline, and increased gas rates for remaining customers.

Another recent study by Gridworks urges the state to develop a gas system transition plan that will "minimize and stabilize" rate increases.[101] Three key, complementary elements are required for the long-term achievement of California's emissions reduction goals (Figure 14): clean energy supply resources (Chapters 1 and 9), energy efficiency improvements in buildings and appliances (gas and electric), and flexibility in electric demand.

Figure 14: Achieving Optimal Decarbonization



Source: CEC

100 Energy and Environmental Economics (E3) produced the study, *Deep Decarbonization in a High Renewables Future* https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf.

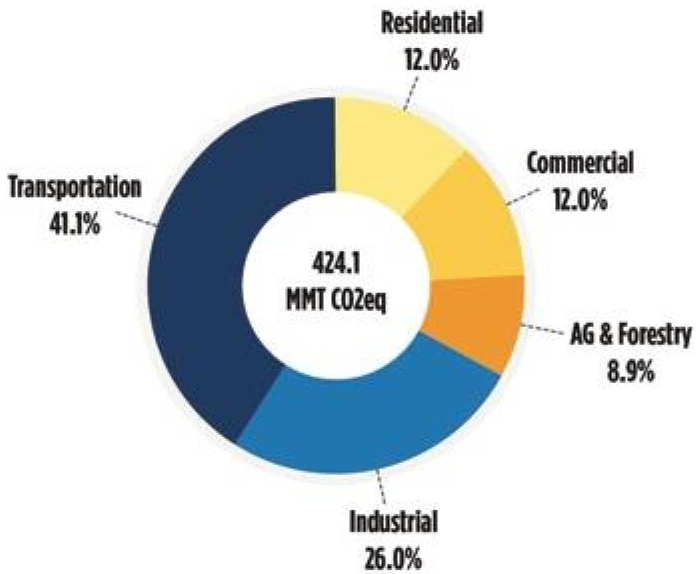
101 Gridworks. *California's Gas System in Transition*, https://gridworks.org/wp-content/uploads/2019/09/CA_Gas_System_in_Transition.pdf.

Decreasing the State's Reliance on Fossil Fuels in Buildings

California's existing buildings (represented by residential and commercial sectors in Figure 15) account for nearly a quarter of the state's GHG emissions. This portion of emissions includes emissions from fossil fuel consumed onsite (gas or propane for heating) and those embedded in electricity use (lighting, appliances, and cooling).

The 2009 Residential Appliance Saturation Survey (RASS) estimated 93 percent of natural gas combusted in statewide households results from these three uses: water heating at 49 percent, space heating at 37 percent, and cooking at 7 percent.[102]

Figure 15: 2017 GHG Emissions by Sector (Percentage of Carbon Dioxide Equivalent)



Source: CEC using data from CARB 2019 GHG Inventory and the adopted 2019 IEPR Electricity Forecast. Emissions estimate extracted from *2018 IEPR Update*, Chapter 1, Figure 1, p. 27.

In 2009, natural gas provided onsite heating for 90 percent of the state's buildings. The remaining 10 percent of buildings had heat provided primarily by propane gas.[103] Figure 16

102 CEC. *2009 California Residential Appliance Saturation Survey (RASS)*. Figure ES-6: Statewide Natural Gas Energy Consumption, 354 therms per household. The CEC RASS is conducting a 2019 RASS with results expected in March 2020. https://www.energy.ca.gov/appliances/rass/.

103 CEC. 2009. *California Residential Appliance Saturation Survey* (RASS). 2010. Table ES-4: Saturation by Dwelling Type. https://www.energy.ca.gov/appliances/rass/.

shows the percentage of GHG fuels consumed in residential and commercial settings. Natural gas is the main source of direct GHG emissions from residential and commercial building sectors at 78 and 50 percent, respectively. GHG emissions from gas space and water heating include carbon dioxide and escaped methane through combustion.

Electrification of heating end uses in California's buildings significantly reduces overall carbon dioxide emissions but does come with a potential concern: leakage of the high global warming potential (GWP) refrigerant gases used in heat pump systems. Since the 1989 passage of the Montreal Protocol on Substances That Deplete the Ozone Layer,[104] which phased out chlorofluorocarbons, hydrofluorocarbons (HFCs) have emerged as a popular refrigerant for space-conditioning systems in buildings. According to CARB, HFCs are among the most potent climate pollutants, and their deployment is growing rapidly. As electric heat pumps using HFCs substitute for conventional thermal heating equipment, the stock of HFCs in buildings will continue to grow. Management of those HFCs—leakage prevention, capture and recycling—is important to minimize GHG emissions going forward, as is the continued development and deployment of alternative refrigerants with low GWP.

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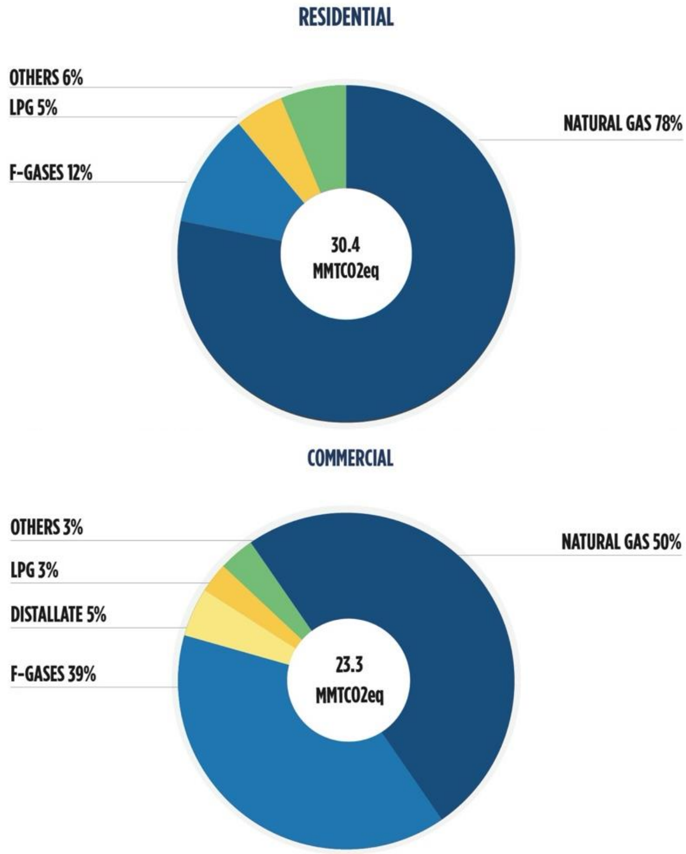
104 The Montreal Protocol on Substances That Deplete the Ozone Layer, https://ozone.unep.org/treaties/montreal-protocol.

Figure 16: 2017 Direct GHG Emissions From the Residential and Commercial Sectors



Source: CEC staff using data from the California Air Resources Board (CARB) Note: Fluorinated gases, or *F-gases*, are man-made gases that have some of the highest global warming potential values. There are four types: hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), and nitrogen trifluoride (NF_3). *LPG* represents liquefied petroleum gases.

Recent research estimates[105] that overall methane emissions from leaks and unburned methane in California homes is equivalent to about 0.5 percent of total consumption in the residential sector.[106] Methane released into the atmosphere is 25 times more potent than the

105 CEC. 2018. Natural Gas Methane Emissions from California Homes, CEC-500-2018-021.

106 Fischer, M. L., W. R. Chan, W. Delp, S. Jeoin, V. Rapp, Z Zhu. 2018. "An Estimate of Natural Gas Methane Emissions From California Homes." *Environmental Science & Technology*. 52, 10205-10213.

same quantity of carbon dioxide, making prevention of escaped methane emissions critical to combating climate change.[107] To make sure that methane is captured in reporting, analysis, and solution sets, CARB is including methane leaks from homes in its California GHG inventory.[108]

In addition to methane emissions in homes and businesses, emissions estimates show that most methane emissions occur during source extraction and processing of natural gas. For example, a recent study by the Environmental Defense Fund estimates methane leaks for the natural gas system, nationwide, from well production through distribution, to be 13 million metric tons carbon dioxide equivalents (MMT CO_2e).[109] Since California imports about 90 percent[110] of its natural gas, it is important to quantify the associated out-of-state emissions. In addition to source extraction sites, the natural gas supply chain relies on an extensive distribution pipeline system, throughout which leaks can occur. Overall, the emissions estimates from the delivery system are less than those for source emissions. Recent studies attribute 5 percent of total U.S. pipeline leakage to the western region (which includes California and 11 other states).[111] The rate is comparatively low because the western region has newer or upgraded piping compared to other regions.

Injection of RNG—produced from biomass—into the pipeline can lower net system GHG emissions relative to an all-fossil natural gas supply. Multiple sectors are already competing for the limited supply of RNG, including heavy-duty transportation.[112] Synthetic natural gas, which

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107 The global warming potential (GWP) of methane (CH_4) gas is 21. Methane is much more potent than carbon dioxide (CO_2) gas by comparison. Carbon dioxide is the gas reference for all GHG's and has a GWP score of 1. All GHG's are indexed to CO_2 using a CO_2 equivalent (CO_2e), unless otherwise noted. (*GWP* is a measure of how much heat a GHG traps in the atmosphere.)

108 CARB, "California GHG 2000–2017 Emissions Trends and Indicators Report," https://www.arb.ca.gov/ghg-inventory-data.

109 Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites. 2016. Environmental Defense Fund (EDF). Lyon, David, Alvarez, Ramon, Zavala-Araiza, Daniel, Brandt, Adam, Jackson, Robert and Hamburg, Steven. *Environmental Science & Technology.*

110 CEC. *California Energy Demand 2014-2024 Final Forecast* https://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-SF-V1.pdf.

111 Lamb, Brian K., Steven L. Edburg, Thomas W. Ferrara, Touché Howard, Matthew R. Harrison, Charles E. Kolb, Amy Townsend-Small, Wesley Dyck, Antonio Possolo, and James R. Whetstone. 2015. Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States https://pubs.acs.org/doi/abs/10.1021/es505116p. (See National Emission Inventory section.)

112 2017 IEPR, Chapter 9, https://efiling.energy.ca.gov/getdocument.aspx?tn=223205.

is produced using carbon dioxide and hydrogen from sustainable sources, is another option;[113] production requires a renewable, climate-neutral CO_2 source. Low-cost waste bio-CO_2 is relatively limited; other more expensive sources of climate-neutral CO_2 are needed to produce synthetic natural gas using not-yet-commercial technologies.[114] Clean hydrogen could also be blended with natural gas, within limitations with regard to the amount that could be safely injected into pipelines.[115] All these options should be considered when looking at potential decarbonization of the natural gas system. Regardless of source, methane leakage must be addressed given the associated direct climate impact. Leakage of methane and associated toxic vapors from oil and gas well sites increase GHG emissions and pose public health risks.[116] Fracturing and flaring methane gas results in the release of harmful particulate matter into the atmosphere. CEC research shows that indoor use of natural gas cooking burners elevates risks of carbon dioxide and nitrous oxide emissions, negatively impacting indoor air quality.[117] The study also found that these pollutants can be controlled with an appropriately sized venting range hood or other kitchen exhaust ventilation that meets minimum airflow and configuration specifications. It is unclear what percentage of existing California kitchens with natural gas cooking burners have range hoods or kitchen exhaust ventilation that meet these specifications.

As indicated above, reducing GHG emissions in California buildings will require a combination of clean energy supplies, deep energy efficiency improvements in buildings and appliances, and electric demand flexibility. The use of fossil natural gas in California's buildings presents a challenge. On the one hand, California's transition toward low-emissions systems begins with a status quo of thorough penetration of gas service and end uses across the state's diverse

113 Synthetic natural gas, which is produced using carbon dioxide and hydrogen from sustainable sources is another option but seems to be costly (Mahone et al., 2018, Aas et al., 2019). Clean hydrogen could also be blended with natural gas, but there are limitations with regard to the amount that could be safely injected (Aas et al., 2019). All these options should be considered when looking at potential decarbonization of the natural gas system.

114 CEC, Natural Gas Distribution in California's Low-Carbon Future (October 2019). CEC-500-2019-055-D

115 Ibid.

116 Concerned Health Professionals of NY and Physicians for Social Responsibility. 2019. Compendium of Scientific, Medical, and Media Findings Demonstrating Risks and Harms of Fracking, Physicians for Social Responsibility

117 CEC-500-2017-034: Final Project Report. Emissions, Indoor Air Quality Impacts, and Mitigation of Air Pollutants from Natural Gas Appliances, October 2017, https://www.energy.ca.gov/2017publications/CEC-500-2017-034/CEC-500-2017-034.pdf.

stock of building types and variable climates. On the other hand, and over the long term, the state must wean itself from fossil natural gas wherever feasible. That is, customers across the state must have reliable, affordable access to non-fossil options for their energy needs.

San Diego Gas and Electric (SDG&E) commented, "The CEC must design and implement technology-neutral programs to achieve building decarbonization and customer's needs and preferences must be represented. This 'customer choice' approach will lead to cost-effective programs for building decarbonization. There are other paths to building decarbonization, which include pairing renewable natural gas with more efficient gas end-use devices, and SDG&E encourages the CEC employ a technology-neutral approach when deciding how to reduce emissions in buildings."[118]

Southern California Gas (SoCalGas) suggested, "If the goal is to make significant strides to combat climate change, a multifaceted approach that considers all pathways to lower the carbon intensity of residential and commercial buildings is best, especially if there are more cost-effective and less disruptive ways to achieve the same goal."[119]

During the April 22, 2019, joint agency workshop on Building Decarbonization, SoCalGas further commented, "Commercial buildings that need reliable energy for critical equipment (such as hospitals) may choose to invest in highly efficient combined heat and power systems that are independent of the electric grid to support their needs. Allowing for such flexibility should be considered."[120]

Investing in energy-efficient natural gas equipment in dual-fuel buildings offers an opportunity to achieve energy savings and carbon reductions in the near and medium terms. Indeed, the *Energy Efficiency Action Plan*[121] focuses on improving both electric and gas efficiency as part of the Senate Bill 350 (De León, Chapter 547, Statutes of 2015) energy efficiency doubling target. At the same time, the state's 2045 GHG reduction goals may not be consistent with maintaining the current size and scale of gas distribution systems. SoCalGas has set a goal of

118 Comments of SDG&E, Docket Number 19-IEPR-06, TN 228288, p. 4, https://efiling.energy.ca.gov/GetDocument.aspx?tn=228288&DocumentContentId=59466.

119 SoCalGas comments on Building Decarbonization Workshop, CEC docket 19-IEPR-06, TN #227834

120 Ibid.

121 Kenney, Michael, Heather Bird, and Heriberto Rosales. 2019. *2019 California Energy Efficiency Action Plan*. California Energy Commission. Publication Number: CEC-400-2019-010-SF.

20 percent RNG for its system by 2030;[122] the pathway is less clear beyond that for achieving a system by 2045 in which most or all retail customers have a choice of safe, carbon-neutral gas for use in buildings. Regardless of methane source, leakage and indoor air quality will require ongoing focus.

These issues will receive focused attention in 2020 and beyond. To promote the enterprise of decarbonizing California's buildings, the Legislature passed Assembly Bill 3232 (Friedman, Chapter 373, Statutes of 2018) and Senate Bill 1477 (Stern, Chapter 378, Statutes of 2018). AB 3232 directs the CEC to assess how to reduce GHG emissions from buildings 40 percent below 1990 levels by 2030. The CEC will develop the building decarbonization assessment in a public process and will transmit the final report to the Legislature by January 1, 2021.

SB 1477 requires the CPUC, in consultation with the CEC, to create two incentive programs—Building Initiative for Low-Emissions Development (BUILD) and Technology and Equipment for Clean Heating (TECH). These two programs will use $50 million of gas corporation cap-and-trade revenues annually for four years to promote the installation of low-emission and near-zero-emission space- and water-heating technologies in new and existing homes. The programs will promote clean emission technology and work to shift the market by coordinating with manufacturers, distributors, and contractors. In addition, SB 1477 addresses energy equity challenges by reserving a minimum 30 percent of total program funding for new housing in low-income and disadvantaged communities. The CPUC issued a building decarbonization order instituting rulemaking (OIR) proceeding in January 2019 (R.19-01-011).[123] A final decision on the SB 1477 programs is expected in early 2020 with implementation to begin in late 2020.

Load Flexibility for Renewables Integration

Steep upward and downward ramps in load—in the morning and particularly in the afternoon and evening—present a daily challenge to electric system operators as discussed in Chapter 1. Flexibility on the load side can help address these ramps and promote the use of renewable energy when it is available and, conversely, avoid using electricity when it has a relatively high

122 SoCalGas published "California's Clean Energy Future: Imagine the Possibilities" in March 2019. The plan describes SoCalGas' vision to replace 20 percent of their system's natural gas supply with renewable natural gas (RNG) by 2030.

123 CPUC opened the order instituting rulemaking regarding building decarbonization in November 2018, R.19-01-011.

carbon content, thus reducing overall GHG emissions.[124] Optimizing demand flexibility can help pave the way for using higher levels of renewable resources and the eventual transition to a zero-carbon electricity grid. With the right automation, grid-level signals can allow devices to minimize the associated impact on the distribution grid while maintaining or improving the ability to meet customer needs throughout the day.

Heat pumps for water and space heating are one example of an enabling technology for load flexibility. Making small adjustments in space-conditioning schedules and using heat pump hot water heaters as thermal batteries can help match the timing of electricity demand to the generation of renewable energy, as well as reduce the severity of the late-afternoon demand ramp as solar output rapidly decreases.[125]

The greater the number of controllable heat pump systems in the built environment, the greater the combined potential to help integrate renewable resources and enhance grid reliability. Many other electric loads, including lighting, pumps and compressors, electric vehicles, and a wide array of appliances can provide analogous flexibility services routinely and cost-effectively.

Rapid electrification poses significant challenges to California's electricity distribution infrastructure. Natural gas has been the preferred energy resource for most heating end uses, and electric distribution systems were not necessarily designed to meet those heating loads. Increased building decarbonization via electrification will require upgrading parts of the existing distribution system to handle the increased load. Transportation electrification will have greater effect—a rapidly growing electrical load that will need to be accounted for in present-day upgrades and future distribution plans.

Onsite solar photovoltaic (PV) systems are now a mainstream reality for planning electricity supply and demand. Historical one-way (utility-scale generation being delivered to the consumer) grid design must adapt to include increasing amounts of generation being pushed from behind-the-meter onto the distribution system. Onsite panel sizing, grid interconnections,

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124 "Renewable integration" involves balancing electricity generation to load while maintaining voltage and frequency within prescribed limits to ensure reliability and provide reserves for unexpected events. Intermittent renewable resources that increase minute to minute and have hourly variability require more ancillary services and ramping capabilities.

125 "Ramping" refers to the ability of generation resources to change output in larger amounts over a 10-minute to three-hour time frame to respond to larger changes in wind and solar output. For example, solar resources will shut down more or less at sunset, requiring that other generation is brought on-line quickly or "ramped up." Generators must be able to "ramp down" as solar resources begin production after sunrise each day.

improved capacity factors, and tolerances for “downstream” power transformers are important elements of load-shift scenarios.

Today’s grid continues to rely on natural gas power plants, especially for meeting reliability requirements, peak-hour demand, and voltage and frequency regulation. New approaches to distribution system management can ensure that the increased decarbonization of transportation and buildings does not increase demand from natural gas power plants (particularly from less efficient peaker plants[126]) in such a way as to cause near-term increases in emissions. Specifically, smarter and more grid-interactive buildings can help meet these integration challenges while allowing existing heating equipment to be used for the associated full-rated life before upgrading.

The CEC and CPUC held a joint agency workshop August 27, 2019, on Energy Efficiency and Building Decarbonization. The workshop covered issues including the feasibility of decarbonizing buildings, load flexibility, energy efficiency, and fuel substitution options. After the workshop, stakeholders submitted comments regarding cost-effective building decarbonization strategies and ideas about mixed-fuel approaches that could reduce emissions. For instance, the Agriculture Energy Consumers Association (AECA), representing industrial sector customers, commented that full electrification of industrial processing is not feasible in the short term.[127] Instead, AECA supports exploring sustainable methods that reduce fossil fuel use (such as energy efficiency, solar thermal, and carbon capture). The American Public Gas Association (APGA) supports overall GHG reductions and policies that advance cleaner fuels such as RNG.[128]

Other stakeholders support policy action on decarbonization that focuses on a planned transition toward all-electric buildings to eliminate building-driven emissions. Redwood Energy, a multifamily housing design firm with experience in zero-carbon buildings, submitted

126 “Peaker plants” are typically simple-cycle generating stations that a utility uses to produce extra electricity during periods of high, or peak demand.

127 Agricultural Energy Consumers Association written comments https://efiling.energy.ca.gov/GetDocument.aspx?tn=229753&DocumentContentId=61189. TN# 229753. Submitted September 17, 2019.

128 American Public Gas Association written comments https://efiling.energy.ca.gov/GetDocument.aspx?tn=229710&DocumentContentId=61136. TN# 229710. Submitted September 10, 2019.

comments requesting the CEC adopt an all-electric building code.[129] Gridworks, a nonprofit organization studying decarbonization solutions, agrees the state should adopt an all-electric building code for new residential and commercial buildings. Gridworks[130] recommends a strategic statewide transition away from the gas network within a public, long-term regulatory planning process that would include integrally the transition of the gas service workforce.

The CEC has reviewed all stakeholder comments[131] from the August 27 workshop and is considering all recommendations. In general, the CEC seeks information and diverse policy options that cost-effectively decarbonize buildings. Speaking at the workshop, Commissioner J. Andrew McAllister stated, "We need to think about load flexibility. I'm convinced that the least-cost pathway is making our buildings all they can be—that they follow supply in a way that's nimble."[132]

Load Management Standards

The past decade has seen remarkable advancements and transformations in supply of and demand for electricity in California. Increased wind and particularly solar resources sharpen the challenge of balancing electric supply and demand in real time throughout each day and across the seasons. These changes bring an urgent need for increased flexibility in demand-side resources to meet cleaner but decreasingly flexible supply resources.

California has long recognized the importance of using load-management strategies to regulate real-time electric demand. As far back as 1976, the Warren-Alquist Act emphasized load management alongside energy efficiency requirements. Taken together, these tools come

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129 Redwood Energy written comments https://efiling.energy.ca.gov/GetDocument.aspx?tn=229746&DocumentContentId=61180. TN# 229746. Submitted September 17, 2019.

130 See Grid work's 2019 report, *California's Gas System in Transition*, for their full list of policy recommendations. https://gridworks.org/initiatives/cagas-system-transition/.

131 Public comments received for the August 27, 2019, joint agency workshop on Energy Efficiency and Building Decarbonization https://www.energy.ca.gov/2019_energypolicy/documents/2019-08-27_workshop/2019-08-27_comments.php.

132 August 27, 2019, joint agency workshop on Energy Efficiency and Building Decarbonization recording https://www.energy.ca.gov/php/yt_player.php?vidNo=J1pcss2twCc&title=Joint%20Agency%20Workshop%20on%20Energy%20Efficiency%20and%20Building%20Decarbonization&desc=California%20Energy%20Commission%20staff%20present%20the%20draft%202019%20California%20Energy%20Efficiency%20Action%20Plan,%20including%20updated%20strategies%20to%20increase%20energy%20efficiency%20in%20existing%20buildings%20and%20updated%20targets%20for%20doubling%20energy%20efficiency%20savings%20by%202030.

first in the selection of approaches to meet energy demand. Today's load-management opportunities dwarf those original aspirations, which addressed mostly emergency load shedding. The *2017 IEPR* and *2018 IEPR Update* articulated the importance of demand response, not only for economically managing onsite loads, but for using other distributed energy resources to provide grid-stabilizing services.

The CPUC-directed and sponsored 2025 California Demand Response Potential Study (DR Potential Study)[133] found a largely untapped, cost-effective potential for thousands of megawatts (MW) of demand response to provide high value to California's electricity system. Demand response can respond to system conditions by shifting load away from high-cost, high-GHG emission resources to lower-cost, low-GHG emissions resources when renewables are highly available and potentially in danger of curtailment. Demand response has traditionally been a utility- or customer-dispatched process, where customers receive the benefits of bill management, incentives, or credits.

In the past few years, attempts to expand the market for third-party demand response and integrate those resources into California ISO markets have been spearheaded through the CPUC's Demand Response Auction Mechanism (DRAM). While utility demand response programs have always counted as resource adequacy, the DRAM provides an auction mechanism to procure resource adequacy from third-party demand response providers in competition with the utility programs. DRAM providers earn capacity revenues through resource adequacy contracts with the utilities and energy revenues through direct participation in California ISO markets. The CPUC, IOUs, and California ISO have made concerted efforts to implement DRAM as a pilot. In its evaluation of the DRAM pilot,[134] the CPUC "found mixed results" and made recommendations to change the design of DRAM to improve the performance and reliability of DRAM resources. Subsequently, the CPUC redesigned DRAM and authorized the continuation of DRAM for four years, with the results to be evaluated for a permanent determination.

The *2017 IEPR* and *2018 IEPR Update* found that demand response in California is underperforming in terms of quantity of demand response megawatts in IOU portfolios and participating in California ISO markets. However, significant gains have been made to improve the quality of demand response through new CPUC rules and enforcement procedures

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133 LBNL. *2025 California Demand Response Potential Study - Charting California's Demand Response Future* https://drrc.lbl.gov/publications/2025-california-demand-response.

134 CPUC. 2019. *Energy Division's Evaluation of Demand Response Auction Mechanism, Final Report*. https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442460092.

prohibiting fossil back-up generation resources from participating in demand response, new click-through platforms to enable customer authorization of third-party demand response provider access to customer data, and integration of demand response into the California ISO market to make the resource more visible to grid operators. Demand response, particularly in combination with other distributed energy resources, could go well beyond DRAM in providing auxiliary services at the bulk-power and distribution levels. Demand response could provide services and earn revenues at multiple levels of the system, making demand response more economically viable in the short run and scalable in the longer term.

The DR Potential Study identifies the potential for expansion of demand response by an order of magnitude. New approaches are needed, coupled with increased focus and priority. The two most recent *IEPRs* have called for the CEC to use its load-management standards authority to contribute to that outcome. The Warren-Alquist Act directs that the CEC:

> *"Adopt standards by regulation for a program of electrical load management for each utility service area … to encourage load shifting through cost-effective rate structures, energy storage, and automation, among other things. … Any expense or any capital investment required of a utility by the standards shall be an allowable expense or an allowable item in the utility rate base and shall be treated by the Public Utilities Commission as such in a rate proceeding."*[135]

In 2008,[136] the state designated energy efficiency and demand response as the top strategies in the state's loading order, giving demand-side resources the highest priority in meeting the state's electricity needs.[137] More recently, the *2017 IEPR* and *2018 IEPR Update* articulated the importance of demand response, not only to achieve onsite bill management objectives, but to support system-wide stability in the electrical grid.

Given the ubiquity of interval meters and internet-connected end uses, the opportunities for demand flexibility today dwarf the state's original aspirations. The DR Potential Study found that nearly 20 years after the California electricity crisis, which sent peak prices soaring and bankrupted the second largest electric utility in the state, significant potential for peak-shaving and load-shifting demand response still exists untapped. This means that thousands of

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135 Warren-Alquist State Energy Resources Conservation and Development Act, https://www.energy.ca.gov/2020publications/CEC-140-2020-001/CEC-140-2020-001.pdf.

136 See the *California Long Term Energy Efficiency Strategic Plan*. The CPUC first adopted the strategic plan in 2008; it was updated in 2011. https://www.cpuc.ca.gov/general.aspx?id=4125.

137 Loading Order policy, California Public Utility Code § 454.5(b) (9) (C).

megawatts of cost-effective capacity (shed) and far more megawatt hours of energy (shift) are left on the table, rather than providing high value to California's electricity system.

Recent state legislation[138] has directed the CEC, via a public process, to investigate load management as a tool for reducing GHG emissions by shifting electric demand to take advantage of abundant renewables. On November 13, 2019, the CEC approved an order instituting rulemaking to identify and institute approaches that would enable statewide expansion of flexible technologies and practices.[139] During the rulemaking development, the CEC will seek the input of the CPUC, California ISO, the CEC and CPUC Disadvantaged Communities Advisory Group, stakeholders, and the public to chart the most constructive path possible. [140] The process will seek to identify the primary barriers to the practice of demand response and investment in flexible demand technologies, and to develop specific recommendations for reducing or removing those barriers.

Finally, and most recently, Senate Bill 49 (Skinner, Chapter 697, Statutes of 2019) gives the CEC expanded authority to include demand flexibility in its Title 20 appliance regulations. This work, with informed public participation in the decision-making process, will complement Load Management Standards efforts by eventually ensuring a larger base of grid-responsive technologies across the state.

Building Decarbonization Technology and Research

Energy research, development, and demonstration (RD&D) that supports and advances technologies is vital to achieving California's energy and climate goals. First are the decades of energy efficiency research that encompass hundreds of projects in support of building and appliance energy efficiency technologies and practices. Deep energy efficiency is the primary carbon reduction strategy for California's buildings, minimizing long-term energy consumption right from the start. Ongoing research on advanced building shells, for example, will help ensure that new structures across the state require only modest amounts of energy for

138 2018 in Assembly Bill 3232 (Friedman, Chapter 373, Statutes of 2018), Public Resources Code, Section 25403(a) (4).

139 Load Management Rulemaking, Docket 19-OIR-01.

140 The CEC seeks stakeholder engagement for the Load Management Rulemaking, as well as other related proceedings such as AB 3232 and SB 49. To receive automated notifications regarding public workshops, materials, and progress on any rulemaking proceeding visit the CEC Mailing List Servers website to subscribe to a list.

mechanical heating and cooling. An appropriate mantra for the construction industry is "Take care of the building shell."

The CEC conducts applied technical and economic research on low- and no-carbon alternatives for space heating, water heating, and cooking in buildings. The CEC is also researching innovative approaches for reducing the carbon intensity of space-conditioning in buildings. Examples include:

- Analysis of heating, ventilation, and air-conditioning (HVAC) supporting technologies and integration into a single system. Technologies analyzed included a variable-capacity compressor and variable-speed blower, automated demand response, intelligent dual-fuel heating, and zonal controls. The project includes testing a single-family residential heat pump[141] conditioning system optimized for California climates.[142]
- Evaluation of operational performance issues and market barriers of heat pump technology.[143] This work will assess barriers to further adoption of heat pumps across markets.
- Review of cost-effective and integrated demand-side retrofits in multifamily buildings.[144] Example measures include "smart" thermostats, plug-load controls, and central system heat pump water heating. The project will focus on solutions to maximize building decarbonization in retrofit markets.

To identify opportunities to reduce energy intensity or improve efficiency in industrial settings while maintaining the ability to meet customer desires, the CEC is researching fuel substitution and energy efficiency in commercial food service research that includes determining energy savings, cooking times, and other parameters of interest to food service operators. As a whole,

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141 "Heat pumps" are devices transferring heat energy between two sources through a refrigerant cycle. Heat pump technologies in buildings are increasingly used for water heating and space heating purposes.

142 Grant EPC-14-021, "Development and Testing of the Next Generation Residential Space Conditioning System for California." [Information on next generation residential space conditioning system project on the CEC's website](http://innovation.energy.ca.gov/SearchResultProject.aspx?p=30005&tks=636963103836691770) http://innovation.energy.ca.gov/SearchResultProject.aspx?p=30005&tks=636963103836691770.

143 Work Authorization NAV-15-007, "Heat Pump Technology Performance and Barriers and Recommendations for EPIC Research, Development, and Demonstration Activities."

144 Grant EPC-15-053. "Customer-Centric Approach to Scaling Integrated Demand-Side Management Retrofits." [Information on customer-centric approach to scaling IDSM retrofits project on the CEC's website](http://innovation.energy.ca.gov/SearchResultProject.aspx?p=30924&tks=636963114547718447) http://innovation.energy.ca.gov/SearchResultProject.aspx?p=30924&tks=636963114547718447.

these commercial food service studies demonstrate the potential for reducing energy consumption through innovative precommercial appliance and control technologies.[145]

At the August 27, 2019, joint agency workshop, the CEC heard stakeholder comments on fuel options and energy efficiency issues. The range of comments on efficient technologies was smaller compared to building decarbonization, and some points overlap with emission-reducing goals. The Western Propane Gas Association supports propane as a low-cost, cleaner fuel option for building technology.[146] The California Hydrogen Business Council (CHBC) supports technology-neutral approaches to building decarbonization and not one-size fits all models.[147] In comments to the IEPR docket, CHBC points to hydrogen assets that can provide zero-carbon onsite energy.[148]

Building Energy Efficiency Standards and Decarbonization

As referenced earlier, decarbonization requires deep efficiency, clean supply, and demand flexibility. When packaged with deep energy efficiency measures, building electrification presents the next most cost-effective path to decarbonization after the direct greening of sources of electricity.[149] Electrification directly leverages the state's renewable sources of generation,[150] is immediately achievable with current building science and technology, and has become a popular path for local jurisdictions seeking to adopt energy-efficient reach codes[151]—building requirements that are stricter than the state's *Building Energy Efficiency Standards* (CCR, Title 24)—that support their local climate plans.

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145 EPC-15-027.

146 Western Propane Gas Association written comments https://efiling.energy.ca.gov/GetDocument.aspx?tn=229780&DocumentContentId=61222. TN# 229780. Submitted September 18, 2019.

147 California Hydrogen Business Council written comments https://efiling.energy.ca.gov/GetDocument.aspx?tn=229840&DocumentContentId=61288. TN# 229840. Submitted September 24, 2019.

148 Ibid.

149 *Decarbonization of Heating Energy Use in California Buildings* https://www.synapse-energy.com/sites/default/files/Decarbonization-Heating-CA-Buildings-17-092-1.pdf. 2018. Synapse Energy Economics, Inc. Introduction. p. 7.

150 Copy of *Residential Building Electrification in California* report on E3's website https://www.ethree.com/wp-content/uploads/2019/04/E3_Residential_Building_Electrification_in_California_April_2019.pdf.

151 As of September 2019, Berkeley and Menlo Park had passed local ordinances banning the expansion of natural gas service to all new construction. Another eight jurisdictions are considering reach code standards that

As discussed above, space heating and water heating remain two of the largest drivers of energy use in buildings, and natural gas is the dominant source for both. The 2019 Building Energy Efficiency Standards included changes to ensure the standards do not prevent electrifying these heating loads in small residential buildings. Future code updates will aim to enable similarly highly efficient, low-carbon pathways for newly constructed commercial and large multifamily buildings.

Single-Family Residential

The *2019 Building Energy Efficiency Standards* (BEES) took two steps to enable decarbonization of new homes:

- Added language that allows electric options for new homes.[152] These options make all-electric building designs simpler and avoid gas-piping installation costs altogether.
- Established an all-electric prescriptive compliance path for homes.[153] Recent advancements in heat pump technology, along with improvements in wall and attic performance, made this change possible.

Both changes took effect January 1, 2020.

Multifamily Residential

In the *2022 BEES* update, the CEC plans to address energy efficiency in multifamily buildings. This update will address some barriers to building decarbonization—including mixed-use buildings that share central systems—ensuring that all-electric emissions reduction pathways are available to all types of multifamily construction.

The practice of placing a per-unit heat pump water heater in the conditioned space of the dwelling poses a challenge in heating-dominant climate zones. If a heat pump uses conditioned air as a source of heat, it will draw heat out of the same area the occupant is trying to keep warm with separate space heating equipment. By improving modeling of centralized systems that use heat pump technology, the *BEES* can promote designs that

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would facilitate all-electric or electric-preferred new construction. Visit the [Building Decarbonization Coalition] website for updates and local government efforts.

152 See CCR Title 24, Part 6, Section 150.0, Water Heating.

153 The "prescriptive compliance path" in the California Energy Code is the default baseline design defined in the code. The alternative is the optional "performance compliance path" which requires modeling the proposed project and showing it just as or more energy-efficient as the prescriptive path.

bypass this potential issue. These designs enable markets to realize the energy efficiency potential, design flexibility, and GHG reductions that heat pump systems offer.

Nonresidential

Commercial buildings have more varied designs than homes, and electric equivalents to commercial gas equipment are not available for some applications. Enabling an electric decarbonization pathway will require establishment of an all-electric baseline, starting with the most common commercial building types. Heat pumps are a technically feasible and cost-effective alternative for many space-heating and water-heating loads in commercial buildings.

The *2019 BEES* consolidated demand response requirements into a single section, allowing advanced demand coordination and holistic building efficiency measures as part of a communicating energy grid. Grid interactivity represents an enormous opportunity to reduce the costs of integrating renewables and achieving California's climate goals and will be a focus of the *2022 BEES*. The next step is to define an ideal set of behaviors (that is, automated control functions) for commercial buildings and identify the communication infrastructure needed to enable interactions with the grid.

California Utility Decarbonization Efforts and Programs

Integrated resource plans (IRPs) are instrumental electricity planning tools for utilities and load-serving entities. IRPs include information on a utility's anticipated energy demand and efforts to decarbonize its resource mix. IRPs also help regulators monitor compliance with the state's Renewables Portfolio Standard (RPS). The CEC reviews final IRPs for publicly owned utilities (POUs) to ensure they meet state mandates. However, POUs are free to establish goals that exceed state requirements. (For more detailed information on POU IRPs, see Chapter 10 and Appendix D.)

Smart grid policy and planning are key in optimizing energy efficiency as a resource and lowering emissions overall. At the August 27, 2019, joint agency workshop on Energy Efficiency and Building Decarbonization, Commissioner J. Andrew McAllister discussed the concept of real-time energy management that ensures supply and demand resources are matched. "We need from energy efficiency the headroom to put all this new electrification on the grid. … It has to be done in a way … that's smart."[154] The CPUC expects to consider proposed plans on aggregated demand-side resources in the next IRP cycle in 2020.

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154 [August 27, 2019, joint agency workshop on Energy Efficiency and Building Decarbonization recording](https://www.energy.ca.gov/php/yt_player.php?vidNo=J1pcss2twCc&title=Joint%20Agency%20Workshop%20on%20Energy%20Efficiency%20and%20Building%20Decarbonization&desc=California%20Energy%20Commission) https://www.energy.ca.gov/php/yt_player.php?vidNo=J1pcss2twCc&title=Joint%20Agency%20Workshop%20on%20Energy%20Efficiency%20and%20Building%20Decarbonization&desc=California%20Energy%20Commission

Sacramento Municipal Utility District

Even with the growth of solar PV, energy efficiency improvements, and increased use of demand response, Sacramento Municipal Utility District (SMUD) expects energy usage to continue to grow between 2019 and 2030.[155] This growth in energy usage is due to expected demand increases from electric vehicles and all-electric homes and buildings.

SMUD's 2018–2022 IRP focuses on achieving decarbonization through electrification strategies in Sacramento while meeting customer affordability and reliability objectives. SMUD also has a net-zero-GHG emissions goal by 2040. This goal is more aggressive than its previous goal to reduce emissions 90 percent below 1990 levels by 2050.[156] To achieve these reductions in the Sacramento region, SMUD's analysis shows that it will be necessary to scale up the pace of electrification of buildings and transportation. SMUD also plans to leverage improvements in energy efficiency, demand response, and renewable energy as it supports continued electrification.[157]

Table 1: Summary of SMUD Building Electrification Programs

SMUD Program	Description
Construction of all-electric new homes	Provides incentives to builders and their design teams for development of all-electric homes.
All-Electric Smart Homes	Provides incentives to homebuilders to include electric heat pump water heaters, heat pump climate controls, and induction cooktops into new homes. (Provides $5,000 for each single-family home and $1,750 for each multifamily unit that declines to install natural gas infrastructure.)

%20staff%20present%20the%20draft%202019%20California%20Energy%20Efficiency%20Action%20Plan,%20including%20updated%20strategies%20to%20increase%20energy%20efficiency%20in%20existing%20buildings%20and%20updated%20targets%20for%20doubling%20energy%20efficiency%20savings%20by%202030.

155 SMUD. *Resource Planning Report: IRP Filing Report for Submission to the CEC*. April 2019. [Link to download SMUD's Resource Planning Report filed on the CEC's website](https://efiling.energy.ca.gov/GetDocument.aspx?tn=227887&DocumentContentId=59276) https://efiling.energy.ca.gov/GetDocument.aspx?tn=227887&DocumentContentId=59276.

156 This goal is more ambitious than the state goal of reducing GHG emissions to 80 percent below 1990 levels by 2050.

157 SMUD also has programs supporting distributed generation adoption, community solar, voluntary green pricing, and energy efficiency.

SMUD Program	Description
SolarShares℠	Offers commercial and residential customers a community solar product giving customers many of the same benefits as behind-the-meter generation.
Equipment efficiency	Provides rebates or SMUD financing or both for qualifying efficiency and electrification improvements to homes building envelopes and equipment.
Home Performance Program	Participating contractors evaluate performance of the whole house and recommend comprehensive improvements. Program packages include both energy efficiency and electrification.
Low-Income Energy Retrofits	Completes energy retrofits for qualifying low-income households through four offerings: Weatherization, Energy Saver Deep Retrofit, Energy Saver House Bundle, and Energy Saver Apartment Bundle.

Source: SMUD 2018–2022 IRP, [Link to download SMUD's Resource Planning Report filed on the CEC's website](https://efiling.energy.ca.gov/GetDocument.aspx?tn=227887&DocumentContentId=59276)
https://efiling.energy.ca.gov/GetDocument.aspx?tn=227887&DocumentContentId=59276

SMUD Building Electrification Plans

In addition, SMUD has a goal to electrify 80 percent of existing homes and 100 percent of low-income homes in Sacramento by 2040 and is developing a program to encourage electrification of homes for low-income customers. SMUD and national homebuilder D.R. Horton teamed up in October 2018 to build "all-electric communities" of more than 100 homes in Sacramento that will be priced for first-time homebuyers.

SMUD also plans to shift program delivery to maximize benefits for the underserved, and it wants to start now, learning along the way and developing a model for success for others to follow.

SMUD's electrification efforts focus mainly on the residential sector, which accounts for most of the gas consumption for space and water heating in the Sacramento region.[158] SMUD's analysis shows that achieving its GHG reduction goals will require more than 85 percent of existing residential and 75 percent of commercial space and water heating equipment to be converted from gas to electricity. This level of electrification assumes that future state Building Energy Efficiency Standards would mandate that most new home construction be all-electric by 2030.

158 SMUD, *Resource Planning Report: IRP Filing Report for Submission to the California Energy Commission*, April 2019.

Of the large utilities, SMUD is the most focused on building electrification and includes an analysis of how many existing buildings will need to convert from gas to electric space and water heating. Targets such as these are the first step toward reaching decarbonization goals from the residential and commercial sectors and should be established for the other electric utilities to help the state to reach its GHG reduction goals.

Los Angeles Department of Water and Power

Since 2007, Los Angeles Department of Water and Power's (LADWP's) energy efficiency programs have reduced consumption by roughly 3,275 GWh per year.[159] The energy efficiency potential study concluded that LADWP could cost-effectively achieve another 15 percent energy efficiency from 2017 through 2027, in addition to the previously committed 15 percent from 2010 through 2020. If LADWP keeps the same pace through 2030, it would meet the state's goal to double energy efficiency.[160]

LADWP's IRP[161] identifies four key initiatives to achieve its resource goals: GHG reduction, transportation electrification, dispatchable resources, and system reliability. LADWP will examine strategies to reduce GHG emissions and expects that a portfolio approach of coal replacement, RPS, energy efficiency, local solar, energy storage, and transportation electrification will reduce GHG emissions an estimated 78 percent below 1990 levels over the next 20 years.

LADWP is accelerating transportation electrification, stating that it is the most effective component for reducing overall GHG emissions. LADWP plans to use transportation electrification as a strategy to absorb overgeneration of renewables. To accomplish this strategy, it plans to offer incentives for charging when solar is abundant.

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159 Los Angeles Department of Water & Power, *2017 Power Integrated Resource Plan*, August 2018. Link to download LADWP's 2017 IRP filed on CEC's website https://efiling.energy.ca.gov/GetDocument.aspx?tn=227897&DocumentContentId=59291.

160 CEC's Web page on Clean Energy and Pollutions Reduction Act – SB 350, https://www.energy.ca.gov/rules-and-regulations/energy-suppliers-reporting/clean-energy-and-pollution-reduction-act-sb-350.

161 Los Angeles Department of Water & Power, *2017 Power Integrated Resource Plan*, August 2018. Link to download LADWP's 2017 IRP filed on CEC's website https://efiling.energy.ca.gov/GetDocument.aspx?tn=227897&DocumentContentId=59291.

Table 2: Summary of LADWP Building Decarbonization Programs

LADWP Program	Description
Low-Income Economic Development	Provides grants to low-income housing developers. Projects must achieve 15 percent greater energy savings than codes.
LADWP Facilities Program	Improves energy efficiency throughout LADWP's facilities with energy efficiency upgrades in HVAC and lighting.
Solar Incentive Program	Offered increased monetary benefits for customers living in areas of low solar penetrations.
Solar Rooftops Program	Provides priority enrollment for customers living in areas of low solar penetrations.

Source: LADWP 2017 IRP, Link to download LADWP's 2017 IRP filed on CEC's website https://efiling.energy.ca.gov/GetDocument.aspx?tn=227897&DocumentContentId=59291

Pacific Gas and Electric Company

Roughly 14 percent of Pacific Gas and Electric Company's (PG&E's) residential customers and 15 percent of commercial customers are in disadvantaged communities. Of these, 72 percent of residential and 62 percent of commercial customers are in the Central Valley, despite the fact that Central Valley customers represent only one-fifth of all residential customers in the PG&E electric service territory.[162] In December 2018, the CPUC approved the San Joaquin Valley Disadvantaged Communities Pilot Project.[163] Under this pilot project, PG&E will expand access to affordable energy options in eight pilot communities[164] that do not have access to natural gas. Projects include replacing propane and wood appliances with efficient electric appliances, assessing electric bill reduction programs, and offering increased savings through community solar.

PG&E's service area has more behind-the-meter solar PV interconnected than any other utility in the United States. PG&E supports customer adoption of solar and other distributed

162 PG&E. *Integrated Resource Plan, 2018. Prepared for the California Public Utilities Commission*. August 1, 2018. Copy of PG&E's 2018 IRP filed with the CPUC http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M229/K725/229725998.PDF.

163 CPUC, December 18, 2019, Decision 1812015, "Decision Approving San Joaquin Valley Disadvantaged Communities Pilot Projects"

164 San Joaquin Valley Disadvantaged Communities Pilot Project communities in PG&E territory: Allensworth, Alpaugh, Cantua Creek, Fairmead, Lanare, Le Grand, La Vina, and Seville. Three additional communities under the San Joaquin Valley Disadvantaged Communities Pilot Project are located in SCE territory: California City, Ducor, and West Goshen.

generation technologies by implementing distributed generation-specific tariffs and incentive programs, working to improve and streamline interconnection processes, and providing customers distributed generation-related educational and customer service resources.

PG&E is implementing California's programs to develop energy storage resources in the state to integrate renewable resources, provide output in periods of peak demand, and reduce GHG emissions. PG&E is accelerating implementation of energy storage in its grid through owning and operating storage resources, procuring storage through third-party contracts, testing innovative storage solutions through pilot projects, and enabling customer adoption of energy storage.

Southern California Edison

Southern California Edison's (SCE's) IRP[165] identifies the residential and commercial sector as a viable opportunity for GHG emission reductions via electrification of space and water heating. Sufficient lead time is needed to supplant GHG-emitting vehicles and space and water heaters with clean energy-powered technologies.

SCE released *Pathway 2045: Update to the Clean Power and Electrification Pathway*[166] in November 2019. This report examined the energy implications of California's long-term decarbonization goals on the economy and the electric sector and mapped a feasible and low-cost path to meeting these goals, including the need to decarbonize buildings. The Pathway 2045 projects the need to provide for 7.5 million electric vehicles statewide by 2030[167] and 26 million by 2045.[168] It further projects 33 percent of space and water heaters will have switched to electric power from natural gas by 2030[169] and 70 percent by 2045. The report states that programs that educate customers about building technologies, such as electric heat pumps for space and water heating, produce the greatest GHG benefits. Education paired with incentives work better at overcoming economic barriers to adoptions on building decarbonization measures.

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165 Combs, Janet S. and Cathy A. Karlstad. *Integrated Resource Plan of Southern California Edison Company (U 228-E)*. Rulemaking 16-02-007. August 1, 2018. Copy of SCE's IRP filed with the CPUC http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M230/K379/230379549.PDF.

166 SCE's, *Pathway 2045: Update to the Clean Power and Electrification Pathway*. November 2019.

167 Southern California Edison's *The Clean Power and Electrification Pathway*, November 2017.

168 Visit SCE's Pathway 2045 webpage to review their estimates for sector decarbonizing goals, including Buildings and Transportation figures.

169 Southern California Edison's The Clean Power and Electrification Pathway, November 2017

Of the state population living in disadvantaged communities, 47 percent are in SCE's service area. Roughly 40 percent of SCE's residential households are in disadvantaged communities or have subsidized rates or both.

San Diego Gas & Electric Company

About 5 percent of San Diego Gas & Electric Company's (SDG&E's) customers are in disadvantaged communities.[170] SDG&E offers incentives for solar installations, as well as community solar options for customers in disadvantaged communities. (See Table 3.)

Table 3: Summary of IOU Building Decarbonization Programs

Program	Description
Distributed Energy Storage Investments and Programs (Assembly Bill 2868 [Gatto, Chapter 681, Statutes of 2016]) (PG&E)	PG&E has proposed an energy storage program that provides incentives for low-income/disadvantaged community customers to electrify water heating and shift the associated load to off-peak hours. If approved, the program would launch in 2020 and enroll 6,600 customers who will benefit from energy bill savings and reduced onsite emission from propane-based water heating.
Home Energy Efficiency Rebates (HEER) (SCE)	Rebates to offset purchase of energy-efficient products, including hybrid electric heat pump water heaters. With the recent adoption of CPUC, D.19-08-009, fuel substitution measures may be eligible for inclusion in HEER and other energy efficiency programs.[171]
Disadvantaged Communities—Single-family Affordable Solar Homes (DAC-SASH) (SCE and SDG&E)	Modeled after SASH program, provides upfront financing incentives toward the installation of solar generation system on homes of low-income customers.
Community Solar Green Tariff (SCE and SDG&E)	Allows primarily low-income customers in disadvantaged communities to benefit from the development of solar generation projects in their own or nearby disadvantaged communities.
Green Tariff Shared Renewables (PG&E, SCE, and SDG&E)	Community solar program that includes a carve-out of 10 MW to be procured from projects sized between 0.5 and 1 MW within disadvantaged communities.

170 Smith, Aimee M. *2018 Individual Integrated Resource Plan of San Diego Gas & Electric Company (U 902 E)*. Rulemaking 16-02-007. August 1, 2018. Copy of SDG&E's IRP filed with the CPUC http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M230/K585/230585448.PDF.

171 Decision 19-08-009, Decision Modifying the Energy Efficiency Three Prong Test

Program	Description
Clean Energy Optimization Pilot (CEOP) (SCE)	CEOP is a performance-based GHG reduction program, offering incentives to SCE customers to reduce GHGs through on-site measures. SCE has partnered with the University of California and California State University to implement the pilot.
Disadvantaged Communities—Green Tariff (DAC-GT) (PG&E, SCE, and SDG&E)	The program enables income-qualified, residential customers in disadvantaged communities who may be unable to install solar on their roof to benefit from utility scale clean energy and receive a 20 percent bill discount.
Multifamily Affordable Solar Homes (MASH) (PG&E, SCE, and SDG&E)	MASH provides fixed, up front, capacity-based incentives for qualifying solar energy systems on low-income, multifamily properties. The MASH program is closed.
Solar on Multifamily Affordable Housing (SOMAH) Program (PG&E, SCE, SDG&E, Liberty Utilities, and PacifiCorp)	Similar to MASH, the SOMAH program provides incentives for the installation and interconnection of at least 300 MW of solar generating capacity on qualified multifamily affordable housing statewide by 2030. The SOMAH program is open.
Energy Savings Assistance (ESA) Program (All privately owned and regulated gas or electric utilities in California)	ESA provides no-cost weatherization services to low-income households who meet income guidelines. ESA is a weatherization program but provides a decarbonization benefit through energy efficiency measures.

Source: PG&E, SCE, and SDG&E IRPs

Similar to LADWP, investor-owned utilities (IOUs) are focused on transportation electrification. This strategy is important for the state to reduce its GHG emissions. Increasing the energy efficiency of buildings and appliances is also a key strategy to reducing GHG emissions from buildings.

Quantifying and setting targets for building decarbonization are a first step toward meeting carbon reduction goals. Utilities can contribute by assessing the potential for GHG reductions from existing buildings in their service territories and targeting buildings for cost-effective retrofits.

Role of the Traditional Energy Efficiency Portfolios

As decarbonization moves to the center of California's energy policy, the role and composition of the traditional gas and electric energy efficiency portfolios are changing. Going forward, traditional programs will need to focus more directly on two areas: first, ensuring low-income residents perceive the full range of benefits of the low-carbon energy economy; second, to expand dramatically the investment in market transformation efforts around low-carbon technologies, whether within electric or gas end uses or in support of fuel substitution. In the IOU realm, given recently tightened cost-effectiveness requirements and reduced efficiency program goals, overall spending on the IOU energy efficiency portfolios may decline going forward. At the same time, the potential exists to incorporate aggregated energy efficiency and load flexibility into utility energy procurement or resource adequacy markets or both. One area of effort going forward—whether by California's publicly owned utilities, IOUS, or community choice aggregators—is the continued development of tools and programs that enable facile aggregation, procurement, and forecasting of these demand-side resources.

Recommendations

The California Energy Commission (CEC) has proposed strategies and policy recommendations as part of the *California 2019 Energy Efficiency Action Plan*. The overarching objectives of the plan are to meet the doubling of energy efficiency savings by 2030, remove barriers to energy efficiency faced by low-income and disadvantaged communities, and reduce GHG emissions from new and existing buildings.

Today, the pressing needs for deepened energy efficiency and widespread building decarbonization are alternative funding sources and financing mechanisms, new and improved tools, and new program structures. The portfolio of programs overseen by the California Public Utilities Commission (CPUC) cannot be the only solution to California's energy efficiency goals. Private markets and other nonratepayer sources of funding need to be tapped through innovative programs designs and collaborative efforts. These new designs must be crafted with an inclusive equity framework that works for the people within a local community, including tribal governments and rural, low-income, or disadvantaged communities.

Codes and standards development will continue to be a significant pathway for change and improvement. Codes and standards tend to leverage successful innovations in the marketplace. Thus, they cannot be the sole mechanism to achieve the state's energy goals—especially as progress slows on federal standards— which often preempt state-level standards. New metrics, improved standards compliance, and expanded data access are essential for success.

Key actions to take include:

- A one-stop shop for energy efficiency and building decarbonization programs that can leverage funds outside the utility portfolio and cover all sectors—residential, commercial, agriculture, and industrial. By combining taxpayer and ratepayer funds from health, energy, air quality, and utility entities, customers can receive deeper energy retrofits.
- Offer programs that offer comprehensive solutions with demand flexibility, demand response, electric vehicle, solar photovoltaic, and storage, in addition to traditional energy efficiency measures. Significant work is needed to break down funding silos, ensure funds are available on a rolling basis and made easily available to low-income and disadvantaged communities.
- Expand pay-for-performance and on-bill repayment programs so customers can more easily finance energy efficiency upgrades.
- Adopt monetary values for the cobenefits of energy efficiency and building decarbonization, including indoor air quality, improved working conditions, and improved comfort.
- Develop demand-flexibility standards. Research the business case for demand-flexible appliances and the infrastructure needed at the building level for success.

- Develop geographically aggregated datasets of energy consumption to help utilities, researchers, program administrators, local governments, tribes, and state agencies more accurately target areas where energy efficiency and building decarbonization are most cost-effective, would reduce local transmission and distribution strain, and would benefit environmental justice communities.
- For investor-owned utilities (IOUs), work with the CPUC integrated resources planning process to develop the ability to incorporate aggregations of energy efficiency and demand-response programs into long-term planning and procurement. For publicly owned utilities (POUs), develop methods to integrate aggregations of energy efficiency and demand-response projects into integrated resource plans (IRPs). The CEC should work with POUs to establish minimum thresholds of cost-effective energy efficiency and demand response that must be included in IRPs.

The diversity of activities, approaches, jurisdictions, and authorities required for building decarbonization requires involvement of the widest array of actors. Key stakeholders in this realm include the CEC, CPUC, the California Air Resources Board, the California Independent System Operator, the California Legislature, the California Governor’s Office, local governments, tribal governments, building officials, the California Department of Community Services and Development, the California Department of Public Health, the California Alternative Energy and Advanced Transportation Financing Authority, IOUs, POUs, community choice aggregators, building contractors, original equipment manufacturers and their distributors and retailers, architects and designers, energy professionals, nongovernmental organizations, program administrators, and more.

A complete list of the recommended actions to achieve the state’s energy efficiency goals, including lead and partner entities, is available in the final *2019 California Energy Efficiency Action Plan*.

CHAPTER 3: Advancing Zero-Emission Vehicles

Introduction

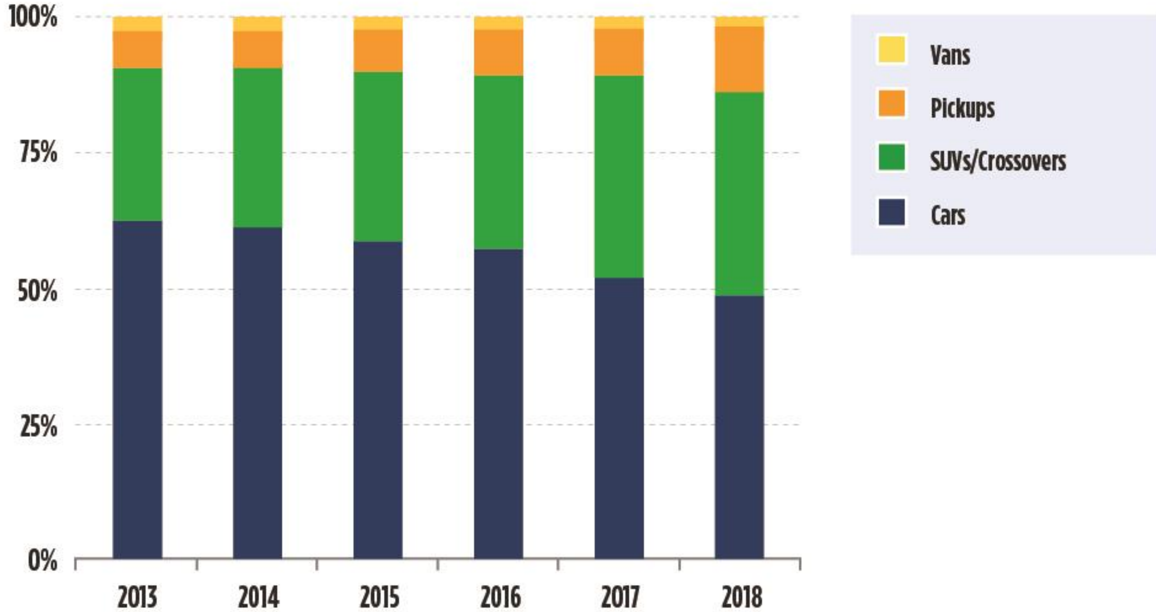
The state's efforts against global climate change have begun to show progress, and in 2017, California continued to exceed its goal of reducing greenhouse gas (GHG) emissions to 1990 levels, three years ahead of schedule. However, despite the state's *overall* reduction in GHG emissions, emissions from the transportation sector have increased by roughly 6 percent from 2013 (the lowest point since 2000) through 2017 (the most recently available data).[172] The transportation sector (including vehicles, oil extraction, and oil refining) is also the largest source of GHG emissions in California, accounting for roughly 50 percent of in-state emissions.[173]

One key reason for the rise in transportation GHG emissions is that California consumers are purchasing larger passenger vehicles, such as light trucks and sport utility vehicles, which emit more GHGs per mile than smaller vehicles. The respective shares of these vehicle sales are shown in Figure 17.

172 California Air Resources Board (CARB). 2019. California Greenhouse Gas Emissions for 2000 to 2017 https://www.arb.ca.gov/cc/inventory/pubs/reports/2000_2017/ghg_inventory_trends_00-17.pdf.

173 CARB. July 11, 2018. *California Greenhouse Gas Emission Inventory* https://www.arb.ca.gov/cc/inventory/data/data.htm.

Figure 17: New Light-Duty Vehicle Registrations by Type



Source: CEC

In addition to being California's largest emitter of GHGs, the transportation sector is also a major emitter of criteria pollutants, with mobile sources responsible for nearly 80 percent of nitrogen oxide emissions and 90 percent of diesel particulate matter emissions statewide.[174]

To address these challenges, major transitions will be necessary within California's transportation sector. On the fuel side, low-carbon fuels (such as ethanol, biodiesel, or biomethane) represent an opportunity to reduce life-cycle GHG emissions within conventional combustion engines. On the engine side, natural gas engines with low oxides of nitrogen (NOx) emissions (which can be paired with biomethane) can reduce tailpipe emissions from the most polluting medium- and heavy-duty vehicles. Zero-emission vehicles (ZEVs), including vehicles that refuel with electricity or hydrogen, can address both sides of this equation.

174 CARB. May 2016. *Mobile Source Strategy*. Link to Mobile Source Strategy on CARB's website https://www.arb.ca.gov/planning/sip/2016sip/2016mobsrc.pdf.

While ZEVs are not alone in the ability to improve air quality or reduce GHG emissions within the transportation sector, this *2019 IEPR* has focused attention onto ZEVs based on the rapid pace of changes in ZEV and ZEV infrastructure markets. California leads the nation in ZEV deployment, with more than 650,000 battery-electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) sold as of September 2019, roughly half the national total.[175] The state is also home to the nation's largest fleet of fuel cell electric vehicles (FCEVs), with nearly 7,000 of these ZEVs using the state's growing network of hydrogen refueling stations.[176]

California's Long-Standing Leadership in Clean Transportation

To understand the expected role of ZEVs in California's evolving transportation sector, it is important to consider the goals and milestones that California has set for itself, the regulations and requirements that guide state progress, and the incentives and other programs that support such progress.

The California Air Resources Board (CARB) has developed a set of regulations to control emissions from passenger vehicles, collectively known as the Advanced Clean Cars Program. These standards regulate per-vehicle emissions of soot and smog-causing pollutants, as well as GHG emissions. The vehicle standards are footprint-based, so that bigger vehicles are permitted to emit more GHGs per mile. The Advanced Clean Cars package also includes a technology-forcing mandate for ZEVs.

For the first time in the 40-plus year history of California's vehicle standards, the Trump Administration is revoking the waiver for the state's vehicle GHG standards and its ZEV mandate. California and 22 other states have filed suit to defend the standards, and several major automakers have already expressed their intention to comply with California's standards. Climate change is real and must be addressed, and many Californians are still breathing some of the nation's dirtiest air. So, California must continue to make progress in reducing emissions from the transportation sector. With these objectives in mind, California has set aggressive goals and milestones for itself.

Clean Transportation Goals and Milestones

Table 4 summarizes California's major policy goals and milestones for reducing GHG emissions, reducing criteria pollutant emissions, and increasing the deployment of ZEVs within the state.

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175 Veloz. October 7, 2019. [September 2019 dashboard of PEV sales from Veloz's website](https://www.veloz.org/wp-content/uploads/2019/10/9_sept_2019_Dashboard_PEV_Sales_veloz.pdf) https://www.veloz.org/wp-content/uploads/2019/10/9_sept_2019_Dashboard_PEV_Sales_veloz.pdf.

176 Based on analysis of data provided by the Department of Motor Vehicles through October 2019.

Senate Bill 32 (Pavley, Chapter 249, Statutes of 2016) amended the Global Warming Solutions Act of 2006 to extend the emission targets of Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006). The amendment set a statewide GHG emission limit for 2030 equivalent to 40 percent below emissions levels in 1990. AB 32 and SB 32 directed CARB to develop *California's 2017 Climate Change Scoping Plan*, published in November 2017.[177] Subsequently, Executive Order B-16-2012, issued by former Governor Edmund G. Brown Jr., set an objective of reducing transportation sector emissions to 80 percent below 1990 levels by 2050.

In addition to the need for GHG emission reductions, California also faces tremendous challenges in meeting federal air quality standards. CARB reports that 12 million Californians live in communities that exceed the ozone and particulate matter standards set by the United States Environmental Protection Agency (U.S. EPA), and that the South Coast and San Joaquin Valley are the only two areas in the nation in extreme nonattainment for the federal ozone standard.[178] A recent report from the American Lung Association states that Los Angeles remains the city with the worst ozone pollution, as it has for 19 years of the 20-year history of the report. The Fresno-Madera-Hanford region returned to the most polluted slot for year-round particle pollution, while Bakersfield maintains its rank as the city with the worst short-term particle pollution.[179]

177 CARB. November 2017. *California's 2017 Climate Change Scoping Plan* https://www.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf.

178 CARB. March 7, 2017. Revised Proposed 2016 State Strategy for the State Implementation Plan https://www.arb.ca.gov/planning/sip/2016sip/rev2016statesip.pdf.

179 The American Lung Association *'State of the Air 2019' Finds Pollution Levels Rising in Many Areas*. Available at Overview of American Lung Association's 2019 State of the Air report on the American Lung Association's website, https://www.lung.org/assets/documents/healthy-air/state-of-the-air/sota-2019-full.pdf.

Table 4: GHG, Fuel, and Air Quality Goals and Milestones

Policy Origin	Objectives	Goals and Milestones
Assembly Bill 32	GHG Reduction	Reduce GHG emissions to 1990 levels by 2020
Senate Bill 32	GHG Reduction	Reduce GHG emissions to 40 percent below 1990 levels by 2030
Executive Order B-55-18	GHG Reduction	Achieve carbon neutrality by 2045
Senate Bill 100	GHG Reduction	Requires 100 percent of retail sales of electricity to end-use customers to come from 100 percent zero-carbon resources by 2045
Clean Air Act; California State Implementation Plans	Air Quality	80 percent reduction in NO_x by 2031
Executive Order B-16-2012	GHG Reduction, Increase Zero-Emission Vehicles and Infrastructure	Reduce GHG emissions from the transportation sector to 80 percent below 1990 levels by 2050 Infrastructure to accommodate 1 million electric vehicles by 2020 1.5 million electric vehicles by 2025
Senate Bill 350	GHG Reduction, Increase Zero-Emission Vehicles and Infrastructure	Requires publicly owned utilities (POUs) with electricity demands exceeding 700 gigawatt-hours to develop integrated resource plans (IRPs) by January 2019. Requires investor-owned utilities (IOUs) to file applications for investments to support transportation electrification. Established the Disadvantaged Communities Advisory Group to review and provide guidance on clean energy and pollution reduction programs to the California Energy Commission (CEC) and the CPUC.
Assembly Bill 1493	GHG Reduction	Reduce GHG emissions from new cars and trucks by to 22 percent below 2002 levels by 2012 and 30 percent below 2002 levels by 2016
Senate Bill 1275	Increase Zero-Emission Vehicles	1 million zero-emission vehicles by 2023
Executive Order B-48-18	Increase Zero-Emission Vehicles and Infrastructure	5 million zero-emission vehicles by 2030 250,000 electric vehicle chargers, including 10,000 direct current fast chargers, and 200 hydrogen refueling stations by 2025
Executive Order B-32-15 on Sustainable Freight	Air Quality, GHG Reduction, Petroleum Reduction	Required an action plan to include targets. The resulting targets included improving system efficiency per GHG emission by 25 percent by 2030, as well as 100,000 vehicles and equipment capable of zero emission operation by 2030

Source: CEC

Adopting ZEVs is a key element of addressing the state's GHG emission reduction targets and air quality improvement requirements. The Governor's Interagency Working Group on ZEVs developed the *ZEV Action Plan*, issued in 2013 and subsequently updated in 2016 and 2018, to identify actions that support the state's ZEV goals.[180] In addition, the Governor's Office of Planning and Research released the *Electric Vehicle Charging Station Permitting Guidebook* in 2019.[181] This guidebook will hasten the transition to plug-in electric vehicles (PEVs) by simplifying the launch of EV charging stations in addition to exploring best practices and a ZEV readiness scorecard.

California has set goals for the deployment of ZEVs for 2023, 2025, and 2030. Senate Bill 1275 (De León, Chapter 530, Statutes of 2014) established the Charge Ahead California Initiative to place 1 million ZEVs and near-ZEVs in service by January 1, 2023. Executive Order B-16-2012 set a goal of 1.5 million ZEVs by 2025. Finally, Executive Order B-48-18 set a target of 5 million ZEVs by 2030.

As part of Executive Order B-32-15, the *California Sustainable Freight Action Plan* was released in 2016 and identifies state policies, programs, and investments to achieve subsequent targets. The executive order directs the CEC and other state agencies to work on corridor-level freight pilot projects within the state's primary trade corridors that integrate advanced technologies, alternative fuels, freight and fuel infrastructure, and local economic development opportunities.

Senate Bill 350 (De León, Chapter 547, Statutes of 2015) called for the formation of the Disadvantaged Communities Advisory Group (DACAG) to review and provide guidance on CEC and CPUC clean energy programs and determine whether those programs are effective and useful in disadvantaged communities. Ensuring the DACAG's participation in ZEV-related activities is a key element of ensuring that the state's ZEV programs benefit all Californians. In spring 2019, the DACAG specifically advised the CEC to focus its Clean Transportation Program investments on zero-emission fuels.

180 *ZEV Action Plan* and updates http://www.business.ca.gov/ZEV-Action-Plan.

181 Governor's Office of Business and Economic Development. 2019. *Electric Vehicles Charging Station Permitting Guidebook* http://businessportal.ca.gov/wp-content/uploads/2019/07/GoBIZ-EVCharging-Guidebook.pdf.

Accelerating the Deployment of ZEVs and the Infrastructure Required to Fuel Them

Rules, Regulations, and Requirements

To meet its numerous GHG emissions reduction and clean air targets, California relies on a mixture of rules, regulations, requirements, and incentives to shape the acceleration of ZEVs.

CARB's Advanced Clean Cars rulemaking consists of a suite of regulations for reducing emissions from the state's light-duty fleet.[182] CARB is updating the ZEV Regulation for the Advanced Clean Cars 2 program, which will look at regulations beyond 2025 and help ensure zero- and near-zero-emission technology options continue to be commercially available.

The Innovative Clean Transit Regulation, developed by CARB, requires state transit agencies to transition an estimated 12,743 large transit agency buses[183] to zero-emission technologies by 2040. California transit agencies subject to the rule will submit rollout plans demonstrating compliance feasibility for large agencies by 2020 and by 2023 for small agencies. On January 9, 2020 CARB issued the updated *Zero-Emission Bus Rollout Plan Guidance for Transit Agencies*[184] in an effort to assure accurate statewide fleets counts, expected technology portfolios, and cost projections necessary to achieve the state's goals. The charging power capacity demanded by these buses will vary dependent on use case, and estimated at 925,167 kWh per day for fleets operating 100 buses driving an average of 130 miles a day.[185]

CARB presented a portfolio of regulatory measures during the CEC's charging infrastructure IEPR workshops on March 11, 2019, and May 2, 2019, highlighting regulatory concepts, milestones, and initial estimates of infrastructure needs.[186] The CEC can build upon these

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182 More information about the Advanced Clean Cars rulemaking is available at https://www.arb.ca.gov/our-work/programs/advanced-clean-cars-program.

183 CARB Staff Report Appendix K, https://www.arb.ca.gov/regact/2018/ict2018/appk-statewidecostanalysis.xlsx?_ga=2.100693381.527455161.1578949014-108560835.1540230111, Small transit agencies fleet sizes and energy demand has not yet been determined.

184 CARB Plan Guidance, https://www.arb.ca.gov/sites/default/files/2020-01/UPDATED%20Rollout%20Plan%20Guidance%20Final_2.pdf.

185 CARB Staff Report Appendix M, https://www.arb.ca.gov/regact/2018/ict2018/appm-batteryelectrictruckandbuschargingcost.xlsm?_ga=2.209960343.345111649.1579634346-2060236217.1564155067.

186 Jaw, Kathy, Joshua Cunningham, and Tony Brasil. CARB. The Need for EV Charging Infrastructure Assessments to Inform Policies, March 11, 2019, IEPR Workshop on Assessing Charging Infrastructure Needs in California. https://efiling.energy.ca.gov/GetDocument.aspx?tn=227307&DocumentContentId=58166 and Jaw,

preliminary analyses in its AB 2127 charging infrastructure assessment, working closely with CARB's implementation of a comprehensive strategy for medium- and heavy-duty vehicle technologies and fuels under Senate Bill 44 (Skinner, Chapter 297, Statutes of 2019).

Kathy, David Quiros, Craig Duehring. California Air Resources Board. Regulatory Drivers for Transportation Electrification of Freight and Off-Road Equipment, May 2, 2019, IEPR Workshop on Assessing Charging Infrastructure Needs in California. https://efiling.energy.ca.gov/GetDocument.aspx?tn=228048&DocumentContentId=59334.

Table 5: Regulatory Measures In-Development for Zero-Emission Transportation

Sector of Vehicles or Equipment	Implementation and Milestones Estimated Statewide Population in 2019	CARB Preliminary Estimate of Electric Infrastructure Needs
Oceangoing Vessels at Berth Container, reefer, cruise, auto carrier, and tanker vessels	Reduce at berth emissions by controlling more visits, vessel types, and ports *Phase-in anticipated 2021–2029* 1,250	Varied by vessel type: container, reefer, & auto carrier ~1 MW; cruise ~3-11 MW; tankers ~0.5-2.5 MW
Harbor Craft Passenger and freight vessels, such as ferries, tugboats, barges, dredges	Cleaner combustion but support introduction of zero-emission technologies where feasible *Phase-in anticipated 2023* 3,500	Additional electrification expected to support augmented use of shore power and charging for emerging full zero-emission or "plug-in hybrid" diesel vessels with battery storage
Airport Ground-Support Equipment Transport baggage, cargo, and passengers to and from aircraft; move, service and provide ground power to aircraft	Transition to zero-emission GSE *Implementation 2023-2031* 7,000	Charging rates up to 80 kW or more (for example, multiport, multi-equipment charger) with a significant variation in charging demands for different types of GSE
Forklifts Warehousing, distribution centers, ports, manufacturing	Fleets of forklifts (<8,000 lb.) to transition to zero-emission technology *Implementation 2023-2035* 100,000	Charging rates up to 80 kW or more (for example, multiport, multi-equipment charger) with a significant variation in charging demands
Advanced Clean Trucks Pickup and delivery, drayage, utility, refuse, public, shuttle, others	Zero-emission trucks as a percentage of manufacturers sales *Implementation 2024+* 150,000	Initial: overnight depot charging Future: Public fast-charging network
Transportation Refrigeration Units Moving container, bulk, or liquid cargo at ports and intermodal rail yards	Trucks to use 100 percent zero-emission TRUs, Trailer TRUs to be zero when stationary, and facilities to provide infrastructure to allow for zero-emission operation on-site. *Phase-in anticipated 2025* 200,000	Up to 10,000 facilities (warehouses, stores, truck stops, etc.) may need to install electric (or other zero-emission technology) infrastructure.
Cargo Handling Equipment Moving container, bulk, or liquid cargo at ports and intermodal rail yards	Transition to full zero-emission technologies *Phase-in anticipated 2026* 5,000	Under development—considerations include charging rate required for battery electric equipment, and use of electric versus other zero-emission alternatives.
Airport Shuttles Transport passengers around airport property and between airports and nearby businesses (hotels, off-airport parking)	Transition to full zero-emission technologies *Phase-in anticipated 2027* 1,000	Majority of chargers will be 50 kW and above, likely requiring infrastructure upgrades at all regulated airports and most regulated businesses.

Source: CEC, based on information from CARB

CARB also administers the Low Carbon Fuel Standard (LCFS), requiring fuel providers to reduce the carbon intensity of transportation fuel by 20 percent by 2030. In 2018, CARB adopted amendments to the LCFS that added a special crediting provision for ZEV infrastructure including direct current (DC) fast charging and hydrogen refueling stations. Beyond the normal credits generated from the dispensed fuel, these special provisions allow an entity to generate infrastructure credits based on the capacity of the charger or station.

In 2014, the CPUC adopted Decision 14-12-079 to allow greater utility investment in electric vehicle charging infrastructure. The CPUC directed IOUs[187] to file applications for programs and investments that authorized nearly $1 billion in IOU transportation electrification spending through 2023.[188] Table 6 summarizes the transportation electrification programs for the three largest utilities subject to the CPUC's oversight.

187 The CPUC regulates six IOUs: Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), Liberty Utilities, PacifiCorp, and Bear Valley Electric Service.

188 CPUC Decision 18-01-024. [Link to Decision 18-01-024 on the CPUC's website](http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M204/K670/204670548.PDF)
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M204/K670/204670548.PDF.

CPUC Decision 18-05-040. [Link to Decision 18-05-040 on the CPUC's website](https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457637)
https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457637.

CPUC Decision 18-09-034. [Link to Decision 18-09-034 on the CPUC's website](http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M231/K030/231030113.PDF)
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M231/K030/231030113.PDF.

CPUC Decision 19-11-017, [Link to Decision 19-11-017 on the CPUC's website](http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K823/319823155.PDF)
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K823/319823155.PDF.

Table 6: CPUC-Jurisdictional Transportation Electrification Programs

Utility	Sector	Program Budget, Size and Scope
PG&E	Light-Duty	**EV Charge Network** ($130M) 7,500 level 2 electric vehicle supply equipment (L2 EVSE), **Fast Charge Program** ($22.39M) 234 direct-current fast chargers (DCFCs), **Home EV Charger Information Resource Project** ($500k) upgrade EV website**, EV Schools** ($5.76M) 88-132 L2 EVSE at 22 sites, **EV Parks** ($5.54M) 40 L2 EVSE & 3 DCFC at 15 sites
PG&E	Medium- and Heavy-Duty	**FleetReady Program** ($236.3M) electrify 700 sites and 6,500 MD/HD EVs, **Medium/Heavy-Duty Fleet Customer Demonstration** ($3.35M) make-ready & EVSE for 1 fleet, **Electric School Bus Renewables Integration** ($2.2M) make-ready equipment for 2-5 school buses
PG&E	Off-Road	**Idle Reduction Technology** ($1.7M) demonstrate idle-reduction technologies for truck stops or transport refrigeration units (TRUs)
SDG&E	Light-Duty	**Power Your Drive** ($45M) 3,500 L2 EVSE, **Electrify Local Highways** ($4M) 80 L2 EVSE & 8 DCFCs at park and rides, **Dealership Incentives** ($1.79M) dealership training, **Schools Pilot** ($18.7M) 184 L2 EVSE & 12 DCFC at 30 sites, **Parks Pilot** ($9.9M) 120 L2 EVSE & 20 DCFC at 10 sites.
SDG&E	Medium- and Heavy-Duty	**Fleet Delivery Services** ($3.69M) up to 90 MD EVs, **Green Shuttle** ($3.15M) L2 EVSE and/or DCFCs with solar/storage, **Medium-duty and Heavy-duty Electric Vehicle Charging Infrastructure Program** ($150.56M) 3,100 class 2-8 EVs, forklifts, and TRUs, **Vehicle-to-Grid Pilot** ($1.73M) utilize 10 school buses for V2G operations
SDG&E	Off-Road/ Ports	**Port Electrification** ($2.4M) 30 EVSEs for medium-duty/heavy-duty vehicles and forklifts
SDG&E	Airports	**Airport Ground Support Equipment** ($2.84M) EVSE retrofitting and assess fleet charging behavior
SCE	Light-Duty	**Charge Ready Pilot** ($44M) 2,500 L1/L2 EVSE, **Residential Make-Ready Rebate** ($3.99M) up to 5,000 L2 EVSE rebates, **Urban DCFC Clusters** ($3.98M) up to 50 DCFCs, **Charge Ready and Market Education Program** ($760.1M) rebates for 48,000 EVSEs, **Schools** ($9.89M) 250 L1/L2 EVSE at 40 sites, **Parks & Beaches** ($9.89M) 120 L2 EVSE, 10 DCFC, 15 mobile EVSE at 27 sites
SCE	Medium- and Heavy-Duty	**Medium/Heavy-Duty Make-Ready** ($342.6M) 870 sites with 8,490 medium-duty/heavy-duty EVs, **Electric Transit Bus Make-Ready** ($3.97M) bus depot make-ready equipment
SCE	Off-Road/ Ports	**Port of Long Beach Rubber Tire Gantry Crane** ($3.03M) make-ready equipment for nine cranes, **Port of Long Beach Terminal Yard Tractor** ($450k) 24 EVSE for yard tractors

Source: CPUC

POU Transportation Electrification

As discussed in Chapter 10, POUs are required to submit integrated resource plans (IRPs) to the CEC. In addition to meeting GHG targets and RPS procurement requirements, POU IRPs must address procurement of transportation electrification.[189] The IRPs describe incentives and rate programs for charging installation, principally for light-duty vehicles requiring residential, workplace, commercial, and public charging.

Within their IRPs, some POUs specifically referenced their current or anticipated incentives for charging infrastructure. Anaheim, for instance, proposes a $500 rebate for private-use chargers, a $5,000 rebate for public chargers, and a $10,000 rebate for Level 2 chargers at schools or affordable housing locations, or for public DC fast chargers. Several POUs are featuring transportation electrification in their IRPs. Plans of the two largest POUs—Los Angeles Department of Water and Power (LADWP) and Sacramento Municipal Utility District (SMUD)—are discussed below.

LADWP Transportation Electrification

LADWP's IRP recognizes the benefits of transportation electrification in reducing overall GHG and criteria pollutants in the Greater Los Angeles Area, increasing electric vehicle sales, and absorbing potential overgeneration from renewable resources. As a result, LADWP's preferred portfolio incorporates high electrification, including doubling the number of electric vehicles (EVs) it would serve from 290,000 to 580,000 in 2030.[190] In addition to vehicle electrification, other transportation electrification opportunities are available, including power for cargo ships at the Port of Los Angeles and electrified cargo transport and mass transit, among others.

LADWP updated its electric transportation program to include installing 10,000 city and private commercial chargers for public, workplace, and city-owned vehicles, as well as supporting residential and commercial EV charging. Other transportation electrification efforts include:

- Electrifying the Los Angeles Metro bus fleet by installing charging infrastructure for depot (overnight) charging and en route charging.

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189 The POU IRPs must also address energy storage, retail rates, reliability, net load, disadvantaged communities, and transmission and distribution systems. Specific discussions of these issues are presented in the staff review papers for each POU. [Link to docket log for 18-IRP-01 on the CEC's website](https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=18-IRP-01) https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=18-IRP-01.

190 The energy use in 2030 for transportation electrification in the base case is 1,172 GWh, which increases to 2,344 GWh in the high-electrification scenario.

- Purchasing 112 zero-emission electric buses for the Los Angeles Department of Transportation while converting 100 percent of buses to electricity by 2030.
- Electrifying equipment to reduce emissions from ships, trucks, harbor craft, and cargo-handling equipment for the San Pedro Bay Ports, which could increase load at the port to 900 GWh by 2030.
- Purchasing 20 electric buses to replace 14 diesel buses and add 6 buses to the Los Angeles World Airport fleet.

LADWP also participates in the electrification working group with Southern California Public Power Authority and the California Electric Transportation Coalition to address opportunities and challenges of a new, electrified transportation system and identify trends, business models, and strategies for rolling out charging infrastructure.

SMUD Transportation Electrification

Transportation electrification is part of SMUD's overall strategy of increased electrification in its service territory. SMUD promotes the adoption of EVs through purchase incentives, investments in charging infrastructure, and consumer education. As of 2018, there were about 9,400 light-duty EVs in Sacramento County. SMUD estimates that the Sacramento region will need more than 200,000 light-duty EVs by 2030 and roughly 1 million by 2050 to meet the state's GHG emission goals.

Specific EV-related incentives that SMUD offers include cash incentives for EV buyers, residential Level 2[191] charger incentives, and incentives for EV chargers at workplaces and multifamily residential housing. SMUD also offers EV owners an EV time-of-day rate that is designed to encourage EV charging after midnight. SMUD has looked at the grid impacts of increased EV charging and is investigating smart charging solutions in addition to strengthening its distribution system to address potential effects.[192]

SMUD is also participating in research projects related to medium- and heavy-duty EVs to prepare for the expected increase in EV adoption in that segment of the market. School bus fleets, refuse trucks, and shuttle buses are expected to be the first fleets to electrify in the medium- and heavy-duty EV sectors.

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191 Level 2 chargers use 208/240 volts, up to 19.2 kW (80 amps), whereas Level 1 chargers use 110/120 volts, 1.4 to 1.9 kW (12 to 16 amps). For reference, 1,000 kW is roughly enough electricity for the instantaneous demand of 750 homes at once.

192 "Smart charging" in the intelligent charging of EVs where charging can be shifted based on grid loads and in accordance with the vehicle owner's needs.

Incentives to Advance ZEVs

As part of meeting the state's targets, the state also administers or supports funding for the implementation of ZEVs and ZEV infrastructure through programs and activities. Key sources of funding are listed below.

- **Clean Transportation Program**: Administered by the CEC, the Clean Transportation Program (formerly known as the Alternative and Renewable Fuel and Vehicle Technology Program) provides funding for projects that help the state meet its GHG reduction and clean air goals. Despite numerous technological, policy, and market developments favoring the development and use of ZEVs and ZEV infrastructure, statutory guidance for the Clean Transportation Program has been only slightly modified since the first investment plan of the program in 2009.[193] For the *2019–2020 Investment Plan Update*, the CEC has sought to emphasize ZEVs and ZEV infrastructure within the $95.2 million in available program funding.[194] This funding includes a $20 million allocation for hydrogen refueling infrastructure.
- **School Bus Replacement Program**: Senate Bill 110 (Committee on Budget and Fiscal Review, Chapter 55, Statutes of 2017) allocated $75 million to the CEC to replace the oldest school buses in California, with a special priority on disadvantaged communities and those with a majority of students eligible for free or reduced-price meals. The CEC received applications listing more than 1,600 buses for replacement and exhausted available funds by providing 233 electric school buses to 64 awardees throughout the state. All these buses will have vehicle-to-grid capabilities built in, with the prospective of providing energy storage, back-up power in an emergency, and load-management services.
- **Air Quality Improvement Program/Low Carbon Transportation Program**: For the 2019–2020 fiscal year, CARB allocated $447 million in GHG Reduction Funds to the Low Carbon Transportation Program. An additional $48 million was allocated under the Air Quality Improvement Program, for a total of $495 million within a combined CARB funding plan. Specifically, the Low Carbon Transportation Program budget includes $200 million available for light-duty ZEV Clean Vehicle Rebate projects, $65 million for

193 The one noteworthy modification has been Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013), which required the CEC to allocate $20 million in each year's investment plan toward hydrogen refueling stations, until there are at least 100 publicly available stations in operation within California.

194 CEC. September 2019. *2019-2020 Investment Plan Update for the Clean Transportation Program - Second Lead Commissioner Report*. Publication Number CEC-600-2018-005-LCF-REV2. Available at https://efiling.energy.ca.gov/getdocument.aspx?tn=229582.

transportation equity projects, and $182 million for heavy-duty and off-road equipment.[195]

- **Electrify America**: Electrify America resulted from a settlement with Volkswagen for its violation of federal and state law by using illegal devices to defeat emission tests beginning with its Model Year 2009 vehicles. California will receive about $423 million from a national Environmental Mitigation Trust to fund projects that will fully alleviate the lifetime emissions caused by the illegal devices. In May 2018, CARB approved a beneficiary mitigation plan outlining how settlement funding will be spent.[196] Volkswagen will also invest $800 million in ZEV-related projects in the state, (including deployment of charging infrastructure, transit buses, freight projects, and drayage trucks) and must offer and sell additional BEV models in California between 2019 and 2025.
- **Transit and Intercity Rail Capital Program (TIRCP)**: Administered by the California Department of Transportation (Caltrans), the TIRCP provides competitive grants for capital improvement projects that will modernize the state's transit, rail, and ferry systems. In the 2015–2018 awards for the program, these projects have included funding for nearly 300 new ZEV buses for transit districts across the state. Funding for the buses came from a mixture of GHG Reduction Funds and the Road Repair and Accountability Act of 2017 (Senate Bill 1 [Beall, Chapter 5, Statutes of 2017]).[197]

Status of the PEV Market

On May 2, 2019, the CEC convened an IEPR workshop to discuss the latest status of the PEV market, including presentations from Bloomberg New Energy Finance (BloombergNEF), the International Council on Clean Transportation (ICCT), Navigant Consulting, and the U.S. Energy Information Administration (U.S. EIA).[198] These researchers discussed how targets to

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195 CARB. June 2019. Link to presentation on Fiscal Year 2019–2020 Funding Plan for Clean Transportaiton Incentives from the CARB website https://www.arb.ca.gov/sites/default/files/2019-06/061319_fundingplanwkshp_presentation.pdf.

196 CARB. June 2018. "Beneficiary Mitigation Plan for the Volkswagen Environmental Mitigation Trust." Link to information on the Volkswagen Environmental Mitigation Trust on the CARB website https://www.arb.ca.gov/our-work/programs/volkswagen-environmental-mitigation-trust-california.

197 More information about the Transit and Intercity Rail Capital Program is available at https://calsta.ca.gov/subject-areas/transit-intercity-rail-capital-prog.

198 Link to notice, presentations, and documents for the May 2, 2019, workshop on the Status of the ZEV Market https://www.energy.ca.gov/2019_energypolicy/documents/#05022019-am.

reduce GHG emissions and air pollution affect the automotive industry's advancement of vehicle powertrain and charging technologies, the possible impacts on the energy system, the outlook for new consumer products using PEV technologies, and emerging mobility options.

PEVs on the Global Stage

Globally in 2018, BEV and PHEV sales reached more than 2 million, with the market in China comprising more than 50 percent of demand.[199] Globally, 10 automakers produced nearly 1.5 million PEVs in 2018. Seven companies supplied batteries for the 1.5 million PEVs.[200]

The United States has the third-largest PEV market in the world, behind China and Europe; in 2018 Americans purchased roughly 350,000 PEVs, representing more than 2 percent of the nation's overall light-duty vehicle sales (shown in Figure 18). Californians purchased more than half of all U.S. EV sales, accounting for nearly 9 percent of the state's new cars.[201] PEV demand originating from the 10 states that adopted California's ZEV regulations accounts for 63 percent of demand nationwide.[202]

199 Nicholas, Michael. *Global Light Duty Electric Vehicle Trends, Costs of Battery Technologies, Consumer Prices, and Implications for Policy*. International Council on Clean Transportation. May 2, 2019, Workshop on the Status of the Zero-Emission Vehicle Market.

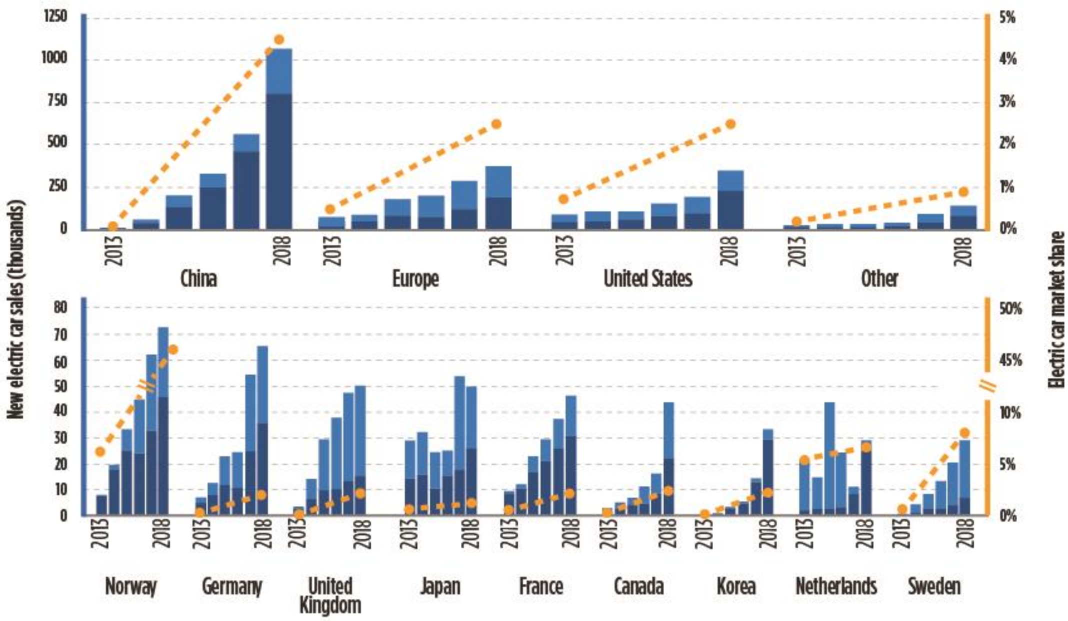
200 Ibid.

201 California New Car Dealers Association, "California Green Vehicle Report," February 2019. Link to California Green Vehicle Report on the California New Car Dealers Association website https://www.cncda.org/wp-content/uploads/Cal-Alt-Powertrain-Report-1Q-19-Release.pdf.

Veloz, "CA Electric Car Sales Broke Year-over-year Increases Every Month in 2018," January 11, 2019. Link to news release about electric car sales on Veloz' website https://www.veloz.org/wp-content/uploads/2019/01/Veloz-2018-Sales-Year-in-review-Release-FINAL.pdf.

202 Chawan, Ajay. *Perspective: Future of Transportation Electrification.* Navigant Consulting. May 2, 2019, Workshop on the Status of the Zero-Emission Vehicle Market.

Figure 18: Global Markets for Plug-In Electric Vehicles (2013–2018)



Source: International Energy Agency, Global EV Outlook 2019, Link to Global EV Outlook 2019 https://www.iea.org/publications/reports/globalevoutlook2019/.

To illustrate the scale of electrification efforts needed in the near term, Navigant and BloombergNEF estimate that global PEV sales are growing toward 25 million to 30 million per year by 2030, reaching cumulative sales of 150 million by the same year. Achieving carbon neutrality in alignment with the goals of the Paris Agreement[203] would likely require deployments well in excess of 200 million ZEVs over the next decade.[204]

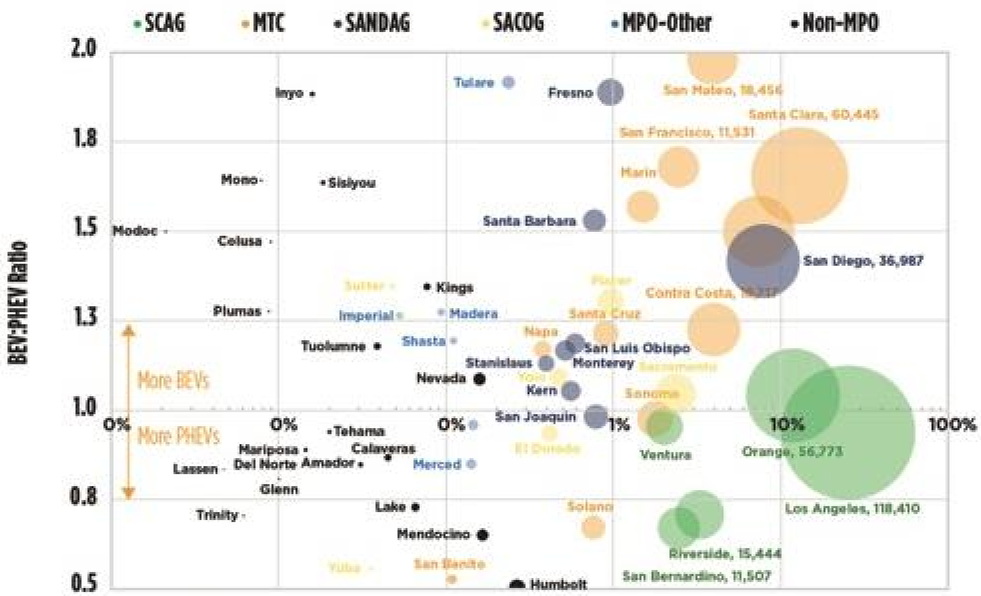
203 The Paris Agreement set a target of no more than 2 degrees Celsius warming, with a goal of 1.5 degrees, to avoid catastrophic climate change. http://unfccc.int/resource/docs/2015/cop21/eng/l09r01.pdf.

204 This level of ZEV deployment aligns with the International Energy Agency's Below 2 Degrees Scenario, which corresponds to a warming of 1.75˚C, which is within the range of the ambition of the Paris Agreement. Per Executive Order B-55-18, California is "pursuing efforts to keep warming below 1.5˚C." International Energy Agency. Global Electric Vehicle Outlook 2017, https://webstore.iea.org/global-ev-outlook-2017.

ZEVs Within California

According to the Department of Motor Vehicles, there were roughly a half-million light-duty ZEVs registered in California at the end of 2018. BEVs slightly outnumber PHEVs, with 51 percent and 48 percent of deployment, respectively, and with FCEVs comprising 1 percent of the ZEV market. PEVs purchased in the four largest metropolitan planning organization regions account for 62 percent of the PEVs in the state.[205] County-level powertrain preferences vary (Figure 19), with the largest southern coastal market purchases for BEVs and PHEVs at roughly equal rates, while drivers in southern inland counties prefer PHEVs, and Bay Area drivers generally prefer BEVs. The largest markets for FCEVs are Los Angeles (1,914 total registrations) and Orange County (1,243 total registrations).

Figure 19: Powertrain Preferences and Share of PEV Market, by County



Source: CEC analysis of Department of Motor Vehicles data. Registrations are as of December 31, 2018.

Heavy-duty vehicles are electrifying more slowly than passenger vehicles. Of the more than 2 million vehicles with weight limits greater than 6,000 pounds (Class 2 through Class 8)

205 These regions include areas covered by the Southern California Association of Governments (SCAG), Metropolitan Transportation Commission (MTC) of the Bay Area, San Diego Association of Governments (SANDAG), and Sacramento Council of Governments (SACOG).

registered in California as of December 2018, nearly 1,500 were BEVs. Of these BEVs, roughly 60 percent were Class 6, and roughly 25 percent were Class 4, both considered "medium-duty." As of the end of 2018, there were no registered Class 2 BEVs nor any Class 3 through Class 8 PHEVs or FCEVs. However, nearly all conventional truck manufacturers have announced plans for commercialization of zero-emission trucks by 2021. Furthermore, new manufacturers specializing in zero-emission trucks and buses are entering the market. The total ownership cost for zero-emission buses, when accounting for reduced fuel and maintenance costs, is lower than for compressed natural gas (CNG) and diesel buses. When accounting for societal benefits and cost of individual ownership, the CEC's School Bus Replacement Program found electric buses to have a cost-effectiveness score of 1.28, compared to a score of 0.73 for CNG and 0.71 for diesel.[206] According to CARB, cost parity for electrified trucks (not including infrastructure) is projected to be comparable to diesel within five years, resulting in increased demand and supply for such configurations.[207] However, ZEV infrastructure investments will be needed to enable the broader adoption of these vehicles. For more detail on projected demand for medium- and heavy-duty vehicles, see Chapter 8 on the Transportation Energy Demand Forecast.

Supply Trends in PEV Industry

The future growth of all ZEV classes in California will be increasingly influenced by the global market. Perhaps the most important factor will be the automotive battery supply chain. In the CEC's May 2019 workshop, BloombergNEF reported that since 2010, the price of automotive lithium-ion battery packs has declined 85 percent to a 2018-weighted average of $176 per kilowatt-hour (kWh). Individual automakers' purchase contracts vary by chemistry and production volume within a range of $125/kWh to $400/kWh.[208] This estimate is consistent with an ICCT review of a bottom-up engineering cost analysis, automaker statements, and

206 The cost-effectiveness score consists of societal benefits and the total cost of ownership (TCOE), an industry standard for measuring lifetime cost of a project over 20 years. If the quotient is 1 or greater, the project is cost-effective. If the quotient is less than 1, the project is not cost-effective. CEC School Bus Replacement Program https://www.energy.ca.gov/sites/default/files/2019-05/Cost-Effectiveness.pdf.

207 Jaw, Kathy, Joshua Cunningham, and Tony Brasil. CARB. The Need for EV Charging Infrastructure Assessments to Inform Policies, March 11,2019, IEPR Workshop on Assessing Charging Infrastructure Needs in California. Link to presentation "The Need for EV Charging Infrastructure Assessments to Inform Policies" filed on the CEC's website https://efiling.energy.ca.gov/GetDocument.aspx?tn=227307&DocumentContentId=58166.

208 Goldie-Scot, Logan. "Battery Storage Costs and Implications for the Electrification of Transportation." BloombergNEF. May 2, 2019, Workshop on the Status of the Zero-Emission Vehicle Market.

other prominent projections.[209] In December 2019, BloombergNEF reported that battery pack prices have further fallen to $156 per kWh, noting that increasing order size, growing BEV sales, and the use of high-energy-density cathodes drove recent cost reductions.[210]

By 2030, the price of a battery pack may range between $50 and $100 per kWh. Major factors that could reduce costs include continued advancement in cathode and anode design, improvements in cell energy density from solid-state electrolytes, higher package efficiency, economies of scale, and manufacturer learning and subsequent process improvements.[211] Price volatility of the component metals used within batteries is unlikely to increase costs greatly. For example, BloombergNEF estimates that doubling the commodity cost of nickel (the metal that would most greatly change pack cost) would only increase the cost of a nickel-manganese-cobalt (NMC 811) cathode-based battery pack by about 6 percent.[212]

Transportation electrification with BEVs is expected to expand across vehicle classes commensurate with cost reductions compared to conventional internal combustion engines and PHEVs, principally driven by battery pack cost reductions. The main factors affecting cost-competitiveness among the different powertrain types include vehicle class (for example, car, light truck, sport utility vehicle), range (affecting the size of the pack), and the incremental costs for combustion engine vehicles to comply with increasing fuel efficiency requirements across international markets. Notably, in contrast to BEVs, PHEVs are unlikely to see a similar cost reduction, given that PHEVs have smaller battery packs that represent a lower share of overall cost, and PHEVs must be engineered to support components for electric and internal combustion powertrains.[213]

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209 ICCT, 2019. "Update on Electric Vehicle Costs in the United States Through 2030," https://theicct.org/sites/default/files/publications/EV_cost_2020_2030_20190401.pdf.

210 Henze, Veronica. "Battery Pack Prices Fall as Market Ramps Up With Market Average at $156/kWh In 2019." BloombergNEF. December 3, 2019. https://about.bnef.com/blog/battery-pack-prices-fall-as-market-ramps-up-with-market-average-at-156-kwh-in-2019/.

211 Presentations from Logan Goldie-Scot and Mike Nicholas at the May 2, 2019, workshop on the Status of the Zero-Emission Vehicle Market.
https://efiling.energy.ca.gov/GetDocument.aspx?tn=228033&DocumentContentId=59317 and
https://efiling.energy.ca.gov/GetDocument.aspx?tn=228037&DocumentContentId=59318.

212 NMC 811 battery packs are commonly used in Chevrolet, BMW, and Nissan electric vehicles. Goldie-Scot, Logan. "Battery Storage Costs and Implications for the Electrification of Transportation." BloombergNEF. May 2, 2019, workshop on the Status of the Zero-Emission Vehicle Market.

213 Presentations from Logan Goldie-Scot and Mike Nicholas at the May 2, 2019, workshop on the Status of the Zero-Emission Vehicle Market.

To further illustrate the modular and flexible design of battery systems, Navigant highlighted Audi's globally standardized battery pack architecture that can accommodate many cell supplier designs and form factors, as well as Ford's $500 million investment to develop trucks based on Rivian's low-profile battery and powertrain platform.[214]

The four researchers at the May 2019 workshop unanimously agreed that BEV growth would likely outpace PHEV growth. BloombergNEF noted that 248 of the 384 PEV models that will be available globally by early 2020 will be BEVs.[215] Both ICCT and BloombergNEF analyses estimate that BEVs will reach purchase cost parity with internal combustion engine vehicles in equivalent classes during the mid-2020s, and one to two years sooner if considering the total cost of ownership parity.[216] However, while PHEVs may not achieve initial cost parity with internal combustion engine vehicles in the near future, they may provide utility for drivers who do not have home charging.[217] By the end of 2022, PHEVs may constitute about half of the 81 PEV models that are expected in the United States.[218] Globally, by 2025, with several hundred models available, auto manufacturers are anticipated to sell 15 million PEVs annually, given the anticipated effects of existing regulatory sales requirements. However, as discussed in the next section, complementary policies to address charging infrastructure needs and enable broader driver acceptance may be necessary to secure the benefits of global economies of scale and continued growth for the California market.[219]

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https://efiling.energy.ca.gov/GetDocument.aspx?tn=228033&DocumentContentId=59317 and https://efiling.energy.ca.gov/GetDocument.aspx?tn=228037&DocumentContentId=59318.

214 Chawan, Ajay. "Perspective: Future of Transportation Electrification." Navigant Consulting. May 2, 2019, workshop on the Status of the Zero-Emission Vehicle Market.

215 Transcript of the May 2, 2019, Workshop on the Market for ZEVs https://efiling.energy.ca.gov/GetDocument.aspx?tn=228404&DocumentContentId=59603.

216 Presentations from Logan Goldie-Scot and Mike Nicholas at the May 2, 2019, workshop on the Status of the Zero-Emission Vehicle Market.
https://efiling.energy.ca.gov/GetDocument.aspx?tn=228033&DocumentContentId=59317 and https://efiling.energy.ca.gov/GetDocument.aspx?tn=228037&DocumentContentId=59318.

217 ICCT, 2019. Update on electric vehicle costs in the United States through 2030.

218 Link to Electric Vehicle Market Status paper by M.J. Bradley & Associates LLC https://www.mjbradley.com/sites/default/files/ElectricVehicleMarketStatus05072019.pdf.

219 Nicholas, Michael. "Global Light-Duty Electric Vehicle Trends, Costs of Battery Technologies, Consumer Prices, and Implications for Policy." International Council on Clean Transportation. May 2, 2019, workshop on the Status

Effects of Automation and Shared Mobility

The confluence of vehicle electrification, driving automation, and connected (capable of remote communication) or shared mobility (which includes ride-hailing, taxis, and car sharing) has the potential to lead to dramatically decreased or increased emissions from the transportation sector. McKinsey & Company analyzed the $220.6 billion invested since 2010 in nearly 1,200 global startup companies operating in 10 mobility technology areas. Overall, U.S. investors have spent the largest amount, and U.S. companies have received $84.5 billion, the most investment of any country.[220] Importantly for emissions reductions, the electric vehicle, charging, and battery sectors garnered 15 percent of cumulative investment ($33 billion). The rate of annual investment in electric vehicles and charging in the 2014–2019 period notably increased to $3 billion per year, a fivefold increase over the 2010–2013 period. Electrification investments rival the $29.9 billion invested in automated vehicle and advanced driver assistance systems. While electrification investments are a relatively small part of the mobility sector, electrification has generated more than 14,000 patents, nearly half of the total.

As the leading market for ZEVs within the United States, it is feasible and imperative for California to promote innovative approaches in mobility to minimize transportation emissions. For example, in its 2018 Annual Energy Outlook, the U.S. Energy Information Administration (U.S. EIA) provides scenarios and costs related to the introduction of autonomous vehicles (AVs) into the transportation sector. The U.S. EIA estimates the costs of nonspeed-limited Level 4 and Level 5 AVs[221] to decline by half between 2025 and 2050 (to about $80,000) as LIDAR[222] technology improves. The U.S. EIA also projects that the ride-hailing providers would

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of the Zero-Emission Vehicle Market. https://efiling.energy.ca.gov/GetDocument.aspx?tn=228037&DocumentContentId=59318.

220 McKinsey & Company. 2019. "Start Me Up: Where Mobility Investments are Going." Memorandum from Noel Crisostomo with the CEC to the Docket Unit of the CEC regarding adding information to the 19-IEPR-04 docket https://efiling.energy.ca.gov/GetDocument.aspx?tn=228310&DocumentContentId=59494.

221 Per the U.S. Department of Transportation, "Automated Driving Systems 2.0, A Vision For Safety," Level 4 automation is "high automation" where the vehicle is capable of performing all driving functions under *certain* conditions and the driver may have the option to control the vehicle. Level 5 automated vehicles can perform all driving functions under *all* conditions. Automated Driving Systems 2.0 document from the National Highway Traffic Safety Administration's website https://www.nhtsa.gov/sites/nhtsa.dot.gov/files/documents/13069a-ads2.0_090617_v9a_tag.pdf.

222 "LIDAR" stands for Light Detection and Ranging and is a key technology allowing vehicles to sense the position of other objects.

begin purchasing full-speed Level 4 AVs in 2025 and in the mid-2030s will pivot to prefer Level 5 AVs. Overall, the U.S. EIA estimated that between 2040 and 2050, AVs would increase from 5 percent to 50 percent of sales for ride-hailing fleets.[223]

For comparison, BloombergNEF's 2019 EV Outlook estimates that shared mobility will serve 20 percent of total passenger travel by 2040, and that 80 percent of the shared mobility fleet will be PEVs because of superior operational costs. Strikingly, when compared to the 2018 EV Outlook, BloombergNEF's 2019 EV Outlook found that 51 million fewer passenger PEVs will be sold globally in 2040 due in part to a "less optimistic view on car sales and a more aggressive view on the growth of shared mobility."[224] Separately, the U.S. EIA estimates that AVs could reduce energy consumption of the U.S. light-duty vehicle fleet by 60 percent or increase it by 200 percent.[225] In general, uncertainty in how autonomous vehicle trends will affect vehicle fuel efficiency, vehicle miles traveled, and energy use has raised the need to minimize emissions of AVs as a key policy priority for California's energy and transportation planning agencies.[226] Aligned with its second Advanced Clean Cars Program and consistent with a requirement to reduce emissions from transportation network companies (Senate Bill 1014, Skinner, Chapter 369, Statutes of 2018), CARB is developing a Clean Miles Standard with the intent of encouraging ZEVs to reduce vehicle miles traveled via pooling, active transport, and transit, and to account for AVs.[227]

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223 Chase, Nicholas. U.S. EIA. "Zero-Emission Vehicles and Automated Vehicles: Uncertainty and Energy Implications." May 2, 2019 workshop on the Status of the Zero-Emission Vehicle Market. Presentation by U.S. EIA at the May 2, 2019, workshop on the ZEV market https://efiling.energy.ca.gov/GetDocument.aspx?tn=228035&DocumentContentId=59320.

224 BloombergNEF Electric Vehicle Outlook 2019. Memorandum from Noel Crisostomo with the CEC to the Docket Unit of the CEC regarding adding information to the 19-IEPR-04 docket https://efiling.energy.ca.gov/GetDocument.aspx?tn=228309&DocumentContentId=59493.

225 Chase, Nicholas. U.S. EIA. "Zero-Emission Vehicles and Automated Vehicles: Uncertainty and Energy Implications." May 2, 2019 workshop on the Status of the Zero-Emission Vehicle Market. Presentation by U.S. EIA at the May 2, 2019, workshop on the ZEV market https://efiling.energy.ca.gov/GetDocument.aspx?tn=228035&DocumentContentId=59320.

226 Governor's Office of Planning and Research. "California Automated Vehicle Principles for Healthy and Sustainable Communities." Automated Vehicle Principles for Healthy and Sustainable Communities information on the Governor's Office of Planning and Research website http://opr.ca.gov/docs/20181115-California_Automated_Vehicle_Principles_for_Healthy_and_Sustainable_Communities.pdf.

227 Jaw, Kathy, Joshua Cunningham, and Tony Brasil. CARB. "The Need for EV Charging Infrastructure Assessments to Inform Policies, March 11 IEPR Workshop on Assessing Charging Infrastructure Needs in

FCEVs and the Hydrogen Refueling Market

While not currently as prevalent as PEVs, fuel cell electric vehicles (FCEVs) represent another opportunity to expand the role and benefits of ZEVs within the state. Like BEVs, FCEVs produce no tailpipe emissions but there are emissions "upstream" through fuel production; unlike today's BEVs, they can be refueled nearly as quickly as conventional vehicles, with long driving ranges. These attributes can help ease the deployment of ZEV technology into important vehicle market segments, including passenger vehicles (especially for drivers with no convenient access to home charging), ride-hailing services, long-haul freight and fleet vehicles, and public transit agencies.

FCEVs are incorporated into some of the state's key planning documents and policies related to ZEVs, including the state's 2016 *Mobile Source Strategy*[228] and 2017 *Climate Change Scoping Plan*.[229] Hydrogen refueling stations are similarly called out under Executive Order B-48-18, which calls for 200 hydrogen refueling stations by 2025.

Looking beyond California, several factors point to the near-term potential of FCEVs. In January 2019, President Moon Jae-in of South Korea announced plans to have 80,000 FCEVs on the road by 2022, including 2,000 fuel cell electric buses.[230] The Japan H2 Mobility project plans to install 80 additional hydrogen refueling stations by the end of its fiscal year 2021 (in addition to the over 100 stations in operation as of January 2020).[231] China has set a target for 1 million FCEVs by 2030, though it has also announced the phaseout of a major FCEV

California." Presentation by CARB at the March 11, 2019, workshop on EV Charging Infrastructure Assessment (AB 2127) https://efiling.energy.ca.gov/GetDocument.aspx?tn=227307&DocumentContentId=58166.

228 CARB. 2016. "Mobile Source Strategy." https://www.arb.ca.gov/planning/sip/2016sip/2016mobsrc.pdf.

229 CARB. 2017. "*California's 2017 Climate Change Scoping Plan.*" https://www.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf.

230 Gasworld, January 17, 2019. "South Korea Unveils Hydrogen Economy Plans." https://www.gasworld.com/south-korea-unveils-hydrogen-economy-plans/2016332.article.

231 Japan H2 Mobility. May 8, 2019. "21 New HRS Installed in Fiscal 2019." https://www.jhym.co.jp/en/wp-content/uploads/2019/05/EN-JHyM_20190508-HRS-installation-plan.pdf.

Reuters. January 16, 2020. "Tokyo Gas Opens New Hydrogen Station Ahead of Olympics in Clean Energy Drive." https://www.reuters.com/article/us-tokyo-gas-hydrogen/tokyo-gas-opens-new-hydrogen-station-ahead-of-olympics-in-clean-energy-drive-idUSKBN1ZF0Z9.

consumer subsidy.[232] In Germany, the H2 Mobility initiative has a near-term goal of 100 hydrogen refueling stations, with another 300 to follow.[233]

California's FCEV Deployment

At the end of 2019, California has nearly 7,000 FCEVs on the road, more than any other jurisdiction in the world. In accordance with Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013), CARB administers an annual survey of automakers to determine the number of FCEVs projected to be sold or leased within the next three years, and optionally within the next four to six years. The latest automaker survey from CARB projects 48,000 FCEVs in California by 2025, as shown in Figure 20.[234] Within this figure, the blue outline represents automakers' FCEV projections within the mandatory reporting period (the upcoming three years), and the orange outline shows projections within the optional reporting period (three additional years thereafter). The red triangles and yellow circles respectively indicate the actual number of FCEV registrations in April and October of those years.

Relative to similar projections made by automakers in 2018 (47,200 by 2024), the 2019 projections continue to suggest significant future growth in FCEV deployment, but with a roughly one-year shift.[235]

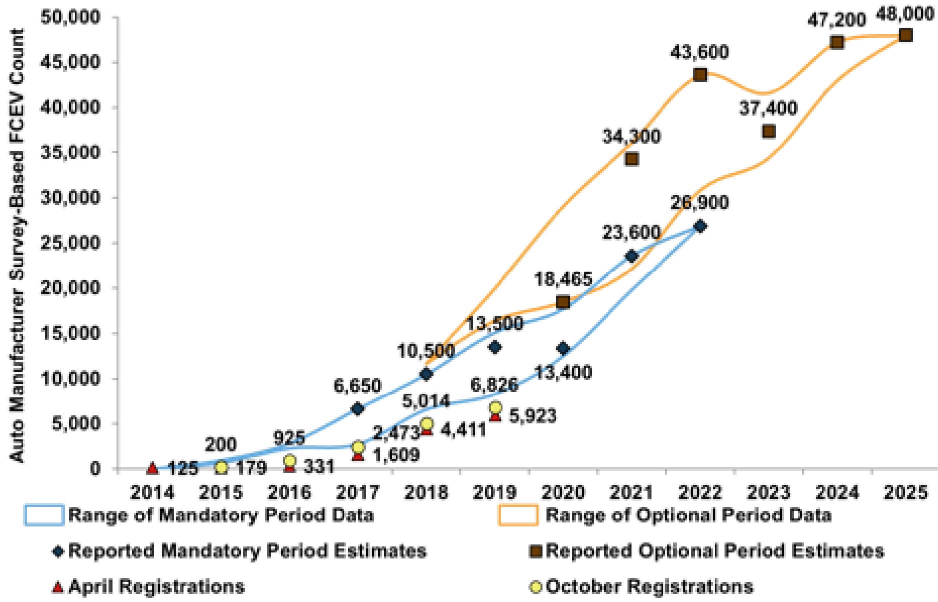
232 Greentech Media. October 15, 2019. "China to Eliminate Subsidies for Hydrogen Fuel-Cell Cars: Report." https://www.greentechmedia.com/articles/read/china-to-eliminate-subsidies-for-fuel-cell-cars.

233 H2 Mobility. "H2 Mobility." https://h2.live/en/h2mobility.

234 Baronas, Jean, Gerhard Achtelik, et al. 2019. *Joint Agency Staff Report on Assembly Bill 8: 2019 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California*. California Energy Commission and California Air Resources Board. Publication Number: CEC-600-2019-039. https://www.energy.ca.gov/2019publications/CEC-600-2019-039/CEC-600-2019-039.pdf.

235 CARB. 2018. *2018 Annual Evaluation of Fuel Cell Electric Vehicle Deployment & Hydrogen Fuel Station Network Development.* https://www.arb.ca.gov/sites/default/files/2018-12/ab8_report_2018_print.pdf.

Figure 20: FCEV Projections From Auto Manufacturer Survey



Source: CARB

Expanding In-State Hydrogen Refueling Stations

A convenient, reliable network of hydrogen refueling stations is critical to supporting the growth of FCEVs within the state.[236] With investment from the CEC's Clean Transportation Program, California has been steadily increasing the coverage of hydrogen refueling stations, focusing first on early adopter communities, and steadily branching out into adjacent communities and interregional corridors. At the end of 2019, California had 43 open retail hydrogen refueling stations available to dispense hydrogen as a transportation fuel to the public. Funding has also been specifically encumbered for another 20 stations, which are in various stages of development.

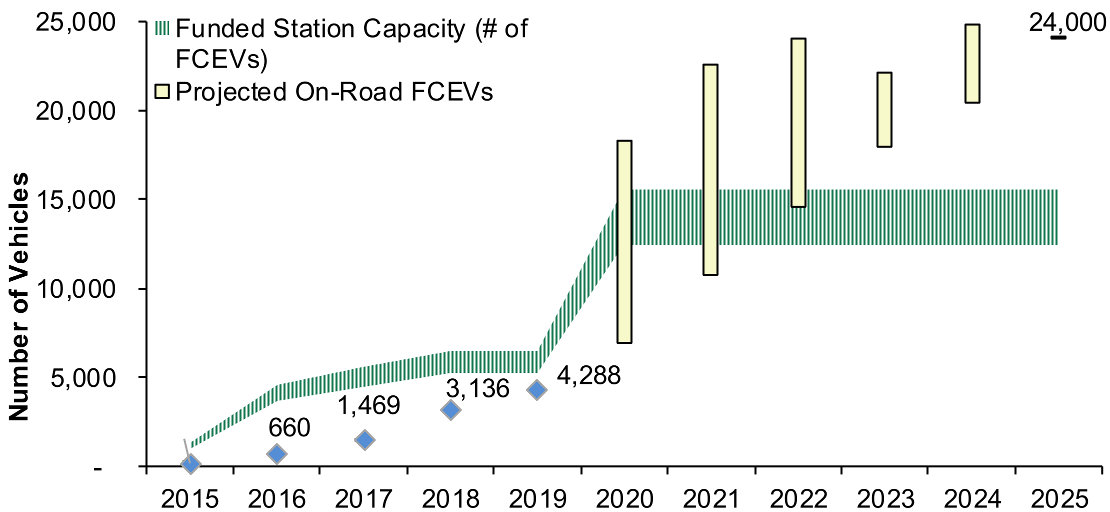
However, expanding the geographic coverage of the refueling network is only one part of ensuring network adequacy. To meet drivers' needs, stations (and regional networks of stations) must be have sufficient refueling capacity. This sufficient capacity is typically expressed in terms of the kilograms of hydrogen that can be dispensed in a day (kg/day). The

236 "The most urgent task… is the required focus on infrastructure build out. Only with further station deployment can the early progress of the FCEV market be turned into long-term success." California Hydrogen Business Council, July 2, 2019. Comments submitted to docket 19-IEPR-04. "CHBC Comments on IEPR Commissioner Workshop on the Status of the Zero Emission Vehicle Market." https://efiling.energy.ca.gov/GetDocument.aspx?tn=228896&DocumentContentId=60270, p. 4.

combined nameplate capacity of the state's current 43 hydrogen refueling stations is more than 11,800 kg/day, roughly sufficient to serve 17,000 FCEVs with a typical use of 0.7 kg/day. When including the 20 additional funded stations, the combined capacity will be roughly 24,500 kg/day, sufficient for 35,000 FCEVs.[237]

It is important to consider this capacity in light of automaker FCEV projections, as well as region-specific variation. For example, Figure 21 depicts a gradual increase in the reported FCEVs and projected ranges of FCEVs over time (as blue diamonds and vertical bars, respectively) within the Greater Los Angeles Area.[238] The green lines in the figure depict the combined capacity of the funded stations in terms of the estimated number of FCEVs the stations could serve.[239] The green lines level off in 2020 as the last of the currently funded stations open for retail. As shown, the projected range of FCEVs could potentially exceed the capacity of the stations to serve them as soon as 2020-2021 and almost certainly by 2022.

Figure 21: Greater Los Angeles Area Station Capacity and Number of Vehicles



Source: CEC and CARB

237 Baronas, Jean, Gerhard Achtelik, et al. 2019.

238 As used here, the "Greater Los Angeles Area" refers to the counties of Los Angeles, Orange, Riverside, San Bernardino, and Ventura. Most FCEVs from automaker projections are expected to be deployed in this area.

239 The range between the top and bottom of the lines represents a range of 80 percent to 100 percent of the combined nameplate capacity of the stations. The lower edge, representing 80 percent, reflects a sustainable level of fueling such that stations are not empty at the end of the day.

To help address coverage and capacity needs, the CEC released a new funding solicitation for hydrogen refueling stations (GFO-19-602) in December 2019, with up to $115.7 million available from past, present, and future fiscal years. This is the first hydrogen refueling solicitation issued by the CEC since the Low Carbon Fuel Standard was amended to incorporate the Hydrogen Refueling Infrastructure Pathway.[240] The additional incentives that may be available from this pathway have allowed the CEC to focus narrowly on funding for equipment expenditures. While results from the solicitation are still pending, CEC staff estimates that at least 60 additional stations could be funded. If these stations can be brought on-line within two years of being funded, California could reach and potentially surpass a milestone of 100 stations on-line by 2023.[241]

Opportunities for Fleet and Heavy-Duty FCEVs

According to the California Fuel Cell Partnership, there were 42 fuel cell electric buses operating within California at the start of 2020.[242] This number is likely to increase in the coming years as transit fleets prepare to comply with requirements under CARB's Innovative Clean Transit regulation. The Advanced Clean Truck regulation is likely to generate demand for FCEVs among other heavy-duty classifications. Relative to today's battery-electric heavy-duty vehicles, fuel cell electric trucks and buses offer the advantages of reduced weight, longer range, and quicker refueling times, all of which are important factors to public and commercial fleets. As noted by the California Hydrogen Business Council, delivery companies such as FedEx and UPS are already using medium duty fuel cell trucks, while heavy-duty trucks are in development and testing with Toyota, Kenworth, Nikola Motor, and Loop Energy.[243]

Public funding may be needed to support the refueling needs of heavy-duty and fleet FCEVs, particularly in the early years of deployment.[244] The integration of fleet refueling can also support stations that serve light-duty vehicles. For instance, on October 10, 2019, the

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240 CARB. "LCFS ZEV Infrastructure Crediting." https://www.arb.ca.gov/fuels/lcfs/electricity/zev_infrastructure/zev_infrastructure.htm.

241 Baronas, Jean, Gerhard Achtelik, et al. 2019. p. 39.

242 California Fuel Cell Partnership, "By the Numbers," as viewed January 1, 2020. Available at https://cafcp.org/by_the_numbers.

243 California Hydrogen Business Council. July 2, 2019. "CHBC Comments on IEPR Commissioner Workshop on the Status of the Zero Emission Vehicle Market." https://efiling.energy.ca.gov/GetDocument.aspx?tn=228896&DocumentContentId=60270.

244 California Hydrogen Business Council. August 1, 2019. "CHBC Comments on CEC Clean Transportation Plan." https://efiling.energy.ca.gov/GetDocument.aspx?tn=229203&DocumentContentId=60601.

hydrogen refueling station at University of California, Irvine, set an in-state record for single-day hydrogen dispensing—nearly 400 kilograms. The station provides fuel to one fuel cell electric bus each day, between 10 p.m. and 2 a.m., when light-duty FCEVs are least likely to use the station.[245] In recognizing this potential synergy, Solicitation GFO-19-602 specifically encourages projects that incorporate fueling agreements with fleets of commercial vehicles and transit buses while stipulating that the fueling of such vehicles must not diminish the light-duty FCEV customer's experience.[246]

Expanding Hydrogen Supply and Integrating Renewable Resources

Events in 2019 demonstrated the importance of focusing on not just hydrogen refueling stations, but on the hydrogen supply chain as well. A disruption at a Northern California hydrogen distribution facility resulted in the plant's downtime from June 1 to October 4, 2019. This downtime decreased the amount of hydrogen that could be distributed to hydrogen refueling stations and FCEV drivers. Stations in the San Francisco Bay and Sacramento Areas were left to dispense roughly half of what they had been dispensing previously. Near-term consequences included FCEV drivers enduring over four months with limited fuel (many not being able to drive their FCEVs at all), paused deliveries of FCEVs by dealers, effects to FCEV drivers' confidence in hydrogen as a transportation fuel, and the delayed commissioning of new stations (which require fuel to complete the commissioning).[247]

The supply disruption demonstrated bottlenecks in the hydrogen supply chain. The California Hydrogen Business Council has noted that relying on a single company to supply the hydrogen refueling network can have significant consequences when that production or distribution is interrupted. Indeed, at the end of 2019, most of the hydrogen delivered to refueling stations comes from a single production plant.[248] With that in mind, the Council supports efforts to use incentives to spur competition and create a more robust supply chain network.[249] Encouragingly, several hydrogen suppliers have announced intentions to develop new production plants in or near California. Air Liquide, a French industrial gas company, is

245 Baronas, Jean, Gerhard Achtelik, et al. 2019.

246 CEC. December 2019. "Grant Funding Opportunity. Clean Transportation Program. Hydrogen Refueling Infrastructure." https://www.energy.ca.gov/sites/default/files/2019-12/01_GFO-19-602_Application_Manual.docx

247 Baronas, Jean, Gerhard Achtelik, et al. 2019. See Appendix A: Hydrogen Supply.

248 Ibid.

249 California Hydrogen Business Council. July 2, 2019.

planning to build a plant in Nevada that would produce 30 tons of liquid hydrogen per day partly from renewable natural gas, which is sufficient to fuel 43,000 FCEVs.[250]

The CEC released a solicitation for renewable hydrogen transportation fuel production facilities and systems in 2018 to increase California's fuel supply. As a result, as of January 2020, one new 100 percent renewable hydrogen facility is in the engineering design and permitting process, and a second project is seeking a site.

Furthermore, as part of its recent solicitation for new hydrogen refueling stations, the CEC requires applicants to have a hydrogen fuel supply and delivery agreement as well as a second supply arrangement as backup. The need to encourage competition and diversification of the hydrogen supply chain pairs well with the state's long-standing policy to encourage renewable, low-carbon hydrogen. Senate Bill 1505 (Lowenthal, Chapter 877, Statutes of 2006) requires that one-third of the hydrogen from state-funded fueling stations come from renewable pathways. The CEC, in its Clean Transportation Program solicitations, has also required applicants to meet this quantity and has given competitive advantage to those who exceed it. More recently, the ability to generate LCFS credit via the Hydrogen Refueling Infrastructure pathway may encourage station developers to increase the renewable content and lower the carbon intensity of their fuels.

About 36 percent of hydrogen dispensed in California's network is considered renewable. With limited opportunities to secure hydrogen directly from renewable resources, most of this renewable content comes from the procurement of renewable energy certificates.[251] However, this could change as business cases arise to deal with oversupply of renewable electricity.

Using hydrogen as both a transportation fuel and energy carrier can enable a renewable energy system that leverages investments in both.[252] As part of a California Hydrogen Infrastructure Research Consortium research agreement between California agencies and the National Renewable Energy Laboratory (NREL), NREL will conduct a literature review of existing hydrogen grid integration and energy storage projects, including those at various

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250 Air Liquide. "Air Liquide Committed to Producing Renewable Hydrogen for the West Coast Mobility Market With New Liquid Hydrogen Plant." October 8, 2019. https://www.airliquide.com/united-states-america/air-liquide-committed-producing-renewable-hydrogen-west-coast-mobility-market.

251 Baronas, Jean, Gerhard Achtelik, et al. 2019. See Appendix A: Hydrogen Supply.

252 Hydrogen Council. "Hydrogen, Scaling Up." November 2017. https://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-scaling-up-Hydrogen-Council.pdf.

national laboratories. NREL will compare electrolyzers against other production and storage technologies, evaluate the associated value towards reducing curtailment of renewable energy, and study affordable pathways for hydrogen integration and transportability.

Charging Infrastructure Analyses for Widespread Deployment

For California to meet its goals to reduce transportation emissions, it is critical to address a key constraint to the sustained long-term growth of ZEVs by accelerating the widespread deployment of charging infrastructure.

In March 2018, the CEC published a projection of the charging infrastructure needed to ease the adoption of 1.5 million ZEVs by 2025. In collaboration with NREL, the CEC developed a modeling framework that quantifies the types of charging infrastructure needed to ensure that light-duty PEV drivers can meet their personal mobility needs.[253] The CEC's resulting "Electric Vehicle Infrastructure Projections" (EVI-Pro) tool estimated the needed types of chargers by county for each year up to 2025. By 2025, these include 121,000 chargers at multiunit dwellings, 99,000–133,000 Level 2 chargers at destinations, and 9,000–25,000 DC fast chargers in public locations.[254]

Later in 2018, the Legislature passed Assembly Bill 2127 (Ting, Chapter 365, Statutes of 2018). The statute directs the CEC to complete biennial assessments of charging infrastructure needed to meet the state's 2030 goals for GHG emissions reductions and the deployment of 5 million ZEVs, as well as achieve ambient air quality standards. The assessment will expand upon the EVI-Pro tool as part of analyzing charging infrastructure, make-ready electrical equipment, supporting hardware and software, and other programs. The assessment will focus on the adoption of PEVs in on-road, off-road, port, and airport applications. The statute requires gathering data and feedback from the CPUC, CARB, utilities, transportation and transit agencies, charging infrastructure companies, environmental groups, automobile manufacturers, and others.

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253 Bedir, Abdulkadir, Noel Crisostomo, Jennifer Allen, Eric Wood, and Clément Rames. 2018. *California Plug-In Electric Vehicle Infrastructure Projections: 2017-2025.* CEC. Publication Number: CEC-600-2018-001. Revised California Plug-in Electric Vehicle Projections: 2017–2025 staff report https://efiling.energy.ca.gov/GetDocument.aspx?tn=224521&DocumentContentId=55071.

254 CEC EV Infrastructure Projection Tool (EVI-Pro) Link to online CEC EV Infrastructure Projection Tool http://maps.nrel.gov/cec.

The CEC presented on the initial scoping of these analyses in IEPR workshops March 11, 2019,[255] and May 2, 2019,[256] as well as a Demand Analysis Working Group meeting June 14, 2019.[257] In these presentations, the CEC described a framework for the factors driving adoption of electric transportation technologies and associated charging infrastructure. Representatives from CARB, the CPUC, the South Coast Air Quality Management District, the San Joaquin Air Pollution Control District, and leading electric transportation researchers at NREL Lawrence Berkeley National Laboratory (LBNL) and the University of California at Davis (UCD) also presented at the workshops.

CARB's Vision scenario planning framework, as discussed in these workshops, is an iterative process for developing scenarios for emission reduction strategies. Within this framework, CARB identifies strategic actions especially relevant to the charging infrastructure assessment, including the need to increase the penetration of zero-emission technologies, reduce growth in travel demand, demonstrate new technology, and provide incentives for adoption.[258] CARB's Vision analysis and strategies will be critical for measuring the demand and trajectory for the CEC's assessment of charging needed in various electrification applications, which in turn may provide feedback to inform decisions on vehicle regulations.[259] California's objectives to simultaneously meet 2030 climate targets and near-term 2023 air quality goals for smog-forming NOx and diesel particulate matter (DPM) illustrate the need for interagency collaboration on implementing Assembly Bill 2127. Since on-road heavy trucks and buses plus all off-road applications account for 68 percent of NOx and 91 percent of DPM (Figure 22),[260]

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255 Link to main webpage for documents from the March, 11, 2019, workshop on the EV Charging Infrastructure Assessment (AB 2127) https://www.energy.ca.gov/2019_energypolicy/documents/#03112019.

256 Link to main webpage for documents from the May 2, 2019, workshop on EV Charging Infrastructure Assessment (AB 2127) https://www.energy.ca.gov/2019_energypolicy/documents/#05022019-pm.

257 Materials from June 14, 2019, Demand Analysis Working Group meeting. Link to documents from the June 14, 2019, meeting of the Demand Analysis Working Group http://dawg.energy.ca.gov/meetings/transportation-electric-vehicle-forecast.

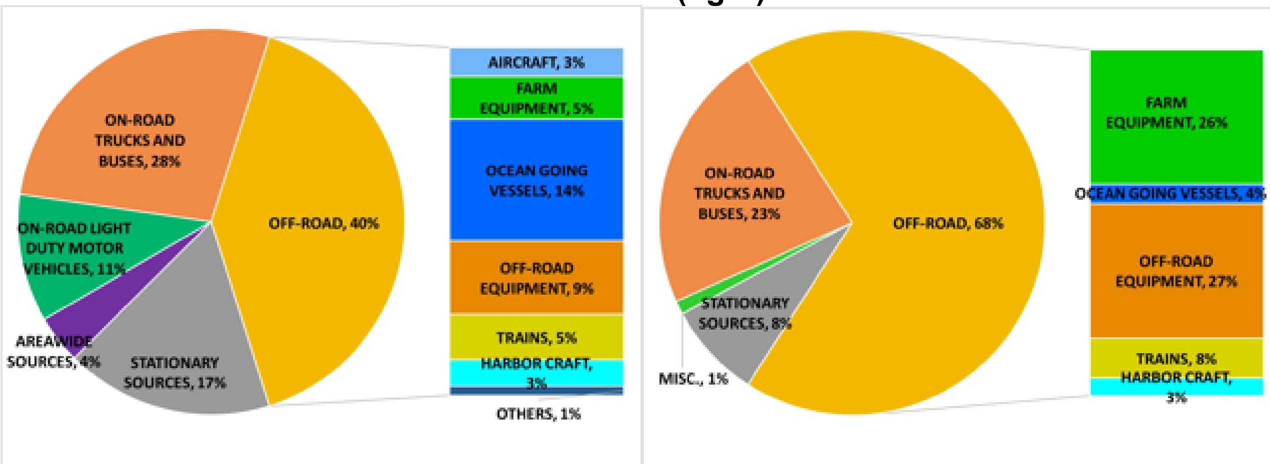
258 Jaw, Kathy, Joshua Cunningham, and Tony Brasil. CARB. The Need for EV Charging Infrastructure Assessments to Inform Policies, March 11, 2019, IEPR Workshop on Assessing Charging Infrastructure Needs in California. https://efiling.energy.ca.gov/GetDocument.aspx?tn=227307&DocumentContentId=58166.

259 Ibid.

260 Jaw, Kathy, David Quiros, Craig Duehring. CARB. Regulatory Drivers for Transportation Electrification of Freight and Off-Road Equipment, May 2, 2019, IEPR Workshop on Assessing Charging Infrastructure Needs in California. https://efiling.energy.ca.gov/GetDocument.aspx?tn=228048&DocumentContentId=59334.

the charging infrastructure assessment will need to address specific end uses by aligning with CARB's technology assessments and regulatory measures, described below.

Figure 22: Statewide Emissions Inventory of Oxides of Nitrogen (left) and Diesel Particulate Matter (right) in 2018



Source: [CARB CEPAM: 2016 SIP - Standard Emission Tool](https://www.arb.ca.gov/app/emsinv/fcemssumcat/fcemssumcat2016.php) https://www.arb.ca.gov/app/emsinv/fcemssumcat/fcemssumcat2016.php.

AB 2127 reinforces the need for consistent charging accounting. Various data collection and reporting initiatives and regulatory and incentive programs at CARB,[261] the CPUC,[262] the California Department of Food and Agriculture (CDFA),[263] and the CEC highlight opportunities to harmonize data and definitions to ensure that stakeholders have accurate and up-to-date information on the availability of charging infrastructure and the adequacy of the charging network as a whole.

Without the ability to track charging installations accurately, capacity and cost may be misrepresented, and opportunities to advance the charging infrastructure may be missed. To further ensure that charging infrastructure assessments reflect timely and accurate

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261 Information on CARB's draft proposed regulation order on EVSE standards https://www.arb.ca.gov/our-work/programs/electric-vehicle-charging-stations-open-access-senate-bill-454.

262 Link to documents from the CPUC's May 9, 2019, meeting on Metrics & Methodologies to Evaluate Transportation Electrification Programs https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442461242.

263 Information on CDFA's EV Fueling Systems Regulation https://www.cdfa.ca.gov/dms/regulations.html.

information, the CEC may explore developing data collection regulations to collect information on the number, type, and usage of deployed charging equipment.

A comment on the *Draft 2019 IEPR* recommended the CEC analyze costs of installing charging infrastructure and develop tools akin to the online statistics from the California Solar Initiative[264] to maximize investment transparency and public-private partnership opportunities.[265] CEC staff continues to analyze the California Electric Vehicle Infrastructure Project (CALeVIP), through which the CEC provides incentives for Level 2 and DC Fast Chargers in 14 counties across California.[266] As depicted in Figure 23, one benchmark for comparison would be a prior CEC solicitation that supported the construction of 634 Level 2 electric vehicle supply equipment (EVSEs) at locations including public destinations, workplaces, and multiunit dwellings.

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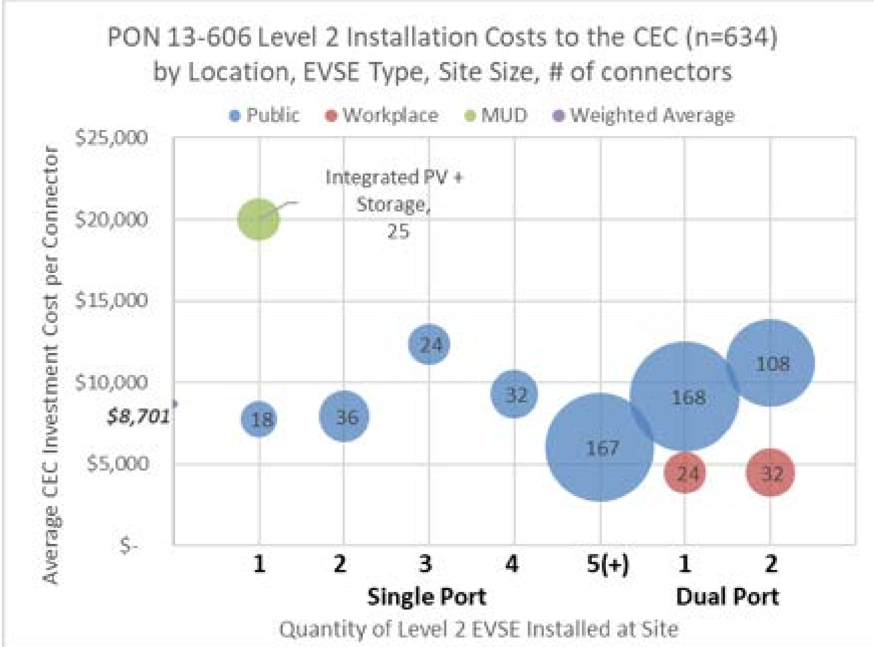
264 See California Solar Statistics at https://www.californiasolarstatistics.ca.gov/ and California Distributed Generation Statistics at https://www.californiadgstats.ca.gov/.

265 Sanders, Diedre. Comments of East Bay Community Energy on the Draft 2019 Integrated Energy Policy Report, November 26, 2019. https://efiling.energy.ca.gov/GetDocument.aspx?tn=230862&DocumentContentId=62495.

266 As of December 2019. Incentive projects will be released in additional counties in 2020. California Electric Vehicle Infrastructure Project, https://calevip.org/. For more information on CALeVIP, see Appendix B.

Figure 23: Charging Installation Costs from Program Opportunity Notice 13-606

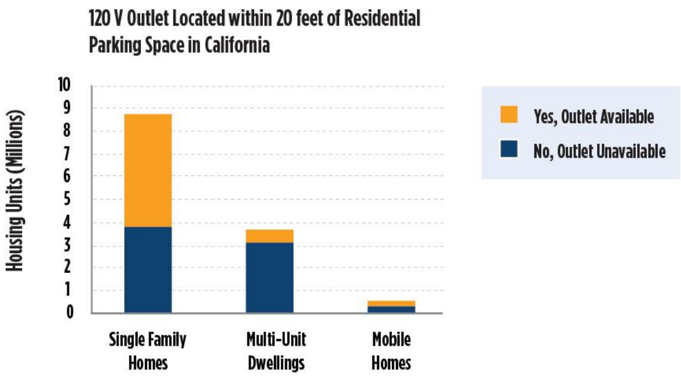


Source: CEC analysis of awardee reported invoices.

As shown in Figure 23 (above), the weighted average cost of the public's investment (the share of costs borne by the CEC program) was nearly $8,700 per Level 2 EVSE. Comparatively, CALeVIP provides incentives ranging from $5,000 to $7,500 per Level 2 EVSE installed[267] as of 2019. Future analyses could expand upon more recent infrastructure deployments from various public programs for several types of electric vehicles, including light-, medium-, and heavy-duty vehicles. In the long term, cost transparency is critical for understanding the level of adequate infrastructure investment needed to support transportation electrification.

267 Eligible equipment costs include the EVSE, "make ready" costs (transformer, electric panels, stub outs), DERs (energy storage, demand management equipment), project management (labor and materials, utility service orders, planning and engineering design), signs, and charging services (network agreement, extended warranties).

Charging for Multiunit Dwellings (MUDs)



CEC analysis of statewide surveys of parking and housing stock estimates that only one in seven MUD housing units in California may offer access to basic charging at 120 volts (Level 1). In addition, installing charging at MUDs faces many transactional barriers, including lack of (or unassigned) parking, fully utilized electrical capacity requiring large capital upgrades, split incentives between landlords and tenants, deeded parking spaces, limited potential to recover installation costs if rent is controlled, and limited ability to achieve economies of scale at smaller buildings. To address these needs, the Clean Transportation Program posed an EV-Ready Community Challenge, in which local governments and their partners competed to develop a holistic and futuristic view of regional electric transportation planning, including solutions for MUDs. These solutions, linked in the footnotes, include creation of new business models, establishing building code retrofit and construction requirements, leveraging load management, sharing public charging placed street-side or next to apartments, targeting education and outreach, and more.[268]

268 City of Sacramento EV Blueprint: https://sacramento.granicus.com/MetaViewer.php?view_id=21&clip_id=4421&meta_id=557883.

City and County of San Francisco Electric Vehicle Ready Community Blueprint: https://sfenvironment.org/sites/default/files/editor-uploads/transportation_vehicle/san_francisco_ev_blueprint.pdf.

Contra Costa County Electric Vehicle Readiness Blueprint: https://www.ccta.net/wp-content/uploads/2019/07/CCTA-EV-Blueprint.pdf.

City of Santa Clara EV Blueprint: https://www.siliconvalleypower.com/home/showdocument?id=64525.

Kern Council of Governments Electric Vehicle Charging Station Blueprint: https://www.kerncog.org/kern-electric-vehicle-charging-station-blueprint/.

Ventura County Electric Vehicle Ready Blueprint: http://vcportal.ventura.org/CEO/energy/ev/Ventura_County_Electric_Vehicle_Ready_Blueprint_July_2019.pdf.

Per the March 2019 workshop, the lack of standardization for varied thresholds of charging, or *different components of charging*,[269] poses a barrier to advancing the EVSE assessment. For instance, the 2018 results from EVI-Pro did not fully analyze the different scenarios that will modify charging needs and opportunities, such as changes to the amount of electricity discharged from the EVSEs (due to utility signals) or changes in end-user behavior.

Based on initial AB 2127 outreach and feedback, the CEC has identified major factors affecting the needs for charging, the extent of make-ready electric infrastructure, and the design of equipment, including:

- Regulatory mandates on mobile source emissions, which induce the creation of supplies of zero-emission and electric vehicles and equipment.
- Research and development of charging technology, especially for power capability in excess of a megawatt of power that can serve medium- and heavy-duty vehicles.[270]
- Regional and local conditions guiding the development and implementation of electric transportation plans.
- Funding for charging infrastructure from private markets, public funds, and ratepayer funds collected from IOUs[271] and POUs.
- Driver adoption and behaviors related to vehicles and charging.

In turn, these factors could be influenced in several ways by the charging infrastructure assessment results, and the frequency of updates occurring at least biennially would promote

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County of Los Angeles Transportation Electrification Blueprint: http://isd.lacounty.gov/wp-content/uploads/2019/07/LAC_EV_Transportation_Electrification_Blueprint_Web_RELEASE.pdf.

269 Such as in increasing order: "connectors," "EVSE" or "chargers," "charging infrastructure," and "stations," as defined in the CEC's presentation at the March, 11, 2019, IEPR staff workshop on EV Charging Infrastructure Assessment (AB 2127). Presentation by CEC at March 11, 2019, workshop on EV Charging Infrastructure Assessment (AB 2127) https://efiling.energy.ca.gov/GetDocument.aspx?tn=227308&DocumentContentId=58167. pp. 25–29.

270 Bracklo, Claas. "General Statement on High Power Charging Infrastructure Projects." CharIN. https://efiling.energy.ca.gov/GetDocument.aspx?tn=229461&DocumentContentId=60851.

271 Consistent with CPUC Order Instituting Rulemaking (R.) 18-12-006, the staff of CPUC's Energy Division is drafting proposal for a Transportation Electrification Framework to consider regulations on transportation electrification targets, cost-effectiveness, infrastructure ownership, cost recovery, and marketing, education, and outreach, among other topics.
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M252/K025/252025566.PDF.

the tracking of how charging infrastructure needs evolve with the market. Throughout the IEPR process and in comments on the *Draft 2019 IEPR*, stakeholders have expressed a desire to see the CEC's charging infrastructure assessments address:

- Improving the consistency of accounting for charging installations and use.
- Implementing improvements recommended in the 2018 EVI-Pro staff report.
- Analyzing interregional DC Fast Charging demand, cost, and grid infrastructure requirements.[272]
- Expanding infrastructure projections for light-duty commercial vehicles.
- Expanding infrastructure projections for medium- and heavy-duty vehicles.
- Quantifying the value of public EV charging infrastructure.[273]
- Identifying the needs of transportation network companies' fleet vehicles and autonomous vehicles.
- Analyzing the demand for make-ready equipment using utilities' distribution system maps.
- Understanding charging resiliency requirements to maintain the reliability of electric transportation amid potential public safety power shutoffs.
- Assessing the costs of charging equipment hardware components and construction and installation of infrastructure.
- Implementing charging equipment software communication protocols.[274]
- Dispersing charging geographically in consideration of travel needs, emissions targets, and grid planning to prepare for potential utility system upgrades.
- Coordinating implementation of state policies and investments to ensure ratepayer funds are being fully leveraged and used efficiently.
- Addressing the need for specialized expertise to permit and install infrastructure within local markets throughout California.[275]

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272 Forthcoming report from National Renewable Energy Laboratory in collaboration with the CEC and Kontou, Eleftheria, Kadir Bedir, Eric Wood. National Renewable Energy Laboratory and California Energy Commission. "Financial Analysis of Electric Vehicle Fast Charging California Stations: A Case Study in San Diego California." Transportation Research Board 98th Annual Meeting. https://trid.trb.org/view/1573195.

273 Forthcoming report from National Renewable Energy Laboratory for the CEC.

274 Crisostomo, Noel and Brian Fauble. "Future Equipment Requirements for CALeVIP." CEC, November 18, 2019. https://efiling.energy.ca.gov/GetDocument.aspx?tn=230794&DocumentContentId=62410.

- Building upon previous and forthcoming infrastructure analysis.

The statute requires the CEC to update the assessment at least every two years, with the first charging infrastructure assessment by December 2020.

The initial scoping and outreach of AB 2127 have occurred within the 2019 IEPR proceeding and in comments on the *Draft 2019 IEPR*. In that time, stakeholders have emphasized how drastically electric transportation options and technologies will change through 2030. This continuous evolution illustrates the importance of pacing the charging infrastructure assessments such that they can inform ongoing planning by state and regional agencies, as well as industry and nongovernmental stakeholders. Because the requirements of AB 2127 do not end with adoption of the *2019 IEPR*, the CEC has opened a separate docket (19-AB-2127) with which to conduct and collect future AB 2127 analysis and feedback.[276]

Updating the Vehicle-Grid Integration Roadmap

Vehicle-grid integration (VGI) represents the ability of plug-in electric vehicles to provide services to the grid. This can be done in a number of ways, including strategic charging (to prioritize cleaner or lower cost electricity) or bidirectional charging (to provide electricity back to the grid, to buildings, or to other vehicles).[277] When implemented, these approaches can improve the economics of plug-in electric vehicles and charging infrastructure while supporting a cleaner, more reliable, more cost-efficient electrical grid.[278]

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275 Governor's Office of Business and Economic Development. "Electric Vehicle Charging Station Permitting Guidebook." July 2019. http://businessportal.ca.gov/wp-content/uploads/2019/07/GoBIZ-EVCharging-Guidebook.pdf.

276 Please visit Link to CEC's online electronic comment system (https://efiling.energy.ca.gov/EComment/EComment.aspx?docketnumber=19-AB-2127) to submit an electronic comment. Enter your contact information and a comment title describing the subject of your comment(s). Email comments may also be submitted; include the docket number 19-AB-2127 in the subject line and send to docket@energy.ca.gov.

277 *Vehicle grid integration* (*VGI*) encompasses the ways EVs can provide grid services. Final 2017 Integrated Energy Policy Report Publication #CEC-100-2017-001-CMF at Appendix H https://efiling.energy.ca.gov/getdocument.aspx?tn=223205.

278 Szinai, Julia K., Colin J.R. Sheppard, Nikit Abhyankar, Anand R. Gopal. Lawrence Berkeley National Laboratory, November 14, 2019. "Reduced grid operating costs and renewable energy curtailment with electric vehicle charge management." *Energy Policy,* Vol. 136, January 2020, 111051. https://doi.org/10.1016/j.enpol.2019.111051.

The California ISO, in coordination with the Governor's Office, the CEC, and the CPUC, developed the original VGI Roadmap in 2014.[279] The *2017 IEPR* recommended that the CEC "work with the California ISO and the CPUC to update the VGI Roadmap reflecting the needs to use open standards, return the value of grid integration to stakeholders, and commercialize prior investments in research and maintain leadership in advanced technology development."[280]

A goal of the updated VGI Roadmap is to provide policy direction that ensures charging infrastructure deployments benefit drivers and ratepayers, in addition to accelerating transportation electrification and carbon neutrality. The agencies expect to release a draft VGI Roadmap for public review and hold a public workshop to solicit input. The CEC anticipates publishing the final updated VGI Roadmap in early 2020.

Automaker Perspective on VGI

The automotive industry continues to support the commercialization of VGI technologies. In comments to the CEC, for instance, American Honda Motor encouraged looking beyond demonstration and pilot projects. Instead, Honda encouraged a focus on policy changes, such as:

-Interconnection of stationary and onboard inverters.

-Regulatory determinations of value that can compensate drivers, site hosts, utilities, and aggregators.

-Modifications to demand-response and net-metering programs to fully realize the value of V2G.

Source: Jessalyn Ishigo. August 6, 2019. Link to Honda's V2G Comments to the CEC https://efiling.energy.ca.gov/GetDocument.aspx?tn=229242&DocumentContentId=60649.

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279 *California Vehicle Grid Integration Roadmap: Enabling Vehicle-Based Grid Services*. 2014. Vehicle-Grid Integration Roadmap on the California ISO's website https://www.caiso.com/Documents/Vehicle-GridIntegrationRoadmap.pdf.

280 See Chapter 4: Accelerating the Use of Distributed Energy Resources on the California Grid and Appendix H regarding the Vehicle-Grid Integration Roadmap in the *2017 Integrated Energy Policy Report*. Link to 2017 IEPR report and dockets on the CEC's website https://www.energy.ca.gov/2017_energypolicy/.

California Vehicle Grid Integration Roadmap: Enabling Vehicle-Based Grid Services. 2014. Vehicle-Grid Integration Roadmap on the California ISO's website https://www.caiso.com/Documents/Vehicle-GridIntegrationRoadmap.pdf.

Through 2018, staff from the CEC worked with staff from the California ISO, CPUC, and CARB to develop an approach, framework, and topics to cover in an update to the VGI Roadmap. On September 6, 2018, to kick off the roadmap update, the joint agencies held a public webinar that presented the proposed approach and a draft list of 14 VGI Roadmap goals and 39 problems/issues that impede achieving those goals.[281]

Building upon the three tracks from the original 2014 VGI Roadmap, staff from the CEC organized the draft goals and problems/issues for the roadmap update into four tracks, including a new one focused on customers:

1) **Policy and Planning**: Identify policy and planning interactions, barriers, and gaps to achieve widespread managed charging deployment.
2) **Economic Potential**: Identify the costs (equipment, operational, and process) and benefits of managed and bidirectional charging versus unmanaged charging at the scale of millions of PEVs. Identifying these costs/benefits will promote business model creation to spur investment.
3) **Technology Needs**: Identify VGI technologies for all vehicle classes to expedite the actions described in the "Policy and Planning" and "Economic Potential" tracks. Delineate key areas of commercialization versus new research.
4) **Customer Experience**: Expand the feasibility of VGI for users, especially low-income residents and residents in disadvantaged communities, to participate in managed charging. Ensure VGI efforts emphasize access to all Californians.

On October 29 and 30, 2018, the CEC hosted a two-day VGI Roadmap workshop that included a VGI technology showcase. At the technology showcase, 12 automotive and electric vehicle supply equipment manufacturers and a large university campus demonstrated some of the advanced vehicles, charging equipment, and tools for optimizing charging available in the market today. Following the technology showcase, the CEC held four panel sessions corresponding to the roadmap tracks that included presentations and discussions from automakers, electric vehicle service providers, national laboratories, utilities, and environmental and ratepayer advocates.[282] As part of the workshop, the joint agencies

281 The September 6, 2018, kickoff webinar material and recording of the webinar are available online. [Link to workshop documents and notices for the California Vehicle-Grid Integration Roadmap Update on the CEC's website](https://www.energy.ca.gov/transportation/vehicle-grid-integration/documents/index.html) https://www.energy.ca.gov/transportation/vehicle-grid-integration/documents/index.html.

282 The October 29 and 30, 2018, VGI Roadmap workshop materials and recording are available online. [Link to workshop documents and notices for the California Vehicle-Grid Integration Roadmap Update on the CEC's website](https://www.energy.ca.gov/transportation/vehicle-grid-integration/documents/index.html) https://www.energy.ca.gov/transportation/vehicle-grid-integration/documents/index.html.

presented a revised list of goals and problems/issues and solicited public comment on potential actions to address them. The joint agencies considered the public input in preparation of the draft roadmap update, which is being coordinated with the development of the Distributed Energy Resources Research Roadmap[283] and other VGI developments in California and globally.

VGI in School Buses

Under the new School Bus Replacement Program created by Senate Bill 110 (Committee on Budget and Fiscal Review, Chapter 55, Statutes of 2017), the CEC targeted electric school buses as distributed energy resources, and challenged bus manufacturers to include bidirectional charging. As a result, in July 2019, the CEC awarded funds for more than 200 electric buses with V2G capabilities (as well as funds for charging infrastructure and training).

Source: CEC, *Energy Commission Awards Nearly $70 Million to Replace Polluting Diesel School Buses With All-Electric School Buses Throughout California*, July 15, 2019. https://www.energy.ca.gov/news/2019-07/energy-commission-awards-nearly-70-million-replace-polluting-diesel-school-buses

In parallel to the VGI roadmap update, the CPUC launched two working groups to examine the costs and benefits of VGI and address vehicle-to-grid (V2G) interconnection. The first working group, known as the Joint Agency Interagency Working Group, , known as the Joint Agency Interagency Working Group, will identify and enable stakeholders to capture the value of smart charging and V2G to help scale electric vehicles as distributed energy resources (DERs). Specifically, this working group is expected to identify which use cases can provide value in the immediate future to serve as demand response or storage that can be "captured" as grid capacity. The CPUC is interested in understanding how the value of VGI compares to other resources and what policies are necessary to support implementation of the technology. Interim completed deliverables include the creation of a "use case assessment methodology," procedure for scoring use cases, and identification of use cases (for example, types and locations of charging that could benefit the electric system, such as daytime smart charging at workplaces).[284] A second working group, the Vehicle-to-Grid Alternating Current Interconnection Subgroup, will identify existing standards to fulfill the necessary safety

283 Information on the Distributed Energy Resources Roadmap proceeding is available: https://www.energy.ca.gov/research/distributed-energy-resource-roadmap/.

284 Information, materials, and meeting schedule for the Vehicle Grid Integration Working Group on Gridworks' website. https://gridworks.org/initiatives/vehicle-grid-integrationwg/.

requirements for interconnecting an AC inverter inside a PEV to the distribution system and act as a distributed energy resource and offer vehicle-to-grid services ("AC V2G"). This group is expected to inform the DRIVE and Rule 21 proceedings.[285] A final report was submitted to the CPUC on December 11, 2019, that identifies and analyzes gaps in standards that pertain to electrical safety, inverter controls, and automotive design including UL 1741, IEEE 1547, SAE J3072, UL 9741, as well as the needs to reconcile differences in norms of the utility and automotive sector.[286] The report highlights recommendations relevant to the CEC regarding V2G equipment certification and policy clarity, including:

- Exploring the development of lists to authenticate and authorize certified PEVs to be able to safely discharge to the grid, similar to the CEC's maintenance of a "static" Grid Support Inverter List for solar photovoltaic interconnections[287] and, potentially, a "dynamic" database that enables EVSEs to recognize various types of EVs during live transactions. (Gap 5 within the report).
- Analyzing the policy implications of multi-utility and cross-state electrical and inverter certification issues to allow V2G PEVs to safely and securely discharge V2G services in multiple locations. (Gap 4 within the report.)

Recommendations

- **The California Energy Commission (CEC) should continue supporting research and development opportunities (including plug-in electric vehicle [PEV] inverter certification systems) and cost-reduction strategies to enable bi-directional charging and minimize the grid impact of medium- and heavy-duty PEVs.** Vehicle-to-grid and vehicle-to-building technologies can reduce the ownership cost of PEVs and reduce the infrastructure upgrades required to support medium- and heavy-duty vehicle electrification. Certain use cases, such as school

285 Joint Administrative Law Judges' Ruling Establishing Subgroup and Schedule to Develop Proposal on Mobile Inverter Technical Requirements for Rule 21 and Noticing Workshop, R.17-07-007 and R.18-12-006, August 23, 2019. Link to CPUC ruling regarding Rulemaking 17-07-007 and Rulemaking 18-12-006 on the CPUC's website http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M311/K582/311582954.PDF.

286 California Energy Storage Alliance on behalf of the Vehicle-to-Grid Alternating Current Interconnection Sub-Group. "Final Report of the Vehicle to Grid Alternating Current Interconnection Subgroup," December 11, 2019. http://efile.cpuc.ca.gov/FPSS/0000143118/1.pdf.

287 The Go Solar California campaign of the CEC and CPUC maintains a "Grid Support Inverter List" that is maintained by the CEC's Renewable Energy Division, https://www.gosolarcalifornia.ca.gov/equipment/inverters.php.

buses, have duty cycles that particularly match the business case for such strategies. Conducting pilot demonstrations of these use cases, exploring the development of PEV inverter certification systems, and providing policy clarity on jurisdictional authority over PEV inverters (as identified in the subgroup report) can accelerate commercialization and promote PEVs as distributed energy resources (DER) that can provide grid services. In addition, integrated DER such as solar and energy storage can reduce the peak demand on the grid and provide onsite, zero-carbon, and reliable generation to support vehicle electrification while minimizing the cost to upgrade the distribution grid and expediting the installation of charging infrastructure.

- **The CEC and collaborating state agencies should continue to identify and eliminate technical and policy barriers to implementing vehicle-to-grid- (VGI) capable infrastructure.** Through various VGI Roadmap Working and Sub-Working Groups, the CEC will collaborate with private industry and adjacent public agencies to ensure the effectiveness of the rollout of grid-integrated charging. As part of this effort, agencies and stakeholders will present their contributions to the working group and develop a strategic VGI valuation method that will enable customers to benefit from supporting grid operations.
- **Consider additional funding for the CEC's School Bus Replacement Program.** The CEC's School Bus Replacement Program provided $75 million for schools to replace older diesel-powered buses with new electric buses, and was supported by additional funding from the CEC's Clean Transportation Program to install charging infrastructure for those buses. School districts applied for grant funds to replace more than 1,600 diesel school buses, but the program had sufficient funding for only 233 zero-emission buses and charging infrastructure. Given the harmful impacts to children from exposure to toxic diesel exhaust, the state should prioritize replacing older diesel school buses with clean new electric buses, particularly in disadvantaged communities.
- **To assess fully the availability and gaps of PEV charging infrastructure, the CEC should pursue additional data collection authority under its Title 20 regulatory authority.** The CEC should also further develop analytical tools to understand the investments in the California Electric Vehicle Infrastructure Project and other publicly funded investments in charging to increase the transparency of and impact on infrastructure availability resulting from public-private partnerships.
- **Continue to support renewable hydrogen production.** Expanding the number of production sources for renewable hydrogen would improve the supply resiliency for hydrogen as a transportation fuel, while further reducing lifecycle GHG emissions.
- **Continue to support research, development, demonstration, and deployment of hydrogen refueling infrastructure for fleet and medium- and heavy-duty FCEVs.** This will provide additional support for the development of refueling infrastructure required for early deployment of medium- and heavy-duty trucks and transit buses under CARB's Innovative Clean Transit and Advanced Clean Truck regulations. As noted, delivery companies are already using medium-duty fuel cell trucks, and heavy-duty trucks are in development and testing with multiple companies

CHAPTER 4: Advancing Energy Equity

"We must map out longer-term strategies ... for California's energy future, to ensure that the cost of climate change doesn't fall on those least able to afford it," Governor Gavin Newsom stated in his State of the State Address on February 12, 2019.[288] California's low-income and disadvantaged communities are the most likely to disproportionately suffer the impacts of climate change. For this reason, the state must continue to strategically direct its investments to address climate change in these communities.

Energy equity is a critical component of the state's strategy for achieving its ambitious climate change and clean energy goals. Addressing barriers to and investing in clean energy and clean transportation for low-income and disadvantaged communities is not only fundamental to help the state protect the most vulnerable communities from climate change, but is necessary to help low-income Californians achieve energy bill savings and benefit from clean energy market opportunities such as workforce development. California remains deeply committed to continuing to advance energy equity to ensure that low-income and disadvantaged communities, as well as tribal and rural communities, reap the benefits of a transformed clean energy future.

SB 350 Requires California to Focus on Energy Equity

Senate Bill 350 (De León, Chapter 547, Statutes of 2015) established ambitious energy goals, including doubling energy efficiency and increasing renewable electricity, to support California's target of reducing greenhouse gas (GHG) emissions to 40 percent below 1990 levels by 2030. SB 350 also requires that the state take steps to focus on equity to ensure that all Californians, including those in the most vulnerable communities, realize the benefits of a transformed clean energy economy.

SB 350 directed the California Energy Commission (CEC) to study barriers for low income-customers, including those in disadvantaged communities, to energy efficiency and weatherization investments, and renewable energy generation and to contracting opportunities for local small businesses in disadvantaged communities. In addition, SB 350 directed the California Air Resources Board (CARB) to publish a study on barriers for low-income

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288 Governor Newsom's February 12, 2019, State of the State address https://www.gov.ca.gov/2019/02/12/state-of-the-state-address/.

customers, including those in disadvantaged communities, to zero-emission and near-zero emission transportation options. SB 350 also requires that the CEC and CARB develop recommendations on how to address these barriers.

As directed by SB 350, in December 2016, the CEC published the *Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities* (Barriers Study Part A). The study identifies 12 recommendations to increase access to address barriers to clean energy.[289] CARB published the *Low-Income Barriers Study, Part B: Overcoming Barriers to Clean Transportation Access for Low-Income Residents* (Barriers Study Part B) in February 2018.[290] The study identifies barriers that limit access to clean transportation for low-income customers and disadvantaged communities and identifies six priority recommendations.

SB 350 Recommendations and Implementation Accomplishments

California state agencies have been working together to implement the recommendations in the Barriers Studies. Table 7 summarizes the 12 recommendations in the Barriers Study Part A to address the barriers to low-income access to clean energy, as well as the lead and supporting agencies implementing the recommendations. Table 8 summarizes the recommendations from CARB's Barriers Study Part B.

Table 7: Barriers Study Part A Recommendations and Lead and Supporting Agencies

	Recommendation	Lead and Supporting Agencies
1	Establish a multiagency task force to promote coordination across state-administered programs.	**Lead:** Governor's Office **Supporting:** CEC, California Public Utilities Commission (CPUC), CARB, Department of Community Services & Development (CSD), California Department of Housing and Community Development, and State Water Resource Control Board
2	Enable the economic advantages of community solar to low-income and disadvantaged populations.	**Lead:** CPUC **Supporting:** CSD

289 CEC, *Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities*. Link to workshop information, notices, and documents regarding SB 350 Barriers Study on the CEC's website https://www.energy.ca.gov/sb350/barriers_report/.

290 CARB, *Low-Income Barriers Study, Part B: Overcoming Barriers to Clean Transportation Access for Low-Income Residents*, Link to CARB Barriers Report on the CARB website https://www.arb.ca.gov/resources/documents/carb-barriers-report-final-guidance-document.

	Recommendation	Lead and Supporting Agencies
3	Strategize and track progress of workforce, community, and clean energy goals.	**Lead:** California Labor and Workforce Agency, California Workforce Development Board (CWDB)
4	Develop new financing pilot programs to encourage investment for low-income customers, including disadvantaged communities.	**Lead:** California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA) **Supporting:** CEC, CPUC
5	Establish common metrics and encourage data sharing across agencies and programs.	**Lead:** CEC **Supporting:** CPUC, CARB, CSD, California Department of Housing and Community Development, California Department of Public Health (CDPH)
6	Expand opportunities for low-income and disadvantaged communities to use photovoltaic and solar thermal technologies.	**Lead:** CPUC, CSD
7	Enhance affordable housing tax credits for housing rehabilitation projects to include energy efficiency and renewable energy upgrades.	**Lead:** California Tax Credit Allocation Committee **Supporting:** CEC, CPUC, California Department of Housing and Community Development, CAEATFA
8	Establish regional outreach and technical assistance, outreach, and funding one-stop shop pilots.	**Lead:** CPUC, CEC, CARB
9	Investigate the need for heightened consumer protection for low-income customers and small businesses in disadvantaged communities seeking access to clean energy.	**Lead:** Governor's Office **Supporting:** CPUC, CEC
10	Direct funding to collaborate with community-based organizations for community-centric delivery of clean energy programs.	**Lead:** CPUC, CEC, CARB **Supporting:** Strategic Growth Council (SGC), CSD, Department of General Services (DGS), Governor's Office of Business and Economic Development (Go-Biz), community-based organizations
11	Direct research, development, demonstration, and market facilitation programs to include targeted benefits for low-income customers and disadvantaged communities.	**Lead:** CEC **Supporting:** CPUC
12	Conduct an in-depth, data-driven study for increasing contracting opportunities for small businesses located in low-income and disadvantaged communities.	**Lead:** Go-Biz **Supporting:** DGS, SGC, CPUC, CEC

Sources: Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities and the CEC's Barriers Study Recommendations Report out on SB 350 Implementation Progress. July 2019. TN 229108. https://efiling.energy.ca.gov/getdocument.aspx?tn=214830 and https://efiling.energy.ca.gov/GetDocument.aspx?tn=229108&DocumentContentId=60513

Table 8: Barriers Study Part B Recommendations and Lead and Supporting Agencies

	Recommendation	Lead and Supporting Agencies
1	Expand assessments of low-income resident clean transportation and mobility needs to ensure feedback is incorporated in transportation planning and for guiding investments.	**Lead:** California Department of Transportation (Caltrans), CARB, California Transportation Commission (CTC) **Supporting:** Local transportation authorities, metropolitan planning organizations (MPOs), councils of government (COGs), transit agencies, CEC, CPUC, SGC, CDPH
2	Develop an outreach plan targeting low-income residents across California to increase residents' awareness of clean transportation and mobility options.	**Lead:** CARB, CEC, CPUC, SGC **Supporting:** CDPH, CTC, Caltrans, Department of Motor Vehicles, Go-Biz, air districts, investor-owned utilities, publicly owned utilities
3	Develop regional one-stop shops to increase consumer awareness and technical assistance.	**Lead**: CARB, CEC, SGC **Supporting:** CPUC, CSD, California Natural Resources Agency, California Department of Housing and Community Development, California Department of Water Resources
4	Develop guiding principles for grant and incentive solicitations to increase access to programs and maximize low-income resident participation.	**Lead:** CARB, CEC, CPUC, SGC **Supporting:** CTC, Caltrans, California Department of General Services, CDPH
5	Maximize economic opportunities and benefits for low-income residents from investments in clean transportation and mobility options by expanding workforce training and development.	**Lead:** California Labor and Workforce Development Agency, CWDB, CARB **Supporting:** CEC, CPUC, CSD, CDPH, California Employment Development Department
6	Expand funding and financing for clean transportation and mobility projects, including infrastructure, to meet the accessibility needs of low-income and disadvantaged communities.	**Lead:** CARB, CEC, CPUC, CTC, Caltrans **Supporting:** SGC, air districts

Source: CARB, Barriers Study Part B, CARB Barriers Report on the CARB website https://www.arb.ca.gov/resources/documents/carb-barriers-report-final-guidance-document

On July 30, 2019, the CEC, CPUC, and CARB held a joint agency workshop on Advancing Energy Equity to review progress toward implementing the recommendations in the Barriers Studies and explore next steps and key actions to advance energy equity throughout California. At the workshop, state agencies discussed the actions they have already taken and the actions they plan to complete to fulfill the recommendations of the Barriers Studies. Appendix E provides a summary of the implementation status of each recommendation in the Barriers Studies.

As demonstrated in Appendix E, California's state agencies have made significant progress toward accomplishing the recommendations in the Barriers Studies. The programs created to implement the recommendations are making a real contribution and benefiting low-income Californians and those living in disadvantaged communities. Moreover, these programs have laid a solid foundation upon which California can construct an equitable energy future. The following list highlights some of the completed and ongoing actions that are removing barriers to clean energy and clean transportation:

- The CPUC created the following:

- The Community Solar Green Tariff (CSGT) program allows low-income customers in disadvantaged communities to benefit from the development of solar generation projects in or near their communities, resulting in a 20 percent discount on their overall bill.
- The Disadvantaged Communities—Single-Family Affordable Solar Homes (DAC-SASH) program provides upfront incentives for installation of solar for low-income resident-owners of single-family homes in disadvantaged communities.
- The Disadvantaged Communities—Green Tariff (DAC-GT) program allows income-eligible residential customers in disadvantaged communities to subscribe to receive electricity generated from a solar facility in California and receive a 20 percent discount on their overall bill.
- The Solar on Multifamily Affordable Housing (SOMAH) program provides funding to offer incentives for solar installation on existing multifamily affordable housing.
- The San Joaquin Valley Affordable Energy proceeding established a program to provide cleaner energy offerings to disadvantaged communities in the San Joaquin Valley. In addition, data are being collected to help inform the feasibility of scaling the program to other disadvantaged communities.
- In conjunction with the Contractors State License Board and the Department of Business Oversight, an interagency solar consumer protection taskforce was formed to 1) provide relief for customers harmed by solar companies' unfair business and lending practices and 2) develop policy solutions to improve consumer protections for solar customers, particularly those in disadvantaged communities.
- The CPUC and CEC jointly established the Disadvantaged Communities Advisory Group (DACAG) in 2018. DACAG reviews and provides advice on the effectiveness and usefulness of clean energy and pollution reduction programs in disadvantaged communities.[291] The DACAG presented its first annual report, covering 2018 activities, to the CPUC and CEC in 2019.
- In February 2019, the CPUC adopted the *Environmental and Social Justice (ESJ) Action Plan*.[292] The ESJ Action Plan acknowledges that the CPUC has a responsibility to serve Californians in a way that helps address inequities. The ESJ Action Plan is a commitment to advancing decisions and programs that strive to provide everyone

291 Information on the Disadvantaged Communities Advisory Group https://www.energy.ca.gov/sb350/DCAG/.

292 *CPUC Environmental and Social Justice Action Plan* https://www.cpuc.ca.gov/CPUCNewsDetail.aspx?id=6442461331.

across the state with consumer protections and other benefits. The ESJ Action Plan represents the CPUC's vision but does not bind the CPUC legally to any specific outcomes or process.

- The CEC accomplished the following:
    - In 2018, the CEC published its Energy Equity Indicators report, which identified a series of metrics designed to help identify opportunities for advancing the progress clean energy access, investment, and resilience in California's low-income and disadvantaged communities.[293]
    - As of July 2019, the Electric Program Investment Charge (EPIC) program, the majority of which is administered by the CEC, invested about 31 percent of its technology demonstration and deployment funds to 104 project sites in disadvantaged communities and an additional 34 percent to 74 project sites that are low-income only.[294]
    - The CEC will implement new scoring criteria in upcoming technology demonstration and deployment solicitations to ensure that projects in disadvantaged and low-income areas are providing direct benefits to the community.
    - As noted above, the CEC and CPUC jointly established the DACAG in 2018 to review and provide advice on the effectiveness and usefulness of clean energy and pollution-reduction programs in disadvantaged communities.
- CSD created the following programs:
    - The Community Solar Pilot Program aims to make the benefits of solar energy more available to eligible low-income households, lower residents' energy bills, and provide cobenefits to communities, including economic and workforce development. The Low-Income Weatherization Program provides low-income households with solar photovoltaic systems and energy efficiency upgrades at no cost to residents.
- CAEATFA has implemented the following programs:
    - The Residential Energy Efficiency Loan Assistance Program is a pilot designed to help homeowners and renters access lower-cost financing for energy efficiency projects by reducing risk to participating lenders. The program has seven active

293 Link to information on Energy Equity Indicators on the CEC's website https://www.energy.ca.gov/sb350/barriers_report/equity-indicators.html.

294 Link to Docket 19-IEPR-05 on the CEC's website, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-05, TN# 229108, p. 16.

lenders and more than $20 million available in loan loss reserve funds to help participating lenders lower energy efficiency loan risk. The program is leveraging nearly $7 million in private capital, with 52 percent of borrowers in low-moderate income census tracts.

    - The Small Business Financing (SBF) pilot program aims to help small businesses access better financing terms for energy-efficient retrofits.
    - The Affordable Multifamily Energy Efficiency Financing pilot program is designed to leverage and complement existing efforts to finance affordable multifamily energy efficiency retrofits and to encourage growth in private-market energy efficiency lending.
- CARB has developed:
    - An outreach plan and roadmap that identifies strategies for effectively coordinating, streamlining, and delivering tailored clean transportation outreach.
    - Regional one-stop shop project for low-income customers that increases awareness of transportation rebates and incentive programs, and provides reliable information about available technologies and clean transportation options. The initial pilot focuses on the development of a streamlined, single application for low-income consumers to apply and qualify for CARB's low-carbon transportation equity programs, such as Clean Cars 4 All, the Clean Vehicle Rebate Project, financing assistance programs, and clean mobility options for disadvantaged communities.
    - Continued funding of transformative, low-carbon transportation projects to support the transformation of California's fleet—supporting clean vehicle ownership, clean mobility, streamlined access to funding and financing opportunities, increasing community education, and exposure to clean technologies.
    - A new Sustainable Transportation Equity project, which uses a community-based approach to identify and address the unique mobility needs of a given community, and will fund a variety of clean transportation activities within disadvantaged communities. Furthermore, the Clean Mobility Options Voucher Pilot project will provide funding for clean mobility projects, such as car-sharing, bike-sharing and other ride-sharing opportunities in low-income and disadvantaged communities.
    - Dedicated funding for community-based organizations to increase outreach and awareness of Low Carbon Transportation Investments, support community transportation needs assessments, and build capacity for clean transportation projects in low-income and disadvantaged communities.
- GO-Biz funded the following:
    - The Small Business Technical Assistance Expansion Program supports small business services, such as free or low-cost one-on-one consulting and low-cost training. Program funding focuses on services to underserved business groups, including women, people of color, veterans and low-wealth, rural, and disaster-affected communities.

- The Capital Infusion Program supports one-on-one business consulting provided by the Small Business Development Network to assist small businesses in accessing capital.
- The Technical Assistance Program (TAP) supports other federal small business technical assistance centers.

Stakeholder Proposed Recommendations for Actions and Strategies Moving Forward

As California continues to chart a path to meet its climate, air pollution, and clean energy goals, it must also identify next steps and key actions needed to improve and increase access to clean energy and clean transportation. As noted in Appendix E, some recommendations have not been fully implemented, and state agencies continue to work on identifying opportunities to implement them. At the July 30, 2019, joint agency workshop on Advancing Energy Equity, Vice Chair Janea Scott asked, "How do we keep moving? How do we get on to the next steps and what some of those key actions should be?"[295] Panelists and participants at the workshop discussed additional actions that could be taken now and in the future to fulfill the recommendations that have not been completely met and are necessary to continue advancing energy equity within the state. The panelists presented recommendations:

- Financing.
- One-stop shop implementation.
- Low-income multifamily housing retrofits.
  - Focus on deed-restricted properties.
- Providing direct support to community-based organizations and having dedicated staff for community outreach.

Stakeholder Recommendations: Financing to Create Equity

Access to capital and credit for financing energy efficiency upgrades was identified as a barrier in the Barriers Study Part A. With competing demands on household income and limited ability to qualify for credit, traditional debt-based financing is not a useful financing mechanism for low-income households. Two of the recommendations in the Barriers Study Part A addressed financing mechanisms for providing energy efficiency upgrades for low-income residents

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295 Transcript for the July 30, 2019, IEPR workshop on Advancing Energy Equity https://efiling.energy.ca.gov/getdocument.aspx?tn=229742, p. 11.

(Recommendations 4 and 7). At the July 30, 2019, joint agency workshop on Advancing Energy Equity, Dr. Holmes Hummel with Clean Energy Works stated that financing building efficiency upgrades by way of utility tariffed on-bill investments has been a very cost-effective financing method that has been available for years in several states (such as Hawaii, Kansas, Kentucky, Arkansas, North Carolina, New Hampshire, and Tennessee).[296] Tariffed on-bill financing works when a utility offers inclusive financing for cost-effective energy upgrades by establishing an opt-in tariff that authorizes the utility to recover its cost with a charge on the bill that is significantly less than the estimated savings. The investment capital is assigned to the meter, so if a participating customer moves, the obligation to pay ends, and the terms of the tariff apply to the successor customer at that site.

Utility tariffed on-bill financing does not require a consumer loan, lien, or debt. It can be used by utility customers of all income levels, whether they are renters or property owners. Utilities and electric cooperatives, such as the New Hampshire Electric Cooperative, Roanoke Electric, and the Mountain Association for Community Economic Development, that have implemented tariffed on-bill financing have reported an order-of-magnitude increase in the pace of capital deployment.[297] When compared to traditional debt-based loans, tariffed on-bill financing has been able to achieve higher customer uptake rates and greater energy savings while experiencing a lower repayment default rate.[298]

Regarding this stakeholder suggestion, East Bay Community Energy noted that increasing access to on-bill financing and as place-fixed tariffs to pay for energy efficiency improvements to rental properties are promising. Representatives also felt that "… this will take sustained funding efforts to ensure equitable results since the vast majority of those financially struggling and members of disadvantaged households live in older and often poorly maintained homes. Nevertheless, the benefits realized from lower bills and increased energy

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296 Link to presentation by Clean Energy Works at the July 30, 2019, IEPR workshop on Advancing Energy Equity https://efiling.energy.ca.gov/GetDocument.aspx?tn=229096&DocumentContentId=60501, p. 1.

Link to transcript for the July 30, 2019, IEPR workshop on Advancing Energy Equity https://efiling.energy.ca.gov/GetDocument.aspx?tn=229742&DocumentContentId=61170, p. 125.

297 Link to Docket 19-IEPR-05 on the CEC's website, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-05, TN 229100, pp. 43-59.

298 Ibid., p. 129.

affordability will help reduce displacement pressure on financially struggling families while also contributing to reduced GHG emissions."[299]

The Ygrene Energy Fund also commented that in addition to on-bill financing, property assessed clean energy (PACE) financing is another effective financing mechanism available to property owners in California. Financing for renewable energy and energy efficiency is repaid "via a special assessment on the property owner's property tax bill," which can result "in lower interest rates, longer terms, and lower payments than comparable home improvement financing options."[300]

Stakeholder Recommendations: One-Stop-Shop Creation

The Barriers Study Part A recommended the creation of regional one-stop shops to "provide technical assistance, targeted outreach, and funding services to enable owners and tenants of low-income housing across California to implement energy efficiency, clean energy, zero-emission and near-zero emission transportation infrastructure, and water-efficient upgrades in their buildings" (Recommendation 8).[301] During the July 30, 2019, workshop, Ted Lamm, a research fellow at the University of California, Berkeley, Center for Law, Energy, and the Environment, presented two case studies that highlight the potential benefits of one-stop shops for energy efficiency incentives. Both case studies showed how complicated it is to consolidate, coordinate, and align existing state and local energy efficiency incentives.[302] However, if done, it could result in greater replicability of successful, energy-efficient, and affordable housing rehabilitation projects.[303]

Mr. Lamm noted that a one-stop-shop will not solve all issues that arise when implementing energy efficiency measures, but "it would help the responsible agencies coordinate and align

299 Link to Docket 19-IEPR-01 on the CEC's website, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-01, TN 230862, pp. 3-4.

300 Link to Docket 19-IEPR-01 on the CEC's website, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-01, TN 230920, pp. 1-2.

301 CEC, *Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities*. Link to workshop information, notices, and documents regarding SB 350 Barriers Study on the CEC's website https://www.energy.ca.gov/sb350/barriers_report/. p. 9.

302 Link to Docket 19-IEPR-05 on the CEC's website, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-05, TN 229153.

303 Transcript for the July 30, 2019, IEPR workshop on Advancing Energy Equity https://efiling.energy.ca.gov/getdocument.aspx?tn=229742, pp. 116–122.

their incentives on the energy and tax sides. And it would give them [the agencies] a forum to address these conflicts, particularly timeline conflicts, in a systematic fashion. At the same time, it would also facilitate a simpler single point of access for customers."[304]

An ongoing effort to support underresourced communities' climate change preparations is being guided by the Strategic Growth Council. In 2018, Senate Bill 1072 (Leyva, Chapter 377, Statutes of 2018) created the Regional Climate Collaborative Program, which would be administered by the Strategic Growth Council. The program would assist underresourced communities with accessing statewide public and other grant funds. Selected collaboratives will provide capacity building services to help build community-driven leadership, knowledge, skills, experience, and resources to identify and access public funding for climate change mitigation and adaption projects within the underresourced community.

Jessica Buendia of the Strategic Growth Council highlighted an important point during the July 30 workshop—for programs to be successful, strong community support for the programs is needed.[305]

East Bay Community Energy supports this stakeholder suggestion too, and in its comments noted that it is "…essential to scale up engagement and scale down entry costs … to help all community members transition to clean energy resources." It also pointed out that "these resources need … long-term funding and … look to the state to provide these needed resources to ensure long-term success."[306]

Stakeholder Recommendations: Low-Income Multifamily Housing Retrofits

As identified in the Low-Income, High-Efficiency report discussed by Ted Lamm at the July 30 workshop, meeting statewide energy efficiency targets is very challenging in the low-income multifamily residential sector. The report details:

> "Unlike single-family, owner-occupied homes, these buildings are subject to split incentives between owners who might pay for an efficiency retrofit and tenants who would reap the savings based on reduced energy consumption in their units. Low-income property owners also typically face reduced access to capital to fund a project,

304 [Link to Docket 19-IEPR-05 on the CEC's website](https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-05), https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-05, TN 229742, p. 120-121.

305 [Link to Docket 19-IEPR-05 on the CEC's website](https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-05), https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-05, TN 229742, p. 198.

306 [Link to Docket 19-IEPR-01 on the CEC's website,](https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-01) https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-01, TN 230862, pp. 4.

increased restrictions on their ability to finance one, and older construction that requires significant renovation in other areas."[307]

One of the case studies described by Mr. Lamm at the workshop illustrated the benefit of the concept of a one-stop shop. The case study described a deed-restricted property in San Diego. The City of San Diego owned the land and leased it to MG Properties Group, which owned the housing structures. The long-term ground lease from the city required that 20 percent of the housing units be for low-income residents. Because the property had a deed restriction, it qualified the rehabilitation project for a Fannie Mae Green Rewards Loan, which provides lower-interest loans and other financial benefits.[308] The project was able to align the new ground lease term and financing event, which helped integrate utility and state incentives with federal tax benefits and favorable loan terms, generating significant energy efficiency increases.

Some specific solutions illustrated by the case study include:

- Subsidizing low-cost or free whole-property energy audits for owners that cannot afford the upfront costs to maximize access to state programs and prepare owners to take advantage of opportunities that arise at refinancing.
- Allowing participants to use incentive funds to pay for retrofits directly as they are contracted and completed. This removes upfront cost barriers for owners and properties that do not have funds available from cash flow or refinancing events.
- Encouraging conversion of market-rate housing to deed-restricted, inclusive mixed-income properties to increase access to energy efficiency retrofit incentives and create new inventories of affordable housing for low-income households.[309]

Stakeholder Recommendations: Provide Direct Support to Community-Based Organizations and Have Dedicated Staff for Community Outreach

Several participants at the July 30, 2019, workshop attributed the success of many of the energy efficiency programs and pilots to the involvement of trusted and established community-based organizations. Self-Help Enterprises, a nonprofit organization in the San

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307 Link to Docket 19-IEPR-05 on the CEC's website, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-05, TN 229099, p. 1.

308 Ibid., p. 121.

309 Link to Docket 19-IEPR-05 on the CEC's website, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-05, TN 229099, p. 23.

Joaquin Valley with more than 50 years' experience in providing project assistance to low-income families to build and sustain healthy homes and communities, was involved in the San Joaquin Valley disadvantaged communities pilots (created by Assembly Bill 2672, Perea, Chapter 616, Statutes of 2014).[310] The pilots seek to bring affordable energy options to residents of disadvantaged communities in the San Joaquin Valley. To inform the community of the pilots and the energy improvement opportunities, Self-Help Enterprises helped conduct more than 100 community meetings and workshops and engaged with roughly 1,000 residents.[311] Significant community engagement and outreach are needed to make projects and programs successful.

Community-based organizations know the communities they serve, and community members know the organizations. At the workshop, Jessica Buendia with the Strategic Growth Council emphasized that the messenger can really make a difference in the success of a program or project, and that when a community-based organization's expertise is used, the organization should be appropriately compensated, as are other technical experts.[312]

Emerging Energy Equity Issues

Participants at the July 30, 2019, joint agency workshop also illuminated issues that state agencies that should consider as they pursue making clean energy equitable for all Californians. These issues are summarized below.

Energy Storage

At the workshop, Srinidhi Sampath with the California Housing Partnership said she has heard from property owners that energy storage may help them better manage the new time-of-use electricity rates being rolled out by utilities throughout the state. She also mentioned that many affordable senior housing properties—in reaction to utilities implementing public safety power shutoff plans (because of catastrophic wildfire risk)—are looking for ways to be energy resilient because of their electricity needs for medical equipment and medication storage.[313] CEC Vice Chair Janea Scott added that she heard that people are purchasing diesel generators

310 Link to San Joaquin Valley Affordable Energy Proceeding on the CPUC's website https://www.cpuc.ca.gov/SanJoaquin/.

311 Transcript for the July 30, 2019, IEPR workshop on Advancing Energy Equity https://efiling.energy.ca.gov/getdocument.aspx?tn=229742, p. 104.

312 Ibid., p. 201.

313 Ibid., pp. 163-164.

for use in the event of power loss, which contradicts the state's goals of reducing GHG emissions and air pollution. Both raised the potential for energy storage as a potential feasible resource in lieu of diesel generators.[314]

Jin Noh with the California Energy Storage Alliance agreed that there is "potential for different source technologies to address longer durations of energy need to service critical load" and said "it's helpful to really understand … what the duration need is so that developers of all different types of storage technologies have information … [about] how they can best provide this resiliency."[315]

Mr. Noh also identified that there could be synergies with solar programs and storage systems. For example, with the CPUC's recently launched Solar on Multifamily Affordable Housing program (SOMAH), adding energy storage to improve the energy resiliency for a development could result in higher incentives for housing developers to include both and "unlock this market."[316]

To help the state develop this market and realize its potential, the CPUC approved the following changes to its Self-Generation Incentive Program (SGIP):[317]

- Expanding eligibility and increasing levels for battery projects in low-income and disadvantaged communities to increase participation.
- Establishing a new $100 million equity resiliency incentive program and budget set-aside for battery storage for medical baseline/critical needs customers and low-income customers in Tier 2 and Tier 3 high-fire-threat districts,[318] critical services facilities

314 Ibid., pp. 170-171.

315 Ibid., pp. 165-166.

316 Ibid., pp. 167-168.

317 The CPUC's Self-Generation Incentive Program provides incentives to support existing, new, and emerging distributed energy resources. SGIP provides rebates for qualifying distributed energy systems installed on the customer's side of the utility meter. Qualifying technologies include wind turbines, waste heat-to-power technologies, pressure-reduction turbines, internal combustion engines, microturbines, gas turbines, fuel cells, and advanced energy storage systems. CPUC Decision 17-10-004 created the SGIP Equity Budget, which will be implemented beginning with Step 3. This equity budget will be allocated 25 percent of SGIP funds already allocated for energy storage projects, and will provide incentives for customer-sited energy storage in disadvantaged communities and low-income communities in California.

318 The CPUC adopted three fire-threat tiers for the state. Tier 1 are areas with zero to moderate wildfire risk. Tier 2 are areas with elevated wildfire risk, and Tier 3 are areas with extreme wildfire risk. Decision Adopting a Work Plan for the Development of Fire Map 2 17-01-009 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M172/K762/172762082.PDF.

serving those districts, and customers in those districts that participate in two low-income solar generation programs.

- Establishing a $10 million budget for SGIP storage incentives to support pilot projects in 11 San Joaquin Valley disadvantaged communities (Allensworth, Alpaugh, Cantua Creek, Ducor, Fairmead, Lanare, Le Grand, La Vina, Seville, West Goshen, and California City).[319]
- Establishing a new equity heat pump water heater incentive set-aside of $4 million for low-income customers and communities.

The agencies may want to explore how to encourage additional energy storage investments in areas subject to weather-related public safety power shutoffs.

Beyond the CalEnviroScreen Definition of Disadvantaged Community

During the workshop, Sarah Stawasz with the Bear River Band of Rohnerville Rancheria, raised the concern that many state programs use the CalEnviroScreen definition of disadvantaged community;[320] however, for many rural tribal communities that "may not meet the CalEnviroScreen definition of environmentally disadvantaged … the definition needs to include economically disadvantaged, including tribal, rural, and low-income communities."[321] She added a more "inclusive definition of disadvantaged community that helps increase funding eligibility could have a great impact" for increasing the independence and resiliency of rural communities. Others present agreed with the concern. As Stan Greschner, chair of the Disadvantaged Communities Advisory Group stated, "We can coalesce around just ensuring all of these hard-to-reach communities are incorporated … [into the definition of disadvantaged community]."[322] The agencies may want to explore working with CalEPA to refine the CalEnviroScreen tool, especially in the associated reflection of tribal communities, while ensuring that the SB 350 barriers work is broadly inclusive of the diversity of California's low-income and vulnerable communities. Alternatively, the agencies could consider designating

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319 For more information about the CPUC's San Joaquin Valley Disadvantaged Communities Pilot Projects, see CPUC Decision 18-12-015. https://www.cpuc.ca.gov/SanJoaquin/.

320 The California Environmental Protection Agency (CalEPA) is responsible for identifying disadvantaged communities for the Cap-and-Trade funding program. CalEPA designated as disadvantaged communities the 25 percent highest scoring census tracts using results of the California Communities Environmental Health Screening Tool (CalEnviroScreen).

321 Transcript for the July 30, 2019, IEPR workshop on Advancing Energy Equity https://efiling.energy.ca.gov/getdocument.aspx?tn=229742, p. 160.

322 Ibid., p. 161.

tribal communities as eligible for disadvantaged community budgets or programs in addition to those designated by CalEnviroScreen.

In its comments on the *Draft 2019 IEPR*, East Bay Community Energy shared a similar concern that the CalEnviroScreen tool may not be refined enough to identify disadvantaged communities, which "can create resource mismatches when, for example, a community that ranks in the top 25 percent because of poor water quality or a hazardous waste facility receives priority funding for electric vehicle infrastructure. Or, perhaps a community with deep poverty and high housing cost burden does not rank in the top 25 percent because it does not have sufficiently adverse environmental features or has a small population lost among larger, more affluent communities in the area."[323]

Create Incentive Programs That Allow for Participation From Those Within Rural Areas

During the workshop, Brian Adkins with the Bishop Paiute Tribe explained that some utility energy programs, such as the CPUC's Disadvantaged Communities Single-Family Solar Homes program (DAC-SASH) (see Recommendation 6 above), required participants to be a customer of Pacific Gas and Electric (PG&E), Southern California Edison (SCE), or San Diego Gas & Electric (SDG&E), which are all CPUC-regulated electricity utilities. On some tribal lands and in other rural parts of the state, electricity service from a regulated utility is not available. In addition, Mr. Adkins stated that some federal programs require information about the past 12 months of electricity use, which is not available in areas or homes without existing electrical service.[324] These homes tend to rely on heating fuels such as fuel oil, propane, and wood, which can come with higher costs and may result in poor indoor air quality and higher GHG emissions. In California, these areas may also be more prone to wildfires and electrical blackouts initiated to prevent wildfires.

Incentive programs created specifically for currently unserved buildings could benefit rural parts of the state.

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323 [Link to Docket 19-IEPR-01 on the CEC's website,](https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-01)
https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-01, TN 230862, pp. 4.

324 Ibid., pp. 180–181.

Strengthening Partnerships With Tribes and Providing Access to Funding Opportunities

The CEC's Tribal Program promotes effective government-to-government cooperation, collaboration, and communication with California Native American tribes.[325] The cornerstone of the program is the CEC's Tribal Consultation Policy, which reflects the CEC's commitment to obtaining tribal input on the development of CEC regulations, rules, policies, plans, and activities that might affect tribes. Under the policy, the CEC sponsored the July 2019 California Sustaining Tribal Resources Conference in Bishop (Inyo County) hosted a May 2019 workshop in Sacramento focused on CEC funding opportunities and improving tribal access to state funds. In addition, the CEC, the Pechanga Band of Luiseño Indians, the Governor's Office of the Tribal Advisor, and the CPUC held a California Tribal Energy Summit in November 2018. The goal of the summit was to initiate or advance dialogue between California Native American tribes and the state's energy agencies on advancing climate change and energy goals.[326] Through such events, the CEC and other state agencies are developing a better understanding of the importance of expanding tribal access to state programs that support clean energy strategies for generation, resiliency, and climate adaptation. It is important that the CEC and state agencies continue to prioritize communication and partnership with tribes to devise effective ways to increase tribal participation on state decision-making and tribal access to state funding and technical assistance.

Scaling Up From Pilot Projects to Statewide

Several of the state's energy-related programs and pilot projects were discussed during the workshop. Dr. Holmes Hummel explained that Clean Energy Works has focused on advancing tariffed on-bill financing because it is trying to address the questions posed by former CEC Chair Robert B. Weisenmiller: "how do we make [programs] go ten times faster, ten times larger? Who can tell me about ideas that will change the rate of progress by an order of magnitude?"[327] On a similar note, CPUC Commissioner Martha Guzman Aceves asked the workshop panelists: "Should we at the CPUC choose … our top 5 percent communities? Should we use the energy indicators to determine where we should geographically focus? Should we get around the silo funding? Should we have some … pot of funding … instead of [each

325 Link to information on the CEC's Tribal Program https://www.energy.ca.gov/programs-and-topics/programs/tribal-program.

326 Link to the CEC staff report on the energy summit https://www.energy.ca.gov/2019publications/CEC-700-2019-001/CEC-700-2019-001.pdf.

327 Ibid., pp. 123–124.

program having different geographic or population focus] … Are we going about this all wrong, or can we keep those silos and have the geographic focus?"[328] Although not an emerging issue, agencies need to continue to explore and seek ways on how to scale up from limited programs and pilots to statewide adoption, deployment, and implementation of programs and projects to achieve the state's clean energy goals.

The state agencies involved in implementing the recommendations in the Barriers Study have made significant progress carrying out the programs that are helping advance energy equity. To more effectively reach all of California's disadvantaged and low-income communities, tribes, and rural communities, the agencies must continue to work together and forge synergies between various energy programs. Moving forward, California must look for new opportunities to create more energy-resilient communities and identify the next key actions the state should pursue to remove barriers vulnerable communities face to accessing investments in clean energy and clean transportation.

Specific to tribes, the state should develop regional data sets and tools that reflect and address the unique features of tribal communities. Some of the state's energy planning tools, like CalEnviroScreen do not appropriately recognize tribes. This effort could also include a statewide assessment of tribal energy needs and a gap analysis. The July 30, 2019, IEPR workshop laid the foundation for exploring areas of further work such as developing attainable opportunities to finance energy upgrades, creating one-stop shops to increase access to clean technologies, advancing retrofits and energy storage in low-income multifamily housing, training and dedicating staff to community outreach, and providing direct support to community-based organizations.

Recommendations

- **State and local agencies should continue working together to ensure that the intent and spirit of Senate Bill 350 (De León, Chapter 547, Statutes of 2015) are met.** In doing so, agencies should strategically and effectively work with low-income and disadvantaged communities and ensure that these communities do not disproportionately bear the burden of sunk costs as the state advances toward its 100 percent clean energy goal.
- **To help energy programs identify areas of need, the California Energy Commission (CEC) should build upon its existing energy equity indicators, expanding and refining them as more data become available.**

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328 Ibid., p. 204.

- **The CEC should continue to work with the California Public Utilities Commission (CPUC) and the CPUC should continue to explore with stakeholders the concept of tariffed on-bill financing, with special attention to consumer protection issues.** This effort would expand access to clean energy technologies and energy efficiency upgrades for consumers in disadvantaged communities and for those who have low incomes.
- **To guide the efforts to ensure affordability of energy, the CPUC should consider:**
    - Adopting a framework for measuring affordability of utility services and determine how best to apply this to its ratemaking and rulemaking processes.
    - Developing a prioritization framework for the Solar on Multifamily Affordable Housing program to help ensure more equitable distribution of solar projects on multifamily affordable housing in disadvantaged communities.
    - Developing policies, rules, and regulations with the goal of reducing energy disconnections by 2024 to curb the rising rates of energy disconnections because of nonpayment of energy utility bills, which pose a significant health risk to vulnerable populations.
- **To further protect residential solar consumers, the Department of Business Oversight, Contractor State License Board, and the CPUC with its Interagency Solar Taskforce should continue to engage with stakeholders, financiers, and industry to develop new policies and practices that address fraudulent sales practices and prevent future harm in the net-energy metering market.**

CHAPTER 5: Climate Change Adaptation

Introduction

A warming climate poses risks to every part of California—from its urban centers to its rural areas, both coastal and inland. Increasingly damaging wildfires endanger people and property across the state. In 2019, up to 2 million Californians were affected by power shutoffs during weather that posed extreme fire risk. Sea-level rise threatens a populous coastline of more than 1,000 miles. Declining snowpack and drought impact households and an economy dependent on reliable water supplies. More frequent and intense extreme heat is a hazard to human health and exacerbates local air quality.

California's energy sector is vulnerable to climate change in many ways. A warmer climate increases demand for indoor cooling, while extreme heat can compromise the performance and accelerate the degradation of generation, transmission, and distribution infrastructure. Reduced spring snowpack reduces hydroelectric supplies during summer months when hydropower has historically provided an important, nonfossil resource for meeting peak demand.

In recent decades, examples of weather-related damages to California's electricity sector are numerous and severe. The July 2018 Southern California heat wave resulted in one of Los Angeles Department of Water and Power's (LADWP's) highest-ever demand peaks, as well as power outages that affected more than 80,000 customers. Some service restorations required more than 48 hours due to the sheer number—more than 700—of local outages and the logistics of restoring underground equipment.[329] The July 2006 California heat wave lasted nearly two weeks and was estimated by Pacific Gas and Electric Company (PG&E) to incur damages of $150 million to $300 million in infrastructure repair costs and increases in the cost of peak electricity.[330] Another example is costs associated with loss of hydroelectric power

329 LADWP (2018). *July 2018 Heat Storm Outage Event Summary*. [Link to news release about heat related power outage in July 2018 on LADWP's website](https://www.ladwpnews.com/weekend-of-july-6-2018-heat-storm-related-power-outages-and-response/) https://www.ladwpnews.com/weekend-of-july-6-2018-heat-storm-related-power-outages-and-response/.

330 PG&E (2016). *Climate Change Vulnerability Assessment and Resilience Strategy* (November 2016).

during the recent drought. From October 2011 through September 2015, these losses totaled more than $2 billion in California.[331]

Adaptation in the energy sector is essential to supporting a healthy economy in California, as climate change has the potential to threaten the financial health of the state's economy unless proper planning and action are taken. California's rapidly evolving energy sector presents opportunities to build a climate-safe energy infrastructure as the state progresses toward its 2030 and 2045 climate goals. Energy sector innovation holds the promise of strengthening community preparedness, supporting resilient recovery efforts, and promoting more stable financial markets—which depend on sound credit ratings of investor-owned utilities (IOUs) and community choice aggregators—while maintaining a reliable electric grid. Meeting this promise will require developing scientifically informed, flexible, and adaptive strategies to increase energy sector resilience to stressors from climate change, with particular attention to vulnerable populations. Successful implementation will rely on cross-sectoral collaboration, community engagement, and help from local jurisdictions with implementing innovative technologies to align with statewide goals.[332]

This chapter discusses recent advances in climate adaptation policy, scientific developments relevant to climate adaptation for California's energy sector, and updates on innovative technologies. Drawing on community perspectives shared at an August 8, 2019, Integrated Energy Policy Report (IEPR) workshop on Climate Adaptation in California's Energy Sector, the chapter highlights opportunities for strengthening community-level resilience through community-driven planning, sustained engagement of communities, and implementation of energy sector innovations to promote community resilience in disadvantaged or vulnerable communities.

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331 Gleick, Peter. 2017. *Impacts of California's Five-Year (2012–2016) Drought on Hydroelectricity Generation*. ISBN: 978-1-893790-79-7.

332 Public comment submitted by Center for Climate Protection to Docket no. 19-IEPR-10. Link to Create an Energy Resilience Planning Handbook for Local Governments on the CEC's website https://efiling.energy.ca.gov/GetDocument.aspx?tn=229513&DocumentContentId=60924.

See discussion in part 1 of August 8, 2019, IEPR workshop. Link to Workshop Transcript. https://efiling.energy.ca.gov/getdocument.aspx?tn=229831.

Policy and Guidance in Support of a Resilient California

As Governor Gavin Newsom observes, recognizing and adapting to climate change are "not an ideological endeavor… [rather, it] is a very practical one for California."[333] Accordingly, California explicitly prioritizes integrated consideration of adaptation and greenhouse gas (GHG) emissions reductions as a cornerstone of its climate policy.[334]

An evolving range of policy initiatives designed to strengthen the state's climate resilience complements California's leadership on reducing GHG emissions. Adapting to climate change is already an important part of community planning in California. The state's General Plan Guidelines,[335] which guide local jurisdictions in developing long-term visions for future growth, recognize that land-use and community planning are central to climate adaptation and resilience. Local governments in California consider climate change in the safety element of their general planning (Senate Bill 379 [Jackson, Chapter 608, Statutes of 2015]). California also recognizes that land-use decisions can compound environmental justice risks. With that in mind, the state requires general planning processes to identify objectives and policies to avoid compounding health risks in disadvantaged communities, encourage stakeholder engagement in public decision-making processes, and prioritize improvements and programs that address the needs of disadvantaged communities (Senate Bill 1000 [Leyva, Chapter 587, Statutes of 2016]).

Through the Safeguarding California Plan: 2018 Assessment (Safeguarding California), the state has continued to refine its roadmap for a resilient California based on an evolving body of research on climate risk and resilience options, as well as lessons learned from case

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333 California Governor Gavin Newsom. Press Conference April 12, 2019. Link to video of Governor Newsom's press conference on April 12, 2019, https://www.youtube.com/watch?v=WrXrAGe3s_8. (Stated around minute 17:50).

334 CEC staff. 2018. *2018 Integrated Energy Policy Report Update, Volume II*. CEC. Publication Number: 100-2018-001-V2-CMF. (p. 197) Link to *2018 IEPR Update* on the CEC's website, https://www.energy.ca.gov/2018publications/CEC-100-2018-001/CEC-100-2018-001-V2-CMF.pdf.

ICARP Technical Advisory Council Charter. Vision and principles approved September 2017. Link to information and meetings for the ICARP Technical Advisory Council http://opr.ca.gov/planning/icarp/tac/.

Climate Change Research Plan for California (2015). Climate Action Team. CalEPA. February 2015. Link to Climate Change Research Plan for California report https://www.climatechange.ca.gov/climate_action_team/reports/CAT_research_plan_2015.pdf.

335 California State General Plan Guidelines, http://opr.ca.gov/planning/general-plan/guidelines.html.

studies.[336] A collaboration of more than 20 state agencies, Safeguarding California describes adaptation risk and strategies for agriculture; biodiversity and habitat; climate justice; emergency management; energy; forests; land-use and community development; oceans and coasts; parks, recreation, and California culture; public health; transportation; and water. Assembly Bill 1482 (Gordon, Chapter 603, Statutes of 2015) directs the California Natural Resources Agency to update the plan every three years.

Senate Bill 246 (Wieckowski, Chapter 606, Statutes of 2015) established California's Integrated Climate Adaptation and Resiliency Program (ICARP) to develop holistic strategies that support coordination of climate activities at the state, local, and regional levels. The ICARP engages state and local government, nonprofit and private sector practitioners, scientists, and community leaders to coordinate activities through its Technical Advisory Council. In 2017, the Technical Advisory Council adopted a vision for adaptation in California and principles to guide implementation of strategies to achieve the vision. (See sidebars.)

Vision for Adaptation in California

"All Californians thrive in the face of a changing climate. Leading with innovation, California meets the challenge of climate change by taking bold actions to protect our economy, our quality of life, and all people. The state's most vulnerable communities are prioritized in these actions. Working across all levels of government, the state is prepared for both gradual changes and extreme events. Climate change adaptation and mitigation is standard practice in government and business throughout the state. California meets these goals with urgency, while achieving the following long-term outcomes:

- **All people & communities** respond to changing average conditions, shocks, and stressors in a manner that minimizes risks to public health, safety, and economic disruption and maximizes equity and protection of the most vulnerable.
- **Natural systems** adjust and maintain functioning ecosystems in the face of change.
- **Infrastructure and built systems** withstand changing conditions and shocks, including changes in climate, while continuing to provide essential services."

ICARP Technical Advisory Council Charter. Vision and principles approved September 2017.
Link to information and documents on the ICARP Technical Advisory Council

336 California Natural Resources Agency (2018). *Safeguarding California Plan: 2018 Update*. Link to Safeguarding California Plan: 2018 Update report http://resources.ca.gov/docs/climate/safeguarding/update2018/safeguarding-california-plan-2018-update.pdf.

Principles to Guide Adaptation in California

- Prioritize **integrated** climate action

- Prioritize **equity, community resilience**, and **protection of the most vulnerable**

- Prioritize **natural and green infrastructure**

- Avoid **maladaptation** by making decisions that do not exacerbate risks or exposure and do not transfer the challenge to another group, location, or sector

- Emphasize **science-based** planning, policy, and investment

- Employ **adaptive** and **flexible** governance that uses collaborative partnership

- Take **immediate actions** to reduce climate change risks

ICARP Technical Advisory Council Charter. Vision and principles approved September 2017. Link to information on the ICARP Technical Advisory Council http://opr.ca.gov/planning/icarp/tac/.

Recognizing Vulnerability and Integrating Equity

In July 2018, ICARP released a resource guide on Defining Vulnerable Communities in the Context of Climate Adaptation.[337] This guide includes a definition of climate vulnerability as adopted by its Technical Advisory Council and describes existing statewide tools and process guides that can help identify communities particularly vulnerable to climate change. Resources provided in the guide can help local planners identify communities vulnerable to climate impacts in a manner consistent with Senate Bill 379 and can help identify environmental justice communities, as required by Senate Bill 1000.

California's Office of Emergency Services is updating the state's adaptation planning guide, which provides guidance to support community-level climate adaptation planning and implementation. The updated guide will integrate climate equity and climate justice as guiding principles to be considered in all phases of adaptation planning and provide best practices for outreach to affected communities, with the goal of safeguarding California's frontline communities.

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337 Governor's Office of Planning and Research. July 2018. Defining Vulnerable Communities in the Context of Climate Adaptation resource guide http://opr.ca.gov/docs/20180723-Vulnerable_Communities.pdf.

New Policy Developments Related to Climate Resilience

In June 2019, Governor Newsom took action to move California toward a safer, more affordable, and more reliable energy future, signing a trio of wildfire safety and accountability bills. Assembly Bill 110 (Ting, Chapter 80, Statutes of 2019), Assembly Bill 111 (Committee on Budget, Chapter 81, Statutes of 2019), and Assembly Bill 1054 (Holden, Chapter 79, Statutes of 2019) all contribute to overall improvement of wildfire safety and utility oversight. They provide resources to implement catastrophic wildfire legislation (AB 110); help establish the California Energy Infrastructure Safety Act and the necessary governmental structure for the associated implementation (AB 111); and help create additional safety oversight for utility infrastructure, recast cost recovery from wildfire damages, and authorize the Wildfire Fund to address future-related wildfire liabilities (AB 1054).

Similarly, Senate Bill 901 (Dodd, Chapter 626, Statutes of 2018), the Governor's Executive Order on Wildfire Safety (N-05-19), and the CPUC's adoption of new policies and procedures to support its risk-informed decision-making have established a new utility safety framework. These actions have already affected how IOUs' Risk Assessment and Mitigation Phase (RAMP) reports are reviewed.[338]

Responding to the need to move swiftly to implement strategies that limit utilities wildfire-related risks, Senate Bill 901 also required electric utilities to prepare and submit wildfire mitigation plans to the CPUC. These plans complement their RAMP filings and describe IOUs' plans to prevent, combat, and respond to catastrophic wildfires affecting their service territories.

Governor Newsom Convenes Expert Team on Wildfire, Climate Change, and Energy

Recognizing the urgency, complexity, and importance of ensuring the stability of California's energy sector, Governor Newsom convened a team composed of bankruptcy lawyers and financial experts from the energy sector to explore these issues. The resulting report[339]—drawn up in 60 days and expanded on in a June 2019 update—outlines steps the state must

338 For example: Kurtovich, M., W. Al-Mukdad, J. Rahman, J. Battis. California Public Utilities Commission. May 24, 2019. *A Regulatory Review of Southern California Edison's Risk Assessment Mitigation Phase Report for the Test Case 2021 General Rate Case*, Investigation 18-11-006.

339 *Wildfire and Climate Change: California's Energy Future. A Report from Governor Newsom's Strike Force.* Governor Newsom's Strike Force, April 2019. [Link to Wildfires and Climate Change: California's Energy Future report](https://www.gov.ca.gov/wp-content/uploads/2019/04/Wildfires-and-Climate-Change-California’s-Energy-Future.pdf) https://www.gov.ca.gov/wp-content/uploads/2019/04/Wildfires-and-Climate-Change-California's-Energy-Future.pdf.

take to reduce the number and severity of wildfires, including the wildfire mitigation and resiliency efforts proposed by the Governor.[340] It also reiterates the state's commitment to clean energy. The report outlines actions to hold the state's utilities accountable and identifies potential changes to stabilize the financial status of California's utilities. These actions help meet the energy needs of customers and the economy by allocating responsibility for wildfire costs, strengthening utility market regulation, and proposing systemic reforms and safety commitments.

In response to unprecedented, widespread public safety power shutoffs that left millions of Californians without electricity for extended periods in late October 2019, Governor Newsom called "for fundamental change to PG&E" and "laid out a path forward to ensure the overly broad application of public safety power shutoffs will never happen again."[341] To ensure prompt action, the Governor delineated how parties involved with PG&E's bankruptcy must take steps to "ensure safety investments and fundamental transformations … before the next fire season." Governor Newsom also appointed an energy czar to "help the state game out every option and be prepared to intervene" in the transformation of PG&E.

Insuring Wildfire-Impacted Communities in California

In the wake of California's two most destructive wildfire seasons, and as directed by Senate Bill 901, the Commission on Catastrophic Wildfire Cost and Recovery examined wildfire liability, insurance, financing mechanisms, and community impacts. In its final report, the commission's recommendations recognize the need to balance providing cost recovery for those with serious damages while enabling the financial stability of utilities. The recommendations also highlight the importance of reducing wildfire risk while structuring a system to pay for fire damages.[342]

Legal experts and researchers on insurance and liability have also been examining the risks and opportunities that the insurance community, utilities, and California residents face in a

340 Proclamation of State of Emergency by Gavin Newsom regarding wildfires https://www.gov.ca.gov/wp-content/uploads/2019/03/3.22.19-Wildfire-State-of-Emergency.pdf.

341 "Governor Newsom Outlines State Efforts to Fight Wildfires, Protect Vulnerable Californians and Ensure That Going Forward, All Californians Have Safe, Affordable, Reliable and Clean Power." Office of the Governor, November 1, 2019. Link to press release. https://www.gov.ca.gov/2019/11/01/governor-newsom-outlines-state-efforts-to-fight-wildfires-protect-vulnerable-californians-and-ensure-that-going-forward-all-californians-have-safe-affordable-reliable-and-clean-power/.

342 *Final Report of the Commission on Catastrophic Wildfire Cost and Recovery*. Governor's Office of Planning and Research, OPR, June 2019. Link to Final Report of the Commission on Catastrophic Wildfire Cost and Recovery http://opr.ca.gov/docs/20190618-Commission_on_Catastrophic_Wildfire_Report_FINAL_for_transmittal.pdf.

changing climate. In June 2018, the Center for Law, Energy & the Environment at the University of California, Berkeley, School of Law convened a group of insurance regulators, industry leaders, climate data scientists, nonprofit researchers, advocates, academics, and California energy and climate policy makers for a symposium. The key findings from this symposium[343] were directed at insurance regulators, insurers, industry, and state and community policy makers. The recommendations encourage actions that address the intersection of climate mitigation and resiliency with insurance innovation, in areas such as land-use planning, economic transition planning, risk assessment, and industry reform. Suggested actions include:

- Innovation of "green insurance products" that are designed to shift consumer decisions and investments in sustainable directions and manage risk.
- Employment of enhanced catastrophe modeling.
- Disclosure of physical, transition, and litigation risks.
- Development of accurate estimations of physical risks to major facilities that are key drivers of the California economy.
- Assessment of and action to address risk on a community and statewide scale.

The symposium also led to a report supported by the California Department of Insurance.[344] The report more fully identifies climate risks and discusses how insurers, regulators, and policy makers are responding. Moving forward, stakeholders will need to discuss issues related to examining the interdependence between the state and local governments, incorporating costs (such as fire risk prevention), and identifying and agreeing on ways to transfer perceived risk.

One step underway is the yearlong effort launched by the California Department of Insurance and the United Nations Environmental Program to develop a Sustainable Insurance Roadmap to confront California's climate risks. Announced in July 2019, the roadmap "is envisioned to pave the way for innovative risk management, insurance and investment solutions that reduce climate risks and protect natural ecosystems."[345] Inspired by emerging insurance solutions in

343 Elkind, Ethan and Ted Lamm. "Insuring California in a Changing Climate. Adapting the Industry to New Needs, Risks and Opportunities." Symposium Brief, Center for Law, Energy & the Environment, Berkeley Law, University of California, March 2019. [Information on Insuring California in a Changing Climate from the University of California, Berkeley Center for Law, Energy, and the Environment website](https://www.law.berkeley.edu/wp-content/uploads/2019/03/Insuring-California-in-a-Changing-Climate-March-2019.pdf) https://www.law.berkeley.edu/wp-content/uploads/2019/03/Insuring-California-in-a-Changing-Climate-March-2019.pdf.

344 Mills, Evan, Ted Lamm, Sadaf Sukhia, Ethan Elkind, and Aaron Ezroj. 2018. *Trial by Fire: Managing Climate Risks Facing Insurers in the Golden State*. Sacramento, California: California Department of Insurance.

345 [Link to Department of Insurance press release](http://www.insurance.ca.gov/0400-news/0100-press-releases/2019/release056-19.cfm), July 24, 2019. http://www.insurance.ca.gov/0400-news/0100-press-releases/2019/release056-19.cfm

other countries, the effort could also examine development of new, insurance solutions using California's protective, life-supporting natural infrastructure—such as wetlands and forests—that could reduce climate and disaster risk.

California Public Utility Commission's Adaptation Rulemaking

Recognizing the risks posed by climate change, the California Public Utilities Commission (CPUC) began a rulemaking (R.18-04-019)[346] to develop strategies and guidance on climate adaptation for IOUs. Led by Commissioner Liane M. Randolph, the rulemaking is informed by working groups that provide feedback to CPUC staff proposals on five topics:

1) Definitions of climate adaptation for utilities
2) Appropriate data sources, models, and tools for climate adaptation decision-making
3) Guidelines for utility climate adaptation assessment and planning
4) Identification and prioritization of actions to address the climate change-related needs of vulnerable and disadvantaged communities
5) Framework for climate-related decision-making and accountability[347]

On November 1, 2019, the CPUC issued a decision[348] on Topics 1 and 2. This decision:

- Defines climate change adaptation for energy utilities in the state.
- Anchors acceptable data for IOUs to use in adaptation planning to California's Climate Change Assessment process, acknowledging the role of the Climate Action Team Research Working Group in selecting recommended scenarios.
- Directs IOUs to Cal-Adapt as a source of data.
- Establishes criteria for acceptability of additional data or models.
- Establishes criteria for any further data or models that energy utilities may develop to understand climate impacts.

346 May 7, 2018, Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation, Rulemaking 18-04-019.
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M213/K511/213511543.PDF.

347 October 10, 2019, Assigned Commissioner's Scoping Memo and Ruling, R.18-04-019, p. 3.

348 Decision 19-10-054 on Rulemaking 19-04-019. "Decision on Phase 1 Topics 1 and 2." Date of Issuance 11/1/2019. Link to CPUC's Decision.
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M319/K075/319075453.PDF.

CPUC’s Public Safety Power Shutoff Rulemaking

In response to the increasing frequency and severity of wildfires in California, the CPUC launched a rulemaking (R.18-12-005)[349] to examine policies and guidelines regarding *de-energization*[350] under extreme fire weather conditions. The rulemaking examines conditions in which proactive and planned power shutoffs are practiced, ensures electric utilities coordinate with first responders, and addresses the need to provide effective notice to affected stakeholders. On May 30, 2019, the CPUC made its Phase 1 decision in the proceeding, improving utility communication and notification protocols before the 2019 wildfire season. The CPUC launched Phase 2 through a scoping memo on August 14, 2019, with two tracks. Track 1 will be on a faster timeline to inform public safety power shutoffs (PSPS),[351] with a decision expected in the first quarter of 2020.

The CPUC has approved IOU plans to reduce fire ignition risk, including PSPS. IOUs have been working on several efforts to harden infrastructure to reduce the risk of wildfires and to minimize the disruptiveness of PSPS. Efforts to make the use of PSPS more surgical are aimed at reducing the number of customers affected, shortening the duration of shutoffs, and improving customer notification about power shutoffs and re-energization plans.[352] Improved weather data and analysis are an important part of these efforts.

In October 2019, Californians experienced unprecedented power shutoffs. On October 9–12, 2019, PG&E shut off power to roughly 732,000 customers in 35 counties, which was estimated to have impacted more than 2 million people directly.[353] PG&E also initiated PSPS events on

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349 December 13, 2018, Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions, Rulemaking 18-12-005. Related documents, ruling, and decisions available through CPUC’s docket web portal.

350 *De-energization* refers to utilities shutting off power to customers to protect public safety, generally because of wildfire risk. It is also referred to as a “public safety power shutoff.”

351 Information on de-energization from the CPUC's website https://www.cpuc.ca.gov/deenergization/.

352 For example, SDG&E provides customer notifications through multiple channels (email, text, and phone) in eight languages. Presentation by Brian D’Agostino, Director – Fire Science & Climate Adaptation, SDG&E. “Resilience Across Climate-Vulnerable Backcountry Populations: Anticipating Extreme Fire Weather and Providing Resources during De-Energization.” 19-IEPR-10, TN# 229245. https://efiling.energy.ca.gov/GetDocument.aspx?tn=229245&DocumentContentId=60652.

353 PG&E's ESRB-8 Report Regarding Proactive De-Energization Event for Oct. 9-12, 2019, https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/PGE%20Public%20Safety%20Power%20Shutoff%20Oct.%209-12%20Report.pdf.

October 5–6, October 23–25, and October 26–29, 2019. Southern California Edison (SCE) turned off power to nearly 24,000 customers between October 10 and October 12, 2019,[354] and de-energized customers at various timeframes between October 17 and October 21, 2019.[355] SDG&E also de-energized parts of its system on October 10–11, 2019, and was able to de-energize portions of four circuits rather than the entire circuit to reduce customer impacts.[356] The PSPS were aimed at reducing the risk of electrical equipment igniting wildfire during sustained extreme winds with gusts and dry conditions. These events affected millions of Californians who were subject to possible power shutoff or actually lost service for hours or several days at a time.

PG&E acknowledged "falling short in several areas of execution" of the October 6, 2019, event, while a letter from Governor Newsom stated, "PG&E implemented this extraordinary measure with astounding neglect and lack of preparation." Further, Governor Newsom called on the CPUC to take further action to build on "the measures to prevent utility-caused wildfires and improve utility safety that were put in place by [Assembly Bill] 1054."[357] In response, the CPUC:[358]

- Initiated a formal investigation of the 2019 PSPS events.

Letter to Mr. William Johnson, Chief Executive Officer at PG&E, from CPUC President Marybel Batjer, October 14, 2019, https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/PGE%20Letter%20-%20PSPS%2010-14-19.pdf.

354 SCE's ESRB-8 Report Regarding Pro-Active De-Energization Event for Oct 2-12, 2019, https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/SCE%20Post%20Event%20Reporting%20October%202%20through%20October%2012%202019.pdf.

355 SCE, Letter to Leslie Palmer at the CPUC, PSPS Post Event Report Regarding Pro-Active De-Energization Event – October 12 to October 21, 2019.

356 SDG&E, Letter to Ms. Elizaveta Malashenko at the CPUC, San Diego Gas & Electric Company (SDG&E) Public Safety Power Shutoff Report, October 25, 2019.

357 Letter from Governor Newsom to CPUC President Marybel Batjer, October 14, 2019, https://www.gov.ca.gov/wp-content/uploads/2019/10/10.14.19-CPUC-Letter.pdf

358 CPUC, press release, October 28, 2019, CPUC Takes Additional Decisive Actions to Hold Utilities Accountable and Increase Public Safety. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M318/K885/318885370.PDF.

- Issued a new ruling to reexamine how utilities use PSPS events with an examination of actions that utilities can take in the next six months to minimize the impacts of future events.
- Is working to ensure additional consumer protection so that customers are not charged for services they do not receive during public safety power shutoff events.
- Will direct the utilities to expand their wildfire mitigation plans.
- Will convene a panel of experts to identify specific projects that can be implemented in coming months to minimize the use and scope of PSPS events in the next fire season.

Scientific Developments in the Understanding of Climate Change in California

California's rapidly evolving energy system must prepare for physical and indirect climate impacts, such as those related to wildfires, changes in precipitation, and extreme heat. The state must also chart a decarbonization trajectory that optimizes health benefits, particularly those associated with disadvantaged communities who have long endured the most environmental pollution. This section briefly reviews recent scientific developments relevant to these topics.

Drivers and Impacts of Wildfires in California

Since 1972, California has experienced a fivefold increase in average annual burned area, with the largest increases in the North Coast and Sierra Nevada. A recent analysis[359] looked at wildfire trends by region, vegetation type, and season over the 1972–2018 period and found that the increase in annual burned area is driven primarily by an eightfold increase in the extent of summer forest fires. The increased fires correspond with substantial increases in dryness of forest fuels because of an increase in summer season temperatures of about 1.4 degrees Celsius (2.5 degrees Fahrenheit) since the early 1970s. With substantial increases in summer season temperatures projected for California, forested area burned is expected to continue rising over the next few decades,[360] although efforts to curb this risk through forest

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359 Williams, P.A., J. T. Abatzoglou, A. Gershunov, J. Guzman-Morales, D. A. Bishop, and D. P. Lettenmaier (2019). "Observed Impacts of Anthropogenic Climate Change on Wildfire in California." *Earth's Future*. Observed Impacts of Anthropogenic Climate Change on Wildfire in California research article https://doi.org/10.1029/2019EF001210.

360 A. L. Westerling (2018). *Wildfire Simulations for California's Fourth Climate Change Assessment: Projecting Changes in Extreme Wildfire Events with a Warming Climate*. California's Fourth Climate Change Assessment, CEC. Publication Number: CCCA4-CEC-2018- 014.

health initiatives are underway. Warmer summers also elevate the likelihood that extreme winds in the autumn, such as those associated with offshore Santa Ana and Diablo winds, will coincide with very dry fuel conditions and, thus, high fire risk.

Given the role of seasonal winds that are directed offshore—such as Santa Ana and Diablo winds–as a contributor to wildfire risk and behavior in coastal California, several studies have explored how offshore-directed winds may change in frequency, magnitude, and timing as the climate changes. Research projecting Santa Ana winds suggests reduced frequency and intensity of these extreme wind events.[361] Similarly, through analysis of the mechanisms governing Santa Ana winds, a study[362] predicted significantly weaker winds by the mid-21st century. A different study,[363] however, found that while Santa Ana winds are expected to decline on average, the historical peak of the Santa Ana wind season (November–January) would be less affected by a projected decrease in frequency of extreme wind events. Coupled with projections of less frequent rain in Southern California and a shorter wet season that begins later in the year, these considerations suggest that climate change may continue to drive heightened risks of winter fires in Southern California. Indeed, one of the largest wildfires in California's recorded history, the Thomas Fire (December 2017–January 2018), was a product of Santa Ana conditions, an abundance of dry fuel produced by a wet spring followed by a hot dry summer, and delayed seasonal precipitation (most of which did not begin until January 2018).

Recognizing that nonclimate, human-associated factors also affect changes in forest fires, a 2019 study[364] considered forest fire trends over a longer timescale, comparing an "early fire suppression" (1911–1924) and a "contemporary fire suppression" (2002–2015) period. These

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361 Guzman-Morales, J. and A. Gershunov (2019). "Climate Change Suppresses Santa Ana Winds of Southern California and Sharpens Their Seasonality." *Geophys. Res. Letters*. Climate Change Suppresses Santa Ana Winds of Southern California and Sharpens Their Seasonality research letter https://doi.org/10.1029/2018GL080261.

362 Hughes, M. A. Hall, J. Kim (2011). "Human-Induced Changes in Wind, Temperature, and Relative Humidity During Santa Ana Events." *Climatic Change*. Abstract for Human-Induced Changes in Wind, Temperature, and Relative Humidity During Santa Ana Events https://doi.org/10.1007/s10584-011-0300-9.

363 Pierce, D. W., D. R. Cayan, J. F. Kalansky. (2018). *Climate, Drought, and Sea Level Rise Scenarios for the Fourth California Climate Assessment*. California's Fourth Climate Change Assessment, CEC. Publication number: CCCA4-CEC-2018-006.

364 Collins, B. M., J. D. Miller, E. E. Knapp, and D. B. Sapsis. 2019. "A Quantitative Comparison of Forest Fires in Central and Northern California Under Early (1911–1924) and Contemporary (2002–2015) Fire Suppression." *Int. J. Wildland Fire*. Abstract for A Quantitative Comparison of Forest Fires in Central and Northern California Under Early and Contemporary Fire Suppression research article http://www.publish.csiro.au/WF/WF18137.

periods represent conditions of less dense ("early fire suppression") and dramatically denser and more continuous ("contemporary") fuels that are more susceptible to severe and extensive forest fires. The study found that large fires (those greater than 12,145 hectares)[365] accounted for a small fraction (less than 10 percent) of total area burned in the early 1900s. Yet large fires represent 53 percent to 73 percent of total area burned in the contemporary period, with greater incidence of these large fires early in the season. These larger fires are typically associated with more extreme conditions in terms of fuel (density and continuity) as well as meteorology (humidity, temperature, wind). Somewhat counterintuitively, the study also observed that average frequencies of human-caused fire (which includes fires associated with utilities) are similar in the early and contemporary periods, despite a more than tenfold increase in California's population. It noted that understanding changes in forest fire regimes requires analysis of the interacting roles of climate, suppression activities, and capacity to suppress multiple simultaneous ignitions (due, for example, to lightning strikes).

Wildfire coupled with climate change can also cause ecosystem transitions, such as shifts from conifer forests dominated by Douglas fir and ponderosa pine to nonforested ecosystems.[366] Moreover, severe wildfires create landscapes that are prone to landslides and mudflows, such as California's deadliest debris flow on record—the 2018 Montecito landslides that also caused severe disruption to the natural gas system.[367]

The 2011–2015 drought and bark beetle outbreak, both of which were exacerbated by warmer temperatures associated with climate change, contributed to the death of unprecedented numbers of trees in California's conifer forests. This massive increase in dead trees led to fears of worsening of fire risk, particularly in the southern Sierra Nevada, where the die-off was most pronounced. Because tree mortality was at an unprecedented scale, there have been insufficient empirical data to describe this factor in fire severity models. As dead trees fall, the buildup of heavy ground fuels could create very hot, slow-moving "mass fires" that California has not experienced before. The effects of tree mortality on fuels and fire severity should be investigated because of the unparalleled nature of the situation.

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365 A *hectare* is a metric system unit of area equal to about 2.47 acres.

366 Davis, K.T., S. Z. Dobrowski, P. E. Higuera, Z. A. Holden, T. T. Veblen, M. T. Rother, S. A. Parks, A. Sala, and M. P. Maneta. 2019. "Wildfires and Climate Change Push Low-Elevation Forests Across a Critical Climate Threshold for Tree Regeneration." *PNAS*. [Abstract for Wildfires and Climate Change Push Low-elevation Forests Across a Critical Climate Threshold for Tree Regeneration article](https://doi.org/10.1073/pnas.1815107116) https://doi.org/10.1073/pnas.1815107116.

367 [Link to NY Times' interactive map of California mudslides](https://www.nytimes.com/interactive/2018/01/16/us/map-california-mudslides.html) https://www.nytimes.com/interactive/2018/01/16/us/map-california-mudslides.html.

Given increased wildfire-related risks, with impacts to natural and managed resources and infrastructure, the role of strategically placed landscape area treatments[368] designed to reduce fire severity is increasingly important. Recent empirical analysis indicates that treated landscapes were characterized by a smaller severe burn area, improved resistance to wildfire, and better indicators of recovery from fire.[369] Such treatments can protect infrastructure, reduce ignition risk of electricity system-ignited fires, and improve forest health.

An example of a strategically placed landscape area treatment that leverages IOU investments to reduce ignition hazards is the California Tahoe Conservancy partnership with the U.S. Forest Service, Liberty Utilities, California State Parks, and the Tahoe Fire and Fuels Team (a group of roughly 20 fire districts, land managers, and regulatory agencies). This partnership developed a strategy crossing several jurisdictions that complemented Liberty Utilities' vegetation management with fuels reduction and forest health treatments. California Tahoe Conservancy presented on the Powerline Resilience Corridors at the August 8, 2019, IEPR workshop on Climate Adaptation in California's Energy Sector. This partnership creates efficiencies that increase the pace and scale of treatments to protect communities and restore forest health better than individually managed interventions could achieve.[370]

Climate Change, Precipitation, and Atmospheric Rivers

California's Fourth Climate Change Assessment (Fourth Assessment) notes that projected changes in precipitation patterns (snow and rain) indicate a future with fewer days when precipitation occurs, stronger variability between years, more dry years, and increases in maximum daily precipitation.[371] The Fourth Assessment cites Swain et al.'s finding that extreme flooding, such as the devastating 1861–1862 flood that inundated Sacramento and

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368 Strategically placed *landscape area treatments* are fuel reduction interventions that are designed to reduce fire severity across an entire landscape through strategic fuel reduction on a fraction of the overall landscape.

369 Tubbesing, C.L., D. L. Fry, G. B. Roller, B. M. Collins, V. A. Fedorova, S. L. Stephens, and J. J. Battles. 2019. "Strategically Placed Landscape Fuel Treatments Decrease Fire Severity and Promote Recovery in the Northern Sierra Nevada." *Forest Ecology and Management*. Abstract for Strategically Placed Landscape Fuel Treatments Decrease Fire Severity and Promote Recovery in the Northern Sierra Nevada article https://doi.org/10.1016/j.foreco.2019.01.010,

370 California Tahoe Conservancy. Presentation by Dorian Fougeres. "Powerline Resilience Corridors: Leveraging Investor-Owned Utilities' Ignition Prevention Efforts With Additional Fuel Reduction and Forest Health Activities That Benefit Local Communities." 19-IEPR-10. TN# 229248.

371 Bedsworth, L., D. Cayan, G. Franco, L. Fisher, and S. Ziaja. 2018. California Governor's Office of Planning and Research, Scripps Institution of Oceanography, CEC, CPUC. *Statewide Summary Report*. California's Fourth Climate Change Assessment. Publication Number: SUM-CCCA4-2018-013.

much of the Central Valley, may become more frequent as the climate changes.[372] At the same time, the Fourth Assessment acknowledges the prospect of multidecadal drought in California's future and identified extended drought scenarios based on downscaled climate projections as a basis for exploring impacts of a near-term and late-century, 20-year drought.[373]

More recently, a study investigated meteorological mechanisms that govern projected changes in precipitation in California.[374] The authors show that the projected increased frequency of days without precipitation is driven by a decline in nonatmospheric river precipitation.[375] The study also found that atmospheric rivers are expected to become stronger, delivering more precipitation when they occur and accounting for a greater proportion of California's precipitation. Atmospheric rivers have historically accounted for the majority of floods in California.

Changes in precipitation patterns will increase the challenges already faced by water reservoir managers who must balance flood risks with ecological, urban, agricultural, and hydropower demand for water resources. Meeting these challenges will require improving near-term and seasonal forecasts of atmospheric rivers, as well as development of adaptive management strategies informed by probabilistic forecasts—which provide estimated probabilities of possible outcomes—to enhance resource management in uncertain situations.

372 Swain, D. L., Langenbrunner, B., Neelin, J. D., & Hall, A. 2018. "Increasing Precipitation Volatility in Twenty-First Century California." *Nature Climate Change*, 8(5), 427–433. https://doi.org/10.1038/s41558-018-0140-y

373 Note that Tarroja et al. (2019), include analysis of extended drought scenario in their assessment of impacts of climate change on hydropower in a renewables-dominated grid. Highlights and abstract for "Implications of Hydropower Variability From Climate Change for a Future, Highly -Renewable Electric Grid in California." https://www.sciencedirect.com/science/article/pii/S030626191831897X.

374 Gershunov, A., T. Shulgina, R. E. S. Clemesha, K. Guirguis, D. W. Pierce, M. D. Dettinger, D. A. Lavers, D. R. Cayan, S. D. Polade, J. Kalansky, and F. M. Ralph. 2019. "Precipitation Regime Change in Western North America: The Role of Atmospheric Rivers." *Scientific Reports*.

375 An "atmospheric river" is a narrow band of concentrated water vapor in the atmosphere that can transport tropical moisture and disperse it in large precipitation events. In California, a few annual precipitation events associated with atmospheric rivers can account for about one-third to one-half of annual precipitation.

Implications of Climate Change on California's Transition to a Carbon-Neutral Energy System

Successful decarbonization of California's energy system requires consideration of the impacts of a changing climate on a high-renewables electric grid. For example, an EPIC-funded[376] study shows the importance of developing long-term energy scenarios that meet the state's carbon goals and account for climate-related considerations, in addition to costs, grid operation requirements, and environmental performance. The analysis of zero-carbon energy pathways includes consideration of issues such as:

- Changes to the overall amount of hydropower available.
- Projected increases in variability of hydropower resources.
- Impacts of climate change on solar thermal and geothermal power plants, which are constrained by water resources.
- Implications of increased heat, more extreme heat waves, and regional heat waves on demand from homes and businesses.

Hydropower is particularly valuable in a high-renewables, zero-carbon grid because it is a fast-ramping, dispatchable electricity resource that maintains high efficiency at partial load. Hydropower has historically been a highly variable resource, and climate change is expected to exacerbate this variability. Recent research provides a detailed assessment of how climate-related changes in hydropower capacity and timing could affect a renewables-dominated grid. The research indicates that changes to hydropower availability and variability are not expected to reduce renewable penetration or impact overall levelized cost of electricity. However, additional dispatchable capacity would be needed to compensate for the increasing variability of hydropower resources that, on average, appear to be in decline.[377]

Funded in part by EPIC, a study[378] analyzed the challenges of, as well as potential strategies for coping with, extreme heat with regard to the Los Angeles electrical grid. Researchers

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376 Burillo, D., M. Chester, S. Pincetl, E. Fournier, K. Reich, A. Hall. 2018. University of California Los Angeles. *Climate Change in Los Angeles County: Grid Vulnerability to Extreme Heat*. California's Fourth Climate Change Assessment, CEC. Publication Number: CCCA4-CEC-2018-013.

377 Tarroja, B., K. Forrest, F. Chiang, A. AghaKouchak, S. Samuelson. 2019. "Implications of Hydropower Variability From Climate Change for a Future, Highly-Renewable Electric Grid in California." *Applied Energy*. https://doi.org/10.1016/j.apenergy.2018.12.079.

378 Burillo, D., M. Chester, S. Pincetl, E. Fournier, K. Reich, A. Hall. 2018. University of California Los Angeles. *Climate Change in Los Angeles County: Grid Vulnerability to Extreme Heat.* California's Fourth Climate Change Assessment, CEC. Publication number: CCCA4-CEC-2018-013. https://www.ioes.ucla.edu/project/climate-change-in-los-angeles-county-grid-vulnerability-to-extreme-heat/.

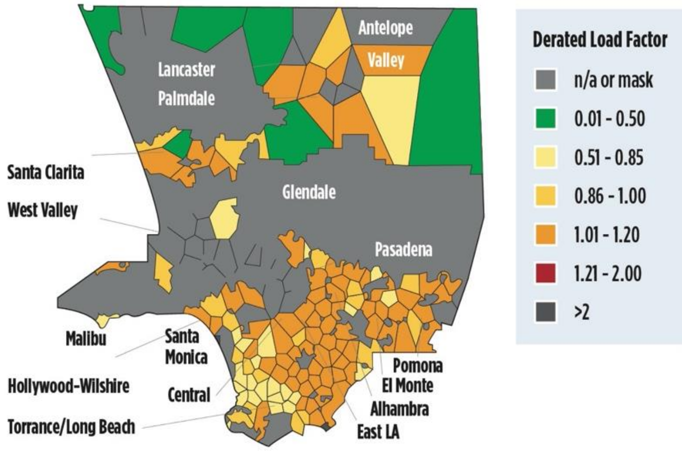
considered projected peak demand as a function of population growth, building stock, appliance efficiency and turnover, and projected temperatures.[379] Based on these factors, the study projects peak demand in Los Angeles County to increase by 2 percent to 51 percent by 2060, with rising temperatures accounting for a 4 percent to 8 percent increase. (For more information on how the statewide electricity forecast accounts for the effects of climate change on energy demand, see Chapter 7.) The approach of the study to developing neighborhood-scale demand forecasts enables exploration of reliability issues at various scales, including transmission, distribution circuit, and neighborhood levels of granularity. This analysis helps identify constraints that can lead to grid failures and can inform the design of infrastructure that is low-carbon and climate-resilient. Researchers developed advanced tools and techniques to enable high-resolution peak-demand forecasting discussed above. To make their modeling techniques accessible to others, they developed prototypes of advanced functionalities for building energy models and software platforms managed by the U.S. Department of Energy and national labs.[380]

Through sensitivity analysis, researchers identified key factors for the high-resolution peak-demand forecasting to be population growth, building and appliance efficiencies, air-conditioner penetration, and daily maximum air temperatures. Researchers found that shared-wall housing could reduce peak demand by up to 50 percent for each building unit. While raising the air conditioner seasonal energy efficiency ratio (SEER) standards in California would reduce annual energy demand, researchers conclude that it would not reduce peak demand during summertime heat waves. With access to SCE's distributed energy interconnection map data, researchers were also able to identify congested areas where strategic siting of distributed energy resources and storage could be a cost-effective option to ensure continued reliability (Figure 24); other options include load-shifting and infrastructure upgrades to increase substation capacity.

379 Burillo, D., M.V. Chester, S. Pincetl, E. Fournier, and J. Reyna. 2019. "Forecasting Peak Electricity Demand for Los Angeles Considering Higher Air Temperatures Due to Climate Change." *Applied Energy*. [Abstract for Forecasting Peak Electricity Demand for Los Angeles Considering Higher Air Temperatures Due to Climate Change article](https://doi.org/10.1016/j.apenergy.2018.11.039) https://doi.org/10.1016/j.apenergy.2018.11.039.

380 The energy models and software platforms are EnergyPlus ([Link to download EnergyPlus program](https://energyplus.net/) https://energyplus.net/) and Building Energy Optimization Tool, also known as BEopt ([Link to Building Energy Optimization tool](https://beopt.nrel.gov/home) https://beopt.nrel.gov/home).

Figure 24: Map of SCE Substation Vulnerabilities to Heat Waves in 2018



Source: Burillo et al., 2019 "Derated load factor" is a temperature-adjusted utilization rating that researchers developed to show conditions under which substations are expected to be overloaded under high demand and reduced capacity conditions during extreme heat. The large amount of areas in red indicate that most substations in the county will be overloaded by 1 to 20 percent during a heat wave.

Health and Equity Issues in the Context of Climate Change

Recent research has highlighted the potential for transportation electrification and decarbonization to help California meet its midcentury GHG emissions reductions goals and reduce air pollution associated with human illnesses and deaths.[381] By 2050, the benefits of reduced mortality due to lower particulate matter pollution could have a similar economic value as the cost of meeting an 80 percent emissions reductions target. Additional benefits would accrue from reduced numbers of illnesses and deaths (such as asthma), as well as from improved indoor air quality resulting from electrification of home heating and cooking. Improved accounting of cobenefits is needed to support development of statewide decarbonization strategies, as well as local strategies aimed at generating benefits for disadvantaged communities and vulnerable populations.

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381 See *Statewide Summary Report* (2018) and Zapata, C.B., C. Yang, S. Yeh, J. Ogden, and M. J. Kleeman. 2018. "Low-Carbon Energy Generates Public Health Savings in California." *Atmospheric Chemistry and Physics*. Abstract for Low-Carbon Energy Generates Public Health Savings in California article https://doi.org/10.5194/acp-18-4817-2018.

Climate Resilience and Interconnected Systems

Assessing climate vulnerability and developing strategies to preserve the energy distribution and transmission systems require considering interconnected systems that may not be designed, regulated, or managed as having interdependencies.[382] For example, interdependencies between the energy, water, transportation, and other critical sectors can result in complex disruptions affecting multiple sectors (Figure 25).[383] Recent research underscores how interconnections between, for example, transportation and energy systems with other sectors such as communications, can thwart traditional risk analysis and limit the effectiveness of resilience strategies that consider a sector in isolation.[384] Preparing complex, interconnected systems for climate change may require—in addition to traditional risk analysis for infrastructure and operations—designing systems to operate with flexibility and agility to support robust adaptation.

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382 Moser, S. and J. F. Hart. 2018. *The Adaptation Blind Spot—Electrical Grid Teleconnected and Cascading Climate Change Impacts on Community Lifelines in Los Angeles.* California's Fourth Climate Change Assessment, CEC. Publication Number: CCCA4-CEC-2018-008, https://www.energy.ca.gov/sites/default/files/2019-07/Energy_CCCA4-CEC-2018-008.pdf.

Radke, J. D., G. S. Biging, K. Roberts, M. Schmidt-Poolman, H. Foster, E. Roe, Y. Ju, S. Lindbergh, T. Beach, L. Maier, Y. He, M. Ashenfarb, P. Norton, M. Wray, A. Alruheili, S. Yi, R. Rau, J. Collins, D. Radke, M. Coufal, S. Marx, A. Gohar, D. Moanga, V. Ulyashin, and A. Dalal. 2018. *Assessing Extreme Weather-Related Vulnerability and Identifying Resilience Options for California's Interdependent Transportation Fuel Sector*. California's Fourth Climate Change Assessment. CEC. Publication Number: CCCA4-CEC-2018-012, https://www.energy.ca.gov/sites/default/files/2019-07/Energy_CCCA4-CEC-2018-012.pdf.

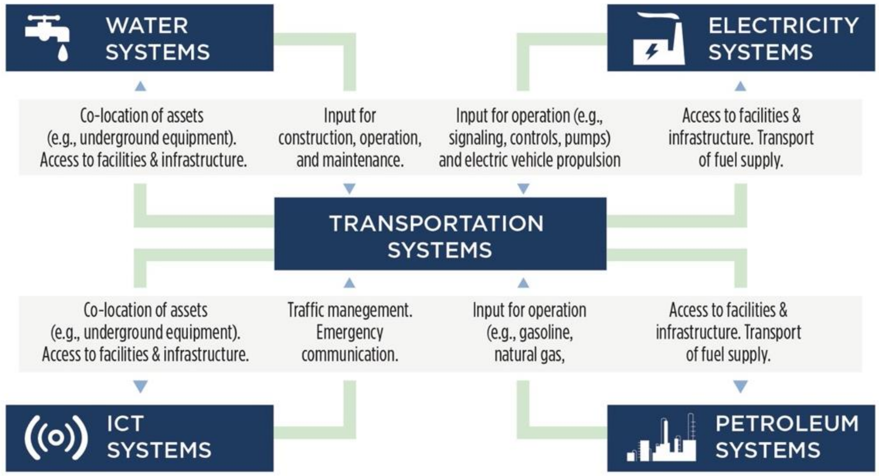
CEC staff. 2016. *2016 Integrated Energy Policy Report Update*. CEC. Publication Number: CEC-100-2016-003-CMF. p. 122.

383 Markolf et al. 2019.

384 Clark, S.S., M.V. Chester, T.P. Seager, and D.A. Eisenberg. 2019. "The Vulnerability of Interdependent Urban Infrastructure Systems to Climate Change: Could Phoenix Experience a Katrina of Extreme Heat?" *Sustainable and Resilient Infrastructure*. Abstract for The Vulnerability of Interdependent Urban Infrastructure Systems to Climate Change article https://www.tandfonline.com/doi/abs/10.1080/23789689.2018.1448668.

Markolf, S.A., C. Hoehne, A. Fraser, M.V. Chester, and B.S. Underwood. 2019. "Transportation Resilience to Climate Change and Extreme Weather Events– Beyond Risk and Robustness," *Transport Policy*. Abstract for Transportation Resilience to Climate Change and Extreme Weather Events article https://www.sciencedirect.com/science/article/pii/S0967070X17305000.

Figure 25: The Importance of Considering Interconnected Systems When Designing Climate Resilience Strategies



Source: Markolf et al., 2019

Crucial Role of Research in Supporting Climate-Resilient Planning and Investment for the Energy Sector

Investing in a climate-resilient, decarbonized energy system requires understanding of the interplay between a changing climate and energy sector infrastructure and operations. As noted by Governor Newsom's strike force report, "Climate change has rendered many assumptions about California's climate outdated. Historical records for humidity, wind, rain, and temperature are regularly broken." The strike force report emphasizes the critical need for utilities to ensure that capital investments are tailored to the realities of a changing climate, and for the state to provide—through its climate assessment process and adaptation clearinghouse—updated climate models to inform those investments.[385] In addition, the *Paying it Forward: The Path Toward Climate-Safe Infrastructure in California* report[386] developed in response to Assembly Bill 2800 (Quirk, Chapter 580, Statutes of 2016) provides

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385 *Wildfires and Climate Change: California's Energy Future.* A Report from Governor Newsom's Strike Force. April 2019, https://www.gov.ca.gov/wp-content/uploads/2019/04/Wildfires-and-Climate-Change-California%E2%80%99s-Energy-Future.pdf.

386 Climate-Safe Infrastructure Working Group. 2018. Paying It Forward: The Path Toward Climate-Safe Infrastructure in California. Report of the Climate-Safe Infrastructure Working Group to the California State Legislature and the Strategic Growth Council. Sacramento, CA: CNRA, Publication Number: CNRA-CCA4-CSI-001. http://resources.ca.gov/docs/climate/ab2800/AB2800_Climate-SafeInfrastructure_FinalNoAppendices.pdf.

recommendations highlighting the importance of sustained financial support for climate science efforts and collaborative interaction among engineers, architects, and climate scientists to support development of climate-safe infrastructure.

Foundational research illuminating projected climate impacts at a fine scale is essential to preparing for this globally warmed world. High-resolution climate projections for California—and the data products that derive from those projections—allow decision makers to identify vulnerabilities to assets and operations, craft science-based adaptation strategies, and understand the appropriate timing and prioritization of adaptation actions. Understanding local and regional impacts is crucial because climate change will affect different climate zones, neighborhoods, and communities in different ways.

This section provides an overview of the CEC's leadership in developing high-resolution climate projections for California. The section also emphasizes the importance of engaging stakeholders to produce scientifically rigorous research for supporting action.

Climate Projections to Support Resilient Infrastructure Investment and Planning for a Decarbonized Energy System

The global climate models that represent how the planet will respond to changes in GHG emissions do not describe local and regional impacts to California with sufficient detail to characterize the nature of threats to key sectors (such as energy, water, or agriculture) or infrastructure and operations (which require very fine resolution in space and time). To fill this critical gap, the state has invested in cutting-edge research to develop downscaled projections, which rely on statistical methods or explicit modeling of chemistry and physics to produce high-resolution, accurate representations of how climate change may affect California.[387] Over more than a decade of research, the state's climate projections have evolved to represent bias-corrected trends and variability of weather-related parameters that most impact the energy system. State-sponsored research has also advanced understanding of underlying science, which, in turn, has illuminated a path to producing projections of wind, surface solar radiation, and other difficult-to-characterize parameters essential for capturing impacts relevant to renewable energy resources, demand forecasting, wildfire-related risks, and other issues germane to a resilient energy transition.

387 Climate Action Team. CalEPA. February 2015. *Climate Change Research Plan for California.* Link to Climage Change Research Plan for California report
https://www.climatechange.ca.gov/climate_action_team/reports/CAT_research_plan_2015.pdf.

California's electricity and natural gas IOUs have expressed an interest in having projected and historical climate data at 2 kilometer (km) spatial resolution and hourly temporal resolution.[388] Projections and historical data at discrete points (such as weather stations) are also needed to complement "gridded" data that represent averages over an area (such as a 2-km-by-2-km grid). These data are needed to assess vulnerabilities for natural gas and electricity system assets and operations, as well as develop flexible adaptation pathways and adaptive management strategies. "Adaptive management strategies" are characterized by a "decision-making framework that maintains flexibility and incorporates new knowledge and experience over time."[389] Such strategies enable institutional learning and are well-suited to situations where historical approaches are not adequate and future circumstances are characterized by uncertainty. "Flexible adaptation pathways" are an adaptive management approach that identifies circumstances that merit reassessment and possible refinement, as well as allow for adjustment of adaptation measures when new or unforeseen information becomes available.[390]

Developing climate projections on a scale that utilities request to inform infrastructure investments, risk analysis, and highly granular demand forecast and management strategies is challenging. For example, the next generation of global climate models[391] that will serve as a

388 CMIP 6 is the sixth phase of the Coupled Model Intercomparison Project, which began in 1995 under the auspices of the World Climate Research Programme (WCRP). "The objective of the CMIP is to better understand past, present and future climate changes arising from natural, unforced variability or in response to changes in radiative forcing in a multi-model context." A suite of global climate modeling results from more than 30 research groups around the world based on the same GHG emissions and land use scenarios are available online. These projections inform international analyses and negotiations. Information on CMIP Phase 6 on the World Climate Research Programme's Web page https://www.wcrp-climate.org/wgcm-cmip/wgcm-cmip6.

389 Butler, P., C. Swanston, M. Janowiak, L. Parker, M.S. Pierre, and L. Brandt. 2012. "Adaptation Strategies and Approaches: Chapter 2." In: Swanston, Chris; Janowiak, Maria, eds. *Forest Adaptation Resources: Climate Change Tools and Approaches for Land Managers*. Gen. Tech. Rep. NRS-87. Newtown Square, Pennsylvania: U.S. Department of Agriculture, Forest Service, Northern Research Station: 15-34., 87, 15-34.

390 See, for example, Bruzgul, Judsen, Robert Kay, Andy Petrow, Tommy Hendrickson, Beth Rodehorst, David Revell, Maya Bruguera, Dan Moreno, and Ken Collison. (ICF and Revell Coastal). 2018. *Rising Seas and Electricity Infrastructure: Potential Impacts and Adaptation Actions for San Diego Gas & Electric*. California's Fourth Climate Change Assessment. CEC. Publication Number: CCCA4-CEC- 2018-004, https://www.energy.ca.gov/sites/default/files/2019-07/Energy_CCCA4-CEC-2018-004.pdf.

391 The Coupled Model Intercomparison Project 6 (CMIP6) is a product of the World Climate Research Programme. CMIP6 provides a suite of global climate modeling results from more than 30 research groups around the world based on the same GHG emissions and land use scenarios. These projections inform international analyses and negotiations.

foundation for international negotiations and assessments does not provide hourly resolution—rather, only a small percentage of projections will provide six-hour resolution or better.[392] Meeting the expectations of IOUs will require methods that portray temporal and spatial patterns of California's microclimates reliably.[393] As PG&E notes, "presently, our understanding of historical climate at fine resolution limits our ability to develop models of future projected climate."[394]

The CEC is supporting ongoing research to help meet the IOU's highly granular climate data needs. For example, an ongoing EPIC grant[395] supports development of a hybrid downscaling technique that leverages strengths of different approaches to produce high-resolution climate projections based on global climate model outputs. The aim is to improve on several critical climate-related parameters, including wind fields (speed, direction, variability). In addition to research on the role of wind fields in extreme fire weather, understanding projected changes in wind fields is important to supporting renewable generation. For example, long periods with very low wind may affect planning and operations of a high-renewables grid.

Ongoing EPIC grants have also provided hourly temperature data (projected and historical) that can be used to support highly granular demand forecasts and integration of climate projections in support of SB 100 and SB 350 goals. For example, the CEC's Demand Forecast Office used projected hourly temperature at 29 locations in the state to incorporate impacts of climate change. On December 18, 2019, the CEC held a staff workshop to discuss energy stakeholders' needs for hourly temperature data and present the projected and historical hourly temperature data sets developed through EPIC-funded research. This workshop also encouraged discussion and coordination among IOUs, state agency technical staff, and other stakeholders. (See Chapter 7 for more information on the forecast.)

Another newly initiated EPIC research project will advance scientific understanding of wildfire behavior in a changing climate and produce updated models of wildfire risk to support

392 Originally noted from public comment TN 228670 to 19-ERDD-01, submitted by Dr. Owen Doherty of Eagle Rock Analytics on June 5, 2019.

393 Public Comment from Eagle Rock Analytics to CEC Docket 19-ERDD-01, TN #228670 submitted June 5, 2019.

394 Public comment from PG&E to CEC Docket 19-ERDD-01, TN#228650, submitted June 5, 2019.

395 Ongoing research under EPIC Grant Number EPC-16-063 with Scripps Institution of Oceanography, University of California, San Diego. "Advanced Statistical-Dynamical Downscaling Methods and Products for California Electricity System Climate Planning."

electricity sector resilience.[396] This research seeks to improve understanding of fire behavior in current and future fuel and climate conditions, including issues related to tree mortality and development of human infrastructure near wildlands. Ultimately, the work will provide stakeholders with actionable wildfire risk forecasts at fine-scale resolution in the near-term (0–7 day forecasts) and longer-term (end-of-century) projections at coarse-scale (5 km) resolution. Stakeholders involved with the effort include not only utilities, but agencies such as the California Tahoe Conservancy and the U.S. Forest Service, who are working in partnership with other local entities to leverage IOU vegetation treatments with additional measures to provide more comprehensive community-scale forest resilience.

Actionable Adaptation Research: Beyond Information Provision to Decision Support

Generating research that informs resilient infrastructure investment and planning is critical. A valuable strategy is to conduct coproduced research, which involves engagement of stakeholders as collaborators. Decades of analysis have shown that coproduced research is more likely to lead to the generation of usable knowledge than research that does not involve collaboration of target users.[397] These studies indicate that successful coproduction processes requires participation and input from stakeholders at multiple stages of the research, from developing the research focus and design to disseminating the research findings. Opportunities to align research focus toward the needs of utilities, communities, and other stakeholders require more vigorous stakeholder engagement during the presolicitation stage. In addition, research proposals should be assessed to ensure engagement plans and stakeholder input are incorporated throughout the research process.

An example of one such successful collaboration is the development of the Integrated Forecast and Reservoir Management (INFORM) framework, which resulted in the adoption of a hydropower and reservoir decision-support tool. Research funded by the CEC's Public Interest Energy Research (PIER) program demonstrated the usefulness of probabilistic forecasting

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396 EPC-18-026 with Spatial Informatics Group. "Comprehensive Open Source Development of Next Generation Wildfire Models for Grid Resiliency."

397 Lemos, M. C., and B. J. Morehouse. 2005. "The Co-Production of Science and Policy in Integrated Climate Assessments." *Global Environmental Change*, 15(1), 57-68, https://www.sciencedirect.com/science/article/abs/pii/S0959378004000652.

Meadow, A. M., D. B. Ferguson, Z. Guido, A. Horangic, G. Owen, and T. Wall. 2015. "Moving Toward the Deliberate Coproduction of Climate Science Knowledge." *Weather, Climate, and Society*. 7(2), 179-191, https://journals.ametsoc.org/doi/full/10.1175/WCAS-D-14-00050.1.

through the development of INFORM.[398] The probabilistic approach of INFORM was coupled with a decision-support system designed to help reservoir operators use short- and long-term runoff forecasts to make informed decisions. Research showed that this approach would lead to improved outcomes under a highly variable and changing climate while balancing among often competing demands, such as hydropower generation, water supply, and flood control.[399] As presented at the August 2019 IEPR Climate Adaptation Workshop, the demonstration phase of INFORM illustrated how adaptive, risk-based reservoir regulation strategies are self-tuning to a changing climate and deliver more robust performance than current management practices.[400] However, research and demonstration efforts were not enough to ensure acceptance of this powerful decision-support tool. Instead, ongoing collaboration between the research team and a network of policy makers and managers was crucial.[401]

Cal-Adapt, the state's interactive website for exploring local climate-related risks, presents an opportunity to strengthen stakeholder engagement to promote the use of climate projections in energy sector climate resilience decision-making. Initial development of Cal-Adapt focused on making California's vast research related to projected climate risks publicly available and easy to access. Moving forward, energy sector adaptation planning and integration of resilience into investments will require:

- Resources dedicated to stakeholder engagement and outreach to describe precise decision-support needs.

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398 HRC-GWRI (2007). *Integrated Forecast and Reservoir Management (INFORM) for Northern California: System Development and Initial Demonstration*. CEC, PIER Energy Related Environmental Research. CEC-500-2006-109. Link to Integrated Forecast and Reservoir Management for Northern California report https://www.energy.ca.gov/2006publications/CEC-500-2006-109/CEC-500-2006-109.PDF.

399 Georgakakos, K. P. et al. 2014. *Integrated Forecast and Reservoir Management (INFORM) Enhancements and Demonstration Results for Northern California (2008-2012)*. CEC Report No. CEC-500-2014-019, https://www.energy.ca.gov/2014publications/CEC-500-2014-019/CEC-500-2014-019.pdf.

400 Presentation by Konstantine P. Georgakakos, Sc.D (Hydrologic Research Center). "Enhancing the resilience of energy and water resources through integrated management and the use of probabilistic forecasts." Presented at the California Energy Commission's August 8, 2019, IEPR workshop on Climate Adaptation in California's Energy Sector.

401 Ziaja, S. 2019. "Role of Knowledge Networks and Boundary Organizations in Coproduction: A Short History of a Decision Support Tool and Model for Adapting Multiuse Reservoir and Water-Energy Governance to Climate Change in California." *Weather, Climate, and Society*. Abstract for Role of Knowledge Networks and Boundary Organizations In Coproduction article. https://doi.org/10.1175/WCAS-D-19-0007.1.

- Support for analytics and research by climate scientists to provide analyses, custom datasets, and tools that align with the CPUC's guidance climate data and projections to support adaptation, address stakeholder needs, and maintain scientific rigor.

These elements will foster energy investments and planning.

California's Climate Change Assessments

California has been assessing climate change impacts on the state for more than 30 years, with an initial report on *The Impacts of Global Warming on California* released by the CEC in 1989. California's first three modern climate change assessments—released in 2006, 2009, and 2012—have been instrumental in guiding California's ambitious, comprehensive, science-based climate policy. California's most recent assessment has made strides in:

- Providing climate projections with sufficient detail to illuminate risks to infrastructure and communities.
- Making locally relevant data on climate-related risks freely accessible.
- Building regional capacity to adapt to climate change.

Local Resilience Lessons From California's Fourth Climate Change Assessment

California's Fourth Climate Change Assessment produced regional reports to foster dialogue between scientists and local practitioners, recognizing that climate resilience is an innately local endeavor.

- In many California coastal communities, development and infrastructure may be damaged by bluff and beach erosion due to sea-level rise. The San Francisco regional report states that oyster beds, marshlands, and dune enhancement reduce wave energy and shoreline erosion. However, managed retreat may be the only viable option in some areas.
- Rising temperatures will poses new challenges in many areas of California. In response, the City of Los Angeles is working to reduce neighborhood "heat islands" through a residential "cool roof" ordinance and the city is piloting cool pavement projects. ("Heat islands" refer to urban areas that are warmer than surrounding rural areas because of human activities, while "cool roofs" are those roofs that reflect more wavelengths of the sun, reducing the heat transferred to the building.)
- Housing developments in heavily forested areas are likely to face increasing frequency of wildfire. To reduce wildfire risks, the California Department of Forestry and Fire Protection (CAL FIRE) is increasing investments in prescribed burns and strategic thinning of forest stands. The Blue Lake Rancheria, a federally recognized tribal government and community in rural Northern California, has installed a local microgrid. The microgrid can provide power to tribal facilities, including a certified American Red Cross shelter, to improve disaster preparedness, reduce costs, and reduce GHG emissions.

California's Fourth Assessment: Building Capacity for Regional Engagement

Released in 2018, the Fourth Assessment provides information to support flexible and adaptive actions to increase California's resilience to climate change. The assessment included 16 peer-reviewed technical reports dedicated to energy sector issues, including development of climate projections of parameters relevant to California's energy sector. Key findings from the energy studies as well as the statewide report,[402] which offered a synthesis of technical work, include the following:

- Analysis of nearly 2 billion residential energy bills was used to quantify projected regional changes in peak and total residential electricity demand, as well as natural gas demand. Because of increased penetration and use of air conditioning, residential electricity demand is projected to increase, particularly in inland and Southern California, with more moderate increases expected in cooler coastal areas. Peak demand is expected to increase by a greater percentage than total demand.[403]
- An analysis of projected increases in peak-hourly electricity demand in Los Angeles County indicates that projected peak summer demand puts local energy infrastructure at risk of service disruptions by about midcentury because of exceeding capacity of local substations and distribution circuits. Adaptation measures such as installation of additional substation capacity, strategic deployment of distributed energy resources, or load shifting could reduce grid vulnerabilities in Los Angeles County.[404]
- Results from a field study in the Sacramento-San Joaquin River Delta indicate subsidence rates for some Delta levees of about 1 to 2 centimeters per year. This subsidence compounds risks associated with rising seas and storm, effectively accelerating the timeline in which storm surge could result in levee overtopping and expose natural gas pipelines and other infrastructure to damage related to inundation or scouring.[405]

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402 Bedsworth, L., D. Cayan, G. Franco, L. Fisher, and S. Ziaja. (California Governor's Office of Planning and Research, Scripps Institution of Oceanography, California Energy Commission, California Public Utilities Commission). 2018. *Statewide Summary Report*. California's Fourth Climate Change Assessment. Publication Number: SUM-CCCA4-2018-013, https://www.energy.ca.gov/sites/default/files/2019-07/Statewide%20Reports-%20SUM-CCCA4-2018-013%20Statewide%20Summary%20Report.pdf.

403 Auffhammer, Maximilian. (University of California, Berkeley and NBER). 2018. *Climate Adaptative Response Estimation: Short and Long Run Impacts of Climate Change on Residential Electricity and Natural Gas Consumption Using Big Data*. California's Fourth Climate Change Assessment. Publication Number: CCCA4-EXT-2018-005, https://www.nber.org/papers/w24397.

404 Burillo, Daniel, Mikhail Chester, Stephanie Pincetl, Eric Fournier, Katharine Reich, and Alex Hall. (University of California Los Angeles). 2018. Climate Change in Los Angeles County: Grid Vulnerability to Extreme Heat. California's Fourth Climate Change Assessment, California Energy Commission. Publication Number: CCCA4-CEC-2018-013, https://www.energy.ca.gov/sites/default/files/2019-07/Energy_CCCA4-CEC-2018-013.pdf.

405 Brooks, Benjamin, Jennifer Telling, Todd Ericksen, Craig L. Glennie, Noah Knowles, Dan Cayan, Darren Hauser, and Adam LeWinter. (U.S. Geological Survey). 2018. *High-Resolution Measurement of Levee Subsidence*

Over a 15-year period (2001–2016), a small fraction of wildfires was responsible for most of the damage to California's electricity grid. Wildfire-related threats to the electricity grid in Northern California are expected to increase in the near term, while uncertain impacts of climate change on Santa Ana wind events create uncertainty in projected wildfire-related risks to Southern California's grid.[406]

Climate adaptation strategies are typically implemented at local and regional scales through planning and land-use decisions, climate-resiliency investments, and community-based efforts.

Responding to a need to interpret technical results in the context of regional and local practitioner needs, the Fourth Assessment included nine regional reports, as well as a comprehensive statewide report and three reports on climate-related topics of statewide importance—ocean and coast, tribal and indigenous communities, and climate justice. In 2018 and 2019, hundreds of people participated in events throughout California to discuss the findings of the Fourth Assessment in regional contexts. This discussion strengthened dialogue among scientists, policy makers, and practitioners and laid the foundation for more vigorous, science-based adaptation action.

California's Fifth Climate Change Assessment: Organization, Scenarios, Key Research Gaps

Research to provide foundational scenarios for California's Fifth Climate Change Assessment is already underway. Interagency efforts involving California's Natural Resources Agency, the Governor's Office of Planning and Research, the Strategic Growth Council, and the CEC are ongoing to scope a governance process that supports the scale and aspirations of the next assessment, identify priority research areas to support local and regional adaptation efforts, and lay a foundation for sustained engagement throughout the assessment. Early, sustained engagement will be crucial to advancing science that addresses regional priorities.

Related to Energy Infrastructure in the Sacramento-San Joaquin Delta. California's Fourth Climate Change Assessment, California Energy Commission. Publication Number: CCCA4-CEC-2018-003.

406 Dale, Larry, Michael Carnall, Gary Fitts, Sarah Lewis McDonald, and Max Wei. (Lawrence Berkeley National Laboratory). 2018. *Assessing the Impact of Wildfires on the California Electricity Grid.* California's Fourth Climate Change Assessment, California Energy Commission. Publication number: CCCA4-CEC-2018-002, https://www.energy.ca.gov/sites/default/files/2019-07/Energy_CCCA4-CEC-2018-002.pdf.

In July 2019, the CEC and the Bishop Paiute Tribe cohosted a conference on Sustaining Tribal Resources.[407] This event advanced the CEC's mission to provide meaningful tribal input into the development of regulations, plans, and activities that may affect tribes. The event also served to build capacity for early engagement in the scoping of the Fifth Assessment.

The CEC anticipates holding workshops to engage energy sector stakeholders and the research community in discussions to help delineate and focus supporting research, including:

- Coproduction of climate projections and decision-support analytics with sufficient resolution to support asset-level vulnerability assessment, infrastructure planning, and charting flexible adaptation pathways that are responsive to changes in scientific understanding, policy, and on-the-ground conditions.
- Integration of climate readiness into electricity system operations, tools, and models, including those that support long-term planning for a high-renewables electricity grid.
- Clarification of interactions between renewable electricity systems and climate change to ensure an effective, resilient transition to low-carbon energy.
- Development of long-term energy scenarios that meet California's climate and energy mandates in a manner resilient to projected changes in climate, including changes in climate variability and extreme events.

Fortifying Community-Level Climate Resilience and Disaster Preparedness Through Energy Sector Innovation

California's energy sector is rapidly innovating to meet ambitious GHG emissions reductions goals. This innovation creates the opportunity to integrate low-carbon technologies while addressing climate resilience and concerns related to local hazard mitigation planning, disaster preparedness, emergency response, and disaster recovery. This innovation is particularly valuable in low-income and disadvantaged communities because the impacts of climate change affect these communities to a greater extent. Technologies are needed that can help provide reliable and resilient power to these communities cost-effectively. A growing suite of technologies, and combinations of technologies, are being demonstrated for the ability to support resilience and are in varying stages of maturity. These technologies include energy storage, solar plus storage, and microgrids as well as the expanded use of fuel cells and green electrolytic hydrogen (hydrogen generated from renewable sources, which can then be used

407 Link to agenda for Sustaining Tribal Resources Conference on July 10-11,2019 https://www.energy.ca.gov/sites/default/files/2019-07/Sustaining-Tribal-Resources-Conference-Agenda-July-2019-V3.pdf.

as an alternative to fossil fuel directly or converted to electricity). As discussed during the Fostering Community Resilience Through Energy Sector Innovation panel at the August 8, 2019, IEPR workshop on Climate Adaptation in California's Energy Sector, advances in controllers coupled with reductions in solar cost and storage options have improved the commercial outlook for renewable-powered microgrid systems. These systems can promote the resilience of critical facilities and provide an alternative to backup diesel generators.[408]

EPIC Investments in Community-Level Resilience and Disaster Preparedness

Through its EPIC research program, the CEC has made investments in promoting community resilience through energy sector innovation. Investment in energy storage, smart inverters, solar plus storage, and microgrids[409] provides new technology solutions and improves resiliency for California's energy sector by helping maintain critical operations and services during grid outages due to extreme weather, wildfires, and other natural disasters. Critical facilities, such as hospitals, fire stations, and emergency shelters, have traditionally relied on backup diesel generators to maintain power during grid outages. Using onsite renewable generation and energy storage to offer a clean source of backup power allows continued operation in the face of grid outages. Renewable power and storage also offers benefits related to GHG emissions reductions and management of peak demand. The following projects describe the flexibility and benefits offered by energy storage and microgrid technologies, ranging from stand-alone building structures to supporting entire communities.

City of Fremont Fire Stations Microgrid Project

Fire stations are vulnerable to power outages that could handicap local emergency response. Possible causes of power outages include extreme weather and earthquakes. With funding from the CEC, Gridscape Solutions designed and built microgrids at three fire stations in Fremont (Alameda County). Each microgrid consists of a microgrid energy management system, a parking lot canopy solar photovoltaic (PV) system, and a battery energy storage

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408 Link to WebEx recording of August 8, 2019, IEPR workshop on Climate Adaptation in California's Energy Sector
https://www.energy.ca.gov/php/yt_player.php?vidNo=icnqtDYPU1g&title=IEPR%20Commissioner%20Workshop%20on%20Climate%20Adaptation%20in%20California%E2%80%99s%20Energy%20Sector&desc=This%20workshop%20explores%20energy%20sector%20climate%20adaptation%20in%20California%20through%20two%20sessions%20focused%20on%20community%20resilience%20needs%20and%20collaborative%20research%20to%20improve%20energy%20sector%20planning%20and%20management.

409 Microgrids combine distributed energy resources with a controller to manage energy use. A key feature of many microgrids is the ability to continue operating even if the surrounding electricity grid experiences an outage, referred to as *islanding*.

system. The systems were required to be able to provide at least three hours of power for critical loads during a utility power outage. However, as Gridscape Solutions noted at the August 8, 2019, IEPR workshop on Climate Adaptation in California's Energy Sector, project performance has exceeded the design goals, including successful islanding for more than 12 hours with renewable power.[410] With additional solar and storage, the microgrids could have even longer operational time in the event of an outage. The three microgrids are anticipated to provide savings of $20,000 per year while producing low-carbon power. These microgrids ensure that critical infrastructure can deliver services in emergencies and avoid competing for limited emergency fuel supplies to power backup diesel generation. Further, these microgrids improve the resiliency of the distribution system by reducing the utility load at substations by providing local renewable generation and energy storage as well as the ability to disconnect from the main electricity grid and provide independent energy services. The project has also resulted in a good business model for replication of renewably powered backup generation and storage systems, which are being implemented by Gridscape Solutions at public sector schools and fire and police stations, and for industrial customers.[411]

Kaiser Permanente Medical Center Microgrid

Richmond's Kaiser Permanente Medical Center is a highly used hospital, with urgent care, emergency, and pharmaceutical capacities. Microgrids can maintain critical life safety functions in the event of a grid outage and reduce electrical demand in normal operation, increasing grid resiliency. With funding from the CEC, the Charge Bliss research team successfully designed and built a microgrid system at the Kaiser Permanente Medical Center, consisting of a 250-kilowatt (kW) solar installation and 1 MWh/250 kW of battery storage. The next-generation microgrid system can optimize renewable energy generation, storage, and power delivery to connected loads, as well as islanding[412] to provide critical emergency power to the life-safety branch of the hospital for at least three hours in case of an outage. This system supplements

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410 Link to WebEx recording of August 8, 2019, IEPR workshop on Climate Adaptation in California's Energy Sector
https://www.energy.ca.gov/php/yt_player.php?vidNo=icnqtDYPU1g&title=IEPR%20Commissioner%20Workshop%20on%20Climate%20Adaptation%20in%20California%E2%80%99s%20Energy%20Sector&desc=This%20workshop%20explores%20energy%20sector%20climate%20adaptation%20in%20California%20through%20two%20sessions%20focused%20on%20community%20resilience%20needs%20and%20collaborative%20research%20to%20improve%20energy%20sector%20planning%20and%20management.

411 Ibid., Quote from Peter Lehman, Founding Director, Schatz Energy Research Center.

412 Microgrid systems can power a local distribution circuit even when the electrical grid is no longer providing power to that circuit. Intentional islanding controls enable microgrids to disconnect a local circuit from the grid and derive power from distributed energy resources.

existing backup generators, which improves the energy reliability of hospitals in crises and reduces energy expenses by up to 50 percent. The Richmond Medical Center system is one of nearly 50 PV systems hosted by Kaiser Permanente, supporting the company's goal of carbon neutrality by 2020 and serving as an example for other medical centers interested in replication. As of August 8, 2018, "more than a half dozen inquiries from…facilities around California and beyond, including Hawaii" had reached out to inquire "exactly how fast and in what ways … [they might] replicate the Richmond project."[413]

Chemehuevi Valley Reservation

High winds and seasonal flooding have historically caused frequent power outages for the Chemehuevi Valley reservation. Due to its remoteness in the Mojave Desert and elderly residents' vulnerability to extreme heat, a loss of power poses a substantial risk to the community. With support from the CEC, the University of California, Riverside, developed a microgrid for the Chemehuevi Valley Tribe. This microgrid is at the community center, which tribal members depend on for emergency response and community services. It also serves as a cooling center when power disruption coincides with extreme heat.

In addition to providing reliability and stability to the Chemehuevi community, the system also lowers demand at peak times, reducing utility costs and generating GHG emissions savings. As articulated by Dr. Alfredo A. Martinez-Morales, managing director and research faculty at UC Riverside's Southern California Research Initiative for Solar Energy, a key "part of our mission is to work closely with the community in terms of outreach and education."[414] The opportunity to work closely with the community has been and will continue to be critical to the long-term success of the project.

Valencia Gardens Energy Storage

The Valencia Gardens Energy Storage project, located in a disadvantaged community of central San Francisco's Mission District, is an important example of using clean local energy to enhance grid resiliency in a dense urban environment. With funding from the CEC, the project is using distributed energy storage in front of the meter as part of an optimized local energy system to increase support for nearby distributed solar PV generation while improving the

413 Seth Baruch, National Director Energy and Utilities, Kaiser Permanente Quote from an interview in "The Planning Report," August 24, 2018. [Link to Kaiser Permanente's Richmond Medical Center Solar-Battery Microgrid a CEC-funded Model article](https://www.planningreport.com/2018/08/24/kaiser-permanente-s-richmond-medical-center-solar-battery-microgrid-cec-funded-model) https://www.planningreport.com/2018/08/24/kaiser-permanente-s-richmond-medical-center-solar-battery-microgrid-cec-funded-model.

414 [Link to August 8, 2019, IEPR workshop transcript](https://efiling.energy.ca.gov/getdocument.aspx?tn=229831).
https://efiling.energy.ca.gov/getdocument.aspx?tn=229831.

overall quality of grid operations and economics. The project will improve distribution system reliability and balancing of local electric supply and demand. Furthermore, this project will serve as a model that supports California's emissions reduction goals, increases the state's resilience and security, drives regional economic development, and lowers the cost of operating the power grid.

Borrego Springs Microgrid Demonstration Project

The Borrego Springs community, in San Diego County, experiences frequent grid outages because of severe storms and winds. With funding from the CEC, SDG&E developed an IOU-owned, IOU-operated, front-of-the-meter microgrid system to provide power during emergencies and planned outages. The system demonstrates an advanced microgrid controller, lithium-ion battery storage, and integration with a third-party solar PV system. It optimizes energy usage, provides ancillary services, supports emergency operations, improves customer utility service, and improves reliability and power quality. During an April 2013 grid outage resulting from a windstorm, the microgrid provided power to 1,225 customers for roughly six hours. During a severe storm in September 2013 that downed 20 utility overhead poles, the microgrid provided power to 1,060 customers for roughly 25 hours. Further, the Borrego Springs microgrid controller avoided adverse grid impacts by using more energy from a large, local solar plant and coordinating generation with resources available from various energy storage units.

Research to Develop Replicable Strategies for Implementation

The EPIC projects previously discussed resulted from two solicitations developed to advance the sophistication and decrease the cost of microgrid-enabling technologies (such as solar, storage, and controllers) with focuses on critical facilities and support to low-income and disadvantaged communities. Though lessons have been learned from prior projects, there continues to be a need for easier implementation of these technologies, such as streamlined permitting and interconnection with the grid and packaged system designs. Recognizing the need for communities to have proven, replicable models to promote effective, affordable, and timely deployment, CEC awarded nine additional microgrid projects in 2018 to design and demonstrate commercially replicable systems.[415] Another area of research being pursued by the CEC is the development and demonstration of longer-duration energy storage. Most of today's energy storage has been designed for four-hour duration. The CEC has recently released several solicitations to develop and demonstrate longer-duration storage systems.

415 David Erne. Link to Workshop Transcript. https://efiling.energy.ca.gov/getdocument.aspx?tn=229831.

The CEC is also evaluating whether mobile renewable plus storage systems can provide resilience support and eventually replace mobile diesel backup generators.

Policy Frontiers Related to Microgrids

Recognizing the potential value that microgrids can provide to customers and the grid, the Legislature passed Senate Bill 1339 (Stern, Chapter 566, Statutes of 2018) on September 19, 2018. The legislation requires the CPUC, CEC, and the California Independent System Operator (California ISO) to "take action to help transition the microgrid from its current status as a promising emerging technology solution to a successful, cost-effective, safe, and reliable commercial product that helps California meet its future energy goals." The bill also requires the CPUC, in consultation with the CEC and California ISO, to advance commercialization through efforts including developing rates and tariffs specific to microgrids, as appropriate, without shifting costs between ratepayers. The CPUC initiated a proceeding through Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies (R19-09-009) on September 19, 2019, and anticipates the first proposed decision on the proceeding before the end of 2020.

Community Perspectives on Energy Sector Innovation: Challenges and Opportunities

As illustrated above, California's EPIC program provides many examples of innovative demonstration projects that advance energy sector resilience and support uninterrupted critical services in vulnerable communities. These energy technologies have an important role to play as communities work to build resilience. As discussed by panelists at the August 8, 2019, IEPR workshop on Climate Adaptation in California's Energy Sector, on-the-ground experience has confirmed that communities grapple with many issues as they seek to identify and implement energy innovations. Critical services such as telecommunications, emergency alerts, and first response highlight the importance of coordination and engagement. At the workshop, panelists shared challenges encountered in communities and approaches that proved effective. These examples include:

- Community-driven planning to build a holistic vision and broad base of support, including vulnerable and historically marginalized communities.
- Sustained on-the-ground engagement to overcome challenges related to implementation and maintenance.
- Identification of critical facilities.
- Development of a cohesive vision across sectors.

Community-Driven Planning

As articulated by the National Association of Climate Resilience Planners, community-driven processes for adaptation planning "create stronger climate resilience solutions because communities most vulnerable to the effects of climate change have relevant direct experience and information … not otherwise accessible to public bureaucracies."[416] The aftermath of the 1999 explosion at Chevron's Richmond refinery illustrates the importance of community engagement to elicit community needs and put appropriate solutions in place. At the August 2019 IEPR workshop, Sylvia Chi with APEN discussed how an English-language emergency response alert system was in place at the time of the refinery explosion, which sent out a "shelter in place" advisory. However, this advisory was not effective for non-English-speaking households, who make up a significant portion of the local community. In the aftermath of the Richmond incident, the Laotian Organizing Project was founded to bring "community leaders together to organize and advocate for a multilingual emergency warning system."[417] Community members can now receive emergency information in Lao, Khmu, Mien, or Hmong.

Jasneet Sharma with the San Mateo Office of Sustainability highlighted that the concept of community-driven planning seems simple but is actually substantially more challenging than anticipated because it requires a shift in how governance typically occurs. Ms. Sharma discussed the importance of grounding community engagement with on-the-ground experience. She noted that it is extremely challenging because conventional processes generally lead with externally generated framings and technical perspectives.

Embracing a community-driven approach for adaptation investments can also promote social cohesion and build community leadership.[418] Sylvia Chi with APEN discussed how energy-resilient community sites—which she referred to as "community resilience hubs"—powered by innovative energy technologies could foster social cohesion. She noted that "using microgrids and solar and storage at community sites, like schools or health centers … would have the benefit of providing disaster relief and shelter. It would also support community cohesion and

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416 National Association of Climate Resilience Planners (NACRP). 2017. *Community-Driven Resilience Planning: A Framework, Version 2.0*. Link to Community-Driven Climate Resilience Planning: A Framework from the National Association of Climate Resilience Planners https://kresge.org/sites/default/files/library/community_drive_resilience_planning_from_movement_strategy_center.pdf.

417 Link to Workshop Transcript. https://efiling.energy.ca.gov/getdocument.aspx?tn=229831.

418 NACRP (2017).

trust and provide a space for education and organizing."[419] Community resilience hubs can also provide benefits that accrue in normal operations, such as reduced energy burdens.

Sustained Engagement to Overcome Challenges

As noted at the August 2019 IEPR workshop, community engagement must extend beyond developing a coherent vision and building a base of support. Dr. Martinez-Morales observed, "Technologies can be engineered, they can be tested in the lab, but when you put them out in the field, they are faced by a series of challenges" that may not have been anticipated.[420] Best practices informed by on-the-ground experience with new technology systems is powerful. In addition to developing and implementing best practices, sustained engagement with communities housing energy projects can provide feedback for technology developers.

Building Resilience Into Disaster Recovery

Disaster recovery—such as the ongoing fire recovery of the town of Paradise and neighboring areas in Butte County—requires extensive resources and leadership. It also provides opportunities to build a new, more resilient infrastructure and align infrastructure investments across sectors, such as the energy sector, telecommunications, and other utilities. As the lead entity on the Community Building and Capacity Building Recovery Support Function—in partnership with the California Office of Emergency Services (CalOES) and Federal Emergency Management Agency (FEMA)—Nuin-Tara Key with the Governor's Office of Planning and Research noted, "There's a tremendous opportunity for alignment and coordination between utility and energy providers and local governments."[421] However, without a cohesive vision and coordinated implementation, investment approaches can be fragmented. Community outreach and education have the potential to develop cohesion and understanding around long-term community resilience goals. Organizing coordinated implementation can ensure near-term disaster response and recovery efforts are building toward those long-term goals and outcomes.

Prioritizing Resilience of Vulnerable Communities

Prioritizing vulnerable community resilience is not just a matter of investment in innovation, but investment in engagement. At its best, energy sector adaptation in vulnerable communities presents opportunities to address issues including:

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419 Link to Workshop Transcript. https://efiling.energy.ca.gov/getdocument.aspx?tn=229831.

420 Ibid.

421 Ibid.

- Building community cohesion.
- Promoting trust between historically marginalized populations and local and state jurisdictions.
- Building local capacity to plan for resilience more broadly.
- Alleviating disproportionate energy and air quality burdens.

ICARP's definition for vulnerable communities in the context of climate change supports efforts to identify the most vulnerable populations[422] and recognizes that "risk shows up in communities very differently. And individuals around the state have very different capacities to be able to respond to climate impacts and … build toward more resilient outcomes."[423]

The CPUC's ongoing adaptation rulemaking anticipates developing recommendations for IOUs on "how to identify and prioritize investments and other activities that address the needs of vulnerable and disadvantaged communities as related to climate change impacts prioritizing community organizations."[424] APEN's publication on mapping resilience considers existing frameworks and tools that provide a basis for understanding community vulnerability to climate change, as well as outstanding needs for identifying and prioritizing vulnerable communities.[425] In the report, the CEC's Social Vulnerability to Climate Change framework was highlighted as one of the strongest examples of a mapping framework in this area. However, promoting broad use of the CEC's framework for the prioritization of clean energy investments may require additional efforts, such as developing an accessible user interface.

Recommendations

- **Identify resources needed to support enhanced technology and knowledge transfer between local jurisdictions and utilities to reduce emissions and enhance resilience.** As noted in the August 8, 2019, IEPR workshop on Climate

422 Governor's Office of Planning and Research. July 2018. *Defining Vulnerable Communities in the Context of Climate Adaptation* http://opr.ca.gov/docs/20180723-Vulnerable_Communities.pdf.

423 Nuin-Tara Key, Transcript for the August 8, 2019, IEPR workshop on Climate Adaptation in California's Energy Sector, TN# 229831, Docket 19-IEPR-10. https://efiling.energy.ca.gov/GetDocument.aspx?tn=229831&DocumentContentId=61278.

424 Assigned Commissioner's Scoping Memo and Ruling, Filed 10/10/18. Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation. R.18-04-019. p.7.

425 Amee Raval et al (2019). Asian Pacific Environmental Network. *Mapping Resilience: A Blueprint for Thriving in the Face of Climate Disasters*, https://apen4ej.org/wp-content/uploads/2019/10/APEN-Mapping_Resilience-Report.pdf.

Adaptation in California’s Energy Sector, local jurisdictions face several challenges in planning for energy sector resilience. The California Energy Commission, in partnership with the Integrated Climate Adaptation and Resiliency Program, should work to develop guidance and resources to support successful engagement of local government and utility stakeholders in energy sector resilience planning. Guidance and resources should align with state priorities and goals, identify replicable examples, and leverage lessons learned from prior launches of innovative technologies.

- **Because community-level resilience requires consideration of interdependent systems under different jurisdictions and regulatory authority, the State of California has a critical convening role to promote coordinated, effective adaptation strategies.** To that end, coordination between energy- and transportation-related agencies as well as California’s Integrated Climate Adaptation and Resiliency Program and the Strategic Growth Council is important to ensure a holistic approach.
- **Continue to prioritize applied research and action that support climate resilience in California’s most vulnerable communities.**
- **State agencies need to redouble efforts to coordinate actionable research that informs climate-resilient decarbonization.** Aggressive strategies to secure substantial decarbonization of buildings and transportation sectors must be well underway by 2030. Further, the state must pursue “reach” technologies that are not yet proven and must consider impacts of climate change in planning a carbon-neutral system.
- **Advance next-generation climate projections that improve understanding of uncertain parameters responsible for key climate-related impacts to the energy system.** Parameters of interest include distribution of wind and the associated extremes as a driver of wildfire risks and wind resources, and cloudiness as a driver of energy demand and solar resources.
- **Leverage projections to inform cost-effective, resilient design of low-carbon energy systems.** Probabilistic interpretations informed by the multiplicity of possible futures will be essential, as will analysis of changing risks of compound events. Interpretation of projections as well as enhanced observed historical records will also be crucial for charting pathways for adapting to climate change. Enabling timely uptake of research results in support of climate resilience will require vigorous stakeholder

engagement at all stages of the research endeavor, including defining the research scope and desired research products.[426]

- **Identify and close knowledge gaps on the role of insurance, costs of inaction, and stability of California's energy markets in developing California's Fifth Climate Change Assessment research portfolio.** California's Fifth Climate Change Assessment provides an opportunity to advance actionable research that supports energy-sector resilience. Early identification of research gaps in this area includes quantification of the economic costs and benefits of transitioning to a resilient energy grid, including an exploration of the intersection of energy reliability, fire risk, and insurance costs. These topics should be explored as potential research priorities during scoping of California's Fifth Climate Change Assessment.

426 Ziaja, S. 2019. "Role of Knowledge Networks and Boundary Organizations in Coproduction: A Short History of a Decision Support Tool and Model for Adapting Multiuse Reservoir and Water-Energy Governance to Climate Change in California." *Weather, Climate, and Society*. [Abstract for Role of Knowledge Networks and Boundary Organizations In Coproduction article](). https://doi.org/10.1175/WCAS-D-19-0007.1.

CHAPTER 6: Southern California Energy Reliability

Introduction

Over the last decade, the state has worked to address concerns about energy reliability in Southern California. These concerns stem from a series of issues related to the aging energy infrastructure in the region that have constrained the system and put energy reliability at risk. These constraints persist to date, requiring ongoing partnerships to monitor developments, assess reliability, and implement mitigation measures as highlighted in this chapter.

In 2010, the state first grappled with reliability issues as the State Water Resources Control Board (SWRCB) developed a policy to reduce the use of ocean water for cooling power plants. The policy phases out the use of once-through cooling technologies (OTC) and affected more than 20,000 MW of generation, much of which is in Southern California.[427]

The closure of the San Onofre Nuclear Generating Station (San Onofre) in 2013[428] presented reliability challenges that were not anticipated when the SWRCB established OTC compliance schedules. The closure of San Onofre required a rapid response because of the importance of the plant in maintaining grid stability, as well as in balancing electricity flows and keeping transmission lines from overloading. The California Energy Commission (CEC), California Public Utilities Commission (CPUC), and California Independent System Operator (California ISO) developed a reliability action plan, outlining mitigation measures and identifying critical preferred resources, transmission upgrades, and conventional generation needed to ensure reliability in the region.

Further compounding reliability concerns, on October 23, 2015, a massive leak at the Aliso Canyon natural gas storage field was discovered and continued until it was sealed on February

427 SWRCB Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/.

Once-through cooling technologies intake ocean water to cool the steam that is used to spin turbines for electricity generation. The technologies allow the steam to be reused, and the ocean water that was used for cooling becomes warmer and is then discharged back into the ocean. The intake and discharge have negative impacts on marine and estuarine environments.

428 On June 7, 2013, Southern California Edison Company (SCE) announced that it would permanently close San Onofre in Southern California.

18, 2016. Aliso Canyon is a depleted oil field that has been used to store natural gas for the Los Angeles region since 1972. SoCalGas has historically used Aliso Canyon to help balance supply and demand in the summer and meet peak demand in the winter. However, in response to the leak at the Aliso Canyon, the state limited its use.

In recent years, SoCalGas experienced pipeline outages that have worsened the constraints, leading to price spikes and gas curtailment of noncore[429] gas customers in 2018. While a major pipeline, Line 235-2, returned to service in October 2019, these constraints persist to date, requiring ongoing monitoring, reliability assessments, and implementation of mitigation measures because of reduced pipeline capacity.

Aliso Canyon Availability

Aliso Canyon operations are restricted under the CPUC's Withdrawal Protocol, which has evolved over time from the first 2016 Aliso Canyon Summer Withdrawal Protocol to the most recent revision July 23, 2019.[430] The November 2, 2017, withdrawal protocol essentially prohibited withdrawals from Aliso Canyon except as an asset of last resort to ensure allowable storage inventory was optimized to meet reliability requirements in Southern California and ensure reasonable costs.

The withdrawal protocol was initially designed in 2016 to push SoCalGas to use storage to support all gas customers in Southern California, not just its core customers, and to assure the public that Aliso Canyon would be used only when necessary. SoCalGas procures gas on behalf of core customers and plans its system, including storage and pipeline infrastructure, to meet core customer demand under adverse conditions forecast to occur once every 35 years, as well as noncore customer demand under 1-in-10 conditions.[431] Noncore customers, including electric generators, refineries, and other large commercial and industrial users, purchase their own gas supplies and obtain gas transmission and storage services on the SoCalGas system under CPUC-approved transmission rates. With Aliso capabilities and access restricted as a result of the well leak, SoCalGas suspended the sale of gas storage service to noncore

429 "Noncore customers" are typically commercial or industrial customers, some of which burn natural gas to produce electricity. "Core customers" are owners of homes and small businesses.

430 Aliso Canyon Withdrawal Protocol, https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/Signed%20Letter%20to%20Roger%20Schwecke%20on%20Aliso%20Canyon%20Withdrawal%20Protocol.pdf.

431 In 1993, the CPUC removed gas utilities' storage service responsibility for noncore customers, along with the cost of this storage service from noncore customers' rates. Information on natural gas in California from the CPUC's website https://www.cpuc.ca.gov/General.aspx?id=4802.

customers.[432] SoCalGas also indicated to the joint agencies that the company would use its remaining storage to support only core customers, leaving gas service to power plants at risk of curtailment under certain summer conditions.[433] The withdrawal protocol addressed this risk.

The CPUC revised the withdrawal protocol on July 23, 2019, with changes it believes improve short-term energy reliability and price stability in Southern California. Specifically, the revisions provide SoCalGas with more flexibility to consider withdrawals from Aliso Canyon on days when the storage field inventory is needed for gas-system balancing or when the inventory of other non-Aliso storage fields in Southern California has substantially declined.[434]

In May 2019, the CPUC and the California Division of Oil, Gas, and Geothermal Resources (DOGGR), who have regulatory authority over Aliso Canyon, released an independent "root cause analysis" of the leak.[435] The report identified that the direct cause of the leak was from a rupture of the outer well casing due to microbial corrosions and raised concerns about SoCalGas' maintenance practice and safety record. On June 27, 2019, the CPUC opened an Order Instituting Investigation (OII) I.19-06-014[436] to determine whether SoCalGas' and Sempra Energy's organizational culture and governance prioritize safety, and OII I.19-06-016,[437] which is reviewing the evidence in the root cause analysis and includes an order to show cause why SoCalGas shouldn't be sanctioned for the leak at Aliso Canyon.

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432 SoCalGas has proposed to eliminate permanently the sale of natural gas storage capacity to noncore customers in its 2020 Triennial Cost Allocation Proceeding (Application No. 18-07-024) which allocates gas system costs to the different customer classes and determines natural gas rates.

433 Noncore customers (including electric generators) are the first to have their natural gas service curtailed when supplies are short. This priority scheme preserves service to core customers (residential and small commercial customers) who are curtailed in only the most extreme conditions.

434 Proposed Revisions to the Aliso Canyon Withdrawal Protocol from the CPUC's website https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/AlisoCanyonWithdrawalProtocol-ProposedRevisionsAndDraft-2019-07-01.pdf.

435 The CPUC has overall authority over rates, the allocation of storage capacity, and the safety of above-ground facilities of SoCal Gas' operation of Aliso Canyon, while the DOGGR has primary responsibility for gas storage well infrastructure, including engineering and maintenance of wells, and safety of below-ground facilities.

436 I. 19-06-014 Order Instituting Investigation on the Commission's Own Motion to Determine Whether Southern California Gas Company's and Sempra Energy's Organizational Culture and Governance Prioritize Safety (U904G). https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:I1812007.

437 I.19-06-016 Order Instituting Investigation on the Commission's Own Motion into the Operations and Practices of Southern California Gas Company with Respect to the Aliso Canyon storage facility and the release of

In November 2019, Governor Newsom sent a letter to CPUC President Marybel Batjer requesting additional action to expedite planning for the permanent closure of Aliso Canyon. He stated that additional actions are necessary to increase public health and safety and to combat climate change while maintaining affordable and reliable energy services for the Los Angeles region.[438] Specifically, the letter requests the CPUC to "immediately engage an independent third-party expert to identify viable alternatives to the facility and scenarios that can inform a shorter path to closure." The CPUC has begun the process of hiring a third-party expert and anticipates vetting the results through Phase 3 of Investigation 17-20-002.

Saddleridge Fire

The October 2019 Saddleridge Fire in Los Angeles County occurred near critical infrastructure, including the Aliso Canyon natural gas storage field and a major high-voltage transmission hub that includes several 500 kV AC transmission lines, the 500 kV DC intertie line and the Sylmar Substation where the DC intertie terminates. At one point, more than 16,000 households in the area were evacuated. No critical infrastructure was damaged and at this time, there are no anticipated impacts to Southern California reliability.

Pipeline Constraints

The SoCalGas system continues to operate at less than full capacity because of pipeline outages and restrictions on the use of the Aliso Canyon natural gas storage field. These constraints continue to pose challenges for ensuring a reliable energy supply in Southern California. The operating conditions of the SoCalGas system going into the winter of 2019–2020 are improved compared to the previous winter, as long as no additional pipeline outages occur.

Four key pipeline outages have reduced system capacity by more than 700 million cubic feet per day (MMcfd), more than 20 percent from full system capacity. The status of the pipelines changes frequently and is as follows as of October 31, 2019:

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natural gas, and Order to Show Cause Why Southern California Gas Should Not Be Sanctioned for Allowing the Uncontrolled Release of Natural Gas from Its Aliso Canyon Storage Facility
https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:I1906016.

438 Letter from Governor Newsom to CPUC President Batjer,
https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-09, TN# 230806.

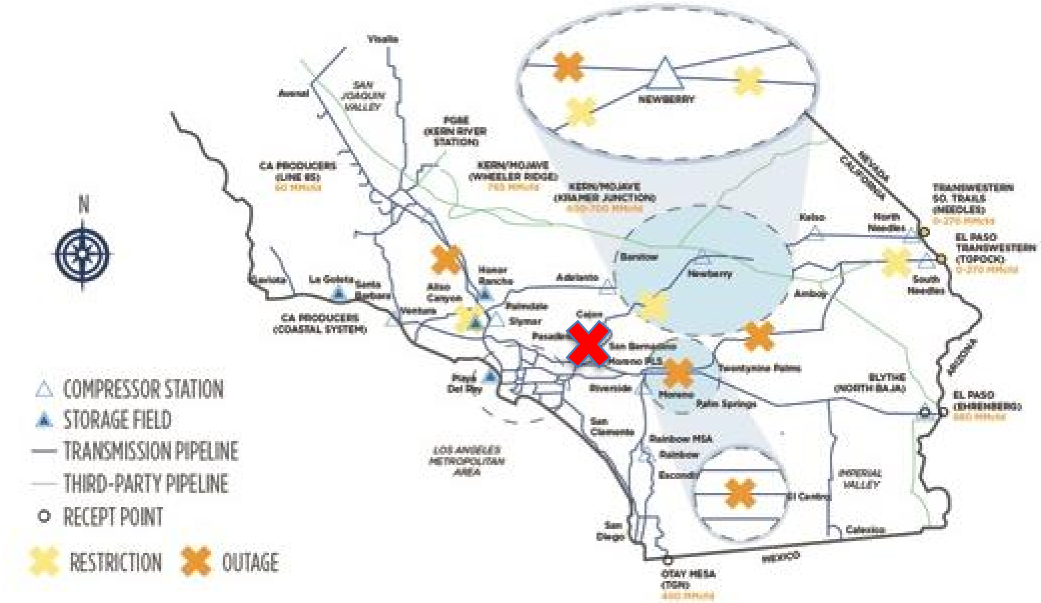
- Line 235-2 ruptured on October 1, 2017, and damaged nearby Line 4000.[439] Line 235-2 returned to service on October 15, 2019, at reduced pressure.
- Line 4000 has mostly been in service but at reduced operating capacity. It was removed from service for validation digs on September 19, 2019, and returned to service on October 24, 2019, at reduced pressure.
- Line 3000 went out of service in July 2016 and returned to service at reduced operating pressure on September 16, 2018.
- Line 2000 has been operating at reduced pressure since 2011 and was reduced by 30 MMcfd because of the expiration of the right-of-way through federal lands.

On May 23, 2019, the joint agencies held a workshop to address the ongoing infrastructure outages and the anticipated near-term impact on reliability in the region identified in their *Aliso Canyon Risk Assessment Technical Report Summer 2019* (2019 Summer Assessment).[440] The workshop highlighted that the ongoing pipeline outages continue to be a critical concern regarding natural gas and electric reliability. Figure 26 shows the status of the pipeline outages as of May 2019, which was the basis of the 2019 Summer Assessment.

439 SoCalGas commented, "The remediation work for Line 4000, however, was not caused by damage from the rupture of Line 235-2." (See TN# 26490 in Docket 18-IEPR-01, February 8, 2018.)

440 Aliso Canyon Risk Assessment Technical Report Summer 2019. Link to information and workshop materials for May 23, 2019, workshop on Energy Reliability in Southern California https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-09.

Figure 26: SoCalGas System Outages/Restrictions on Line 235-2, Line 4000, and Line 3000 as of May 2019



Source: SoCalGas

Questions surrounding the pace of repairs and continued delays surfaced during the workshop. Information presented indicated that the national average for time to repair is weeks or months and not years for pipeline repairs.[441] For example, Enbridge, a Canadian energy transportation company, suffered a rupture of a natural gas transmission line in British Columbia on October 9, 2018, and had the line back in service within several weeks. SoCalGas, in its comments to the workshop, countered this by stating that not all pipelines are the same and, the work on Line 235-2 has been challenging because of the remote nature of the multiple worksites and the unique working conditions (such as narrow workspaces and special environmental constraints).[442]

441 Rod Walker presentation, TN-228352, [Link to presentations from the May 23, 2019, workshop on Energy Reliability in Southern California](https://www.energy.ca.gov/2019_energypolicy/documents/2019-05-23-workshop/2019-05-23_presentations.php) https://www.energy.ca.gov/2019_energypolicy/documents/2019-05-23-workshop/2019-05-23_presentations.php.

442 SoCalGas comments, TN-228704. [Link to comments received regarding the May 23, 2019, workshop on Energy Reliability in Southern California](https://www.energy.ca.gov/2019_energypolicy/documents/2019-05-23-workshop/2019-05-23_comments.php) https://www.energy.ca.gov/2019_energypolicy/documents/2019-05-23-workshop/2019-05-23_comments.php.

The workshop discussed the 2019 Summer Assessment, which indicated that SoCalGas has been operating Line 4000 at reduced pressure, allowing only an incremental 270 MMcfd into the system. SoCalGas reported that when Line 235-2 returns, it would remove Line 4000 for validation digs. This change was not expected to impact capacity, and SoCalGas did remove Line 4000 from service on September 14, 2019, with a projected return to-service date of November 5, 2014. Once Line 4000 is returned to service and both lines are operating at reduced pressure, SoCalGas projects capacity to increase an incremental 80 MMcfd. When operating pressure is eventually increased on Line 4000, SoCalGas projects capacity to increase an incremental 300 MMcfd. Given the numerous delays in the return to service of Line 235-2 due to additional leaks detected, system capacity did not increase during summer 2019 as expected.

During the workshop, SoCalGas explained that Line 235-2 is a cathodically protected steel pipeline built in the 1950s, making it more than 60 years old, and that is an additional challenge to repairing it expeditiously.[443] Rod Walker, a natural gas engineering expert from Walker & Associates, stated that these types of pipelines generally have a useful life of around 70 to 75 years, so, Line 235-2 may be reaching the end of its useful life.[444] Walker's presentation suggested that repairs or replacements should be limited to hazardous issues, and repairs should be expedited to get pipelines back in service while planning for permanent replacements.[445]

Planned maintenance events can exacerbate already constrained conditions. As discussed at the May 23, 2019, workshop, there is a need to "optimize the timing of discretionary maintenance to maximize injections while minimizing peak summer and winter season maintenance. This would be done through having SoCalGas provide additional information on its maintenance outlook and whether those maintenance activities are being pursued pursuant to regulatory requirements."[446] Determining when planned maintenance can be deferred and

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443 *Cathodic protection* is a technique used to protect the steel pipe from corrosion by making it the cathode of an electrochemical cell.

444 Transcript of the May 23, 2019, workshop on Energy Reliability in Southern California, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-09, TN# 228898, p. 175.

445 Presentation by Walker & Associates at the May 23, 2019, workshop on Energy Reliability in Southern California https://efiling.energy.ca.gov/GetDocument.aspx?tn=228352&DocumentContentId=59538.

446 Simon Baker with the CPUC, Transcript from January 23, 2019, Joint Agency Workshop on Energy Reliability in Southern California https://efiling.energy.ca.gov/getdocument.aspx?tn=228898.

when it must be completed immediately because of safety or reliability reasons is a balancing act during these constrained conditions.

In light of California's climate change policies, decisions about making cost-effective investments in the state's aging natural gas infrastructure will be challenging but are necessary for maintaining energy reliability. In the near term, aging pipeline infrastructure that result in pipeline outages are the most critical concern affecting Southern California's energy reliability.

Technical Assessments of Reliability

Over the last few years, the joint agencies have engaged in regular monitoring to address concerns about natural gas curtailments and the related impact on gas customers and electricity system reliability in Southern California. The CEC, CPUC, California ISO, and LADWP performed reliability assessments (summer and winter) to determine the likelihood of curtailments, minimum electric generation gas burn necessary to maintain reliability, and identified actions that could be taken to reduce the possibility of natural gas and electricity interruptions.[447] Since the summer of 2015, the joint agencies have developed seven analyses of the short-term electric reliability in the region. The intent is to keep policy makers abreast of reliability risks and propose recommendations to improve reliability in the near term. More than 50 mitigation measures have been developed, many of them ongoing, ranging from tariff changes and better coordination between SoCalGas and the electric balancing authorities to reducing electricity and natural gas use.

Long-term analysis and recommendations of electric reliability in the region are handled in other proceedings or reports. For example, the Legislature directed the CPUC to consider the feasibility of minimizing or eliminating the use of the Aliso Canyon storage field while maintaining energy reliability, and the CPUC opened Order Instituting Investigation I.17-02-002 to examine the long-term viability of the gas storage field. In 2017, then-Governor Edmund G. Brown Jr. asked the CEC for a plan to phase out use of the field within 10 years.

Conditions going into the winter of 2019–2020 are similar to those going into the winter of 2018–2019, meaning reliability concerns will persist. A review of conditions during last winter is discussed below.

447 Winter is defined as November 1 through March 31, and summer is April 1 to October 31. These dates coincide with the traditional underground gas storage withdrawal and injection seasons for the natural gas industry.

Winter 2018–2019 Look Back

The *Aliso Canyon Risk Assessment Technical Report Winter 2018–2019 Supplement* concluded that reliability challenges remained for the winter of 2018–2019.[448] Similar to winter 2017–2018, Southern California faced the risk of curtailments in winter 2018–2019 because of continued natural gas pipeline outages. It also concluded that the need for curtailments would depend on the weather and how effectively consumers reduce gas demand when requested. Curtailments are not desirable and can lead to increased costs because electric utilities may be required to import more expensive electricity.

Meeting winter 2018–2019 demand turned out to be challenging toward the second half of the season. The weather was mild in the beginning but turned cold in the latter half and remained cold for an extended period. The temperatures in downtown Los Angeles remained below 70 degrees in February, and gas from storage was used to meet demand each day of the month. Prior analysis predicted that the continued pipeline outages could lead to greater reliance on storage, and that forecast was borne out: 42 billion cubic feet (Bcf) was withdrawn from storage in winter 2018–2019 compared to 19 Bcf to 21 Bcf during the prior two winters. (See Table 9.) A little more than 1 Bcf was withdrawn from Aliso Canyon on six days during the prior winter, but in the 2018-2019 winter, 14 Bcf of gas was withdrawn from Aliso Canyon on 37 gas days.[449] The ending inventory level was lower for winter 2018–2019 than prior years.

Table 9: Winter Season Inventory Levels and Withdrawals

(Billion Cubic Feet)	2016–2017	2017–2018	2018–2019
Starting Winter Storage Inventory November 1	60.9	67.0	80.5
Ending Winter Storage Inventory April 1	39.5	47.7	38.7
Total Net Withdrawal	21.4	19.3	41.8

Source: SoCalGas Envoy

The sustained cold weather led to 80 operational flow orders (OFOs),[450] 41 days with voluntary electric generator curtailments in effect, and 5 days with Rule 23 curtailments in

448 *Aliso Canyon Winter Risk Assessment Technical Report Winter 2018-2019 Supplement*. TN# 224939. Prepared by the staff of the CPUC, CEC, the California ISO, and LADWP. November 28, 2018. CEC-100-2017-002. Link to information and documents for the May 22, 2017, workshop on Energy Reliability in Southern California http://www.energy.ca.gov/2017_energypolicy/documents/#05222017.

449 A "gas day" is from 7:00 a.m. to 7:00 a.m.

450 "Operational flow orders" are an operating tool used by SoCalGas to evaluate the amount of storage withdrawal or injection needed versus what is allocated for balancing.

effect.[451] This is the first time SoCalGas used Rule 23 curtailments since the gas leak at Aliso Canyon. More details on winter 2018–2019 can be found in the CPUC's *Winter 2018–2019 SoCalGas Conditions and Operations Report.*[452]

Natural Gas Prices

In summer 2018, the number of OFOs increased, and in winter 2018–2019, the number of calls for voluntary and mandatory curtailments of electric generation was greater than previous years. These operational challenges have been reflected in the price spikes and increased volatility of natural gas prices at the SoCal Citygate.[453] The CEC and CPUC held a joint agency workshop January 11, 2019, to discuss natural gas prices in Southern California, the related impact on customers, and potential mitigation measures to reduce high natural gas prices.[454] Figure 27 shows prices for natural gas transactions at the SoCal Citygate, which shows that price spikes have reached as high as $40/million British thermal units (MMBtu) in summer 2018 and $22/MMBtu in winter 2018–2019, while prices at SoCal Border and PG&E Citygate were less volatile. This finding is consistent with increased volatility at the SoCal Citygate since the rupture of Line 235-2 and the maintenance outage on Line 4000, which were noted in the CEC's *2018 IEPR Update*.

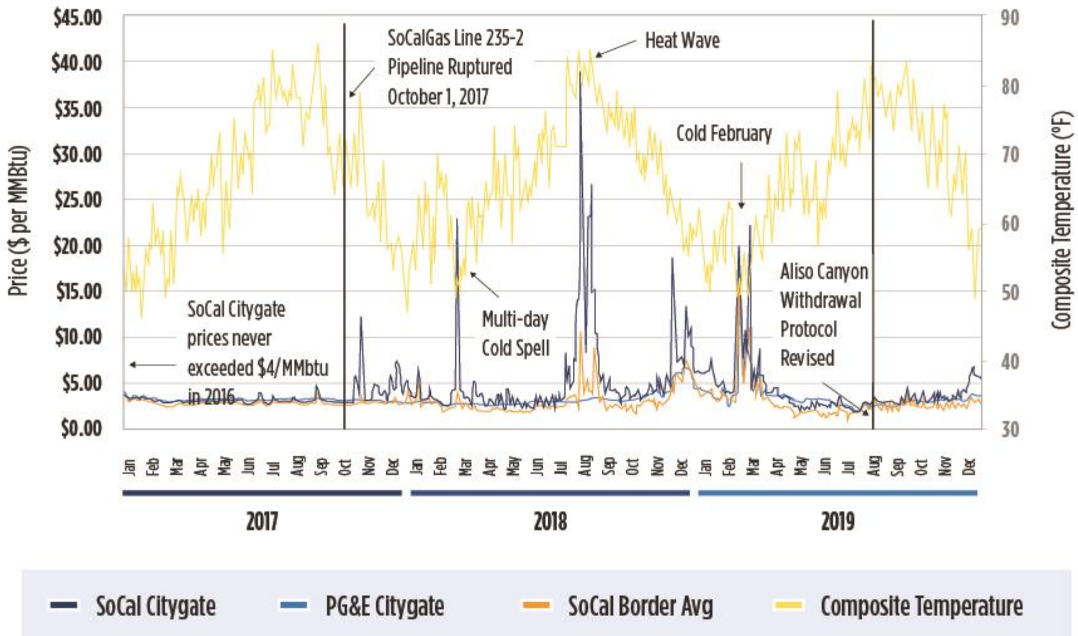
451 SoCalGas Tariff Rule 23 describes the continuity of service and interruption of delivery in the event of curtailments and is a mandatory curtailment.

452 Link to Winter 2018–2019 SoCalGas Conditions and Operations Report on the CPUC's website https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/Winter2018-19LookbackReport_PublicDraft.pdf.

453 *SoCal Border* is a trading hub in Southern California on the border with Arizona, while *SoCal Citygate* is a trading hub that provides firm access rights on the SoCalGas system to deliver gas to customers. Transactions at SoCal Citygate include local distribution charges.

454 Link to transcript from the January 11, 2019, workshop on Southern California Nautral Gas Prices https://www.energy.ca.gov/2018_energypolicy/documents/#01112019.

Figure 27: SoCal Citygate Prices During Heat Waves and Cold Spells



Source: CEC staff

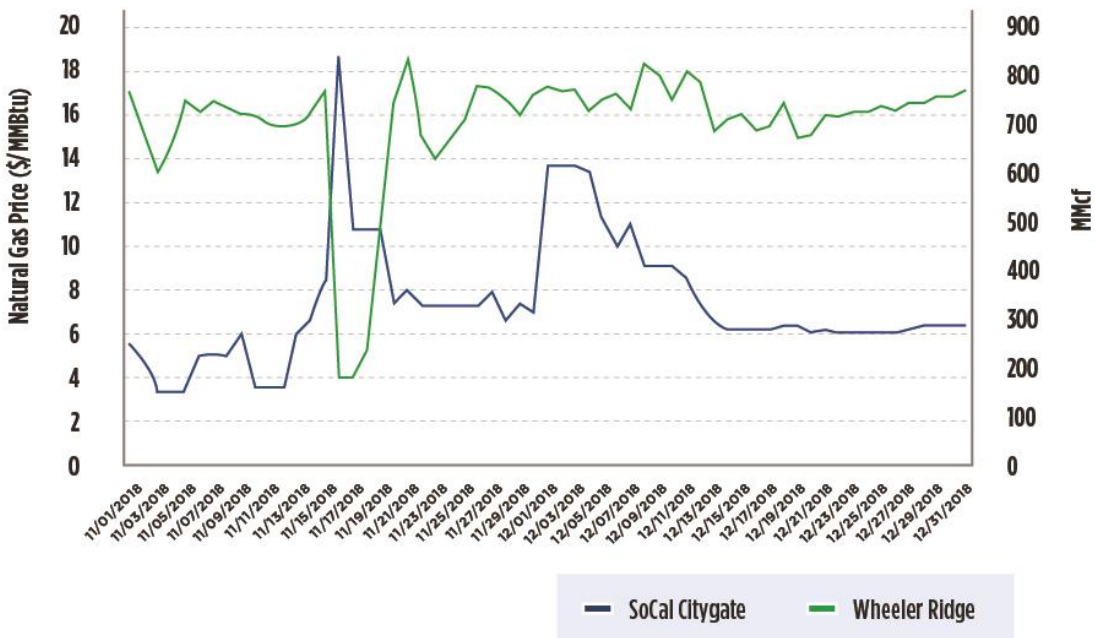
The highest price increases occurred on days that the composite weighted average temperature was at the highest during summer and lowest during winter.[455] In winter, price increases tended to coincide with withdrawals from Aliso Canyon. Price spikes also tended to occur when additional maintenance, whether planned or unplanned, further reduced system capacity.

Figure 28 shows that price spikes at SoCal Citygate are somewhat correlated to the utility's scheduled maintenance at Wheeler Ridge. The maintenance that started on November 16, 2018, at Wheeler Ridge reduced firm capacity available from 765 MMcfd to 145 MMcfd. On November 15, 2018, the price of natural gas at SoCal Citygate was $8.51 per MMBtu, which spiked to $18.64 per MMBtu on November 16, 2018. For comparison, the winter of 2016–2017 had more high-demand days above 3.2 Bcf than either winter 2017–2018 or winter 2018–2019, but prices remained stable and reached a high of only $4.05 in early January 2017. The

455 *Composite weighted average temperature*, as found on SoCalGas Envoy, takes the average daily temperature of several locations in SoCalGas' territory, and then averages those into one number.

rupture of Line 235-2 occurred after the winter of 2016–2017 on October 1, 2017, and contributed to increased price spikes and price volatility seen since then.

Figure 28: SoCal Citygate Natural Gas Prices and Wheeler Ridge Receipt Point Capacity



Source: CEC

At the January 2019 joint agency workshop on Southern California Natural Gas Prices, a repeating theme was the urgency of SoCalGas repairing its infrastructure.[456] Workshop participants, including the energy agencies, industry stakeholders, and members of the public, agreed that pipeline outages were a cause of price spikes. Industry stakeholders such as power plant owners expressed the negative impact of the high natural gas prices on their businesses and indicated they needed to file with the Federal Energy Regulatory Commission to recover the costs incurred to operate their natural gas plants.[457] Workshop participants,

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456 Link to transcript from the January 11, 2019, workshop on Southern California Nautral Gas Prices https://www.energy.ca.gov/2018_energypolicy/documents/#01112019.

457 Jan Smutney Jones, p. 140, Independent Energy Producers, Link to transcript from the January 11, 2019, workshop on Southern California Nautral Gas Prices, https://www.energy.ca.gov/2018_energypolicy/documents/#01112019.

including CEC staff, raised concerns about whether there is an incentive problem since consumers were bearing the costs of this, not SoCalGas. In addition, removing an asset from rate base was discussed if assets are not used or useful. The issue of removing an out-of-service pipeline asset from the customer rate base was also raised at the May 23, 2019, workshop[458] and was discussed as a mediation tool for delays in pipeline repair or replacement that has been used in other parts of the country.[459]

High natural gas prices also raised electricity prices, as shown in Figure 29. For example, Southern California Edison (SCE) indicated at the January 2019 workshop that its electricity procurement costs for 2018 were undercollected by roughly $833 million,[460] although this amount was later revised to $815.43 million dollars.[461] On November 13, 2018, SCE sent the CPUC an Expedited Application Regarding Energy Resource Recovery Account (ERRA) Trigger Mechanism showing that SCE undercollected $983.8 million from customers as of December 31, 2018.[462] SCE cited high natural gas prices as the main reason for the higher-than-expected electricity costs because natural gas generators are often setting the market clearing price in the California ISO market. The electric utility's ERRA application sought approval to pass these costs to the ratepayers, resulting in higher bills for 2019. Since that time, the CPUC approved a rate increase for SCE to cover these additional costs. The rate increase was about 1.4 cents/kWh, adding roughly $11.50 to an average customer's electricity bill in the summer and $7.67 in winter.[463]

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458 CPUC Commissioner Guzman Aceves, p. 173, Link to transcript from the May 23, 2019, workshop on Energy Reliability in Southern California https://efiling.energy.ca.gov/getdocument.aspx?tn=228898.

459 Rod Walker, pp. 134 and 143, Link to transcript from the May 23, 2019, workshop on Energy Reliability in Southern California https://efiling.energy.ca.gov/getdocument.aspx?tn=228898. PU Code Section 455.5 and the applicable language reads "In establishing rates for any electrical, gas, heat, or water corporation, the commission may eliminate consideration of the value of any portion of any electric, gas, heat, or water generation or production facility which, after having been placed in service, remains out of service for nine or more consecutive months, and may disallow any expenses related to that facility."

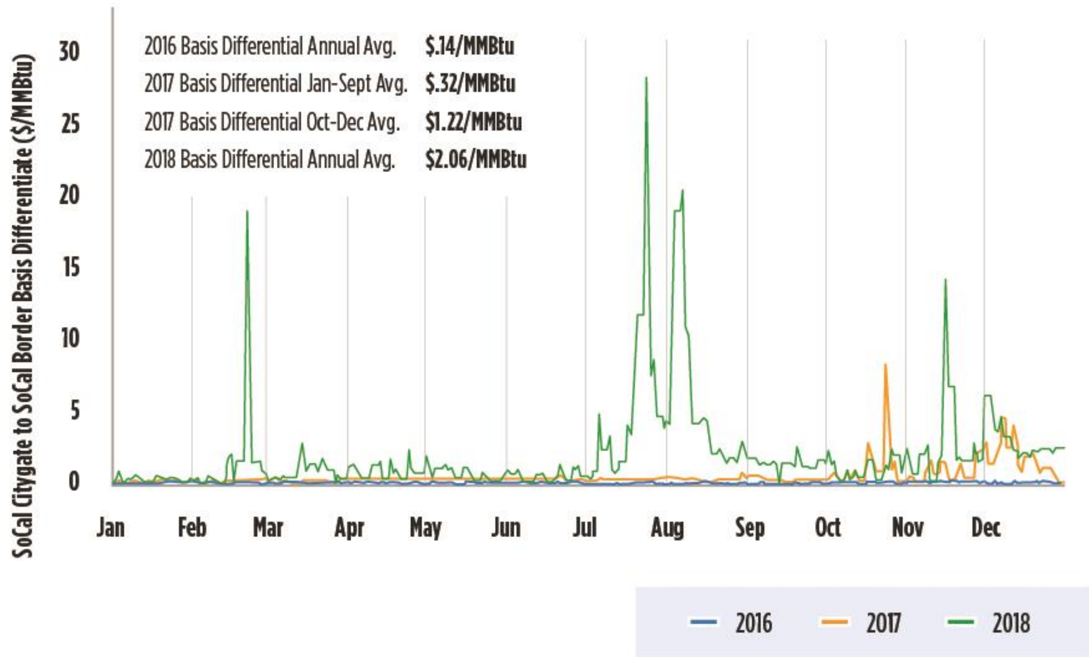
460 Link to transcript from the January 11, 2019, workshop on Southern California Nautral Gas Prices https://www.energy.ca.gov/2018_energypolicy/documents/#01112019.

461 February 15, 2019, Advice Letter 3954-E from SCE, updating the amount to $815.432 million.

462 CPUC A.18-11-009.

463 *RTP Insider*, February 5, 2019, "SCE's $1 Billion Shortfall Perturbs State Regulators." Link to SCE's $1 Billion Shortfall Perturbs State Regulators article https://www.rtoinsider.com/sce-cpuc-shortfall-110490/.

Figure 29: SoCalGas Citygate to SoCal Border Price Differential



Source: CEC

Summer 2019 Assessment

The technical assessment group's 2019 Summer Assessment is a short-term analysis of electric reliability in Southern California. This report was based on the existing and expected operational status of the SoCalGas system as of May 2019. (See the "Update on SoCalGas System Status" sidebar for the status of the gas system in Southern California since the 2019 Summer Assessment.) The 2019 Summer Assessment reported that natural gas pipeline outages from summer 2018 persisted through winter, and that temporary capacity reductions for maintenance work appeared likely through the remainder of 2019.

The analysis also found that with the pipeline outages, it could be difficult for SoCalGas to fill its natural gas storage fields to a level sufficient to ensure energy reliability throughout the coming winter. The study found that if the pipelines return to service, this risk diminishes. Moreover, it noted that customers could be called on to reduce their electricity use, if needed.

The 2019 Summer Assessment evaluates reliability risks for an electric-peak day in summer 2019 and a monthly gas balance analysis through the beginning of winter. A gas balance analysis assesses the gaps between capacity and demand that must be met with gas from storage and the impacts of storage drawdown over the winter to evaluate possible storage inventory levels. The assessment includes several analytical components:

- System capacity (or supportable demand)[464] calculations for three cases: *base*, *pessimistic*, and *optimistic* that differ by the timing of the remediation work for peak-demand conditions.
- An electric-impact analysis, including power-flow analysis, by the California ISO and LADWP using the deliverable gas demand estimates to determine whether electric generator gas demand could be served and whether electricity service interruptions could occur on a summer peak day. The analysis includes calculating minimum generation levels to meet reliability and electric import sensitivities.
- Gas balance analysis by the CEC for three cases through December 31, 2019. The cases are based on normal weather conditions and average demand for varying pipeline outages and mitigation scenarios.

The assessment found that the forecast 1-in-10-year electric-peak day forecast demand of 3,368 MMcfd could be met under base case results of supportable demand on July 1, 2019, and August 9, 2019, (which are estimated to have 3,385 MMcfd and 3,465 MMcfd of supportable demand, respectively).[465] Conditions were more constrained in June, however, because of additional maintenance on Line 2001 between March 15, 2019, and July 1, 2019, which reduced estimated system capacity.

The *2019 Summer Assessment* found that meeting a 1-in-10-year electric-peak in June 2019 (estimated to have 3,035 MMcfd of supportable demand) could be met if regional electric generation is curtailed to minimum generation levels. Curtailing to minimum generation levels is an emergency measure that presumes the balancing authorities can procure the necessary electricity imports to replace natural gas generation, but it leads to higher costs. Minimum generation levels were lower in summer 2019 and have continued the downward trend, in part because of transmission upgrades.

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464 *Supported* or *supportable demand* is a term used by SoCalGas to describe how much demand its system can support, but it also can be viewed as system capacity.

465 The term *1-in-10-year* represents the warmest condition expected to occur once in 10 years, and analysts use it for planning capacity needed to serve noncore customers that burn natural gas to produce electricity. The 1-in-10 year peak day is most likely to occur in July through September.

The analysis also considered lower levels of electricity imports to determine whether reliability could be maintained at these lower levels. A lower level of imports means more in-basin gas generation may be needed to meet demand. This sensitivity analysis first assumed minimum generation levels, and any surplus of gas above the amount needed for minimum generation could be used for additional gas generation needed if electricity transmission import use is reduced from 100 percent. The sensitivity analysis found that electric reliability could be maintained on a 1-in-10-year electric-peak day, with 85 percent electricity import capability, without using gas from Aliso Canyon. However, the analysis showed a shortfall at 90 percent of electricity import capability for June. The actual demand for June 2019 was lower than projected, so there was no shortfall.

The technical assessment group developed the gas balance cases assuming normal weather conditions. Cold weather cases were not evaluated for the *2019 Summer Assessment*, but the assessment would be tighter with higher demand under cold weather conditions in early winter months. The gas balance cases showed full inventory of 80 Bcf to 81 Bcf by November 1, 2019. However, reserve margins would be 0 percent throughout the summer, leaving no margin for higher-than-average demand or unforeseen events. December month-end storage inventory levels ranged from 69 Bcf in the pessimistic case to 81 Bcf in the optimistic case.

Summer 2019 Storage Inventories

The 2019 Summer Assessment stated that inventory at the non-Aliso fields was likely to be a little lower on July 1, 2019, than in summer 2018, and the corresponding withdrawal capability would be lower.

The technical assessment group projected that use of Aliso Canyon was more likely in summer 2019, compared to summer 2018, when no withdrawals were made from Aliso Canyon. The findings depended on whether the July 1, 2019, inventory projection at all of SoCalGas' storage fields was achieved. If the withdrawal capability at the non-Aliso storage fields was insufficient to meet demand, then withdrawals from Aliso Canyon would be necessary.

The technical assessment group projected 57 Bcf in storage by July 1, 2019, and SoCalGas achieved 64 Bcf in storage by that date, which should have provided sufficient withdrawal capability out of the non-Aliso Canyon storage fields. However, the revised Aliso Canyon Withdrawal Protocol allowed more latitude to use Aliso Canyon in summer 2019. Based on the revised withdrawal protocol, use of Aliso Canyon was allowed to avoid the price impacts associated with Stage 2 through Stage 5 low OFOs and was drawn upon once in August 2019 and once in September 2019.

SoCalGas has continued with its Storage Integrity Management Program, which is a continuous well inspection program that includes the conversion of wells to tubing-only flow.[466] The switch to tubing-only flow was expected to change the maximum withdrawal and injection capacity and the withdrawal and injection curves as each field undergoes this work. The maximum withdrawal capability, if the storage fields are full, was expected to be lower than summer 2018 because of this program.

At the May 23, 2019, workshop, participants raised questions about the non-Aliso storage fields—Honor Rancho, La Goleta, and Playa del Rey—and whether there were any obstacles to the use of these fields in meeting reliability. SoCalGas indicated at the workshop that it manages its storage fields and the maintenance schedule for shut-ins[467] for field testing and inventory verification, which impacts injection capabilities. Aliso Canyon was the first field to reach the maximum allowable capacity level. Aliso Canyon was full by June 20, 2019, while injections to the other fields were still occurring as of August 28, 2019. It does not appear to be a prudent decision to fill Aliso Canyon completely before filling the other storage fields.

On September 19, 2019, a CPUC Executive Director Letter was sent to SoCalGas directing it to release up to 100 MMcfd of the injection capacity allocated to balancing to the market.[468]

Winter 2019–2020 Assessment

On October 24, 2019, the CPUC released a *2019-2020 Winter Assessment* authored by CPUC staff and shared with the technical assessment group for review and comment.[469] The assessment includes updates about SoCalGas' pipelines as well as gas balance analyses. The gas balance analysis tool used by CPUC staff was developed by CEC consultants Aspen Environmental Consultants and may be used to consider a range of scenarios and assumptions

466 "Tubing-only flows" mean that gas from storage can be injected or produced only through the interior metal tubing. Before this change, gas was injected and produced from the tubing and annulus between the tubing and the well casing.

467 When a natural gas storage field is *shut-in*, it is not available for injection or withdrawal.

468 CPUC letter to SoCalGas Subject: Injection Required for SoCalGas Winter Reliability and Storage Inventory https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/Signed%20Letter%20to%20Bret%20Lane%20So%20Cal%20Gas%20Company%20re%20Injection%20Required%20for%20SCG%20Winter%20Reliability%20and%20Storage%20Inventory_v2.pdf.

469 *Winter 2019-20 Southern California Reliability Assessment* by CPUC staff: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/Winter2019-20ReliabilityAssessment_Final.pdf.

from best to worst case. The analysis results provide insight about what may happen if natural gas supply, demand, and storage assumptions were to occur.

CEC staff prepared a gas balance analysis with slightly different assumptions and presented it at the October 30, 2019, IEPR Lead Commissioner Workshop on Revised Natural Gas Price Forecast and Draft Natural Gas Outlook/Electricity Modeling and Results.[470] CEC staff presented an outlook for the upcoming winter 2019–2020 based on the gas balance results. If actual supply is lower or demand is higher than what is assumed in the gas balance, the results would look worse. For example, if pipeline supply is lower than projected, more storage withdrawal would be required to meet overall demand and result in lower storage inventory. The outlook also considered the CPUC *2019/2020 Winter Assessment* and SoCalGas' *Winter 2019/2020 Technical Assessment* that was released October 8, 2019.[471]

Overall, the winter 2019/2020 outlooks appear to depict the following:

- Reliability outlook is the best in three winters.
- Pipeline constraints continue because Line 235-2 and Line 4000 are operating at reduced operating pressure and capacity.
- In the best-case scenario with both lines in service and average weather, the gas balance shows sufficient inventory to meet demand and no curtailments.
- Use of Aliso Canyon may be necessary to meet 1-in-10-year peak-day demand.
- Core reliability is not projected to be at risk.
- Risk of noncore curtailments is diminished with both lines in service.
- Electric reliability can be maintained.

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470 TN 230442 https://www.energy.ca.gov/2019_energypolicy/documents/2019-10-30_workshop/2019-10-30_presentations.php

471 SoCalGas Winter 2019/2020 Technical Assessment, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-09, TN# 230065. SoCalGas assumes a 10 to 15 percent discounting of pipeline supply depending on the scenario. The joint agencies including the CEC rejected SoCalGas' proposal to discount pipeline supplies by 15 percent in April 2017 and began producing their own technical assessments separate from SoCalGas. Staff recognizes that customers choose how much gas to deliver. Staff relies on the long-standing treatment of receipts used in the utilities' California Gas Report and has not accepted SoCalGas' request to discount pipeline supply in staff's analysis of the utility's system. In general, SoCalGas' analysis is more conservative due to the discounting of pipeline supply and shows noncore curtailments in the cold weather case with both lines in service whereas CEC's analysis does not. Staff recognizes that if customers do not bring in supply or are unable as in the scenario with both lines out of service, the risk of noncore curtailments increases.

- Pipelines return to service is key to improving reliability.

Mitigation Measures

Energy reliability remains challenging because of the pipeline outages and capacity reductions on the SoCalGas system. Based on the Summer 2019 Assessment, the technical assessment group recommends continuing most of the mitigation measures implemented over the past four years and exploring several others. Some of the mitigation measures have not been implemented, such as contracting for liquefied natural gas (LNG). The U.S. EIA reported that LNG imports played a key role in reducing price spikes in New England this winter.[472]

More than 50 mitigation measures are in place or have been proposed, including changing the gas balancing rules, implementing new demand response programs, revising the Aliso Canyon Withdrawal Protocol, and procuring battery energy storage. On December 5, 2019, CPUC Resolution E-5033 approved 95 MW of battery energy storage selected from SCE's Second Aliso Canyon Energy Storage Request for Offers. The mitigation measures focus on short-term reliability concerns and managing price volatility. Appendix B of the 2019 Summer Assessment details the full list of mitigation measures, including seven new ones listed below:

- Revise OFO penalty structure. In May 2019, the CPUC approved Decision 19-05-030, which implemented this measure.
- Revise the Aliso Canyon Withdrawal Protocol. The CPUC revised the Aliso Canyon Withdrawal Protocol on July 23, 2019.[473] The revised Aliso Canyon Withdrawal Protocol includes a provision to allow the withdrawal capacity of Aliso Canyon to be made available when preliminary low OFO calculations result in a Stage 2 through Stage 5 low OFO. This change resulted in SoCalGas calling no low OFOs higher than a Stage 1 in the summer of 2019.
- Revise the OFO formula.
- Help customers with injection rights use available injection capacity.

472 EIA reported that liquefied natural gas imports played a key role in reducing price spikes in New England this winter, Link to Natural Gas Weekly Update for the week ending April 17, 2019 from the U.S. EIA's website https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/04_18/.

473 Aliso Canyon Withdrawal Protocol, Link to July 23, 2019, Aliso Canyon Withdrawal Protocol from the CPUC's website https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/UpdatedWithdrawalProtocol_2019-07-23%20-%20v2.pdf.

- Research any interaction between the gas cost incentive mechanism[474] and pipeline usage.
- Continue working six days a week and 12 hours a day to expedite the schedule of repairs.
- Optimize the timing of discretionary maintenance to maximize injections.

Update on Southern California Electricity Reliability

The early retirement of San Onofre required actions to replace not just the 2,200 MW of capacity, but the voltage support and reactive power it provided to maintain grid reliability. Preserving reliability means replacing all those services, as well as planning for the retirement of the various coastal power plants that use ocean water for cooling. Since 2013, the joint agencies, along with representatives from the investor-owned utilities and local air districts in the South Coast Air Basin, have conducted public workshops at least annually to discuss these intertwined issues.

Using the action plan developed in 2013 as a guideline, the joint agencies put in place a multipronged plan of preferred resources, transmission upgrades, and conventional generation to meet the reliability needs of Southern California.[475] The agencies also developed a backup plan of two contingency mitigation measures in case any of the solutions are delayed or do not come to fruition. The contingency mitigation measures consist of an OTC compliance date deferral process and new gas-fired generation options, which are available to be triggered if needed to address reliability concerns.[476]

The agencies periodically review progress in securing preferred resources, transmission projects, and conventional generation to determine whether further actions are needed. As uncertainties become clearer, the agencies will seek mitigation solutions that maintain Southern California grid reliability and promote the state's policy goals.

The 2013 action plan suggested that the shuttered capacity of San Onofre and OTC generation retirements can be replaced with roughly 50 percent preferred resources, 50 percent

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474 The *gas cost incentive mechanisms* established by the CPUC encourage utilities to procure natural gas at or below a benchmark price. The benchmark price is based on a basket of monthly and some daily natural gas price indices.

475 Southern California Reliability Plan for the greater Los Angeles area and San Diego. See TN 71933, [Link to Preliminary Reliability Plan for LA Basin and San Diego filed on the CEC's website](https://efiling.energy.ca.gov/GetDocument.aspx?tn=71933) https://efiling.energy.ca.gov/GetDocument.aspx?tn=71933.

476 The *2016 IEPR Update* and *2017 IEPR* provide details of these two options.

conventional generation, and transmission infrastructure improvements that could provide voltage support. The joint agency workshop on May 23, 2019, provided an update on overall reliability and the status of projects. The information below updates progress documented in the *2018 IEPR Update*.

Preferred Resources

Historically, the CPUC's Long-Term Procurement Plan (LTPP) proceeding evaluated generation resources in the California ISO system every two years. The intent was to evaluate whether existing and projected resources were sufficient to meet future demand, and to authorize procurement of additional resources if they were insufficient. The CPUC incorporated updates from the OTC retirement schedules into this analysis. In addition to systemwide analyses, the LTPP also evaluated capacity requirements in localized, high-demand areas to ensure electric reliability locally. The CPUC is implementing the integrated resource planning (IRP) process in response to the legislative requirements of Senate Bill 350 (De León, Chapter 547, Statutes of 2015), which replaced the LTPP and periodically evaluates generation resources in the California ISO system.[477] Table 10 presents the preferred resources[478] and storage that have been procured in the San Onofre area to meet reliability requirements necessitated by retirement of the nuclear plant and pending closures of OTC facilities.

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477 Rulemaking 16-02-007 Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO.

478 *Preferred resources* are those used for energy efficiency, demand response, renewable resources, and distributed generation. Preferred resources are described in the *2005 State Energy Action Plan II* http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

Table 10: SCE and SDG&E Approved Applications for Preferred Resources in the San Onofre Area

Resource Type	PTO	Location	Capacity MW	Application Status	Status
Demand Response	SCE[479]	West LA Basin	5	Approved	On-line
Distributed Solar Generation	SCE	Johanna/Santiago	12	Approved	Expected commercial operation date in 2020
Distributed Solar Generation	SCE	West LA Basin	28	Approved	7.78 MW on-line
Energy Efficiency	SCE	Johanna/Santiago	23	Approved	12.84 MW on-line
Energy Efficiency	SCE	West LA Basin	101	Approved	22.81 MW on-line
Energy Storage	SCE	Johanna/Santiago	153	Approved	10 MW on-line
Energy Storage	SCE	Long Beach	100	Approved	Expected commercial operation date 1/1/2021
Energy Storage	SCE	West LA Basin	138	Approved	45.5 MW on-line
Demand Response	SDG&E[480]	San Diego/Imperial Valley	4.5	Approved	On-line

479 Link to SCE's Application 14-11-012 to the CPUC
http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M143/K307/143307429.PDF.

Link to SCE's Application 14-11-016 to the CPUC
http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M143/K307/143307496.PDF.

Link to SCE's Application 15-12-013 to the CPUC
http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M156/K571/156571612.PDF.

Link to SCE's Application 16-11-002 to the CPUC
http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M169/K917/169917051.PDF.

Link to Resolution E-4804 from the CPUC's website
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M167/K245/167245981.PDF.

480 Link to SDG&E's Application 14-07-009 to the CPUC
https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1407009.

Resource Type	PTO	Location	Capacity MW	Application Status	Status
Energy Efficiency	SDG&E	San Diego/Imperial Valley	19	Approved	Operational and ramping up through 2023
Energy Storage	SDG&E	San Diego/Imperial Valley	121	Approved	37.5 MW on-line; remainder on-line in 2021 and 2022

Source: 2019 Report of the Statewide Advisory Committee on Cooling Water Intake Structures

Conventional Generation

The joint agency team continues to track conventional generation projects in the San Onofre area. Table 11 presents the status for five projects in the area. The CPUC approved power purchase agreements for all five projects. Legal challenges surfaced for the Carlsbad, Alamitos, and Huntington Beach projects, but they have been resolved. Carlsbad came on-line at the end of 2018. As of August 2019, construction is about 98 percent complete for Huntington Beach and Alamitos. Commissioning of the plants began first with the auxiliary boilers in July 2019. Once those boilers are complete, the commissioning stage will move to the combined-cycle gas turbines start-up and testing in October 2019. The CEC approved the Stanton Energy Reliability Center project application for certification on November 7, 2018; construction is underway and about 25 percent complete as of August 2019.

Table 11: Conventional Generation Projects in San Onofre Area

Conventional Generation Projects	Capacity	Sponsor	Target In-Service Date
Pio Pico	305	SDG&E	Operational 10/20/2016
Carlsbad Energy Center	500	SDG&E	Operational 12/3/2018
AES Alamitos	640	SCE	6/1/2020

Link to SDG&E's Application 16-03-014 to the CPUC
https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1603014.

Link to SDG&E's Application 17-04-017 to the CPUC
https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1704017.

Link to Resolution E-4798 from the CPUC's website
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M166/K269/166269958.PDF.

Conventional Generation Projects	Capacity	Sponsor	Target In-Service Date
AES Huntington Beach	644	SCE	5/1/2020
Stanton Energy Reliability Center	98	SCE	7/1/2020

Source: CEC

Transmission Projects

Numerous transmission projects have come on-line over the last several years to provide voltage and frequency stability or reduce local capacity requirements or both in the San Onofre area. The joint agency team continues to track one remaining active transmission project out of nine projects approved in the San Onofre area. The other eight projects were completed and placed in service as of 2018, as shown in Table 12. The California ISO has found that the synchronous condensers[481] in Southern California have contributed significantly to reliability by providing voltage support, allowing increased imports into the San Diego area and between San Diego and the greater Los Angeles area and decreasing dependence on gas-fired generation to provide voltage support during outages.

481 *Synchronous condensers* are synchronous motors whose shaft spins freely and are not connected to anything. They are used to adjust conditions on the electric power transmission grid.

Table 12: Transmission Projects in San Onofre Area

	Transmission Projects	Sponsor	Target In-Service Dates
1	Talega Synchronous Condensers (2x225 mega volt amps reactive [MVAr])	SDG&E	In-service 8/7/2015
2	Extension of Huntington Beach Synchronous Condensers (280 MVAr)	SCE	Retired 12/31/2017
3	Imperial Valley Phase Shifting Transformers (2x400 MVAr)	SDG&E	In-service 5/1/2017
4	Sycamore Canyon–Peñasquitos 230 kilo volt (kV) Line	SDG&E	In service 8/29/2018
5	Miguel Synchronous Condensers (450/-242 MVAr)	SDG&E	In-service 4/28/2017
6	San Luis Rey Synchronous Condensers (2x225 MVAr)	SDG&E	In-service 12/29/2017
7	San Onofre Synchronous Condensers (1x225 MVAr)	SDG&E	In service 10/16/2018
8	Santiago Synchronous Condensers (1x225 MVAr)	SCE	In-service 12/31/2017
9	Mesa Loop-In Project and South of Mesa 230kV Line Upgrades	SCE	Delayed until 3/1/2022

Source: CEC

Triggering OTC Compliance Date Extensions

In 2010, the State Water Resources Control Board (SWRCB) adopted a policy on the use of coastal and estuarine waters for power plant cooling, OTC, to reduce harmful effects on marine life associated with cooling intake structures.[482] To comply with the OTC policy, coastal power plant owners could either install closed-cycle evaporative cooling systems or replace, repower, or retire existing coastal power plants. Recognizing the need to maintain reliability and allow for effective long-term planning of transmission and generation as replacement infrastructure, the SWRCB adopted a compliance schedule with the input from the State Advisory Committee on Cooling Water Intake Structures (SACCWIS), which is composed of representatives from several state agencies, including the CEC.[483]

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482 Marine life, including millions of fish, larvae, eggs, seals, sea lions, turtles, and other creatures, is harmed through impingement, as larger aquatic organisms are trapped against a power plants intake screen, and entrainment, when smaller aquatic organisms are drawn into the plant’s cooling system and killed.

483 SACCWIS is composed of the CEC, CPUC, California ISO, California Coastal Commission, California State Lands Commission, the California Air Resources Board, and the SWRCB.

The SACCWIS ensures the compliance schedule accounts for local and statewide reliability, permitting constraints, and other factors affecting the availability of adequate electricity supplies in the state. As noted in Chapter 1, to date, more than 8,100 MW of natural gas OTC power plants have retired, with another 5,300 MW retiring by 2020 and an additional 1,600 MW by 2029. SACCWIS annually reviews reliability and compliance dates to determine whether conditions may warrant an extension.

The Mesa Loop-in project was projected to increase the imports into the Greater Los Angeles Area and reduce the amount of in-basin generation needed to meet reliability requirements. A delay of the Mesa Loop-in project could result in a need to keep older OTC units like Alamitos on-line until the project is completed. With confirmation of the Mesa Loop-in delay, the California ISO conducted a special study to determine whether the OTC compliance schedule for Alamitos (December 31, 2020) and the revised on-line date for the Mesa Loop-in would adversely impact electric system reliability. The California ISO prepared the special study to initiate the OTC deferral process. The California ISO found that Alamitos is not needed under baseline assumptions. Under sensitivity analysis with higher load and removal of at-risk of retirement generation,[484] however, between 476 MW to 816 MW of Alamitos capacity is needed to maintain reliability.

At the May 23, 2019, joint agency workshop, the CPUC raised the issue of tightening system capacity in the CPUC Resource Adequacy program as a concern, and the California ISO concurred. This concern is a result of various factors, including lowering of the effective load-carrying capability factors for wind and solar,[485] increasing reliance on imports, and shifting peak to later in the evening when solar is not available. On June 20, 2019, the CPUC issued a ruling in its IRP Proceeding R.16-02-007, identifying potential system capacity shortfalls beginning in 2021 due to tightening of the bilateral resource adequacy market. The CPUC ruling identified three simultaneous approaches to meet system needs, including procurement of 2,000 MW new capacity by August 2021, SCE procurement of 500 MW of existing non-OTC capacity, and extension of OTC compliance deadlines.

484 "At-risk of retirement generation" is generation that may retire due to its age and that it is nearing the end of its useful life or due to economic reasons.

485 "Effective load-carrying capability factor" refers to the percentage of wind and solar nameplate capacity that can contribute toward meeting peak demand.

The CPUC ruling raised the possibility of an OTC compliance date extension to meet system reliability, not just local reliability.[486] Several remaining OTC plants are in Southern California.

Based on the information and California ISO special study, SACCWIS decided the best action was to recommend that the SWRCB defer the OTC compliance date for Alamitos Units 3, 4, and 5 (1,166 MW) to maintain grid reliability.[487] Alamitos Units 1, 2, and 6 retired early in December 2019 to make way for the new Alamitos Energy Center. SACCWIS documented the findings in the Statewide Advisory Committee on Cooling Water Intake Structures Draft Local and System-wide 2021 Grid Reliability Studies Report[488] and adopted it at an August 23, 2019, SACCWIS meeting with slight revisions. The main revision states the compliance date extension will be based on the minimum amount of capacity and time to meet grid reliability. The report was presented to the SWRCB as an informational item on November 19, 2019.

On November 7, 2019, the CPUC issued a decision[489] in the IRP Proceeding recommending that the SWRCB extend the OTC compliance deadlines for units currently slated to retire by December 31, 2020, for the periods specified:

- Alamitos Generating Station, Units 3-5, totaling roughly 1,200 MW, for up to three years
- Huntington Beach Generating Station, Unit 2, roughly 200 MW, for up to three years
- Redondo Beach Generating Station, Units 5, 6, and 8, roughly 850 MW, for up to two years
- Ormond Beach Generating Station, Units 1 and 2, roughly 1,500 MW, for up to one year

The decision also required incremental procurement, in addition to the OTC requirement extensions, of system-level resources adequacy capacity of 3,300 MW, by all load-serving entities serving load within the California ISO balancing authority area.[490]

On January 23, 2020, SACCWIS met to discuss and approve the *Statewide Advisory Committee on Cooling Water Intake Structures Draft Recommended Compliance Date Extensions for*

486 A "system resource" can be located anywhere in the California ISO Balancing Authority, whereas a local resource must be within a specified local capacity area.

487 AES has stated that Unit 5 is limited to 300 MW (installed capacity 487 MW) due to electrical limitations.

488 Link to Report of the Statewide Advisory Committee on Cooling Water Intake Structures, https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/sccwintrpt.pdf.

489 CPUC Decision Requiring Electric System Reliability for 2021-2023, R. 16-02-007, released November 7, 2019, http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=318169119.

490 Ibid.

Alamitos, Huntington Beach, Ormond Beach, and Redondo Beach Generating Stations. The report presents several alternatives for OTC compliance date extensions.[491]

Assessing Progress

As evident from workshops in previous IEPR cycles and from the most recent workshop held May 23, 2019, the CEC and collaborating agencies are committed to assuring electrical reliability for the region. The CPUC took action in February 2019 to approve a three-year requirement for local capacity requirements to discourage early retirement of resources. Discussions about using a centralized procurement entity, which would procure resources on behalf of all load-serving entities, for local capacity requirements are also occurring in resource adequacy proceedings. There has been significant progress in implementing the 2013 plan to address San Onofre and OTC generation retirements. The Alamitos, Huntington Beach, and Stanton generation projects are under construction and on-track to be on-line in 2020.

Recommendations

Southern California Gas Company (SoCalGas) Infrastructure

- **Require SoCalGas to explore all options available to safely expedite repair of the natural gas pipelines to full operating service.** In addition, SoCalGas should identify areas where agency assistance is needed to speed up pipeline repairs.
- **Require regular reporting to increase transparency into the emergency maintenance and repair process.** The California Public Utilities Commission (CPUC) should consider requiring SoCalGas to provide, in addition to the information already posted on its Envoy electronic information system, detailed reports indicating specific actions taken to restore pipelines to service on a monthly basis to keep policy makers and the public informed about infrastructure conditions, as well as where the new leaks are located, what repair techniques are being applied, and at what pressure the leaks are occurring. Alternatively, the CPUC could retain a third party to prepare a condition

491 Statewide Advisory Committee on Cooling Water Intake Structures. January 23, 2020. *Draft Recommended Compliance Date Extensions for Alamitos, Huntington Beach, Ormand Beach, and Redondo Beach Generating Stations*. https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/dsccws.pdf

assessment and monitor repair work, with regular reports back to the agencies and public.

- **The CPUC should consider financial consequences that balance ratepayer benefits with appropriate shareholder incentives.** The CPUC should align economic incentives with efficient and effective management and operation of SoCalGas' natural gas system, such that ratepayers are not held accountable for management errors. Failure to identify and resolve system vulnerabilities promptly could trigger disallowance of costs associated with service interruptions. Failure to maintain reasonable return-to-service timelines could lead to penalties.
- **Identify and explore the steps needed to implement existing and new mitigation measures.** The California Energy Commission (CEC), the CPUC, the California Independent System Operator, and the Los Angeles Department of Water and Power should collaborate to determine the viability of the existing and any new mitigation measures and the steps needed to implement them. Tighter balancing rules adopted from the first joint agency technical assessment in 2016 should continue and SoCalGas should maximize withdrawal capability at La Goleta, Playa del Rey, and Honor Rancho by ensuring they are filled first.
- **Continue developing a long-term strategy that would allow the eventual close of the Aliso Canyon natural gas storage field.** The CPUC should look to the CEC for support as both agencies develop strategies for replacement energy resources that ensure electricity reliability in Southern California and allow retirement of Aliso Canyon. These strategies will be led by advances in building decarbonization, energy efficiency, and distributed energy resources such as demand response and storage of electricity or heat. The agencies should incorporate the findings from the Pacific Northwest transmission study into a long-term plan.

San Onofre Nuclear Generation Station Shutdown and Once-Through Cooling (OTC)

- **To ensure local and system reliability in the Greater Los Angeles Area and San Diego regions, the agencies should continue working together to ensure sufficient replacement resources are in place to enable the most expedient retirement of the remaining OTC power plants.**
- **Continue focus on implementing the Southern California reliability action plan.** The preferred resources, transmission upgrades, and conventional generation identified in the 2013 report are crucial to continuing electric reliability.

CHAPTER 7: Electricity and Natural Gas Demand Forecast

Background

The California Energy Commission (CEC) provides new forecasts for electricity and natural gas demand every two years as part of the *Integrated Energy Policy Report* (*IEPR*) process. The CEC develops new forecasts in odd-numbered years such as for this *2019 IEPR*, with updates in the intervening years. The forecasts are used in various proceedings, including the California Public Utilities Commission's (CPUC's) Integrated Resource Planning (IRP) process and the California Independent System Operator's (California ISO's) Transmission Planning Process (TPP). The CPUC identified the IEPR process as "the appropriate venue for considering issues of load forecasting, resource assessment, and scenario analyses, to determine the appropriate level and ranges of resource needs for load-serving entities in California."[492] In addition, the CEC provides monthly peak demand forecasts for the resource adequacy process in coordination with the California ISO and the CPUC.

The forecast includes three demand cases designed to capture a reasonable range of demand outcomes over the next 10 years. The "high-energy demand case" incorporates relatively high economic/demographic growth, relatively low electricity and natural gas rates, and relatively low committed efficiency program, self-generation, and climate change impacts. The "low-energy demand case" includes lower economic/demographic growth, higher assumed rates, and higher committed efficiency program and self-generation impacts. The "mid" case uses input assumptions at levels between the "high" and "low" cases.

The CEC held two *IEPR* workshops in August and December 2019 to present preliminary and revised versions of the forecast. The results shown in this chapter represent the final version of the forecast, which reflects changes made in response to stakeholder comments on earlier versions and which was adopted by the CEC at the January 22, 2020, Business Meeting.

Data and Analytic Improvements

While the *2019 IEPR* forecast employs many of the same models used to develop the forecast update for the *2018 IEPR Update*, this forecast used several updated tools.

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492 Peevey, Michael. September 9, 2004. Assigned Commissioner's Ruling on Interaction Between the CPUC Long-Term Planning Process and the CEC IEPR Process. Rulemaking 04-04-003.

Through an Electric Program Investment Charge contract with ADM Associates, the CEC refreshed its hourly electric end-use load profiles, as well as hourly savings profiles for efficiency measure categories, generation profiles for behind-the-meter solar photovoltaic (PV) systems, and charging profiles for electric vehicles.[493] For future IEPR forecasts, these profiles will be combined into a new bottom-up hourly electric load model (HELM 2.0) that will translate the CEC's annual end-use consumption forecasts into hourly and peak-load forecasts. In the meantime, the CEC continues to leverage its top-down hourly load model (HLM) to forecast annual and monthly peak loads. The HLM has been updated to incorporate the staff-estimated impacts of behind-the-meter battery storage, as well as electric vehicle charging profiles from the ADM analysis.

Climate change impacts were incorporated into the forecast through adjustments to daily and—for the first time—hourly temperatures based on new projections developed by Scripps Institute of Oceanography. Annual load impacts are estimated by running the CEC's demand models with and without projected changes to annual heating and cooling degree days. To project hourly impacts, staff first estimates the temperature elasticity of demand for specific hours of the day and months of the year and then applies those elasticities to Scripps' projections of hourly temperature changes. This approach is meant to capture the average impacts that a general warming trend will have on demand—less heating load in the winter and more cooling load in the summer.

The CEC's forecasting is benefiting from newly available data as a direct consequence of Phase I revisions to Title 20.[494] Beginning in 2019, utility distribution companies are required to report regularly to the CEC on all generation and storage system interconnection data. Notably, these data give a comprehensive picture of California's current and historical behind-the-meter PV installation activity, which will improve forecasts of future adoption.

This year's IEPR process remains focused on tracking statewide progress toward doubling energy efficiency savings by 2030—a goal outlined in the Clean Energy and Pollution Reduction Act (Senate Bill 350, De León, Chapter 547, Statutes of 2015)—and in developing strategies and targets to meet that goal. (See Chapter 2 for more information.) CEC analysis of programs

493 Baroiant, Sasha, John Barnes, Daniel Chapman, Steven Keates, and Jeffrey Phung. ADM Associates, Inc. April 2019. *California Investor-Owned Utility Electricity Load Shapes*. Final Project Report. CEC. Publication Number: CEC-500-2019-046. Link to California IOU Electricity Load Shapes final project report on the CEC's website https://www.energy.ca.gov/2019publications/CEC-500-2019-046/CEC-500-2019-046.pdf.

494 Link to Docket 16-OIR-03 on the CEC's website https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=16-OIR-03.

related to Senate Bill 350 has expanded this year such that additional achievable energy efficiency (AAEE) scenario development may now consider:

- Several publicly owned utility (POU) program potential scenarios, with variability comparable to investor-owned utility (IOU) scenarios.
- A set of nonutility programs expanded to include fuel substitution, conservation voltage reduction, and savings opportunities within the agricultural and industrial customer sectors.

During the *2017 IEPR* forecast cycle, staff analyzed the potential ramifications of cannabis legalization on electricity demand.[495] Especially for smaller LSEs, the addition of energy-intensive indoor cultivation facilities can have a sudden and significant impact on relative load growth. Recognizing this possible impact, for the *2019 IEPR*, the CEC adjusted its forecast for Valley Electric Association to account for specific cannabis cultivation facilities expected to begin operation by 2020, and adjusted its individual planning area forecasts to reflect increased cultivation activity that would not otherwise be picked up in the CEC's econometric demand models. To refine these estimates, staff will continue to gather data around current and historical production and consumption of cannabis, as well as the relative quantities and energy intensities associated with different outdoor versus indoor versus greenhouse cultivation methods.

Emerging Issues

The CEC held a workshop September 26, 2019, to explore topics that present emerging analytic challenges to the CEC's incumbent forecast process. As part of this workshop, Southern California Edison (SCE) described challenges to distribution planning posed by a high-electrification future. For example, SCE's Charge Ready Transport program received dozens of applications over a short period to install charging infrastructure for electric vehicle fleets. SCE expressed concern that clusters of such projects could necessitate distribution upgrades that require 7 to 10 years to implement. Because the CEC's forecast sets benchmarks for IOU distribution planning assumptions, SCE suggested that, as part of its annual distribution planning, utility planners should work with CEC forecasters to identify areas of emerging and significant load growth that may not have been captured in the most recently adopted CEC forecast.

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495 Kavalec, Chris, Asish Gautam, Mike Jaske, Lynn Marshall, Nahid Movassagh, and Ravinderpal Vaid. CEC. February 2018. California Energy Demand 2018-2030 Revised Forecast. Commission Final Report. [Link to California Energy Demand 2018-2030 Revised Forecast on the CEC's website](https://efiling.energy.ca.gov/getdocument.aspx?tn=223244) https://efiling.energy.ca.gov/getdocument.aspx?tn=223244.

Ten new community choice aggregators began offering electricity service to customers in 2018. Total CCA load in California nearly doubled in 2018, reaching 13 percent of load within IOU service territories. This rapid departure of IOU load to community choice aggregators has implications for several regulatory processes that use the CEC's demand forecast, prompting staff to consider developing a departing load forecast. Through the CPUC's Resource Adequacy program, the CEC has good visibility into likely year-ahead departures. A longer-term forecast, however, requires staff to evaluate new modeling approaches and data needs.

The CEC develops forecasts for particular geographic regions, such as IOU distribution service territories. Load migration within such a territory—all else equal—is an attribution problem having little to no effect on the overall forecast. However, many community choice aggregators have unique tariffs, program offerings, and carbon-reduction strategies that could conceivably alter the expected load growth or profile of their specific customers. Community choice aggregation representatives discussed such programs at the September 26 workshop. Sonoma Clean Power (SCP), for example, offers incentives for electric vehicles as well as free charging stations and encourages customers to enroll in its GridSavvy demand response program. Although GridSavvy covers electric vehicle charging, SCP intends to expand the program to cover "smart" thermostats, heat pump water heaters, heat pump space conditioning, and behind-the-meter storage. East Bay Community Energy recently launched a demand response program consisting of about 500 kW of aggregated commercial and residential battery storage, calling events based on wholesale pricing to address procurement needs. As community choice aggregators serve a growing share of total electric load, it becomes increasingly important for CEC forecasters to collect and consider information from community choice aggregators regarding rates, efficiency, behind-the-meter storage and generation, building and transportation electrification, and other load-management strategies.

At an August 15, 2019, IEPR workshop on the 2019 Preliminary California Energy Demand Electricity and Natural Gas Demand Forecast, CEC forecasters acknowledged that state and local policy sentiment for carbon reduction will likely translate to some amount of electrification in buildings. Assembly Bill 3232 (Friedman, Chapter 373, Statutes of 2018), for example, requires the CEC to assess the potential for California to reduce the GHG emissions in residential and commercial buildings by 40 percent below 1990 levels by January 1, 2030. Senate Bill 1477 (Stern, Chapter 378, Statutes of 2018) directs $50 million annually toward fuel substitution programs over four years. At a December 2, 2019, IEPR workshop, CEC staff presented an exploratory analysis of potential annual energy and hourly system load impacts that might arise as a consequence of such policies. While the results of the study are too uncertain and preliminary to include in the California Energy Demand forecast done as part of the *2019 IEPR* (CED 2019), staff intends to publish a stand-alone report detailing the study approach and results to enable discussion and induce additional analytic work among stakeholders.

Economic/Demographic Outlook for California

California leads the nation in economic growth. In 2018, according to the U.S. Department of Commerce, California's economy surpassed the United Kingdom's to become the fifth largest in the world. The steady pace of growth is exhibited throughout the state; however, four counties in particular made significant contributions to growth in California's gross state product (GSP): Los Angeles County ($789.7B), Orange County ($299.4B), Santa Clara County ($275.3B), and San Diego County ($261.4B).[496]

Looking forward, economic experts at Moody's Analytics, IHS Global Markit, and the University of California Los Angeles, (UCLA) Anderson Forecast expect growth to slow in their reference scenarios, projecting California's GSP to increase in the range of 2.5 percent to 3 percent in 2019, dropping to 1 percent to 2 percent in 2020 and 2021. These projections are driven by slower growth in the Bay Area's job market, slower growth in California's residential construction, a weaker housing market, and reduced in-migration and increased outmigration of firms and individuals seeking cheaper options. These projections do not assume a potential recession in the near term, though there are evident risks that could lead to a more significant economic slowdown.

One such risk is the threat of escalating U.S. trade conflicts, which create significant uncertainty for California's economic prospects as the state is home to some of the largest seaports in the country. President Trump announced plans to impose 15 percent tariffs on $123 billion of Chinese imports, effective September 1, 2019, prompting China to respond with retaliatory tariffs on U.S. goods. Reduced trade would likely impact industries such as manufacturing, logistics, transportation, warehousing, and retail.

According to the California Department of Finance's latest estimates, in 2018, California added nearly 187,000 residents. This number is less than 1 percent year-over-year growth. The state's population growth will continue to be relatively slow, growing less than 1 percent, (as compared to other nearby states) as the demand for housing increases.

The largest in- and out-migration numbers are flowing into and out of Texas, Nevada, Arizona, and Washington. As a comparison, the U.S. Census states that for 2018 Nevada and Idaho grew 2 percent, 1.7 percent in Arizona, 1.4 percent in Washington, and 1.3 percent in Texas. The attraction to these states is primarily due to overall affordability, including lower housing costs, allowing first-time homebuyers to enter the market and lower their taxes. Similarly, people migrate to California to seek opportunities in the high-tech industry with higher incomes.

496 The CEC uses several sources to develop its economic/demographic outlook including Moody's Analytics, IHS Global Markit, UCLA Anderson Forecast, California Department of Finance, California Employment Development Department, U.S. Bureau of Labor Statistics, and the U.S. Census Bureau. Information was also presented at the CEC's Economic and Demographic workshop held January 17, 2019.

Labor and housing constraints are increasingly evident. Jerry Nickelsburg, director of the UCLA Anderson Forecast, states that California is running out of people to employ in this tight labor market. Employment growth decreased considerably from a few years ago but is still on pace with the nation. Nonetheless, employment growth is still growing and fueled by the fundamentals that lead to increased consumption and household formation. Statewide unemployment remains low with 4.2 percent, which is significantly lower than the recession era high of more than 12 percent in December 2009.

California has nearly 14 million homes. Single- and multifamily housing building permits are down year-over-year due to constraints on supply. The supply of homes is growing slowly, but home prices are not decreasing, as demand continues to rise. The California Association of Realtors report indicates that 30 percent of California households could afford to purchase the $608,660 median-priced home with a minimum annual income of $122,960 in the second quarter of 2019, up from 26 percent a year ago.[497] The recent drop in mortgage rates will contribute to higher demand, especially in areas with higher housing costs such as the San Francisco Bay Area, Los Angeles, and San Diego regions.

Recovery is slow following the 2018 wildfires in Butte County, Lake County, Shasta County, and Ventura County that destroyed more than 20,000 structures, further inflating housing demand. Tariffs have kept the price of building materials high, and there is a shortage of available construction workers to rebuild homes.

According to the California Department of Finance, California's statewide housing growth in 2018 (net unit growth in completed housing units) was up 0.6 percent from the previous year, which includes the addition of 77,000 housing units. The total number of housing units in the state now exceeds 14.2 million. Statewide multifamily units represented 31.5 percent of unit growth last year, continuing a seven-year trend. Multifamily units cost less to build and require fewer workers. Los Angeles, San Diego, Irvine, Santa Clarita, and Sacramento added the most housing units in 2018. However, the California Department of Finance has stated the state would need to build 200,000 housing units each year to keep up with population growth. California is not close to that number, with around 120,000 housing units in 2018.

497 California Association of Realtors. "Second Quarter Housing Affordability Report." August 7, 2019. Link to news release about California housing affordability on the California Association of Realtors' website https://www.car.org/aboutus/mediacenter/newsreleases/2019releases/2qtr2019affordability.

California Energy Demand Baseline Forecast, 2019–2030

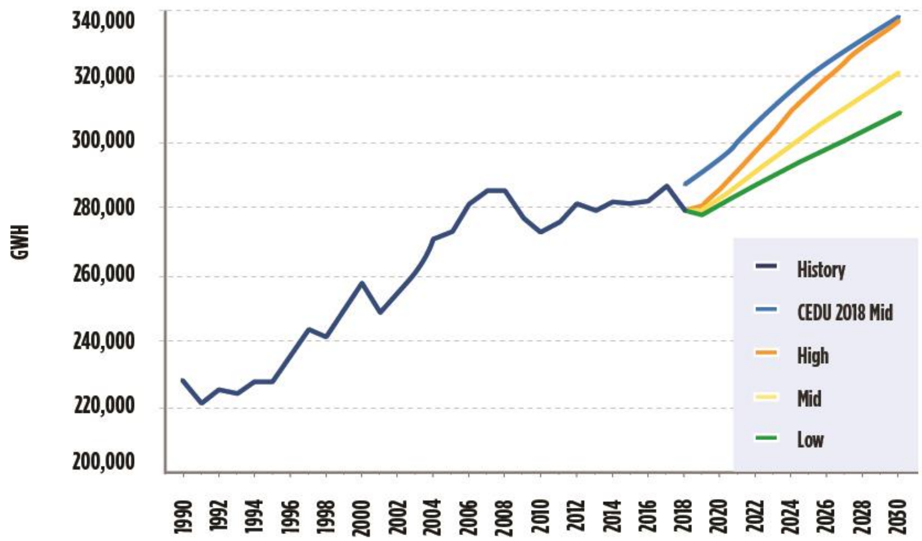
The IEPR forecast process began in November 2018 with a formal request for demand forecast data from load-serving entities. The CEC held several public workshops intended to inform demand-forecasting efforts. The first workshop, held January 17, 2019, featured moderated panels of expert economists, demographers, and industry representatives responding to questions around California's economy, population characteristics, and business outlook. The perspectives presented at the January workshop informed the selection of a reasonable set of forecast inputs and assumptions, which staff then presented at another workshop March 4, 2019.

Staff presented a preliminary set of baseline forecast results at a public workshop on August 15, 2019, and is considering comments from stakeholders as it develops a revised set of baseline forecasts (California Energy Demand [CED] 2019 revised) and AAEE savings projections. A final workshop was held December 2, 2019, to present these revised results and receive additional stakeholder comments before the forecast was finalized adopted in January 2020.

Generally, the CED 2019 forecast employs the same models and methods used to develop the previous IEPR forecast. Differences between the two reflect changes in economic drivers and other key inputs. Relative to California Energy Demand Update (CEDU) 2018, the CED 2019 forecast includes additional historical load data, efficiency program savings, Title 24 building standards impacts, refreshed electricity and natural gas rate projections, and behind-the-meter storage and generation system interconnection data.

Figure 30 shows historical and projected CED 2019 baseline electricity consumption statewide for three demand scenarios. The CEDU 2018 mid baseline consumption forecast is included for comparison. In 2030, consumption in the new mid case is about 5 percent lower than CEDU 2018, reaching nearly 321,300 GWh.

Figure 30: Statewide Baseline Electricity Consumption

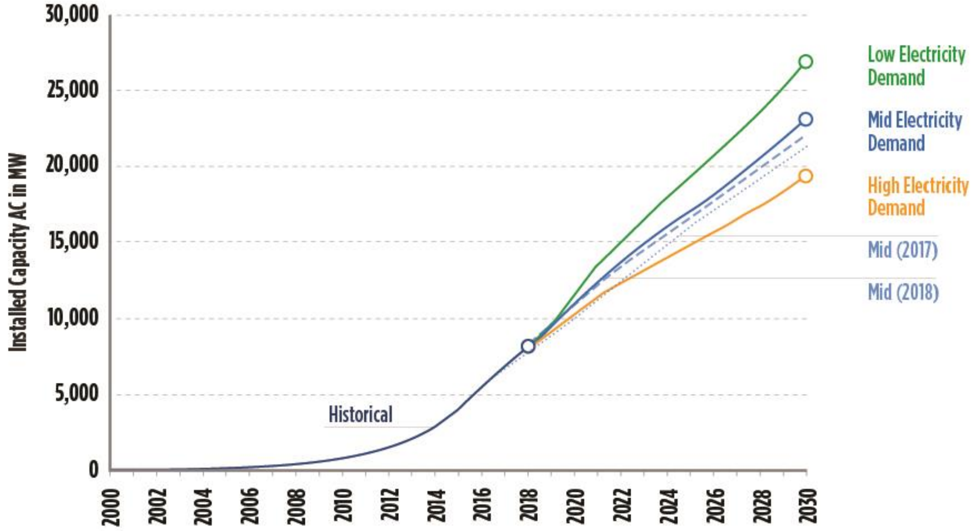


Source: CEC

Adoption of behind-the-meter (BTM) PV systems is a key consideration in deriving retail sales from end-user consumption and analyzing the timing and magnitude of system peaks. Historical and projected statewide PV capacities for the three CED 2019 demand cases and the CEDU 2018 and CEDU 2017 mid cases are shown in the figure above. In 2018, the state added more than 1,300 MW of new BTM PV, and by the end of 2018, there was more than 8,000 MW of installed BTM PV capacity in California. By 2030, the CED 2019 forecast projects installed capacity to reach about 19,900 MW, 23,300 MW, and 26,700 MW in the high, mid, and low energy demand scenarios, respectively. The projected BTM PV capacities lead to an estimated 35,000 to 47,000 GWh of energy production.

The CEC's 2019 Title 24 building standards update, which requires PV installations on new homes, was adopted by the CEC and approved by the California Buildings Standards Commission. As such, standards-driven system adoption—previously considered additional achievable photovoltaic (AAPV) system adoption—is now incorporated into the baseline forecast. Forecasted adoption from CED 2017 and CEDU 2018 in Figure 31 has been restated to include the contribution of AAPV to provide a consistent point of comparison to CED 2019.

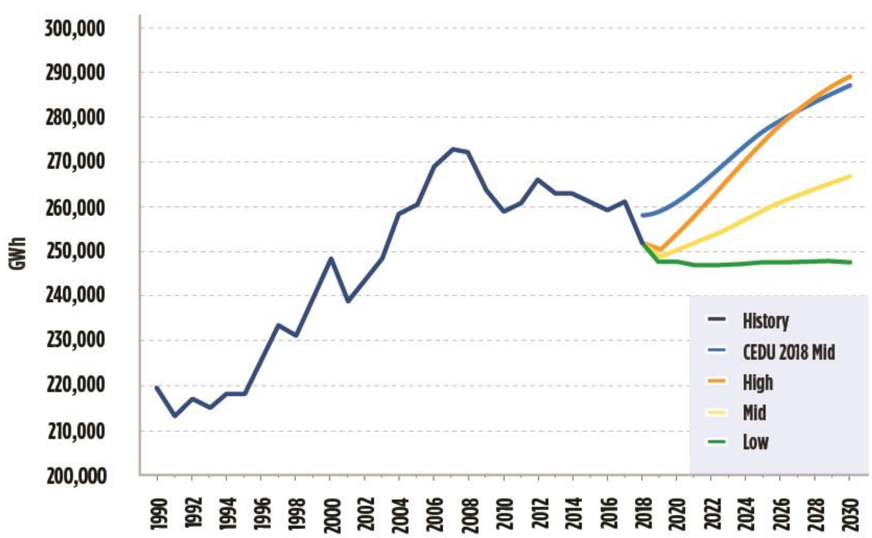
Figure 31: Statewide Behind-the-Meter Photovoltaic Capacity



Source: CEC

Figure 32 shows projected statewide baseline electricity sales for the three CED 2019 cases and the CEDU 2018 mid demand case. Here, the impact of standards-driven PV adoption can be seen lowering growth in sales relative to CEDU 2018. By 2030, sales in the CED 2019 mid case are projected to reach more than 266,137 GWh.

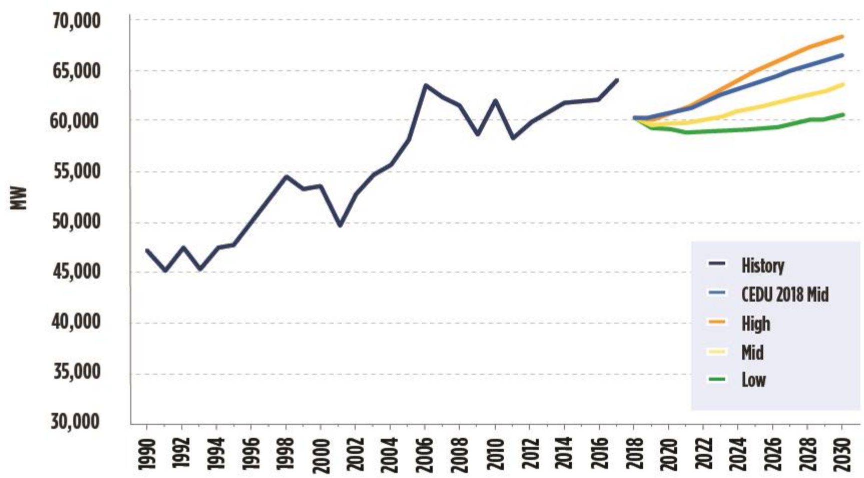
Figure 32: Statewide Baseline Electricity Sales



Source: CEC

Figure 33 shows the projected CED 2019 noncoincident net peak demand for the three baseline cases and the CEDU 2018 mid demand case. The CED 2019 peak forecast begins from a 2019 weather-normalized value, or from an estimate of what peak load would have been in 2019, assuming average temperatures. Peak shift impacts within the IOU TAC areas add nearly 4,200 MW of demand over traditional peak hours. By 2030, statewide peak demand in the CED 2019 preliminary mid case is projected to reach more than 63,600 MW. The mid case peak demand forecast reflects the impact of roughly 1,800 MW of projected BTM energy storage capacity in 2030.

Figure 33: Statewide Baseline Noncoincident Peak Electricity Demand



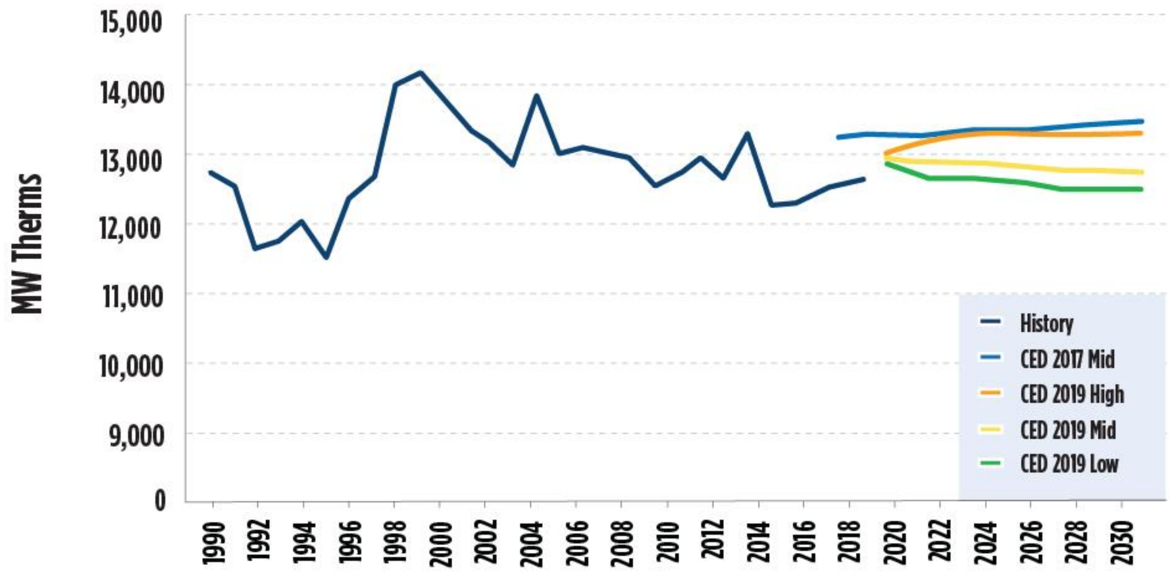
Source: CEC

Figure 34 shows the statewide end user natural gas consumption demand for the three CED 2019 cases and the CED 2017 mid case.[498] The historical series shows the variability in consumption from year to year, largely a response to weather. On average, 2018 was a particularly cool year for Southern California; so the forecast begins from a higher normalized starting point relative to the last year of recorded consumption. CED 2019 preliminary includes impacts from projected natural gas vehicle adoption, amounting to an additional 150 million therms by the end of the forecast period. This modest increase is more than offset by the

498 CED 2017 is shown for comparison as CEDU 2018 did not include a forecast of end-user natural gas consumption.

energy savings impacts from new building standards, as well as reduced consumption in the mining sector. Climate change impacts, which reduce heating demand, are included only in the mid and high cases, resulting in a relatively small difference between the low and mid case. By 2030, statewide end-user natural gas consumption in the CED 2019 preliminary mid case declines to just less than 12,800 million therms in 2030.

Figure 34: Statewide End-Use Natural Gas Consumption



Source: CEC

Additional Achievable Energy Efficiency

CEC staff routinely develops managed forecasts, which adjust baseline demand forecasts for AAEE, or energy savings resulting from efforts that are reasonably expected to occur but lack funding commitments or implementation plans. These efforts include future updates of building standards, appliance regulations, and new or expanded energy efficiency programs. AAEE is central to developing a managed demand forecast, which in turn is the basis for resource planning and procurement efforts at the CPUC and California ISO.

Senate Bill 350 (De León, Chapter 547, Statutes of 2015) directs the CEC to "establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030." This law also directs the CEC to "base the targets on a doubling of the mid case estimate of AAEE savings, as contained in the California Energy Demand Updated Forecast, 2015–2025."

AAEE scenarios are designed to reflect reasonably expected savings from programs developed in support of SB 350 aspirational goals, as well as IOU and POU program savings potential assessed by Potential and Goals (P&G) studies. Improvements in this process for the 2020-2030 AAEE forecast include:

- A more robust analysis of beyond-utility programs originally evaluated in the 2017 IEPR cycle,[499] as well as consideration of additional programs.
- Further analysis performed on data obtained from the POU P&G study.
- An increased use of software tools to simplify labor-intensive data manipulation and merging of the three main savings streams.

Staff is developing six scenarios to capture a broad range of uncertainty around key drivers of program activity. Since the CEC has explicit agreements with other agencies that plan on using specific AAEE scenarios in various resource planning and transmission planning studies,[500] staff sought input from these stakeholders throughout the scenario design process.

The savings accounted for in the AAEE scenarios come from three main sources:

- CPUC-jurisdictional program savings derived from the 2019 P&G study[501]
- POU potential savings derived from the California Municipal Utilities Association's (CMUA) 2017 P&G study[502]
- Beyond-utility savings from programs run by the CEC and other agencies, as well as all savings derived from future ratcheting of codes and standards (C&S)

The sections below describe various elements of the AAEE scenario design for CED 2019. The resulting savings estimates were not available for the preliminary but will be incorporated into the revised forecast.

CPUC Program Savings

The CPUC's 2019 P&G study presents five scenarios that assess program savings potential within each IOU service territory over the next 10 years. This study is undertaken biennially, and the most conspicuous differences between the 2019 P&G study and the predecessor are:

499 CEC staff. 2017. *2017 IEPR*. CEC. Publication Number: CEC-100-2017-001-CMF. https://www.energy.ca.gov/2017_energypolicy/. pp. 54-58.

500 The single forecast set agreement is listed in its entirety elsewhere in this chapter.

501 CPUC. *2020 Potential and Goals Study*, https://www.cpuc.ca.gov/General.aspx?id=6442461220.

502 CMUA. *Appendix B Energy Efficiency in California's Public Power Sector, 11th Edition*. April 2017. https://www.cmua.org/Files/Reports/SB1037/2017_Energy_Efficiency_Report.pdf.

- A significant drop of C&S savings in the attributable portions of Title 24 due to an effective LED lighting baseline in the commercial sector.
- An increase in behavioral, retrocommissioning, and operations savings (BROs).
- Program portfolios that must reach a higher level of cost-effectiveness.

As in previous IEPR cycles, the reference scenario adopted by the CPUC for its 2020–2030 program goals defines Scenario 3, and the CEC used variations from that starting point to develop more conservative and more aggressive estimates of IOU potential savings for each overall AAEE scenario. Table 13 shows the elements chosen for the final six scenarios in the AAEE portfolio. Staff carefully processed the scenarios to eliminate duplication with the baseline forecast.

Table 13: AAEE Scenario Design Elements for IOU Territories

Lever	High-Low (Scenario 1)	Mid-Low (Scenario 2)	Mid-Mid (Scenario 3)	Mid-High (Scenario 4)	Low-High (Scenario 5)	Mid-High Plus (Scenario 6)
Building Stock and Retail Prices	*2017 IEPR* High Case	*2017 IEPR* Mid Case	***2017 IEPR* Mid Case**	*2017 IEPR* Mid Case	*2017 IEPR* Low Case	*2017 IEPR* Mid Case
AIMs ETs	Reference	Reference	**Reference**	Average of Reference and Aggressive	Average of Reference and Aggressive	Aggressive
Incentive Levels	Capped at 25 Percent of Incremental Cost	Capped at 50 Percent of Incremental Cost	**Capped at 50 Percent of Incremental Cost**	Capped at 50 Percent of Incremental Cost	Capped at 50 Percent of Incremental Cost	Capped at 75 Percent of Incremental Cost
Cost-Effectiveness Measure Screening Threshold (Total Resource Cost Using 2019 Avoided Costs)	1.25	1.25	**1**	0.85	0.85	0.65
Marketing and Outreach	Default Calibrated Value	Default Calibrated Value	**Default Calibrated Value**	Increased Marketing Strength	Increased Marketing Strength	Increased Marketing Strength
Financing Programs	No Modeled Impacts	No Modeled Impacts	**No Modeled Impacts**	IOU Financing Programs Broadly Available to Residential and Commercial	IOU Financing Programs Broadly Available to Residential and Commercial	IOU Financing Programs Broadly Available to Residential and Commercial
Low Income	P&G Study Result Unchanged	P&G Study Result Unchanged	**P&G Study Result Unchanged**	P&G Study Result Unchanged	P&G Study Result Unchanged	P&G Study Result Unchanged
BROs Program Assumptions	Reference	Reference	**Reference**	Average of Reference and Aggressive	Average of Reference and Aggressive	Aggressive

Source: CEC

As can be seen in Table 13, building stock and retail prices are taken from CED 2017, consistent with the high, mid, and low baseline demand scenarios. The four basic bins of the IOU potential study savings—agricultural, industrial, and mining sector emerging technologies (AIMs ETs); rebate or financing programs; BROs; and low-income programs—are retained from CED 2017, and a range of scenarios is generated for each. AIMs ETs and BROs are treated independently of rebate or financing programs. Financing programs are influenced by marketing and outreach and further bounded by the cost-effectiveness screening methods and thresholds and incentive levels. Low-income programs have traditionally been included as a scenario lever; however, the 2019 P&G study analyzed these programs using new stock turnover model, which did not permit analysts to vary assumptions.

POU Program Savings

The CMUA's 2017 P&G study contains only a single savings estimate and is prepared every four years. During the CED 2017 forecast cycle, staff held this single estimate of POU program savings potential constant across all AAEE scenarios. For CED 2019, however, the P&G study results serve as a reference case around which staff developed additional scenarios, comparable to those developed for the CPUC programs. Savings projections for the largest 16 POUs are based on three sets of assumptions (consistent across all POUs) applied to CMUA's proprietary ELRAM model. Savings for the remaining POUs were extrapolated from those results.

Table 14 below lists the scenario levers chosen for the POU potential savings contributions to the six scenarios in the final AAEE portfolio.

Table 14: AAEE Scenario Design Elements for POU Territories

Lever	High-Low (Scenario 1)	Mid-Low (Scenario 2)	Mid-Mid (Scenario 3)	Mid-High (Scenario 4)	Low-High (Scenario 5)	Mid-High Plus (Scenario 6)
Expand Measure List	Reference	Reference	Reference	Add New Measures	Add New Measures	Add New Measures
Incentive Level	Reference x 75 percent	Reference x 75 percent	Reference	Reference	Reference	Reference
Promotional Expenditures	Reference x 5 percent	Reference x 75 percent	Reference	Reference x 125 Percent	Reference x 125 Percent	Reference x 125 Percent
Behavioral Programs	Remove Newly Planned BROs	Remove Newly Planned BROs	Reference	Reference	Reference	Reference
Early Retirement Programs	Reference	Reference	Reference	Implement ER Programs	Implement ER Programs	Implement ER Programs
Net to Gross	IOU	IOU	IOU	IOU	IOU	IOU
Re-participation Rates	IOU	IOU	IOU	IOU	IOU	IOU

Source: CEC

Beyond-Utility Programs Contributions

CED 2019 AAEE includes savings from future California Title 24 building efficiency standards, California Title 20 appliance efficiency standards, and federal appliance efficiency standards, as well as additional beyond-utility (BU) programs that have been assessed as potential contributors toward the state's SB 350 doubling goal. These BU savings elements were adjusted downward from an aspirational SB 350 perspective to levels that can be considered reasonably expected to occur given program-specific assumptions.[503] Table 15 illustrates how each standards savings category varies by compliance rate and number of assumed ratchets across the six scenarios.

Table 15: AAEE Scenario Design Elements for BU Codes and Standards

Authority	Lever	High-Low (Scenario 1)	Mid-Low (Scenario 2)	Mid-Mid (Scenario 3)	Mid-High (Scenario 4)	Low-High (Scenario 5)	Mid-High Plus (Scenario 6)
Title 24	Compliance Reduction or Enhancement	No Additional Included	20 Percent Compliance Rate Reduction	Reference Case Compliance	Compliance Enhancements	Compliance Enhancements	Compliance Enhancements
Title 24	Code Cycles (Vintages)	No Additional Included	2022 Nonresidential New Construction and Additions and Alterations (A&A); 2022 Residential A&A BU Workbook	2022 Nonresidential New Construction and Additions and Alterations (A&A); 2022 Residential A&A BU Workbook	2022 Nonresidential New Construction and A&A; 2022 Residential A&A BU Workbook	Same Scope Through 2025 Standards BU Workbook	Same Scope Through 2025 Standards BU Workbook
Title 20	Compliance Reduction or Enhancement	No Additional Included	20 Percent Compliance Rate Reduction		Compliance Enhancements	Compliance Enhancements	Compliance Enhancements
Title 20	Code Cycles (Vintages)	No Additional Included	Selected Standards Through 2022 P&G Study	Selected Standards Through 2022 P&G Study	Selected Standards Through 2022 P&G Study	Selected Standards Through 2027 P&G Study and BU Workbook	Selected Standards Through 2027 P&G Study and BU Workbook

503 Link to *2017 IEPR* on the CEC's website https://www.energy.ca.gov/2017_energypolicy/. p. 177

Authority	Lever	High-Low (Scenario 1)	Mid-Low (Scenario 2)	Mid-Mid (Scenario 3)	Mid-High (Scenario 4)	Low-High (Scenario 5)	Mid-High Plus (Scenario 6)
Federal Standards	Compliance Reduction or Enhancement	No Additional Included	No Additional Included	Reference Case Compliance	Compliance Enhancements	Compliance Enhancements	Compliance Enhancements
Federal Standards	Code Cycles (Vintages)	No Additional Included	No Additional Included	Through 2023 (Excluding 2020 General Service Lamp Standard) Plus 2026 Water Source Heat Pump P&G Study	Through 2023 (Excluding 2020 General Service Lamp Standard) Plus 2026 Water Source Heat Pump P&G Study and BU Workbook	Through 2023 Plus 2026 Water Source Heat Pump (Including 2020 General Service Lamp Standard Expanded Scope) P&G Study and BU Workbook	All Through 2026 Water Source Heat Pump Plus Selected Standards Through 2030 P&G Study and BU Workbook

Source: CEC

For CED 2019, BU savings analysis includes additional programs and sectors not previously considered part of AAEE. Specifically, BU now considers programs offered by air quality management districts, proposals for energy asset rating programs, smart-meter data analytics, conservation voltage reduction, agricultural and industrial savings potential, and fuel substitution. The BU scenario savings are assessed statewide and allocated to each utility in proportion to that utility's retail sales. Program-specific levers are adjusted and grouped to define conservative, reference, and aggressive savings scenarios, as indicated in Table 16.

Table 16: AAEE Scenario Design Elements for BU (Programs)

Program Savings Scenario	High-Low (Scenario 1)	Mid-Low (Scenario 2)	Mid-Mid (Scenario 3)	Mid-High (Scenario 4)	Low-High (Scenario 5)	Mid-High Plus (Scenario 6)
Prop 39	Mid: Established Programs With Historical Performance Data and Expected Future Funding Allocations	Mid: Established Programs With Historical Performance Data and Expected Future Funding Allocations	Mid: Established Programs With Historical Performance Data and Expected Future Funding Allocations	Mid: Established Programs With Historical Performance Data and Expected Future Funding Allocations	High	High
DGS Energy Retrofit	Mid: Established Programs With Historical Performance Data and Expected Future	Mid: Established Programs With Historical Performance Data and Expected Future	Mid: Established Programs With Historical Performance Data and Expected Future	Mid: Established Programs With Historical Performance Data and Expected Future	High	High

Program Savings Scenario	High-Low (Scenario 1)	Mid-Low (Scenario 2)	Mid-Mid (Scenario 3)	Mid-High (Scenario 4)	Low-High (Scenario 5)	Mid-High Plus (Scenario 6)
	Funding Allocations	Funding Allocations	Funding Allocations	Funding Allocations		
ECAA Financing	Mid: Established Programs With Historical Performance Data and Expected Future Funding Allocations	Mid: Established Programs With Historical Performance Data and Expected Future Funding Allocations	Mid: Established Programs With Historical Performance Data and Expected Future Funding Allocations	Mid: Established Programs With Historical Performance Data and Expected Future Funding Allocations	High	High
GGRF: Water Energy Grant	Low	Low	Mid: Limited Historical Data on a Pilot or Other Subset of Programs and Reasoned Assumption on Future Funding Allocations	Mid: Limited Historical Data on a Pilot or Other Subset of Programs and Reasoned Assumption on Future Funding Allocations	High	High
GGRF: Low-income Weatherization	Low	Low	Mid: Limited Historical Data on a Pilot or Other Subset of Programs and Reasoned Assumption on Future Funding Allocations	Mid: Limited Historical Data on a Pilot or Other Subset of Programs and Reasoned Assumption on Future Funding Allocations	High	High
Local Government Ordinances	Low	Low	Mid: Limited Historical Data on a Pilot or Other Subset of Programs and Reasoned Assumption on Future Funding Allocations	Mid: Limited Historical Data on a Pilot or Other Subset of Programs and Reasoned Assumption on Future Funding Allocations	High	High

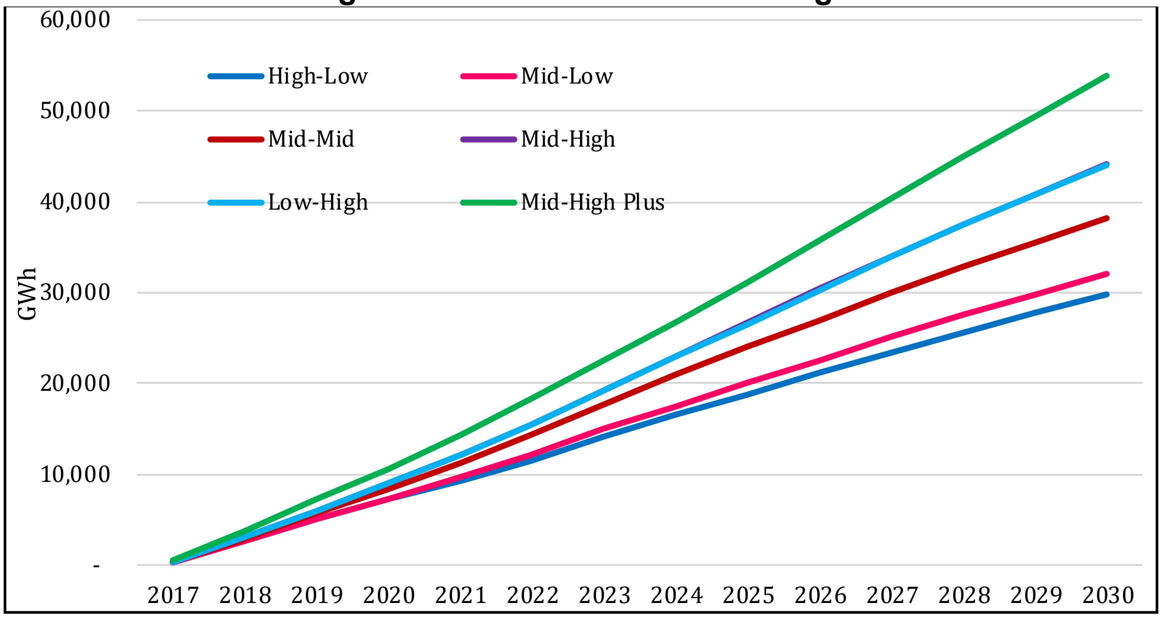
Program Savings Scenario	High-Low (Scenario 1)	Mid-Low (Scenario 2)	Mid-Mid (Scenario 3)	Mid-High (Scenario 4)	Low-High (Scenario 5)	Mid-High Plus (Scenario 6)
PACE Financing	Low	Low	Mid: Limited Historical Data on a Pilot or Other Subset of Programs and Reasoned Assumption on Future Funding Allocations	Mid: Limited Historical Data on a Pilot or Other Subset of Programs and Reasoned Assumption on Future Funding Allocations	High	High
Benchmarking and Public Disclosure	Low	Low	Mid: Limited Historical Data on a Pilot or Other Subset of Programs and Reasoned Assumption on Future Funding Allocations	Mid: Limited Historical Data on a Pilot or Other Subset of Programs and Reasoned Assumption on Future Funding Allocations	High	High
Fuel Substitution	Low	Low	Mid: Limited Historical Data on a Pilot or Other Subset of Programs and Reasoned Assumption on Future Funding Allocations	Mid: Limited Historical Data on a Pilot or Other Subset of Programs and Reasoned Assumption on Future Funding Allocations	High	High
Behavioral, Retrocommissioning, Operational Savings	Not Included	Not Included	Not Included	Not Included	Low	Mid: Assumptions Based on Pilot or Proposed Programs
Local Government Challenge	Not Included	Not Included	Not Included	Not Included	Low	Mid: Assumptions Based on Pilot or Proposed Programs

Program Savings Scenario	High-Low (Scenario 1)	Mid-Low (Scenario 2)	Mid-Mid (Scenario 3)	Mid-High (Scenario 4)	Low-High (Scenario 5)	Mid-High Plus (Scenario 6)
Energy Asset Ratings	Not Included	Not Included	Not Included	Not Included	Low	Mid: Assumptions Based on Pilot or Proposed Programs
Smart Meter Data Analytics	Not Included	Not Included	Not Included	Not Included	Low	Mid: Assumptions Based on Pilot or Proposed Programs
Air Quality Management District	Not Included	Not Included	Not Included	Not Included	Not Included	Mid: Limited Assumptions Based on Pilot or Proposed Programs
Agricultural	Not Included	Not Included	Not Included	Not Included	Not Included	Mid: Limited Assumptions Based on Pilot or Proposed Programs
Industrial	Not Included	Not Included	Not Included	Not Included	Not Included	Mid: Limited Assumptions Based on Pilot or Proposed Programs
Conservation Voltage Reduction	Not Included	Not Included	Not Included	Not Included	Not Included	Mid: Limited Assumptions Based on Pilot or Proposed Programs

Source: CEC

Figure 35 shows the total GWh savings estimated for each of the six AAEE scenarios described above. The mid-mid consumption savings, commonly used for system planning, reach about 38,000 GWh by 2030, while the more aggressive mid-high plus scenario reaches nearly 54,000 GWh by the end of the forecast period.

Figure 35: Statewide AAEE Savings



Source: CEC

Choice of Single Managed Forecast Set for Planning Purposes

Alongside each CEC Demand Forecast since 2013, the CEC, the CPUC, and the California ISO have actively engaged in collaborative discussions around how to account consistently and rigorously for reduced energy demand from energy efficiency, and for the growth of other distributed energy resources, within their respective planning and procurement processes. The three organizations developed a process for creating and sharing a common informational and analytical basis that would ensure collaboration and transparency in carrying out these functions. Over time, the three organizations implemented the process alignment, prioritizing use of a common managed forecast to the extent possible for their respective planning purposes. The interagency collaboration is primarily coordinated through the Joint Agency Steering Committee (JASC), composed of senior staff from the CPUC, CEC and California ISO, with oversight by the assigned CPUC and CEC commissioners and a senior executive from the California ISO, jointly referred to as JASC principals.

The six scenarios discussed above, combining energy efficiency savings scenarios with the baseline forecasts, are managed forecasts that are options for a "single forecast set" to be used for planning purposes in CEC, CPUC, and California ISO (the joint agencies and the California ISO) proceedings. The joint agencies' respective staff and the California ISO's leadership have agreed that specific elements of this forecast set will be used for planning and procurement in the California ISO's TPP and the CPUC's IRP, resource adequacy, and other planning processes as outlined below. The details of this agreement will be adapted appropriately through time, with the consent of leadership, as the needs of planning and procurement evolve.

The term "single forecast set" is intended to clarify that what has commonly been called a "single forecast" is not a single number, but is actually a set of forecast numbers drawn from the CED 2019 forecast, adopted as part of the *2019 IEPR.* CED 2019 contains six managed scenarios, as discussed above, which combine baseline forecasts using alternative weather variants and AAEE scenarios, and hourly load forecasts for TAC areas.[504] Agreement on a single forecast set includes specification on the use for each component of the set.

The single forecast set consists of three components of the IEPR demand forecast:

- Three baseline scenarios of annual energy and peak demand, each with three peak event weather variants.
- Three scenarios of hourly loads for baseline forecasts for each of three IOU TAC areas.
- Six scenarios of AAEE described by annual energy and hourly load impacts.

The combination of a CED 2019 baseline forecast using a specific weather variant plus an AAEE scenario depends on their use. The selected CED 2019 baseline case will be the "mid demand" case for the combined IOU service areas that comprise the California ISO balancing area. The mid demand case includes variants for different weather conditions. To account for uncertainty, variations of IEPR CED outputs that diverge from the single forecast set may be used in CPUC IRP modeling sensitivities. However, CPUC staff agrees to coordinate so that adopted IRP portfolios conform to the single forecast set.

The following list is the existing agreement among the joint agencies respective staff and California ISO leadership:

- CPUC IRP Reference System Plan, Preferred System Plan, and California ISO economic studies:
    - Baseline mid-case annual energy and annual peak demand
    - AAEE mid-mid scenario annual energy and peak demand
    - 1-year-in-2 peak event weather conditions
- California ISO TPP policy studies and bulk system studies:
    - Baseline mid-case annual energy and annual peak demand
    - AAEE mid-mid scenario annual energy and peak demand

504 A TAC area denotes a portion of the California ISO balancing authority area that has been placed in the California ISO's operational control through an agreement with an electric utility or other entity operating a transmission system component. A TAC area typically consists of an IOU and multiple publicly owned utilities using the transmission system owned by the IOU.

- 1-year-in-5 peak event weather conditions
    - Mid-mid hourly loads
    - CEC staff allocations of AAEE to load buses used in transmission studies
- California ISO TPP and resource adequacy local capacity studies:
    - Baseline mid-case annual energy and annual peak demand
    - AAEE mid-low scenario annual energy and peak demand
    - 1-year-in-10 peak event weather conditions
    - CEC staff allocations of AAEE to load buses used in transmission studies
- California ISO maximum import capability allocation for CPUC's system resource adequacy requirements for LSEs:
    - Baseline mid-case monthly peak demand derived from the mid-mid managed demand forecast case of hourly loads
- CPUC resource adequacy LSE system requirements:
    - Baseline mid-case monthly peak demand derived from Mid-case hourly loads
    - AAEE mid-mid annual and monthly peak demand
    - 1-year-in-2 peak event weather conditions
- CPUC IOU distribution planning requirements:
    - Baseline peak demand (also known as the IEPR demand forecast) and AAEE scenarios (also known as "DER growth forecasts")
    - Weather variants and AAEE scenario variants may differ by IOU as per CPUC D. 18-02-004
- California ISO flexible capacity studies for resource adequacy:[505]

505 The methodology for assessing flexible capacity is recent and still evolving, and the Joint Agencies and California ISO are collaborating to integrate fully this use case into the overall forecasting work flow. CPUC staff have expressed reservations regarding use of the CEC's existing hourly load model outputs for this purpose, and the California ISO and the CEC acknowledge those concerns and the expressed desire to transform the flexible capacity analysis on a going forward basis. The Joint Agencies and the California ISO are actively working to resolve these concerns, respecting each other's transformational processes. Until these transformational changes are made, the California ISO will continue to use the CEC's hourly forecast.

- Baseline mid-case hourly loads by California ISO area
- AAEE mid-mid scenario hourly loads by California ISO area
- 1-year-in-2 peak event weather conditions

Assigned staff at the joint agencies and the California ISO outlined a process by which the CPUC or California ISO can make a request to deviate from this agreement because a desired demand forecast variant or combination is not yet produced by the CEC. If the CEC does not have the resources to develop such a variant, then the joint agencies' and the California ISO's leadership will consider allowing the requesting entity to develop and use such a variant for the period until the CEC is able to develop it. Such requests should also be made and approved using appropriate procedures of the requesting agency to ensure all interested stakeholders are aware of such a deviation.

The following description illustrates an even more complex interaction among the two agencies and the California ISO that could lead to changes in the scope of demand variants prepared by the CEC. CPUC staff has commented that California ISO studies of flexible capacity needs could be improved by using a distribution of hourly load and renewable performance profiles that are correlated with respect to weather conditions, rather than the current CEC hourly load forecast which is based on most likely weather conditions. The CPUC has already implemented a similar probabilistic approach to support reliability assessments in the IRP, developing its own set of load profiles. In the California ISO's flexible capacity needs assessment study process, CPUC staff has requested that the California ISO modify its study methodology to conform to a similar probabilistic approach, and that the CEC provide the required set of hourly load forecasts.

For illustrative purposes, the three entities might address these concerns through a special project whereby the CEC develops a range of weather year-specific hourly forecasts that the California ISO uses to develop correlated weather year load and renewable performance profiles and evaluates a range of resulting flexibility requirements. The California ISO would consider the pros and cons of this methodological change in its stakeholder process, and, if approved, undertake necessary tariff changes. The agencies' respective staff and California ISO's leadership should agree that a permanent expansion of CEC demand forecast variants is warranted as part of the broader methodological change in flexibility studies. The CEC would then invest the effort necessary to prepare weather-year-specific hourly load variants in each IEPR cycle to be used in CPUC and California ISO flexible capacity needs studies.

Recommendations

The California Energy Commission (CEC) should:

- **Further explore options for forecasting load migration.** Identify stakeholders and explore potential use cases for near- and long-term forecasts of load departing from investor-owned utilities to energy service providers and community choice aggregators. Assess options for developing a forecast that responds to stakeholder needs.
- **Expand IEPR data collection efforts to include community choice aggregator-specific demand-side programs.** During the 2020 revision to the *Integrated Energy*

Policy Report demand forms, engage community choice aggregators to ensure that the CEC's data request adequately captures impacts from load-management and electrification programs that are developed and funded locally.

- **Consider emerging electrification programs and standards in the baseline demand forecast.** Also, identify other drivers of electrification that may be considered reasonably expected to occur. Work with stakeholders to identify the data and analytic challenges that must be overcome before fuel substitution scenarios can be developed and included formally in CEC managed forecasts.
- **Propose a forum for stakeholders to identify emerging sources of load growth and determine whether they are already embedded in the CEC's demand forecast.**
- **Continue to refine and expand the CEC's hourly forecast**. Further work should prioritize improvements that are responsive to the needs of state planning efforts, such as the CPUC's Integrated Resource Planning process.
- **Continue to refine and develop the CEC's projections of behind-the-meter resources, especially storage adoption and charging patterns.**
- **Gather data critical to refining estimates of energy use associated with historical cultivation activity already embedded in the demand forecast, as well as new activity that may be incremental to historical trends.**
- **Gather data critical to refining estimates of energy use associated with historical cultivation activity already embedded in the demand forecast, as well as new activity that may be incremental to historical trends.**

CHAPTER 8: Transportation Energy Demand Forecast

Introduction

California is home to roughly 30 million registered cars, trucks, buses, and other motorized on-road vehicles. Over the last 60 years, an increase in vehicle ownership and the number of miles driven has made the transportation sector the largest contributor of greenhouse gas (GHG) emissions in the state, as well as a leading cause of air pollution and ozone-forming gas emissions. Chapter 3 describes the set of rules, policies, goals, and programs to meet federal clean air standards, lower GHG emissions, and reduce California's petroleum dependence. In total, these efforts are transforming California's transportation sector and dramatically changing the way people and goods move throughout the state.

The Public Resources Code, Section 25304, requires the California Energy Commission (CEC) to conduct transportation forecasting and assessment, including a forecast of "statewide and regional transportation energy demand" and assessment of "the factors leading to projected demand growth."[506] Forecasting California's transportation sector is challenging given the rapid evolution toward a clean transportation system, and because transportation fuels and vehicles are influenced by developments in the global market.

This chapter provides an overview of the preliminary CEC transportation energy demand forecast, including a comparison of the present and future mix of existing fuels and vehicles against some of the state's goals and benchmarks. The forecast reflects the implications of a mix of existing policies, current consumer preferences, fuel price cases, and projected market and technological conditions.

Summary of Revised Forecast Results

CEC staff developed a transportation energy demand forecast and presented it at a workshop July 22, 2019.[507] Based on feedback from the workshop participants, along with updated data, CEC staff developed a revised transportation energy demand forecast and presented results at a workshop on December 2, 2019. The transportation forecast is integrated into the larger

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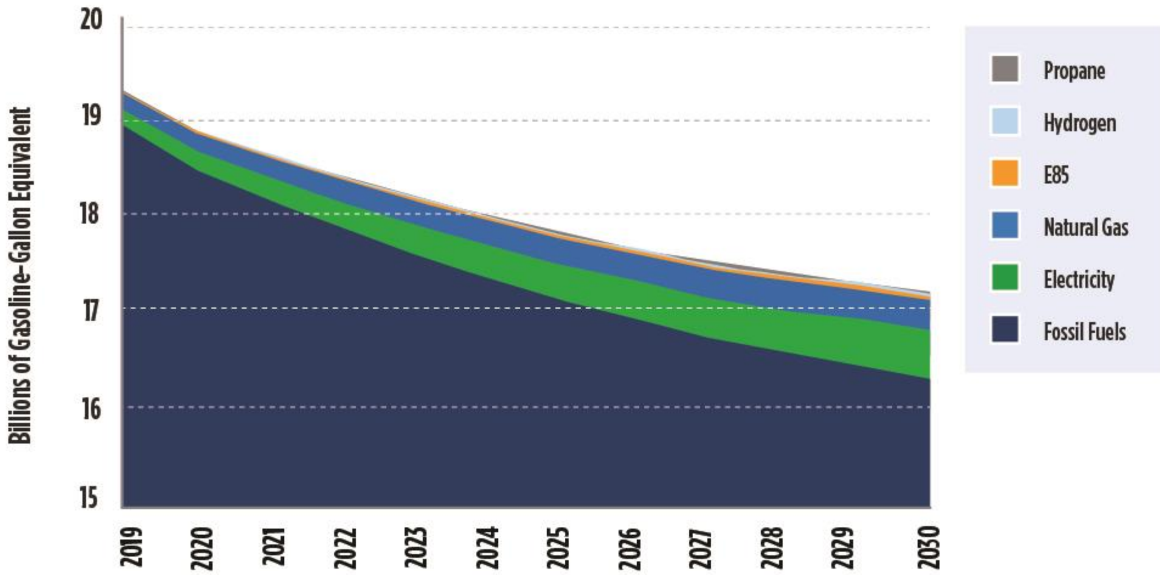
506 Public Resources Code, Section 25304 (b).

507 [Link to workshop documents for the July 22, 2019, workshop on Preliminary Transportation Energy Demand Forecast](https://www.energy.ca.gov/2019_energypolicy/documents/#07222019) https://www.energy.ca.gov/2019_energypolicy/documents/#07222019.

California energy demand forecast for electricity and natural gas that is discussed in Chapter 7. Figures 36–38 summarize forecast results for transportation energy demand and light-, medium-, and heavy-duty zero-emission vehicles (ZEVs), with more results presented later in this chapter and Appendix C. To be consistent with the ZEV Action Plan, ZEV vehicles in this report include plug-in electric vehicles (PEVs) and fuel cell electric vehicles (FCEVs). PEVs include battery-electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs). BEVs, FCEVs, and plug-in hybrid FCEVs are considered pure ZEVs, while PHEVs are considered transitional ZEVs. Figure 36 shows the distribution of transportation energy demand by fuel type, measured by a common energy unit: gasoline gallon equivalent.[508] Petroleum-based fuels continue to represent the largest shares of transportation energy demand, at present and through the forecasted period. The decline in gasoline demand forecast is primarily due to improvements in fuel efficiency and increased electrification. The growth in electricity consumption is mostly a result of growth in light-duty vehicle (LDV) electrification, while the growth in natural gas consumption reflects increased fuel diversification in trucks and buses. In the mid demand case, the transportation electricity consumption represents 5.4 percent of overall electricity demand in 2030.

508 A gasoline gallon equivalent is defined as the amount of alternative fuel equivalent in energy to one gallon of gasoline.

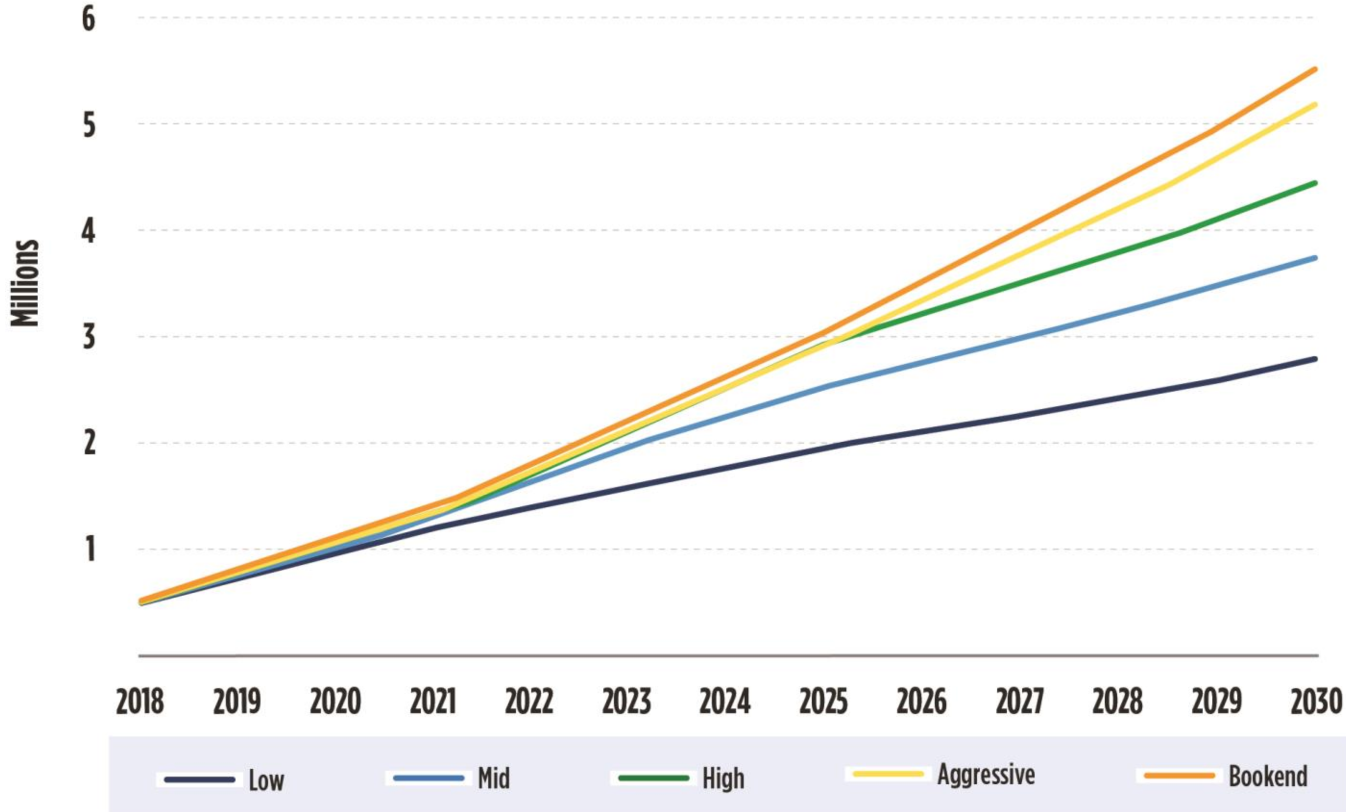
Figure 36: Transportation Energy Demand Forecast (Mid Case)



Source: CEC

The CEC's forecast shows an increase in light-duty ZEV population to more than 3.7 million vehicles on the road in 2030 in the mid case and more than 4.4 million in the high case, as shown in Figure 37. In 2030, light-duty ZEVs account for 10.6 percent of all LDVs on the road in the mid case and 12.5 percent in the high case. In the aggressive and bookend cases designed to reflect the most optimistic scenarios of the total LDV population, the light-duty ZEV stock is 14.6 percent (5.2 million) and 15.5 percent (5.5 million), respectively.

Figure 37: Forecast of Light-Duty ZEVs by Scenario



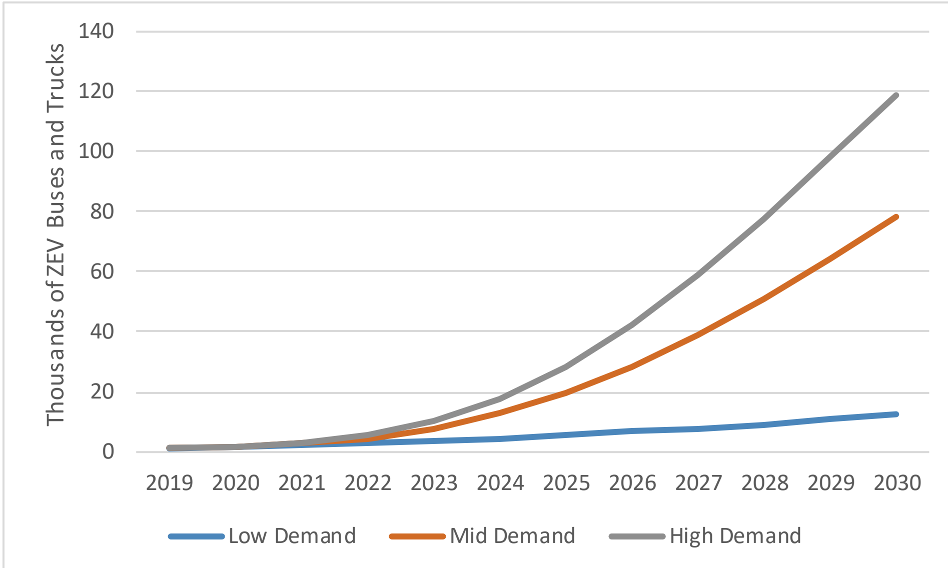
Source: CEC

Figure 38 shows the forecast of medium-duty (MD) and heavy-duty (HD) buses and trucks. The high-demand case results in about 118,850 MD and HD ZEVs by 2030, including:

- 93,200 battery-electric trucks.
- 5,000 catenary-electric trucks (primarily port drayage trucks).
- 13,000 hydrogen fuel-cell Class 8 tractor-trailers.
- 7,650 ZEV buses.

The mid-demand case includes about 78,360 MD and HD ZEVs, composed of roughly 71,800 electric trucks and 6,500 ZEV buses. The low-demand case results in about 12,600 MD and HD ZEVs and includes around 5,850 buses and 6,750 trucks. The absence of incentives after 2021 in the low-demand case results in the lower number of electric MD and HD trucks.

Figure 38: Forecast of Medium- and Heavy-Duty Zero Emission Vehicle Stock

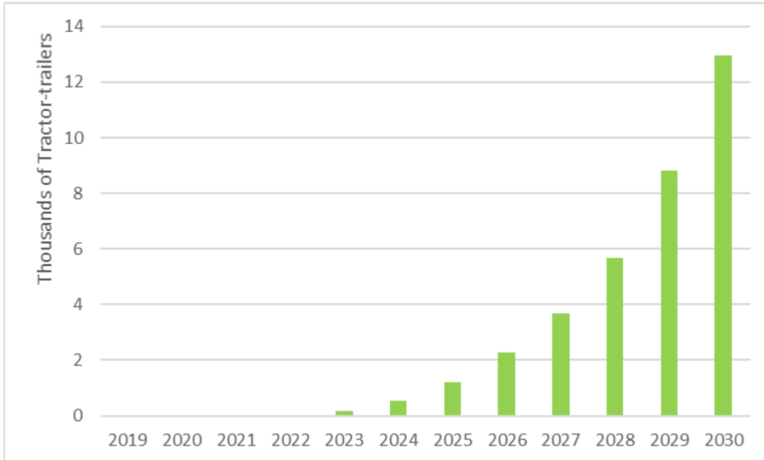


Source: CEC

Figure 39 shows about 13,000 hydrogen fuel cell Class 8 tractor-trailers in the high-demand case, based on a hydrogen price of $6.50 per kilogram (kg) and refueling availability for fleets with dedicated routes. Hydrogen prices of $5 to $7 per kg may be achieved when stations are located and sized to the usage of a dedicated truck fleet to maximize station use.[509] Moreover, refueling to 5,000 pounds per square inch (psi) rather than the 10,000 psi used for LDVs lowers the delivered cost of hydrogen. See Appendix C for further discussion.

509 IEA. *The Future of Hydrogen: Seizing Today's Opportunities*. Prepared by International Energy Agency for the G20, Japan. June 2019. Also BNEF "Hydrogen: The Economics of Production from Renewables, Costs to plummet" Bloomberg New Energy Finance. August 2019.

Figure 39: Hydrogen Fuel-Cell Class 8 Tractor-Trailers, High Demand Case



Source: CEC

Forecasting Approach

The CEC's *Transportation Energy Demand Forecast* uses a suite of models (described in Appendix C) that incorporate consumer preferences, regulations, economic and demographic projections, projected improvements in technology, and other market factors to forecast transportation energy demand. The approach starts with current market conditions and forecasts transportation energy demand based on the projected inputs briefly described below (and detailed in Appendix C). No constraints are imposed for the forecast to meet a future target. In contrast, methods used by others for strategic planning begin with a target (such as a quantity of vehicles, fuels, or emissions goals to meet by a future year) and work backward from there to create intermediate goals for the intervening years. In this way, policy makers can use the forecast in conjunction with a corresponding strategic plan to assess progress toward statewide goals.

Key Inputs and Assumptions

CEC staff designed different combinations of inputs and assumptions to create several plausible transportation demand cases. The low-, mid-, and high-electricity cases are consistent with the demand cases used for forecasting total electricity and natural gas demand. These three demand cases are based on different ZEV incentive scenarios, projected vehicle attributes, economic, demographic, and fuel price inputs (presented in Appendix C), varying in relative favorability for ZEV market penetration. The high-demand case represents favorable conditions for ZEVs and natural gas trucks with low emissions of nitrogen oxides. The low-demand case represents the least favorable conditions, while the mid-demand case represents what staff believes to be most likely, given the current economic conditions, policies, and incentives. The transportation demand forecasts are then integrated into the corresponding demand forecast cases for electricity and natural gas. Furthermore, the transportation energy demand forecast considers aggressive and bookend cases for LDVs.

Major variations among different transportation energy demand cases include assumptions about the amount and extension of the ZEV incentives, as well as economic, demographic, and fuel price projections. These inputs and assumptions influence the vehicle and travel demand forecasts as measured by vehicle population and vehicle miles traveled.

A high-level description of the low-, mid-, and high-electricity demand cases is listed below, as well as in Table 17. Low alternative fuel prices along with high petroleum fuel prices will drive higher adoption of ZEVs (in the high case). Conversely, if petroleum fuel prices are low and alternative fuel prices are high, it will result in a lower adoption of ZEVs (in the low case).

- Low Electricity Demand Case
  - Low income and population growth
  - Low petroleum fuel prices
  - High electricity, natural gas, and hydrogen prices
  - Results in low adoption of ZEVs
- Mid Electricity Demand Case
  - Mid income and population growth
  - Mid petroleum fuel prices
  - Mid electricity, natural gas, and hydrogen prices
  - Results in mid adoption of ZEVs
- High Electricity Demand Case
  - High income and population growth
  - High petroleum fuel prices
  - Low electricity, natural gas, and hydrogen prices
  - Results in high adoption of ZEVs

The aggressive and bookend cases use the same inputs for population, income, and fuel prices as the high electricity demand case.

Table 17: Common Electricity Demand Cases Main Inputs

Electricity Demand Case	Population Growth	Income Growth	Fuel Prices-Petroleum Fuels	Fuel Prices-Electricity/Natural Gas/Hydrogen
High Demand	High	High	High	Low
Mid Demand	Mid	Mid	Mid	Mid
Low Demand	Low	Low	Low	High

Source: CEC

Table 18 provides an overview of the key inputs and data sources for the transportation energy demand forecast. Appendix C provides more details about these inputs.

Table 18: Key Inputs to the Transportation Energy Demand Forecast

Key Input(s)	Description	Data Source(s)
On-Road Vehicle Population	The CEC receives vehicle registration data from the DMV and classifies data into 15 LDV classes and 6 MD and HD vehicle classes. Model-year vintages are distinguished for all on-road vehicles. Staff identifies four market segments for LDVs: residential, commercial, rental, and government. Bus populations are drawn from the 2017 National Transit Database, CARB's EMFAC2017, and the California Highway Patrol.	California Department of Motor Vehicles, National Transit Database, CARB EMFAC2017, CA-VIUS, and CHP
Future Vehicle Attributes	The CEC contracts with outside experts to forecast vehicle attributes, including vehicle price, range, fuel economy, model availability, acceleration, and maintenance costs.	CEC analysis
Economic and Demographic Data	The CEC uses household population, per capita income, and gross state product data to forecast overall vehicle sales and MD and HD truck activity. Freight Analysis Framework 4.4 projections drive growth in the freight commodity sector.	Moody's Analytics, U.S. Department of Finance, and Federal Highway Administration Freight Analysis Framework
Fuel Prices	Retail fuel price forecast is based on historical data from several sources. NREL forecasts the retail hydrogen prices. In the high demand case, hydrogen prices for HD truck fleets with dedicated routes are based on industry analysis.	CEC analysis, U.S. Energy Information Administration, National Renewable Energy Laboratory, California Fuel Cell Partnership
Consumer Preferences	The CEC periodically surveys residential and commercial LDV consumers to assess preferences for fuel type and vehicle class and different LDV attributes.	2017 California Vehicle Survey
Policies and Incentives	Government policies and incentives, such as the state near-ZEV and ZEV rebates and HOV lane access federal tax credit, are incorporated into the forecast.	CEC analysis
Miles per Vehicle	Travel demand models as well as average annual miles traveled per vehicle data specific to class and vintage for LD, MD, and HD vehicles are used to forecast statewide miles traveled and energy demand.	CEC analysis, Bureau of Automotive Repair, 2017 California Vehicle Inventory and use Survey

Source: CEC

Light-Duty ZEV Scenarios

California's transportation sector is quickly transforming in response to clean vehicle policies, investments, and market pressures from changing technology and consumer preferences. The CEC's transportation energy demand forecast must keep pace with this market transformation, and the CEC must continue robust engagement with transportation sector stakeholders. For this reason, staff has formed a subgroup of the Demand Analysis Working Group (DAWG) with a diverse group of transportation and electricity sector stakeholders to discuss assumptions and technical issues that affect transportation electrification.

Because of the challenge of projecting ZEV market characteristics over the forecast period, CEC staff created light-duty ZEV scenarios designed to capture different levels of electricity consumption. CEC staff presented these scenarios at the June 14, 2019, and November 14, 2019, DAWG transportation subgroup meetings to seek feedback from sister agencies, utilities, air quality management districts, manufacturers, and other stakeholders. CEC staff considered the feedback in developing the ZEV scenarios and assumptions. The economic and demographic inputs used in each ZEV scenario correspond with those used in total electricity demand forecast cases. Table 19 shows consumer preferences, vehicle attributes, ZEV incentives, and infrastructure availability assumptions for each light-duty ZEV scenario. The scenarios use updated ZEV vehicle attributes, while internal combustion engine vehicle attributes are similar to those used in the *2018 IEPR Update*. The bookend scenario incorporates makes and models in additional LDV size classes for FCEVs and plug-in hybrid FCEVs (PHFCEVs).

As previously noted, the inputs and assumptions for these scenarios range from less favorable for ZEV adoption in the low-electricity-demand case to more favorable for ZEV adoption in the high-, aggressive-, and bookend-demand cases. The aggressive- and bookend-demand cases used the economic, demographic, and fuel price inputs from the high-demand case.

Table 19: Inputs and Assumptions for Light-Duty ZEV Scenarios

Demand Case	Low	Mid	High	Aggressive	Bookend
	Preferences	**Preferences**	**Preferences**	**Preferences**	**Preferences**
Consumers' ZEV Preference	Constant at 2017 Level	Increase With ZEV Market Growth	Increase With ZEV Market Growth	Increase With ZEV Market Growth	Increase With ZEV Market Growth
	Incentives	**Incentives**	**Incentives**	**Incentives**	**Incentives**
Federal Tax Credit	PEVs: decreasing starting in 2019, eliminated after 2022 FCEVs: None	PEVs: decreasing starting in 2019 FCEVs: None	PEVs: decreasing starting in 2019 FCEVs: None	PEVs: decreasing starting in 2019 FCEVs: None	PEVs: decreasing starting in 2019 FCEVs: None
State Rebate	To 2025	To 2025	To 2025	To 2030	To 2030
HOV Lane Access	To 2021	To 2023	To 2025	To 2025 for PHEV, to 2030 for BEV/FCEV	To 2025 for PHEV, to 2030 for BEV/FCEV
	Attributes in 2030	**Attributes in 2030**	**Attributes in 2030**	**Attributes in 2030**	**Attributes in 2030**
Classes Available (out of 15 total classes)	BEV: 11 PHEV: 14 FCEV: 5 PHFCV: 0	BEV: 12 PHEV: 14 FCEV: 5 PHFCV: 1	BEV: 13 PHEV: 14 FCEV: 6 PHFCV: 1	BEV: 13 PHEV: 14 FCEV: 6 PHFCV: 1	BEV: 15 PHEV: 14 FCEV: 8 PHFCV: 7
Vehicle/Battery Price	PEVs: Prices based on battery price declining to ~$120/kWh FCEVs: $38,000	PEVs: Prices based on battery price declining to ~$100/kWh FCEVs: $25,000	PEVs: Prices based on battery price declining to ~$80/kWh FCEVs: $25,000	PEVs: Prices based on battery price declining to ~$70/kWh FCEVs: $25,000	PEVs: Prices based on battery price declining to ~$70/kWh FCEVs: $25,000
Max Range for a Midsize Vehicle (Miles)	PEVs: ~333 FCEVs: ~365	PEVs: ~341 FCEVs: ~365 PHFCEV: ~334	PEVs: ~341 FCEVs: ~461 PHFCEV: ~505	PEVs: ~341 FCEVs: ~461 PHFCEV: ~505	PEVs: ~341 FCEVs: ~461 PHFCEV: ~505
Refuel (minutes)	PEVs: 15-21 FCEVs: 5	PEVs: 15-21 FCEVs: 5	PEVs: 10-16 FCEVs: 5	PEVs: 10-16 FCEVs: 5	PEVs: 10-16 FCEVs: 5
Time to Station *	PEVs: same as gasoline FCEVs: 7 min	PEVs: same as gasoline FCEVs: 7 min	PEVs: same as gasoline FCEVs: 7 min	PEVs: same as gasoline by 2025 FCEVs: 7 min	PEVs: same as gasoline by 2025 FCEVs: 7 min
	Forecast Results	**Forecast Results**	**Forecast Results**	**Forecast Results**	**Forecast Results**
2030 ZEV Population	**2.7 Million**	**3.7 Million**	**4.7 Million**	**5.5 Million**	**5.7 Million**

Source: CEC *The time to hydrogen refueling station is based on a projection of 300 hydrogen fueling stations by 2030, which builds upon existing plans to fund 110 stations by 2024. Hydrogen stations are not located throughout the state but are placed in geographic clusters. "Time to station" is the measure of the travel time to a station assuming that the vehicle is located within a cluster. This measure aggregates the areas of all clusters in determining the average travel time. The size and number of clusters are projected to increase over time.

MD and HD Vehicle Inputs and Assumptions

Table 20 shows key inputs and assumptions for MD and HD vehicles. Existing regulations are implicit, since staff estimated truck retirement rates from CARB's EMFAC2017 data, which includes regulatory effects.[510] Recent voucher amounts awarded by the CARB Hybrid and Zero-emission Truck and Bus Incentive Program (HVIP) are the basis for incentives. The low, mid, and high demand cases use staff's commercial fuel price forecast, except for hydrogen in the high demand case after 2021, where staff assumes a dedicated fleet price. Battery-electric medium- and heavy-duty truck battery pack prices are based on the LDV battery pack prices, plus 30 percent to account for more cooling and higher power ratings to perform in the more intense MD and HD truck drive cycles. Battery-electric trucks are constrained to replacing existing trucks with either a typical daily vehicle miles traveled (VMT) under 100 miles (all classes) or port drayage duties among Class 8 tractor-trailers.[511]

Table 20: Key Inputs and Assumptions for MD and HD Vehicles

Demand Case	Low	Mid	High
	California Regulations	**California Regulations**	**California Regulations**
CARB Regulations	Applied to urban transit bus and shuttle bus, implicit for current truck rules	Applied to urban transit bus and shuttle bus, implicit for current truck rules	Applied to urban transit bus and shuttle bus, implicit for current truck rules
	Incentives	**Incentives**	**Incentives**
HVIP Incentives	99 percent of current HVIP voucher percentage of vehicle incremental cost for each fuel type and zero incentives after 2021*	99 percent of current HVIP voucher percentage of vehicle incremental cost for each fuel type and 90 percent after 2021*	99 percent of current HVIP voucher percentage of vehicle incremental cost for each fuel type 2019-2030*
	Fuel Prices	**Fuel Prices**	**Fuel Prices**
Hydrogen Price	Commercial high case	Commercial mid case	Commercial high case through 2021; constant at $6.50/Kg from 2022 on
All Other Fuels	Commercial high price	Commercial mid price	Commercial low price

510 CARB's EMFAC2017 https://www.arb.ca.gov/emfac/2017/

511 Based on the length of typical daily trips reported by fleets in the Caltrans 2017 California Vehicle Use and Inventory Survey.

	Attributes	Attributes	Attributes
Battery Pack Price (MHD vehicle, in 2030)	MHD BET prices based on battery pack price declining to ~$158/kWh	BEV prices based on battery pack price declining to ~$131/kWh	BEV prices based on battery pack price declining to ~$106/kWh
MPG	Low	Mid/High	Mid/High
Truck Range of Operation	Battery-electric range of operation is a constraint. Trucks are not included in the choice set if the range is insufficient for daily movement.	Battery-electric range of operation is a constraint. Trucks are not included in the choice set if the range is insufficient for daily movement.	Battery-electric range of operation is a constraint. Trucks are not included in the choice set if the range is insufficient for daily movement.
Station Cost/Time	Not Considered	Not Considered	Not Considered
	Forecast	**Forecast**	**Forecast**
Total ZEV stock 2030	**12,604**	**78,358**	**118,871**

Source: CEC *The incremental cost is the difference between the purchased truck and the least expensive truck in the class.

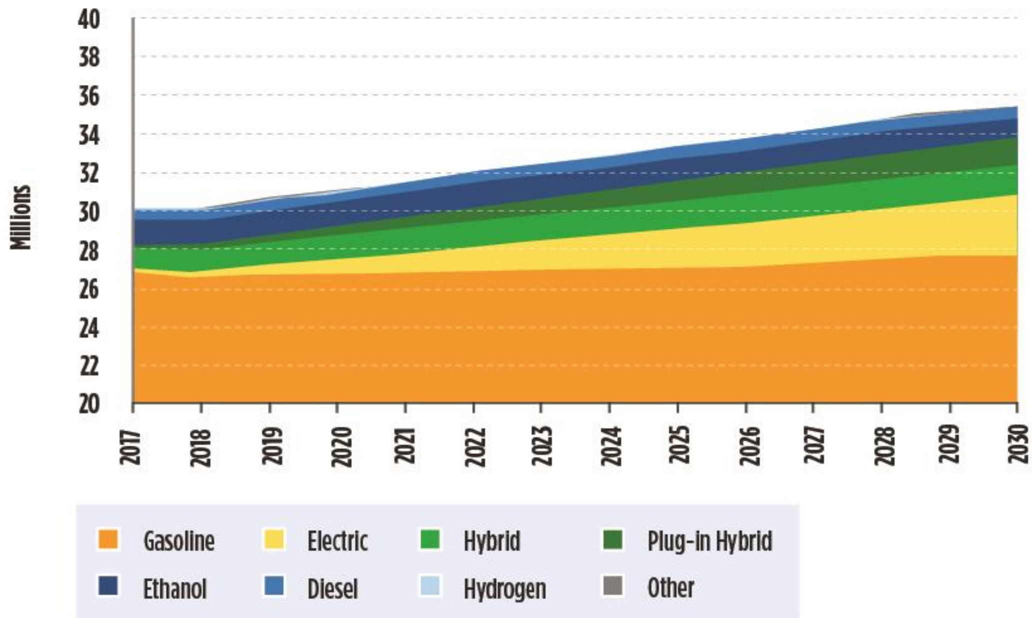
Forecast Results

Using the projected inputs and assumptions in the suite of transportation demand models, CEC staff developed a forecast for LD, MD, and HD vehicles and the associated transportation energy demand.

LDV Population Forecast

The LDV demand forecast indicates significant market penetration by plug-in EVs. Through 2018, there were about 500,000 LD ZEVs on the road in California, and the CEC forecasts more than 3.6 million by 2030 in the mid case. Figure 40 shows that the high-demand case is even more optimistic for ZEV population growth, with more than 4.4million by 2030. The aggressive and bookend cases forecast 5.2 million and 5.5 million ZEVs, respectively, in 2030.

Figure 40: Revised Forecast of LDV Population by Fuel Type, High Case



Source: CEC

MD and HD Vehicle Demand Forecast

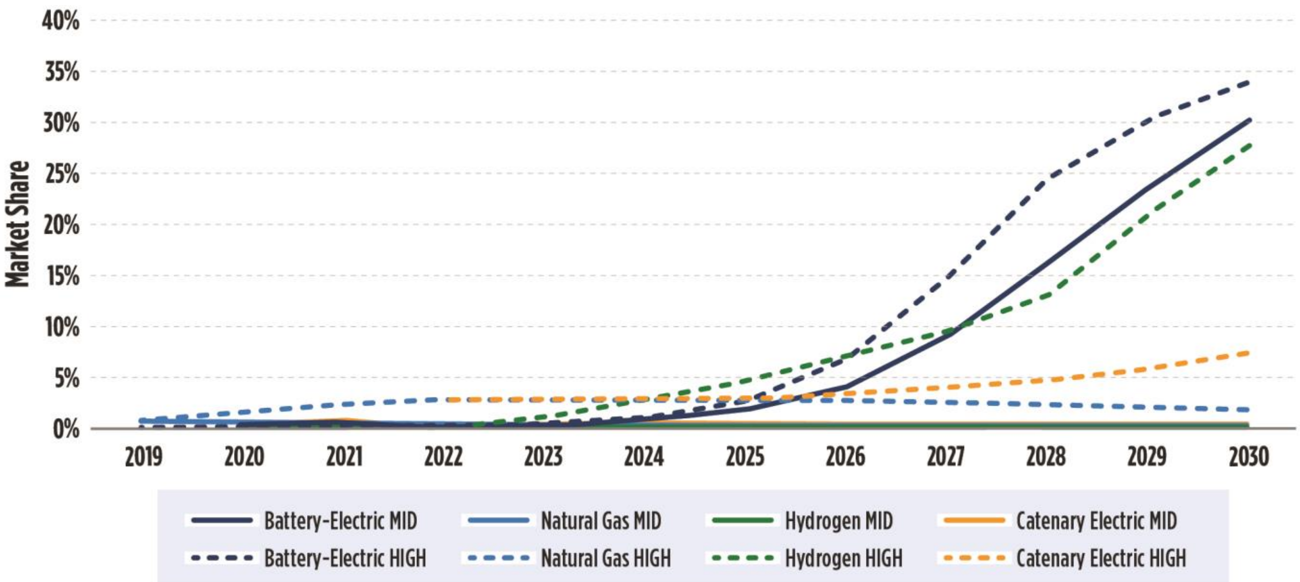
Results from the forecast show an expansion of alternative fuel and advanced technology vehicles among trucks and buses, assisted by the Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project (HVIP) and CARB clean transit regulation.[512] As an example, Figure 41 highlights the growth of battery-electric, catenary-electric, hydrogen fuel cell, and natural gas Class 8 (tractor-trailer) truck market share in the mid- and high-demand cases. Battery-electric achieves 34 percent share in 2030 in the high-demand case and 30 percent in the mid-demand case. Catenary-electric, natural gas, and hydrogen show little penetration in the mid

512 CARB and CALSTART partnered to offer incentives to accelerate the purchase of cleaner and more efficient trucks and buses. Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project https://www.californiahvip.org/.

CARB's proposed Advanced Clean Trucks regulation is not yet finalized as of the time this forecast was being developed; therefore staff has not incorporated this into the MD and HD forecast. Staff is tracking this regulation and will incorporate it into future forecasts.

case. Hydrogen fuel cell trucks achieve 28 percent penetration in the high-demand case, with a dedicated fleet price after 2021 for renewable hydrogen of $6.50 per kg.

Figure 41: Market Share Forecast of the In-State, New Class 8 Truck Sales by Alternative Fuel Type (Incentivized*)

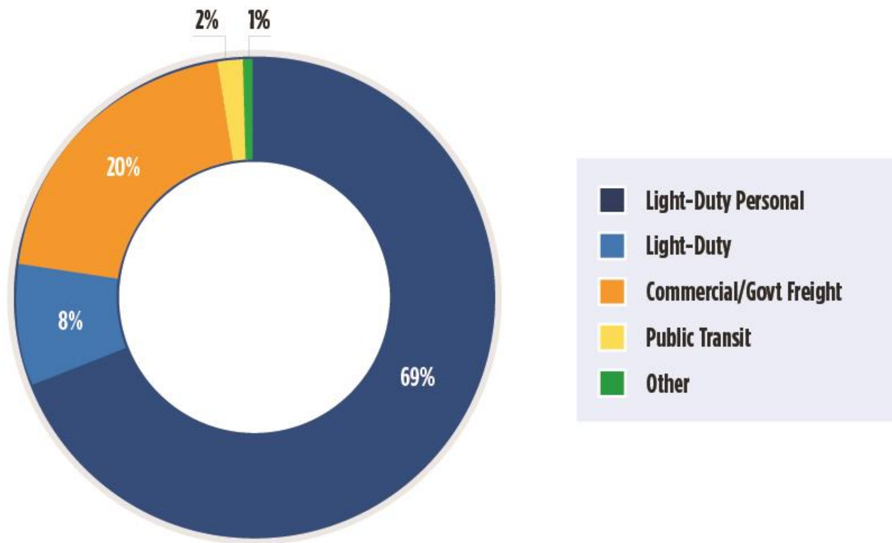


Source: CEC *Catenary electric trucks are not offered incentives

Forecast of Transportation Energy Demand

Energy demand by sector is the primary product of the transportation demand forecast. Figure 42 shows the forecast distribution of total on-road and rail energy consumption in different transportation segments in 2030. LDVs represent 77 percent of on-road transportation energy demand in California, while freight accounts for 20 percent.

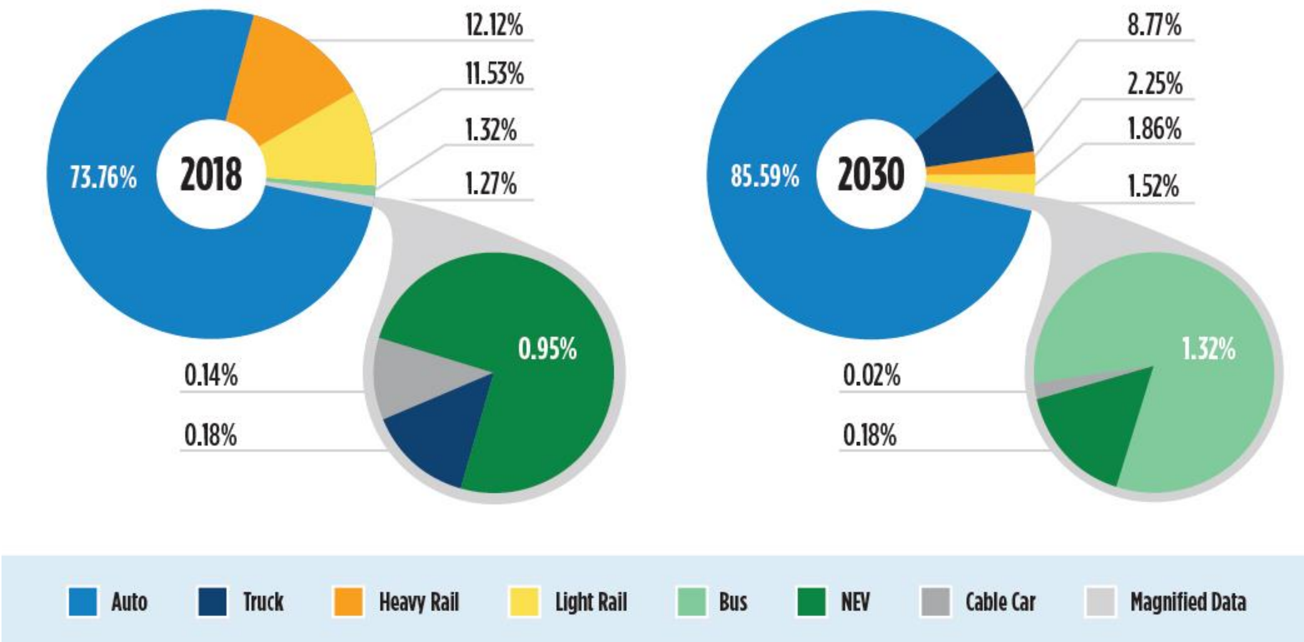
Figure 42: Forecast of 2030 Total On-Road Energy Consumption by Transportation Segment, Mid Case



Source: CEC (*On-road* includes rail energy demand, but excludes aviation energy demand as well as motorcycles and off-road transportation energy demand.)

As the amount of alternative fuel consumed within the transportation sector grows, the role of the transportation sector in the broader electricity demand forecast becomes increasingly relevant. Figure 43 shows the changes in distribution of transportation electricity consumption by vehicle type, between 2018 and 2030, in the high-demand case.

Figure 43: Distribution of Transportation Electricity Consumption by Vehicle Type in 2018 and 2030, High Case



Source: CEC. Note: NEVs are neighborhood electric vehicles (for example, golf carts).

Emerging Trends

CEC staff is considering ways to better incorporate emerging transportation trends in future transportation forecasts. These trends are related to the implementation of Senate Bill 375 (Steinberg, Chapter 728, Statutes of 2008), Senate Bill 1014 (Skinner, Chapter 369, Statutes of 2018), and the 3 Revolutions[513] (electrification, autonomy, and mobility as a service) that were discussed at a workshop September 26, 2019.[514]

513 Link to the 3 Revolutions Future Mobility Program website https://3rev.ucdavis.edu/.

514 Link to presentations from the September 26, 2019, IEPR workshop on Emerging Trends for the California Energy Demand Forecast https://www.energy.ca.gov/2019_energypolicy/documents/2019-09-26_workshop/2019-09-26_presentations.php.

SB 375 requires regional transportation plans to adopt a sustainable community strategy (for example, walkable and bike-friendly neighborhoods near transit) that will reduce GHG emissions from vehicles by reducing VMT.

SB 1014, also known as the Clean Miles Standard, directs CARB and the CPUC to develop and implement GHG reduction targets for transportation network companies (TNCs) starting in January 2023. The targets will be based on GHG emissions per passenger mile and can be met by increasing pooling passengers and the number of ZEVs in the TNC fleet.

The 3 Revolutions (3R) of electrification, autonomy, and mobility as a service will also affect transportation fuel consumption. It is challenging to forecast the potential effect since fully autonomous vehicles are not yet market-ready and data on mobility as a service are limited. Moreover, the effects will be based largely on consumer decisions and behavior. For example, widespread adoption of ridesharing using electric autonomous vehicles could decrease VMT, transportation fuel consumption, and emissions. Conversely, if autonomous gasoline vehicles are used by individuals riding alone or if vehicles frequently travel unoccupied between drop-off and pick-up locations, then VMT, fuel consumption, and emissions could increase. There are also other considerations around how future policies, incentives, or partnerships could influence transportation options and decisions. For example, partnerships between TNCs and regional transit agencies where TNC trip costs are subsidized when the rider is connecting to transit could decrease reliance on personal vehicles and VMT. The 3R could have a potentially significant effect on the transportation forecast, so it is important for the CEC to stay engaged with partner agencies and organizations as technologies, incentives, collaborations, and policies evolve.[515] Staff plans to expand on these discussions.

Recommendations

The California Energy Commission (CEC) offers the following recommendations to consider for future assessments of transportation energy demand.

- **Continue assessing progress toward state goals and assessing transportation market trends.** In collaboration with other agencies, the CEC should continue monitoring which emerging market trends and policies are succeeding in the transportation sector. The CEC should continue to conduct the California Vehicle Survey to ensure consumer preferences used in the forecast reflect the rapidly changing vehicle

515 The public can follow the proceeding, participate in the workshops, provide comments on the reports, follow comments in the dockets, access workshop presentations and recordings on the CEC website, and access DAWG presentations online. http://dawg.energy.ca.gov/.

market. The CEC should also continue to track changes to vehicle attributes. In particular, the zero-emission vehicle market is continuously evolving, and staff should monitor fuel cell and battery prices and efficiency improvements.

- **Assess how time-of-use electricity rates and charging infrastructure availability affect the plug-in electric vehicle forecast.** Compared to other transportation fuels, electricity cannot easily be stored over time. As a result, the timing and location of electricity demand by plug-in electric vehicles are also a key element of incorporating the transportation sector into the larger electricity demand forecast. The CEC continues to work with partner agencies and organizations to determine the current charging patterns of electric vehicles, and assess how the evolving vehicle grid integration technologies might help address other state goals. For instance, utilities can set rates or develop programs for this new electricity load to reshape hourly load curves in ways that better use existing renewable energy production and promote grid stability.
- **Expand scope of data and models to respond to the evolving transportation sector.** The transportation sector has been and will continue to keep changing rapidly, requiring frequent updates to forecasting methods to incorporate new technologies and new ways that transportation is used. For example, CEC staff is considering how ridesharing and autonomous vehicles will influence vehicle miles traveled. There are limited data from transportation network companies, but more comprehensive data would improve the forecast of vehicle miles traveled by fuel type.
- **Leverage the transportation energy demand forecasting models to assess zero-emission transportation policies.** The CEC's forecast data and models can be useful in assessing clean transportation policies that improve air quality and reduce greenhouse gas emissions. For example, the models can be used to assess the effect of state incentive levels or time-of-use electricity prices on the adoption rates of zero-emission vehicles. CEC staff will be proactive in conducting analyses that inform current, proposed, and innovative transportation policies.

CHAPTER 9: Natural Gas Assessment

Introduction

This chapter reviews market trends and provides updates on natural gas supply and production, consumption, and infrastructure on national and state levels. It also provides the California Energy Commission's (CEC's) natural gas price projections for the continental United States and California from 2019 to 2030. A recurring theme of the chapter is the potential effect that recently enacted clean energy and decarbonization policies in the state may have on California's fossil natural gas use and consumption in the short and long terms. An overview of the two major gas utilities provides updates on pipelines, storage, and reliability concerns. In addition, this chapter assesses natural gas trends in Canada and Mexico and provides data on natural gas imports and exports and the potential effect on California (including liquefied natural gas).

Key findings and recommendations include the following:

- On a national level, staff expects Henry Hub[516] natural gas prices to remain below $3.50 per Mcf through 2030 and below $5.00 Mcf through 2050. Statewide, staff expects the natural gas wholesale border price average to remain below $3.50 Mcf through 2030 and below $4.00 Mcf through 2050. Furthermore, staff expects the average natural gas citygate[517] price to remain just below $4.00 Mcf through 2030 and below $4.50 Mcf through 2050.
- California will continue to rely on out-of-state natural gas imports for roughly 85 percent to 90 percent of its supply as in-state production continues to decline.
- The transition to cleaner energy sources will result in declining fossil natural gas consumption in California over the next few decades.
- The use of renewable natural gas (RNG) in the transportation sector is likely to grow due to the Low Carbon Fuel Standard (LCFS) and state-funded research and development that promotes the use of RNG in the transportation sector.

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516 "Henry Hub" is a pipeline hub on the Louisiana Gulf Coast. It is the delivery point for the natural gas futures contract on the New York Mercantile Exchange (NYMEX).

517 The point where gas leaves the backbone transportation system for the local transmission and distribution system.

- Current estimates of in-state RNG indicate the quantity is not sufficient to meet emissions reduction goals of 80 percent below 1990 levels by 2050. However, the amount of RNG coming from outside the state is increasing due to the financial incentives being provided by the LCFS.
- California should initiate a planning process to identify short- and long-term natural gas needs as part of the state's transitions to cleaner energy sources.
- California will need to address aging natural gas infrastructure and the costs to maintain it as the state transitions to electrification and zero-carbon resources.
- California's natural gas system could be used for transporting alternatives to fossil natural gas, such as RNG and hydrogen.

Hydrogen is cleaner to burn than methane and, if mixed with natural gas for transport via pipeline, can modestly reduce methane leakage. Under Senate Bill 100 (De León, Chapter 310, Statutes of 2018), it is the policy of the state for eligible renewable energy and zero-carbon resources to supply 100 percent of retail sales of electricity to California customers (and 100 percent of electricity procured to serve all state agencies) by December 31, 2045. This policy—along with building electrification, electric vehicle adoption, the Renewables Portfolio Standard (RPS), and increased use of renewable natural gas—sets the stage for a decrease in fossil natural gas use in California.[518] As such, the expectation is that natural gas production and consumption will continue to decline in the state over the next few decades. Whatever the trajectory, the CEC will continue to provide a biennial natural gas market outlook on trends and issues that could affect the state.

In California, natural gas plays an important role in space heating, oil refining, industrial processes, cooking, electricity generation, and grid reliability. The CEC tracks trends and issues associated with natural gas infrastructure, including natural gas pipeline flows, storage injections and withdrawals, maintenance events and outages, and regulatory proceedings. The CEC analyzes how these trends affect prices, supply (including in-state production), out-of-state deliveries, and demand (particularly by power plants). In addition to tracking trends, the CEC looks ahead by producing a forecast of natural gas prices at key trading hubs.[519]

In California, market trends are signaling the start of a transition away from natural gas as the state's primary electricity source. For example, in the electricity sector, as renewable resource

518 There may be industrial uses of natural gas as a chemical feedstock, rather than an energy source, in commercially important organic chemicals or processes for which it may be difficult to find substitutes.

519 A "natural gas hub" is a central pricing point for natural gas usually at the heart of natural gas infrastructure such as pipelines and LNG hubs.

prices have dramatically dropped, particularly for solar photovoltaic (PV), in-state solar generation increased by 12 percent between 2017 and 2018.[520] California also is looking to retire aging coastal natural gas plants that use ocean water for cooling. These retirements were previously scheduled for 2020, but the California Public Utilities Commission (CPUC) recently recommended a delay due to reliability concerns. (See Chapter 6 for more information.) Some of this capacity will be replaced by imported gas-fired generation, but renewables, transmission upgrades, and energy storage will replace the remainder as part of the strategy to meet air quality goals and reduce GHG emissions. California is also the first state to require rooftop solar on new homes under new building standards that went into effect on January 1, 2020. Moreover, building electrification is a key strategy for the state's residential and commercial building stock to meet new requirements calling for GHG reductions from buildings to 40 percent below 1990 levels by January 1, 2030.[521] (See Chapter 2 for more information.)

As the state reduces reliance on fossil natural gas, it must ensure a safe natural gas system while minimizing environmental impacts associated with natural gas infrastructure, including methane leakage. In addition, implementing the most cost-effective uses of renewable natural gas—including for transportation—will require research and development. To prepare California for the energy system of the future, the CEC is collaborating with state and federal agencies, utilities, private industry, and other stakeholders to develop:

- Natural gas vehicle technologies and infrastructure.
- Low-carbon fuels such as renewable natural gas and hydrogen.
- Technologies to track and account for methane emissions.
- Technologies that aim to enhance the safety and reduce the environmental impact of the natural gas system.

The CEC's Energy Research and Development Division is also assessing pathways to the decarbonizing the energy system, as detailed in Chapter 1. Through the Electric Program Investment Charge (EPIC) program, the CEC funded a study that evaluates deep decarbonization scenarios in California for the 2030 and 2050 time frames. The study was published in June 2018 and provides results from a model that developed 11 long-term energy scenarios to examine the amount of GHG reductions possible with a variety of technologies

520 CEC, Energy Almanac, Total System Electric Generation database, https://www.energy.ca.gov/almanac/electricity_data/total_system_power.html.

521 Assembly Bill 3232 (Friedman, Chapter 373, Statutes of 2018).

and mitigation strategies.[522] A major focal point of the study is the strategy of "high electrification" that includes, among other clean energy goals, a high rate of electrification in buildings. This scenario predicts a dramatic reduction in natural gas demand at the distribution level, yet it raises concerns regarding reliability and economic impacts.

A publication released in September 2019 by Gridworks references the E3 study and urges the state to initiate an integrated, interagency long-term transition plan for the state's gas system with the goal of minimizing costs and risks for all.[523] Furthermore, the Southern California Edison study, Pathway 2045 estimates that a small number of gas generators will still be necessary in the future for grid reliability. The study also asserts that at least 40 percent of the remaining gas in 2045 will need to be low-carbon fuels such as biomethane or hydrogen.[524] Finally, Lawrence Livermore National Laboratory released a report in January 2020 detailing three pathways California could take to achieve carbon neutrality by 2045 (1) increase the uptake of carbon in its natural and working lands, (2) convert waste biomass into fuels and store carbon dioxide emissions associated with fuel processing, and (3) remove carbon dioxide directly from the atmosphere with purpose-built machines. [525]

In addition, the CPUC initiated a process to prepare for the decline in natural gas and the state's transition to other energy sources. On January 6, 2020, the CPUC posted a draft OIR on natural gas reliability and long-term planning. The CPUC approved the OIR on January 16, 2020. The CEC will be coordinating with the CPUC during this process.

In addition, this chapter includes CEC proposals for future analysis in these areas. Finally, Assembly Bill 1257 (Bocanegra, Chapter 749, Statutes of 2013) requires the CEC to identify strategies that maximize the benefits of natural gas. Appendix A of this report addresses these

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522 Energy and Environmental Economics (E3) produced the study, *Deep Decarbonization in a High Renewables Future*, https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf.

523 Gridworks, *California's Gas System in Transition*, https://gridworks.org/wp-content/uploads/2019/09/CA_Gas_System_in_Transition.pdf.

524 Southern California Edison, "Pathway 2045," November 2019, https://newsroom.edison.com/internal_redirect/cms.ipressroom.com.s3.amazonaws.com/166/files/201910/201911-pathway-to-2045-white-paper.pdf.

525 Lawrence Livermore National Laboratory, Getting to Neutral: Options for Negative Carbon Emissions in California, January 2020, https://www-gs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdf.

requirements and references other chapters for more information regarding strategies or actions relating to natural gas.[526]

Natural Gas Price Outlook

CEC staff uses the North American Market Gas-Trade model (NAMGas) to simulate the economic behavior of natural gas producers in supply basins and natural gas consumers in demand centers. The structure of the model includes representations of intrastate and interstate pipelines, liquefied natural gas (LNG), import and export centers, and other infrastructure.

The model encompasses regions of the continental United States, as well as Canada and Mexico. Staff developed three "common" cases for the 2019 Integrated Energy Policy Report (IEPR)—high demand, mid demand, and low demand—using inputs and assumptions that will affect the natural gas market. These inputs and assumptions include the effect of increased energy efficiency, renewable generation growth under the state's RPS, and varying amounts of coal-fired electrical generation retirements on demand for natural gas. Values for proved and potential reserves in North America appear on the supply side of the NAMGas model.[527]

The model projects prices and supply of natural gas for California and the continental United States for 2019 through 2030.[528] In recent years, natural gas prices have been low. Staff calculated that after accounting for inflation, prices dropped an average of 6.7 percent per year between 2010 through 2016. The development of shale-deposited natural gas accounts for much of the lowering of real prices.[529] Assuming current trends in shale gas production, in the mid-demand forecast, the model estimates that the Henry Hub price for 2019 will be $2.66

526 This legislation states, "Beginning November 1, 2015, and every four years thereafter, the commission shall, with the integrated energy policy report prepared pursuant to Section 25302, identify strategies to maximize the benefits obtained from natural gas, including biomethane for purposes of this section, as an energy source, helping the state realize the environmental and cost benefits afforded by natural gas."

527 In general, the gas industry categorizes reserves as either proved or potential, and the natural gas resource base consists of proved plus potential reserves. "Proved reserves" tend to have a high degree of recovery certainty. Production of potential reserves is more costly and recovery tends to be less certain.

528 The NAMGas model provides estimates through 2050. However, staff publishes projections only through 2030 to maintain consistency with the CEC's demand forecast and PLEXOS electricity dispatch modeling.

529 Inflation adjusted.

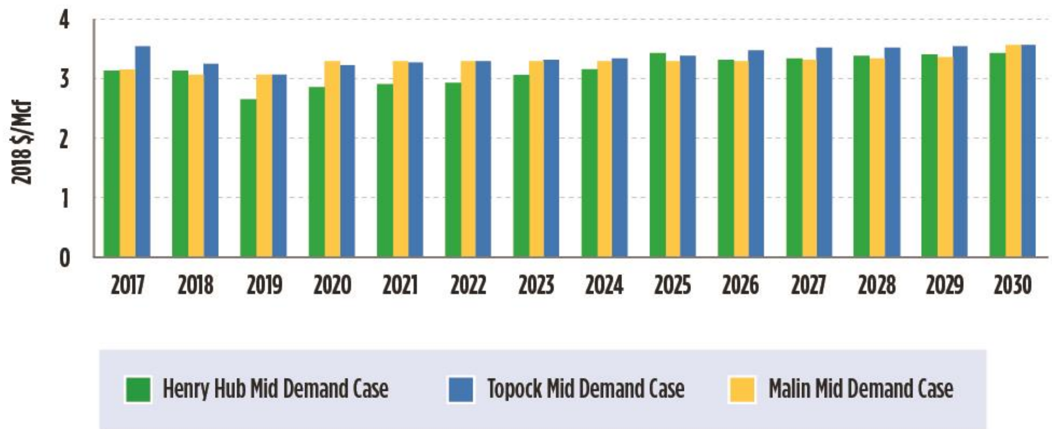
(2018 $) per thousand cubic feet (Mcf).[530] Prices are expected to rise at about 2.37 percent per year between 2019 and 2030 to $3.42 Mcf.

North American natural gas supply is assumed to remain abundant for several generations to come, despite continued low prices. The implementation of technology is driving production costs lower and allowing producers to operate economically in the low-price environment the market is experiencing. This trend, along with high amounts of associated gas production in the Permian Basin and the Bakken Shale (North Dakota), are leading to projections of inflation-adjusted natural gas spot prices at Henry Hub remaining below $5 (2018$)/Mcf until 2050. The CEC will need to assess production data for shale gas on an ongoing basis to determine the long-term availability of supplies, since this resource is a relatively recent development.

Figure 44 shows the forecasted mid-case demand prices (2018–2030) for Henry Hub and the Malin and Topock hubs. The Malin and Topock hubs are at the state line and represent key trading locations into California. Prices at Henry Hub are lower than Malin and Topock in 2019; however, Henry Hub becomes higher than Malin in 2026 and higher than Topock in 2035. This decrease is due to low production costs of natural gas in the Permian, Rockies, San Juan, and Western Canadian sedimentary basins.

530 "Henry Hub" is a pipeline hub on the Louisiana Gulf Coast. It is significant as the delivery point for the natural gas futures contract on the New York Mercantile Exchange (NYMEX). Link to definition of Henry Hub on U.S. EIA's website https://www.eia.gov/tools/glossary/index.php?id=H.

Figure 44: Mid-Demand Case Prices for Henry, Topock, and Malin Hubs



Source: CEC staff

For California, staff assumed that pipeline capacities for interstate and intrastate lines that deliver to California would not change during the forecasted period. As such, the model shows that California's natural gas supply portfolio—the production basins (Western Canada, Rocky Mountains, San Juan, and Permian Basins) that supply California—will not change from 2018 to 2030. Staff assumed that pipeline capacities for interstate lines and intrastate lines would not increase.[531] Much of California's in-state natural gas production comes from existing resources in the Central Valley, and the model projects that production from those resources will decline over time.

The full results of the modeling efforts, method and the calculations appear in the 2019 Natural Gas Market Trends and Outlook Report.[532]

531 Interstate pipelines cross state borders and deliver natural gas to California and intrastate pipelines do not cross state borders and deliver gas within the state.

532 CEC 2019. *2019 Natural Gas Market Trends and Outlook Report,* https://www.google.com/search?sxsrf=ACYBGNQKXmkeD2ct_2i9WLtwM_gIP-ciAA%3A1579800147756&ei=U9YpXqrmLbTR9APB0ab4BA&q=California+Energy+Commission+2019+Natural+Gas+Market+Trends+and+Outlook+Report.&oq=California+Energy+Commission+2019+Natural+Gas+Market+Trends+and+Outlook+Report.&gs_l=psy-ab.3...16381.20853..21998...0.2..2.611.3717.18j3j2j2j0j1......0....1..gws-

Natural Gas Supply and Production

United States

Natural gas reserves have increased in the United States largely due to shale gas development.[533] The Potential Gas Committee is a group of industry experts (organized by the Colorado School of Mines) who compile estimates of natural gas reserves for the United States. In 2004, it published an estimate of total U.S. natural gas reserves of 1,311.8 trillion cubic feet (Tcf). The resource base expanded at an average rate of 7.5 percent per year and, by 2016, total natural gas reserves reached 3,141.0 Tcf. At current consumption levels in the United States, this translates into a reserve life index of about 125 years.[534]

Since 2005, U.S. natural gas production has been growing at an annual rate of about 4.1 percent, and since 2009, the United States has been the world's largest producer of natural gas.[535] In 2018, production averaged about 83,400 million cubic feet per day (MMcfd). Figure 45 displays U.S. dry natural gas (equivalent) production relative to consumption between 2000 and 2018. Since 2011, natural gas production has outpaced natural gas consumption.

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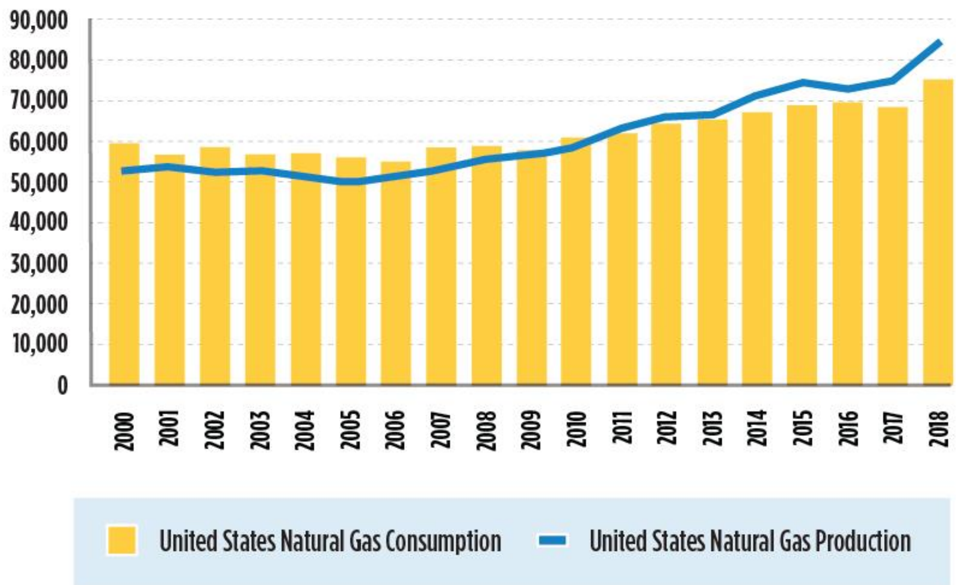
wiz.......0i71j33i10.aT99vuCEVJE&ved=0ahUKEwjq2_2UnprnAhW0KH0KHcGoCU8Q4dUDCAo&uact=5#spf=1579800170854.

533 The combination of hydraulic fracturing and horizontal drilling in the United States has significantly increased the production of natural gas, particularly from tight oil formations.

534 "Reserve life index" is the total natural gas reserves divided by current consumption. This number represents a broad approximation of the life of natural gas reserves within a jurisdiction and does not include due to less favorable economics and reservoirs that are less susceptible to increased production via hydraulic fracturing, imports, or exports of natural gas.

535 Link to information on the U.S. EIA's website about U.S. petroleum and natural gas production, https://www.eia.gov/todayinenergy/detail.php?id=36292.

Figure 45: United States Dry Natural Gas Production and Annual Consumption



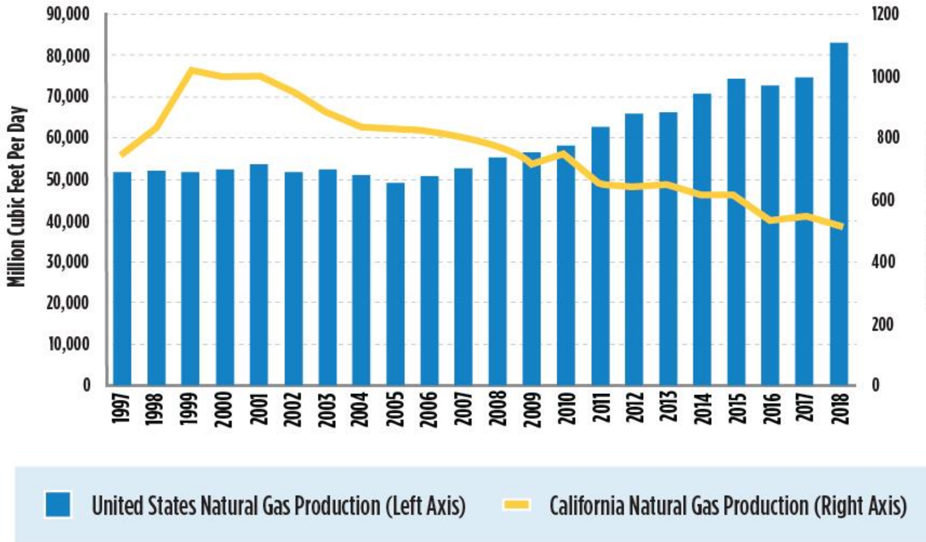
Source: U.S. Energy Information Administration (U.S. EIA)

In 2018, the production of natural gas from shale formations (reservoir pools) provided about 66 percent of U.S. natural gas production. This growth has created opportunities for increased U.S. exports by pipeline and LNG shipments, and in 2017, the United States became a net exporter of natural gas. The national natural gas supply-demand balance, as it stands, shows enough supply from U.S. natural gas production, pipeline imports from Canada, and LNG imports to satisfy U.S. domestic consumption/demand, pipeline exports to Mexico, and LNG exports.

California

California's in-state natural gas production, much of which comes from geologic basins in the Central Valley, will continue to decline because of less favorable economics and reservoirs that are less susceptible to increased production via hydraulic fracturing. In 2017, in-state sources provided about 548 MMcfd, or 10 percent, of the natural gas consumed in California, while interstate pipeline shipments satisfied the remaining 90 percent. Figure 46 shows California's natural gas production as compared to the rest of the United States between 2000 and 2018.

Figure 46: California Natural Gas Production Versus the Rest of the United States



Sources: U.S. EIA and California Division of Oil, Gas, and Geothermal Resources (DOGGR)

Most of California's out-of-state supply comes from the Western Canadian Sedimentary Basin (Alberta and British Columbia, Canada), Permian Basin (west Texas and southwestern New Mexico), San Juan Basin (northwestern New Mexico and southwestern Colorado), and Rocky Mountains (Wyoming). Concerns over greenhouse gas (GHG) emissions associated with these imports led to the passage of Assembly Bill 2195 (Chau, Chapter 371, Statutes of 2018), which requires the California Air Resources Board (CARB) to establish an out-of-state emissions tracking system.

Starting January 1, 2020, CARB will annually publish the amount of GHG emissions resulting from the loss or release of uncombusted natural gas and emissions from natural gas flares associated with the production, processing, and transporting of natural gas imported into the state from out-of-state sources.[536]

536 Assembly Bill 2195 (Chau, Chapter 371, Statutes of 2018).

Canada

The oil and gas industry in Canada has implemented many of the same technological innovations seen in the United States. Since 2012, natural gas production has been growing at a rate of 2.5 percent per year, reaching an average of 16,154 Mmcfd in 2018. In addition, the Canadian Association of Petroleum Producers estimates that the country has about 1,225 Tcf of natural gas reserves, signaling a reserves life index of about 300 years. Natural gas satisfies one-third of Canada’s energy requirements. The growth in natural gas production, along with the size of reserves, supports the country’s exports to the United States, which averaged about 7,800 Mmcfd in 2018.

Mexico

Mexico produced about 4,500 Mmcfd in 2014, but this amount declined to an estimated 3,800 Mmcfd in 2017.[537] The country has a vast amount of proved reserves, ranging between 200 and 280 Tcf.[538] Potential reserves exceed 545 Tcf.[539] Yet, the development of the country’s natural gas resources lags behind that of the United States and Canada because Mexico has not implemented the technical innovations realized in the rest of North America. As a result, over the last five years, Mexico’s natural gas production has been falling, and the need for imports is rising.

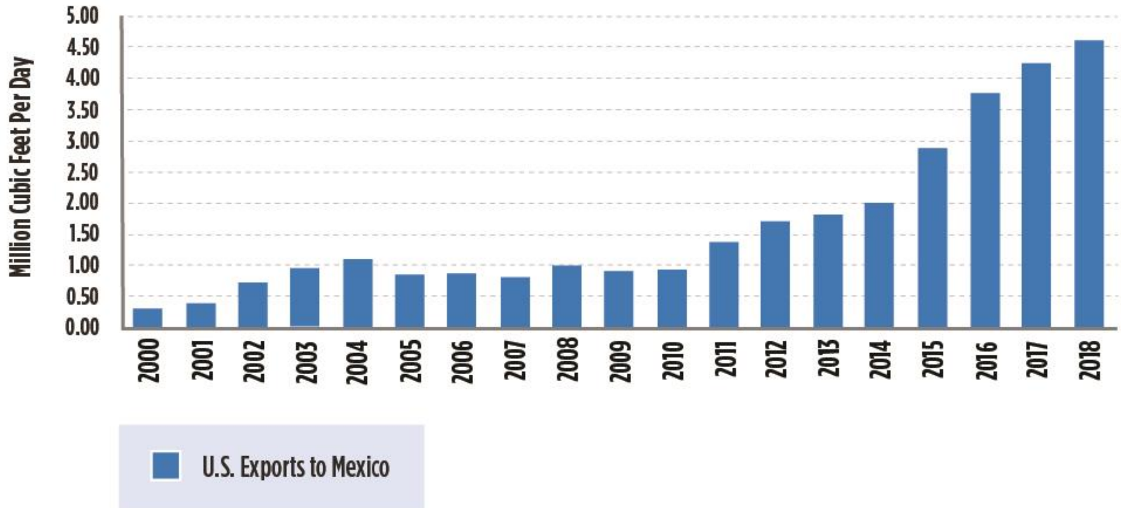
In 2010, shipments from the United States to Mexico averaged less than 1 Bcf/d. Since then, pipeline shipments to Mexico have been expanding at an annualized rate of 22.5 percent as Mexico’s natural gas demand has increased for power generation and industrial use. By 2018, shipment volumes exceeded 4.5 Bcf/d. As Mexico imports natural gas from the Permian Basin, increased demand there may reduce the volume of Permian Basin supply available to California. Figure 47 displays annual pipeline shipments to Mexico between 2000 and 2018.

537 Estimated from EIA production data.

538 Link to information on Mexico's petroleum production https://www.eia.gov/beta/international/analysis.php?iso=MEX. “Proved reserves” are those for which sufficient drilling has occurred that geologists are relatively certain the reserves can be produced.

539 “Potential reserves” are those that geologists believe exist but for which there remains uncertainty.

Figure 47: United States Pipeline Shipments to Mexico



Source: U.S. EIA

This growing export market has attracted investments in pipeline construction. Since early July, Mexico's President Andrés Manuel López Obrador has been negotiating contracts for seven natural gas pipeline systems that were in various stages of construction. In late August 2019, Mexico's president announced a deal that will allow natural gas deliveries to his country to increase.[540]

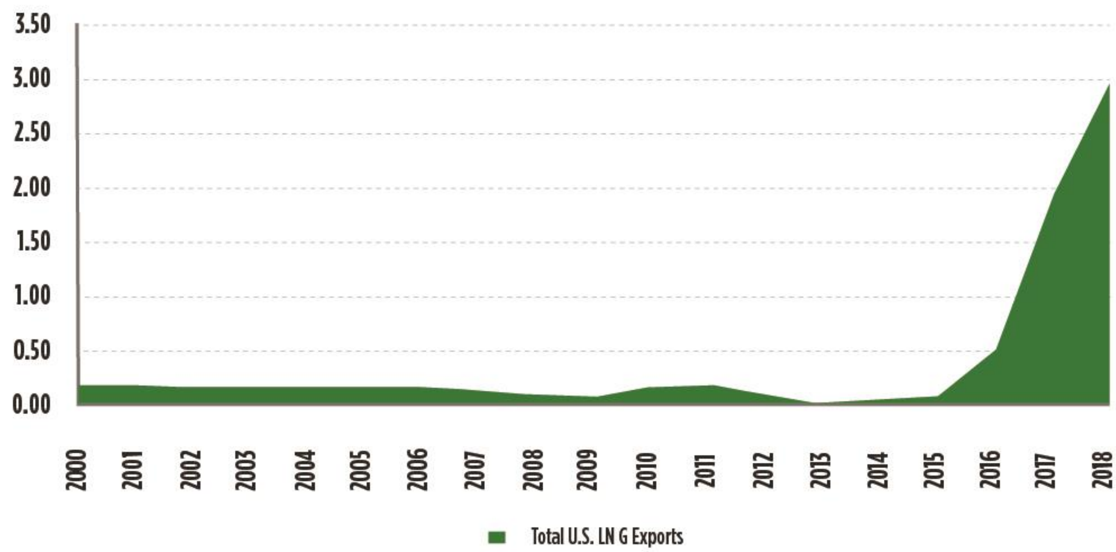
The imports from these pipelines will help Mexico meet its energy demands. Mexico has struggled to meet its energy demand requirements in several sectors, particularly in power generation, and the delays add uncertainty to its markets. More than 75 percent of feedstock in power generation originates from fossil energy (fuel oil and natural gas).

540 *The Wall Street Journal*, "Mexico Reaches Deal with Pipeline Operators on Gas Delivery Contracts" https://www.wsj.com/articles/mexico-reaches-deal-with-pipeline-operators-on-gas-delivery-contracts-11566916579.

North America LNG Exports

The growth in natural gas production in excess of domestic demand in the United States has resulted in the United States becoming a net exporter of LNG in 2018. Demand from other countries because of rapid growth in natural gas consumption is driving demand for U.S. LNG exports. With new LNG export facilities coming on-line in recent years, the amount of exports has grown rapidly. Between 2000 and 2015, U.S. LNG exports averaged about 0.13 Bcf/d. Three new LNG facilities added between 2016 and 2018[541] brought total export capacity at the end of 2018 to 4.3 Bcf/d, while export volume reached almost 3.0 Bcf/d. As of 2019, there are more than 110 LNG plants in the United States.[542] Figure 48 displays the profile of LNG exports between 2000 and 2018.

Figure 48: Total United States LNG Exports



Source: U.S. EIA

541 Since 2016, Trains 1-5 of the Cheniere/Sabine Pass LNG facility in Sabine, Louisiana, the Dominion-Cove Point LNG facility in Cove Point, Maryland, and Train 1 of the Cheniere-Corpus Christi LNG facility in Corpus Christi, Texas, came on-line. [PowerPoint slide showing North American LNG export terminals](https://www.ferc.gov/industries/gas/indus-act/lng/lng-existing-export.pdf) https://www.ferc.gov/industries/gas/indus-act/lng/lng-existing-export.pdf.

542 FERC, LNG, [Link to information on LNG from the FERC website](https://www.ferc.gov/industries/gas/indus-act/lng.asp) https://www.ferc.gov/industries/gas/indus-act/lng.asp.

Shipments from the Sempra-Cameron LNG facility in Hackberry, Louisiana, began in June 2019. Sempra-Cameron LNG is the fourth new plant to come on-line since 2016, raising U.S. LNG export capacity to about 4.8 Bcf/d.[543] By the end of 2020, new export plants should push capacity to almost 9.0 Bcf/d.[544] Further, pipeline projects coming on-line between 2020 and 2022 to deliver natural gas to the Gulf Coast for LNG export will increase California's competition for Permian Basin natural gas. This chapter provides more information about these pipeline projects in the infrastructure section below.

In addition to the newly constructed LNG export plants on the Gulf Coast and Atlantic Ocean, there are proposals to construct facilities in Oregon; Baja California, Mexico; and British Columbia, Canada, to serve markets in Asia and the Pacific. These proposed facilities, if they export gas upon completion, would compete with California for natural gas supplies, as these plants would receive gas from the same natural gas supply basins that serve California.

Early in 2020, the Federal Energy Regulatory Commission (FERC) is expected to make a decision on the application for the proposed 1.08 Bcf/d Jordan Cove LNG export facility in Coos Bay, Oregon.[545] The project includes a 229-mile feeder pipeline that will bring natural gas from the Ruby and Gas Transmission Northwest pipelines in Malin, Oregon, to Coos Bay. Malin is near the border with California and Pacific Gas and Electric's (PG&E's) Redwood Path (Lines 400/401) and connects to the Ruby and Gas Transmission Northwest pipelines there. FERC accepted public comment until July 2019 on the draft environmental impact statement issued by FERC staff.

Across the U.S. border in Baja California, Mexico, Sempra announced in March 2019 that it received authorizations to export U.S.-produced natural gas to its Energía Costa Azul (Costa Azul) LNG facility near Ensenada. In addition, Sempra can re-export LNG from Costa Azul to countries that do not have a free-trade agreement with the United States. Adjacent to the existing Costa Azul import terminal, Sempra plans to construct a three-train export facility in two phases that will serve natural gas demand in Mexico and Asia.[546] Development of the

543 The Cameron LNG project is in southwest Louisiana. Link to Cameron LNG's website https://cameronlng.com/lng-import-export/.

544 Link to information on LNG facilities from the U.S. EIA's Web page, https://www.eia.gov/todayinenergy/detail.php?id=39312.

545 Final Environmental Impact Statement on FERC's Web page, https://www.ferc.gov/industries/gas/enviro/eis/2015/09-30-15-eis.asp.

546 An "LNG train" is a liquefaction and purification facility for an LNG plant, where clean feed gas is cooled using refrigerants. The liquefaction plant may consist of several parallel units arranged sequentially, which is why they are called LNG trains.

Costa Azul LNG export project is contingent upon obtaining binding customer commitments, permits (including additional export authorization from the Mexican and U.S. governments), financing, incentives and other factors, and reaching a final investment decision.

According to Natural Resources Canada, there are 13 proposed export terminals in British Columbia ranging in capacity from 0.3 Bcf/d to 4.3 Bcf/d.[547] These 13 proposed terminals have been issued export licenses.

Natural Gas Consumption/Demand

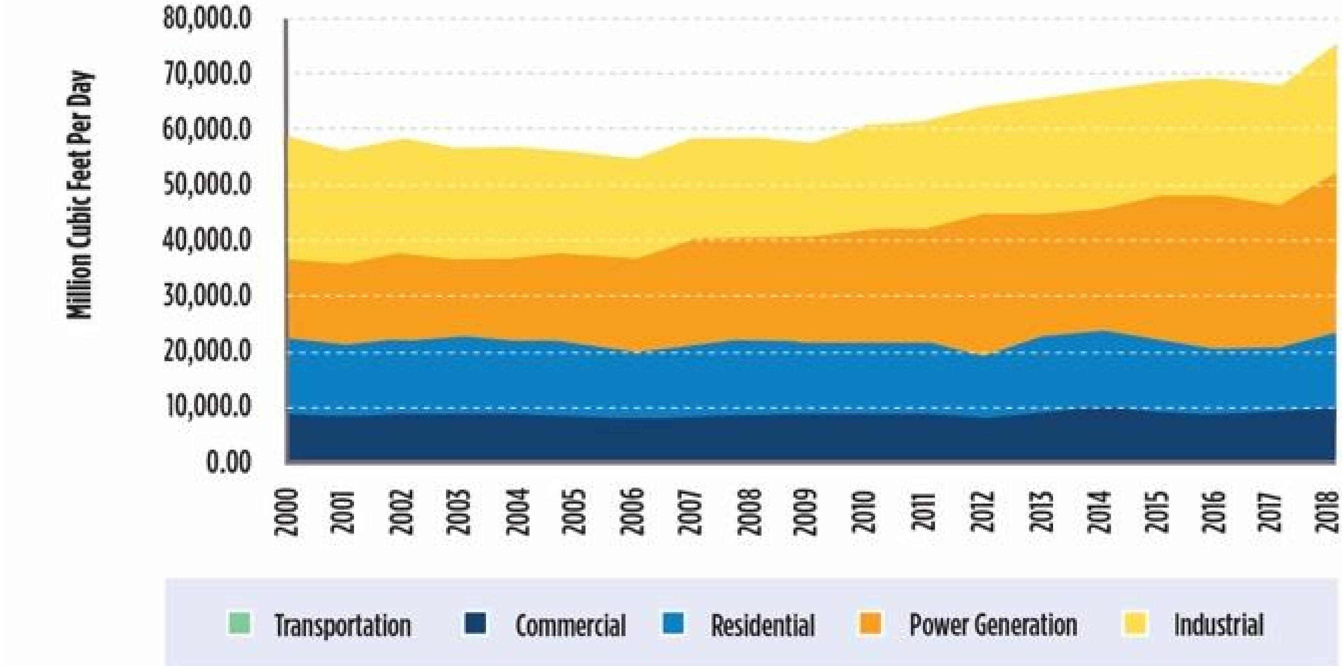
United States

Demand for natural gas in the United States has been growing at an annualized rate of 2.3 percent since 2005. In 2018, the five demand sectors of the United States consumed 27.4 Tcf (or an average of 75,087 Mmcfd).[548] Since 2005, demand from the residential and commercial sectors has remained flat. Most of the growth in natural gas demand originated in the industrial and power generation sectors. The share of natural gas usage in the transportation sector, while growing, reaches only about 0.2 percent of total U.S. consumption. Figure 49 shows U.S. natural gas consumption, segregated by sector, between 2000 and 2018.

547 Information on Canadian LNG Projects on the Natural Resources Canada website https://www.nrcan.gc.ca/energy/energy-sources-distribution/natural-gas/canadian-lng-projects/5683.

548 U.S. EIA. Natural Gas Monthly. Link to Natural Gas Monthly Report for June 2019 on the U.S. EIA's website, https://www.eia.gov/naturalgas/monthly/.

Figure 49: United States Natural Gas Consumption (All Sectors, 2000–2018)

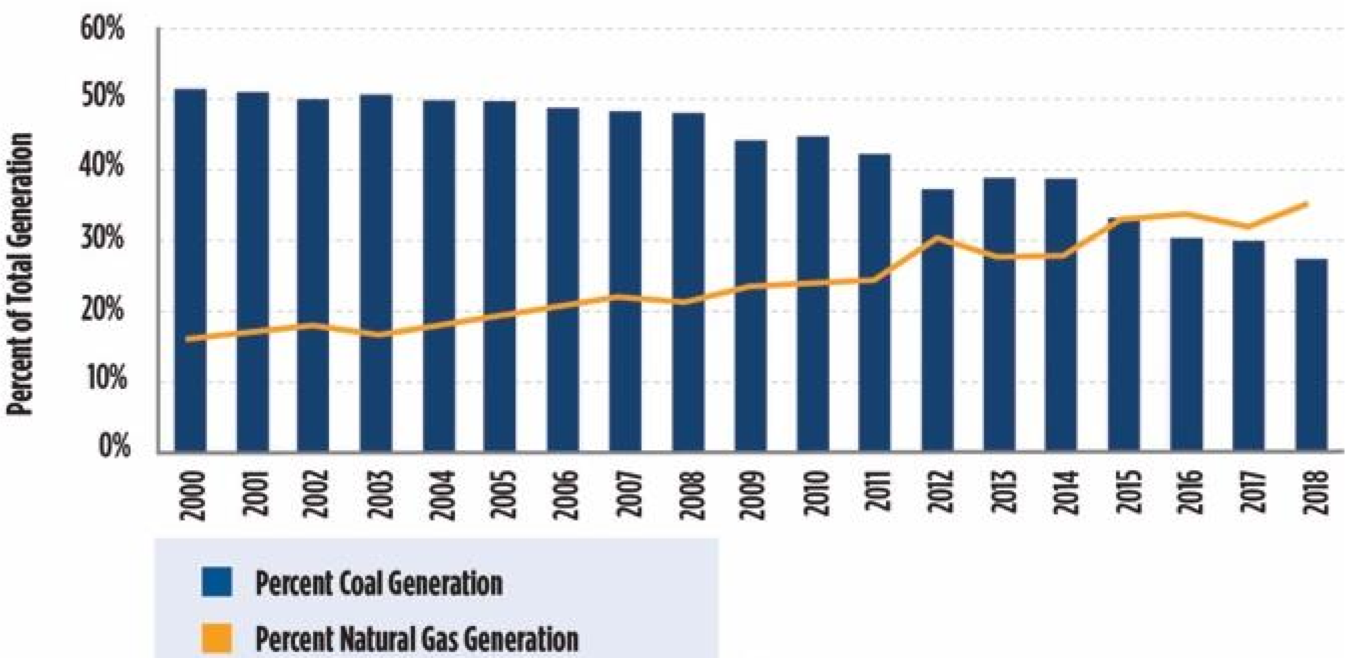


Source: U.S. EIA

The U.S. EIA projects that overall growth will continue at an annual rate of about 0.49 percent between 2018 and 2050. The growth in natural gas production and the lower-than-average prices seen in the last few years support the expanded usage of natural gas, particularly in the industrial and power generation sectors.

An ongoing trend outside California is the shift from coal-fired generation to natural gas. In 2005, coal-fired generation accounted for almost 50 percent of total generation and, in 2018, accounted for only about 27 percent of total generation, a continuation of the decline that started more than a decade prior. Low natural gas prices coupled with compliance with environmental regulations are transforming generation preferences. Coal-fired power plants are facing retirement, are undergoing retrofit, or may need to invest in expensive additional retrofits to remain operating. Lower-than-average natural gas prices are pushing plant owners and operators to replace the lost generation with natural gas-fired electric generation. Figure 50 displays the share of total generation by fuel type (coal and natural gas).

Figure 50: Share of Total Generation by Fuel Type (Coal and Natural Gas, 2000–2018)



Source: U.S. EIA

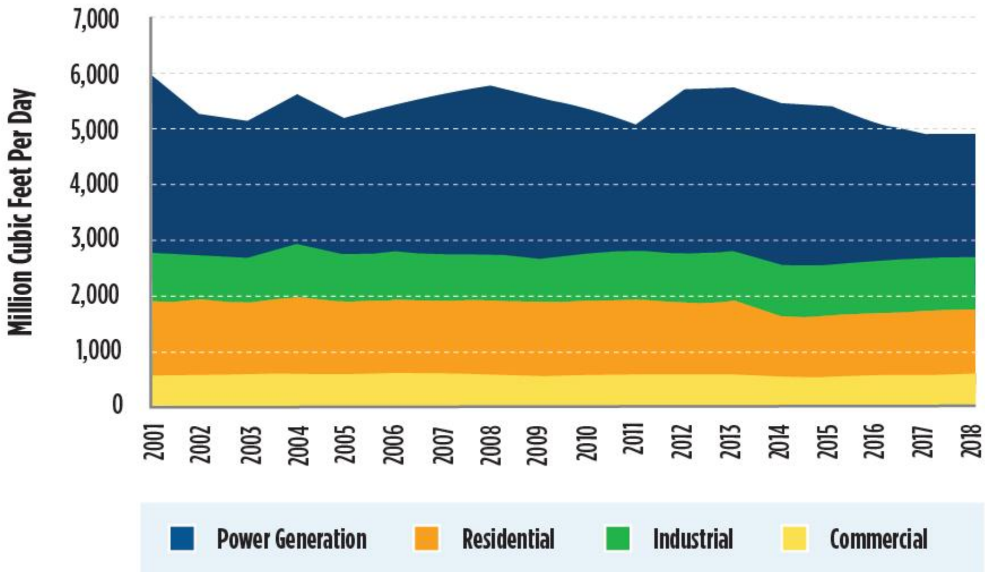
The U.S. EIA estimates that, by the end of 2017, plant operators had retired about 62 gigawatts of coal-fired generation. Natural gas-fired generation is filling the shortfall, climbing to 35.1 percent of total generation in 2018.

California

While natural gas demand is growing in most of the United States, California expects a decline because of policies such as Senate Bill 350 (De León, Chapter 547, Statutes of 2015) and SB 100. (See Chapter 1 for more discussion of SB 100.) Decarbonization strategies such as building electrification will reduce retail demand for fossil natural gas. Yet, in 2017 and 2018, natural gas was still the most consumed fuel or energy source in California. California's five end-use sectors—residential, commercial, industrial, transportation, and electric generation—consumed 1,799,292 MMcf (4,930 MMcfd average) of natural gas in 2018. Figure 51 displays California natural gas consumption for the four major consuming sectors between 2001 and 2018.[549]

549 The transportation sector accounts for only about 1 percent of consumption of natural gas, so Figures 51 and 52 do not show this sector.

Figure 51: California Natural Gas Consumption (All Sectors, 2000–2018)

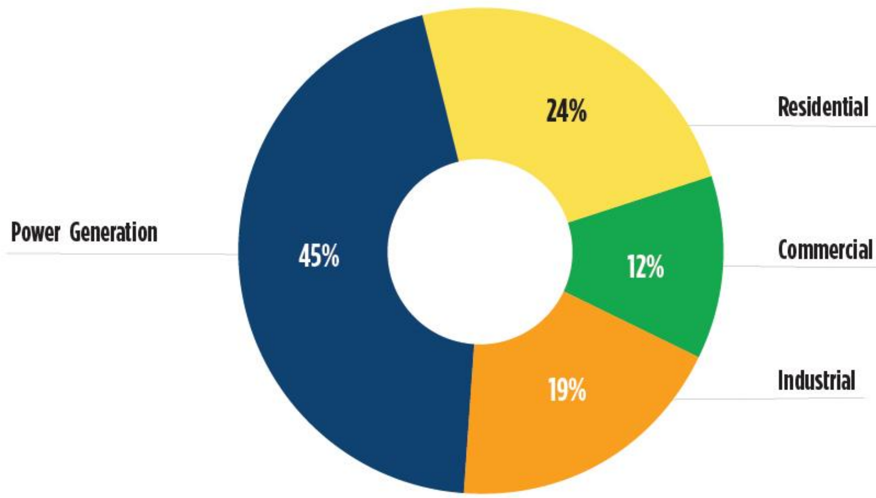


Source: CEC staff

The power generation sector comprises the largest share of the state's natural gas consumption at 45 percent. At 24 percent, the residential sector runs second. Figure 52 breaks down the percentage use by the power generation, residential, industrial, and commercial sectors.[550]

550 Based on CEC data.

Figure 52: Percentage Usage of Natural Gas by Sector in California (2018)



Source: CEC staff

As noted in the *2017 IEPR*, natural gas demand in the residential sector has experienced a slight yet continuous decline since 1990, while demand has been relatively flat in the commercial, industrial, and power generation sectors.[551] The CEC reports that in 2018, the power generation sector in California consumed 813,238 MMcf of natural gas—a slight increase from 2017.

Staff expects demand for RNG in the transportation sector to continue to grow throughout the forecast period. The LCFS, which is part of the Global Warming Solutions Act of 2006 (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006), aims to reduce transportation carbon intensity 20 percent by 2030. CARB revised the LCFS, effective January 4, 2019, making RNG a viable alternative to gasoline or diesel.[552] RNG has a carbon intensity lower than the new CARB target, which means the fuel will generate LCFS credits that regulated parties can use to offset LCFS deficits. According to the U.S. EIA, RNG accounted for about 7 percent

551 *2017 IEPR*, https://www.energy.ca.gov/2017_energypolicy/. p. 225.

552 CARB, Low Carbon Fuel Standards https://www.arb.ca.gov/fuels/lcfs/lcfs.htm.

of LCFS credits during the first three quarters of 2018.[553] RNG is used commonly in heavy-duty commercial fleets. In 2018, the transportation sector's consumption of natural gas totaled 19,819 MMcf, representing about 1 percent of the state's natural gas consumption.

The CEC-funded study, *Deep Decarbonization in a High Renewables Future*, identifies a high biofuel scenario for transportation as "high risk" due to concerns about the long-term availability and sustainability of growing crops for biofuels.[554] The availability of RNG could constrain its use on a large scale; however, RNG imports from out-of-state are increasing due to the LCFS.

At a CEC IEPR Preliminary Natural Gas Price Forecast workshop on April 22, 2019, Jonathan Bromson with the CPUC presented an overview on the agency's RNG and hydrogen program. With regards to RNG, Mr. Bromson stated, "It is too early to tell how much RNG will be introduced and when into the California supply" but highlighted RNG benefits, including how "…reducing waste gas from flaring directly into the atmosphere, and instead putting it to beneficial use via pipeline injection for use in electric and transportation sectors, moves the state towards the short-lived climate pollutant reduction goals."[555]

In the power generation sector, over the last decade there has been a large influx of renewable generation on California's electricity system that is reducing natural gas use. The amount of generation from natural gas plants has decreased by roughly 22 percent, from 117 GWh in 2009 to 91 GWh in 2018. At the same time, renewable generation, including rooftop solar, has more than doubled from 33 GWh in2009 to 77 GWh in 2018. In terms of installed capacity, the change is even more dramatic. During the last decade, installed renewable capacity in the state more than tripled, increasing from 9,313 MW in 2009 to 32,313 MW in 2018.

Between 2009 and 2018, California retired more than 6,600 MW of natural gas power plants using once-through cooling. While the state expects to retire another almost 9,000 MW by the end of 2020, the CPUC recommended (as part of proceeding R.16-02-007) extending the

553 Link to Natural Gas Weekly Update for the week ending March 27, 2019, on the U.S. EIA's website https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2019/03_28/.

554 E3. June 2018. *Deep Decarbonization in a High Renewables Future*, p. 59, https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf.

555 Transcript from the April 22, 2019, IEPR workshop on Preliminary Natural Gas Price Forecast and Outlook, https://efiling.energy.ca.gov/getdocument.aspx?tn=228226.

deadline due to system reliability concerns as discussed in Chapter 6.[556] Over the last decade, natural gas installed capacity declined from 43,676 MW to 42,885 MW. Peaking gas plants, which run less frequently than other natural gas plants—often only a few hours on the hottest days—make up only a portion of the once-through cooling plant retirements. For power generation, natural gas generation has typically been the swing generation to make up for loss of hydro resources during droughts. In recent years, renewable generation has begun to serve that purpose, further reducing California's reliance on natural gas in the power generation sector.

Infrastructure and Reliability

United States

Production of natural gas from the Permian Basin of West Texas has been growing, and some industry observers expect production will double by 2025. However, the pipeline transmission infrastructure needed to move natural gas from this basin is lagging behind the surge in production. Three pipelines, at differing stages of planning and construction, are attempting to close the gap. Each gas transmission line will haul about 2.0 Bcf/d from the Permian Basin to the Texas Gulf Coast and will mostly serve the LNG export market.

These pipelines, expected to begin service between 2020 and 2023, will add a dimension of competition for natural gas coming from the Permian Basin. Natural gas that flows to western and other markets, including California, could experience upward pressure on prices as new markets emerge for gas from this basin. However, the abundance of natural gas now available may lower the risk of higher prices.

California

Pipeline infrastructure serving California remains largely unchanged over the last two years. The state expects no expansions, but Questar Southern Trails (a small pipeline with a capacity of 300 Bcf) discontinued service to California in 2019 because of economic considerations. The CEC expects that this closure will have little or no effect on California's natural gas supply, as deliveries on Southern Trails into California had dropped significantly—from 1,791 MMcf in 2017 to 7.4 MMcf in June 2019, when the pipeline service ended. This delivery amount was small, and this demand can be met with other pipelines.

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556 On June 20, 2019, the CPUC issued a ruling in its IRP Proceeding R.16-02-007 identifying potential system capacity shortfalls beginning in 2021 because of tightening of the bilateral resource adequacy market. The CPUC ruling identified three simultaneous approaches to meet system needs, one of these being extension of OTC compliance deadlines. Chapter 6 provides more details.

At this time, no new natural gas pipelines or storage fields are planned for California. As such, the state's reliance on an existing infrastructure that is aging raises concerns. The San Bruno pipeline explosion in 2010, the gas leak at Aliso Canyon natural gas storage facility in 2015, and ongoing pipeline maintenance issues discussed in detail in Chapter 6 highlight the potential problems.

Should the state transition to RNG or hydrogen (or both) for pipeline injection, pipeline leakage and other potential safety issues would remain. If mixed in the natural gas pipeline, hydrogen would partially displace methane during leakage due to the mobility of the hydrogen molecules.[557]

Another consideration is that when used in a combustion engine, hydrogen is cleaner than methane with water vapor as the primary byproduct, although some nitrogen oxides can also be produced. If hydrogen is used in a fuel cell, then water is the only by-product, nitrogen oxides may be produced during the treatment of exhausted hydrogen but are considered low to negligible.

The LCFS is resulting in increased out-of-state RNG imports because of the financial incentive that is not available in other states. The LCFS could increase the amount of RNG available for transportation and other uses. At this time, however, research shows RNG in-state supply is somewhat limited and being used primarily in the transportation sector. The University of California, Davis, estimated 93 billion Bcf/year of RNG potential in 2013—enough to meet about 4.5 percent of an average day's demand in California.[558] In addition, *Deep Decarbonization in a High Renewables Future* states that there is an insufficient amount of RNG in California to meet long-term demand for low-carbon fuels in buildings and industries without widespread electrification.[559] It is uncertain how much of a role RNG will play in power generation, but the state should give this issue more attention as part of its long-term planning.

In the *2017 IEPR*, the CEC identified "cost-effective strategies and considered priority end uses of renewable gas in relation to existing state policies and climate goals" in response to Senate

557 M. W. Melaina, O. Antonia, and M. Penev, National Renewable Energy Laboratory, Technical Report, NREL/TP-5600-51995, March 2013, *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*, https://www.nrel.gov/docs/fy13osti/51995.pdf.

558 Catherine Elder, *Effects on California of Winding Down Natural Gas*, https://www.onlinelibrary.wiley.com/doi/10.1002/gas.22108.

559 E3, *Deep Decarbonization in a High Renewables Future*, June 2018, https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf.

Bill 1383 (Lara, Chapter 395, Statutes of 2016).[560] The report recommended that the CEC "re-examine the status of renewable gas, including power-to-gas, as part of the *Integrated Energy Policy Report* in four years" (as part of the *2021 IEPR*).

Underground natural gas storage plays an important role in balancing California's demand requirements with supply availability. This component of the natural gas system is necessary to meet winter demand. It also maintains the daily supply/demand balance and keeps natural gas flowing to customers in the event of temporary disruptions in production. These operations ensure reliability since operators withdraw or inject natural gas or both, as demand dictates. As a result, about 20 percent of all natural gas consumed each winter comes from underground storage.

In California, the working gas capacity of natural gas storage fields connected to the systems of PG&E and Southern California Gas Company (SoCalGas) totals 376 Bcf.[561] Natural gas storage fields (including independently owned)[562] that are interconnected to PG&E's natural gas system have a working gas capacity of 238 Bcf. SoCalGas operates four storage fields that interconnect with its transmission system and have a working gas capacity totaling 138 Bcf. In 2018, the U.S. EIA reported that operators injected 149,116 MMcf into California's storage fields and withdrew 201,291 MMcf.

There is a need to address California's aging natural gas infrastructure and the costs to maintain it as the state transitions to electrification and zero-carbon fuels. The state should also be mindful about potential effects on customers. A recent Gridworks report notes "As the state transitions to higher electrification, the last customers remaining on the gas system could face unreasonably high rates and potential safety issues. These groups may well be those among us who are least able to afford high rates and least able to finance the new appliances

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560 The *2017 IEPR* defined renewable gas as "Renewable gas is gas that is generated from organic waste or from electricity generated by an 'eligible renewable energy resource' as defined in Subdivision (e) of Section 399.12 of the California Public Utilities Code or at a 'renewable electric generating facility' as defined in Section 25741 of the California Public Resources Code. Renewable gas includes, but is not limited to, biogas; biomethane (also known as renewable natural gas); synthetic natural gas generated from organic waste, or electricity generated by an eligible renewable energy resource or at a renewable electric generating facility; renewable hydrogen; and gaseous products composed of the aforementioned, such as renewable dimethyl ether."

561 PG&E, in its 2018 gas transmission and storage rate case, has asked the CPUC for permission to retire and decommission two of these facilities.

562 Independently owned storage facilities include Lodi Gas Storage, Wild Goose Storage, Central Valley Storage, and Gill Ranch Storage.

needed to convert to electricity."[563] The CEC recognizes this concern and acknowledges that short- and long-term planning must examine the role of the natural gas system, aging infrastructure, and the cost impacts on consumers of moving away from natural gas.

The CEC continues to monitor infrastructure issues for the state's two major gas utilities—SoCalGas and PG&E—to assist with energy planning. Below are updates on new or existing infrastructure issues for both utilities.

Sempra/SoCalGas

Southern California has been the focus of major electric reliability concerns, starting with the unexpected retirement of Southern California Edison's (SCE's) San Onofre Units 2 and 3 in 2013, years ahead of schedule. At the same time, several natural gas-fired power plants along the Southern California coast have closed, and others are scheduled to close in compliance with requirements to phase out the use of once-through cooling.[564] In addition, a major gas leak at the Aliso Canyon natural gas storage field has constrained the operation of the facility that SoCalGas historically used to balance gas supply and demand throughout the year and used in winter to meet peak heating demand. These events, coupled with the multiyear outages of natural gas pipelines 235-2, 4000, and 3000 on the SoCalGas system, are tightening the region's energy supply. For details and updates on pipeline maintenance and related issues in Southern California, see Chapter 6.

In the *2017 IEPR*, the CEC reported on a pending application from SoCalGas and San Diego Gas & Electric Company (SDG&E) seeking permission from the CPUC to build a new 47-mile pipeline, Line 3602, to replace an aging Line 1600 in San Diego County.[565] SoCalGas and SDG&E argued that the new line and derating of Line 1600 would provide a measure of redundancy and additional safety and reliability for gas service into San Diego. Opponents to the project cited concerns over the path of the pipeline through neighborhoods and regional parks. The CPUC rejected the application on June 21, 2018, because the company had not

563 Gridworks, *California's Gas System in Transition* https://gridworks.org/wp-content/uploads/2019/09/CA_Gas_System_in_Transition.pdf.

564 "Once-through cooling" refers to the use of coastal water sources for the cooling of power plants, which has detrimental impacts on marine life and estuarine ecosystems. In 2010, the State Water Resources Control Board established a policy to eliminate once-through cooling at power plants by 2020.

565 The new pipeline would have transported natural gas from the existing Rainbow Metering Station at the Riverside/San Diego County line, south to the Marine Corps Air Station Miramar in San Diego.

shown why it needed to increase gas pipeline capacity in an era of declining demand and the state moving away from fossil fuels.[566]

PG&E

While storage has played an important role in PG&E's gas balancing requirements, the utility has introduced a new storage strategy that reduces its role in managing seasonal prices for core customers. PG&E owns three natural gas storage fields in California—McDonald Island, Los Medanos, and Pleasant Creek. Furthermore, PG&E owns 25 percent of the Gill Ranch Storage LLC facility. PG&E's largest facility, McDonald Island, has an operating capacity of 82 Bcf.[567] Pleasant Creek and Los Medanos are considerably smaller, with operating capacities of 2.0 Bcf and 17.9 Bcf, respectively. In addition to Gill Ranch Storage, PG&E's system is connected to three independently owned storage facilities in Northern California—Wild Goose Storage, Central Valley Gas Storage, and Lodi Gas Storage.

As part of its 2019 Gas Transmission and Storage Rate Case (A. 17-11-009), PG&E is proposing to change its storage asset holdings to help decrease long-term costs.[568] Reasons for the change include increased maintenance costs under DOGGR's new safety regulations (effective October 2018),[569] the abundance of natural gas, lower seasonal price differences, and a decline in natural gas use in California.[570] PG&E also has a robust natural gas backbone pipeline system (primarily composed of Lines 300, 400, and 401) that stretches from the California-Arizona border in Topock, Arizona, to the California-Oregon border in Malin, Oregon. In addition to storage resources, PG&E can use "line pack" within its backbone system as a form of storage.[571]

566 CPUC. December 4, 2018. [Information on SDG&E and SoCalGas' Application 15-09-013 to the CPUC on the CPUC's website](https://www.cpuc.ca.gov/Environment/info/ene/sandiego/sandiego.html) https://www.cpuc.ca.gov/Environment/info/ene/sandiego/sandiego.html.

567 McDonald Island is located on a man-made island in the Sacramento-San Joaquin River Delta.

568 Chapter 11, Natural Gas Storage Strategy, http://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A1711009/1700/228895701.pdf.

569 California Department of Conservation, DOGGR, Link to regulations https://www.conservation.ca.gov/dog/general_information/Pages/Pipelines.aspx.

570 Volume 1 of PG&E's 2019 Gas Transmission and Storage Rate Case on the CPUC's website http://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A1711009/1700/228895701.pdf. See Chapter 11.

571 "Line pack" refers to the volume of gas that can be stored in a pipeline. Gas can be injected at a receipt point on a pipeline (or pipeline segment), increasing the pressure in the line, and can be removed later at a delivery point, lowering the pressure in the line.

California Incentives for Natural Gas Research and Development, Clean Transportation, and RNG

In addition to the declining costs of renewables and storage, the state offers financial incentives for natural gas research and development and for promoting the use of RNG in the transportation sector. The CPUC, for example, oversees the Renewable Natural Gas program, which recently funded six dairy biomethane pilot projects in response to SB 1383. The goal is to inject the renewable natural gas from the dairies into the natural gas pipeline system and utilize other government incentives (such as CARB's LCFS and federal EPA renewable identification numbers) to help influence the market and market price.

The CEC administers two research and development programs targeted at improving natural gas efficiency: the Natural Gas Research and Development Program and the Food Production Investment Program. In addition to the research and development programs, the CEC administers the Renewable Energy for Agriculture Program, which uses cap and trade dollars to provide grants for the installation of onsite renewable energy on agricultural operations in California, to reduce GHG emissions.

The Natural Gas Research and Development Program is ratepayer-funded for energy efficiency programs and public interest research and development projects benefiting natural gas ratepayers. One role of this program is to examine the role of natural gas in California's transition to a low-carbon economy. The projects funded by this program support the following strategic objectives:

- Reduce vulnerabilities and fugitive methane emissions in the natural gas infrastructure
- Drive large-scale customer adoption of energy-efficient and low-carbon technology solutions for natural gas end uses that will be challenging to electrify
- Improve the cost-competitiveness of renewable natural gas
- Minimize air quality impacts from natural gas end uses to zero or near-zero levels

The Natural Gas Research and Development Program has funded the following successful projects:[572]

- The Gas Technology Institute developed a platform for notifying utilities and heavy-equipment operators when they are conducting construction work near natural gas pipelines. This solution also provides real-time visibility. It is anticipated that use of this

572 Link to Natural Gas Research and Development Program Annual Report on the CEC's website https://www.energy.ca.gov/2019publications/CEC-500-2019-026/CEC-500-2019-026.pdf.

technology by third-party contractors will result in a 43 percent reduction of nonfatal and noninjury excavation incidents caused by excavators, backhoes, and trenchers.

- The demonstration of a technology developed by Mosaic Materials that aims to lower the cost of cleaning and upgrading biogas. Instead of using a liquid solvent, Mosaic uses low-cost, solid adsorbent pellets. Not only did the solid adsorbent pellets remove carbon dioxide to the purity required to meet pipeline-quality natural gas standards, the simpler process and the use of less equipment showed a capital cost reduction of about 14 percent compared to conventional systems.
- The University of California, Merced, developed aluminum minichannel solar thermal collectors that use flat minichannels or tiny tubes, as opposed to a conventional, copper flat-plate collector. The minichannel technology increases the surface area exposed to sunlight for heat transfer, which improves the efficiency of the collector. The aluminum minichannel solar thermal technology has the potential to lower the cost of solar thermal water heating in single-family and multifamily homes by up to 30 percent while improving the efficiency of the solar collectors by 10 to 15 percent.
- The University of California, Davis' Western Cooling Efficiency Center developed a portable automated process for sealing gaps and tightening the envelope of a building. In real-world tests, a two-person team reduced the air leakage of a 2,200 square-foot, three-bedroom house by 68 percent in fewer than three hours compared to traditional sealing methods that require more than 20 hours of labor.

For Fiscal Year 2019–2020, the CEC submitted a program plan and funding request to the CPUC for the Natural Gas Research and Development Program that proposes the addition of two crosscutting program areas—Natural Gas Strategic Planning Research and a Natural Gas Small Grants Program.[573] Projects under the proposed strategic planning research program area are conducting a long-term strategic plan for natural gas technology research and exploring a strategic approach to natural gas pipeline decommissioning. The proposed natural gas small grants program would provide a recurring opportunity for entrepreneurs to apply for funding to test the feasibility of their energy concepts.

The CEC provides grants to help food processors save energy and money while reducing GHG emissions through the Food Production Investment Program. Funding comes from the California Climate Investments program, a statewide initiative that uses cap-and-trade dollars to help reduce GHG emissions, strengthen the economy, and improve public health and the

573 CPUC Resolution G-3555. Link to Resolution G-3555 on the CPUC's website
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M303/K479/303479245.PDF.

environment. At its February 2019 Business Meeting, the CEC approved Food Production Investment Program funding for projects that aim to reduce natural gas use in various plants including dehydrated food manufacturing, dairy processing, meat processing, and tomato processing. Technologies funded include waste heat capture and recycling, solar thermal energy systems, and factory electrification.

In June 2019, the CEC awarded nearly $9 million for solar energy and electric vehicle fast chargers on farms, orchards, vineyards, and other facilities in top agricultural counties statewide through the Renewable Energy for Agriculture Program. Agricultural facilities awarded funds include a school, a winery, and orchards.

Appendix A of the *2019 IEPR* discusses funding programs being administered by other state agencies in the area OF RNG.

Recommendations

- **California should initiate an interagency strategic transition planning process to identify the short and long-term transition of the natural gas system to non-fossil gases and other cleaner energy solutions.** Potential needs include improved forecasting, technology assessment of alternative gases, and assessments of existing gas system infrastructure.
- **California will need to address aging natural gas infrastructure and the costs to maintain it as the state transitions to electrification and zero-carbon fuels.**
- **California should deepen the understanding of current and potential future end uses of natural gas and its alternatives, especially in the industrial and commercial noncore sector.**

CHAPTER 10:
Senate Bill 350 Integrated Resource Plans

Senate Bill 350 (De León, Chapter 547, Statutes of 2015) transformed California's electricity system planning model by shifting to integrated resource plans (IRPs) that are required to meet several mandates and goals in 2030, including Renewables Portfolio Standard (RPS) procurement requirements and greenhouse gas (GHG) emission reduction goals. IRPs are long-term planning documents that outline how utilities and load-serving entities (LSEs) will meet demand reliably and cost-effectively while achieving state policy goals and mandates. Before SB 350, investor-owned utility (IOU) procurement planning was done through the Long Term Procurement Plan (LTPP) process at the California Public Utilities Commission (CPUC), though for decades publicly owned utilities (POUs) have generally used IRPs to guide their resource procurement.

The processes for developing IRPs for CPUC jurisdictional entities and POUs differ in significant ways. The CPUC is responsible for overseeing the process of developing IRPs for IOUs, community choice aggregators, and other LSEs. In contrast, individual POUs are responsible for developing their own IRPs. In its 2017–2018 IRP process, the CPUC attempts to ensure consistency in inputs and assumptions used in the analysis supporting the IRPs to make comparing and aggregating them easier. However, in the 2017–2018 IRP, LSEs can deviate from the Reference System Plan's (RSP's) resource mix when developing their respective IRP as long as their IRP complies with the planning standards outlined in the filing requirements accompanying the RSP.[574] In contrast, SB 350 allows the POUs to decide which inputs and assumptions to include in analysis supporting their IRPs. All LSEs and POUs must meet GHG emissions targets, RPS procurement requirements, as well as several planning goals. The CPUC adopts or certifies LSE IRPs, while the CEC reviews POUs' IRPs to determine consistency with these requirements.

As discussed below, the GHG emissions from the CPUC's preferred resource plan developed through its 2017–2018 IRP process combined with the emissions from the POU IRPs shows a statewide total that is within the GHG emission target range for 2030.

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574 The Reference System Plan is the portfolio that an optimal resource mix for the California ISO system based on capacity expansion modelling and is adopted by the CPUC in Year 1 of the IRP cycle. The Preferred System Plan is the portfolio informed by the aggregation individual LSE plans and is adopted in Year 2 of the IRP cycle.

CPUC 2017–2018 IRP Process

SB 350 requires the CPUC to develop a portfolio of resources for LSEs including IOUs, community choice aggregators, small and multijurisdictional utilities, and electric service providers (ESPs). Commission Decision D.18-02-018 established a two-year IRP planning cycle.

Year one is focused on:

- Generating and evaluating optimal resource portfolios at the California ISO system-level using a capacity expansion model and production cost model in parallel.
- Adopting one portfolio as the reference system portfolio to be used in statewide planning and in the California ISO transmission planning process.
- Identifying actions needed to implement the selected portfolio, such as new procurement authorization.
- Developing filing requirements for LSEs to use when developing their respective IRPs.

Year two is focused on:

- LSEs developing their respective IRPs.
- Staff evaluation of LSE IRPs, both individually and in aggregate.
- Commission adoption of a preferred system portfolio, informed by the aggregation of LSE IRP plans, to be used in statewide planning and in the California ISO transmission planning process.
- The preferred system plan, which also includes actions needed to implement the selected portfolio, such as new procurement authorization.

2017–2018 Reference System Plan

The CPUC adopted a statewide GHG target of 32,000 MT CO_2e for 2030 for the reference system plan based on targets established by CARB, in consultation with the CEC and CPUC (discussed in the "POU IRPs—Common Themes and Trends" section of this chapter). The modeling of the California ISO footprint resulted in the new resource buildout, or the collection of resource additions necessary in 2030 to meet demand, shown in Table 21.

SB 350 requires LSEs with an average annual load of 700 GWh or more to file IRPs with the CPUC. In their IRPs, LSEs were required to develop at least one portfolio meeting a GHG benchmark set by the CPUC using assumptions matching those used to develop the reference system plan. LSEs are also allowed to develop alternative or preferred portfolios that use different assumptions. LSEs are required to describe the impacts on air pollution and disadvantaged communities, costs and rates, and local needs, and to describe future actions and lessons learned.[575]

Table 21: 2017–2018 IRP Reference System Plan Resource Buildout in 2030

Resource Type	Total Capacity (MW)
Lithium Battery	1,992
Solar	8,828
Wind	1,145
Geothermal	202
Total New Renewables	10,175
Total New Renewables and Storage	**12,167**

Source: Administrative Law Judge's Ruling Seeking Comment on Proposed Reference System Plan and Related Commission Policy Actions Attachment, Link to Attachment C "Summary of Resolve Inputs and Outputs" from the CPUC's website http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M195/K910/195910922.PDF.

CPUC Decision on 2017–2018 IRP Preferred System Plan

SB 350 requires LSEs with an average annual load of 700 GWh or more to file IRPs with the CPUC. In their IRPs, LSEs were required to develop at least one portfolio meeting a GHG benchmark set by the CPUC using assumptions matching those used to develop the 2017–2018 IRP Reference System Plan. LSEs were also allowed to develop alternative or preferred portfolios that used different assumptions. LSEs were required to describe the impacts on air pollution and disadvantaged communities, costs and rates, and local needs, and to describe future actions and lessons learned.[576]

575 Alternative IRPs were required for LSEs with an average annual load under 700 GWh. Under alternative plans, small LSEs, with an annual load less than 700 GWh, filed IRPs including a portfolio conforming to the reference system plan, supply forms already required by the CEC and EIA, as well as qualitative descriptions of how the LSE was planning on meeting each SB 350 requirement.

576 Alternative IRPs were required for LSEs with an average annual load under 700 GWh. Under alternative plans, small LSEs, with an annual load less than 700 GWh, filed IRPs including a portfolio conforming to the reference system plan, supply forms already required by the CEC and EIA, as well as qualitative descriptions of how the LSE was planning on meeting each SB 350 requirement.

Six IOUs, 20 community choice aggregators, 17 ESPs, and four electric cooperatives filed IRPs with the CPUC.[577] Table 22 shows the total resource buildout proposed in the LSE IRPs collectively. The CPUC's decision approving LSE IRPs noted that many LSEs indicated that resources ultimately procured could vary depending on supply availability, supply cost, and other market conditions.[578]

Table 22: 2017–2018 IRP Aggregated LSE New Resource Buildout in 2030

Resource Type	Fully Deliverable Capacity (MW)	Energy Only Capacity (MW)	Total Capacity (MW)
Lithium Battery, 1 hour	90		90
Lithium Battery, 4 hour	1,065		1,065
Solar	4,412	2,396	6,807
Wind, In-State	917	412	1,329
Wind, Out-of-state	1,399	375	1,773
Geothermal	310		310
Biomass	7	156	163
Total New Renewables	7,044	3,338	10,382
Total New Renewables and Storage	**8,199**	**3,338**	**11,537**

Source: CPUC, D.19-04-040, pp. 112–113

For the development of the preferred system plan, the CPUC combined the portfolios proposed in the individual LSE plans, relocating some resources due to transmission availability, and termed it the *hybrid conforming portfolio*. Despite each LSE IRP portfolio meeting the individual GHG target, the modeling of the portfolio of the California ISO footprint resulted in an estimated 42,700 MT CO_2e of GHG emissions—exceeding the midpoint of the CARB-adopted GHG target range selected by the CPUC for use in the IRP by 10,700 MT CO_2e.

577 One ESP did not file on time but did file late. 19 LSE IRPs were initially rejected and required refiling due to not meeting the criteria pollutant reporting requirements.

578 CPUC, D.19-04-040, *Decision Adopting Preferred System Portfolio and Plan for 2017-2018 Integrated Resource Plan Cycle*, April 25, 2019, p. 17.

In Decision 19-04-040, the CPUC rejected the hybrid conforming portfolio, citing "[it] would not result in emissions reductions consistent with the electricity sector GHG goals established by this Commission."[579] The CPUC instead adopted a version of the reference system plan, modified to included updated *2017 IEPR* demand forecast assumptions, a 40-year age-based retirement assumption for gas-fired power plants, and updated transmission assumptions from the California ISO. Table 23 and Figure 53 detail the new resource buildout for this portfolio through 2030.

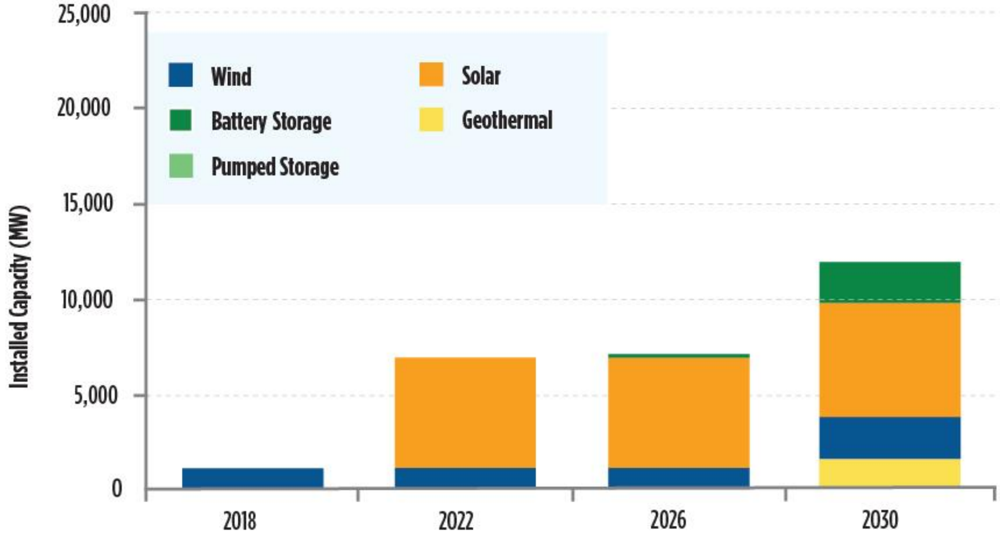
Table 23: 2017–2018 IRP Preferred System Plan New Resource Buildout in 2030

Resource Type	Fully Deliverable Capacity (MW)	Energy Only Capacity (MW)	Total Capacity (MW)
Lithium Battery, 1 hour	2,104		2,104
Solar	2,709	3,207	5,619
Wind, In-State	341	803	1,145
Wind, Out-of-State	1,101		1,101
Geothermal	1,048	652	1,700
Total New Renewables	5,200	4,662	9,862
Total New Renewables and Storage	**7,304**	**4,662**	**11,966**

Source: CPUC, D.19-04-040, pp. 112-113.

579 Ibid., p. 106.

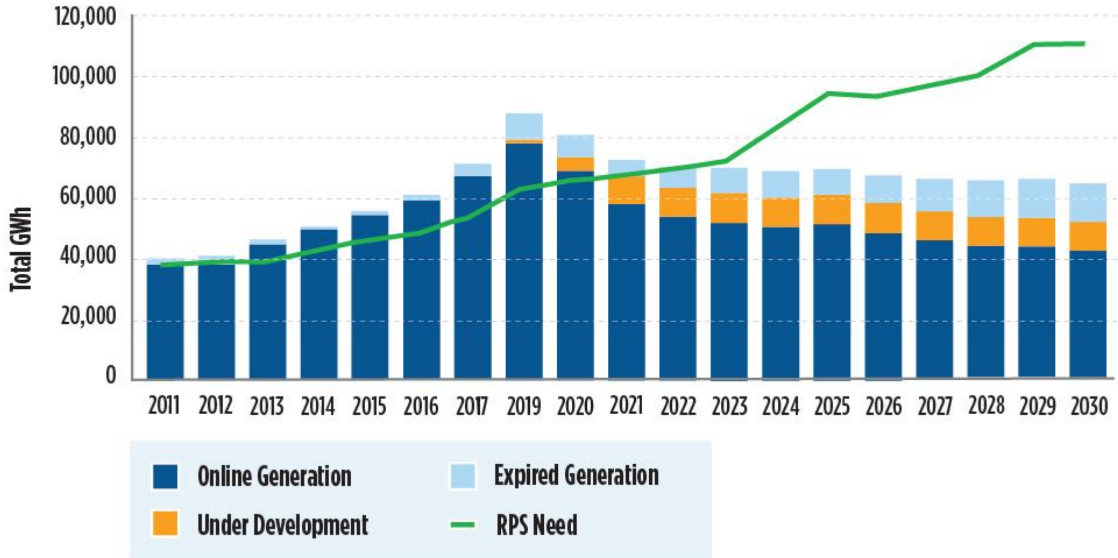
Figure 53: CPUC 2017–2018 IRP-Adopted Preferred System Plan



Source: Senate Bill 100 Joint Agency Kick-off Workshop Presentation, CPUC slide no. 59, September 5, 2019, Docket no. 19-SB-100, [Link to SB 100 Joint Agency Kickoff Workshop Presentation](https://efiling.energy.ca.gov/GetDocument.aspx?tn=229654&DocumentContentId=61073)
https://efiling.energy.ca.gov/GetDocument.aspx?tn=229654&DocumentContentId=61073

Figure 54 shows the aggregate forecast need and progress in achieving the 60 percent RPS for CPUC jurisdictional load-serving entities.

Figure 54: CPUC 2017–2018 IRP Jurisdictional Load-Serving Entity Forecast Need and Progress on RPS



Source: CPUC Renewable Net Short calculations, 2019 RPS Procurement Plans. June 21, 2019.

CPUC 2017–2018 IRP Procurement Tracks

CPUC Decision 19-04-040 identified the need for a procurement track in the 2019–2020 IRP cycle to act as a backstop for LSE procurement and ensure that the resources required to meet the clean energy goals and maintain reliability are procured.[580] The CPUC formally established the procurement track for the 2019–2020 IRP cycle in June 2019.[581] The ruling identified three resource types, or *attributes*, to be addressed through the procurement track: short- to medium-term renewable integration and reliability, renewables, and long-term reliability.

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580 Ibid., pp. 139-141.

581 CPUC, *Assigned Commissioner and Administrative Law Judge's Ruling Initiating Procurement Track and Seeking Comment on Potential Reliability Issues*, June 20, 2019, pp. 2-5.

The preliminary schedule prioritized near- to medium-term reliability. Under a final decision issued on November 13, 2019, the CPUC recommended that the State Water Resources Control Board extend the compliance deadlines for several fossil natural gas units using once-through cooling slated to retire by December 31, 2020, as discussed in Chapter 6 on Southern California Energy Reliability.[582] In addition to once-through cooling unit procurement, the CPUC directs load-serving entities to procure an additional 3,300 MW of system-level resource adequacy capacity for both existing and new resources on an all-source basis to address system adequacy shortages beginning in 2021. PG&E, SDG&E, and SCE must present the results of their solicitations in advice letters filed by January 1, 2021. All load-serving entities are required to provide progress reports on their procurement by February 15, 2020. Renewables procurement track is scheduled to be initiated in early 2020, while long-term reliability track will be initiated in summer 2020.

POU IRPs—Progress and Trends

The state's POUs are a diverse group of not-for-profit utilities with wide variations in the number and types of customers they serve, the size of their service areas, the types of loads they meet, and the resources in their current portfolios.[583] Local boards govern the POUS and, as a result, they answer directly to their customers. The POUs are subject to state laws with respect to achieving RPS procurement requirements, attaining the SB 350 doubling targets for energy efficiency, meeting SB 350 IRP requirements, and other state policies and mandates.[584] SB 350 requires the state's 16 largest POUs to develop IRPs and submit them to the CEC for review.[585] The CEC reviewed the POU IRPs to determine consistency with SB 350

582 CPUC, *Decision Requiring Electric System Reliability Procurement for 2021-2023*, November 13, 2019, pp. 2-4.

583 Since only 16 of the POUs are required to file IRPs with the CEC, the discussion in this section is specific to those POUs and does not address the state's smallest POUs.

584 For example, Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006) established the emission performance standard, which limits utilities long-term investments in baseload generation of high GHG-emitting power plants, set at 1,100 pounds of carbon dioxide per megawatt-hour of electricity.

585 The governing board of a POU with an annual electrical demand exceeding 700 GWh is required to adopt an IRP and a process for updating it at least once every five years by January 1, 2019.

requirements, including meeting GHG reduction targets and RPS procurement requirements and meeting several other planning goals.[586]

The POUs relied on public input in developing their IRPs and found that their customers generally support increasing the amount of renewables in their future resource portfolios. POU customers also supported efforts to move toward clean energy sources. While cost considerations were paramount to the POUs in selecting resource portfolios, none identified major increases in costs or rates, even though they include significant amounts of renewables. The POUs' IRPs demonstrate their commitment to meeting the state's clean energy goals and aligning their resource portfolios to achieve GHG reductions.

Unique Characteristics of POUs

California's POUs have some distinct characteristics that set them apart from the state's IOUs and some load-serving entities. POUs were not subject to electricity market restructuring in the late 1990s and, as such, remain vertically integrated utilities.[587] The following discusses some of factors that make them unique.

POU Size Differences

The largest POU in terms of number of customers is LADWP, with more than 1.5 million residential and business customers. LADWP's service territory encompasses 465 square miles. In contrast, Imperial Irrigation District's (IID's) has the largest service area, covering 6,741 square miles, but it has only 150,000 customers. The smallest POU in terms of area served is the City of Vernon, with a service territory of only 5 square miles and 1,910 customers. The size of the load served by POUs also varies widely, with LADWP as the largest, supplying 27,144 GWh of energy and meeting a peak demand (including a 15 percent reserve margin) of 9,104 MW in 2019. The smallest is the City of Redding, which delivers 767 MWh of energy and meets a peak demand (including a 15 percent reserve margin) of 273 MW in 2019.

586 The CEC adopted the *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines (POU IRP Guidelines)* to govern the submission of the POU's IRPs. [Link to information on POU IRPs on the CEC's website](https://www.energy.ca.gov/sb350/IRPs/) https://www.energy.ca.gov/sb350/IRPs/.

587 "Vertically integrated utilities" are monopoly businesses that have a franchise service territory and provide a full suite of services including generation, transmission, distribution, metering and billing, and customer service. Following restructuring, the IOUs no longer provide transmission and generation services, although they do own some legacy generation and are subject to retail competition.

Variations in Load

The types of customers POUs serve vary significantly, which means their load shapes, or the average change in load served over a 24-hour period, are markedly different. Burbank Water and Power serves almost exclusively residential and commercial customers. As a result, Burbank Water and Power experiences a relatively sharp peak demand occurring from 4:00 p.m. to 6:00 p.m., with an average load factor of 40 percent.[588] Other POUs that serve significant residential and commercial loads and have low load factors, include the City of Glendale at 37 percent, the City of Redding at 38 percent, and IID and the City of Pasadena each at about 40 percent. Programs such as demand response can help utilities with low load factors reduce their peak load, improving reliability and lowering costs.

In contrast, the City of Vernon is composed primarily of industrial areas, with 99 percent of its demand and energy sales serving commercial and industrial customers. Consequently, it has a slight peak, typically between 12:00 p.m. and 2:00 p.m., with an average load factor of 70 percent. Silicon Valley Power has a similar load factor of roughly 70 percent largely because commercial and industrial customers make up more than 90 percent of its retail sales. Expected growth in data centers for Silicon Valley Power, with load factors as high as 85 percent, will mean loads that are relatively flat throughout the day. Other POUs with high load factors include San Francisco at almost 78 percent and Palo Alto at about 65 percent. Utilities with high load factors have less opportunity for deployment of demand response programs; however, energy efficiency programs can reduce their overall loads and lower costs.

Differences in Resource Portfolios

Some POUs have substantial amounts of large hydro resources in their portfolios, while others have large amounts of fossil generation such as coal and natural gas. Each utility is unique in terms of its current resource mix. The resource mixes of each of the 16 POUs that filed IRPs for 2019, 2025, and 2030 are provided in Appendix D.

A few POUs have high proportions of large hydro resources in their portfolios and, as a result, have low GHG emissions. For example, the City of Palo Alto Utilities relies heavily on large hydro, which accounts for about 59 percent of its resources in 2019. Other POUs that rely heavily on large hydro include the San Francisco Public Utilities Commission with more than 70 percent large hydro and Redding Public Utility with 38 percent large hydro in 2019. Utilities with significant amounts of large hydro are reevaluating large hydro contracts as they begin

588 A "load factor" is the ratio of average energy demand to peak demand. A high load factor implies a relatively constant load throughout the day, where a low load factor indicates a high peak demand and low off-peak demand.

expiring in the mid-2020s. Even though they help reduce GHG emissions, there is uncertainty about future costs and availability of large hydro resources, which depend on unpredictable precipitation, especially in light of the potential impacts of climate change.

Several POUs have large amounts of fossil resources in their portfolios, including natural gas and coal generation. In 2019, nearly 88 percent of the City of Anaheim's supply is from fossil fuels, with about 50 percent coal and 38 percent natural gas. The City of Burbank relies on fossil fuel for more than 86 percent of its supply in 2019, with 38 percent from coal and 48 percent from natural gas. LADWP relies on fossil resources for about 50 percent of its supplies in 2019, with coal accounting for almost 17 percent and natural gas at about 33 percent. The POUs as a group are eliminating their reliance on coal resources by 2025 to reduce their GHG emissions.

Sacramento Municipal Utility District (SMUD) has no coal generation in 2019 but relies on natural gas for about 48 percent of its supplies. Similarly, Vernon has no coal resources in 2019 but relies on natural gas for about 61 percent in 2019. Turlock Irrigation District also has no coal resources in 2019 but relies on natural gas for about 40 percent of its supply. Utilities with significant amounts of natural gas generation are looking to limit their use of these resources to reduce GHG emissions.

At the other end of the spectrum, because it has so much large hydro generation, San Francisco has no coal or natural gas resources in 2019. Palo Alto also has no coal or natural gas generation in 2019, although it does rely on market purchases, which are assumed to have some level of fossil generation as their source. Redding has less than 1 percent natural gas in its portfolio and no coal.

Disadvantaged and Low-Income Communities

The proportion of disadvantaged and low-income communities, which are exposed to a combination of economic, health, and environmental burdens, varies significantly among the POUs.[589] LADWP has a high percentage of disadvantaged communities. A key indicator for it is air pollution, since most of LADWP's service territory exceeds federal public health standards for ozone and particulate matter. To improve air quality, LADWP's IRP focuses on finding clean alternatives to repowering of aging in-basin natural gas plants and transportation electrification.

589 One way the state identifies disadvantaged communities is by using CalEnviroScreen, an analytical tool that combines census tract data into scores that define disadvantaged communities.

Similarly, Riverside has high pollution levels, which is why much of its service territory is designated a disadvantaged community. Forty percent of Riverside's population resides in disadvantaged communities, with 30 percent of households having incomes below 200 percent of the federal poverty level. Like LADWP, Riverside is promoting transportation electrification. Most of Turlock's service territory is classified as either low-income or disadvantaged. Turlock has focused on maintaining low rates and offers discount electricity demand charges and weatherizes homes to reduce customer bills. IID also has a high proportion of disadvantaged communities and low-income customers and provides residential and emergency energy assistance.

In contrast, Palo Alto has no areas that are classified as disadvantaged communities, but it does offer rate assistance for customers with low incomes who qualify. Similarly, Redding does not have any disadvantaged communities but deems many of its customers as low-income, offering bill assistance and weatherization programs. Silicon Valley Power has only one disadvantaged community, situated between Highway 101 and the San Jose Airport. Consequently, local governments have limited residential housing development in the area to minimize impacts. While Vernon does not have any disadvantaged communities, many such communities lie at its borders, so it designed programs for its customers that will minimize impacts on neighboring disadvantaged communities.

Other Distinguishing Characteristics

Several POUs serve not only as vertically integrated utilities, but also as balancing authorities that must control generation and transmission throughout their control areas to balance supply and demand continuously. LADWP serves as its own balancing authority and provides these services to other POUs, including Burbank and Glendale. It is the largest POU balancing authority and California's second largest balancing authority after the California ISO. The Balancing Authority of Northern California, a joint power authority consisting of SMUD, Modesto Irrigation District, Roseville Electric Utility, Redding, and a few smaller POUs, operates the third largest system in California. IID and TID are also California balancing authorities. In addition, several POUs are members of the California ISO balancing authority, including Anaheim, Pasadena, and Riverside. Balancing authorities are required to meet stringent reliability requirements, which places some constraints on POUs in terms of the types and amounts of resources they must carry.[590]

590 Reliability standards and protocols are established by the Western Electric Coordinating Council and the North American Electric Reliability Corporation, which have delegated authority over reliability from the Federal Energy Regulatory Commission.

POU IRP Trends and Issues

In general, the POUs' IRPs demonstrate their commitment to meeting the state's clean energy goals and aligning their resource portfolios to achieve GHG reductions. The following discusses how the POUs conducted their portfolio planning and the trends and issues that emerged from aggregating individual POU IRPs. These issues include GHG emission reductions, RPS resource additions, forecasted energy and peak needs, fossil fuel (coal and natural gas) use, energy efficiency, transportation electrification, and others. Chapter 2 includes a discussion of how energy efficiency is addressed in IRPs and Chapter 3 includes a summary of transportation electrification in IRPs.

POU Future Resource Needs

Most POUs are forecasting very slow or flat growth in energy and peak demand between now and 2030. One exception is Silicon Valley Power, which is projecting load growth because of the expected addition of new data centers as noted above. The POUs' energy demand forecasts generally align with the CEC's demand forecast. However, several POUs expect higher peak demand than forecasted by the CEC. Differences between POU forecasts and the CEC's forecast are likely the result of using differing forecasting methods and assumptions.[591]

In general, POUs are fully resourced through 2025-2027, meaning they have sufficient resources to meet forecasted energy and peak demand. Many of the POUs have natural gas-fired generation that they could use to meet demand. However, without the addition of renewables, POUs would not be able to meet their RPS requirements and GHG emissions targets. Many POUs have long-term contracts that do not expire until later in the planning period that are likely to be replaced by renewable resources.

The IRPs demonstrate that POUs have committed to lowering their GHG emissions by eliminating coal from their portfolios by 2025. Several POUs, including LADWP, Burbank, Glendale, Pasadena, Riverside, and Anaheim, have long-term contracts with the Intermountain Power Plant coal plant in Utah that will expire late in the forecast period. LADWP and other owners of IPP intend to convert the facility from a coal-fired power plant to a combined-cycle natural gas power plant by 2025.[592] This conversion allows LADWP and the other POUs to

591 POUs were not required to use the CEC's forecast in their IRPs but were required to provide information on the methods and assumptions used in their forecasts.

592 Riverside and Anaheim are not participating in the long-term repower of IPP. Since the current contract does not end until 2027, they will receive electricity from the project between 2025 and 2027.

accelerate their divestiture of coal by two years and eliminates coal from California's resources mix.[593]

Several POUs also accelerated their divestiture of the San Juan Generating Station, a coal generator in New Mexico. Southern California Public Power Authority members—including IID, Modesto Irrigation District, Silicon Valley Power, and the cities of Glendale, Redding, and Anaheim—held interests in the San Juan Generating Station.[594] The early retirement of two units of the power plant provided an opportunity for POU owners to accelerate divestiture of their interests in the coal plant by the end of 2017.

Other POUs have long-term contracts with hydroelectric plants operated by the Western Area Power Administration, which expire in the mid-2020s. Some POUs have raised concerns about too much reliance on hydro resources due to the associated year-to-year variability and the potential long-term impacts of climate change on hydro availability. Because they do not have to make these decisions about these contracts for several years, they have time to evaluate their options.

Aggregate POU Resources

POU resource portfolios are expected to change significantly between 2019 and 2030. Table 24 shows the aggregated generation resources from the individual POU IRP portfolios. Most of the POU resource portfolios in 2030 contain large increases in solar resources, both rooftop PV and utility-scale solar. The total amount of solar for the POUs increases from more than 6,000 GWh in 2019 to more than 16,000 GWh in 2030, more than doubling. The combination of utility-scale and rooftop solar accounts for 22 percent of total POU generation in 2030. Wind resources increase more moderately from about 6,300 GWh to 10,000 GWh, accounting for about 10 percent of total resources in 2019 and increasing to 13 percent in 2030. Over the same period, total renewable resources increases from almost 21,000 GWh to almost 36,000 GWh. However, the total amounts of renewable generation resources include some

593 LADWP, Burbank, Glendale, and Pasadena intend to participate in the repowering of IPP, while Anaheim and Riverside have chosen to not participate. LADWP, Burbank, Glendale, and Pasadena provided the CEC with the necessary compliance filings demonstrating that their renewed contracts for the repowered IPP project meet the Emission Performance Standard.

594 Other POUs that were participants in the San Juan plant but were not required to file IRPs include the cities of Colton, Azusa, and Banning,

renewables that are not RPS-eligible. POU progress in achieving RPS requirements is discussed below.[595]

By 2030, POUs plan to eliminate reliance on coal resources, accounting for significant reductions in GHG emissions, as discussed below. Natural gas use decreases from 33 percent of total generation in 2019 to 27 percent in 2030. Natural gas continues to play a large role in meeting peak and ensuring reliability, as well as integrating increasing amounts of renewable resources. Large hydro resources increase only slightly over the planning period. Energy storage accounts for about 2 percent of generation in 2030; however, POUs will be evaluating the costs and performance of energy storage over the planning period to determine whether and when to include additional storage.

Table 24: POU Resources by Type by Year (MWh)

	Generation by Resource (GWhs)	Generation by Resource (GWhs)	Generation by Resource (GWhs)	Percent
Fuel/Technology Type	**2019**	**2025**	**2030**	**2030**
Solar	6,134	12,067	16,103	22
Other Renewables	8,490	8,692	9,352	13
Wind	6,278	7,991	10,023	13
Energy Storage	133	874	1,325	2
Large Hydro	5,764	5,818	6,051	8
Nuclear	3,725	3,724	3,724	5
Coal	7,185	3,412	0	0
Natural Gas	21,892	21,174	20,271	27
Net Market Purchases	6,589	7,096	7,960	11
Total Energy	**66,190**	**70,848**	**74,809**	**100**

Source: CEC Energy Assessments Division staff using data from POU IRP Filings

POUs Are Meeting GHG Targets

To ease planning and achievement of GHG reductions, SB 350 required CARB, in coordination with the CEC and CPUC, to establish GHG reduction targets for the electricity sector and individual LSEs and POUs. GHG emissions for the electricity sector are generally a function of

595 Rooftop solar is not an RPS-eligible resource. In addition, the RPS is calculated as the percentage of retail sales, where total generation in Table 5 represents net energy for load. RPS resources are shown in Figure 50.

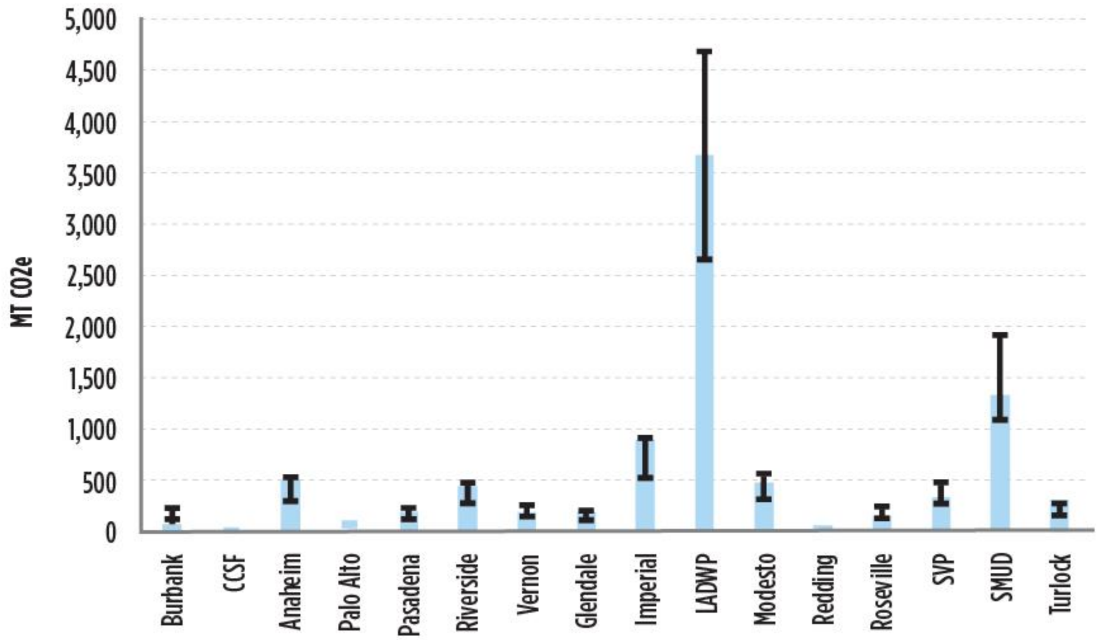
the demand for electricity and the carbon intensity of the fuel used to generate electricity. The GHG targets for the state's POUs and other LSEs reflect the electricity sector's percentage in achieving the economywide GHG emission reductions of 40 percent from 1990 levels by 2030.[596] CARB's GHG planning target for the electricity sector is a range of roughly 30,000 MT CO_2e to 53,000 MT CO_2e, which it determined was sufficiently ambitious on the low end to support POUs and LSEs in planning for greater reductions.[597] Figure 55 shows the resulting emission targets for POUs.

All 16 POUs' IRPs meet these targets, with several falling at or below the low end of the target range. Table 25 shows the GHG emission associated with each POU's portfolio of resources in 2030. The total amount of emissions from POUs in 2030 is 8,900 MT CO_2e, which is about 21 percent below the high end of the target range.

596 In setting the GHG targets CARB relied on the 2017 Scoping Plan Update, which identifies an achievable and cost-effective path to reducing GHG emissions and establishes targets ranges for each sector of the economy including the electricity sector. https://www.arb.ca.gov/cc/scopingplan/scopingplan.htm.

597 CARB used information about loads and resources developed for allocating emission allowances under the Cap-and-Trade Program as the basis for apportioning emissions targets to individual POUs and LSEs. Staff Report: SB 350 IRP Planning Electricity Sector GHG Planning Targets on CARB's website https://www.arb.ca.gov/cc/sb350/staffreport_sb350_irp.pdf.

Figure 55: POU GHG Emission Target Ranges (MT CO_2e)



Source: CEC Energy Assessments Division based on CARB SB 350 IRP GHG Planning Targets

Table 25: POU GHG Emissions

POU	2030 GHG Planning Target Range, 30-53 MMT CO_2e- Low	2030 GHG Planning Target Range, 30-53 MMT CO_2e- High	Utility Projections- IRP Emissions Projection (MMT CO_2e)	Utility Projections- Percentage Below High End of Range
Burbank Water and Power	129	228	73	68
City & County of San Francisco	12	22	0	100
Anaheim Public Utilities	305	538	505	6
City of Palo Alto	52	92	3	97
Pasadena Water and Power	128	226	201	11
Riverside Public Utilities	275	487	486	0
Vernon Public Utilities	149	263	193	27
Glendale Water and Power	119	210	193	8
Imperial Irrigation District	524	925	899	3
LADWP	2,665	4,691	3,683	21
Modesto Irrigation District	317	559	476	15
Redding Electric Utility	57	101	64	36
Roseville Electric	136	240	161	33
Silicon Valley Power	275	485	334	31
SMUD	1,086	1,919	1,338	30
Turlock Irrigation District	189	333	316	5
POU Total	**6,408**	**11,319**	**8,926**	**21**
Reference System Plan	**23,077**	**40,764**	**34,000**	**17**
Statewide Total	**29,485**	**52,083**	**42,926**	**18**

Source: CEC Energy Assessments Division staff using POU IRP Filings

The CPUC evaluated the individual IRPs submitted by the LSEs, which, when aggregated, met the LSE-specific GHG emission targets. The modeling of the combined portfolio of LSEs resulted in an estimated 42,700 MT CO_2e of GHG emissions, which exceeds the target by 10,700 MT CO_2e.[598] However, as noted before, the CPUC rejected that portfolio and instead selected a preferred resource plan, which has 34,000 MT CO_2e, slightly above the CPUC's GHG

598 CPUC Decision Adopting Preferred System Portfolio and Plan for 2017-2019 Integrated Resource Plan Cycle Attachment at slide 89.

target. When added to the POU GHG emissions, the statewide total GHG emissions for the electricity sector in 2030 is nearly 43,000 MT CO_2e, which falls about 18 percent below the high end of the target range by 2030.

POU RPS Plans—Emphasis on Solar Resources

SB 350 requires that POU IRPs ensure procurement of at least 50 percent renewable energy resources under the RPS by 2030. SB 100 increases the RPS requirement for 2030 from 50 to 60 percent. However, since POUs were required to adopt their IRPs before SB 100 went into effect, POUs were only required to plan for the 50 percent RPS in their IRP. Despite this, many of the POUs updated IRPs that were already underway to include the 60 percent RPS and several filed updated RPS procurement plans to reflect the increased RPS.[599] All POUs meet the 50 percent RPS in 2030 and plan to update IRPs to meet the 60 percent RPS.[600]

Many of the POUs made early commitments to RPS-eligible resources under long-term contracts or ownership shares, which will allow them to meet their RPS requirements by banking the renewable energy credits from the generation and applying them to meet their future procurement obligations.[601] All POU IRPs demonstrate that they plan to meet the RPS requirement of SB 350 in 2030 and interim compliance periods.[602] Table 26 shows the amount of RPS-eligible renewable resources in the POU portfolios in 2019, 2025, and 2030. Figure 56 shows the aggregate POU forecast need and progress in achieving the 60 percent RPS. The resource additions identified in their IRPs are primarily utility-scale solar PV with some wind generation.

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599 The CEC requires POUs to adopt and file a renewable energy procurement plan detailing how the POU will achieve its RPS procurement requirements for each compliance period and RPS targets annually under April 2016 amended regulations. [Amended regulations for Enforcement Procedures for the RPS for Local POUs on the CEC's website](https://www.energy.ca.gov/2016publications/CEC-300-2016-002/CEC-300-2016-002-CMF.pdf) https://www.energy.ca.gov/2016publications/CEC-300-2016-002/CEC-300-2016-002-CMF.pdf.

600 PUC Section 9621(b) requires POUs with an electrical demand exceeding 700 GWh to adopt an IRP and a process for updating the plan at least once every five years.

601 A renewable energy credit consists of the renewable and environmental attributes associated with the production of electricity from a renewable source. Renewable energy credits are "created" by a renewable generator simultaneous to the production of electricity and can subsequently be sold separately from the underlying energy.

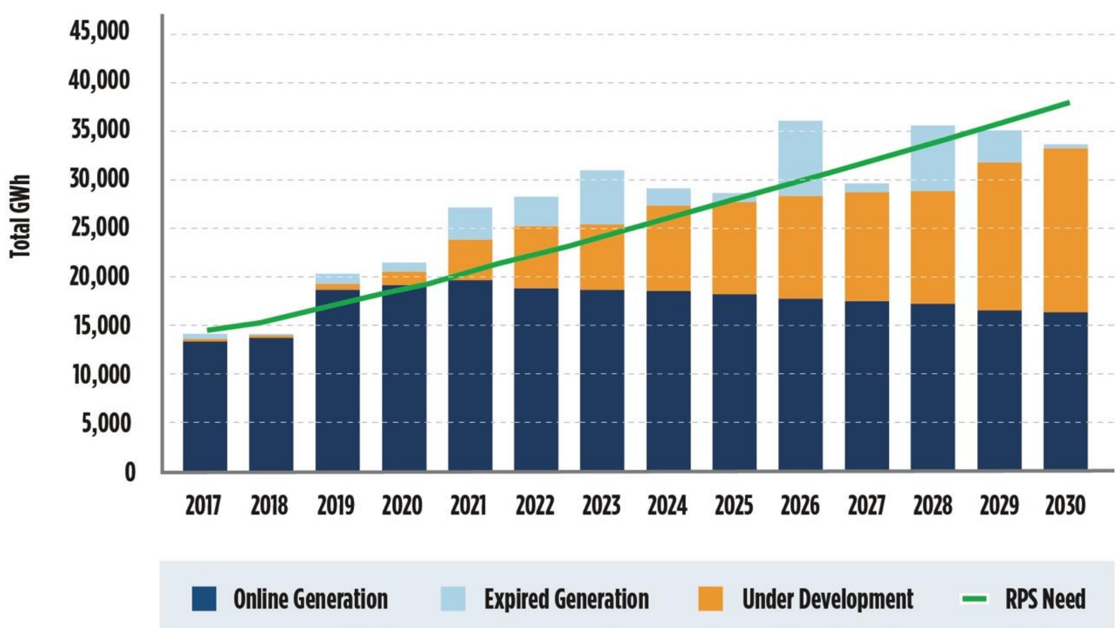
602 Actual procurement of resources in the future may vary from those identified in IRPs. Staff performed analysis to determine whether the plans would meet future RPS requirements prospectively. Staff did not perform the type of detailed analysis used in verifying compliance with RPS requirements, since that can be done only retrospectively.

Table 26: POU RPS Resources (GWh)

POU	2019	2025	2030	2030 Percentage RPS of Retail Sales
Anaheim Public Utilities	732	977	1,172	50 percent
Burbank Water and Power	354	793	728	76 percent
City & County of San Francisco	10	10	10	NA
Glendale Water and Power	315	484	653	50 percent
Imperial Irrigation District	1,048	1,513	1,935	50 percent
LADWP	6,599	9,881	12,793	50 percent
Modesto Irrigation District	774	1,074	1,338	50 percent
City of Palo Alto	417	364	507	58 percent
Pasadena Water and Power	330	516	672	60 percent
Redding Electric Utility	216	293	359	50 percent
Roseville Electric	363	486	557	53 percent
Riverside Public Utilities	1,001	1,135	1,421	57 percent
SMUD	3,253	4,371	5,466	52 percent
Silicon Valley Power	1,190	2,304	2,405	53 percent
Turlock Irrigation District	660	1,010	1,321	60 percent
Vernon Public Utilities	356	579	772	62 percent
POU Total	17,619	25,791	32,109	52 percent

Source: CEC Energy Assessments Division using data from POU IRP filings.

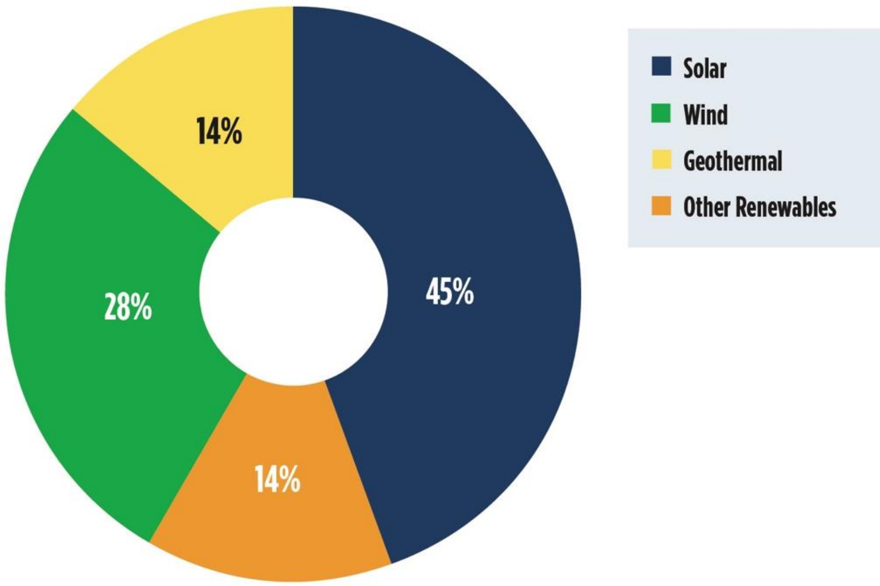
Figure 56: POU Forecast Need and Progress Toward 60 Percent RPS



Source: Presentation by Simon Baker with the CPUC at the Senate Bill 100 kickoff workshop on September 5, 2019

In 2030, the POUs' portfolio of RPS resources is made up of 44 percent solar, 28 percent wind, 14 percent geothermal, and the remainder small hydro and biomass resources, as shown in Figure 57.

Figure 57: POU RPS Resources Mix in 2030



Source: CEC Energy Assessments Division using data from POU IRP filings.

The projected reliance on solar resources by POUs, combined with an additional 5,600 MW of solar capacity in the CPUC's Preferred System Plan,[603] results in additions of solar resources that raise concerns about potential solar over generation and the future availability of flexible resources to meet ramping requirements associated with solar. In addition, large amounts of wind resources will pose integration challenges. The state's POUs and LSEs, along with the California ISO and other balancing authorities, will need to continue to plan for sufficient tools to help reliably integrate intermittent renewable resources, as discussed.

603 CPUC, D.19-04-040. April 25, 2019. *Decision Adopting Preferred System Portfolio and Plan for 2017-2018 Integrated Resource Plan Cycle*
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M287/K437/287437887.PDF.

Acronyms

AAEE	—	additional achievable energy efficiency
AB	—	Assembly Bill
APEN	—	Asian Pacific Environmental Network
AV	—	autonomous vehicle
Bcf	—	billion cubic feet
BEES	—	Building Energy Efficiency Standards
BEV	—	battery-electric vehicle
BOSR	—	Body of State Regulators
Btu	—	British Thermal Unit
BUILD	—	Building Initiative for Low-Emissions Development
CAEATFA	—	California Alternative Energy and Advanced Transportation Financing Authority
CAL FIRE	—	California Department of Forestry and Fire Protection
California ISO	—	California Independent System Operator
CAPCOA	—	California Air Pollution Control Officers Association
CARB	—	California Air Resources Board
CCR	—	California Code of Regulations
CEC	—	California Energy Commission
CED	—	*California Energy Demand Forecast*
CEDU	—	*California Energy Demand Updated Forecast*
CH_4	—	methane
CLIMB	—	Clean Energy in Low-Income Multifamily Buildings
CNCDA	—	California New Car Dealers Association
CNG	—	compressed natural gas
CO_2	—	carbon dioxide
CO_2e	—	carbon dioxide equivalent
CPUC	—	California Public Utilities Commission
CSD	—	Department of Community Services and Development
CSGT	—	Community Solar Green Tariff
CWDB	—	California Workforce Development Board
DAC-GT	—	Disadvantaged Communities Green Tariff Program
DAC-SASH	—	Disadvantaged Communities Single-Family Affordable Solar Homes Program
DAWG	—	Demand Analysis Working Group
DC	—	direct current
DCFC	—	direct current fast charging
DER	—	distributed energy resource
DGS	—	Department of General Services
DPM	—	diesel particulate matter
DR	—	demand response

DRAM	—	Demand Response Auction Mechanism
dth	—	Dekatherm
E3	—	Energy and Environmental Economics
EDD	—	Employment Development Department
EDF	—	Environmental Defense Fund
EIM	—	energy imbalance market
EPIC	—	Electric Program Investment Charge
ESCO	—	energy service company
ESP	—	electric service provider
EV	—	electric vehicle
EVI-Pro	—	Electric Vehicle Infrastructure Projections tool
EVSE	—	electric vehicle supply equipment
FCEV	—	fuel cell electric vehicle
FERC	—	Federal Energy Regulatory Commission
GHG	—	greenhouse gas
Go-Biz	—	Governor’s Office of Business and Economic Development
GovOPS	—	California Government Operations Agency
GRC	—	Governance Review Committee
GSP	—	gross state product
GWh	—	gigawatt hours
GWP	—	global warming potential
HD	—	heavy-duty
HFC	—	hydrofluorocarbon
HVAC	—	heating, ventilation, and air conditioning
ICARP	—	Integrated Climate Adaptation and Resiliency Program
ICCT	—	International Council on Clean Transportation
IEPR	—	Integrated Energy Policy Report
IID	—	Imperial Irrigation District
INFORM	—	Integrated Forecast and Reservoir Management
IOU	—	investor-owned utility
IRP	—	integrated resource plan
JASC	—	Joint Agency Steering Committee
kV	—	kilovolt
kW	—	kilowatt
LADWP	—	Los Angeles Department of Water and Power
LBNL	—	Lawrence Berkeley National Laboratory
LCFS	—	Low Carbon Fuel Standard
LSE	—	load-serving entity
LTPP	—	Long-Term Procurement Plan
MD	—	medium-duty
MMBtu	—	million British Thermal Units
MMcf	—	million cubic feet
MMcfd	—	million cubic feet per day

MTC	—	Metropolitan Transportation Commission
MMT CO_2e	—	million metric tons of carbon dioxide equivalent
MT CO_2e	—	metric tons of carbon dioxide equivalent
MVAr	—	mega volt amp reactive
MW	—	megawatt
MWh	—	megawatt-hour
NERC	—	North American Electric Reliability Corporation
NF_3	—	nitrogen trifluoride
NO_x	—	oxides of nitrogen
NREL	—	National Renewable Energy Laboratory
OFO	—	operational flow order
OIR	—	order instituting rulemaking
OPR	—	Governor's Office of Planning and Research
OTC	—	once-through cooling
PEV	—	plug-in electric vehicle
PFC	—	perfluorocarbon
PG&E	—	Pacific Gas and Electric
PHEV	—	plug-in hybrid electric vehicle
PIER	—	Public Interest Energy Research
POU	—	publicly owned utility
PPA	—	power purchase agreement
PSPS	—	public safety power shutoff
PV	—	photovoltaic
Quad Btus	—	quadrillion British thermal units
RASS	—	Residential Appliance Saturation Survey
RD&D	—	research, development, and demonstration
RFS2	—	Renewable Fuel Standard
RNG	—	renewable natural gas
RPS	—	Renewables Portfolio Standard
SACOG	—	Sacramento Council of Governments
SANDAG	—	San Diego Association of Governments
San Onofre	—	San Onofre Nuclear Generating Station
SB	—	Senate Bill
SCAG	—	Southern California Association of Governments
SCE	—	Southern California Edison
SCP	—	Sonoma Clean Power
SCRP	—	Southern California Reliability Project
SDG&E	—	San Diego Gas & Electric
SF_6	—	sulfur
SMUD	—	Sacramento Municipal Utility District
SoCalGas	—	Southern California Gas Company
SOMAH	—	Solar on Multifamily Affordable Housing Program
TCOE	—	total cost of energy

TECH	—	Technology and Equipment for Clean Heating
TOU	—	time-of-use
TRU	—	transportation refrigeration units
TPP	—	Transmission Planning Process
UCD	—	University of California, Davis
U.S. DOE	—	United States Department of Energy
U.S. EIA	—	United States Energy Information Administration
U.S. EPA	—	United States Environmental Protection Agency
V2G	—	vehicle-to-grid
VGI	—	vehicle grid integration
Western EIM	—	Western Energy Imbalance Market
WIEB	—	Western Interstate Energy Board
WIRAB	—	Western Interconnection Regional Advisory Board
ZEV	—	zero-emission vehicle

Glossary

Additional achievable energy efficiency

Additional achievable energy efficiency savings include incremental savings from the future market potential identified in utility potential studies not included in the baseline demand forecast, but reasonably expected to occur, including future updates of building codes, appliance regulations, and new or expanded investor-owned utility or publicly owned utility efficiency programs.

Biogas

Biogas is a type of biofuel that is naturally produced from the decomposition of organic waste (such as food scraps). Biofuels differ from fossil fuels because a biofuel is fuel from recently living biological matter, where fossil fuels come from long dead biological matter.

Biomass

Biomass refers to plant or animal matter used for energy production.

Carbon intensity

Carbon intensity refers to the amount of carbon (in terms of weight) emitted per unit of energy consumed.

Climate adaptation

A growing body of new policies—referred to as "climate adaptation"—is intended to grapple with what is known from climate science and incorporate planning for climate change into the routine business of governance, infrastructure management, and administration.

Community choice aggregation

Community choice aggregation (or CCA) lets local jurisdictions aggregate, or combine, their electricity load to purchase power on behalf of their residents. In California, community choice aggregators are legally defined by state law as electric service providers and work together with the region's existing utility, which continues to provide customer services (for example, grid maintenance and power delivery). (For more information see "What Is CCA?" http://www.leanenergyus.org/what-is-cca/ or "Community Choice Is Transforming the California Energy Industry," http://newsroom.ucla.edu/releases/community-choice-is-transforming-the-california-energy-industry.)

Disadvantaged Communities Green Tariff Program

The *Disadvantaged Communities Green Tariff Program*, or *DAC-GT*, allows disadvantaged community residents to subscribe to receive electricity generated from a solar generating plant in California and receive a 20 percent discount on their overall bill.

Disadvantaged Communities Single-Family Affordable Solar Homes Program

The *Disadvantaged Communities Single-Family Affordable Solar Homes Program*, or *DAC-SASH*, provides upfront incentives for solar installations by low-income residents/owners of single-family homes in disadvantaged communities.

Distributed energy resources

Distributed energy resources include:

- *Demand response*, which has been used traditionally to shed load in emergencies. It also has the potential to be used as a low-greenhouse gas, low-cost, price-responsive option to help integrate renewable energy and provide grid-stabilizing services, especially when multiple distributed energy resources are used in combination and opportunities to earn income make the investment worthwhile. Demand response generally refers to a temporary change in energy consumption, generally with a decrease in service level.
- Distributed renewable energy generation, primarily rooftop photovoltaic energy systems.
- "Vehicle grid integration," or all the ways plug-in electric vehicles can provide services to the grid, including coordinating the timing of vehicle charging with grid conditions.
- Energy storage in the electric power sector to capture electricity or heat for use later to help manage fluctuations in supply and demand.

Electric service provider

An *electric service provider* is a company that purchases wholesale electricity from electricity generators and sells it at a retail level to the general public.

Federal Energy Regulatory Commission

The *Federal Energy Regulatory Commission*, also known as *FERC*, is an independent agency that regulates interstate transmission of electricity, oil, and natural gas. It also regulates natural gas and hydropower projects in the United States.

Fossil natural gas

Fossil natural gas is hydrocarbon gas found in the earth, composed of methane, ethane, butane, propane, and other gases.

Greenhouse gas emission profile

A *greenhouse gas emission profile* offers detailed information about the energy use of a building and levels of greenhouse gas emissions and identifies initiatives that could reduce energy use and cost.

Hybrid resources

Hybrid resources are a combination of multiple generation technologies that are physically and electronically controlled by a single owner/operator and scheduling coordinator and behind a single point of interconnection that participates in the California Independent System Operator

(California ISO) market as a single resource with a single market resource ID. The hybrid resource definition is evolving as the California ISO progresses through its stakeholder process and receives feedback.

Inverter

An *inverter* is an electronic device or circuitry that converts power from a direct current source (such as solar panels or a wind turbine) to alternating current, so that it can be moved over the transmission and distribution system and be used by consumers.

Load-serving entity

A load-serving entity is defined by the California Independent System Operator as an entity that has been "granted authority by state or local law, regulation or franchise to serve [their] own load directly through wholesale energy purchases." For more information see the California Independent System Operator's Web page.

Metric ton

A *metric ton* is a unit of weight equal to 1,000 kilograms (or 2,205 pounds).

Microgrid

A group of interconnected loads and distributed energy resources (DER) within clearly defined electrical boundaries that act as a single controllable entity with respect to the grid. Additionally, a microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode. Finally, microgrids can also manage customer critical resources and provide the customers, utilities, and grid system operators different levels of critical services and support as needed.

Net load

Net load is electricity load minus solar and wind generation.

North American Electric Reliability Corporation

The *North American Electric Reliability Corporation*, also known as *NERC*, is an international regulatory authority whose mission is to reduce risks to the reliability and security of the grid. Its area of responsibility spans the continental United States, Canada, and the northern part of Baja California, Mexico.

Once-through cooling

Once-through cooling technologies intake ocean water to cool the steam that is used to spin turbines for electricity generation. The technologies allow the steam to be reused, and the ocean water that was used for cooling becomes warmer and is then discharged back into the ocean. The intake and discharge have negative impacts on marine and estuarine environments.

Public safety power shutoff

A *public safety power shutoff*, also known as *PSPS*, is a system used by utilities to prevent wildfires by proactively turning off electricity when gusty winds and dry conditions present a heightened fire risk. More information can be found at the Prepare for Power Down Web page.

Renewable natural gas

Renewable natural gas, also referred to as RNG, is a pipeline quality alternative to fossil natural gas that is made by capturing and upgrading biomethane from a variety of sources, including municipal solid waste landfills, digesters at water resource recovery facilities (wastewater treatment plants), livestock farms, food production facilities, and organic waste management operations. RNG is not found in the earth and is the result of processing. RNG can be produced by combining hydrogen (produced from excess renewable generation) with carbon dioxide (from carbon capture and sequestration) at elevated temperatures and pressures in the presence of a catalyst to produce methane and water.

Renewables Portfolio Standard

The *Renewables Portfolio Standard*, also referred to as *RPS*, is a program that sets continuously escalating renewable energy procurement requirements for California's load-serving entities. The generation must be procured from RPS-certified plants and the California Energy Commission verifies RPS claims.

Solar-plus-storage

A *solar-plus-storage* project is a battery system that is charged by a connected solar system.

Solar on Multifamily Affordable Housing Program

The *Solar on Multifamily Affordable Housing Program*, or *SOMAH*, provides funding to encourage the installation of solar on existing multifamily affordable housing.

Transmission Planning Process

The California Independent System Operator's annual transmission plan serves as the formal roadmap for infrastructure requirements. This process includes stakeholder and public input and uses the best analysis possible (including the Energy Commission's annual demand forecast) to assess short- and long-term transmission infrastructure needs.

Western Electricity Coordinating Council

The *Western Electricity Coordinating Council*, also known as *WECC*, is a nonprofit organization that works to address risks to the reliability and security of the Western Interconnection's power system.

Western Energy Imbalance Market

The *Western Energy Imbalance Market*, or Western EIM, is a real-time bulk power trading market. The Western EIM's systems automatically find the lowest-cost energy to serve customer demand across a wide geographic area in the western United States.

Western Interconnection

The *Western Interconnection* is a wide area synchronous grid. It is one of the two major alternating current power grids in the continental United States (the other is the Eastern Interconnection).

Western Interstate Energy Board

The *Western Interstate Energy Board* is an organization of 11 western states and three Canadian provinces. The Board promotes energy policy that is developed cooperatively among member states and provinces and with the federal government.

Zero-emission vehicles

There are three types of zero-emission vehicles:

- Battery-electric vehicles (BEVs) that refuel exclusively with electricity.
- Plug-in hybrid electric vehicles (PHEVs) that can refuel with either electricity or another fuel, typically gasoline. BEVs and PHEVs are collectively known as "plug-in electric vehicles," or PEVs.
- Fuel cell electric vehicles (FCEVs) that refuel with hydrogen.

APPENDIX A: Assembly Bill 1257- Natural Gas Benefits

Background

This appendix meets the requirements of Assembly Bill 1257 (Bocanegra, Chapter 749, Statutes of 2013), referred to as the Natural Gas Act. The legislation directs the California Energy Commission (CEC) to "identify strategies to maximize the benefits obtained from natural gas, including biomethane for purposes of this section, as an energy source, helping the state realize the environmental and cost benefits afforded by natural gas." The statute required the CEC to perform this analysis first as part of the *2015 Integrated Energy Policy Report* (*2015 IEPR*) and then every four years thereafter. This analysis for the *2019 IEPR* is the first update to the one completed as part of the *2015 IEPR*.

Since the passage of AB 1257, Senate Bill 1374 (Hueso, Chapter 611, Statutes of 2018) amended the Natural Gas Act statutes by ending the reporting requirement on November 1, 2025.[604] Further, the state has enacted policies with potentially significant impacts on natural gas use, including Senate Bill 32 (Pavley, Chapter 249, Statutes of 2016) and Senate Bill 100 (De León, Chapter 310, Statutes of 2018).

As directed by AB 1257, the CEC is consulting with the California Public Utilities Commission (CPUC); the State Water Resources Control Board (SWRCB); the California Independent System Operator (California ISO); the California Air Resources Board (CARB); the Department of Oil, Gas, and Geothermal Resources (DOGGR); and the Department of Conservation to obtain relevant input. The CEC is also collaborating with California's gas utilities, other state and federal agencies, and other organizations on developing low-emission natural gas and hydrogen technologies for the transportation sector, more efficient uses for natural gas, low-carbon fuels and a fueling infrastructure, as well as pathways to decarbonize California's energy system. In addition, the CEC's Natural Gas Research and Development Program and the Clean Transportation Program (formerly known as the Alternative and Renewable Fuel and Vehicle Technology Program) have provided funding and technical expertise in support of these collaborations.

604 The last report will be due in 2026.

This section discusses these strategies, which include studies, research, projects, and other initiatives by the CEC and other agencies to optimize the use of natural gas while working to achieve carbon neutrality.

Requirements of the Statute

Section 25303.5(b) (1): Optimizing Natural Gas as a Transportation Fuel

This section summarizes CEC compliance with AB 1257 requirements to optimize natural gas as a transportation fuel, using funding from the CEC's Natural Gas Research and Development Program and the Clean Transportation Program.

Natural Gas Vehicles

Natural gas vehicles and fueling infrastructure are commercially mature alternative transportation technologies, and California has deployed a significant number of these vehicles. Nearly 19,000 medium- and heavy-duty natural gas vehicles operate in California, making this fuel type the most common alternative fuel vehicle in each of these vehicle classes. California leads the nation in the number of compressed natural gas (CNG) and liquefied natural gas (LNG) fueling stations, with 328 public or private CNG stations and 46 public or private LNG stations. Low-carbon biomethane and the latest natural gas engine emission control technologies can also provide substantial reductions in greenhouse gas (GHG) and criteria pollutant emissions compared to a conventional diesel truck. Biomethane has some of the lowest carbon intensity values. Biomethane from wastewater biogas offers life-cycle GHG emissions reductions of as much as 92 percent compared to diesel, while biomethane derived from high-solids anaerobic digestion can reduce life-cycle GHG emissions by upward of 125 percent.[605]

The CEC's Natural Gas Research and Development Program supports the development of advanced near-zero emission natural gas engines that use renewable natural gas and hybrid gas/electric fuels. Past funding awards supported natural gas engines designed to meet the 2010 emissions standard. The program funded the development of Cummins Westport Inc.'s Near-Zero natural gas engines to provide low-emission alternatives to diesel engines for the heavy-duty vehicle market to power transit buses, refuse haulers, vocational trucks, and goods movement trucks. With this funding, Cummins Westport Inc. was able to certify 9-liter and 12-liter variations of the Near-Zero engines that met the CARB's most stringent optional low NO_x

605 Brecht, Patrick. 2019. 2019-2020 Investment Plan Update for the Clean Transportation Program. California Energy Commission, Fuels and Transportation Division. Publication Number: CEC-600-2018-005-LCF-REV2.

standard.[606] Cummins Westport Inc. has produced 3,900 Near-Zero engines as of June 2018. Since the introduction of the Near-Zero engines into the market, several state and local clean transportation incentive programs have provided funding for fleets to accelerate adoption of these engines because of the associated low NO_x and GHG emissions compared to diesel engines.

In its Fiscal Year 2019–2020 funding request and program plan for the Natural Gas Research and Development Program submitted to the CPUC, the CEC proposed projects that will demonstrate advanced zero-emission fuel cell technologies in rail and marine applications at California ports because these are difficult to decarbonize using battery-electric alternatives. Possible projects include the conversion of an existing diesel switcher or intrastate locomotive operating at a California port to zero emissions. The conversion would entail using fuel cell technology and the development of a zero-emission fuel cell harbor craft such a tugboat or ferry with sufficient torque, speed, and operating range to support the specific duty cycle.

Clean Transportation Program

Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007), created the Clean Transportation Program. The statute authorizes the CEC to develop and launch alternative and renewable fuels and advanced transportation technologies to help attain the state's climate change goals. These fuels include biomethane, which, along with fossil natural gas, fuels some of the advanced transportation technologies supported by the Clean Transportation Program. Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013) reauthorizes the Clean Transportation Program through January 1, 2024, and required the CEC allocate up to $20 million per year (or up to 20 percent of each fiscal year's funds) for hydrogen station development until at least 100 stations are operational. These policies have shifted motor vehicle programs, grants, and other incentives away from petroleum-based fuels and fossil natural gas to reach GHG emissions goals at the lowest cost by promoting the transformation of zero-emission vehicle (ZEV) markets.

As of March 2019, the Clean Transportation Program has provided $83 million for the deployment of natural gas vehicles. This amount includes funding to the San Joaquin Valley Unified Air Pollution Control District and the South Coast Air Quality Management District to support incentive programs for natural gas vehicles. Additional Clean Transportation Program funds targeted the oldest diesel school buses operating in districts with disadvantaged

606 "NO_x," also known as oxides of nitrogen, forms when fuel is burned at high temperatures. Information on Earth's atmosphere from the Cool Cosmos Web page http://coolcosmos.ipac.caltech.edu/ask/64-What-is-the-atmosphere-of-Earth-made-of-.

communities and high participation in free or reduced price lunches. While most of the available funding was for electric buses the Clean Transportation Program awarded a limited amount of funding for natural gas vehicle deployment that could go toward natural gas school buses for school districts that certified an electric school bus would be unable to meet their needs. The Clean Transportation Program has also funded natural gas fueling infrastructure—nearly $22 million toward the installation or upgrade of about 64 natural gas fueling stations.

The CEC did not allocate any Fiscal Year 2019–2020 Clean Transportation Program funding for natural gas vehicle incentives or infrastructure projects.[607] However, incentives for natural gas vehicles are available through CARB's Hybrid and Zero-Emission Truck and Bus Voucher Initiative and Low NO_x Engine Incentives.[608]

Section 25303.5(b) (2): Determining the Role of Natural Gas-Fired Generation as Part of a Resource Portfolio

Natural Gas for Electric Generation

Through SB 100, the Legislature has directed state energy agencies to accelerate the transformation of California's electric grid to 100 percent zero-carbon resources by 2045. Natural gas-fired generation accounts for the largest share of in-state generation,[609] and has declined in recent years. In the near term, natural gas will continue to play an important role in the integration of renewable resources and ensuring reliability. A proposed decision, issued by the CPUC on September 12, 2019, requires electric system reliability procurement by all CPUC-jurisdictional load-serving entities (LSEs) from 2021 through 2023 and calls for extending the retirement dates of 2,500 megawatts (MW) to 3,750 MW of natural gas-fired once-through cooling (OTC) capacity on the South Coast beyond the current December 31, 2020, retirements.[610] Chapters 1 and 6 discuss these topics further.

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607 Brecht, Patrick. 2019. 2019-2020 Investment Plan Update for the Clean Transportation Program. California Energy Commission, Fuels and Transportation Division. Publication Number: CEC-600-2018-005-LCF-REV2.

608 CARB, in partnership with CALSTART, launched this program in 2009. Link to program information https://www.californiahvip.org/how-to-participate/#steps-to-participate-in-hvip.

609 CEC. California Electrical Energy Generation. Link to download California Electrical Energy Generation file from the CEC's website https://www.energy.ca.gov/almanac/electricity_data/electricity_gen_2001-current.xlsx.

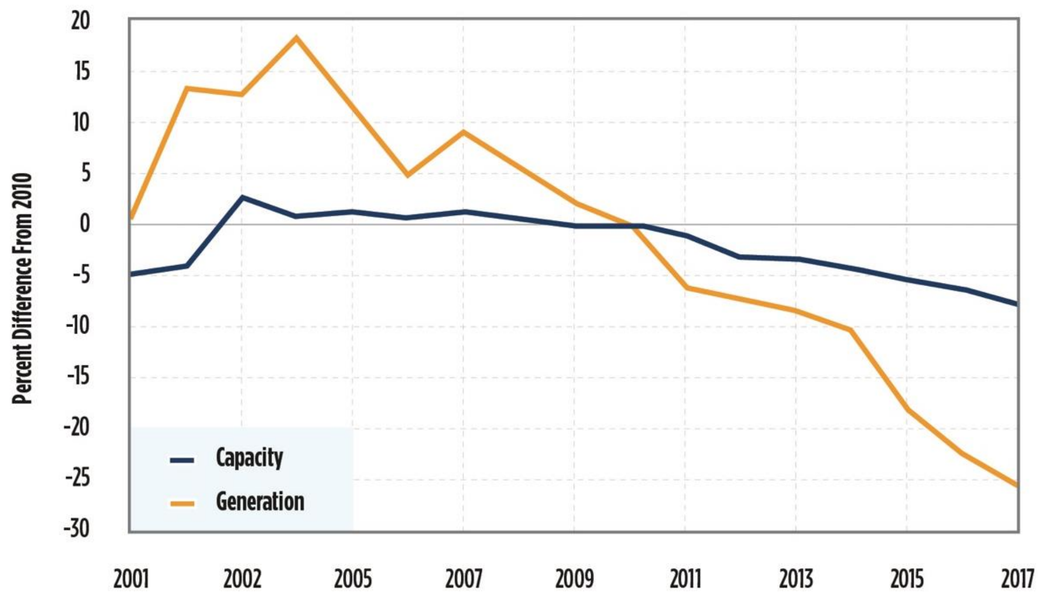
610 CPUC. 2019. Decision Requiring Electric System Reliability Procurement for 2021-2023 (R.16-02-007). Link to Proposed Decision in Rulemaking 16-02-007 on the CPUC's website http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M312/K522/312522263.PDF.

Combined Heat and Power

A properly sized and operated combined heat and power—also known as cogeneration—plant can produce thermal, mechanical, and electrical energy using less fuel than would otherwise be used to produce the same energy via a more traditional system of boilers and central-station grid electricity. In the near term, large-scale combined heat and power use will continue as energy-intensive industries make use of efficiency and cost-saving opportunities, particularly at refineries, chemical plants, and food processing plants. However, as California looks to decrease its use of fossil natural gas as required by SB 100, combined heat and power generation is expected to decline.

Recent years have seen a decline in capacity and output from existing resources that significantly outpaces the addition of new combined heat and power plants. From 2010 to 2017, California's combined heat and power fleet has decreased 8 percent in nameplate capacity and 25 percent in annual electrical generation. Figure 58 shows the annual percentage changes to combined heat and power capacity and generation relative to 2010.

Figure 58: Historical Capacity and Generation Relative to 2010



Source: CEC staff

California's primary combined heat and power program is the CPUC-administered Qualifying Facilities and Combined Heat and Power Program.[611] The Qualifying Facilities Settlement Agreement sets capacity targets for investor-owned utilities (IOUs) to contract (through competitive solicitations) with eligible combined heat and power plants and sets GHG emissions reduction targets. Tables 27 and 28 show the settlement targets and progress to date. The IOUs based the revised GHG targets and progress toward their procurement and GHG reduction targets on their April 2016 semiannual reports to the CPUC. These are subject to change as more data become available.

Table 27: Tracking QF Settlement MW Targets (MW)

Utility	Combined Heat and Power Capacity Procured by IOUs to Date	IOUs 2015 Combined Heat and Power Targets	Remaining Capacity to Procure
Pacific Gas and Electric (PG&E)	1,497	1,387	0
Southern California Edison (SCE)	1,455	1,402	0
San Diego Gas & Electric (SDG&E)	134	211	77
Total	3,086	3,000	77

Source: CPUC

611 Link to Overview of the Combined Heat and Power Program at the CPUC https://www.cpuc.ca.gov/General.aspx?id=5432.

Table 28: Tracking Qualifying Facilities Settlement GHG Targets (in Million Metric Tons Carbon Dioxide Equivalent [MMT CO_2e])

Utility	Revised GHG Target (D.15-06-028)	Utility Progress Toward GHG Target	Remaining Reductions
PG&E	1.23	1.53	0
SCE	1.23	1.01	0.22
SDG&E	0.283	0.02	0.26
Total	2.74		0.48

Source: CPUC

Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007), the Waste Heat and Carbon Emissions Reduction Act, established a feed-in tariff for eligible combined heat and power projects less than 20 MW that meet certain performance and emission standards.[612] However, participation has been minimal. To date, there are six certified projects totaling 53.9 MW.

The Self-Generation Incentive Program provides incentives to eligible distributed energy systems installed on the customer's side of the utility meter, including small, clean, and efficient combined heat and power units. The program has been modified over the years to support the commercialization of emerging technologies, reduce emissions, and provide GHG benefits. As the program evolved, funding was reduced from a majority allocated to combined heat and power and fuel cells in 2015 to mostly energy storage to date.[613] Starting in 2016, new generation projects (including CHP) were allocated 25 percent of the funds in 2016 and 15 percent of the funds in 2017.[614] In addition, beginning in 2017, natural gas technologies had to be fueled by a mixture of at least 10 percent biogas to retain program eligibility. This requirement becomes more stringent each year, reaching 100 percent biogas in 2020.

There is potential for combined heat and power at plants that produce biogas, as the heat can be used to maintain digester temperatures. Development at potential digester sites, such as wastewater treatment plants and dairy farms, is supported by Senate Bill 1122 (Rebio, Chapter 612, Statutes of 2012), the Bioenergy Feed-in Tariff Program. While the biogas may be used

612 Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007).

613 CPUC, Decision 16-06-055, Rulemaking 12-11-005, July 1, 2016, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K928/163928075.PDF

614 CPUC, Decision17-04-017, Rulemaking 12-11-005, April 13, 2017, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M183/K843/183843620.PDF.

onsite to generate electricity, the greatest financial incentive is to use the gas as vehicle fuel. However, this use as a vehicle fuel relies on the use of substantial federal and California environmental credits, which are vulnerable to the risk of policy change.

In May 2017, the CPUC followed through with a previous decision to enact a Distributed Energy Resources Tariff. This tariff allows Southern California Gas Company (SoCalGas) to design, install, own, operate, and maintain advanced energy systems, including many forms of combined heat and power, on or near the customer's premises. It is designed to help overcome barriers for potential customers that might lack the internal capital and experience necessary to develop and operate such facilities. The Distributed Energy Resources Tariff could help develop the largely untapped market potential of combined heat and power plants with 20 MW or less in nameplate capacity.

In March 2019, the CEC issued a report on the assessment of small-scale combined heat and power technical and market potential in California.[615] In addition to identifying potential, the report highlights the role of combined heat and power in microgrid applications and the ability of flexible combined heat and power systems to support the grid while enabling further adoption of renewable energy resources.

Section 25303.5(b) (3): Optimizing Natural Gas as a Low-Emission Resource

Renewable Natural Gas

According the United States Energy Information Administration (U.S. EIA), the share of renewable natural gas (RNG) in the total natural gas quantity supplied to California's transportation sector grew from roughly 10 percent in 2013 to 70 percent in 2018. This share has reached more than 30 million diesel gallons equivalent, or about 45 million cubic feet per day, for the first time during the third quarter of 2018.[616]

State policies spurred much of this progress. Senate Bill 1440 (Hueso, Chapter 739, Statutes of 2018) requires the CPUC, in consultation with CARB, to consider adopting "specific biomethane procurement targets or goals for each gas corporation."[617] Through March 2019, the CEC also

615 Link to A Comprehensive Assessment of Small Combined Heat and Power Technical and Market Potential in California report on the CEC's website https://www.energy.ca.gov/2019publications/CEC-500-2019-030/CEC-500-2019-030.pdf.

616 Link to Natural Gas Weekly Update for the week ending March 27, 2019, on the U.S. EIA's website

617 CEC staff. 2018. *2018 Integrated Energy Policy Report Update, Volume II*. CEC. Publication Number: 100-2018-001-V2- CMF. p. 16.

provided almost $77 million to 27 biomethane projects and $8 million to two renewable hydrogen projects under the Clean Transportation Program. For Fiscal Year 2019–2020, CEC staff proposes a $10 million allocation for zero- and near-zero-carbon fuel production under the Clean Transportation Program.[618] The CEC will continue to use this funding to support low-carbon fuel and renewable hydrogen production plants in California.

Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016) supports policies that improve the cost-effectiveness and environmentally beneficial uses of biomethane derived from solid waste as part of a strategy to reduce emissions of methane and other short-lived climate pollutants and reduce organic waste in landfills. As part of this legislation, the CPUC is directing natural gas utilities to start at least five pilot projects to demonstrate pipeline injection of biomethane produced by California dairies. On December 14, 2017, the CPUC established an implementation and selection framework for these dairy pilot projects, including a requirement that they demonstrate interconnections with the natural gas pipeline system that meet existing regulations.[619] The procurement program must be a cost-effective means of achieving the forecasted reduction in emissions and short-lived climate pollutants and must adhere to environmental and energy policies. The CPUC expects these pilot projects to demonstrate the feasibility of these project types and provide a model to increase the use of biomethane fuel in California. In December 2018, the CPUC, CARB, and the California Department of Food and Agriculture (CDFA) announced funding for six pilot projects in the San Joaquin and Sacramento Valleys designed to demonstrate the collection of biomethane from dairy digesters and the associated injection into natural gas pipelines. Forty-five dairies will participate in the pilot projects, and the six projects will receive roughly $319 million in infrastructure investments and operation expenses over a 20-year period. More information on these projects is provided below.[620]

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618 Brecht, Patrick. 2019. *2019-2020 Investment Plan Update for the Clean Transportation Program*. CEC, Fuels and Transportation Division. Publication Number: CEC-600-2018-005-LCF-REV2., p. 96, Table 22. Link to 2019-2020 Investment Plan Update for the Clean Transportation Program on the CEC's website https://efiling.energy.ca.gov/getdocument.aspx?tn=229582. Retrieved September 10, 2019.

619 CPUC Decision 17-12-004, Rulemaking 17-06-015, Link to information on Dairy Biomethane pilot projects on the CPUC's website https://www.cpuc.ca.gov/General.aspx?id=6442455827#Dairy_Biomethane_Pilot_Projects.

Link to Decision 17-12-004 on the CPUC's website http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M201/K352/201352373.PDF.

620 Link to press release on dairy biomethane projects on the CPUC's website http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M246/K748/246748640.PDF.

Moreover, Assembly Bill 3187 (Grayson, Chapter 598, Statutes of 2018) required the CPUC, to open a proceeding by July 1, 2019, to consider funding biomethane interconnection infrastructure through a gas corporation's utility rates. In February 2019, SoCalGas and SDG&E filed an application with the CPUC requesting authority to offer a voluntary RNG tariff program that gives their residential, small commercial, and industrial customers the option to purchase this fuel as part of their natural gas service. Under this proposal, customers could designate a portion or all of their natural gas service to come from renewable resources. The CPUC released a scoping memo for this proceeding on August 6, 2019, which set a schedule for a rate-setting proceeding.[621] A proposed decision is expected in spring 2020. While SoCalGas and SDG&E filed the application to offer a voluntary RNG tariff program, PG&E seeks CPUC authority to participate in a program that will allow the utility to begin adding RNG to its supply portfolio, limited initially to its compressed natural gas fueling stations.

The CPUC held a workshop on May 23 and 24, 2019, to consider a standard RNG interconnection tariff and an inquiry into standards required to inject and interconnect renewable methane and hydrogen projects.[622] The CPUC held a follow-up workshop on August 20, 2019, to consider a joint utility proposal to establish a process for considering interconnection requests that would allow RNG blending in pipelines. In R.13-02-008, on August 20, 2019, the CPUC ordered a rulemaking to adopt biomethane standards and requirements, pipeline open access rules, and related enforcement provisions. This proceeding remains open.[623]

CDFA Dairy Digester Research and Development Program

The CDFA Dairy Digester Research and Development Program offers financial assistance for the installation of dairy digesters in California, which reduce dairy manure GHG emissions. The Dairy Digester Research and Development Program Demonstration Projects award competitive grants to California dairy operations and digester developers for implementing dairy digester

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Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016). Link to bill analysis of SB 1383 https://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=201520160SB1383#.

621 CPUC. Scoping Ruling http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M310/K226/310226767.PDF.

622 Link to information on workshops related to dairy biomethane pilot projects on the CPUC's website https://www.cpuc.ca.gov/General.aspx?id=6442455827#R._13-02-008___Phase_3.

623 CPUC. Link to upcoming schedule on the CPUC's Web page https://www.cpuc.ca.gov/General.aspx?id=6442455827#R._13-02-008___Phase_3.

projects that demonstrate innovative technologies to achieve long-term methane emission reductions from California dairies and minimize or address adverse environmental impacts.[624] This program awarded $35.2 million in October 2017 for anaerobic digesters at dairies, along with an additional $72.4 million for additional dairy digester projects in 2018. For the Dairy Digester Research and Development Program, the CDFA receives funding from California Climate Investments, a statewide program that puts billions of cap-and-trade dollars to work reducing GHG emissions, strengthening the economy and improving public health and the environment—particularly in disadvantaged communities. The CDFA posted invitations to apply for 2019 grants on December 28, 2018, with an April 3, 2019, deadline to submit applications. It received 66 applications for the 2019 Dairy Digester Research and Development Program requesting $101,691,712 and received four applications for 2019 Dairy Digester Research and Development Program Demonstration Projects requesting $7,015,333.

California Department of Resources Recycling and Recovery (CalRecycle)

CalRecycle's Organics Grant Program conducted three grant cycles in 2014, 2017, and 2018, which awarded $32.9 million to nine biomethane-producing projects. This competitive grant program sought to lower overall GHG emissions by expanding existing capacity or establishing new plants in California to reduce the amount of California-generated green materials, food materials, alternative daily cover,[625] or a combination thereof, sent to landfills. California Climate Investments funds this program.

Summary

These programs demonstrate the commitment by the CEC, with the support of other state agencies, to meeting the directives of this section of AB 1257.

Section 25303.5(b) (4): Optimizing Natural Gas for Heating, Water Heating, Cooling, Cooking, Engine Operation, and Other End Uses

Building Decarbonization

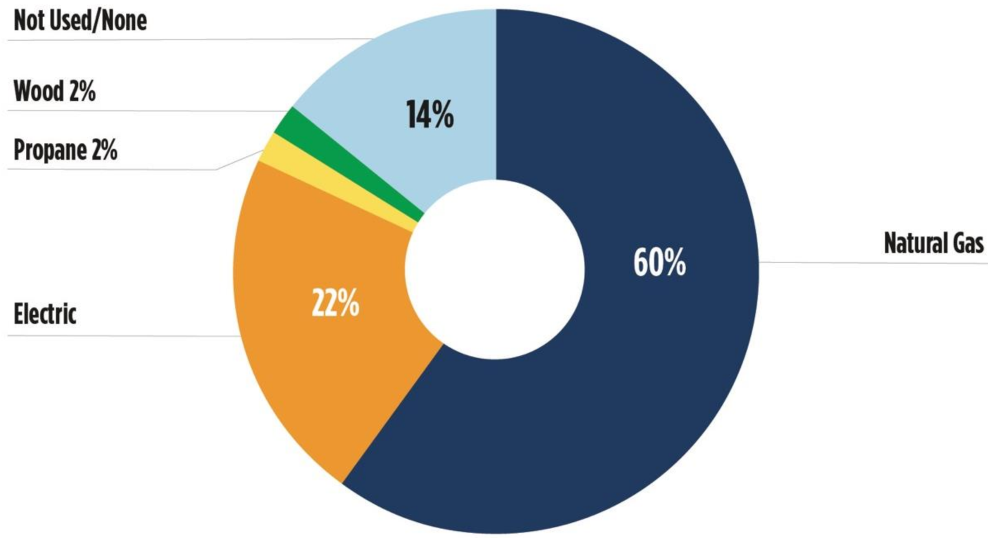
As discussed in Chapter 2, homes use about two-thirds of California's natural gas, 90 percent of which is for space and water heating. Figure 59 below provides a breakdown of space

624 Link to information on DDRDP demonstration projects on CDFA's website https://www.cdfa.ca.gov/oefi/ddrdp/DemoProject.html.

625 "Alternative daily cover" refers to cover material other than earthen material that is placed on the surface of a landfill at the end of each day.

heating by source or fuel type and shows that natural gas is the dominant fuel source over electric.

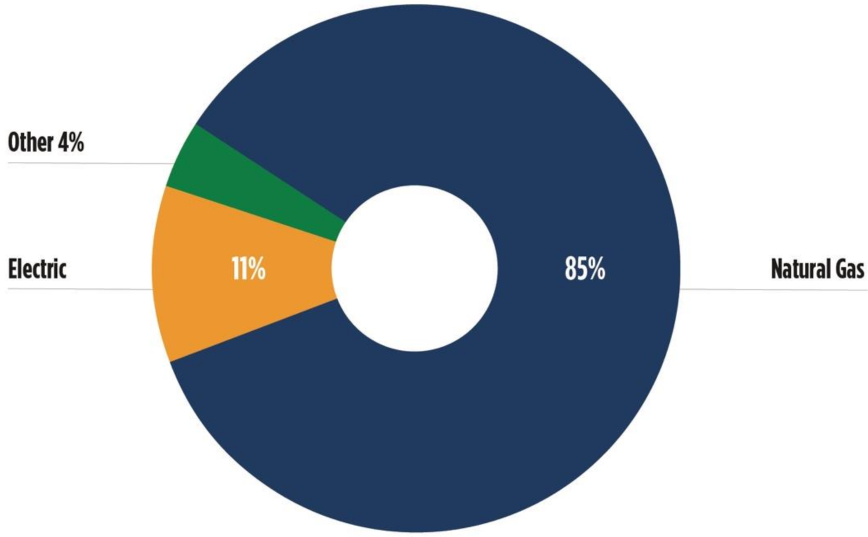
Figure 59: California Residential Space Heating Fuel Type



Source: U.S. EIA Office of Energy Consumption and Efficiency Statistics, Forms EIA-457 A and C of the 2009 Residential Energy Consumption Survey

Figure 60 shows that at 85 percent, natural gas is also the dominant fuel source for residential water heating.

Figure 60: California Residential Water Heating Fuel Type



Source: U.S. EIA, Office of Energy Consumption and Efficiency Statistics, Forms EIA-457 A and C of the 2009 Residential Energy Consumption Survey

In commercial buildings, space heating accounts for a similarly large portion of gas use.[626] The 2018 IEPR Update reviewed research on methane emissions inside California homes, finding that average emissions are equivalent to about 0.5 percent of total natural gas consumed in the residential sector, or 5.8 MMcf per day.[627] The CEC is also funding research testing of 60 to 80 commercial buildings and a handful of industrial plants for fugitive methane emissions.[628]

Building decarbonization was a policy focal point of the 2018 IEPR Update. The 2018 IEPR Update discussed policy goals, sources of GHG emissions in buildings, reasons for pursuing building electrification strategies, the challenges to building decarbonization, utility and CPUC efforts in electrification, and research and development efforts.[629] The potential GHG emissions reductions from building decarbonization prompted the Legislature to pass two bills to offer

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626 CEC staff. 2018. *Draft 2018 Integrated Energy Policy Report Update.* California Energy Commission. Publication Number: 100-2018-001-V2-CMF.

627 Based on statewide residential demand of 1,160 MMcf per day, as estimated by the 2018 California Gas Report, p. 17, "Statewide Total Supply Sources and Requirements."

628 CEC staff. 2018. *Draft 2018 Integrated Energy Policy Report Update.* California Energy Commission. Publication Number: 100-2018-001-V2-CMF, p. 47.

629 Ibid., p. 16.

incentives for the development and deployment of building decarbonization solutions: Senate Bill 1477 (Stern, Chapter 378, Statutes of 2018)[630] and Assembly Bill 3232 (Friedman, Chapter 373, Statutes of 2018).[631] Chapter 2 provides more information on work to implement these bills.

The CEC is funding research to evaluate long-term decarbonization scenarios that identify these solutions, and how they can be integrated into the building stock in the most cost-effective, consumer-friendly manner. The Energy Research and Development Division's Electric Program Investment Charge (EPIC) Program funded the E3 study, Deep Decarbonization in a High Renewables Future published in 2018.[632] The E3 report analyzed long-term energy scenarios for meeting the state's GHG emissions reduction goals in 2030 (40 percent below 1990 levels) and 2050 (80 percent below 1990 levels). E3 found that the high electrification scenario is one of the lower-cost, lower-mitigation scenarios. This scenario includes high levels of energy efficiency and conservation, renewable electricity, and transportation electrification. It also assumes that the state's residential and commercial buildings transition from using natural gas to electricity for heating. Further, it includes pipeline-supplied biomethane to serve mainly industrial end uses, which can include heating, water heating, cooling, cooking, and engine operations.

EFI conducted a study that used a different approach and inputs to analyze pathways to decarbonize the energy system. Its 2019 study Optionality, Flexibility, and Innovation, Pathways for Deep Decarbonization in California analyzed a wide range of sector-specific pathways for meeting the state's 2030 and 2050 targets.[633] The study does not identify a

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630 Under CPUC's oversight, SB 1477 provides incentives for near-zero emission homes through incentives and market support of low emission space- and water-heating equipment and technologies in new and existing homes. The bill also provides incentives for low-income residents.

631 AB 3232 commits the CEC to developing by 2021 a feasibility assessment of a 40 percent reduction in building GHG emissions from 1990 levels by 2030.

CEC. 2019. "Notice of Joint Agency Workshop on Building Decarbonization." [Link to Notice of Joint Agency Workshop on Building Decarbonization filed on the CEC's website](https://efiling.energy.ca.gov/getdocument.aspx?tn=227441)
https://efiling.energy.ca.gov/getdocument.aspx?tn=227441.

632 Mahone, Amber, Zachary Subin, Jenya Kahn-Lang, Douglas Allen, Vivian Li, Gerrit De Moor, Nancy Ryan, Snuller Price. 2018. Deep Decarbonization in a High Renewables Future: Updated Results from the California PATHWAYS Model. California Energy Commission. Publication Number: CEC-500-2018-012.

633 EFI. May 2019. *Optionality, Flexibility, and Innovation, Pathways for Deep Decarbonization in California*
https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5ced6fc515fcc0b190b60cd2/1559064542876/EFI_CA_Decarbonization_Full.pdf.

single technology or fuel as the sole solution to achieve existing decarbonization targets; however, in the industrial sector, EFI found that the biggest GHG emission reductions by 2030 came from carbon capture, utilization, and storage (CCUS) technologies.[634] EFI's analysis also showed that, in the building sector, energy efficiency achieved the largest reduction of emissions by 2030 and therefore was more cost-effective than building electrification.[635]

Section 25303.5(b) (5): Identifying Effective Methods by Which Electric and Natural Gas Industries Can Facilitate Implementation of Any of These Strategies

As discussed above, natural gas-fired generation is poised to continue to support electric load in circumstances where other resources are not reliable or cost-effective. These circumstances are described in Chapters 1 and 10 in the discussion of the grid support provided by natural gas-fired capacity as the state integrates increasing amounts of renewable resources.

As the CEC, CPUC, California ISO, and other state agencies plan for the energy future mandated by Senate Bill 100 (De León, Chapter 312, Statutes of 2018), Senate Bill 32 (Pavley, Chapter 249, Statutes of 2016), and other climate and energy legislation, there are opportunities for the electric and natural gas industries to ease implementation of the strategies identified by AB 1257. These opportunities are being explored through SB 100.

Section 25303.5(b) (6): Determining the Need for a Long-Term Infrastructure Reliability Policy

Methane Leak Reduction on the Natural Gas System

Methane is a GHG that is 25 times more potent than carbon dioxide. The production and distribution of natural gas results in intentional (vented or flared) and unintentional (leaked or fugitive) emissions from the wellhead through the transmission and distribution system to the homes, businesses, and manufacturers that use natural gas. The CEC has funded research quantifying methane leakage from oil and gas production fields, oil refineries, natural gas storage fields and compressor stations, natural gas refueling stations, and single-family homes.[636] Oil and gas production, processing, and storage facilities and natural gas

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634 Ibid, pp. XVI-XVII.

635 Ibid.

636 Fischer, Marc, Seongeun Jeong, Ian Faloona, and Shobhit Mehrota. 2016. *A Survey of Methane Emissions from the California Natural Gas System*. California Energy Commission. Publication Number: CEC-500-2017-033.

compressor stations allow the escape of the largest amount of emissions in the natural gas supply chain. In March 2017, CARB addressed these emissions with the adoption of the GHG Emission Standards for Crude Oil and Natural Gas Facilities, which CARB designed to reduce methane emissions from oil and gas facilities and equipment.[637] These facilities account for an estimated 4 percent of methane emissions in California.[638] The regulatory framework requires oil and gas entities to take actions to limit all emissions. (See Chapter 2 for more information on methane leakage.)

California's aging natural gas infrastructure further complicates efforts to reduce GHG emissions. However, climate change policies and economic losses are pushing natural gas pipeline operators to implement programs aimed at methane leak reductions from this infrastructure. Further, the CEC's Natural Gas Research and Development Program has funded technologies that increased the cost-effectiveness of methane leak detection and developed innovative methods to protect natural gas infrastructure. In 2016, the CEC awarded Natural Gas Research and Development funds to the National Aeronautics and Space Administration's Jet Propulsion Laboratory to conduct an aerial survey of natural gas infrastructure in high priority parts of the state to identify locations emitting large amounts of methane.

The CEC provided funding for research that will support life-cycle accounting of methane emissions from the natural gas supply chain and to conduct a comprehensive field study identifying and addressing methane emissions in the southern San Joaquin Valley. Climate change policies and economic losses are also leading natural gas pipeline operators to implement programs aimed at reducing methane leaks. Pipeline operators of transmission and distribution systems are using innovative technologies for detecting leaks, monitoring pipelines, and prioritizing leak repair. Technologies include optical gas imaging cameras, remote methane leak detection, combustible gas detectors, and optical methane detectors. Finally, the Environmental Defense Fund and Google Earth Outreach are piloting a program for

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Fischer, Marc L., Wanyu Chan, Seongeun Jeong, and Zhimin Zhu. Lawrence Berkeley National Laboratory. 2018. *Natural Gas Methane Emissions From California Homes*. California Energy Commission. Publication Number: CEC-500-2018-021.

637 California Air Resources Board (California Environmental Protection Agency). 2018. CARB's Oil and Gas Methane Regulation https://www.arb.ca.gov/sites/default/files/2018-08/CARB_Oil_and_Gas_Fact_Sheet_8-15-18_0.pdf.

638 Information on oil and natural gas production, processing, and storage from CARB's website https://www.arb.ca.gov/our-work/programs/oil-and-natural-gas-production-processing-and-storage. Retrieved September 12, 2019.

gas utilities throughout the United States that demonstrates new technologies (mobile monitoring equipment) to locate and assess methane leaking from underground natural gas pipelines and other infrastructures.[639]

Assembly Bill 1420 (Salas, Chapter 601, Statutes of 2015) requires stricter natural gas pipeline safety rules, effective January 1, 2018. Previous law only required minimum safety standards for oil and gas production facilities, including pipelines. Owners or operators of gathering[640] or urban pipelines over 4 inches in diameter were required to "perform a mechanical integrity test on the pipeline every 2 years, unless it was less than 10 years old." The new safety regulations, promulgated by DOGGR at the California Department of Conservation, as directed by AB 1420, require the following:

> "Operators shall inspect all active gas pipelines in sensitive areas that are 10 or more years old for leaks or other defects at least once a year, or at a frequency approved by the Supervisor and listed in the operator's Pipeline Management Plan. The operator shall conduct the inspection in accordance with applicable regulatory standards or, in the absence thereof, an accepted industry standard that is specified by the operator and listed in the Pipeline Management Plan."[641]

In the wake of the massive leak at the Aliso Canyon gas storage facility, the CEC has partnered with DOGGR and other agencies in conducting research and considering regulation and remediation efforts to satisfy the Legislature's directives to ensure pipeline safety while protecting sensitive areas.[642]

Considerations for Using Hydrogen in the Natural Gas System

Hydrogen offers multiple uses as a sustainable energy source for stationary fuel cell systems for buildings, backup power, and distributed generation, and fuel cell electric vehicles used in transportation. As noted in Chapter 1, the CEC received comments on the draft *2019 IEPR*

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639 [Link to Four Steps to Reduce Natural Gas Leaks article on EDF's website](https://www.edf.org/climate/methanemaps/four-steps-reduce-natural-gas-leaks)
https://www.edf.org/climate/methanemaps/four-steps-reduce-natural-gas-leaks.

640 "Gathering pipelines" are those that transport gas from a production facility to a transmission line or main.

641 California Code of Regulations, Section 1774.1. [Link to final text of regulations for California Code of Regulations Title 14, Chapter 4](https://www.conservation.ca.gov/index/SiteAssets/Pages/rulemaking/Final%20Text%20of%20Regulations.pdf)
https://www.conservation.ca.gov/index/SiteAssets/Pages/rulemaking/Final%20Text%20of%20Regulations.pdf.

642 AB 1420 defines "sensitive areas" as areas containing a building for human occupancy, areas that present a significant potential threat to life, health, property, or natural resources, and areas with an active gas pipeline with a history of chronic leaks.

highlighting the role hydrogen and fuel cells can play in helping integrate renewable resources, providing long-term energy storage, and adding resilience to the grid.

For example, hydrogen can serve as a "power-to-gas" fuel that stores renewable energy at utility scale.[643] Consequently, policy makers have taken action to promote its production and supply in California. One way to distribute hydrogen is through the natural gas infrastructure. Relatively low concentrations of hydrogen of 5 to 15 percent by volume may be feasible with few modifications to existing pipeline systems or end-use appliances; however, this feasibility assessment will vary from location to location. Higher concentrations introduce challenges, as different types of steel pipe are susceptible to becoming weak or embrittled due to hydrogen exposure, which can increase the risk of pipeline rupture. Policy makers have introduced legislation to research and address these issues and plan and develop an electrolytic hydrogen production and supply infrastructure.

Senate Bill 1369 (Skinner, Chapter 567, Statutes of 2018) requires the CPUC and CEC to, where feasible, authorize procurement of energy storage using "green electrolytic hydrogen," which the statute defines as hydrogen gas produced through electrolysis alone. This legislation therefore rules out hydrogen gas manufactured using steam reformation of natural gas or any other fossil fuel feedstock.

Section 25303.5(b) (7): Determining the Role of Natural Gas in Zero Net Energy Buildings

In the *2018 IEPR Update*, the CEC recommended that "the state should replace its zero-net-energy policy goals with appropriate goals for low-carbon buildings. Zero-emission building goals, while ambitious, are a necessary component of the state's aggressive GHG emission reduction policy initiatives."[644] Chapter 2 discusses the efforts to moving toward zero-emission buildings. Research suggests that reducing emissions from buildings at the lowest cost and with the widest public benefit may require a more comprehensive suite of measures, which can only be efficiently implemented at the larger scale and in phases. Natural gas will continue to be used as existing buildings and new construction transition to zero-emission buildings.

643 "Power-to-gas" refers to the strategy of converting electrical energy into gaseous chemical energy for energy storage or other useful purposes.

644 CEC staff. 2018. *2018 Integrated Energy Policy Report Update, Volume II*. CEC. Publication Number: 100-2018-001-V2-CMF. (p. 197) Link to *2018 IEPR Update* on the CEC's website https://www.energy.ca.gov/2018publications/CEC-100-2018-001/CEC-100-2018-001-V2-CMF.pdf.

Section 25303.5(b) (8): Optimizing Jobs Development in the Private Sector, Particularly in Distressed Areas

The CEC continues to support investment in jobs that develop the infrastructure needed to satisfy legislative mandates for a carbon-neutral economy. With respect to the natural gas sector, these jobs include production of natural gas from dairy digesters, municipal solid waste and wastewater treatment plants, wood waste plants, and other biomass sources. Much of this support is funded by the CEC's Natural Gas Research and Development Program, which complies with the statutory requirement of SB 350 (De León, Chapter 547, Statutes of 2015) to improve participation by applicants from distressed communities and other historically underrepresented stakeholders. The proposed program plan and funding request for Fiscal Year 2019–2020 affirms both SB 350 and the CEC's April 2015 Diversity Policy Resolution to improve fair and equal opportunities for economically disadvantaged and underserved communities to participate in and benefit from CEC programs.[645]

Section 25303.5(b) (9): Optimizing Facilitation of Proposed Strategies with State and Federal Policy

The CEC enables participation of all interested state, regional, and federal agencies in the preparation of the IEPR, of which this AB 1257 analysis is included as an Appendix. The IEPR contains assessments of major energy trends and issues facing California's electricity, natural gas, and transportation fuel sectors and provides policy recommendations for energy policies and programs to address those issues.

The CEC works closely with other agencies through other forums as well, for example:

- Natural Gas Research and Development Program— Each year the CEC's Energy Research and Development Division holds workshops to receive input from experts in energy research to explore research initiatives and to help develop the annual Natural Gas Research and Development Program Proposed Program Plan and Funding Request submitted annually to the CPUC. Additionally topical workshops are held throughout the year to gather input on various research areas and topics. Participants include the state's investor-owned gas utilities, state agencies (such as CARB) and federal agencies (such as the U.S. Department of Energy [U.S. DOE]), industrial experts, academic researchers, and other interested parties. These workshops help avoid research duplication; generate new research ideas; create the best research industry practices;

645 Uy, Kevin. 2019. *Natural Gas Research and Development Program Proposed Program Plan and Funding Request for Fiscal Year 2019–2020*. California Energy Commission Research and Development Division. Publication Number: CEC-500-2019-035. pp. 18–21.

and, bring together utilities, researchers, manufacturers, end users, and policy makers from state and federal agencies.

- U.S. DOE Advance Research Projects Agency-Energy (ARPA-E) Energy Innovation Summit—The ARPA-E Energy Innovation Summit was held near Washington, D.C. March 13–15, 2018. Energy Commission staff attended the event where experts from different technical disciplines and professional communities discussed energy challenges and innovations in terms of industry, research, and policy. Participants discussed program concepts and "out-of-the-box" opportunities. Insights from the summit informed ongoing work by the CEC to coordinate with ARPA-E. Guided by an interagency memorandum of understanding, the CEC and ARPA-E work together to move transformational energy technologies out of the lab and into the market. Common areas of R&D include energy efficiency, energy storage, transportation, DERs, and power electronics.
- Clean Transportation Program—Under the Clean Transportation Program, the CEC has previously partnered with SCAQMD to develop and demonstrate low-oxides of nitrogen natural gas engines. These medium- and heavy-duty vehicles subsequently became available for incentives under CARB's HVIP incentive project.

  Under SB 1383, the CEC, has worked with the CPUC, CARB, CDFA, and CalRecycle, to identify cost-effective strategies that are consistent with existing state policy and climate change goals, prioritizing end uses of renewable gas, and providing recommendations to other state agencies on policy. Some of those recommendations included CalRecycle's policies to reduce statewide disposal of organic waste, and CPUC's pilot program for pipeline injection dairy biomethane.

  In implementing its School Bus Replacement Program, the CEC worked closely with CARB (as they administered natural gas school bus funds) to ensure that schools with route profiles not suited for an electric school bus could still replace older, polluting diesel school buses with alternative fueled vehicles.

Section 25303.5(b) (10): Evaluating Incremental Economic and Environmental Costs and Benefits of Proposed Strategies

The Legislature required CARB to evaluate "the total potential costs and total potential economic and noneconomic benefits of the plan for reducing greenhouse gases to California's economy, environment, and public health, using the best available economic models, emission estimation techniques, and other scientific methods."[646] CARB leads the Climate Action Team,

646 Health and Safety Code Section 38561(d).

which includes 18 state agencies, including the CEC.[647] The Climate Action Team implements the Scoping Plan.[648] The CEC and other participating state agencies work together to comply with the statutory mandate to provide evaluations of the economic and environmental costs and benefits of different potential energy resource options, including impacts on natural gas and other fuels. These evaluations are included in the CEC's Integrated Energy Policy Report and other planning documents that guide research and clean energy investments, which include stakeholder and public participation in workshops and other meetings. The CEC will continue to identify strategies by supporting research and analysis of the natural gas system and related health and safety issues. In its proposed decision, the CPUC recommends the CEC include the following elements in its Fiscal Year 2020–2022 natural gas research and development plan:

- Ensure coordination and consistency with goals of CARB's 2017 Climate Change Scoping Plan Update by 1) ensuring safety of the natural gas system, 2) decreasing fugitive methane emissions, and 3) reducing dependence on fossil fuel natural gas.
- Consider the health impacts associated with natural gas usage inside homes.
- Ensure coordination with the CPUC's Methane Leak Proceeding (R.15-01-008) for any leakage-related gas research and development, especially energy-related environmental research.
- Examine the causes, diagnostics, and mitigation of microbiologically influenced corrosion of pipelines and storage fields in the California natural gas industry.
- Assess the effects of delivering hydrogen through the existing natural gas pipeline network, including the impact on pipelines, natural gas generators, and appliances.
- Research the operational, health, and safety consequences of various concentrations of siloxane in biomethane supplies.
- Perform research to establish a standard test method approved by the National Environmental Laboratory Accreditation Program and Department of Defense Environmental Laboratory Accreditation Program for detecting siloxane in biomethane.

As shown in this review of legislative and regulatory activity since the passage of AB 1257, the state has been highly responsive to the legislative and administrative direction for a transition

647 Link to Climate Action Team Members https://www.climatechange.ca.gov/climate_action_team/members.html.

648 CARB. 2017. *California's 2017 Climate Change Scoping Plan*, https://www.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf.

to a carbon-neutral economy that increases the environmental benefits for and welfare of more Californians at a reasonable cost. The CEC will stay engaged on these important issues.

APPENDIX B: Clean Transportation Program Successes and Benefits

To help achieve the decarbonization policies outlined in Chapter 1, the California Energy Commission (CEC) administers the Clean Transportation Program (formerly known as the Alternative and Renewable Fuel and Vehicle Technology Program [ARFVTP]), which was created by the Legislature under Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007). Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013) subsequently extended the collection of fees that support the ARFVTP through January 1, 2024. With roughly $100 million per year from vehicle registration fees, the Clean Transportation Program provides funding to "develop and deploy innovative technologies that transform California's fuel and vehicle types to help attain the state's climate change policies."[649]

The statutes also require the CEC evaluate of Clean Transportation Program efforts as part of each biennial Integrated Energy Policy Report (IEPR).

Funding Summary

Each year, the CEC develops an investment plan update to guide funding allocations for the coming fiscal year. The allocations reflect a combination of the state's clean transportation priorities, the barriers and opportunities for achieving the state's goals, and an awareness of the role of the Clean Transportation Program as part of a broader suite of state policies and programs. The 2019–2020 Investment Plan Update, adopted at the CEC business meeting in September 2019, was the eleventh and most recent edition of this report.

Since its first Clean Transportation Program grant in 2009, the CEC has provided $829.4 million in funding. These project awards are summarized in Table 29.

649 California Health and Safety Code Section 44272(a).

Table 29: Clean Transportation Program Awards as of March 1, 2019

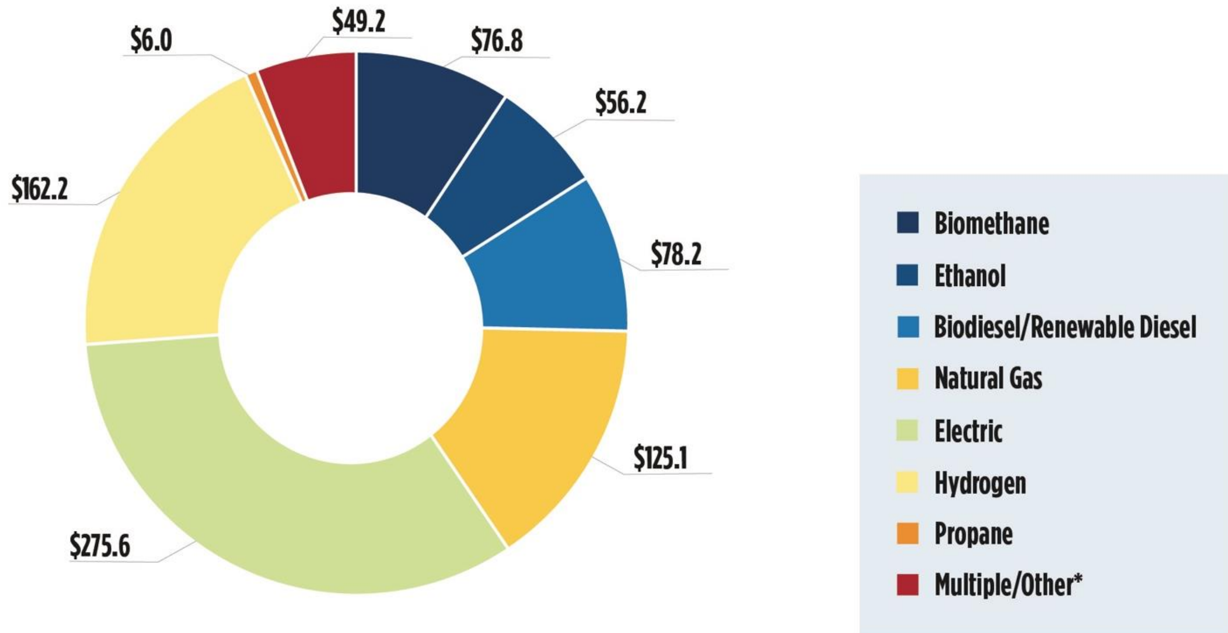
Category	Funded Activity	Cumulative Awards to Date (in millions)	Number of Projects or Units
Alternative Fuel Production	Biomethane Production	$76.8	27 Projects
Alternative Fuel Production	Gasoline Substitutes Production	$39.5	16 Projects
Alternative Fuel Production	Diesel Substitutes Production	$74.2	26 Projects
Alternative Fuel Production	Renewable Hydrogen Production	$7.9	2 Projects
Alternative Fuel Infrastructure	Electric Vehicle Charging Infrastructure**	$94.9	9,655 Charging Connectors
Alternative Fuel Infrastructure	Hydrogen Refueling Infrastructure	$140.6	64 Fueling Stations
Alternative Fuel Infrastructure	E85 Fueling Infrastructure	$13.7	59 Fueling Stations
Alternative Fuel Infrastructure	Upstream Biodiesel Infrastructure	$4.0	4 Infrastructure Sites
Alternative Fuel Infrastructure	Natural Gas Fueling Infrastructure	$24.1	70 Fueling Stations
Alternative Fuel and Advanced Technology Vehicles	Natural Gas Vehicle Deployment***	$86.8	3,252+ Vehicles
Alternative Fuel and Advanced Technology Vehicles	Propane Vehicle Deployment	$6.0	514 Trucks
Alternative Fuel and Advanced Technology Vehicles	Hybrid and Zero-emission Vehicle Deployment	$32.0	10,700 Cars and 150 Trucks
Alternative Fuel and Advanced Technology Vehicles	Advanced Technology Freight and Fleet Vehicles	$126.3	48 Demonstrations
Related Needs and Opportunities	Manufacturing	$43.6	21 Manufacturing Projects
Related Needs and Opportunities	Workforce Training and Development	$30.2	17,440 Trainees
Related Needs and Opportunities	Fuel Standards and Equipment Certification	$3.9	1 Project
Related Needs and Opportunities	Sustainability Studies	$2.0	2 Projects

Category	Funded Activity	Cumulative Awards to Date (in millions)	Number of Projects or Units
Related Needs and Opportunities	Regional Alternative Fuel Readiness and Planning	$11.4	52 Regional Plans
Related Needs and Opportunities	Centers for Alternative Fuels	$5.6	5 Centers
Related Needs and Opportunities	Technical Assistance and Program Evaluation	$5.7	N/A
	TOTAL	**$829.4**	

Source: CEC *Includes all agreements that have been approved at a CEC business meeting or are expected for business meeting approval following a notice of proposed award. For canceled and completed projects, includes only funding received from Clean Transportation Program, which may be smaller than initial award. Due to rounding, "total" may not match sum of rows. **Includes $38.8 million for the California Electric Vehicle Infrastructure Project to provide electric vehicle incentives throughout California, which will fund a yet-to-be-determined number of electric vehicle chargers. ***Funding includes completed and pending vehicle incentives, as well as funds reserved for future incentives. ****Includes projects from the former Medium- and Heavy-Duty Vehicle Technology Demonstration category.

These funding allocations can also be grouped by fuel or technology type. As Figure 61 depicts, roughly one-quarter of Clean Transportation Program funds have gone toward the production or distribution of low-carbon alternative fuels that can directly displace fossil fuels, such as biomethane (also known as renewable natural gas), ethanol, biodiesel, or renewable diesel. About 15 percent, or $125 million, has gone toward natural gas vehicle or fueling infrastructure projects. Roughly half of the Clean Transportation Program funds have gone toward zero-emission vehicle (ZEV) technologies (hydrogen and electricity), including a mixture of refueling infrastructure investments and vehicle demonstration, deployment, or manufacturing projects, or a combination thereof. The remaining funds, about 7 percent, have gone toward projects that do not have a specific fuel type or involve multiple fuel types (such as workforce development projects or localized alternative fuel readiness plans).

Figure 61: Clean Transportation Program Funding by Fuel Type as of March 1, 2019 (in Millions)



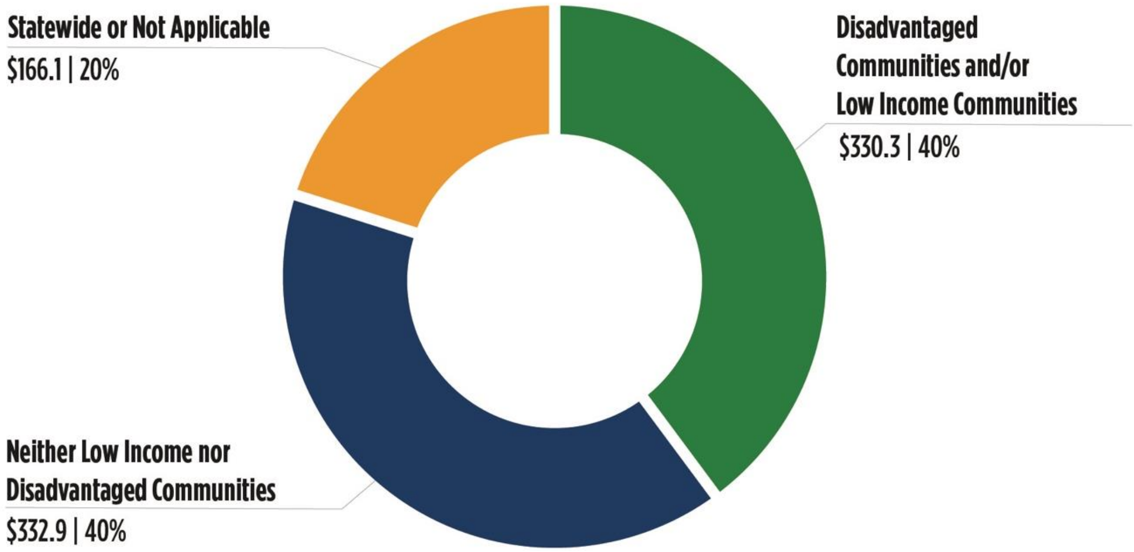
Source: CEC

Within its funding portfolio, the CEC seeks to increase the participation of disadvantaged and underrepresented communities from a diverse range of regions in implementing the Clean Transportation Program. As shown in Figure 62, roughly 40 percent of Clean Transportation Program project funding has gone into disadvantaged communities as defined by CalEnviroScreen. (When not including "Statewide or Not Applicable" projects, the number is closer to 50 percent.)

However, the funding amounts of projects are not a complete metric for assessing the benefit of a project to disadvantaged communities. In response to a request for feedback from the CEC, the Disadvantaged Community Advisory Group recommended that the CEC revise the approach of the program toward defining, measuring, and tracking the program benefits toward disadvantaged communities.[650] As the CEC continues to implement the program, this revised approach will need to be discussed and assessed.

650 SB 350 Disadvantaged Communities Advisory Group, "SB 350 Disadvantaged Communities Advisory Group Comments on 2019-2020 Investment Plan Update,"

Figure 62: Clean Transportation Funding Toward Disadvantaged Communities (in Millions)



Source: CEC

Overall Contributions of the Clean Transportation Program

Charging Infrastructure

The mass-market adoption of plug-in electric vehicles (PEVs) will depend on the availability of a convenient and reliable network of charging stations within the state. Recognizing this dependency, the CEC, through its Clean Transportation Program, has funded the installation of nearly 10,000 charging connectors within the state since the program's inception. Table 30 summarizes the number and types of connectors funded by the Clean Transportation Program to date. While a large number of initially funded charging connectors focused on single-family Level 2 residential charging, the CEC has since shifted its funding to focus on shared charging connectors, such as multifamily charging, workplace charging, fleet charging, and DC fast charging.

https://efiling.energy.ca.gov/GetDocument.aspx?tn=228878&DocumentContentId=60238. June 28, 2019. Submitted to Docket 18-ALT-01, TN# 228878.

Table 30: Charging Connectors Funded by the Clean Transportation Program as of March 1, 2019

Status	Private Access-Residential (Single and Multifamily)	Private Access-Fleet	Private Access-Workplace	Publicly Accessible-Multifamily Housing	Publicly Accessible-Public	Publicly Accessible-Corridor/Urban Metro	Total
Installed	3,936	115	364	341	3,118	226	**8,100**
Planned	0	0	76	8	191	1,280	**1,555**
Total	**3,936**	**115**	**440**	**349**	**3,309**	**1,506**	**9,655**

Source: CEC (Does not include connectors that have yet to be approved at a CEC business meeting, or connectors that have yet to be funded under CALeVIP.)

To estimate California's charging infrastructure needs for the near future, the CEC and the U.S. Department of Energy's National Renewable Energy Laboratory codeveloped the Electric Vehicle Infrastructure Projections (EVI-Pro) tool. EVI-Pro estimates the number of charging connectors that will be needed at the local level while accounting for differing charger power levels, location types, and PEV adoption rates.[651] The EVI-Pro estimates of the amount of charging infrastructure needed to support 1.5 million ZEVs by 2025 helped inform Executive Order B-48-18, which calls for 250,000 charging points (including at least 10,000 DC fast chargers) by 2025.

To track progress toward this 2025 goal, CEC staff sought data and estimates regarding the number of public or shared charging connectors that exist within California, as well as the recent and proposed charging infrastructure investments of the Clean Transportation Program and other key state funding mechanisms. Table 29 includes:

- The estimated number of existing public or shared or both Level 2 and DC fast-charging connectors within the state.
- The estimated number of connectors to be installed with previous years' Clean Transportation Program funds, as well as announced plans from other major funding programs (such as utility investments and settlement agreements).

651 Bedir, Abdulkadir, Noel Crisostomo, Jennifer Allen, Eric Wood, and Clément Rames. 2018. *California Plug-In Electric Vehicle Infrastructure Projections: 2017-2025.* CEC. Publication Number: CEC-600-2018-001. Link to California PEV Infrastructure Projections 2017-2025 report on the CEC's website https://efiling.energy.ca.gov/GetDocument.aspx?tn=223286&DocumentContentId=31667. An interactive EVI-Pro map is also available online. Link to interactive EVI-Pro map https://maps.nrel.gov/cec/.

- The estimated shortfall in charging infrastructure relative to the goals of Executive Order B-48-18.

As shown in Table 31, nearly 80,000 additional Level 2 connectors are needed within next six years, along with 3,000 to 4,000 direct current (DC) fast chargers.

Table 31: Progress Toward 250,000 Charging Connectors by 2025

	Level 2 Charging Connectors	DC Fast Charging Connectors
Existing Charging Connectors (Estimated)*	37,400	2,900
Allocated Funding for Chargers (includes anticipated funding from Clean Transportation Program)	124,600	3,500
Total	162,000	6,400
2025 Goal (Executive Order B-48-18)	*240,000*	*10,000*
Gap From Goal	78,000	3,600

Source: CEC (Analysis as of March 8, 2019.) *Existing charging ports estimated based on available data from the U.S. Department of Energy's Alternative Fuels Data Center as well as informal interviews with some (but not all) major charging infrastructure providers. **Estimate of ports from other state programs derived from public presentations and statements by utilities, California Public Utilities Commission, CARB, other entities, and the CEC.

To streamline the targeting and funding of additional charging infrastructure, the CEC introduced the California Electric Vehicle Infrastructure Project (CALeVIP). The incentives provided through CALeVIP simplify the funding process and accelerate charger deployment compared to the previously used grant solicitations. Each CALeVIP project provides incentives for infrastructure in specific regions throughout the state, with funding targeted at regions that have low rates of infrastructure installation or lack adequate incentives from utilities and other sources.

To date, the CEC has funded the installation of about 6,750 public or shared charging connectors that will count toward the state's goals under Executive Order B-48-18. This number does not yet include any of the to-be-installed charging connectors funded under CALeVIP through June 2019, for which the CEC has allocated roughly $76 million.

"The CALeVIP program really represents the maturity of the Clean Transportation Program and acknowledges where the market needs to go while increasing velocity. The Clean Transportation Program were very critical investments, matched with private investments that we utilized to be able to grow our business. Looking at where we've come in 12 years, we now have approximately 100,000 EV charging spots in North America, and about 700 employees that are strictly dedicated to EV charging."

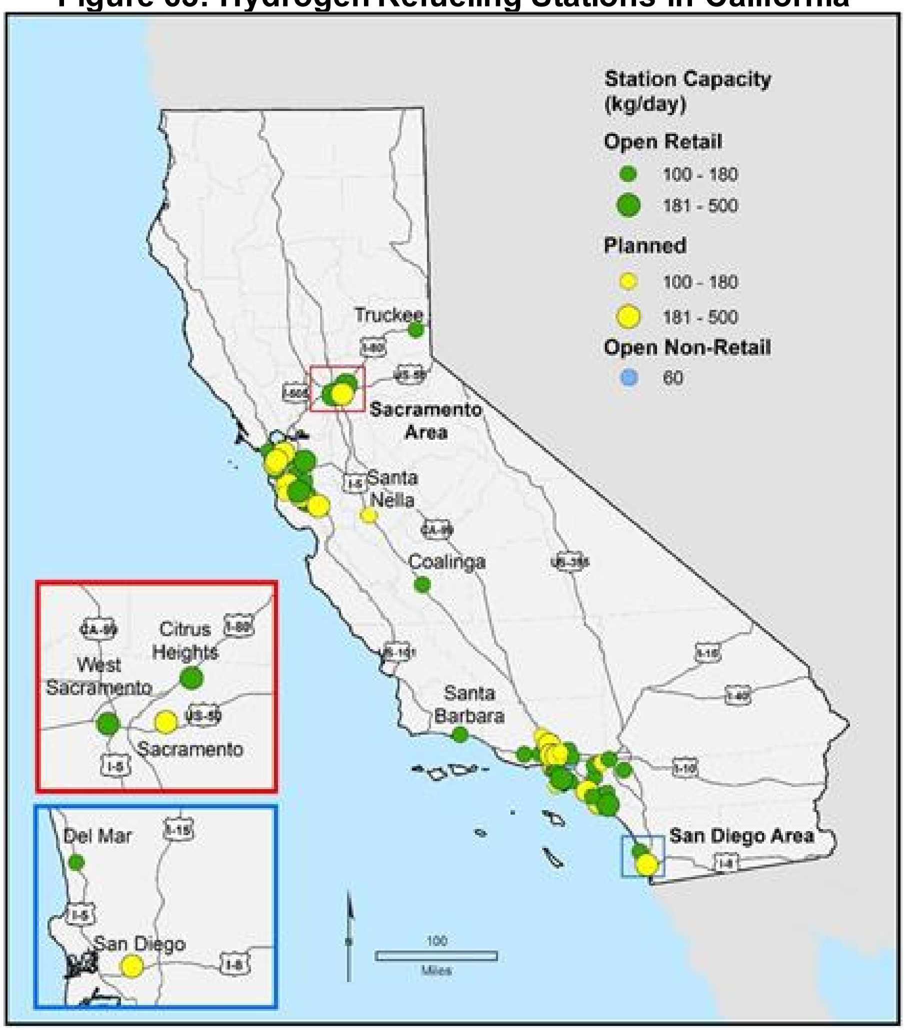
Quote from John Schott, ChargePoint, Inc., July 18, 2019, staff workshop on Clean Transportation Program Benefits Report and Successes for *2019 IEPR*, Sacramento, CA. ChargePoint, Inc. has received six awards totaling over $91 million and provided match funding of over $8.5 million.

Hydrogen Refueling Infrastructure

Since the inception of the program, the Clean Transportation Program has been the state's primary funding mechanism for the state's hydrogen refueling stations. As of March 2019, the CEC had approved nearly $125 million in Clean Transportation Funding for 64 new or upgraded hydrogen refueling stations. These stations will help serve an emerging population of fuel cell electric vehicles, as well as the development of retail fueling standards to enable hydrogen sales on a per-kilogram basis. As of August 2019, 40 stations were open for retail service, with another 24 under various stages of permitting and construction. These 64 stations have a combined fueling capacity up to 17,000 kilograms of hydrogen per day, equivalent to the daily fueling needs of roughly 24,000 fuel cell vehicles.

The stations funded by the Clean Transportation Program represent two-thirds of the initial network of 100 hydrogen refueling stations called for by AB 8, or one-third of the way toward the 2025 goal of 200 hydrogen refueling stations. Figures 63 and 64 depict the growing number of hydrogen stations around the state, with all but one station resulting from Clean Transportation Program funding.

Figure 63: Hydrogen Refueling Stations in California



Source: CEC

Figure 64: Hydrogen Refueling Stations in the Greater Los Angeles Area

Source: CEC

"FirstElement Fuel would not exist were it not for the Clean Transportation Program's investment in hydrogen refueling stations. We built 19 stations—with 12 more stations in the works—at unprecedented speed and scale. This creates a stable and statewide network of hydrogen stations across California."

Quote from Dr. Shane Stephens, FirstElement Fuel, Inc., July 18, 2019, staff workshop on Clean Transportation Program Benefits Report and Success for *2019 IEPR*, Sacramento, CA. FirstElement Fuel, Inc., has been the recipient of multiple awards totaling more than $52 million and provided nearly $20 million in match funding.

Alternative Fuel Production

The Clean Transportation Program investments in low-carbon alternative fuel production have focused on two main outcomes: developing and demonstrating next-generation biofuel production processes and feedstocks and expanding in-state production of low-carbon fuels. Biofuels such as nonpetroleum diesel substitutes, gasoline substitutes, and biomethane represent the largest existing stock of alternative fuel in California transportation sector. In addition, the production of and demand for renewable hydrogen are expected to increase in the coming years as more hydrogen fuel cell electric vehicles enter the market.

Tables 32 and 33 summarize key attributes of pre-commercial and commercial-scale alternative fuel production projects funded under the Clean Transportation Program, including their feedstock or production pathway or both; greenhouse gas (GHG) emission reduction relative to gasoline or diesel; and (in the case of commercial-scale projects) the estimated increases in annual production capacity in diesel gallon equivalents (DGE).

Table 32: Commercial-Scale Alternative Fuel Production Projects

Fuel Type	Feedstock Descriptions	Average GHG Emission Reduction*	Range of Annual Capacity for Individual Projects
Biomethane	Dairy manure; fats, oils, & grease; food, green, yard, and municipal waste	166 percent	140,000 – 2,870,000 DGE
Diesel Substitutes	Waste oils* (various)	83 percent	1,928,311 – 20,000,000 DGE
Gasoline Substitutes	Sugar beets; grain sorghum	47 percent	2,600,000 – 26,000,000 GGE
Renewable Hydrogen	Renewable electricity & water	100 percent	750,000 GGE

Source: CEC *Compared to conventional diesel (for biomethane and diesel substitutes) or gasoline (for gasoline substitutes and renewable hydrogen).

"The AltAir Renewable Fuels Project, funded by the Clean Transportation Program, was located at an old petroleum refinery that was ramping down operations. We created renewable jet fuel. We're the only commercial producer of this fuel in the world. Additionally, the project allowed us to keep about 65 direct employees and 25 indirect employees in the community."

Quote from Erin Donnette, July 18, 2019, staff workshop on Clean Transportation Program Benefits Report and Success for *2019 IEPR*, Sacramento, CA. AltAir Fuels, LLC, received a $5 million award for this project.

Table 33: Sample of Pre-Commercial Alternative Fuel Production Projects

Fuel Type	Pathway Description	Average GHG Emission Reduction*
Biomethane	Anaerobic codigestion of wastewater; manure; or food, beverage, or green waste	89 percent - 150 percent
Diesel Substitutes	Esterification or trans-esterification[652] of algae, manure, or food waste	45 percent - 55 percent
Diesel Substitutes	Gasification of green waste or manure	67 percent
Gasoline Substitutes	Fermentation of cellulosic or agricultural residues*	76 percent - 85 percent

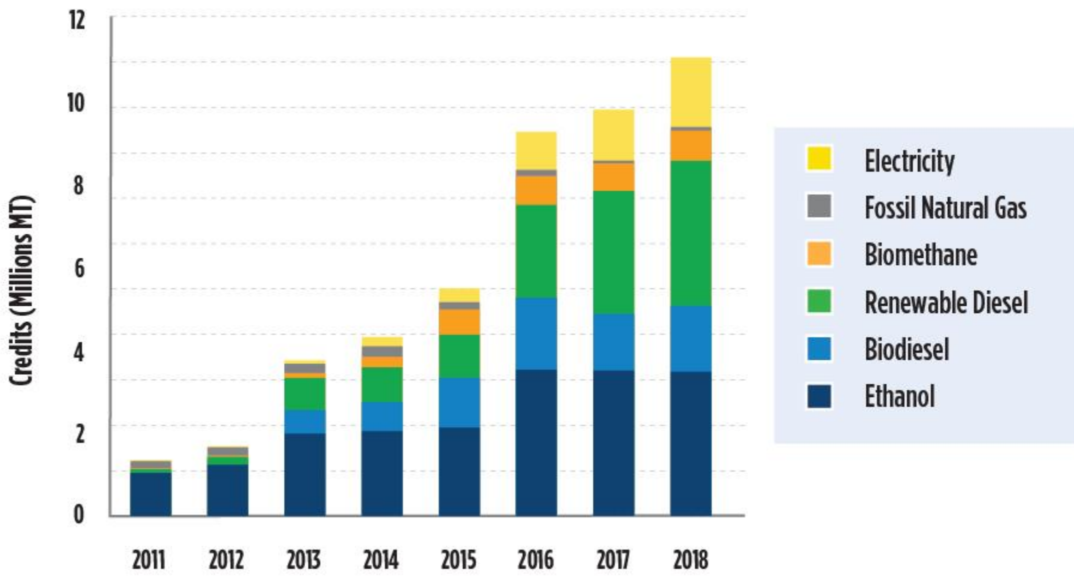
Source: CEC *Compared to conventional diesel (for biomethane and diesel substitutes) or gasoline (for gasoline substitutes and renewable hydrogen).

Fuel production projects funded by the Clean Transportation Program support the in-state production of alternative fuels, as well as the repurposing of waste-based feedstocks. These projects also benefit significantly from credits under the Low Carbon Fuel Standard (LCFS) and, in turn, support the state's ability to meet its near-term GHG emission reduction requirements with in-state investments. As Figure 65 shows, biofuels have historically represented (and continue to represent) the vast majority of credits under the LCFS. With LCFS credits nearing $200 per metric through early 2019, this represents a sizeable per-gallon incentive to support the continued production (or importation) of low-carbon alternative fuels.

This makes it especially difficult to separate the GHG reduction benefits of the Clean Transportation Program fuel production projects from the GHG reduction benefits of the LCFS. While this connection generally applies to any low-carbon fuel project funded under the Clean Transportation Program, it is especially relevant for biofuels, given the significant volume of credits they have generated (and corresponding amount of funding they have received) under the LCFS.

652 "Esterification and transesterification" are defined in this context as a chemical reaction between oil and alcohol to produce esters, which are the primary component of biodiesel.

Figure 65: LCFS Credits by Fuel Type



Source: California Air Resources Board (CARB)

Vehicle Investments

The Clean Transportation Program has made significant investments into alternative fuel and advanced technology vehicles, with a special emphasis on medium- and heavy-duty vehicles that generate a disproportionate share of the state's GHG and criteria pollutant emissions. The earlier incentives of the program for more than 500 propane trucks and more than 3,000 natural gas vehicles represented near-term opportunities to bring quick criteria emission reductions and, in the case of natural gas, expand the potential population of trucks that could utilize ultra-low-carbon biomethane. Before the availability of funding from the Greenhouse Gas Reduction Fund, the CEC also partnered with CARB to provide funding for hybrid and ZEV deployment projects, such as the Clean Vehicle Rebate Project and the California Hybrid and Zero-Emission Truck and Bus Incentive Project.

However, Clean Transportation Program investments have especially focused on the development and demonstration of advanced technology trucks and buses. Given the diversity of sizes and duty cycles for medium- and heavy-duty vehicles, the CEC has invested in a broad variety of low-carbon solutions. As of March 1, 2019, the CEC had invested $126 million in program funds into 54 technology demonstration projects for freight and fleet vehicles. These projects include in-use demonstrations of medium- and heavy-duty hybrids, plug-in hybrid electric vehicles (PHEVs), and battery electric vehicles (BEVs); fuel cell buses and trucks; low-NO_x natural gas engines; and vehicle-to-grid and intelligent transportation systems.

"The Energy Commission has played a major role in advancing vehicle technology at the San Pedro Bay Ports. What is unique about the Clean Transportation Program is that it integrates different aspects of the transition to zero-emissions technologies, including freight workforce analysis, EV infrastructure planning, or cost-effectively demonstrating trucks so that these technologies can advance industry."

Quote from Morgan Caswell, July 18, 2019, staff workshop on Clean Transportation Program Benefits Report and Success for *2019 IEPR*, Sacramento, CA. The Port of Long Beach has received three awards totaling nearly $18 million and has provided nearly $13 million in match funding.

Related Needs and Opportunities

The Clean Transportation Program has also provided funding for related needs and opportunities that support the aforementioned fuel, infrastructure, and vehicle projects. The CEC's investment in workforce training and development, for instance, has grown in size and scope since the program began. To date, the CEC's training and development investments have reached more than 17,000 trainees. Most of this training has been delivered under the CEC's funding agreement with the California Employment Training Panel, which funds training for incumbent workers in the alternative fuel production, infrastructure, or vehicle industries, or a combination thereof.

Under the Clean Transportation Program, the CEC has similarly invested in the ability of California's community college system to provide training and coursework on alternative fuel vehicles. Under an agreement with the Advanced Transportation and Logistics Initiative within the California Community Colleges Chancellor's Office, the CEC has provided funding to 15 campuses around the state to purchase specialty equipment required for hands-on training, as well as technical training for instructors to stay at the forefront of clean transportation technologies.

Funding from the Clean Transportation Program is also supporting in-state ZEV and ZEV infrastructure manufacturers, with nearly $50 million encumbered across more than 20 projects as of July 2019. These investments into the ZEV and ZEV infrastructure supply chain, while minor compared to the overall costs of bringing new technologies to market, address niche opportunities to ramp up innovative products for early commercialization. The awards also provide prospective investors with a signal of public commitment to the company or technology. Furthermore, this funding (like the workforce training and development funding) will help ensure that California's transition to cleaner vehicles will also lead to expanded economic opportunities and revenues within California.

"For Proterra, there are multiple benefits to our Clean Transportation Program Project. Number one is job creation right in the community where we are manufacturing our all-electric transit buses. As we continue to grow this market, we will keep adding jobs to build more zero-emission buses. It is not just Proterra and our buses. It is also all of the other manufacturers of zero-emission vehicles and their suppliers within California, up and down the state that create jobs."

Quote from Kent Leacock, Proterra, Inc., July 18, 2019, staff workshop on Clean Transportation Program Benefits Report and Success for *2019 IEPR*, Sacramento, CA. Proterra, Inc., has received two awards for a total of nearly $5 million and provided over $11 million in match funding.

Quantifying Benefits From Clean Transportation Program Projects

Section 44273 of the Health and Safety Code requires the CEC to evaluate the following types of benefits for projects funded under the Clean Transportation Program:

- Petroleum Use Reduction
- Air quality
- GHG emissions reduction
- Benefit-cost assessment
- Technology advancement

The CEC partnered with the National Renewable Energy Laboratory (NREL) to develop quantifiable estimates of petroleum use reduction, air quality benefits, and GHG emissions reductions associated with Clean Transportation Program projects. NREL had similarly helped develop Clean Transportation Program benefits analysis in the *2013 IEPR*, *2014 IEPR Update*, *2015 IEPR*, and *2017 IEPR*.

On the Attribution of Benefits to the Clean Transportation Program

The Clean Transportation Program is one tool among a broader suite of incentives and regulations designed to achieve the state's goals for GHG reduction and cleaner air.

As such, projects funded by the program also benefit (directly or indirectly) from other incentives or regulations, such as the LCFS, CARB's low carbon transportation investments (and other GHG Reduction Fund investments), and the ZEV regulation, among others.

Moreover, the roughly $829.4 million invested under the program has been contractually matched by more than $860 million in outside funding.

As such, the CEC does not intend to convey the sole responsibility for the benefits of the projects funded under the program, nor as an analysis of these benefits in excess of regulatory requirements.

For the *2019 IEPR*, NREL used the same approach toward quantifying Clean Transportation Program project benefits as it did in previous years. This quantification includes analyzing two categories of benefits: expected benefits and market transformation benefits. These categories are discussed further in the respective sections.

On July 18, 2019, the CEC hosted an IEPR workshop on the Clean Transportation Program Benefits Report and Successes that included a presentation from NREL on the initial results and findings from its 2019 analysis.[653] A subsequent stand-alone report from NREL will be published in fall 2019, which will document the full method and revised results.

Inputs and Assumptions

CEC staff provided NREL a list of pending, active, and completed Clean Transportation Program projects through March 2019, along with relevant information about each.[654] The list included projects totaling about $663.6 million, or roughly 80 percent of all Clean Transportation Program project funding. Other projects were not included in this analysis, such as projects without direct petroleum displacement or emissions reduction benefits (including regional readiness planning grants, workforce training, or fueling standards and certification), projects that were canceled or otherwise not expected to be completed, and projects that had only recently been proposed for awards. Table 34 shows the amount and percentage of funding included in the NREL analysis by project type.

653 NREL, "CEC ARFVTP Benefits and Market Transformation Update." Presented on July 18, 2019. [Presentation by NREL on CEC ARFVTP Benefits and Market Transformation Update](https://efiling.energy.ca.gov/GetDocument.aspx?tn=229019&DocumentContentId=60398)
https://efiling.energy.ca.gov/GetDocument.aspx?tn=229019&DocumentContentId=60398.

654 Projects that were canceled by the CEC, or pending cancellation, were not included.

Table 34: Funding Analyzed by NREL by Project Type Through March 2019

Category	Project Type	Funding Analyzed by NREL (in millions)	Percent of Funding Analyzed by NREL
Alternative Fuel Production	Biomethane	$70.7	94
Alternative Fuel Production	Gasoline Substitutes	$32.4	82
Alternative Fuel Production	Diesel Substitutes	$57.0	81
Alternative Fuel Infrastructure	Electric Vehicle Charging	$90.5	95
Alternative Fuel Infrastructure	Hydrogen Refueling	$109.9	91
Alternative Fuel Infrastructure	E85 Fueling	$6.3	100
Alternative Fuel Infrastructure	Upstream Biodiesel Infrastructure	$3.9	97
Alternative Fuel Infrastructure	Natural Gas Fueling	$25.0	100
Alternative Fuel and Advanced Technology Vehicles	Natural Gas Commercial Trucks	$80.5	93
Alternative Fuel and Advanced Technology Vehicles	Light-duty BEVs and PHEVs	$28.0	100
Alternative Fuel and Advanced Technology Vehicles	Electric Commercial Trucks	$4.0	100
Alternative Fuel and Advanced Technology Vehicles	Medium- and Heavy-Duty Truck Demonstration	$126.3	100
Alternative Fuel and Advanced Technology Vehicles	Manufacturing	$29.1	66
	Other	**$0.0**	**0**
	Total	**$663.6**	**80**

Source: CEC staff

The CEC staff also provided NREL with project information from a variety of sources, including initial funding proposals, surveys of funding recipients, and (when available) final project reports.

The most critical information included:

- The amount of alternative fuel produced at program-funded production plants, dispensed at program-funded fueling stations, or consumed by program-funded vehicles. This amount is used to estimate petroleum displacement.
- The life-cycle carbon intensity of the alternative fuel of the project (if distinct from statewide averages). This information is used to estimate GHG emissions reduction.
- The type of conventional vehicle replaced by the Clean Transportation Program-funded vehicle or alternative fuel (if applicable). This information is used to estimate petroleum displacement, air quality pollutant reduction, and GHG emissions reduction.

In addition to project data from the CEC, NREL also relied on other established models. NREL incorporated carbon intensity values from the California LCFS and the California-adjusted Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model when possible. NREL also used the VISION and GREET models to estimate reductions of oxides of nitrogen (NO_x) as well as particulate matter of less than 2.5 micrometers (PM 2.5).

Results from this analysis are reported primarily per-year (for example, GHG emissions reduced in 2030) rather than a cumulative basis (such as GHG emissions reduced through 2030). NREL assumed lifespans for each project class, with fuel production and fueling infrastructure projects having a longer lifespan than vehicle projects. Only vehicle projects, with an estimated lifespan of 16 years, had a shorter lifespan than the analysis duration. Projects were assumed to begin accruing benefits at the time of completion of the Clean Transportation Program agreement. For vehicle projects, NREL applied a "vehicle miles traveled depreciation rate" to account for the fact that older vehicles typically drive fewer miles per year as they age. Conversely, fuel production projects were assigned a three-year "ramp up" period to reach anticipated capacity.

Within NREL's analysis, the benefits of a project are assumed to include all alternative fuel produced, dispensed, or consumed by a Clean Transportation Program-funded project. This approach is the most straightforward to quantifying benefits but risks overstating the direct impacts of the investment of the Clean Transportation Program. In almost all cases, Clean Transportation Program funding for a project must be matched by private funding. To date, the Clean Transportation Program total investment of $829 million has been contractually matched with more than $800 million in outside funding.[655] Furthermore, other public funding and regulatory programs help ensure the success of Clean Transportation Program projects,

655 Not including the match funding associated with as-yet-unsigned grant agreements.

including the LCFS, the Renewable Fuel Standard, the ZEV mandate, the Air Quality Improvement Program, and the GHG Reduction Fund. For similar reasons, benefits from this analysis should not be viewed as independent of (or in addition to) the estimated benefits of related programs.

Expected Benefits

In NREL's analysis, "expected benefits" represent the direct outcomes of projects funded by Clean Transportation Program funding. These benefits assume a one-to-one substitution of conventional petroleum-derived fuels with an alternative fuel or improved vehicle efficiency or both. The amount of gasoline or diesel displaced, multiplied by the carbon intensity ratio of the new alternative fuel against gasoline or diesel, results in an estimate of GHG reductions.

Table 35 highlights the expected benefits from program-funded projects in terms of annual petroleum fuel reductions and GHG reductions. Based on NREL's analysis, projects supported by the Clean Transportation Program are expected to contribute to the reduction of 261 million gallons of petroleum fuel consumption and 1,423 thousand tonnes of carbon dioxide-equivalent (CO_2e) GHG emissions per year by 2030.

The ratio between petroleum fuel reductions and GHG reductions in Table 34 also illustrates the relative carbon reduction benefits of various alternative fuels. For example, in 2030, the biomethane fuel production projects reduce GHG emissions by about 1,900 tonnes of CO_2e per million gallons of displaced petroleum (22.6/11.8), while the natural gas commercial trucks reduce GHG emissions by just 2,700 tonnes per million gallons (9.7/3.6).

Table 35: Annual Petroleum Fuel and GHG Reductions (Expected Benefits)

Project Type	Petroleum Fuel Reductions (in million gallons)	Petroleum Fuel Reductions (in million gallons)	GHG Reductions (in thousand tonnes CO_2e)	GHG Reductions (in thousand tonnes CO_2e)
Year	**2020**	**2030**	**2020**	**2030**
Fuel Production				
Biomethane	1.6	11.8	20.8	22.6
Diesel Substitutes	51.5	85.7	483.7	643
Gasoline Substitute	7	38	24.6	18.8
Fueling Infrastructure				
Biodiesel	5.8	5.8	21.6	21.6
E85	13.8	13.9	41.8	42.1
Electric Charging	3.9	4.9	29.6	37.2
Hydrogen	8.8	12.6	62.1	89
Natural/Renewable Natural Gas	30.3	33.7	72.8	85.5
Vehicles				
CVRP and HVIP Support	1.8	0.9	14.3	6.5
Light-duty BEVs and PHEVs	0.0	0.0	0.2	0.2
Manufacturing	18.5	48.9	158.9	437.6
Medium- and Heavy-duty Truck Demonstration	1.1	1.3	8.4	9.3
Natural Gas Commercial Trucks	5.5	3.6	15.1	9.7
Total	**150**	**261.1**	**953.9**	**1,423.1**

Source: NREL. Note: subtotals and totals may not match due to rounding. *Does not include pre-2020 benefits from projects funded under the California Ethanol Producers Incentive Program.

In its expected benefits analysis, NREL also included tailpipe reductions of certain key criteria pollutants: NO_x and PM 2.5. However, for this analysis, NREL focused specifically on fuel and vehicle types with emission reductions recognized under the VISION and GREET models. This focus narrows the analysis to projects using electricity and hydrogen as the alternative fuel.[656] Table 36 summarizes the annual NO_x and PM2.5 reductions anticipated from the expected benefits approach.

Table 36: Annual Air Pollutant Reductions (Expected Benefits)

	Project Type	No_x Reductions (Tonnes/year)	No_x Reductions (Tonnes/year)	PM2.5 Reductions (Tonnes/year)	PM2.5 Reductions (Tonnes/year)
Year		**2020**	**2030**	**2020**	**2030**
Fuel Infrastructure	Electric Chargers	2.7	2.9	0.3	0.1
Fuel Infrastructure	Hydrogen	6	7.5	0.6	0.4
Fuel Infrastructure	Natural Gas	N/A	N/A	N/A	N/A
Vehicles	Clean Vehicle Rebate Project/Hybrid and Zero-emission Truck and Bus Voucher Incentive Project Support	7.0	1.8	0.1	0.0

656 Discussions are underway with CEC staff and NREL as to how natural gas can be included as well.

	Project Type	No_x Reductions (Tonnes/year)	No_x Reductions (Tonnes/year)	PM2.5 Reductions (Tonnes/year)	PM2.5 Reductions (Tonnes/year)
Vehicles	Light-duty BEVs and PHEVs	0.0	0.0	0.0	0.0
Vehicles	Natural Gas Commercial Trucks	55.3	53.5	0.0	0.0
Vehicles	Medium- and Heavy-duty Demonstration	9.2	15.9	0.2	0.2
Vehicles	Manufacturing	157.7	515.5	5.5	25.9
	Total	**237.9**	**597.1**	**6.7**	**26.6**

Source: NREL

Market Transformation Benefits

Unlike expected benefits, market transformation benefits represent estimates of how Clean Transportation Program funding might indirectly influence the expansion of alternative fuel production and use in the future. A simple example might be the impact of seeing additional charging stations in the vicinity makes a prospective vehicle buyer more willing to consider buying a PEV or the impact of a successful demonstration of an advanced technology truck increases the likelihood of that technology achieving future commercial success. The latter example is one way of evaluating program-funded "technological advancement" as required by the statutes of the program.

NREL has identified four potential ways Clean Transportation Program projects can influence market transformation. Table 37 describes these potential influences. There may be other ways that Clean Transportation Program projects influence the future market growth of clean fuels and vehicles; however, these are the examples NREL found to be the most readily quantifiable. The methods used to quantify these influences were established in the 2014 Program Benefits Guidance: Analysis of Benefits Associated with Projects and Technologies Supported by the ARFVTP, produced by NREL for that year's IEPR Update.[657]

Table 37: Market Transformation Benefits Description

Market Transformation Influence	Applicable Project Types	Description of Influence Outcomes
Perceived Vehicle Price Reduction	Electric charging Hydrogen stations Light-duty BEVs and PHEV incentives	Increased consumer awareness Removal of consumer choice barriers via increased refueling access
Vehicle Cost Reduction	Manufacturing	Reduced cost to produce or supply a technology "Learn by doing" Economies of scale
Next-Generation Trucks	Medium-Duty/Heavy-Duty truck demonstration Medium-duty BEV incentives	Additional trucks deployed as a result of successful demonstration projects
Next-Generation Fuels	Biofuel production (all fuel types)	Additional or expanded biofuel production facilities in response to successful projects

Source: NREL

Because the market transformation benefits analysis relies on future market conditions and decisions in a way that the expected benefits analysis does not, NREL includes two sets of assumptions to generate a "low case" and "high case."[658] In general, the *low case* reflects more conservative assumptions about demand elasticity for ZEVs, savings from economies of

657 NREL. 2014. *Program Benefits Guidance: Analysis of Benefits Associated With Projects and Technologies Supported by the ARFVTP*, draft project report. Link to Program Benefits Guidance report on the CEC's website http://www.energy.ca.gov/2014publications/CEC-600-2014-005/CEC-600-2014-005-D.pdf.

658 These are unrelated to the demand cases used in the IEPR's energy demand forecasts in Chapter 7.

scale, and the ability of successful demonstration projects to leverage private interest for larger commercial-scale projects. The "high case" reflects the opposite.

Table 38 summarizes the total market transformation benefits under consideration for petroleum displacement, GHG emission reduction, and air pollutant reduction. Because market transformation benefits lag behind the initial expected benefits of a project, this table focuses on benefits in 2030. As with the expected benefits, NREL did not attempt to quantify air pollutant reductions associated with the market transformation benefits of biofuel production projects (under "Next-Generation Fuels"). Moreover, air quality improvements for "Next-Generation Trucks" could not be reliably calculated because of significant uncertainties about what varieties of baseline vehicles would be displaced and their respective emissions profiles.

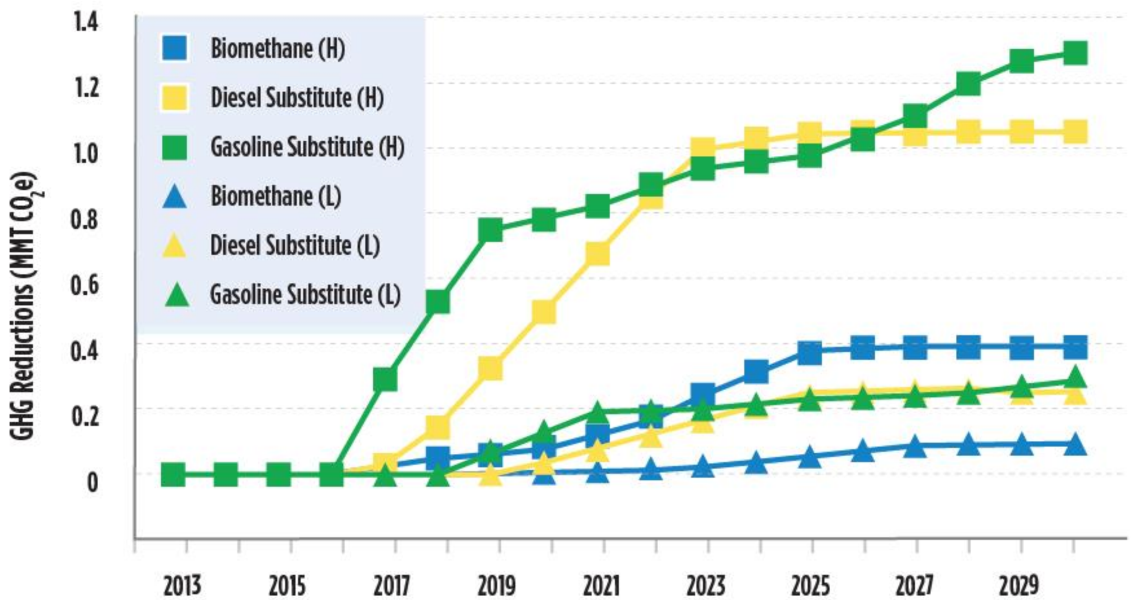
Table 38: Annual Market Transformation Benefits in 2030

Market Transformation Influence	Case	Petroleum Displacement (million gallons)	GHG Reduction (thousand tonnes CO_2e)	Nox Reduction (tonnes)	PM2.5 Reduction (tonnes)
Year		**2030**	**2030**	**2030**	**2030**
Perceived Vehicle Price Reductions	High	141	820	56.8	52.4
Perceived Vehicle Price Reductions	Low	55.4	326	14.4	13.3
ZEV Industry Experience	High	9.4	51	3.7	2.8
ZEV Industry Experience	Low	9.1	56	3.5	2.7
Next-generation Trucks	High	329	1,867	3,995	28.7
Next-generation Trucks	Low	17	150	206.6	1.5
Next-generation Fuels	High	323	2,730	N/A	N/A
Next-generation Fuels	Low	79	660	N/A	N/A
Total	**High**	**802.4**	**5,468**	**4,055.5**	**83.9**
Total	**Low**	**160.5**	**1,192**	**224.5**	**17.5**

Source: NREL

As an example of how market transformation benefits can change over time, Figure 66 shows the low case and high case for GHG reductions per year from the market transformation benefits assigned to "next-generation fuels."

Figure 66: Annual GHG Reduction From Fuel Production Projects Funded by the Clean Transportation Program



Source: NREL

Benefit-Cost Assessment

As part of the biennial evaluation of the program, Health and Safety Code Section 44273 also requires the CEC to include a "benefit-cost assessment" for program-funded projects. While "benefit-cost" is not specifically defined within the section, the term "benefit-cost score" is defined elsewhere in the Clean Transportation Program's statute as the "expected or potential GHG emissions reduction per dollar awarded by the commission to the project."[659]

Unlike the previously discussed estimates of benefits, this evaluation requires assessing GHG emission reductions on a cumulative basis, not annually. A simple yet conservative assumption is to include the cumulative GHG emission reductions of program-funded projects through 2030. Based on this approach, the cumulative GHG emission reductions of expected benefits

659 Health and Safety Code Section 44270.3.

and market transformation benefits by 2030 range from roughly 29.9 million metric tons (using the low case for market transformation benefits) to 73.9 million metric tons (using the high case).

The CEC has awarded $663.6 million toward Clean Transportation Program projects (not including canceled and defunded projects) with GHG emission reductions that are measurable using NREL's method. When including projects that do not readily lend themselves to measurable GHG emissions (such as regional fuel readiness grants, workforce training agreements, and fuel standards and certification agreements), this amount increases to nearly $830 million. Table 39 shows the resulting benefit-cost ratios, depending on which funding amount is used as the cost and whether the low case or the high case for market transformation benefits is applied. The values in Table 38 represent the approximate amount of carbon dioxide-equivalent metric tons reduced for every dollar invested by the Clean Transportation Program.

Table 39: Kilograms CO_2e Reduced Through 2030 per Program Dollar

	Cost Basis: Analyzed Projects Only	Cost Basis: All Projects
Expected Benefits + Market Transformation (Low Case)	45 kg/$	36 kg/$
Expected Benefits + Market Transformation (High Case)	111 kg/$	89 kg/$

Source: CEC

APPENDIX C: Transportation Energy Demand Forecast Historical Market Trends and Forecast Method

This appendix presents historical vehicle sales trends, energy consumption and price trends, as well as the method and assumptions supporting the transportation energy demand forecast.

Vehicle Sales and Fuel Consumption Trends

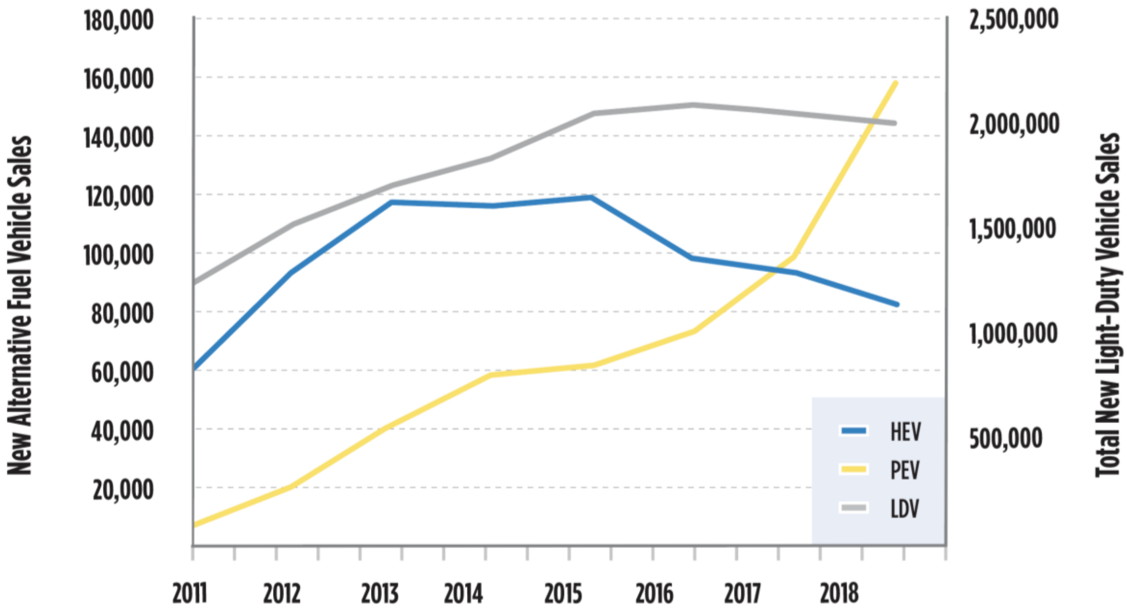
Total transportation fuel consumption increases with the growth in vehicle population, when fuel economy is relatively stable. The distribution among different fuels will change over time, depending on the changes in vehicle sales trends.

Vehicle Sales Trends

The economic recovery since the great recession of 2008 has led to growth in new vehicle sales. . Figure 67 shows new vehicle sales in California obtained from the California New Car Dealers Association (CNCDA) from 2011 through 2018.[660] Light-duty vehicle (LDV) sales peaked in 2016 with a slight decline since as shown in Figure 61.Gasoline vehicles are the predominant share of the new LDV sales, but the share of new plug-in electric vehicles (PEV) sales in California has been steadily growing since 2009. The growth in PEV sales, however, seems to have come mostly at the expense of the hybrid electric vehicles (HEV), through 2017, and have surpassed hybrid sales. Meanwhile, fuel cell electric vehicle (FCEV) sales (not shown) have increased exponentially since 2015, when only 68 new vehicles were sold statewide, to nearly 2,500 in 2018.

660 The CNCDA vehicle sales data come from IHS Markit, and are released quarterly in "California Auto Outlook" reports. Recent quarterly reports can be found on CNCDA.org; the most recent quarterly report is available at https://www.cncda.org/wp-content/uploads/Cal-Covering-3Q-19.pdf

Figure 67: New Vehicle Sales in California (2011–2018)



Source: IHS Markit, via California New Car Dealers Association

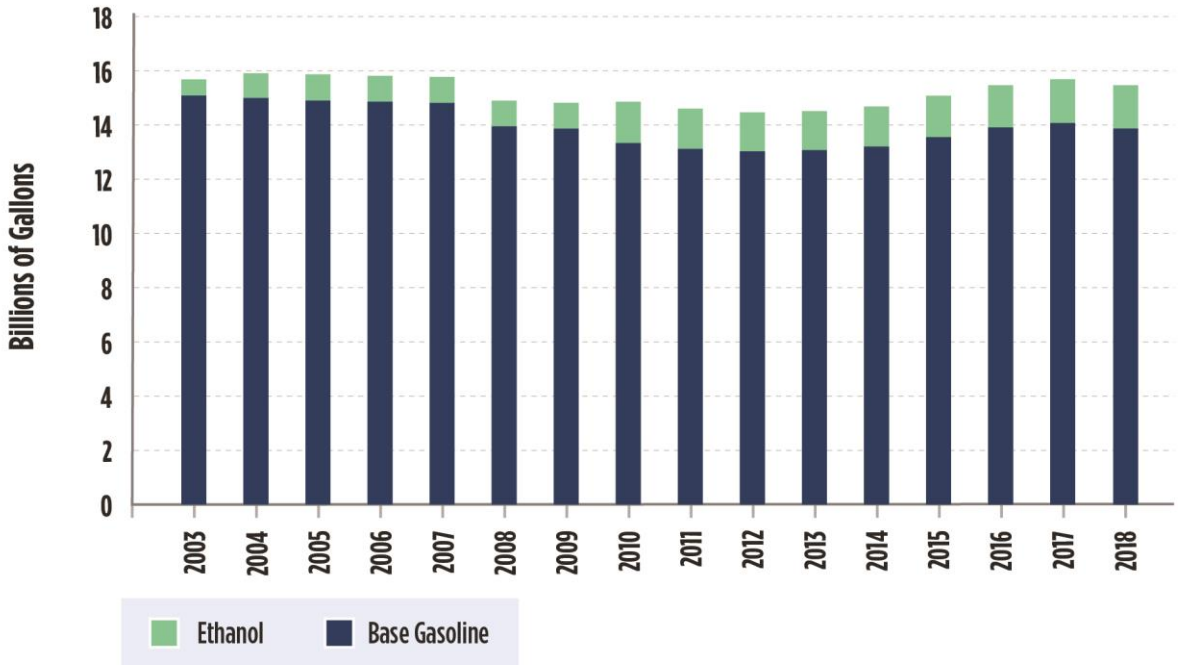
Energy Consumption Trends

Gasoline is the dominant fuel within the transportation sector, with diesel and aviation fuels following. Figures 68, 69, and 70 present trends for these fuels from 2003 through 2018. Diesel fuel reached peak consumption in 2007, while base gasoline consumption peaked in 2005. The economic recession caused consumption of all fuels to dip in 2008 and 2009. Since then, aviation fuel consumption surpassed the previous peak in 2015, but diesel and gasoline consumption have recovered more slowly and have not yet surpassed the prerecession peaks.

Since 2003, the ethanol blend in gasoline has increased from about 3.75 percent by volume to 10.1 percent in 2017. While the regulatory limit on blending ethanol into gasoline in California is 10 percent, sale of E85, which is a fuel blend of 85 percent ethanol and 15 percent gasoline, adds to ethanol consumption.

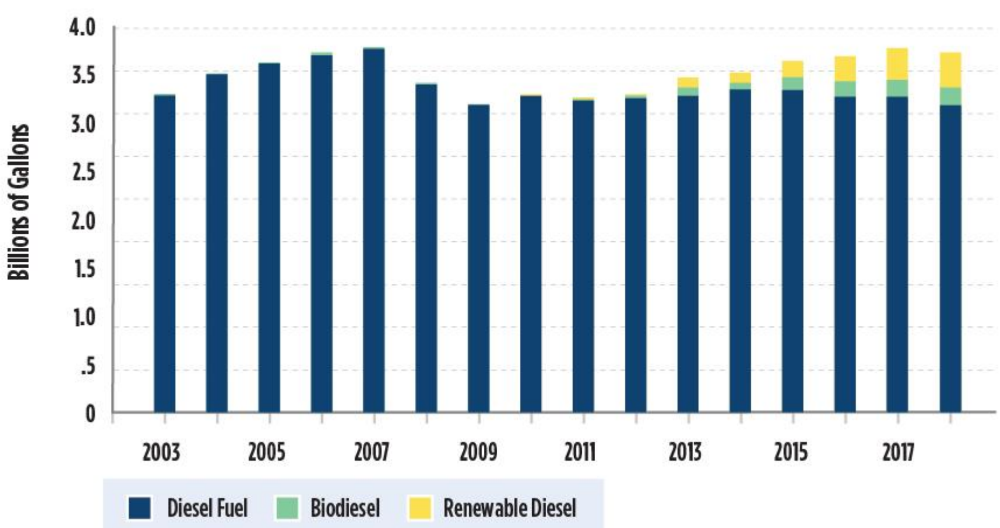
Biodiesel and renewable diesel consumption have been spurred by obligations under the Low Carbon Fuel Standard (LCFS), representing more than 13 percent of diesel and diesel substitute consumption. Taken together, diesel fuel, biodiesel, and renewable diesel consumption are down in 2018 compared to 2017.

Figure 68: California Gasoline and Ethanol Consumption (2003–2018)



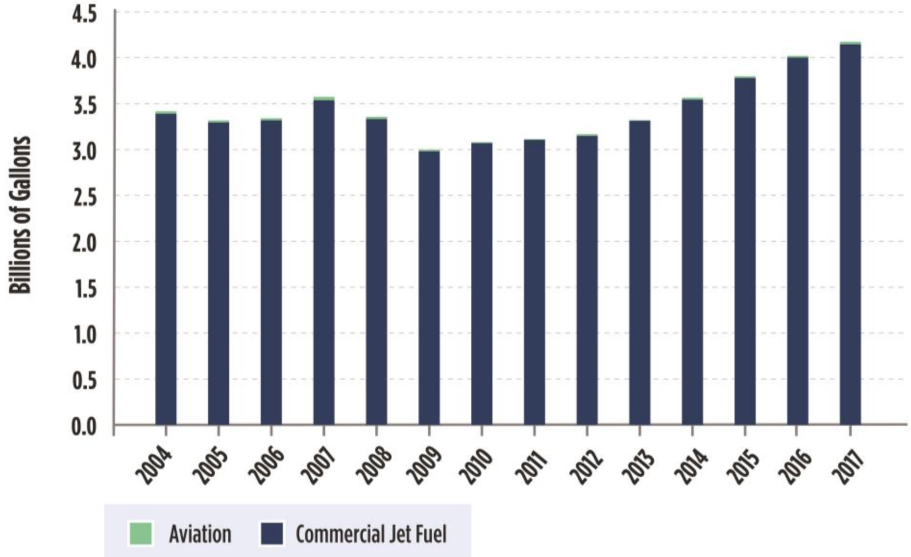
Source: CEC analysis

Figure 69: California Diesel Fuel, Biodiesel, and Renewable Diesel Consumption (2003–2018)



Source: CEC analysis

Figure 70: California Jet Fuels and Aviation Gasoline Consumption (2004–2017)



Source: CEC analysis

Table 40 presents the consumption trends for alternative gaseous fuels including propane (liquefied petroleum gas (LPG]), liquefied natural gas (LNG), compressed natural gas (CNG), and hydrogen.

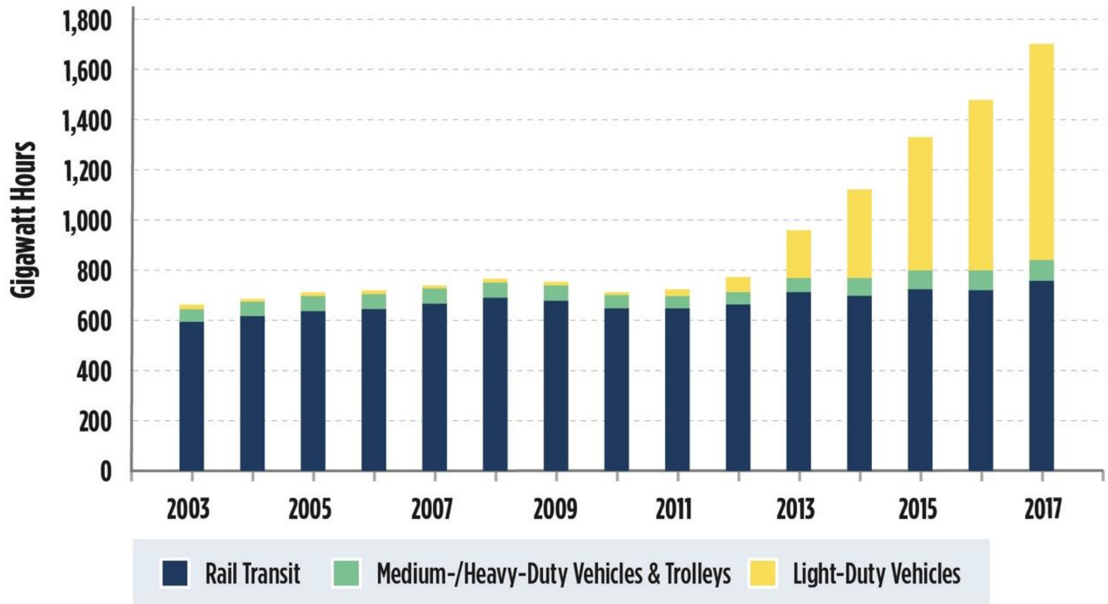
Table 40: California Gaseous Fuel Consumption (2003–2017)

Year	LPG [1] (Propane) Consumption (Gallons)	LNG [2] Consumption (Gallons)	CNG [3] Consumption (Therms)	Total Natural Gas [4] Consumption (Therms)	Total Natural Gas [4] Consumption (Diesel-gallon-equivalent)	Hydrogen[5] Consumption (Kilograms)
2003	18,455,500	27,970,031	64,686,479	98,033,540	75,605,656	728
2004	23,317,500	28,307,916	64,686,479	98,291,858	75,804,877	15,555
2005	22,999,500	28,645,800	77,007,713	113,150,176	87,263,944	9,275
2006	19,983,500	28,983,685	80,088,022	117,058,495	90,278,127	17,454
2007	18,316,000	22,400,000	86,248,639	119,325,161	92,026,231	19,987
2008	18,391,000	18,900,000	95,489,564	127,599,355	98,407,474	23,971
2009	22,861,067	29,635,453	98,569,873	139,456,782	107,552,186	38,292
2010	26,632,877	32,356,377	101,650,181	145,186,972	111,971,437	34,096
2011	29,139,991	35,487,647	104,730,490	151,230,879	116,632,633	52,179
2012	33,028,638	30,492,564	110,891,107	160,369,476	123,680,523	73,443
2013	34,755,459	31,868,353	113,971,416	165,759,354	127,837,318	66,276
2014	31,834,779	33,082,102	124,752,495	179,462,285	138,405,324	64,499
2015	25,806,328	34,000,572	126,292,650	181,989,469	140,354,345	62,708
2016	6,048,158	31,605,833	141,694,192	198,408,653	153,017,186	110,575
2017	9,320,651	37,320,039	187,252,522	217,261,208	167,556,698	574,747
2018	-	-	193,606,113	-	-	890,000

Source: 1) California State Board of Equalization Annual Report Table 25A- Taxable Distributions of Diesel Fuel and Alternative Fuels, 1937–1938 to 2009–2010 fiscal year data averaged over two years to estimates calendar year values for years 2003 through 2008. 2) LNG data from verbal reports to CEC reporting unit by suppliers. 3) CNG data obtained from the annual California Gas Reports. 1998–2016 reports online. Link to California Gas Report Index on PG&E's website https://www.pge.com/pipeline/library/regulatory/cgr/index.page. CNG reported values for 2017–2018 obtained from the LCFS Quarterly Data Spreadsheet. 4) Total natural gas is the sum of LNG and CNG. 5) National Transit Authority annual reports and California Department of Motor Vehicles fuel cell vehicle registrations. Fuel cell vehicles assumed driven 9,600 miles/vehicle/year and U.S. Environmental Protection Agency Adjusted Combined Cycle fuel economy National Transit Authority Reports, Data Tables, Table 17, Energy Consumption, Other, or Hydrogen Fuels. The year 2018 reported hydrogen consumption exclusive to light-duty vehicles. The year 2018 represents hydrogen consumption sourced from CEC staff.

Finally, use of electricity as a transportation fuel is increasing, as depicted in Figure 71. The growth since 2010 is chiefly due to increased market penetration of light-duty PEVs.

Figure 71: California Transportation Electricity Consumption (2003–2017)



Sources: Federal Transit Administration and CEC analysis of California Department of Motor Vehicle data (2017 Light and heavy-duty vehicle electricity consumption is an estimate.)

Forecasting Approach

Due to fundamental differences among transportations sectors, the CEC uses 11 models to forecast energy demand in each sector. While these models often share inputs, these inputs are applied differently based on their known effect on the sector.

Suite of Models

Table 41 describes the CEC's transportation forecasting models, highlighting the methodology and inputs used to run each model.

Table 41: CEC Transportation Forecasting Models

Model Category	Model	Description	Key Inputs
Vehicle Demand Models	Personal Vehicle Choice (LDV)	Generates forecast of household demand for LDVs by 15 size classes and 9 fuel types, in 3 market segments, based on consumer preferences and behavior.	Fuel cost, vehicle attributes and incentives, household population and income
Vehicle Demand Models	Commercial Vehicle Choice (LDV)	Generates forecast of commercial demand for LDVs by 15 size classes and 10 fuel types, based on consumer preferences and behavior.	Fuel cost, vehicle attributes and incentives, gross state product
Vehicle Demand Models	Government (LDV)	Uses rules to grow government LDVs by fuel/technology types, from the base-year stock	Gross state product, fuel economy
Vehicle Demand Models	Rental (LDV)	Uses rules to grow rental vehicles from the base-year stock	Gross state product, fuel economy
Vehicle Demand Models	Neighborhood Electric Vehicles (NEV)	Grows vehicles from the base-year stock	Gross state product
Vehicle Demand Models	Truck Choice Model (Medium-/Heavy-duty)	Uses Argonne TRUCK 5.1 model to project different truck fuel types and technology market penetration	Fuel cost, fuel economy, vehicle prices and incentives, maintenance cost
Travel Demand Models	Urban Travel	Predicts choices among travel modes (including auto, bus, rail, and others) and forecasts short-distance personal travel and fuel demand for all travel modes	Fuel cost, travel cost, in-and-out of vehicle travel time, population, personal income
Travel Demand Models	Intercity Travel	Composed of two models: one predicts volume of travel, and the other predicts choices among long-distance travel modes (auto, rail, airplane)	Fuel cost, travel cost, departure frequency, personal income
Travel Demand Models	Air Travel	Composed of two models: one predicts passenger aviation, and another predicts freight aviation	Travel cost, personal income, population
Travel Demand Models	Freight Energy Demand (Freight Movement)	Composed of two models: one forecasts vehicle movement and fuel demand for goods movement and modal choice for truck vs. rail by 41 commodities; the other forecasts local and regional movement and fuel demand for medium- and heavy-duty delivery, services, and other economic activities	Fuel cost, shipment size, travel time, gross state product
Travel Demand Models	Other Bus Travel	Model predicts bus miles and fuel demand based on projections of bus fleets such as school buses, demand response (paratransit), shuttle buses etc. and ridership trends	Population, grants (federal, state, local)

Source: CEC

Key Inputs and Assumptions

CEC staff use a variety of inputs and assumptions to generate the forecast results. Staff use different combinations of inputs and assumptions to create the low, mid, and high electricity demand cases.

California Department of Motor Vehicles Data

The 2017 vehicle registration data from the California Department of Motor Vehicles (DMV) serves as base-year data for forecasting the growth of various vehicle types within the state. The CEC periodically receives raw vehicle registration data from the DMV and processes the data to classify into LDV and medium-duty (MD)/heavy-duty (HD) vehicles. The LDV data are then broken down into 15 vehicle classes, nine fuel and vehicle technology types, model-year vintages, and four market segments (residential, commercial, rental, and government). Buses are classified by function, as identified in the CARB Emission Factors model (EMFAC), into urban transit, school, intercity motor coaches, and "other" buses such as institutional use or shuttles at airports. Medium-duty trucks include Classes 3, 4 and 5, and 6. Heavy-duty trucks include Classes 7 and 8, including straight trucks such as beverage delivery and garbage trucks operating within regions, as well as articulated tractor-trailers operating at ports, in regional service, and in intrastate and interstate duties. The interstate tractor-trailers are determined using a combination of DMV data and CARB's emissions Factor (EMFAC) database.[661]

Fuel Price Forecast

Within the forecast, fuel prices affect the types of vehicles purchased, as well as the total number of miles traveled per year. Specifically, higher prices for a particular fuel make a consumer less likely to buy a vehicle using that fuel, less likely to use that fuel in a vehicle that can use multiple fuels, less likely to use that vehicle for travel, and more likely to buy a vehicle with greater fuel economy.

All forecast fuel price cases are developed by CEC staff (with the exception of the hydrogen prices) and are based on broader price trends.[662] Gasoline and diesel fuel price cases are

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661 Based on CARB Mobile Source Division analysis of International Registration Plan data, characterizing both interstate trucks based in California and those based elsewhere.

662 A number of refineries and related facilities have had significant outages in 2019, however, the impact of these outages on future fuel prices is unclear at this time and is not accounted for in the fuel price forecast. The most recent outage, on October 15, 2019, was caused by a fire and explosion of ethanol storage tanks at the NuStar tank farm, which is adjacent to the Phillips 66 Rodeo refinery in Contra Costa County. As of October 25, gasoline prices have not been impacted due to the NuStar outage, and it remains unclear what impact this will have on ethanol distribution logistics.

based on the United States Energy Information Administration's (U.S. EIA's) nationwide forecasts in its 2019 Annual Energy Outlook.[663]

To translate national fuel price forecasts into California fuel price forecasts, CEC staff considered the historical influences of several factors on California retail prices. These include:

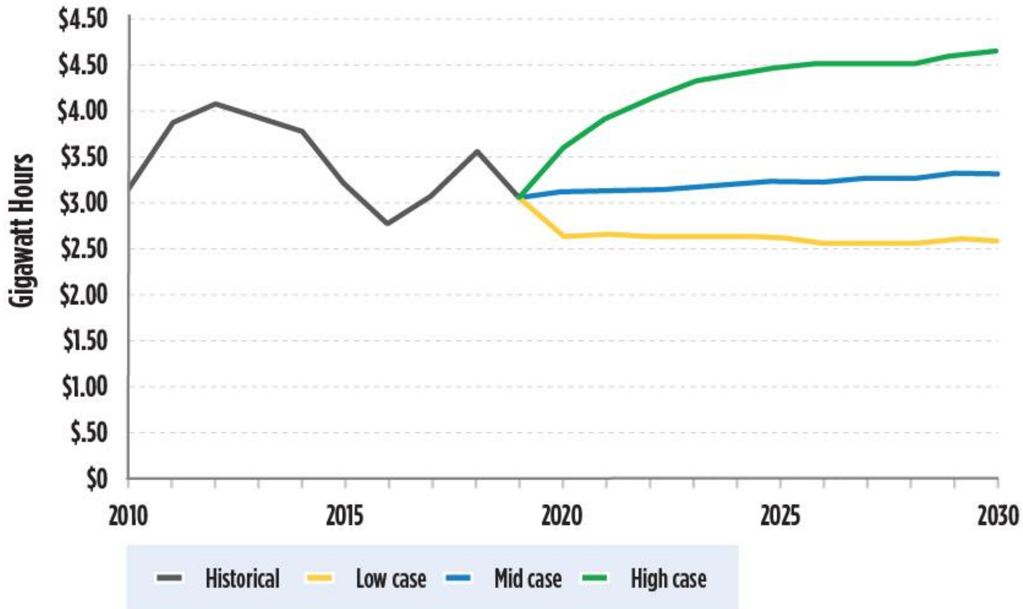
- U.S. gasoline prices.
- Crude oil prices paid by both California and U.S. refiners (on average).
- California taxes.
- Predicted LCFS credit prices and carbon prices.
- The large influence of the Torrance outage on the price of gasoline in California.[664]

The resulting gasoline price cases proposed for the low, mid, and high energy demand cases are shown in Figure 72.

663 Link to Annual Energy Outlook 2019 on the U.S. EIA's website https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf.

664 Producing a dummy variable is done by means of an ordinary least squares regression analysis with historical data (1995-2018): California retail (gasoline) price as the dependent variable and the following independent variables: U.S. (gasoline) price, California (gasoline) sales tax, California (gasoline) excise tax, underground storage tank fee, LCFS credit price, carbon price, and a dummy for the outage at the Torrance refinery. The coefficients from this regression are then used to predict future California prices with predicted future values of all the independent variables.

Figure 72: California Gasoline Price Cases (2018 Dollars per Gallon)



Source: CEC

Alternative fuel price forecasts are based on a variety of sources but are usually tied to broader market prices for the fuel outside the transportation sector. For instance, the price cases for electricity in the transportation forecast match the average residential electricity rate used in the electricity demand forecast. Similarly, the transportation price cases for CNG reflect the residential, commercial, and industrial price scenarios developed by CEC staff for the natural gas demand forecast. These transportation CNG price cases reflect the relationship among the residential, commercial, industrial, and transportation nationwide forecasts generated by the U.S. EIA.

The National Renewable Energy Laboratory (NREL) developed a hydrogen price forecast for the CEC. These prices also inform the 2019 version of an annual hydrogen station assessment by the CEC and CARB as required by Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013).[665]

665 Baronas, Jean, Gerhard Achtelik, et al. 2017. *Joint Agency Staff Report on Assembly Bill 8: 2018 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California.* CEC and CARB.

This hydrogen price incorporates the utility-level price forecasts for natural gas and electricity developed for the *2019 IEPR*. The price also incorporates the requirement by Senate Bill 1505 (Lowenthal, Chapter 877, Statutes of 2006) to dispense a minimum of one-third renewable hydrogen from publicly funded hydrogen refueling stations.[666] The low, mid, and high retail hydrogen price forecast was used for all LDV demand cases and the low and mid demand cases for MD and HD vehicles. The hydrogen price used after 2021 in the high demand case is $6.50 per kg, representing the price that stations could achieve with high station use, low electricity prices (or using renewables) to produce hydrogen using electrolysis, and refueling to 5,000 psi instead of the 10,000 psi required for LDV. High use occurs by serving fleets dedicated to fixed routes or returning daily to home bases. High station use can be achieved at stations owned or under contract with the fleet owner, sized to the truck fleet's fuel usage, and located along the fleet's dedicated routes.[667]

Conventional and alternative fuel prices can be converted into common energy units, such as megajoules,[668] British thermal units, or gasoline-gallon equivalents. However, comparing these efficiencies without respect to fuel price does not capture the operating cost of different vehicle technologies. For example, a battery-electric vehicle (BEV) will travel farther than a comparably sized car with a gasoline combustion engine on the same number of megajoules. For this reason, the transportation energy demand forecast uses cost per mile (not just cost per energy unit) in gauging consumer and fleet preferences across the different fuel options.

Publication Number: CEC-600-2018-008. [Link to AB 8: 2018 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California report](https://www.energy.ca.gov/2018publications/CEC-600-2018-008/CEC-600-2018-008.pdf)https://www.energy.ca.gov/2018publications/CEC-600-2018-008/CEC-600-2018-008.pdf..

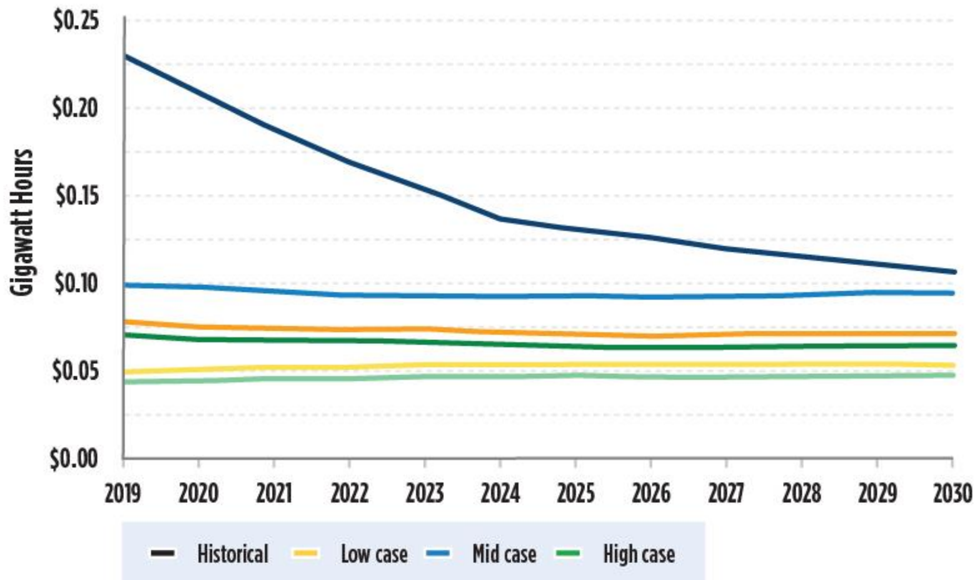
666 NREL prepared two sets of retail price forecasts, with production of hydrogen by either steam methane reformation or electrolysis. Electrolysis is more expensive. The hydrogen price scenarios used here were prepared by incorporating an increasing share of electrolysis production over time, beginning with none in 2020 and increasing to 25 percent in 2030.

667 The California Hydrogen Fuel Cell Partnership estimate is comparable, with projections of $5 - $7/kg, but stays above the Bloomberg projection of $1.50 - $2.90/kg by 2030 for hydrogen production using electrolysis and renewable energy. The dedicated fleet hydrogen price projection explicitly excludes costs arising from retail dispensing.

668 A "megajoule" is one million joules. It is the standard unit of work or energy in the International System of Units, equal to the work done by a force of one newton when the point of application moves through a distance of one meter in the direction of the force.

Figure 73 compares the approximate cost per mile of gasoline and several alternative fuels among midsize cars in the LDV sector for the mid case fuel price forecast. While fuel prices are forecast to increase, fuel economy is forecast to see a similar rise, so cost per mile is not expected to see a significant change for gasoline, plug-in hybrid electric vehicles (PHEVs), or BEVs. As shown, the cost per mile of electricity remains significantly lower than gasoline for both residential and commercial consumers. Based on input from NREL, the cost per mile of hydrogen for FCEVs is expected to decline over time in response to increasing economies of scale for new hydrogen refueling stations. (However, most light-duty FCEVs are leased with special "free fuel" conditions for a period of several years, and a similar business arrangement is anticipated for heavy-duty FCEVs, although no such vehicle is available.)

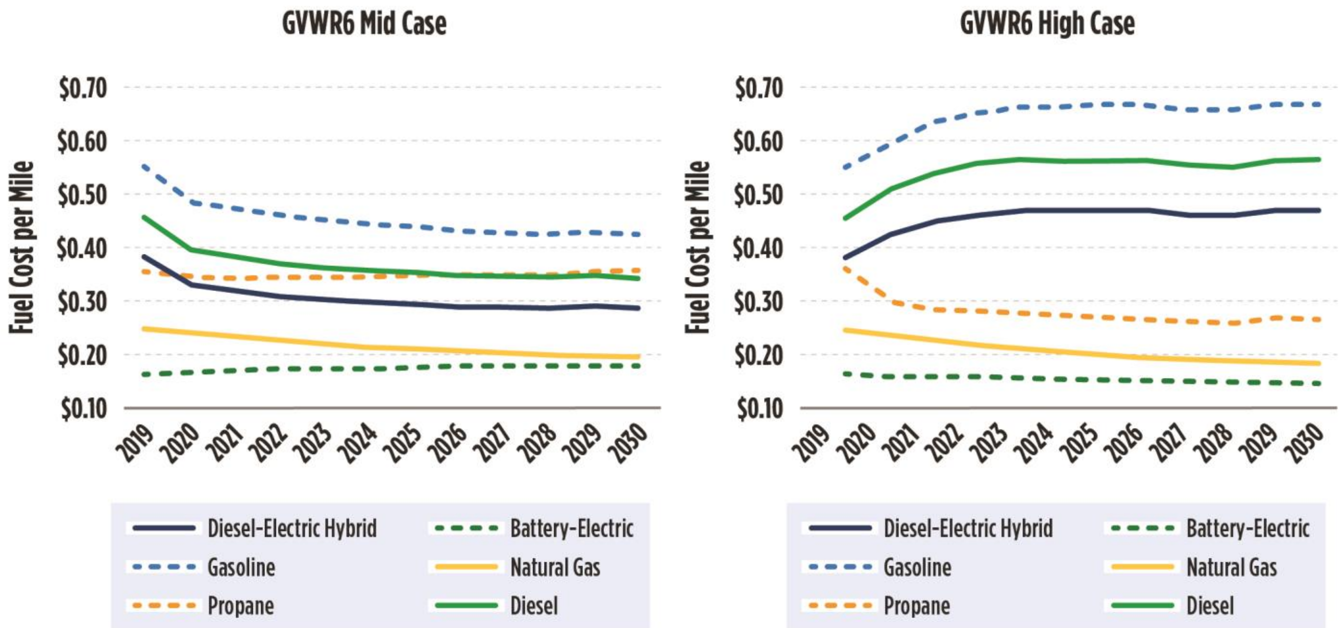
Figure 73: Fuel Cost per Mile Forecast for LDVs (Midsize Cars), Mid Case



Source: CEC, NREL

Figure 74 shows the mid and high demand case cost per mile of various fuels for Classes 6 trucks, which are larger stepvans and box trucks under 26,000 pounds gross. The relative ranking of gasoline, diesel, and electricity cost per mile for Class 6 trucks are the same as for the LDVs. The Class 6 truck costs per mile are higher than LDVs because of additional weight and typically a more intense urban cycle, as compared to LDVs. Note that the diesel cost per mile in 2030 in the mid demand case is about 16 cents higher than the battery-electric cost per mile, but in the high demand case it is 42 cents higher. As a result, battery-electric penetration is higher in the high demand case.

Figure 74: Fuel Cost per Mile Forecast for MD Trucks (Classes 4 and 5), Mid and High Cases

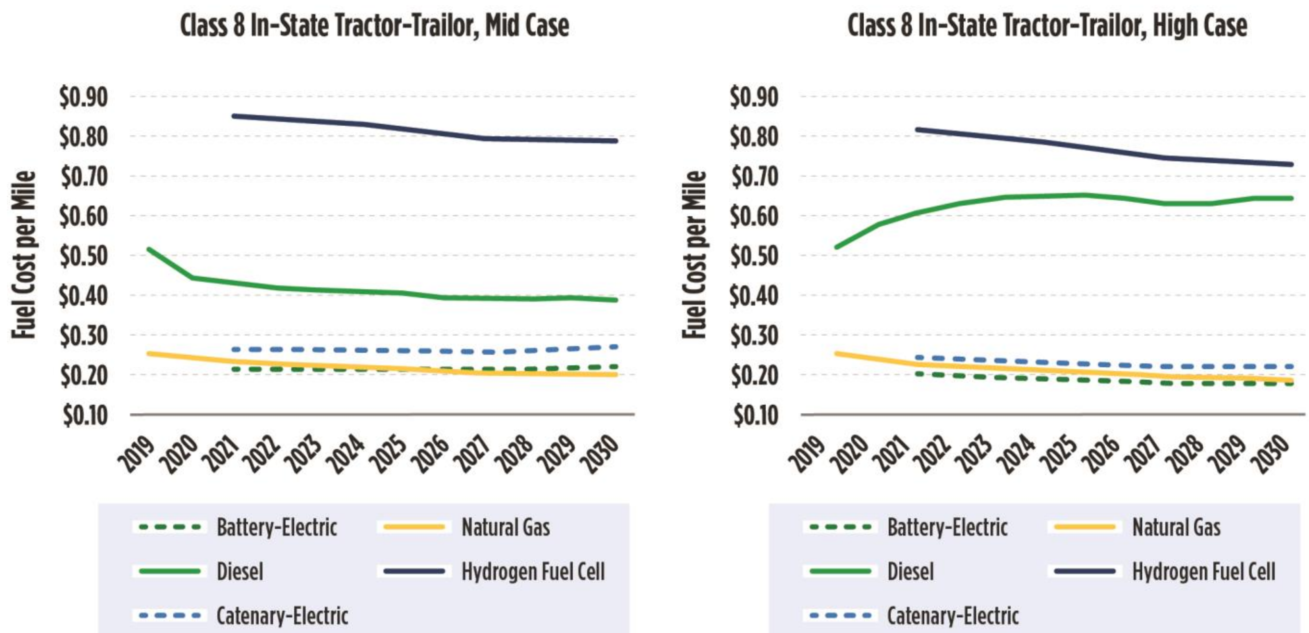


Source: CEC

Figure 75 shows the mid and high demand cases for cost per mile of various fuels in Class 8 intrastate tractor-trailers operating within California. Battery-electric has the lowest cost per mile, followed closely by natural gas and catenary-electric, then diesel-electric hybrid and the other fuels, with hydrogen having the highest cost per mile in both cases. The relative importance of purchase price versus fuel costs depends on the annual miles per tractor-trailer, which ranges from as low as 20,000 to over 100,000. Fleets with lower annual miles tend to purchase the less expensive diesel tractor-trailer, while fleets with high annual miles tend to purchase battery-electric or hydrogen fuel cell, particularly when incentives are available to lower purchase prices.

Hydrogen prices in 2030 are about 39 cents per mile higher than diesel in the mid demand case, but only nine cents per mile higher than diesel in the high demand case. Incentive levels are 99 percent of the incremental cost of ZEV trucks in the high demand case and 90 percent in the mid demand case. As a result, hydrogen fuel cell trucks are more competitive in the high demand case. The mid demand case hydrogen fuel cell truck market share is virtually zero, whether using the mid demand case retail hydrogen price or when testing a dedicated fleet price as low as $6.75 per kg. In the low demand case, incentives are eliminated after 2021 and diesel prices are even lower, leading to zero market share for hydrogen fuel cell tractor-trailers.

Figure 75: Fuel Cost per Mile Forecast for In-State HD Tractor-Trailers (Class 8), Mid Case and High Case



Source: CEC*Note that adoption of electric and hydrogen trucks is forecasted to begin in 2021 and so that is the first year fuel cost per mile can be calculated.

Consumer Preferences (LDVs)

Consumer preferences are a key component in developing the CEC's forecasts of size and composition of the LDV population. To gauge consumer preferences, the CEC periodically surveys residential and commercial LDV owners to capture the historically distinct preferences between the two groups. The survey provides participants with a series of hypothetical vehicles with different attributes and government incentives and then asks them to choose one for purchase. Their choices help the CEC assess consumer preferences for different vehicle attributes, fuel types, and vehicle classes.

The CEC is completing the 2019 survey. The *2019 IEPR* forecast relies on the last survey conducted in 2017 by Resource Systems Group.[669] The 2019 survey results will be available in

669 [Link to information on the California Vehicle Survey on the CEC's website](https://www.energy.ca.gov/data-reports/surveys/california-vehicle-survey) https://www.energy.ca.gov/data-reports/surveys/california-vehicle-survey.

2020 and staff will incorporate the results into the *2021 IEPR*. Because the 2019 survey includes more detailed questions than previous years about charging infrastructure, staff anticipates revising the infrastructure availability metrics.[670]

Vehicle Attributes (LDVs)

Once the survey measures consumers' preferences for different attributes, fuel types, and vehicle classes, those preferences can be matched against a forecast of vehicle attributes by vehicle class and fuel type that are anticipated to be offered in the market.

Key vehicle and infrastructure attributes include:

- Range.
- Vehicle price.
- Fuel economy.
- Fuel cost per mile.
- Acceleration.
- Number of makes and models.
- Time to fuel station.
- Refueling time.
- Maintenance costs.
- Cargo capacity.

Given the heightened focus on vehicle electrification and compliance with CARB regulations for ZEVs, CEC staff generated different scenarios for ZEV price and range, presented in Chapter 8.

MD and HD Truck Alternative Fuel Penetration Rates

To determine the penetration rates of alternative fuels and advanced vehicle technologies for MD and HD trucks, the forecast relies on Argonne National Laboratory's TRUCK 5.1, a truck choice model. As constructed, the model is limited to one conventional "base" fuel (such as gasoline or diesel) and up to three alternative fuel trucks for each class. In response to this limitation, CEC staff assigned alternative fuels and technologies in classes already commercialized. Trial runs of possible fuels in each class were used to arrive at a set of

670 The public can participate in workshops, provide and follow comments in the dockets, and access prior workshop presentations and recordings on the CEC IEPR website, https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report. DAWG presentations can be accessed online, http://dawg.energy.ca.gov/.

competing fuel types with significant market penetration. For example, hydraulic hybrid trucks were dropped from consideration because they showed zero market penetration in trial runs.

Staff also applied California-specific annual vehicle miles traveled by class and model-year vintage, based on a 2017 survey of trucking activity.[671]

For zero emission trucks, staff applied CARB's Hybrid and Zero-Emission Voucher Incentive Project (HVIP) incentives for alternative fuels according to the percentage of incremental costs covered for each fuel and class. Staff also assume funding is not constrained, so that all eligible buyers can receive incentives.

H-D Systems provided truck price and fuel economy forecasts. Prices for alternative fuel trucks were based on an assumption that production reaches high volume by the end of the forecast period, achieving a lower price than the low volume typical during early commercialization. H-D Systems assigned fuel efficiency for each MD and HD class by truck duty cycle most common for each truck class.[672]

Policies, Regulations, and Incentives

California has implemented a range of regulations and incentives to advance its clean transportation goals. Several of these regulations and incentives are incorporated into the transportation forecast and vary between LDVs and MD and HD vehicles.

California's ZEV regulation and the federal Corporate Average Fuel Economy standards apply to LDVs. Several government incentives included in the LDV choice analysis include the state rebates from the Clean Vehicle Rebate Project administered by CARB, the federal income tax credit, and access to the state's high-occupancy vehicle lanes.

Among MD and HD vehicles, staff incorporated several regulatory requirements into the forecast. The NHTSA/EPA Phase 2 Medium- and Heavy-duty Truck GHG Emissions and Fuel Efficiency Standards[673] are the basis of truck fuel economy used in the Truck Choice and Freight models. CARB's truck and bus regulations, for instance, require diesel particulate filters

671 2017 California Vehicle Inventory and Use Survey, Caltrans Division of Planning. See: https://journals.sagepub.com/doi/abs/10.1177/0361198119849400?journalCode=trra

672 The CEC contracted with *H-D Systems* to forecast the medium and heavy-duty vehicle attributes used for the 2017 and 2019 IEPR. "Duty cycle" is the pattern of operation, such as refuse trucks that stop at each residence and use energy to process each curbside container are assigned lower fuel efficiency than would be typical for freeway driving.

673 Final Rule for Phase 2 Greenhouse Gas Emissions Standards https://www.epa.gov/regulations-emissions-vehicles-and-engines/final-rule-greenhouse-gas-emissions-and-fuel-efficiency

and updates to 2010 or newer engines, with a provision for alternative compliance by fleets. Existing fleet requirements in the South Coast Air Quality Management District area, which require the procurement of lower-emission and alternative fuel vehicles for transit buses, refuse trucks, and certain other fleets are implicit in the historical truck population and by calibration of truck choice to current fuel type market shares.

The Advanced Clean Truck regulation will be included in future forecasts, after final language is available from CARB. CARB released the draft regulation in October 2019, which was too late to incorporate into the *2019 IEPR*.[674]

For transit buses, the forecast assumes a significant expansion of zero-emission buses within the forecast period. This expansion is in line with CARB's proposed Innovative Clean Transit goal of transitioning all transit buses to zero-emission technologies by 2040. Leasing of battery-electric buses can be cost-competitive with conventional buses, due to the reduced costs of fuel and maintenance, based on CARB analysis.

> "Compared with purchasing conventional buses, even without funding, the impact of leasing battery electric buses on annual cash flow is not expected to be noticeable, and would not result in adverse changes in transit service or fares."[675]

The initial incremental capital purchase costs for buses and infrastructure may be reduced with a combination of leasing options, state grants, and programs to support transportation electrification. Also, on a total cost of ownership (TCO) basis, operational savings are expected to offset initial costs:

> "CARB understands there is an initial capital cost for purchasing zero emission buses (ZEBs) and associated infrastructure greater than for conventional buses but also recognizes operational savings offset these costs over the life of a bus."[676]

Figure 76 shows the simplified Innovative Clean Transit (ICT) requirements (without credits) with the forecasted statewide zero-emission bus purchases in each scenario. Credits can be earned by transit agencies that already own or purchase zero-emission busses prior to the onset of the regulations. These can later be used toward fulfilling ICT bus purchase requirements. There is flexibility in how individual transit agencies implement the regulations

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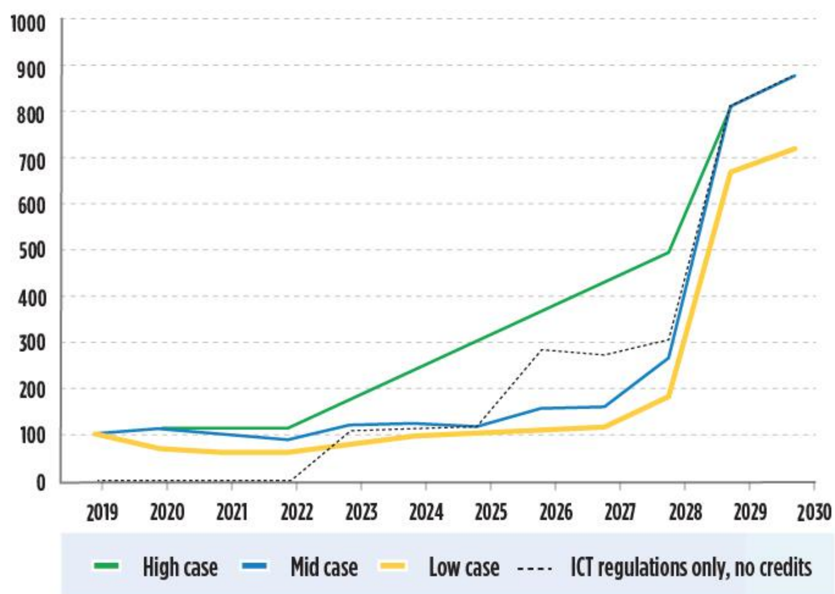
674 Proposed Advanced Clean Truck Regulation https://www.arb.ca.gov/rulemaking/2019/advancedcleantrucks

675 Innovative Clean Transit Regulation, a Replacement of the Fleet Rule for Transit Agencies, Final Statement of Reasons, June 2019. p. 267. https://www.arb.ca.gov/rulemaking/2018/innovative-clean-transit-2018.

676 Ibid., p. 104-5.

and use credits. Agencies that desire to accelerate their zero-emission bus purchases face no limits in doing so, as seen in the high scenario. Agencies that prefer to delay purchases of zero-emission busses can do so by purchasing diesel and natural gas buses in the early years of the regulation as seen in the low scenario.

Figure 76: Zero-Emission Bus Purchases, Three Demand Cases and Simplified Innovative Clean Transit Regulations



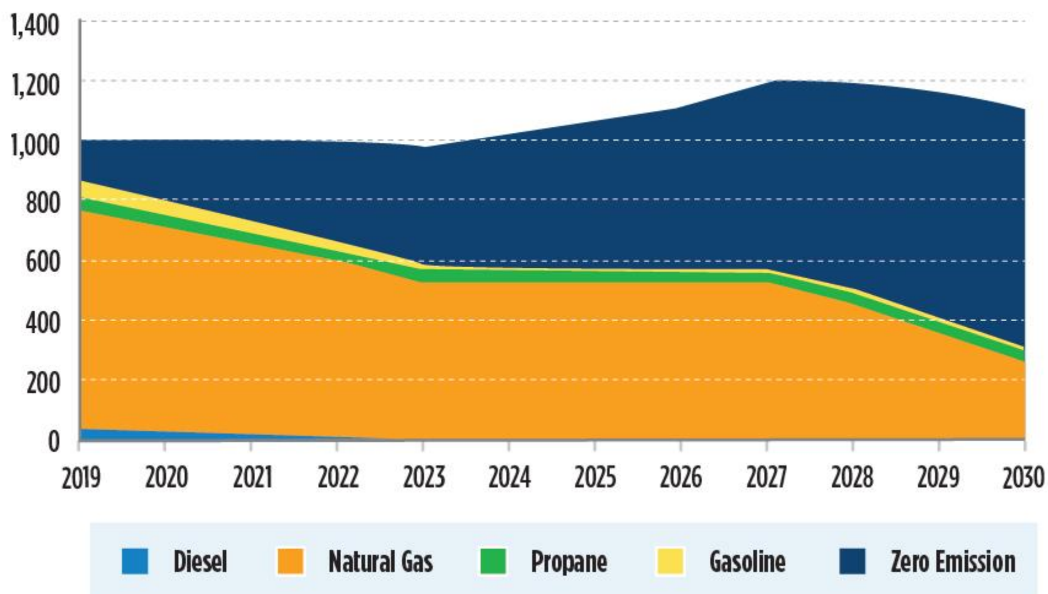
Source: CEC

For airport shuttle buses, the forecast closely aligns with CARB's proposed zero-emission airport shuttle (ZEAS) regulation.[677] CARB's proposal requires private and public fleet owners that service the 13 largest airports in California to gradually convert their fleets to zero emission. Figure 77 shows estimates of airport shuttles by fuel type during the forecast period, where one scenario was used for all three demand cases. It also reflects the major components of the CARB regulation, which are:

677 CARB submitted the Zero Emission Airport Shuttle (ZEAS) rulemaking package to Office of Administrative Law (OAL) on July 29, 2019. CARB resubmitted the package on December 18, 2019. OAL has until February 3, 2020, to make a final determination. https://www.arb.ca.gov/rulemaking/2019/asb19

- In-use fleet requirement with three compliance deadlines:
    - At least 33 percent of the fleet must be zero emission by December 31, 2027.
    - At least 66 percent of the fleet must be zero emission by December 31, 2031.
    - 100 percent of the fleet must be zero emission by December 31, 2035.
- A purchase requirement that if a fleet owner is replacing a ZEAS on or after January 1, 2023, the fleet owner must replace that vehicle only with another ZEAS.

Figure 77: Airport Shuttle Bus Stock by Fuel Type, All Demand Cases



Source: CEC

For school buses, the forecast shows an increase in the number of electric school buses. By 2030, roughly ten percent of operational home-to-school statewide fleet would be electric. California continues to lead the nation in electric school bus adoption because, in addition to the Volkswagen settlement,[678] the state and electric utilities are allocating and awarding

678 In spring-summer of 2018, CARB approved a plan for the Volkswagen (VW) Environmental Mitigation Trust that provides about $423 million for California to mitigate the excess nitrogen oxide emissions caused by VW's

millions of dollars in grants and subsidies to school districts for purchasing electric buses and installing charging infrastructure. Until recently, California schools had limited options in the number of electric bus providers and models, and even more constraints related to charging infrastructure and localized service and support. However, many bus manufacturers such as Blue Bird, Lion, Cummins and others are now offering more options for electric school buses and providing temporary charging equipment for school districts that are still building their charging infrastructure.

Figure 78 shows school bus stock by fuel type throughout the forecast period, for all demand cases. The estimates are primarily driven by availability of grants and funds for replacing an old school bus with a new one. Although award sizes are larger for zero emission technology, in some cases, CNG, clean diesel,[679] and propane school buses are a better fit for school districts because of affordability and convenience. Currently school buses are not subject to CARB's zero emission regulation and that is why the significant share of school buses are still natural gas, diesel, and propane throughout the forecast period.

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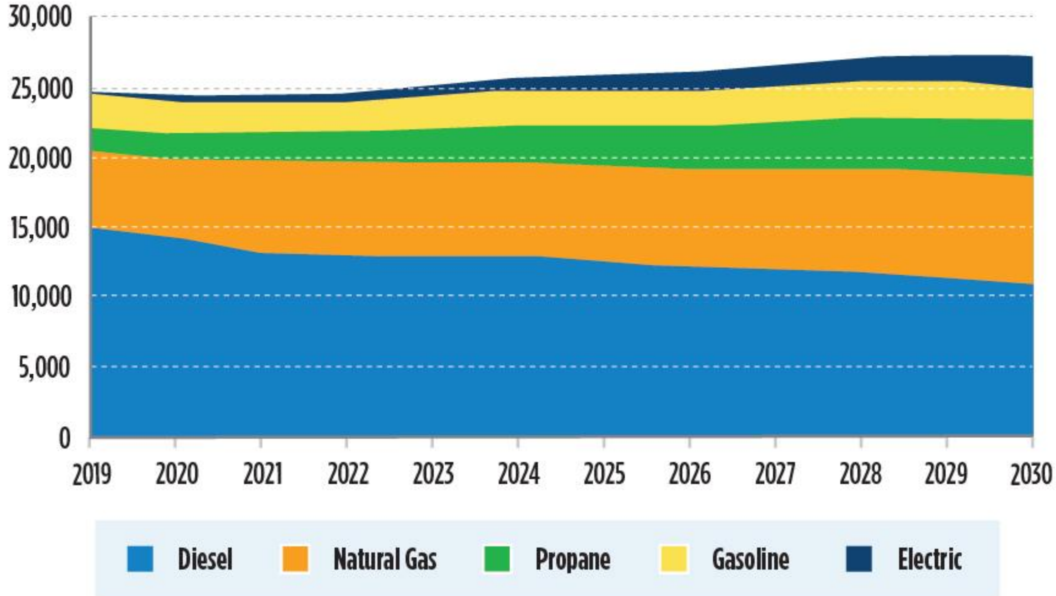
use of illegal emissions testing defeat devices in certain VW diesel vehicles. https://www.arb.ca.gov/our-work/programs/volkswagen-environmental-mitigation-trust-california.

679 Clean diesel refers to advanced engines and emission controls that result in near-zero emissions of particulates and oxides of nitrogen.

Figure 78: School Bus Count by Fuel Type, All Demand Cases



Source: CEC

APPENDIX D:
Summary of Publicly Owned Utilities' Integrated Resource Plan Resource Mix

This table presents the portfolio of electricity resources for each publicly owned utility (POU) required to submit an integrated resource plan (IRP) to the California Energy Commission (CEC) for review, as described in Chapter 1. Senate Bill 350 (De León, Chapter 547, Statutes of 2015) required POUs to adopt an IRP by January 1, 2019, for review by the CEC. The CEC reviewed the IRPs to determine if they met certain requirements, including achieving Renewables Portfolio Standard procurement requirements set in SB 350 and greenhouse gas emissions reduction targets established by the California Air Resources Board. SB 350 also identified a number of planning goals and procurement requirements that the IRPs must meet or address. The table shows each POU's generation resources by resource type, and the percentage of total energy by resource type for the years 2018, 2019, 2025, and 2030. The table reflects the resource mix identified in each POU's IRP.

Table 42: Summary of POUs' Integrated Resource Plan Resource Mix

POU Name	Generation by POU and Resource Type (GWhs)	Generation by POU and Resource Type (GWhs)	Generation by POU and Resource Type (GWhs)	Generation by POU and Resource Type (GWhs)	Percentage of Total Energy, by Year and POU	Percentage of Total Energy, by Year and POU	Percentage of Total Energy, by Year and POU	Percentage of Total Energy, by Year and POU
	2018	**2019**	**2025**	**2030**	**2018**	**2019**	**2025**	**2030**
Anaheim								
Solar	7	7	123	122	0%	0%	5%	5%
Other Renewables	366	370	372	759	16%	16%	16%	33%
Wind	169	169	56	131	7%	7%	2%	6%
Large Hydro	38	38	38	38	2%	2%	2%	2%
Coal	1,086	1,141	1,097	0	47%	50%	48%	0%
Natural Gas	873	866	746	794	38%	38%	33%	35%
Net Market Purchases	-247	-297	-157	427	-11%	-13%	-7%	19%
Anaheim Total	**2,292**	**2,294**	**2,275**	**2,272**	**100%**	**100%**	**100%**	**100%**
Burbank								
Solar	98	91	268	264	8%	8%	22%	22%
Other Renewables	48	60	60	60	4%	5%	5%	5%
Wind	54	76	465	404	4%	6%	39%	33%
Energy Storage	0	0	0	106	0%	0%	0%	9%
Large Hydro	19	21	21	22	2%	2%	2%	2%
Nuclear	81	86	86	86	6%	7%	7%	7%
Coal	444	455	180	0	35%	38%	15%	0%
Natural Gas	472	586	507	466	37%	49%	43%	38%

POU Name	Generation by POU and Resource Type (GWhs)	Generation by POU and Resource Type (GWhs)	Generation by POU and Resource Type (GWhs)	Generation by POU and Resource Type (GWhs)	Percentage of Total Energy, by Year and POU	Percentage of Total Energy, by Year and POU	Percentage of Total Energy, by Year and POU	Percentage of Total Energy, by Year and POU
Net Market Purchases	43	-171	-393	-194	3%	-14%	-33%	-16%
Burbank Total	**1,260**	**1,204**	**1,194**	**1,215**	**100%**	**100%**	**100%**	**100%**
Power Enterprise of the San Francisco Public Utilities Commission (CCSF)								
Solar	8	8	10	12	1%	0%	1%	1%
Other Renewables	420	567	568	493	28%	29%	28%	26%
Large Hydro	1,064	1,375	1,421	1,376	71%	70%	71%	73%
Natural Gas	10	10	10	10	1%	1%	1%	1%
CCSF Total	**1,503**	**1,961**	**2,009**	**1,892**	**100%**	**100%**	**100%**	**100%**
Imperial Irrigation District (IID)								
Solar	385	466	449	435	10%	12%	11%	10%
Other Renewables	624	1,186	821	1,642	17%	32%	20%	38%
Large Hydro	166	180	169	150	4%	5%	4%	3%
Nuclear	119	114	114	114	3%	3%	3%	3%
Natural Gas	1,088	1,313	1,203	1,155	29%	35%	30%	27%
Net Market Purchases	1,381	505	1,279	847	37%	13%	32%	20%
IID Total	**3,764**	**3,764**	**4,035**	**4,343**	**100%**	**100%**	**100%**	**100%**
Los Angeles Department of Water and Power (LADWP)								
Solar	3,502	3,915	7,076	7,906	13%	14%	24%	26%
Other Renewables	1,834	2,444	3,368	3,751	7%	9%	12%	12%
Wind	2,447	2,446	2,469	3,033	9%	9%	8%	10%
Energy Storage	14	133	883	885	0%	0%	3%	3%
Large Hydro	1,103	1,164	1,585	1,839	4%	4%	5%	6%
Nuclear	3,176	3,177	3,177	3,176	12%	12%	11%	10%
Coal	4,652	4,558	1,635	0	18%	17%	6%	0%
Natural Gas	9,249	8,899	8,509	9,711	35%	33%	29%	32%
Net Market Purchases	409	409	409	409	2%	2%	1%	1%
LADWP Total	**26,386**	**27,144**	**29,111**	**30,710**	**100%**	**100%**	**100%**	**100%**
Modesto Irrigation District (MID)								
Solar	67	67	397	818	2%	2%	13%	22%
Other Renewables	10	21	10	141	0%	1%	0%	4%
Wind	477	493	493	367	18%	18%	16%	10%
Large Hydro	13	13	13	13	1%	0%	0%	0%
Natural Gas	780	733	659	724	29%	26%	21%	20%

POU Name	Generation by POU and Resource Type (GWhs)	Generation by POU and Resource Type (GWhs)	Generation by POU and Resource Type (GWhs)	Generation by POU and Resource Type (GWhs)	Percentage of Total Energy, by Year and POU	Percentage of Total Energy, by Year and POU	Percentage of Total Energy, by Year and POU	Percentage of Total Energy, by Year and POU
Net Market Purchases	1,332	1,451	1,600	1,648	50%	52%	50%	44%
MID Total	**2,680**	**2,779**	**3,174**	**3,712**	**100%**	**100%**	**100%**	**100%**
Palo Alto								
Solar	345	322	386	377	38%	34%	42%	41%
Other Renewables	118	113	113	47	13%	12%	12%	5%
Wind	107	100	43	0	12%	11%	5%	0%
Energy Storage	0	0	0	0	0%	0%	0%	0%
Large Hydro	355	560	481	481	39%	59%	52%	53%
Nuclear	0	0	0	0	0%	0%	0%	0%
Coal	0	0	0	0	0%	0%	0%	0%
Natural Gas	0	0	0	0	0%	0%	0%	0%
Net Market Purchases	-19	-152	-92	7	-2%	-16%	-10%	1%
Palo Alto Total	**906**	**942**	**930**	**912**	**100%**	**100%**	**100%**	**100%**
Pasadena								
Solar	106	103	312	452	8%	8%	25%	36%
Other Renewables	388	397	251	205	30%	29%	20%	16%
Wind	24	28	10	0	2%	2%	1%	0%
Large Hydro	44	44	44	44	3%	3%	4%	4%
Nuclear	79	75	74	72	6%	6%	6%	6%
Coal	484	413	205	0	38%	30%	16%	0%
Natural Gas	156	77	96	78	12%	6%	8%	6%
Net Market Purchases	0	219	271	394	0%	16%	21%	32%
Pasadena Total	**1,280**	**1,357**	**1,264**	**1,244**	**100%**	**100%**	**100%**	**100%**
Redding								
Solar	0	0	24	174	0%	0%	4%	31%
Other Renewables	26	32	32	32	3%	5%	6%	6%
Wind	175	180	180	180	23%	29%	34%	32%
Large Hydro	183	242	237	237	24%	38%	45%	43%
Natural Gas	245	4	15	16	32%	1%	3%	3%
Net Market Purchases	127	170	39	-82	17%	27%	7%	-15%
Redding Total	**756**	**628**	**527**	**557**	**100%**	**100%**	**100%**	**100%**
Roseville								
Solar	91	1	179	254	8%	0%	15%	22%
Other Renewables	190	189	128	48	16%	15%	11%	4%
Wind	175	138	179	255	15%	11%	15%	22%
Large Hydro	159	215	215	215	13%	17%	18%	19%

POU Name	Generation by POU and Resource Type (GWhs)	Generation by POU and Resource Type (GWhs)	Generation by POU and Resource Type (GWhs)	Generation by POU and Resource Type (GWhs)	Percentage of Total Energy, by Year and POU	Percentage of Total Energy, by Year and POU	Percentage of Total Energy, by Year and POU	Percentage of Total Energy, by Year and POU
Natural Gas	259	274	249	249	22%	22%	21%	22%
Net Market Purchases	326	419	251	125	27%	34%	21%	11%
Roseville Total	**1,200**	**1,235**	**1,200**	**1,147**	**100%**	**100%**	**100%**	**100%**
Riverside								
Solar	259	258	394	383	11%	11%	17%	15%
Other Renewables	384	650	648	944	17%	28%	27%	37%
Wind	97	93	93	93	4%	4%	4%	4%
Large Hydro	30	30	30	30	1%	1%	1%	1%
Nuclear	92	93	93	95	4%	4%	4%	4%
Coal	634	617	295	0	28%	27%	12%	0%
Natural Gas	49	99	273	150	2%	4%	11%	6%
Net Market Purchases	745	474	556	861	33%	20%	23%	34%
Riverside Total	**2,291**	**2,315**	**2,382**	**2,557**	**100%**	**100%**	**100%**	**100%**
Sacramento Municipal Utility District (SMUD)								
Solar	0	552	1,293	1,742	0%	5%	11%	15%
Other Renewables	0	1,371	1,537	1,519	0%	12%	13%	13%
Wind	0	1,636	1,823	2,899	0%	14%	16%	24%
Large Hydro	0	719	704	704	0%	6%	6%	6%
Natural Gas	0	5,503	5,599	4,628	0%	48%	48%	39%
Net Market Purchases	0	1,624	682	455	0%	14%	6%	4%
SMUD Total	**0**	**11,405**	**11,638**	**11,948**	**0%**	**100%**	**100%**	**100%**
Silicon Valley Power (SVP)								
Solar	61	61	155	521	2%	2%	3%	11%
Other Renewables	850	966	881	838	23%	25%	19%	18%
Wind	449	453	1,416	1,767	12%	12%	31%	37%
Large Hydro	487	814	1,083	814	13%	21%	23%	17%
Natural Gas	1,282	1,285	1,140	981	35%	33%	25%	21%
Net Market Purchases	564	308	-55	-164	15%	8%	-1%	-3%
SVP Total	**3,694**	**3,888**	**4,621**	**4,758**	**100%**	**100%**	**100%**	**100%**
Turlock Irrigation District (TID)								
Solar	159	158	451	743	5%	5%	13%	19%
Other Renewables	138	141	125	123	4%	4%	4%	3%
Wind	370	370	370	370	11%	11%	10%	10%
Large Hydro	244	336	330	372	7%	10%	9%	10%

POU Name	Generation by POU and Resource Type (GWhs)	Generation by POU and Resource Type (GWhs)	Generation by POU and Resource Type (GWhs)	Generation by POU and Resource Type (GWhs)	Percentage of Total Energy, by Year and POU	Percentage of Total Energy, by Year and POU	Percentage of Total Energy, by Year and POU	Percentage of Total Energy, by Year and POU
Coal	308	0	0	0	9%	0%	0%	0%
Natural Gas	1,516	1,333	1,111	886	46%	40%	31%	23%
Net Market Purchases	527	968	1,158	1,384	16%	29%	33%	36%
TID Total	**3,261**	**3,306**	**3,544**	**3,878**	**100%**	**100%**	**100%**	**100%**
Vernon								
Solar	124	124	419	476	11%	10%	33%	36%
Other Renewables	61	61	47	184	5%	5%	4%	14%
Wind	0	0	79	79	0%	0%	6%	6%
Large Hydro	21	21	21	21	2%	2%	2%	2%
Nuclear	94	94	94	94	8%	8%	7%	7%
Natural Gas	719	753	689	0	64%	61%	54%	0%
Net Market Purchases	103	173	-67	451	9%	14%	-5%	35%
Vernon Total	**1,123**	**1,226**	**1,281**	**1,304**	**100%**	**100%**	**100%**	**100%**
Glendale Water and Power (GWP)								
Solar	0	0	131	257	0%	0%	12%	20%
Other Renewables	0	51	51	51	0%	6%	5%	4%
Wind	0	97	314	445	0%	11%	30%	34%
Energy Storage	0	0	-10	-14	0%	0%	-1%	-1%
Large Hydro	0	53	53	53	0%	6%	5%	4%
Nuclear	0	86	86	86	0%	10%	8%	7%
Natural Gas	0	166	379	384	0%	20%	36%	30%
Net Market Purchases	0	388	44	33	0%	46%	4%	3%
GWP Total	**0**	**841**	**1,048**	**1,294**	**0%**	**100%**	**100%**	**100%**

APPENDIX E:
Report on the Implementation Status of the Recommendations in the Senate Bill 350 Low-Income Barriers Study Part A and Part B

Status of Recommendations in Barriers Study Part A

On July 30, 2019, the California Energy Commission (CEC), the California Public Utilities Commission (CPUC), and the California Air Resources Board (CARB) held a joint agency workshop on Advancing Energy Equity to review progress towards implementing the recommendations in the Barriers Studies, Part A[680] and B[681] and to explore next steps and key actions to advance energy equity throughout California. At the workshop, state agencies discussed the actions they have already taken and the actions they plan to complete to fulfill the recommendations of the Barriers Studies. This appendix provides a summary of the implementation status of each recommendation in Barriers Study Part A and Part B.

California's state agencies have made significant progress towards accomplishing the recommendations in the Barriers Studies. The programs created to implement the recommendations are making a real contribution and benefiting low-income Californians and those living in disadvantaged communities. Moreover, these programs have laid a solid foundation upon which California can construct an equitable energy future.

680 CEC, Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities. Link to workshop information, notices, and documents regarding SB 350 Barriers Study on the CEC's website https://www.energy.ca.gov/sb350/barriers_report/.

681 CARB, Low-Income Barriers Study, Part B: Overcoming Barriers to Clean Transportation Access for Low-Income Residents, Link to CARB Barriers Report on the CARB website https://www.arb.ca.gov/resources/documents/carb-barriers-report-final-guidance-document.

Recommendation 1: Establish a Multiagency Taskforce to Facilitate Coordination Across State-Administered Programs

Status: Completed

In May 2017, the Governor's Office established an interagency task force to implement priority recommendations from both the CEC's Barriers Study Part A and CARB's Final Guidance Document. The task force was comprised of over 15 state agencies implementing clean energy and transportation programs, as well as related disciplines including but not limited to public health, water, and housing. The task force met through the end of 2018 to ensure continued coordination across agencies. State agencies continue to collaborate through workshops and other informal activities.

The CEC, in coordination with partner agencies, developed the Clean Energy in Low-Income Multifamily Buildings Action Plan (CLIMB Action Plan) which identifies actions to improve existing programs in the multifamily sector and lays the foundation to develop long-term solutions.[682] The CLIMB Action Plan identifies programs and policies, remaining challenges, and concrete actions the state can take to accelerate the implementation of distributed energy resources (such as demand response, onsite renewable energy, electric vehicle infrastructure, energy storage, and energy and water efficiency) strategies within California's multifamily housing stock. With a significant number of Californians living in multifamily buildings, these buildings offer an opportunity and a challenge to accelerating the state's clean energy progress. The final Climb Action Plan was adopted in November 2018. In June 2019, the CEC launched the multifamily component of the Building Energy Benchmarking Program, which was identified in the CLIMB Action Plan as information needed to better understand multifamily buildings.[683]

Next Steps

The CEC continues to engage with state partners on current multifamily-related program activities (CLIMB Strategy 4.3.1). As recommended in CLIMB Strategy 2.1.3, the CEC will implement multifamily building energy benchmarking activities, including outreach and education to multifamily building owners. For example, the CEC is funding a grant to Energy

682 CEC's Clean Energy in Low-Income Multifamily Buildings Action Plan
https://www.energy.ca.gov/business_meetings/2018_packets/2018-11-07/Item_06.pdf.

683 The Building Energy Benchmarking Program is the state's program to publicly disclose the energy use of buildings in California. It requires owners of large commercial and multifamily buildings to report energy use to the CEC by June 1 annually. Data to better understand energy use in commercial properties and multifamily buildings will be released fall 2020.

Council (a joint powers agency) to launch a project that will accelerate multifamily building upgrades in the San Francisco Bay Area.[684] In addition, as recommended in CLIMB Strategy 2.1.3,[685] the CEC will implement multifamily building energy benchmarking activities, including outreach and education to multifamily building owners.[686]

Recommendation 2: Enable the Economic Advantages of Community Solar to Low-income and Disadvantaged Populations

Status: Ongoing

The CPUC and California Department of Community Services and Development (CSD) have made significant progress establishing new programs and pilots to implement this recommendation. In 2018, the CPUC issued decision D.18-06-027, which adopted the Community Solar Green Tariff Program (CSGT). This program allows low-income customers in disadvantaged communities to benefit from the development of solar generation projects located in or near their communities. Eligible customers participating in this program are able to receive a 20 percent discount on their overall utility bill. The IOUs filed their implementation plans in August 2018 and the CPUC issued Resolution E-4999, which approved the IOUs implementation plans with modification in May 2019. The IOUs have updated their CSGT tariffs to comply with the direction provided in the resolution.

In August 2019, the IOUs submitted to the CPUC their marketing, education, and outreach plans, 2019–2020 program budgets, and project solicitation documents. Community Choice Aggregators (CCAs) who serve residential customers in disadvantaged communities are eligible to offer their own CSGT programs, as long as they are consistent with all program requirements.

In June 2019, CSD awarded $4.43 million in funding for its Community Solar Pilot Program (CSPP)—two community solar projects that will provide benefits to low-income households and test prototype delivery models. The CSPP, part of California Climate Investments,[687] aims to

684 Transcript for the November 7, 2018, CEC Business Meeting https://efiling.energy.ca.gov/getdocument.aspx?tn=225914.

685 CLIMB Strategy 2.1.3: Establish a repository of multifamily building data for program development, implementation, and evaluation, including data such as that from the Building Energy Benchmarking Program (Assembly Bill 802) and Tax Credit Allocation Committee affordable housing inventory.

686 Barriers Study Recommendations Report https://efiling.energy.ca.gov/GetDocument.aspx?tn=229108&DocumentContentId=60513. TN# 229108. p. 1.

687 California Climate Investments is funded by the Greenhouse Gas Reduction Fund.

make the benefits of solar energy more available to eligible low-income households, lower residents' energy bills, and provide co-benefits to communities, including economic and workforce development. CSD selected the following two projects:

Santa Rosa Band of Cahuilla Indians Empowering Communities: CSD awarded approximately $2 million to GRID Alternatives Inland Empire in Riverside to install a 994 kilowatt (kW) direct current (DC) ground-mounted solar array in partnership with the Santa Rosa Band of Cahuilla Indians and the Anza Electric Cooperative, Inc. Anza Electric Cooperative, Inc. will assign credits to subscribers on their monthly bills that will reduce household usage costs by up to 50 percent. The system will be sited on Santa Rosa Tribal lands and will benefit approximately 38 homes on those lands and an additional 150 to 250 low-income households within the cooperative's boundaries.

Port of Richmond Community Solar Project: CSD awarded approximately $2.38 million to GRID Alternatives Bay Area in Oakland to install a 989 kW DC solar array at the Port in Richmond. The project will benefit approximately 155 low-income households in Richmond's disadvantaged communities. The project will generate revenue from a feed-in-tariff offered by Marin Clean Energy and utilize an off-bill mechanism to distribute benefits.

Next Steps

The CPUC hosted a stakeholder workshop on September 16, 2019, to discuss CCA CSGT implementation issues. CSD's selected projects are estimated to be operational and delivering benefits by the first quarter of 2021.

Recommendation 3: Strategize and Track Progress of Workforce Development and Clean Energy Goals

Status: Ongoing

In 2018, the CWDB hosted nine consultations that addressed labor market strategies for achieving the state's climate targets in a way that benefits all Californians. Feedback gathered informed the development of a state draft plan for economic and workforce development in a carbon-neutral economy. The draft plan reviews job growth, job quality, job access, and training in the energy sector (for example, renewable energy and energy efficiency). The draft plan is currently under review at the Governor's Office.

In addition, the CWDB is developing an initiative for High Road Construction Careers with Senate Bill 1 (Beall, Chapter 5, Statutes of 2017) funds, and basing it on the successful model of multi-craft pre-apprenticeship developed with Proposition 39 funds (2014–2018).

Lastly, the CWDB and CPUC are collaborating to explore ways to integrate economic and workforce development in clean energy programs.

Next Steps

Following the public release of the draft plan, CWDB will pursue an interagency strategy to implement key recommendations. CWDB will also begin making investments in workforce partnerships that will advance an equity agenda across climate-impacted industries, including accessible apprenticeship pathways in energy and transportation sectors. This includes $30 million from the Greenhouse Gas Reduction Fund (GGRF) in fiscal year 2019–2020 for CWDB's two main initiatives under its Equity, Climate, and Jobs agenda: High Road Construction Careers and High Road Training Partnerships.

Recommendation 4: Develop New Financing Pilot Programs to Encourage Investment for Low-income Customers

Status: Ongoing

CAEATFA is implementing financing pilots for energy efficiency retrofits in the investor-owned utility territories at the request of the CPUC. These pilots are designed to lower the cost and expand access of private capital financing across the residential, affordable multifamily, and small business/commercial markets to help remove the upfront barrier of capital.

In 2017, CAEATFA streamlined the California Hub for Energy Efficiency Financing pilot programs to remove structural barriers and address challenges. The Residential Energy Efficiency Loan (REEL) Assistance Program was the first of the pilot programs to launch in 2016. The REEL Program helps homeowners and renters access lower cost financing for energy efficiency projects by reducing risk to participating lenders. The program has seven active lenders and more than $20 million available in loan loss reserve funds to help participating lenders mitigate energy efficiency loan risk. The program has leveraged nearly $7 million in private capital, with 52 percent of borrowers located in low-moderate income census tracts.[688]

In September 2019, CAEATFA launched the Small Business Financing (SBF) pilot. The goal of the program is to help small businesses access better financing terms for energy efficient retrofits. Eligible customers include for-profits and nonprofits meeting one of the following requirements: fewer than 100 employees, annual revenues of less than $15 million, or adherence to Small Business Administration size limitations. Three finance companies have enrolled, and contractor enrollment has begun. Products supported include loans, leases, equipment financing agreements, service agreements, and savings-based payment agreements. CAEATFA plans to add an on-bill repayment option to the program in 2020.[689]

In May 2019, CAEATFA launched the third pilot program—the Affordable Multifamily Energy Efficiency Financing pilot. The program is designed to leverage and complement existing

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688 Residential Energy Efficiency Loan Assistance Program
https://www.treasurer.ca.gov/caeatfa/cheef/reel/index.asp

689 Ibid.

efforts to finance affordable multifamily energy efficiency retrofits and to encourage growth in private-market energy efficiency lending. The establishment of on-bill repayment functionality is also under design.

Next Steps

CAEATFA is working to identify a funding source to expand the pilots statewide, to provide a more comprehensive (solar and zero-emission vehicle charging) and streamlined financing program for energy projects across the state. CAEATFA is incorporating lessons learned to develop other effective financing solutions to leverage private capital.

Recommendation 5: Establish Common Metrics and Encourage Data Sharing Across Agencies and Programs

Status: Ongoing

In June 2018, the CEC released the *2018 Tracking Progress Report for Energy Equity Indicators,* which helps identify opportunities to improve access to clean energy, to increase clean energy investment in low-income and disadvantaged communities, and to improve local energy resilience. The report includes geospatial indicators related to the local economy, geography, demography, social engagement, public health, and environmental quality that can identify low-income and disadvantaged communities with the most need, as well as performance indicators to inform a baseline and evaluate progress on energy equity efforts across California.

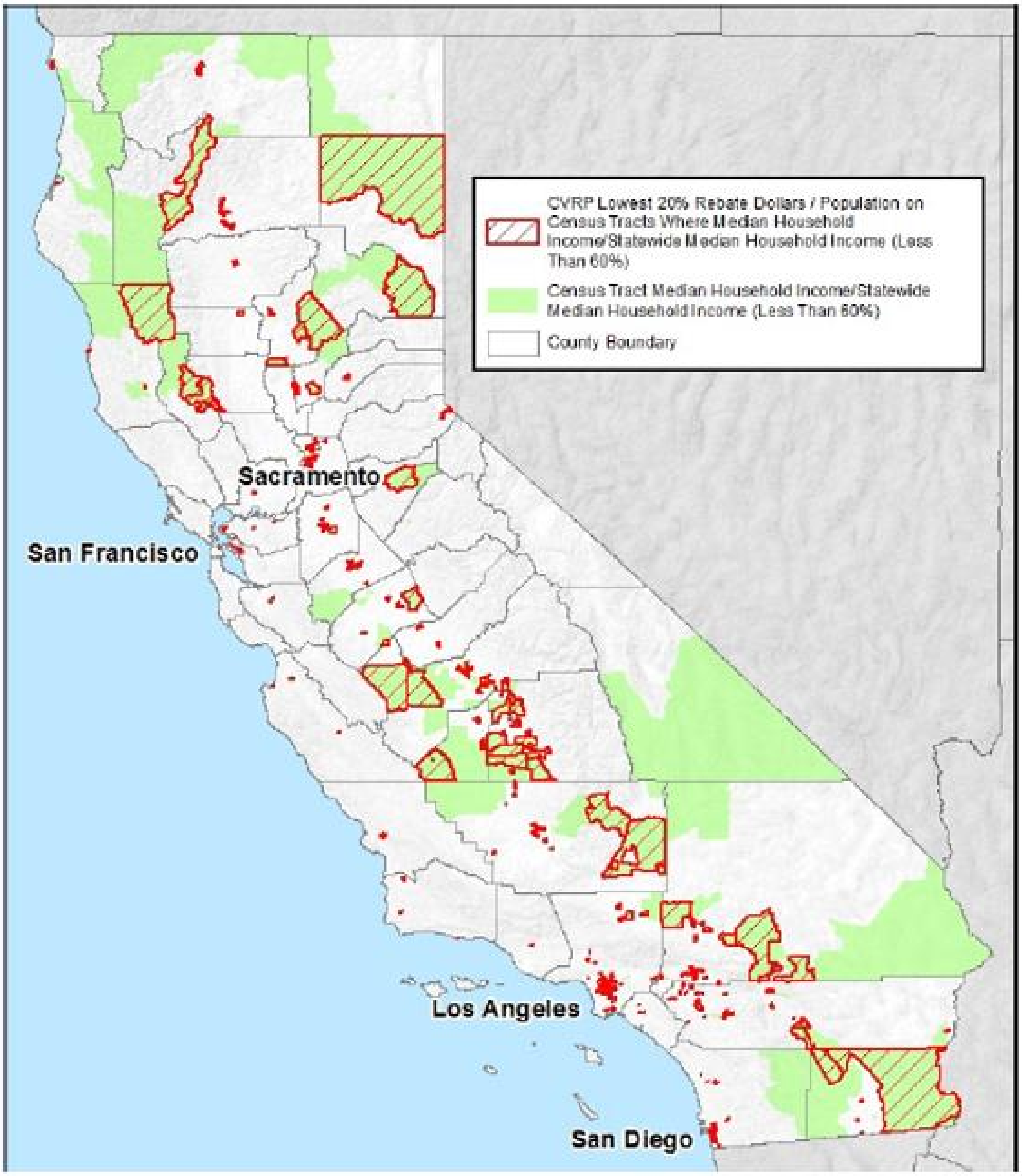
The energy equity tracking progress report will serve as a mechanism to monitor performance of state-administered clean energy programs in low-income and disadvantaged communities across the state. The CEC also developed an accompanying interactive internet-based map that will allow for various data viewing options. CARB is working with the CEC, other state agencies, communities, and the public to develop a similar set of indicators related to clean transportation access for low-income residents.

Next Steps

The interactive web map continues to be refined. Additional data and improvements to the online data visualization tool are expected in the fall of 2019 and an updated Energy Equity Indicator report is expected in 2020.

Examples of information provided in the 2018 tracking progress report for energy equity indicators are shown below.

Figure 79: Clean Vehicle Rebate Program Incentive Opportunities in Low-Income Areas



Source: California Clean Vehicle Rebate Project, U.S. Census Bureau 2010 census tract boundaries, 2011–2015 American Community Survey five-year estimates.[690]

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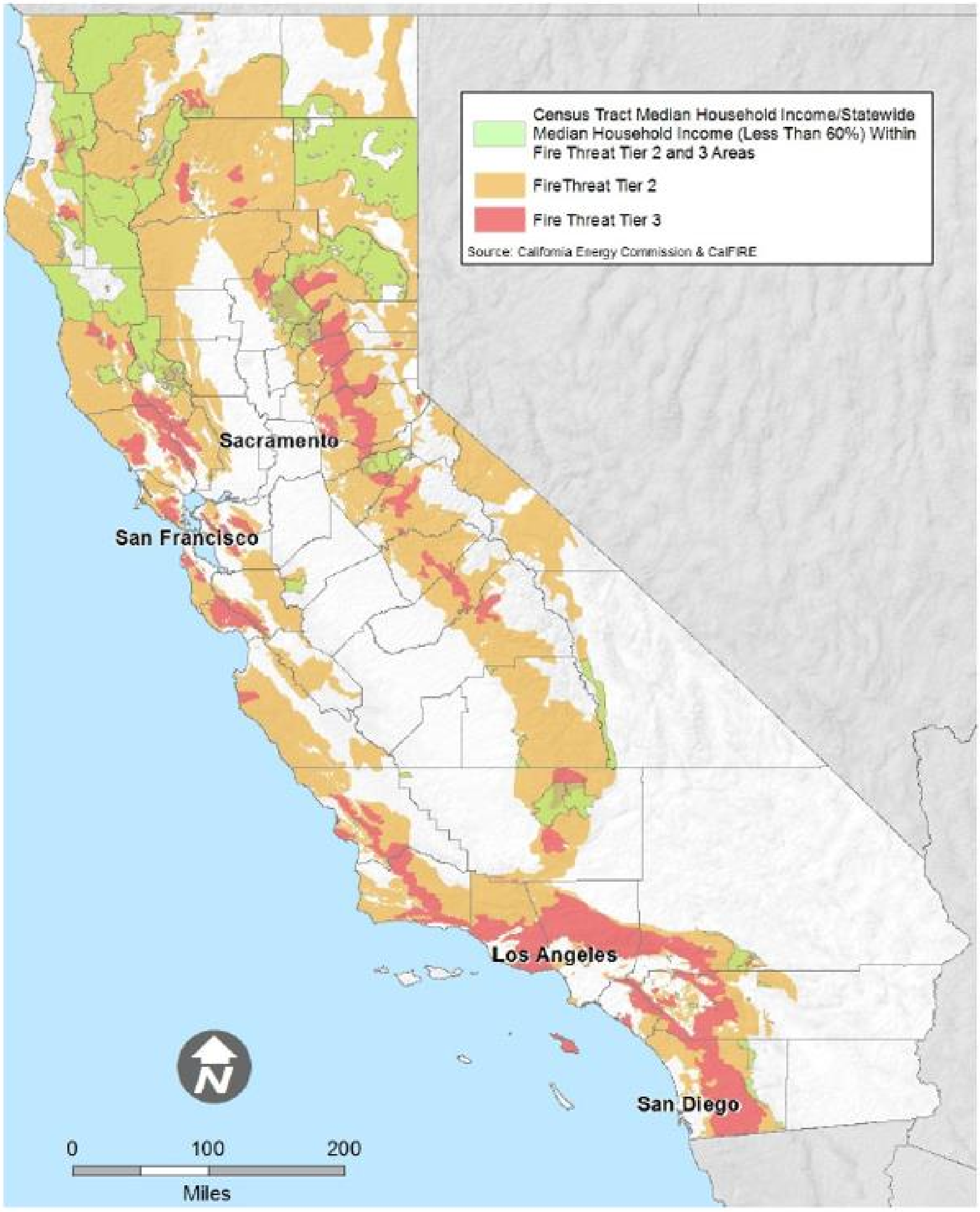
690 California Clean Vehicle Rebate Project https://cleanvehiclerebate.org/eng.

Figure 80: Low-Income Areas That Intersect With Tier 2 and Tier 3 Fire Threat Areas



Source: CPUC fire-threat map, U.S. Census Bureau 2010 census tract boundaries, 2011–2015 American Community Survey five-year estimates[691]

691 CPUC fire-threat maps https://www.cpuc.ca.gov/firethreatmaps/.

Recommendation 6: Expand Opportunities for Low-income and Disadvantaged Communities to Use Photovoltaic and Solar Thermal Technologies

Status: Ongoing

In D.18-06-027, the CPUC adopted two additional programs to promote solar services in disadvantaged communities: the Disadvantaged Communities Single-Family Affordable Solar Homes Program (DAC-SASH) and the Disadvantaged Communities Green Tariff Program (DAC-GT).

The DAC-SASH program provides upfront incentives for solar installations by low-income residents and owners of single-family homes in disadvantaged communities. In January 2019, the CPUC selected GRID Alternatives as the DAC-SASH program administrator through a competitive solicitation process. GRID Alternatives and Southern California Edison (SCE) executed a purchase order for administration of the DAC-SASH program in April 2019. After a stakeholder engagement process, GRID Alternatives submitted a DAC-SASH program handbook and program implementation plan in May 2019. The CPUC approved the handbook and program implementation plan on September 12, 2019.[692]

The DAC-GT program allows disadvantaged community residents to subscribe to receive electricity generated from a solar facility in California and receive a 20 percent discount on their overall bill. The IOUs filed tariffs for the DAC-GT program in August 2018. A number of parties raised issues with the IOUs' proposed implementation plans and suggested improvements. In May 2019, the CPUC adjudicated these issues and approved the implementation plans for the DAC-GT program with modification in Resolution E-4999.

In addition to the DAC-SASH and the DAC-GT programs, the CPUC is implementing other programs that are expanding funding for photovoltaic and solar thermal offerings for low-income customers. For instance, in December 2017, the CPUC created the Solar on Multifamily Affordable Housing (SOMAH) program, which provides funding to incentivize the installation of solar on existing multifamily affordable housing. In March 2019, the CPUC issued Resolution E-4987 to approve modifications to the SOMAH Program Handbook Program Implementation Plan. In April 2019, the CPUC issued D.19-03-015 to provide more flexibility in IOU administrative expenditures, outlining options for future actions regarding the auditing or

692 CPUC. Resolution E-5020
http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M313/K697/313697139.PDF.

review of the SOMAH program, and establishing deadlines for the execution of the necessary co-funding and incentive agreements to launch the program.

The SOMAH program formally launched and began accepting incentive applications on July 1, 2019. By close of business that same day, the entirety of SCE's, San Diego Gas & Electric's (SDG&E's), and Pacific Gas and Electric's (PG&E's) 2019 incentive budgets were fully reserved by a total of 226 applications. These applications represent roughly 70 MW of installed capacity, or nearly a quarter of the SOMAH Program's total goal of developing at least 300 MW of installed solar generating capacity by December 31, 2030.

The CPUC also established a program to provide cleaner energy offerings to disadvantaged communities in the San Joaquin Valley. In December 2018, the CPUC issued decision D.18-12-015, which approved pilot projects in 11 San Joaquin Valley disadvantaged communities. The pilots will provide either natural gas or electric appliances to households that currently rely on wood and propane appliances. Electrification pilots allow for electrical panel upgrades and leverage energy efficiency, solar thermal, and energy storage options. There are also bill protection and split incentive provisions to protect the participants from any potential increases in energy costs or displacement of renters due to the home upgrades. The primary goals of the pilots are to provide cleaner and more affordable energy options to households in disadvantaged communities and to collect data to help inform the feasibility of scaling the program to other disadvantaged communities.

CSD also administers programs that are helping implement this recommendation. CSD's Low-Income Weatherization Program (LIWP) provides low-income households with solar photovoltaic (PV) systems and energy efficiency upgrades at no cost to residents. LIWP currently operates three program components: community solar pilots (discussed under Recommendation 2), multifamily energy efficiency and renewables, and farmworker housing energy efficiency and solar PV.

The LIWP multifamily program provides technical assistance and financial incentives for installing energy efficiency and solar PV systems in low-income multi-family dwellings. Due to strong market demand, the program is currently oversubscribed and lack of program funding has forced the scale-down of marketing, outreach, and new project enrollment activities. To date, CSD has allocated $54.4 million to this program and current funding will support the completion of pending projects by June 2021. Across the portfolio of properties served to date, the LIWP multifamily program has realized an impressive 40 percent energy usage reduction on average. At some projects, where deep energy efficiency retrofits have been paired with electrification measures (for example, switching to heat pump water heaters) and solar PV energy systems, the result has been near net-zero projects.

The farmworker program provides energy efficiency upgrades and solar PV systems to low-income farmworker households. On January 22, 2019, CSD released a request for proposals seeking to award approximately $10.5 million ($5.25 million per region) to farmworker housing administrators in two defined 6-county regions. On April 9, 2019, CSD selected La Cooperativa Campesina de California to be the administrator of the two regions.

Next Steps

The CPUC will host a stakeholder workshop in fall 2019 to discuss CCA implementation issues with programs similar to the DAC-SASH program.[693]

IOUs have updated their DAC-GT tariffs to comply with the direction provided in Resolution E-4999. IOUs will submit marketing, education, and outreach plans, 2019–2020 program budgets, and solicitation documents in early August for CPUC review.

SOMAH incentive funding (sourced from the IOUs' 2019 Cap-and-Trade Program proceeds) will be considered for replenishment once the CPUC approves the IOUs' 2020 Energy Resource Recovery Account forecast updates or energy cost adjustment Clause applications. This is expected in the first or second quarter of 2020.

For San Joaquin Valley disadvantaged communities, a request for proposals for a third party program administrator and "community energy navigator" are in process. IOUs have begun community outreach and education efforts. Other details of the electrification and natural gas extension pilots are under review. The goal is to finish the planning process and begin implementation of the pilots in 2020.

For CSD's multifamily program, the 2019–2020 budget act appropriated $10 million from the GGRF to CSD to continue LIWP low-income solar and multifamily weatherization services. CSD is developing an allocation plan for the 2019–2020 LIWP appropriation and anticipates the plan will dedicate some newly appropriated funding to the LIWP multifamily component.

CSD's farmworker program implementation will begin 90 days following contract execution and conclude by December 31, 2020.

Recommendation 7: Enhance Affordable Housing Tax Credits for Housing Rehabilitation Projects to Include Energy Efficiency and Renewable Energy Upgrades

Status: Completed

Under the California Tax Credit Allocation Committee's (TCAC) 9 percent and 4 percent credit programs, a point system has been incorporated which allows projects to get additional points by committing to environmental certification programs (such as LEED, GreenPoint Rated, or Passive House) or incorporating renewable energy and energy efficiency measures.

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693 Transcript of the July 30, 2019, IEPR workshop on Advancing Energy Equity https://efiling.energy.ca.gov/GetDocument.aspx?tn=229742&DocumentContentId=61170, TN 229742, p. 38. 20-23.

Additionally, TCAC uses the California Utility Allowance Calculator in these credit programs to set project-specific utility allowances that recognize energy efficiency and solar improvements. This allows project owners to keep a larger portion of their gross rent allocation, which can then be used to finance energy efficiency and solar improvements, or other project financing gaps.

In January 2019, the CEC informed the CPUC and the IOUs implementing the Energy Savings Assistance Common Area Measures Program about tax credit properties and how these deed-restricted low-income multifamily buildings may benefit from the program.[694] The CEC noted how these buildings could be improved by deep energy retrofits beyond the common areas at times of ownership and financing change.

Next Steps

The TCAC is conducting rulemaking proceedings in 2019 that will affect the funding and competitiveness of low-income multifamily housing applying for low- income housing tax credits. The CEC will continue collaborate with the CPUC and IOUs and monitor regulatory changes affecting the funding and incentivizing of energy efficiency measures in low-income multifamily housing.

Recommendation 8: Establish Regional Outreach and Technical Assistance One-stop Shop Pilots

Status: Ongoing

The CEC and CPUC have explored options for developing a one-stop shop; however, given the complexity and broad crosscutting nature of a comprehensive one-stop shop, additional resources need to be identified for implementation.

Senate Bill 1072 (Leyva, Chapter 377, Statutes of 2018) requires the establishment of a regional climate collaborative program to provide capacity building for under-resourced communities to access climate mitigation funding. This law directs the Strategic Growth Council (SGC) to adopt guidelines for the regional climate collaborative program by October 2019. The law also requires the SGC to develop technical assistance guidelines that a state agency would be authorized to use in delivering its technical assistance resources or in developing additional technical assistance policies, standards, or guidelines by July 1, 2020. If this law is implemented, it could serve as a platform for implementing one-stop shop pilots.

694 This conversation took place during the CPUC’s monthly Energy Savings Assistance Common Area Measures conference call.

For the status of one-stop-shops for transportation programs, please see "Status of Recommendations in Barriers Study Part B", recommendation 3.

Next Steps

The CEC, CPUC, and CARB will continue to explore options for ongoing development of regional one-stop-shops, however, additional resources likely need to be identified for implementation.

Recommendation 9: Investigate Consumer Protection Issues for Low-Income Customers and Small Businesses in Disadvantaged Communities Seeking Access to Clean Energy

Status: Ongoing

Several agencies have been working to address consumer protection in the growing clean energy economy. In March 2019, the CPUC, the Contractors State License Board, and the Department of Business Oversight entered into a joint enforcement agreement and formed a taskforce with working groups to provide relief for customers harmed by solar companies' unfair business and lending practices, and collaborate on future policy solutions that enhance consumer protections for solar customers, particularly in vulnerable communities.

The taskforce is working to improve coordination on complaint tracking and response, enforcement and preventative outreach and education.

In October 2018, the CPUC issued the Net Energy Metering (NEM) Consumer Protection decision D.18-09-044. The decision establishes a process for creating a solar information packet for consumers and directs utilities to require valid Contractors State License Board licenses from solar providers to interconnect residential single-family solar systems to the grid, along with solar disclosure documents.[695]

Next Steps

The CPUC is continuing to consider ways to enhance NEM consumer protections, such as a consumer complaint mediation, a restitution fund, enhanced enforcement, citations, or an administrative penalty mechanism under CPUC authority. As required by Assembly Bill 1070 (Gonzalez Fletcher, Chapter 662, Statutes of 2017), the CPUC is developing standardized inputs and assumptions for the calculation of electric bill savings for solar customers. The CPUC is also monitoring the alternative energy provider complaints filed with the CPUC's

695 CPUC. Solar Consumer Guide https://www.cpuc.ca.gov/solarguide/.

Consumer Affairs Branch, as well as complaints filed with the Contractors State License Board and California Department of Business Oversight, to determine if existing consumer protections are deterring bad actors or whether further action is needed. The CPUC continues to reach out to stakeholders.

Recommendation 10: Direct Funding to Collaborate with Community-Based Organizations for Community-Centric Delivery of Clean Energy Programs

Status: Ongoing

CARB, the CEC, the CPUC, and other supporting agencies continue to work on identifying opportunities where additional funding is needed to support collaboration and increased access to clean energy and transportation for low-income residents.

Next Steps

The agencies will continue working together to identify opportunities where additional funding could support further collaboration and increased access. The agencies will also continue working to ensure that existing programs are benefiting low-income and disadvantaged communities.

Recommendation 11: Direct Research, Development, Demonstration, and Market Facilitation Programs to Include Targeted Benefits for Low-income Customers and Disadvantaged Communities

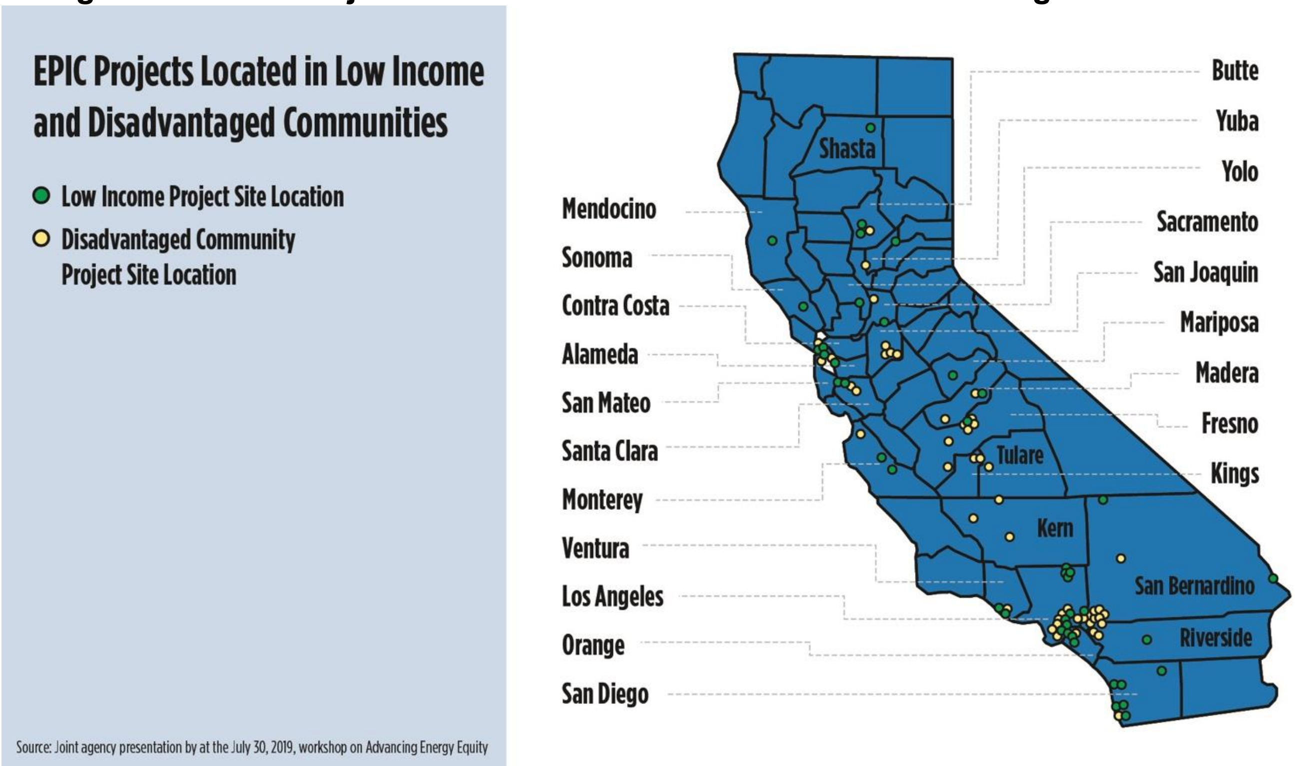
Status: Complete

The CEC has taken several actions to implement this recommendation.

Targeted Investments

Assembly Bill 523 (Reyes, Chapter 551, Statutes of 2017) requires at least 25 percent of the Electric Program Investment Charge's (EPIC) technology demonstration and deployment (T&D) funds collected from investor-owned utility ratepayers be allocated to projects located in and benefitting low-income or disadvantaged communities. As of July 2019, the CEC's EPIC program has invested approximately 31 percent of T&D funds to 104 project sites located in disadvantaged communities, and an additional 34 percent to 74 project sites located in communities that are low-income but not considered disadvantaged. Project locations are shown in Figure 81.

Figure 81: EPIC Projects Located in Low-Income and Disadvantaged Communities



Source: Joint presentation by the CEC, CPUC, CSD, CAEATFA, and CWDB at the July 30, 2019, joint agency workshop on Advancing Energy Equity, slide 12, https://efiling.energy.ca.gov/GetDocument.aspx?tn=229158&DocumentContentId=60578.

Changes to Proposal Scoring Criteria

The CEC will implement new scoring criteria in upcoming TD&D solicitations to ensure that: 1) T&D projects located in disadvantaged and low-income areas are providing direct benefits to the community, and 2) scorers can evaluate the projected localized health impacts, if any. Additionally, the criteria requires community support and ongoing community engagement. The CEC will continue to provide funding set-asides for low-income and disadvantaged communities, where applicable.

Expanding Opportunities

The CEC directed Navigant Consulting to evaluate market strategies that have been piloted to overcome barriers to mass deployment of distributed energy resources in existing buildings in low-income/disadvantaged communities. The evaluation focused on renters, multifamily buildings, and small businesses and identified barriers and key drivers for adoption. The final report provided 13 recommendations from successes and lessons learned in programs throughout the United States and grouped them into three critical areas for success:

Outreach barriers: lack of awareness, lack of customer trust, and lack of education channels.

Outreach recommendations:

- Develop partnerships with community-based organizations to build trust and awareness.

- Conduct tailored marketing, education, and outreach that considers culture, language, and geography and is targeted at contractors, building owners, and tenants.
- Educate target community about program benefits.
- Use customer engagement from one program to co-enroll customers in other programs.

Funding barriers: split incentives, code compliance issues, and insufficient funding.

Funding recommendations:

- Establish long-term policy signals on programs and funding levels to improve program planning and align with stakeholder infrastructure investment cycles.
- Develop program funding mechanisms that deliver cash flow-positive projects from day one to encourage low-income and disadvantaged community stakeholders to act.
- Develop a program to manage and fund the code compliance repairs required to implement DER.
- Determine a methodology to calculate non-energy benefits to improve the cost-effectiveness of distributed energy resource programs.
- Consider bundling existing funding sources to finance low-income and disadvantaged community initiatives.

Execution barriers: inadequate customer and contractor support, slow program response times, and excess/complex paperwork.

Execution recommendations:

- Create a low-income and disadvantaged community program “Czar” role to streamline and combine programs and an online portal that serves as a single resource for potential applicants.
- Streamline and simplify eligibility application criteria.
- Develop program offerings that provide direct value for all stakeholders.

Design programs that provide adequate technical assistance and deliver cost savings.

These recommendations were incorporated into the various goals and strategies provided in the CLIMB report (discussed in Recommendation 1).

EPIC Challenges

The CEC created two-phase competitions, known as *EPIC Challenges*, with the first phase centering on the design and planning to create advanced energy communities, and the second phase awarding winners with funding for the buildout of their design. Phase 1 for the first EPIC Challenge was issued in 2016 for the design and planning of advanced energy communities. Both Phase I (planning and design) and Phase II (build) included funding set asides for disadvantaged communities. The CEC has selected two of the Phase I projects to move to the build phase and plans to select two additional projects, both located in disadvantaged communities, to move to the build phase. For the two projects selected for the build phase, one will build two new affordable housing developments in Lancaster (Los Angeles County) that will be all-electric zero-net-energy microgrids. The second project will retrofit a mixed-income neighborhood block in Oakland (Alameda County) to be a zero-net-energy microgrid.

EPIC Symposiums

The 2018 and 2019 EPIC Symposiums included panels highlighting projects located in various underserved communities. In 2019, the CEC awarded a 3-year contract to Gladstein, Neandross and Associates (GNA) to ramp up the CEC technical transfer and knowledge dissemination activities for the EPIC Program. As part of this work, GNA will conduct forums to ensure project results and lessons learned from technology demonstration projects—especially those located in and benefitting disadvantaged and low-income communities—are shared with the relevant stakeholders.

Next Steps

The CEC will make Navigant's final report publicly available on the CEC website so other stakeholders can read the analysis and utilize the findings. In addition, the CEC plans to launch its next design-build competition titled "Reimagining Affordable Mixed-Use Development in a Carbon-Constrained Future," which will be released in late 2019. For this upcoming design-build competition, all projects sites are required to be located in disadvantaged and low-income communities.

Recommendation 12: Conduct a Follow-up Study for Increasing Contracting Opportunities for Small Businesses Located in Disadvantaged Communities

Status: Ongoing

In 2018–2019, GO-Biz was allocated $23 million from the General Fund to support three grant programs for small business technical assistance centers throughout California. The Small Business Technical Assistance Expansion Program provides $17 million each year through 2022–2023 to expand small business services, such as free or low-cost one-on-one consulting and low-cost training. The program's funding is focused on services to underserved business groups, including women, people of color, veterans, and low-wealth, rural, and disaster impacted communities.

The 2018–2019 budget also included the continuation of $3 million in annual funding through 2022–2023 for the Capital Infusion Program, which supports one-on-one business consulting provided by the Small Business Development Network to assist small businesses in accessing capital. The 2018-2019 budget also allocated $3 million in one-time local cash match grants for the Technical Assistance Program, which supports other federal small business technical assistance centers. This one-time local cash match grant sunsets on September 30, 2019.

Next Steps

GO-Biz will make grant awards for the 2019–2020 Small Business Technical Assistance Expansion Program.

Status of Recommendations in *Barriers Study Part B*

At the July 30, 2019, joint agency workshop on Advancing Energy Equity, CARB described the status of the six priority recommendations from their *Barriers Study Part B* report.[696] Table 43 contains a summary of the recommendations, followed by a description of the status and actions taken to date.

The Barriers Study Part B continues to be a key driver as CARB develops clean mobility access and transportation equity policy and solution building. SB 350 has helped shape how CARB moves ahead with program implementation and identification of funding and other needs that address barriers to clean transportation access for low-income residents. CARB will continue to apply lessons learned, evaluate priorities to ensure that efforts promote community-level achievements in transportation equity, and support capacity to both transition to and identify projects that are sustainable and applicable in other communities.

696 [SB 350 Barriers Study Part B CARB Implementation Progress presentation by CARB](https://efiling.energy.ca.gov/GetDocument.aspx?tn=229101&DocumentContentId=60505) https://efiling.energy.ca.gov/GetDocument.aspx?tn=229101&DocumentContentId=60505.

Table 43: *Barriers Study Part B* Priority Recommendations and Lead and Supporting Agencies

	Recommendation	Lead and Supporting Agencies
1	Expand assessments of low-income resident clean transportation and mobility needs to ensure feedback is incorporated in transportation planning and for guiding investments.	**Lead:** California Department of Transportation (Caltrans), CARB, California Transportation Commission (CTC) **Supporting:** Local transportation authorities, metropolitan planning organizations (MPOs), councils of government (COGs), transit agencies, CEC, CPUC, SGC, CDPH
2	Develop an outreach plan targeting low-income residents across California to increase residents' awareness of clean transportation and mobility options.	**Lead:** CARB, CEC, CPUC, SGC **Supporting:** CDPH, CTC, Caltrans, Department of Motor Vehicles, Go-Biz, air districts, investor-owned utilities, publicly owned utilities
3	Develop regional one-stop shops to increase consumer awareness and technical assistance.	**Lead**: CARB, CEC, SGC **Supporting:** CPUC, CSD, California Natural Resources Agency, California Department of Housing and Community Development, California Department of Water Resources
4	Develop guiding principles for grant and incentive solicitations to increase access to programs and maximize low-income resident participation.	**Lead:** CARB, CEC, CPUC, SGC **Supporting:** CTC, Caltrans, California Department of General Services, CDPH
5	Maximize economic opportunities and benefits for low-income residents from investments in clean transportation and mobility options by expanding workforce training and development.	**Lead:** California Labor and Workforce Development Agency, CWDB, CARB **Supporting:** CEC, CPUC, CSD, CDPH, California Employment Development Department
6	Expand funding and financing for clean transportation and mobility projects, including infrastructure, to meet the accessibility needs of low-income and disadvantaged communities.	**Lead:** CARB, CEC, CPUC, CTC, Caltrans **Supporting:** SGC, air districts

Source: CARB, Barriers Study Part B, https://www.arb.ca.gov/resources/documents/carb-barriers-report-final-guidance-document.

Recommendation 1: Expand Assessments of Low-income Resident Clean Transportation and Mobility Needs to Ensure Feedback is Incorporated in Transportation Planning and for Guiding Investments

Status: Ongoing

The California Department of Transportation (Caltrans) is coordinating with regional and local governments to promote expanding assessments of low-income community transportation needs. Additionally, CARB has integrated community transportation needs assessments into its clean mobility projects and has created a voucher program to provide resources in support of these efforts.

Next Steps

Caltrans plans to develop best practices that highlight successful local and regional engagement efforts and provide recommendations for objectives that can be achieved through needs assessments.[697] CARB is designing a complementary approach for working with communities to assess their transportation needs and resources. The process has been integrated into new and existing CARB incentive programs to ensure funds are prioritized toward projects that meet transportation needs and have community support.

Recommendation 2: Develop an Outreach Plan Targeting Low-income Residents Across California to Increase Residents' Awareness of Clean Transportation and Mobility Options

Status: Ongoing

CARB is leading implementation of an outreach roadmap that identifies strategies for effectively coordinating, streamlining, and delivering tailored clean transportation outreach. The roadmap highlights the importance of a robust community engagement process that values community knowledge and includes community-based organizations and residents in developing solutions and strategies.

Next Steps

A public draft of the outreach plan is expected in fall 2019.

Recommendation 3: Develop Regional One-stop Shops to Increase Consumer Awareness and Technical Assistance

Status: Ongoing

CARB, using $5 million of Volkswagen Settlement funds and a recent addition of $5 million in Low Carbon Transportation Investment funds, is developing regional one-stop shops for low-income customers. The aim is to increase awareness of transportation rebates and incentive programs, and provide reliable information about available technologies and clean transportation options. In October 2018, CARB selected GRID Alternatives to advance this concept. The initial pilot focuses on the development and maintenance of a streamlined, single

697 Transcript for the July 30, 2019, IEPR workshop on Advancing Energy Equity https://efiling.energy.ca.gov/getdocument.aspx?tn=229742. p. 82.

application for low-income consumers to apply and qualify for CARB's low-carbon transportation equity projects, such as Clean Cars 4 All, the Clean Vehicle Rebate Project, financing assistance programs, and clean mobility options for disadvantaged communities.

The pilot will focus on providing coordinated community-based outreach and education to maximize program participation and promote advanced technology vehicle adoption among low-income residents.

Next Steps

The streamlined, single application is in the testing phase and the first public version is expected to launch in 2020.[698]

Recommendation 4: Develop Guiding Principles for Grant and Incentive Solicitations to Increase Access to Programs and Maximize Low-income Resident Participation

Status: Ongoing

With the goal of increasing the ability of low-income residents and disadvantaged communities to access grant funding, CARB is developing guiding principles for state and local agencies to incorporate into designing competitive solicitations. CARB has also consulted with other agencies, program administrators, and applicants to develop solutions that streamline and simplify the grant and incentive application process.[699]

Next Steps

CARB intends to release the public guidance document in 2020 to promote the best practices identified through collaboration and begin incorporating the feedback into the development of grants and solicitations.

Recommendation 5: Maximize Economic Opportunities and Benefits for Low-income Residents From Investments in Clean Transportation and Mobility Options by Expanding Workforce Training and Development

Status: Ongoing

698 Ibid., p. 84.

699 Ibid., p. 85.

With funds from Senate Bill 1 and the GGRF, the CWDB has three investment projects related to the transportation sector.[700] CARB is also integrating workforce development into program implementation, which can provide direct employment benefits in addition to the CWDB's efforts. Strategies include investment in projects that contain targeted hiring and job training, as well as exploring workforce development and fellowship opportunities as part of project outreach and capacity-building.

Next Steps

The CWDB plans to invest in 12 new partnerships with strong connections to the industries and occupations critical to reaching the state's 2030 climate change targets.[701]

Recommendation 6: Expand Funding and Financing for Clean Transportation and Mobility Projects, Including Infrastructure, to Meet the Accessibility Needs of Low-income and Disadvantaged Communities

Status: Ongoing

Over the past six budget cycles (Fiscal Year 2013/2014 to Fiscal Year 2018/2019), the Legislature has appropriated approximately $1.7 billion to CARB for low-carbon transportation projects to support the transformation of California's fleet–supporting clean vehicle ownership, clean mobility, streamlined access to funding and financing opportunities, increasing community education, and exposure to clean technologies.[702]

The CPUC has also authorized funding of electric vehicle charging infrastructure in the territories of all of its jurisdictional utilities, and the majority of these authorizations have required significant portions of this infrastructure be built in disadvantaged communities and/or targeted to low-income customers.

Next Steps

CARB will continue funding transformative transportation projects, including plans to provide $22 million for the Sustainable Transportation Equity Project through a community-based approach to identify and address the unique mobility needs of a given community. Through facilitated collaboration and capacity building, the pilot intends to work with communities to develop context-specific solutions for a cleaner, more accessible, and integrated transportation

700 Ibid., p. 79.

701 Ibid., p. 79.

702 Ibid., p. 85.

system that benefits the community resident that need it most. CARB will also, through its Clean Mobility Options Voucher Pilot, provide over $20 million to low-income and disadvantaged communities for carsharing, bikesharing, and other clean mobility projects. In addition, CARB plans to provide up to $7 million for outreach and education coordination, expand community transportation needs assessments, and provide technical assistance and the one-stop shop.[703]

703 SB 350 Barriers Study Part B CARB Implementation Progress presentation by CARB https://efiling.energy.ca.gov/GetDocument.aspx?tn=229101&DocumentContentId=60505. TN# 229101. p. 8.