Clean Energy Replacement for California's Retiring Nuclear Plants

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Abstract

A proposal by PG&E not to pursue relicensing of the Diablo Canyon Power Plant would close the last nuclear plant in California by 2025, and replace a portion of the electrical generation with various clean energy sources, including measures to reduce electricity demand, and increase renewable energy, and energy storage. This report includes the following topics:

1. General background of the proposed retirement of PG&E's nuclear power plant, including the accumulating challenges that make it increasingly difficult to continue operating the plant in the future.

2. How the claim that retiring nuclear power plants will seriously damage California's climate policies is invalid, because the state's various clean energy policies rapidly replace, and over time far exceed, the amount of electricity provided by the nuclear plants.

3. An overview and analysis of PG&E's proposal to replace a portion of Diablo Canyon with new clean energy resources that are intended to be additional to the State's clean energy policies.

4. How retirement of Diablo Canyon will put PG&E further down the road away from the business of generating electricity, and toward being a utility that primarily provides wires and other support services; this should reduce the competitive role the utility has with other electricity suppliers, such as Community Choice agencies and customers who generate their own electricity.

5. Why Community Choice agencies should not be required to pay "non-bypassable charges" for renewable energy that replaces Diablo Canyon, but is not delivered to Community Choice customers.

The report also includes appendices with extensive data from the California Energy Commission regarding electricity supply and demand, and Air Resources Board data on greenhouse gas emissions.

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Pacific Gas and Electric Company (PG&E) has drafted a Joint Proposal with utility unions and activist organizations to retire the Diablo Canyon Power Plant ("Diablo Canyon"), California's last remaining nuclear power plant, by 2025.[1] The Joint Proposal includes provisions to replace a portion of the 18,000 gigawatt-hours per year of energy produced by the nuclear plant through customer efficiency programs and purchasing new clean energy sources. The privately drafted document would need to be approved through the California Public Utilities Commission (CPUC), and there is the possibility for significant changes.

The Joint Proposal lays out several key steps:

- Between 2018 and 2025 energy efficiency would be procured that saves 2,000 gigawatt-hours per year by the time the nuclear plant retires

- Between 2025 and 2030, PG&E would procure an additional 2,000 gigawatt-hours per year of either energy efficiency or renewable energy

- After 2030, PG&E would adopt a voluntary requirement that 55 percent of the utility's total electricity retail sales be from renewable energy, rather than the 50 percent required by California law

- PG&E proposes adding other greenhouse gas (GHG) free resources to replace reliability characteristics of the nuclear plant, with energy storage specifically mentioned; PG&E also acknowledges that additional procurement might be necessary

PG&E proposes that expenses associated with the replacement energy for the nuclear plant be billed as "non-bypassable charges," which means that the costs would have to be paid by all customers who purchase electricity supply directly from PG&E. However, other customers who do not actually get their electricity from PG&E might also have to pay, simply because their electricity is delivered over PG&E's wires—including Direct Access (DA) and Community Choice Aggregation (CCA) customers—even though these customers do not and will not be getting any of their electricity from Diablo Canyon, or from the replacement energy. How costs are recovered will be an important topic for the CPUC to consider.

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[1] Joint Proposal of Pacific Gas and Electric Company, Friends of the Earth, Natural Resources Defense Council, Environment California, International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees and Alliance for Nuclear Responsibility to Retire Diablo Canyon Nuclear Power Plant at Expiration of the Current Operating Licenses and Replace It With a Portfolio of GHG Free Resources, June 20, 2016. https://www.pge.com/en_US/safety/how-the-system-works/diablo-canyon-power-plant/dcpp-independent-analysis.page

PG&E was facing a series of expenses related to the long-standing intention to keep the nuclear plant running for another 20 years after 2025.

1. In 2005, the CPUC approved PG&E spending up to $800 million on new steam generators, which was already billed to customers.[2]

2. Regulations from the State Water Resources Control Board require phasing out of use of ocean water for cooling power plants in California; Diablo Canyon uses large amounts of this water due to 24/7 operation at close to full capacity.[3] In 2002, Tetra Tech estimated the cost of an alternative cooling system at $1.3 billion for Diablo Canyon; a revision by Tetra Tech just a few years later increased the estimate to $3 billion.[4,5] One of the stated intents of the Joint Proposal is to avoid this expense by retiring the nuclear plant.

3. Another set of expenses is related to the hazards of earthquakes and tsunamis. The Hosgri Fault is located just a few miles offshore from Diablo Canyon, and is labeled in the state seismic hazard map as having the potential to generate a magnitude 7.5 earthquake.[6] The area around the plant is riddled with faults, and there are concerns regarding the safety of the plant due to

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[2] Application of Pacific Gas and Electric Company (U 39 E) for Authority to Increase Revenue Requirements to Recover the Costs to Replace Steam Generators in Units 1 and 2 of the Diablo Canyon Power Plant. Decision 05-11-026 November 18, 2005, http://docs.cpuc.ca.gov/published/FINAL_DECISION/51409.htm

[3] Diablo Canyon is reported to have to comply with ocean cooling water regulation by Dec. 31, 2024; Tracking Progress, Once-Through Cooling, California Energy Commission, 2/9/2016
http://www.energy.ca.gov/renewables/tracking_progress/documents/once_through_cooling.pdf

[4] The $3 billion cost was based on discounting future cash flows at 7% per year; the undiscounted cost was $4.6 billion. These include building the towers, operation & maintenance of the cooling system, and replacing electricity losses caused by the cooling system. Additional changes to the property, financing costs, and other costs of the nuclear plant, are not included. *California's Coastal Power Plants: Alternative Cooling System Analysis, Tetra Tech, C*. Diablo Canyon POWER PLANT, Prepared for California Ocean Protection Council, February, 2008; p. C-7, p. C-40.
http://www.opc.ca.gov/webmaster/ftp/project_pages/OTC/engineering%20study/Chapter_7C_Diablo_Canyon_Power_Plant.pdf

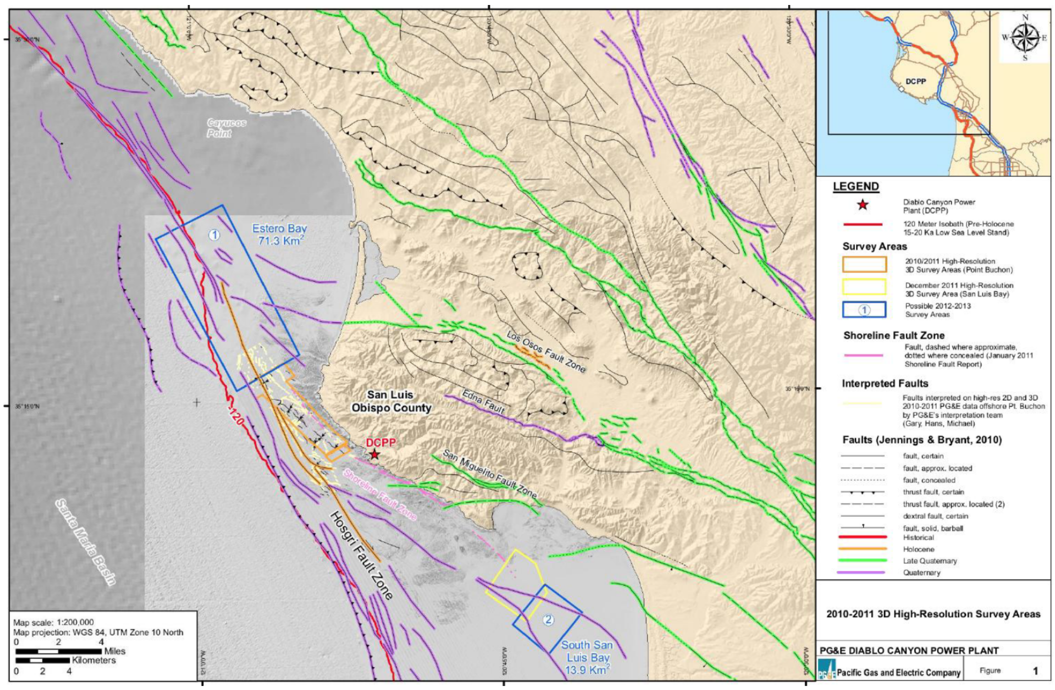
[5] A more recent evaluation by Bechtel for PG&E showed costs from $6.2 to $14.1 billion for the towers, plus billions more in associated expenses. Comments of Pacific Gas and Electric Company, Alternative Cooling Technologies or Modifications to the Existing Once-Through Cooling (OTC) System for Diablo Canyon Prepared by Bechtel Power Corporation for the State Water Resources Control Board – Nuclear Review Committee, September 12, 2014.
http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/rcnfpp/docs/pgebechcom_091214.pdf

However, these costs have been criticized as highly inflated.
http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/rcnfpp/docs/foe_cmmnts_to_bechtel.pdf

[6] The 7.5 magnitude rating on the Hosgri Fault is designated as the Maximum Credible Earthquake, which is intended to be the standard to which major structures are supposed to be built. California Seismic Hazard Detail Index Map 1996, California Department of Transportation, Office of Earthquake Engineering, by Lalliana Maulchin, Engineering Seismologist.

its original construction being designed to a "probabilistic" earthquake model, a lower standard than the maximum credible earthquake that experts believe could occur. While PG&E insists the plant is "safe," millions of dollars are being spent on seismic studies, billed to a special account, which PG&E intends to recover from customers. The status of these costs is briefly discussed in the Joint Proposal. It is not clear if PG&E would have been required to make additional upgrades to the power plant had they gone through with relicensing. A third category of expense, not discussed in the Joint Proposal, is the risk of damage to the plant and associated regional problems if there is radioactive release, such as occurred at Fukushima. A portion of this risk might be avoided if the plant is retired by 2025—assuming no major incidents before that date, which of course cannot be guaranteed.

Figure 1: Diablo Canyon Area Earthquake Fault Map



On top of the repairs, PG&E has to cover the eventual costs of decommissioning the nuclear plant; in the Joint Proposal this is projected to be $3.779 billion (in 2014 dollars). All customers, except those on low-income rates, pay into a special trust account for this purpose which is a line item in the utility bill charged at $0.00022 per kilowatt-hour.[7] As of June 30, 2015, PG&E reports holding $2.5 billion that has been collected for nuclear decommissioning.[8] This implies the need to collect an additional $1.3 billion, plus inflation, over the next decade to cover the

[7] http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-1.pdf

[8] Exhibit A, Table 2, Pacific Gas and Electric Company Condensed Consolidated Balance Sheets, Application filed by Pacific Gas and Electric Company on 09/01/2015 Conf# 89554 (Attachment1), Proceeding: A1509001, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M154/K291/154291523.PDF

cost of decommissioning. These charges are also billed to CCA and DA customers, even though they do not get any electricity from Diablo Canyon.

In addition to addressing the challenges of seismic safety, the use of ocean water for cooling, licensing and regulatory hurdles, and uncertain financial risks, associated with continued operation of the nuclear plant itself, there are also significant commercial risks associated with electricity markets and public policies. State law requires increasing amounts of resources that directly reduce the need for PG&E's electricity in the future:

Energy Efficiency (EE)—SB 350 requires doubling the amount of additional energy efficiency savings in the electricity sector by 2030.[9]

Distributed Generation (DG)—AB 327 requires that tariffs adopted by the CPUC "ensures that customer-sited renewable distributed generation continues to grow sustainably."[10]

Another commercial risk to Diablo Canyon is the existence of competing electricity suppliers inside of its service territory. These include:

Direct Access (DA), where large commercial customers purchase electricity directly from an alternative supplier; DA accounts for 9,500 gigawatt-hours of retail sales in PG&E's service territory.[11]
Community Choice Aggregation (CCA), where local governments purchase electricity for all customers in the jurisdiction; CCA is rapidly growing in PG&E's service territory, and CCAs already being implemented will reach 12,000 to 15,000 gigawatt-hours of retail sales over the next few years, with additional growth likely.[12]

Analysis by a consultant for PG&E shows that even if CCA does not grow significantly beyond current levels, the amount of electricity the utility needs to supply to customers will be severely

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[9] SB-350 Clean Energy and Pollution Reduction Act of 2015.
http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

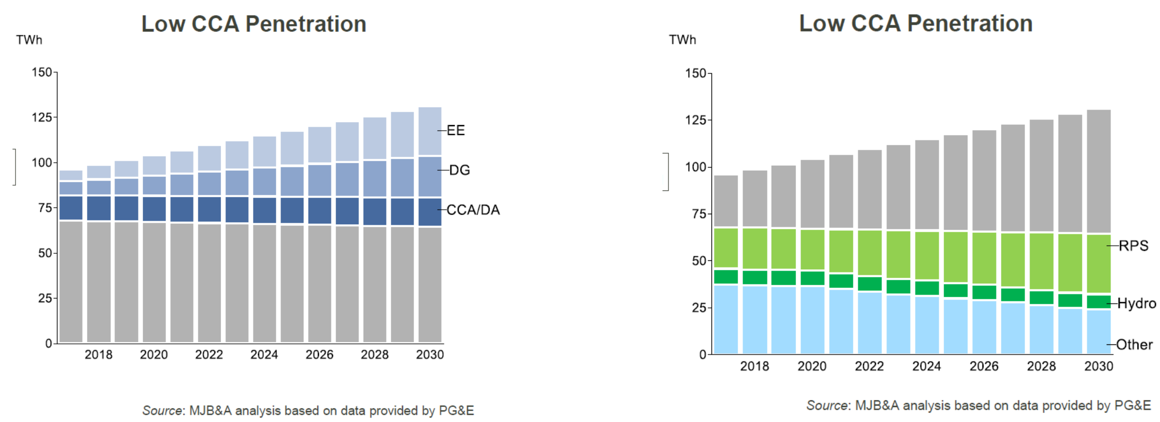
[10] Section 2827.1.(b)(1) added to the Public Utilities Code
http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327

[11] Data from California Energy Commission, California Energy Demand Revised/Final Forecast 2016 - 2026, Mid Demand Baseline Case, Mid AAEE, docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN209989_20160127T094920_LSE_and_BA_Tables_Mid_Demand_Baseline__Mid_AAEE.xlsx

[12] The most recent demand forecast cited above shows about 3500 gigawatt-hours provided by the two existing CCAs in Sonoma County and Marin Clean Energy (see Appendix A); however, this does not include the more recent addition of San Francisco, nor the new CCAs in San Mateo and Santa Clara County, as well as expansion of Marin CCA. Planning documents, including implementation plans and feasibility studies, from the new CCAs imply the addition of about 10,000 gigawatt-hours over the next few years. A number of additional CCAs in California, including in PG&E's service territory, are at various stages of evaluation and/or planning; see LEAN Energy California webpage, http://www.leanenergyus.org/cca-by-state/california/

constrained in the future, and is expected to decrease. In addition, an increasing share of the shrinking supply of electricity is required by state law to be from renewable energy.

Figure 2: Projected PG&E Electricity Resources



The chart above on the left (in Figure 2) shows how future demand in PG&E's service territory will be met by sources other than retail sales of electricity supplied by PG&E to its customers. The top three segments are energy efficiency (EE), distributed generation (DG) where customers produce energy for their own use, and community choice and direct access (CCA/DA) where customers purchase their electricity from an alternative provider than PG&E. The grey area is what is left over for PG&E to supply after subtracting these other factors.

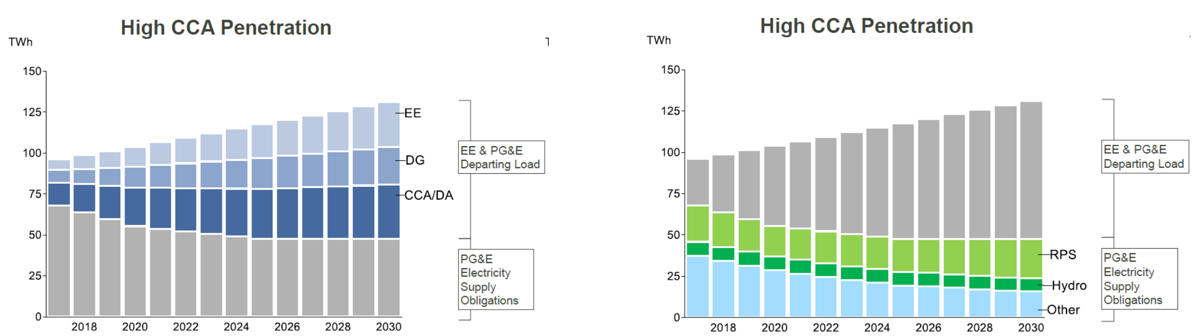
The chart above on the right grays out the three segments in the first chart, to highlight in three colors PG&E's electricity from different categories. The light green section, labeled "RPS" is the increasing amount of renewable energy that PG&E must procure according to the state's existing Renewables Portfolio Standard (RPS) law, which increases to 50 percent of PG&E"s retail sales by 2030. The dark green area is the projected amount of hydropower that is part of PG&E's electricity supply, largely due to PG&E owning these plants. The light blue area on the bottom of the chart on the right shows how a shrinking share of PG&E's electricity is left over for "other" sources of electricity—including natural gas and nuclear power— after accounting for the legally required renewable energy and existing hydropower.[13]

[13] Economic Analysis presentation; Joint Proposal for the Orderly Replacement of Diablo Canyon Power Plant with Energy Efficiency and Renewables, MJB&A, J U N E 2 1, 2 0 1 6, Last update: July 8, 2016 (appendix), http://www.pge.com/includes/docs/pdfs/safety/dcpp/MJBA.pdf

By 2030, this "Low CCA Penetration" scenario shows only minimal room for the nuclear plant to operate, and even that is very likely to diminish as the state further increases its requirement for renewable energy. In this scenario, the rigid 24/7 operation of the nuclear plant is also a poor fit, because the plant cannot ramp up and down in a flexible manner to balance the large amount of independently varying solar and wind.

On the other hand, if alternative energy suppliers—CCA and DA—grow significantly, then the picture is even more bleak for Diablo Canyon, as shown in the two charts below in Figure 3.

Figure 3: PG&E Service Territory High CCA Penetration



The chart on the left (in Figure 3) shows major growth of CCA; this dramatically shrinks the gray area at the bottom, which is the amount left over for PG&E to supply. The color sections of the chart on the right breaks down the portions of PG&E's electricity supply into the RPS renewables, hydropower, and "other".

By 2030, the remaining gap in the chart on the right labeled "other" is very small after accounting for renewable energy and hydropower. In the 2030 "High CCA" scenario, there is not enough room for full operation of the nuclear plant. And the situation would only get worse for the nuclear plant after 2030.

In fact, only a fraction of the section labeled "other" would be available for Diablo Canyon to continue operating. There are multiple sources for additional claims:

1. Spot market purchases required to balance hourly load; PG&E reported in 2014 that this amounted to 21% of its electricity supply,[14] equivalent to about 10 TWh in the "High CCA Penetration" scenario;[15] even if PG&E pares back spot market purchases, some will be needed to balance the wind and solar energy with daily fluctuations in demand.

[14] Electricity Retail Suppliers' 2014 Power Content Percentages, California Energy Commission. http://www.energy.ca.gov/sb1305/documents/index.html

[15] The charts from the PG&E consultant report are measured in terawatt-hours (TWh), which are 1,000 gigawatt-hours. Thus, Diablo Canyon's 18,000 gigawatt-hours per year is equal to 18 TWh.

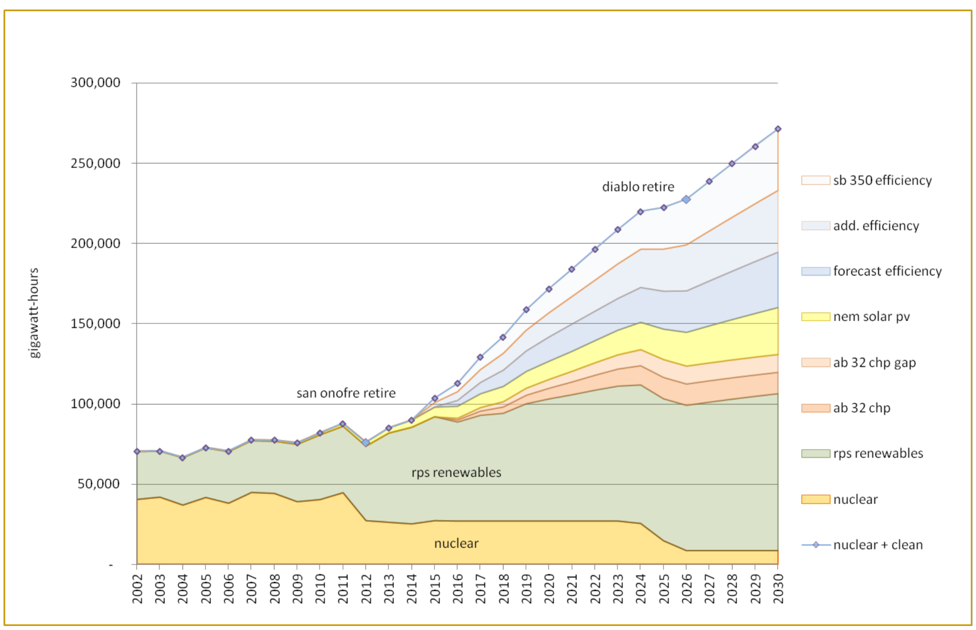
2. PG&E is required to purchase 1,387 megawatts (MW) capacity of new combined heat and power,[16] which could produce anywhere from 5 to 10 TWh of electricity, depending on how these plants are operated.

3. Hydropower can fluctuate greatly from year to year; in 2011 PG&E reported 18 percent of its electricity from large hydropower, equivalent to nearly 15 TWh, which is about double the amount shown in the charts; the risk of years with larger amounts of hydropower constrains PG&E's ability to lock down firm energy deliveries through long term contracts.

Adding all of these sources together could supply from 10 to 25 TWh, which needs to fit inside of the category called "other." Thus, any requirement for replacing Diablo Canyon must take into account these constraints. Framing longer term renewable energy requirements in terms of a percentage of retail sales rather than an absolute amount of gigawatt-hours is a prudent way to manage the risk of additional growth of Community Choice or customer self-generation.

Statewide Perspective on Nuclear Plant Retirements
Supporters of nuclear power argue that retiring nuclear plants does great damage to California's clean energy and climate goals. However, these criticisms radically underestimate the magnitude of California's existing clean energy commitments—which include dramatic increases in renewable energy and energy efficiency—against which a retiring nuclear plant appear as merely a temporary blip.

Figure 4: California New Clean Energy Policies & Retiring Nuclear Plants



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16 CHP Program Settlement Agreement Term Sheet, October 8, 2010, p.8.

The chart above (Figure 4) adds California's various clean energy programs on top of its nuclear generation to show the net effect of removing nuclear power plants on overall progress in the state's clean energy programs.[17,18] The lowest section shows the amount of electricity delivered from nuclear power to California. Initially, three nuclear power plants produce about 45,000 gigawatt-hours per year combined, followed by the two in-state nuclear plants retiring—San Onofre in 2012, and then Diablo Canyon in 2025. After 2025, the Palo Verde nuclear power plant in Arizona is shown continuing to deliver about 8,000 gigawatt-hours per year of electricity, although none of this is provided to PG&E.

The stack above the nuclear segment in ascending order includes the renewables portfolio standard (RPS), new combined heat and power (CHP), and net metered solar photovoltaics (NEM Solar PV). The top sections show three sources of energy efficiency, which are included in the broad category of "clean energy" even though they are demand-side resources rather than energy supply. The top line sums up all these selected energy sources.

The top line shows a modest dip in 2012, due to retirement of San Onofre Nuclear Generation Station (SONGS), followed by rapid recovery within two years due to the great speed at which clean energy resources were added. This is because clean energy resources far more than make up for the loss of nuclear power and continue to grow dramatically on a relatively steady trendline after 2012. The projections after 2015 are estimates subject to contingencies including the level of future demand and the degree of success in meeting the state's clean energy targets. These uncertainties only marginally affect the main point illustrated in the future projections of the graph— that retirement of Diablo Canyon in 2025 would have minimal and temporary effect when measured against the scope of California's clean energy policies.

Renewable energy includes in-state generation and imports. It also includes power from facilities installed prior to 2012 that are still in operation, because the state renewable energy goals are not limited to new generation. However, the energy efficiency savings are only shown for what is new after 2014, in accordance with state policy set by law in SB 350.[19] Similarly, the

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[17] Historical data from 2002 to 2015 for nuclear and renewable electricity generation from California Energy Commission system power reports, which can be accessed from this webpage: http://energyalmanac.ca.gov/electricity/total_system_power.html

[18] Projections for future energy efficiency, net meter solar photovoltaics, combined heat and power, and renewable energy are explained below. Retirement of Diablo Canyon assumes implementation of the plan to retire the nuclear plant in 2024 and 2025, with the chart reflecting the loss of 18,000 gigawatt-hours distributed over two years.

[19] SB 350 amends Section 25310 of the Public Resources Code to read, "(c) (1) On or before November 1, 2017, the [California Energy] commission, in collaboration with the Public Utilities Commission and local publicly owned electric utilities, in a public process that allows input from other stakeholders, shall 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. The commission shall base the targets on a doubling of the midcase estimate of additional achievable energy efficiency savings, as contained in the California Energy Demand Updated Forecast, 2015-2025, adopted by the commission, extended to 2030 using an average annual growth rate, and the targets adopted by local publicly owned electric

graph also only shows new combined heat and power, since that is what state policy specifies.[20] The clean energy resources for California include the following:

California Clean Energy Policy Resources by 2030

Category	Chart Label	Gigawatt-hours
SB 350 Energy Efficiency	sb 350 efficiency	38,000
Additional Achievable Energy Efficiency	add. Efficiency	38,000
Efficiency Embedded in the Forecast	forecast efficiency	34,500
Net Meter Solar Photovoltaics	nem solar pv	29,000
New Combined Heat and Power	ab 32 chp/ab 32 chp gap	24,500
50% Renewable Portfolio Standard	rps renewables	98,000
Subtotal Clean Energy		262,000

Renewable energy and new energy efficiency programs add up to a total of over 260,000 gigawatt-hours per year by 2030, compared to 18,000 gigawatt-hours lost from each of the nuclear plants. In other words, the state's existing clean energy programs are about seven times larger than the two retiring nuclear plants combined.

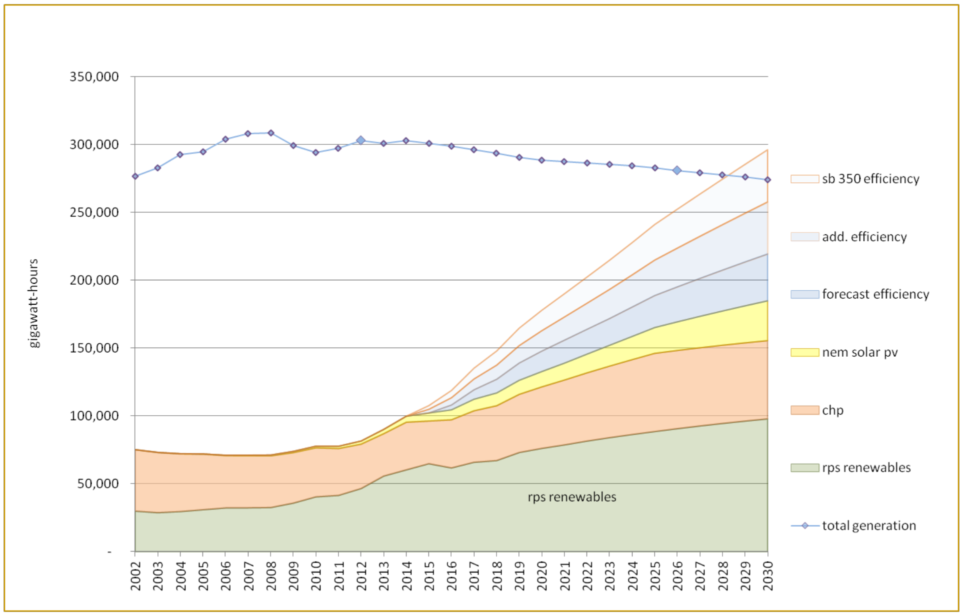
The assumptions are in certain ways resilient. For example, assume a worst case scenario where none of the additional SB 350 energy efficiency is realized. This in turn will increase the retail sales of electricity by an equal amount. Since California's renewable energy requirement reaches 50 percent of retail sales by 2030, the amount of renewable energy will increase to offset half the loss of energy efficiency. Thus the top line in the chart—showing the sum of nuclear plus clean energy— would only decrease marginally in 2030 in the event of a radical policy failure for energy efficiency. Also, the chart does not reflect the Joint Proposal's clean energy that is additional to the state policies.

Another way to look at the scale of California's clean energy resources is to stack them up in comparison to total electricity generation, shown in the line at the top of the graph (Figure 5):

utilities pursuant to Section 9505 of the Public Utilities Code, extended to 2030 using an average annual growth rate, to the extent doing so is cost effective, feasible, and will not adversely impact public health and safety." http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

[20] Change Scoping Plan, California Air Resources Board, December 2008, p. 44. https://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm

Figure 5: California Clean Electricity Policies Compared to Total Generation

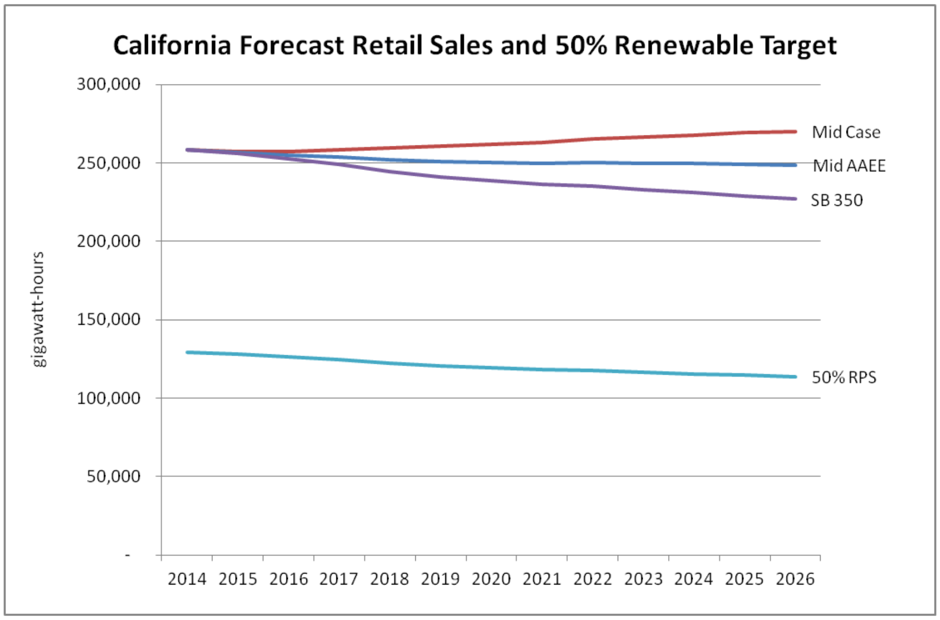


Together, the clean energy sources are equivalent to 108 percent of the total amount of electricity generation by 2030. This apparent paradox of clean resources exceeding the actual power supply is possible because the negative attribute of energy efficiency savings—so called "negawatt-hours"— is also counted, and efficiency savings are by definition not electricity generation. In this chart, existing combined heat and power (CHP) is also included, in addition to the new CHP required by the state's climate plan.

Here is a summary explanation of the clean energy resources:

Renewable Energy: State legislation (SB 350) requires electric utilities, CCAs, and electric service providers to DA customers, to increase renewable energy (RPS renewables), to 50 percent of retail sales by 2030, which is projected in the chart above (Figure 5) to reach about 100,000 gigawatt-hours by that year. The additional efficiency from SB 350, and the energy that customers generate for their own use, both reduce utility retail sales. These two factors, in turn, reduce the amount of renewable energy that is required to significantly less than might otherwise be assumed. [See Appendix F]

Figure 6: Decreasing Renewable Energy Target in Response to Efficiency Policies



The top line in the chart (Figure 6) shows the California Energy Commission's 2015 mid-case demand forecast for electricity deliveries to customers, while the next line below it ('Mid-AAEE") reflects the mid-case savings from additional efficiency that is not embedded in the baseline forecast. The line labeled "SB 350" shows the effect of doubling savings from additional efficiency as required by SB 350. The bottom line shows 50 percent of the retail sales after implementing SB 350's efficiency target. The state's actual renewable energy requirement does not reach 50 percent until 2030, but this graph shows how decreasing retail sales also decreases the amount of renewable energy that would be needed to meet a 50 percent requirement—as if it applied for the full time period in the graph. The trend-line for the 50 percent renewable energy requirement leads to about 108,000 gigawatt-hours if it were extended to 2030.

Net metered solar photovoltaics (NEM solar PV), where customers generate their own electricity to offset their utility bills, is currently forecast by the Energy Commission to reach 18,000 gigawatts of installed capacity by 2030, which would generate another 29,000 gigawatt-hours of energy beyond the renewable energy from utilities and other retail sellers of electricity.[21]

Combined Heat and Power (CHP): The state's climate plan sets an installed capacity target of 4,000 megawatts of new highly efficient CHP, generating 30,000 gigawatt-hours per year—about 10 percent of the state's electricity. While this electrical generation is assumed to use natural gas, its high efficiency is intended to save 6.7 million tons per year of carbon dioxide emissions (See Appendix D1). A 3,000 megawatt program, representing the proportionate share of the three major investor owned utilities (IOUs), PG&E, SCE, and SDG&E, has been

[21] The California Energy Commission projects that net metered solar photovoltaics will reach 21,085 gigawatt-hours by 2026, increasing at the rate of about 2,000 gigawatt-hours per year. Data is shown in Appendix E.

implemented by a settlement agreement approved by the CPUC.[22] The most recent reported procurement by the IOUs is 2,163 megawatts of installed capacity, which is 72% of the IOUs' share of the program goal.[23] The balance of the climate plan goal, 1,837 megawatts of installed capacity is shown as a separate section on the first chart as "AB 32 CHP gap", whereas the second chart shows all CHP together. The new CHP from the climate plan is assumed to be deployed over ten years between 2016 and 2025 in order to be conservative, although the three large IOUs are expected to procure their targets by 2020.

The new CHP replaces about 90 percent of the capacity and most of the energy of the two retiring nuclear plants in California. Furthermore, the improved efficiency created by CHP—compared to conventional coal and natural gas that it replaces— reduces fossil fuel consumption, equivalent to most of the carbon benefit of one of the nuclear power plants.[24]

While the 4,000 megawatts of CHP capacity is consistent with original climate plan target, the amount of electrical generation is assumed to be about 25,000 gigawatt-hours, significantly less than the 30,000 gigawatt-hours stated in the original climate plan. The climate plan assumed that CHP plants operate at very high capacity factor of about 86 percent, which implies operation as an inflexible base load plant. However, in a future with a large amount of solar and wind power it will be necessary to operate CHP plants in a more flexible manner. The revised scoping plan in 2014 took note of this point:

" CHP is primarily a baseload resource but needs to be dispatchable to help the
State address load balancing needs."[25]

This change in operational service will require producing significantly less electricity from a given amount of CHP installed capacity. Therefore, energy generation from the new CHP is decreased to a somewhat arbitrary level near 25,000 gigawatt-hours to illustrate this effect. Existing natural gas CHP apparently has even lower average capacity factor, with nearly 8,000

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[22] Decision Adopting Proposed Settlement, California Public Utilities Commission, http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/128624.PDF

[23] Tracking Progress, Combined Heat and Power, California Energy Commission, Last updated 9/16/2015, http://www.energy.ca.gov/renewables/tracking_progress/documents/combined_heat_and_power.pdf

[24] The IOU share of the greenhouse gas goal would have been to save 4.8 million tons, but this was decreased to 2.72 million tons due to technical corrections. The IOUs have lower carbon emission rate from the conventional than the state average due to almost no use of coal. Since combined heat and power replaces other fossil fuel generation, the savings in CO2 will also be less. The publicly owned utilities have significant coal in their energy supply, so replacing that with combined heat and power will have proportionally greater CO2 reduction. To date it is not clear if publicly owned utilities have implemented this climate plan measure.

[25] First Update to the AB 32 Scoping Plan, Appendix C Focus Group Working Paper on Energy, posted March 14, 2014. https://www.arb.ca.gov/cc/scopingplan/document/updatedscopingplan2013.htm

megawatts of installed capacity producing less than 30,000 gigawatt-hours per year, reflecting a capacity factor of only about 40 percent.[26,27]

Energy Efficiency is shown in the top three sections in the graph, with each section contributing similar amounts of energy savings. The lower section, called "forecast efficiency", is the amount of energy efficiency embedded within the Energy Commission's 2015 California Energy Demand forecast (CED 2015); this represents savings from programs and standards that have already been implemented and that will continue to save energy in the future. This category is conventionally referred to as committed efficiency, and reaches annual savings of 30,000 gigawatt-hours by 2026 that is embedded in the baseline forecast, when compared to the 2015.[28]

The middle efficiency section, "add. efficiency", shows Additional Achievable Energy Efficiency (AAEE) beyond what is embedded in the baseline forecast; these savings include potential future improvements to efficiency standards, and likely future efficiency programs. In recent years, the Energy Commission has been providing forecasts for retail sales of electricity both with and without the AAEE. Therefore, these values must be compared in order to determine the amount of AAEE that is implied.[29]

SB 350 requires doubling the AAEE amount of energy savings by 2030, which additional contribution is shown in the top section of the graphs in Figures 5 and 6. The AAEE by 2030 is projected to reach 33,000 gigawatt-hours of savings per year, with SB 350 adding another 33,000 gigawatt-hours. These savings do not include the publicly-owned utilities, which have efficiency requirements in SB 350 that are to be determined by the Energy Commission.[30]

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[26] Capacity data for combined heat and power is from earlier editions of the California Energy Commission's California Power Plant Database.
http://energyalmanac.ca.gov/electricity/

[27] U.S. Energy Information Administration data shows the following amount of cogeneration from natural gas in California for 2015— 16,129 gigawatt-hours of "electric utility" cogeneration, 10,862 gigawatt-hours from industrial cogeneration, and 1,573 gigawatt-hours from commercial sector cogeneration, for a total of 28,564 gigawatt-hours. Filters for state and category must be selected from the browser.
http://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=fg2g&geo=000000000004&sec=0g&freq=A&start=2002&end=2015&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=

[28] The California Energy Commission demand forecast begins measurement from 1975, however this report focuses on new savings beginning in 2015. Residential efficiency adds approximately 12,000 gigawatt-hours and non-residential 18,000 gigawatt-hours by 2026 when compared to 2015; See Appendices G1 and G2.

[29] The data behind these calculations are shown in the tables in Appendices E1, E2, and E3. However, SB 350 also requires the Energy Commission to apply criteria screens for cost effectiveness, feasibility, and public health and safety. The results of this evaluation are yet to be determined; however, the projection in the chart assumes these criteria can be met.

[30] See previous cite from SB 350.

The table and graphs above only show new efficiency after 2015, with some of the benefits of improvements carrying over from year to year. If the programs are all successful in meeting state projections and policy goals pursuant to SB 350, California should reach over 100,000 gigawatt-hours per year of energy efficiency savings in 2030.

Climate Effect of Nuclear Retirements

When San Onofre Nuclear Generating Station retired abruptly in 2012, state's growing clean energy programs replaced the nuclear plant with renewable electricity by early 2014. Diablo Canyon is assumed to fully retire by August 2025, as in the Joint Proposal between PG&E and other negotiating parties. Because Diablo Canyon is planned to be retired over two years, the effect is only a flattening of progress on the net benefits of clean energy for about a year and a half, followed by continued steep increase. Palo Verde Nuclear Plant in Arizona is assumed to be providing electricity after 2026, since its operating license continues until the mid-2040s.[31]

When operating, each of the retiring nuclear plants on average has generated about 6 percent of the state's total electricity supply. This is smaller than the often-cited figure of 9 percent, which is the fraction of in-state generation, and is misleading because it excludes accounting for a third of California's electricity imported from out-of-state.

Combined, the two retiring plants add up to 12 percent of the State's electricity. This is half the amount of The Breakthrough Institute founder Michael Shellenberger's claim that retirement of the two nuclear plants would cause natural gas generation to rise from 45 to 70 percent—an increase of 25 percent share—of California's electricity![32] This error was based, in part, on the confusion between in-state generation and California's total electricity supply. In the year after San Onofre Nuclear Generating Station retired, electricity from natural gas increased from 45 to 60 percent of in-state generation. But if both in-state and imported electricity is accounted, then natural gas only increased from 35 to 43 percent of the total supply. (See Appendices C1 & C2)

However, the increase of natural gas power generation was only partially due to the retiring nuclear plant. In fact, a lot was going on between 2011 and 2012, including the onset of a major drought that reduced hydropower generation by almost 15,000 gigawatt-hours.[33] Less

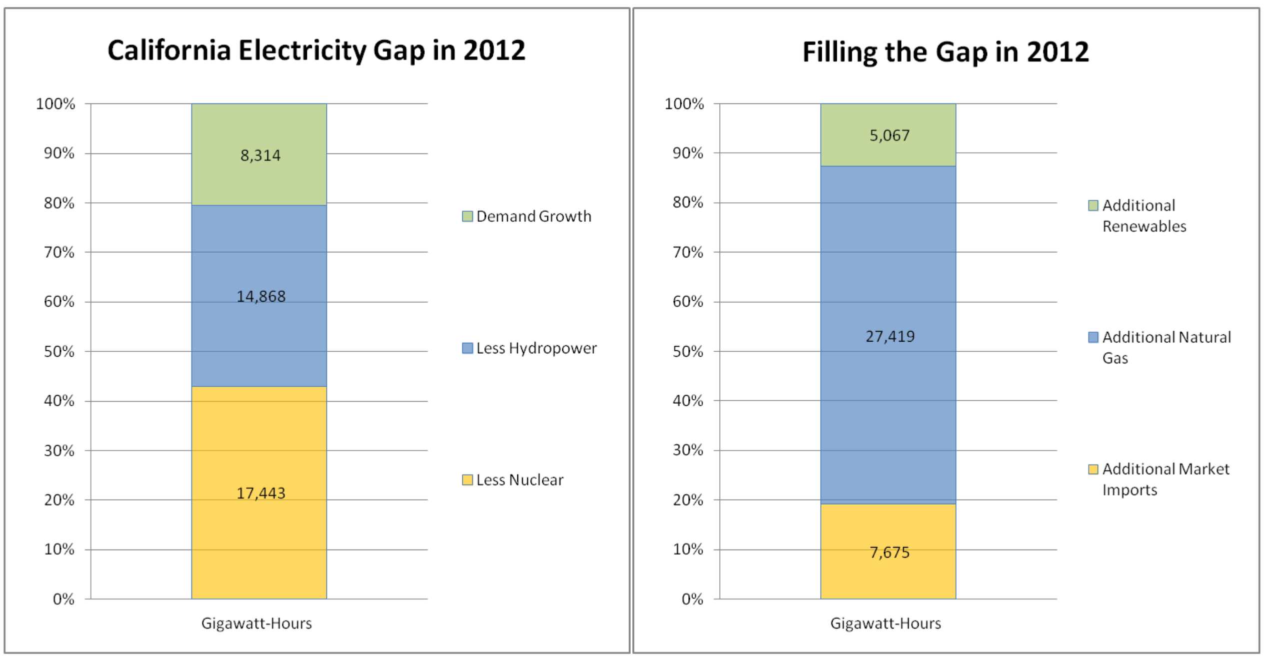
[31] *TOP PLANTS: Palo Verde Nuclear Generating Station*, Wintersburg, Arizona, Dr. Robert Peltier, PE, 11/01/2015, http://www.powermag.com/palo-verde-nuclear-generating-station-wintersburg-arizona/

[32] Anatomy of a nuke closure: How PG&E decided to shutter Diablo Canyon, By Herman K. Trabish | July 7, 2016 http://www.utilitydive.com/news/anatomy-of-a-nuke-closure-how-pge-decided-to-shutter-diablo-canyon/421979/

[33] California Energy Commission data shows hydroelectricity from large hydroelectric plants, including both in-state and out-of-state sources, decreasing from 38,000 gigawatt-hours in 2011 to slightly less than 25,000 gigawatt-hours in 2012—a reduction of about 13,000 gigawatt-hours. Small hydropower, which qualifies for the state's RPS program, generated over 6,000 gigawatt-hours in 2011, and decreased to less than 4,500 gigawatt-hours in 2012. Thus total hydropower decreased by nearly 15,000 gigawatt-hours. (see Appendices C1 and C2)

hydropower is usually backfilled by increased natural gas generation, a factor that was nearly as large as the retiring nuclear plant. Another change was recovery from the Great Recession of 2008, which added a demand spike of 6,000 to 8,000 gigawatt-hours in 2012.[34] In other words, several factors together created a "gap" of about 40,000 gigawatt-hours that needed to be filled by other sources of electricity.

Natural gas backfilled most of this gap, supplemented by over 7,000 gigawatt-hours of additional spot market imports from other states, plus 5,000 gigawatt-hours of new renewable energy that came on-line in 2012. The chart on the left (in Figure 7) shows the causes of the "gap", of which retirement of San Onofre Nuclear Generating Station was only one factor, while the chart on the right shows what resources filled that gap in 2012.
Figure 7: Changes in California's Electricity Supply in 2012



The increase in natural gas generation and spot market purchases caused increased greenhouse gas emissions from the electricity sector, as the following quote[35] from nuclear advocate Revis James[36], echoed around the Internet, points out:

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[34] California Energy Commission system power reports show total electrical generation of 293,652 gigawatt-hours in 2011, and 301,966 gigawatt-hours in 2012, an increase of 8,314 gigawatt-hours of demand for electrical generation. (see Appendices C1 and C2)

[35] Closing Diablo Canyon: California Rolls the Dice with Renewables (and Natural Gas), By Revis W. James, June 27, 2016
http://www.realclearenergy.org/articles/2016/06/27/closing_diablo_canyon_california_rolls_the_dice_with_renewables_and_natural_gas_109179.html

"Take what has already happened in California, for example. The California Air Resources Board said in 2014 that the state's carbon dioxide emissions had increased by 9 million metric tons in the 12 months following the 2012 closure of two San Onofre reactors in Southern California." No source from the Air Resources Board is provided to verify this claim. The specific figure of an additional 9 million tons of carbon dioxide in the 12 months after closing San Onofre does appear in a report from the Energy Institute at Haas, UC Berkeley. However, there are serious limitations to using this as a reliable source. For one, the report comes with the following notification on the cover page: "Energy Institute at Haas working papers are circulated for discussion and comment purposes. They have not been peer-reviewed or been subject to review by any editorial board."[37]

Another problem is that the analysis relies on U.S. Energy Information Administration data for in-state generation, and the CAISO data for spot market imports. This does not capture the large amount of contracted energy imports, especially nuclear, hydropower, and renewable energy, similar to Mr. Shellenberger's error. The Haas report also discusses the fact that the retiring nuclear plant was not the only change happening in 2012 to increase GHG emissions, and points out that hydropower was low.

An article by the senior editor for MIT's Technology Review acts as an echo chamber for Mr. Shellenberger's Breakthrough Institute, but ups the ante:
"According to the Breakthrough Institute, a San Francisco-based research organization that supports nuclear power to limit climate change, the 2013 closing of the San Onofre nuclear plant added nearly 11 million tons of carbon dioxide annually to the atmosphere. Closing Diablo Canyon would result in a similar amount."[38]

Not to be outdone, another nuclear advocate increased the estimate even further:
"In 2013, per industry statistics, Diablo Canyon avoided 13.43 million metric tons of carbon dioxide emissions, equal to the carbon dioxide emissions from about 72 million modern design automobiles."[39]

Aside from exaggerations, these figures are misleading because—as already pointed out—reduced nuclear power was not the only factor that tended to increase emissions, and there

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36 Revis James' LinkedIn account claims he is Vice President, Policy Planning and Development for the Nuclear Energy Institute, and a Director in EPRI's Generation R&D Sector, responsible for a staff of 35 researchers and an overall budget of $35M.

37 Market Impacts of a Nuclear Power Plant Closure, Lucas Davis and Catherine Hausman, Revised May 2015, https://ei.haas.berkeley.edu/research/papers/WP248.pdf

38 Nuclear Shutdowns Could Ramp Up U.S. Carbon Emissions, by Richard Martin, May 20, 2016, https://www.technologyreview.com/s/601533/nuclear-shutdowns-could-ramp-up-us-carbon-emissions/

39 Why we should keep Diablo Canyon nuclear power plant open, Letters to the Editor , by Gene Nelson March 15, 2016, http://www.sanluisobispo.com/opinion/letters-to-the-editor/article66255217.html

were countervailing factors that tended to decrease emissions. Most importantly, the claim of 9 million tons (or 11 million tons, or 13.4 million tons, or—wandering off into terra incognita— 72 million automobiles 40) increase is not consistent with the state's official GHG inventory,[41,42] which showed California's total emissions in 2011 as 441.71 million metric tons, and 448.33 million tons in 2012;[43] an increase of 6.62 million tons—substantially smaller than the pro-nuclear estimates. Furthermore, the state's emissions decreased in the next two years, such that by 2014 they were slightly below 2011. The Air Resources Board provides the following graph

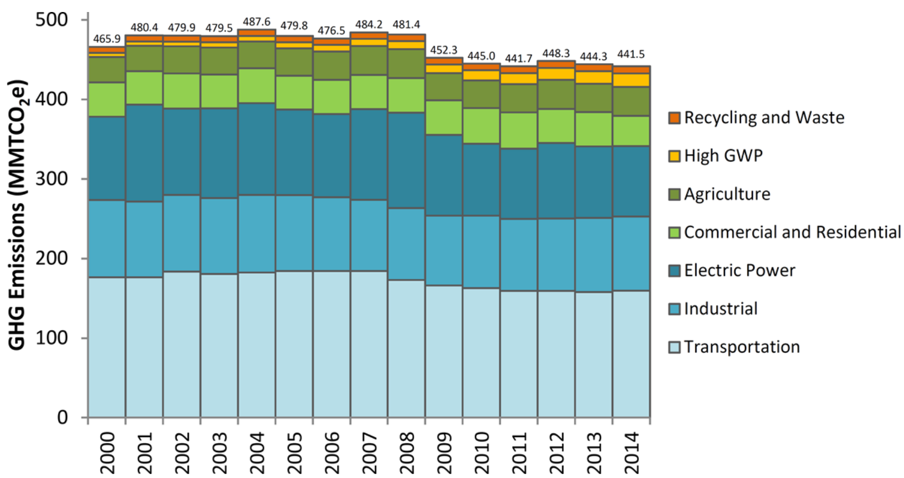
[40] A gallon of gasoline produces about 20 pounds of CO2 emissions. Assuming an average automobile gets 25 miles per gallon, and is driven 12,000 miles per year, results in annual consumption of 480 gallons of gasoline, and 4.36 metric tons of CO2. Therefore, this fleet of automobiles would emit 4.36 tons times 72 million = 313 million metric tons of CO2 (MMTCO2e) per year, far more than California's entire electricity sector (88 MMTCO2e) and transportation sector (160 MMTCO2e) combined in 2014.

[41] The previous inventory showed California's total emissions in 2011 as 454.61 million tons, and 460.82 million tons in 2012; an increase of 6.21 million tons; California Greenhouse Gas Inventory for 2000-2013— by Category as Defined in the 2008 Scoping Plan, California Environmental Protection Agency, Air Resources Board, Updated April 24, 2015.
http://www.arb.ca.gov/cc/inventory/pubs/reports/2000_2013/ghg_inventory_scopingplan_2000-13_20150831.pdf

[42] California Greenhouse Gas Inventory for 2000-2014— by Category as Defined in the 2008 Scoping Plan, California Environmental Protection Agency, Air Resources Board,
https://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_scopingplan_2000-14.pdf

[43] All figures cited as "tons" mean metric tons in conformity with the state's greenhouse gas inventory data.

Figure 8: California Greenhouse Gas Emissions 2000 to 2014[44]



Overall, California's GHG emissions are down 46 million metric tons from the peak in 2004. Figure 8 shows clearly that the events of 2012, of which retirement of San Onofre was only one aspect, resulted in a minor up-tick that was erased within two years. More importantly, California by 2014 was 10.5 million metric tons above the 2020 target of 431 million tons, more than 80 percent of the reduction needed from the peak year of 2004 to reach the 2020 goal.[45] The 2020 goal should be achievable within the framework of projected retirement of out of state coal contracts, in addition to what is required to meet the 33 percent renewable electricity mandate.

Looking more narrowly at the electricity sector also reveals interesting trends.

Figure 9: Greenhouse Gas Emissions from California Electricity[46]

(next page)

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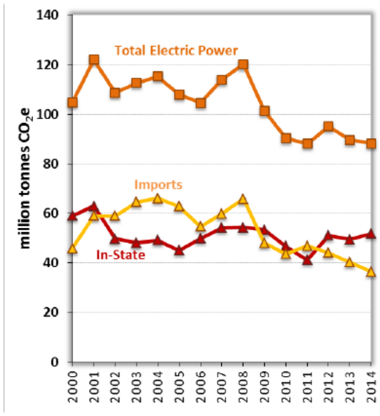
[44] https://www.arb.ca.gov/cc/inventory/data/graph/bar/bar_2014_scopingplan.png

[45] California 1990 Greenhouse Gas Emissions Level and 2020 Limit, Last reviewed on May 6, 2015 https://www.arb.ca.gov/cc/inventory/1990level/1990level.htm

[46] 2016 Edition California GHG Emission Inventory, 0F1FCalifornia Greenhouse Gas Emissions for 2000 to 2014– Trends of Emissions and Other Indicators, *VERSION June 17, 2016, https://www.arb.ca.gov/cc/inventory/pubs/reports/2000_2014/ghg_inventory_trends_00-14_20160617.pdf*



The chart above (Figure 9) shows that electric power emissions peaked in 2001 at 122 million tons, and decreased to 88 million tons by 2011. The next year showed an increase, but nearly all of the effect of 2012 had been erased in the following year when electricity sector emissions went down to 89.65 million tons. In other words, the recovery of reduced carbon emissions in the electricity sector was even more rapid than for the state as a whole. The breakdown between in-state and imported electricity shows the reason—while in-state emissions increased, emissions from imported electricity maintained a decreasing trend every year after 2011. This was a factor that the Haas study did not adequately capture, due to its reliance on data that was biased toward in-state generation.

Similar factors will be at work in the 2020s, as more coal is scheduled to retire, and the state requires all retail sellers of electricity—including PG&E—to increase renewable energy to 50% of retail sales by 2030.

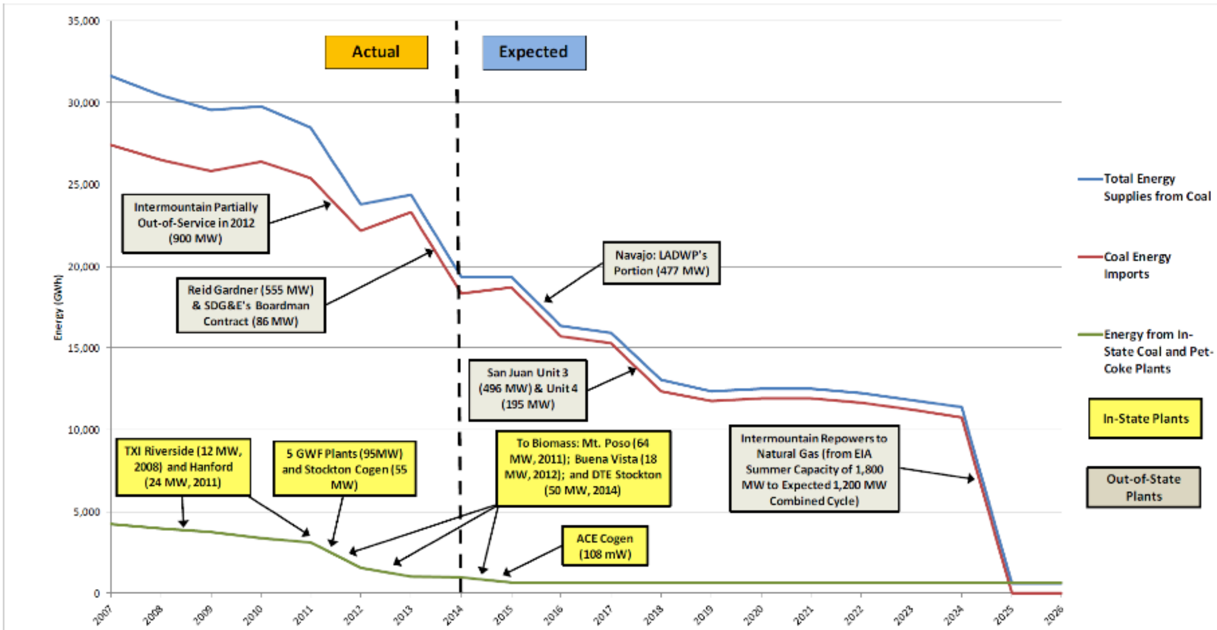
The following chart shows retiring coal contracts:[47]

Figure 10: Retirement of California Coal-fired Electrical Generation

(next page)

[47] California Energy Commission –Tracking Progress, Actual and Expected Energy From Coal for California–Overview, Last updated 12/7/2015, http://www.energy.ca.gov/renewables/tracking_progress/documents/current_expected_energy_from_coal.pdf

Actual and Expected Reductions of Energy by Coal- and Petroleum Coke-Fired Plants Used to Serve California Loads (2007-2026)



Sources: 1) Electricity Supply Forms (S-2 and S-5) submitted by load-serving entities (LSEs) for the California Energy Commission's 2009, 2011, 2013, and 2015 *Integrated Energy Policy Reports (IEPR)* available at http://energyalmanac.ca.gov/electricity/; 2) M-S-R Resolution No. 2015-02.

Figure 10 (above). The reduction of about 6,000 gigawatt-hours in coal between 2010 and 2012 was close in time to the loss of 18,000 gigawatt-hours from San Onofre Nuclear Plant. In other words, retiring coal helped to mitigate San Onofre's retirement in regard to carbon dioxide emissions. Similarly, an expected decrease of about 11,000 gigawatt-hours of imported coal-fired electricity in 2025 coincides with the planned retirement of Diablo Canyon. While a portion of the coal is replaced by natural gas, the ongoing state polity to greatly increase renewable energy will reduce the use of natural gas.

The overall state climate goal is to reduce GHG emissions to 1990 levels by 2020.[48] In 1990, electricity was reported to be responsible for 110.6 million tons of carbon dioxide equivalent.[49] Even though the general target is not applied equally to each sector, if it were, the electric sector is far below the 1990 level. Out of the reduction of 33 million tons from the peak, 19 million tons is essentially a gift to other sectors that are short on their contributions. So, the notion that the electricity sector is not pulling its weight due to retiring nuclear plants is opposite of the truth.

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[48] AB 32, California Global Warming Solutions Act of 2006, http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB32

[49] California Air Resources Board, https://www.arb.ca.gov/cc/inventory/pubs/reports/staff_report_1990_level.pdf

Replacement Energy Resources for Diablo Canyon

PG&E proposes that, upon closing Diablo Canyon, they would promise deployment of three tranches of clean energy, including 2,000 gigawatt-hours gross of annual energy efficiency savings ("efficiency") prior to closing the plant in 2025, another 2,000 gigawatt-hours of either renewable energy, or gross efficiency savings, or both combined until 2030, and a voluntary 55 percent renewable portfolio standard ("RPS") until the 2040s, or an earlier date if the state adopts a higher renewable energy requirement.

Quantifying the cumulative benefit of this proposal is difficult because 1) efficiency is measured in "gross" terms, before losses that are unavoidable both initially in the deployment of efficiency measures, and over time as decay of program benefits occurs, and the proposal does not make clear if this loss must be compensated either during or beyond the time period of each tranche; and 2) the amount of renewable energy from the higher RPS percentage depends upon how much retail sales PG&E will have after 2030, but this will decline if there is increasing energy efficiency, self-generation, and departing load to community choice or direct access.

It is possible to estimate the cumulative amount of these resources by making certain assumptions, which also illuminates some of the potential issues associated with the proposal:

First Tranche (to 2025): The Joint Proposal states that the initial request for offers of efficiency would be released by June 1, 2018, implying that significant savings are not likely to begin until 2019. The proposal aims for 2,000 "gross" gigawatt-hours of savings to be installed by January 1, 2025. Therefore, it is assumed here that this efficiency would be gradually ramped up between 2019 and 2024. There are a few options for how these savings might persist after 2025:

- Deployment of efficiency reaches 2,000 gigawatt-hours in 2025, and then gradually decays over a number of years because the program savings are not refreshed

- The proposal is modified and/or clarified to ensure that PG&E maintains these savings in future years through backfilling decay of the efficiency

- The savings are preserved by being incorporated into later programs, either through second tranche efficiency described below, or through the increasing amount of efficiency through SB 350

Because there is no explicit assurance in the proposal to the contrary, it is assumed here that the savings will decay after installation is complete in 2025. And because PG&E assures that these measures are additional to other efficiency programs, it is assumed that these savings are additional to SB 350 over the longer term. However, the efficiency targets of SB 350 are so ambitious, and measurements of efficiency savings sufficiently challenging, that it may prove difficult to create and to prove additionality over the longer term.

Second Tranche (2025 to 2030): The second tranche is for procurement of 2,000 gigawatt-hours of efficiency and/or electrical generation, with an all-source request for offers by June 1, 2020. The proposal's assurance is that deliveries would be for a minimum of five years, and achieve 2,000 gigawatt-hours per year between 2025 and 2030. Any additional efficiency after 2025 is assumed to be additional to efficiency from the first tranche, since otherwise there would be little net benefit to this portion of the proposal. To the extent that part or all of the 2000 gigawatt-hours for the second tranche is met with additional electrical generation, it is not specified whether this will extend beyond 2030. It is assumed here that the commitment in tranche 3, as written, only promises a total of 55% renewable energy after 2030, rather than generation additional to the second tranche.

Third Tranche (2030 to mid-2040s): PG&E commits to a voluntary 55 percent renewable portfolio standard (RPS) after 2030. This commitment is proposed to continue up to the mid-2040s, during the period that Diablo Canyon would have operated had relicensing been approved. Both the state's RPS and PG&E's proposed voluntary 55 percent renewable energy are measured as a percentage of retail sales, rather than a percentage of electrical generation. Electrical generation is a larger number because it must produce extra energy to offset "line losses" in the power grid, which average about 7 percent for California.[50]

The proposal leaves the door open for additional procurement if PG&E wishes and the CPUC agrees. In addition to energy efficiency and renewable electricity generation, the proposal supports new resource integration and energy storage that PG&E could procure. The proposal also aims to address other important issues, including transitional funding for employees of the plant, as well as temporary compensation for loss of local tax revenue.

The proposal binds the signatory parties to support recovery of costs associated with the replacement GHG-free energy resources through non-bypassable charges, presumably meaning the signatory parties support the position that all customers in PG&E's entire service territory will have to pay for this replacement, even customers who are not receiving their electricity from PG&E. In order for the terms of the Joint Proposal to impose actual costs on customers, the position of the parties would need to be accepted for specific procurement of energy resources approved by the CPUC. Furthermore, any actual procurement following the Joint Proposal is voluntary on the part of PG&E. Thus, the proposal has no current power in terms of what procurement will actually occur, and would only have limited power even if approved by the CPUC. Part of this limitation is inherent in the 55% RPS commitment, which exposes the target to risk of:

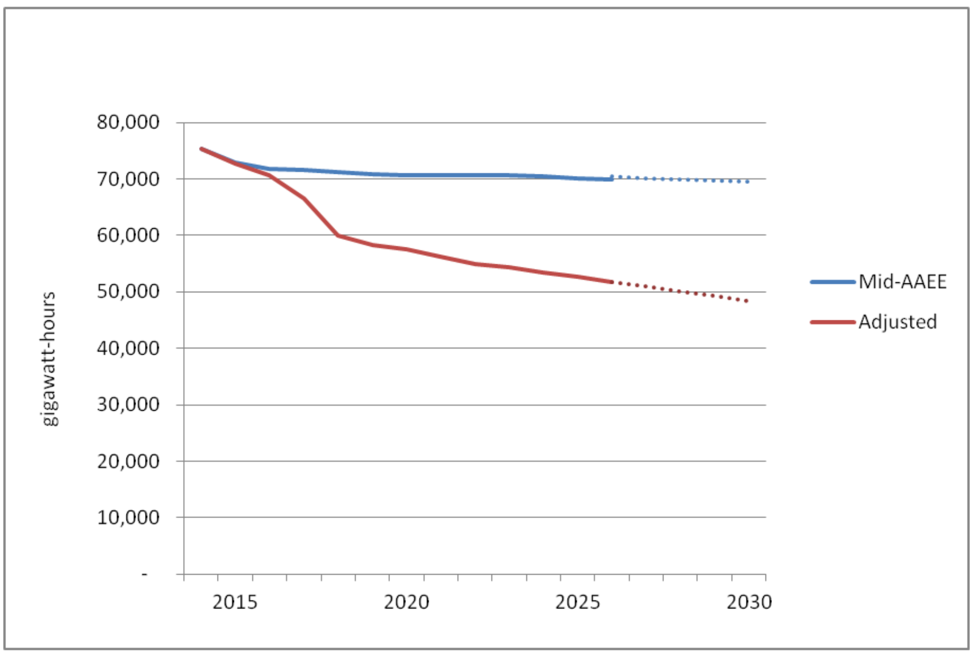
The state adopting a higher RPS and making the renewable energy portion of the proposal moot
Factors that affect demand, including energy efficiency, eroding the quantitative amount of the higher voluntary RPS

[50] http://www.energy.ca.gov/2011publications/CEC-200-2011-009/CEC-200-2011-009.pdf

Departing load from Direct Access and Community Choice programs, which reduces the amount of electricity required to meet the 55% RPS commitment from PG&E

Quantification of the difference between the existing 50% RPS and PG&E's proposed voluntary 55% RPS depends on retail sales. The California Energy Commission's most recent forecast for PG&E shows retail sales decreasing from 75,000 gigawatt-hours in 2014 to 70,000 gigawatt-hours from 2026 to 2030, using mid-case assumptions for base-line demand and additional achievable energy efficiency. However, if this is adjusted for 1) the requirement from SB 350 to double energy efficiency savings, 2) new CCA programs that have already announced start-up, and 3) the commitment under the Joint Proposal to procure an additional 2,000 gigawatt-hours per year of efficiency savings, then PG&E's demand would decrease to about 47,000 gigawatt-hours per year by 2030.

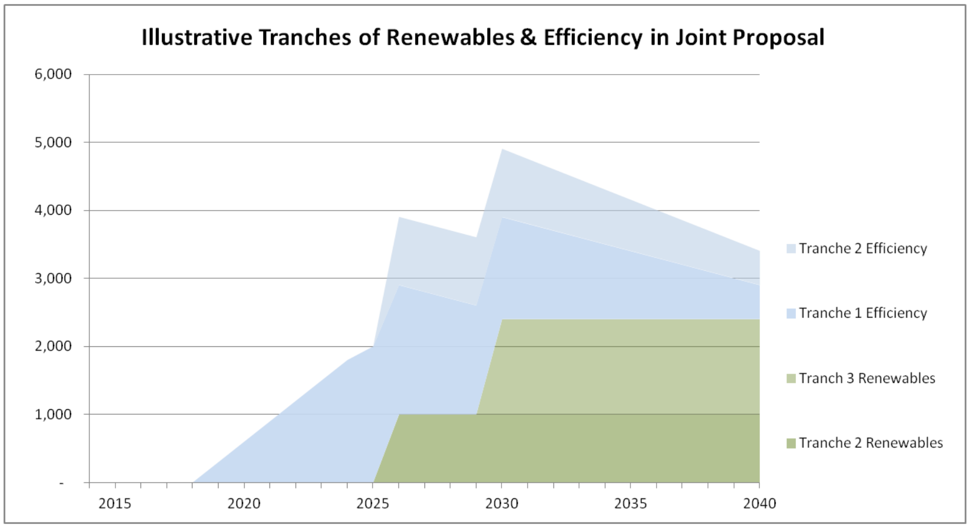
Figure 11: PG&E Forecast and Adjusted Demand for Energy Efficiency



After these adjustments are made to the demand forecast, the voluntary commitment to five percent renewable energy would equal about 2,350 gigawatt-hours, in addition to the state's 50 percent renewable requirement.

The first tranche of 2,000 gigawatt-hours of efficiency gradually decays after 2025, while the second tranche of efficiency begins to decay after 2030. The second tranche of 2,000 gigawatt-hours is assumed to be evenly split between efficiency and renewable generation. The tranche 3 commitment to the extra 5 percent renewable energy requires adding more renewable energy beginning in 2030. The following chart illustrates how this might unfold.

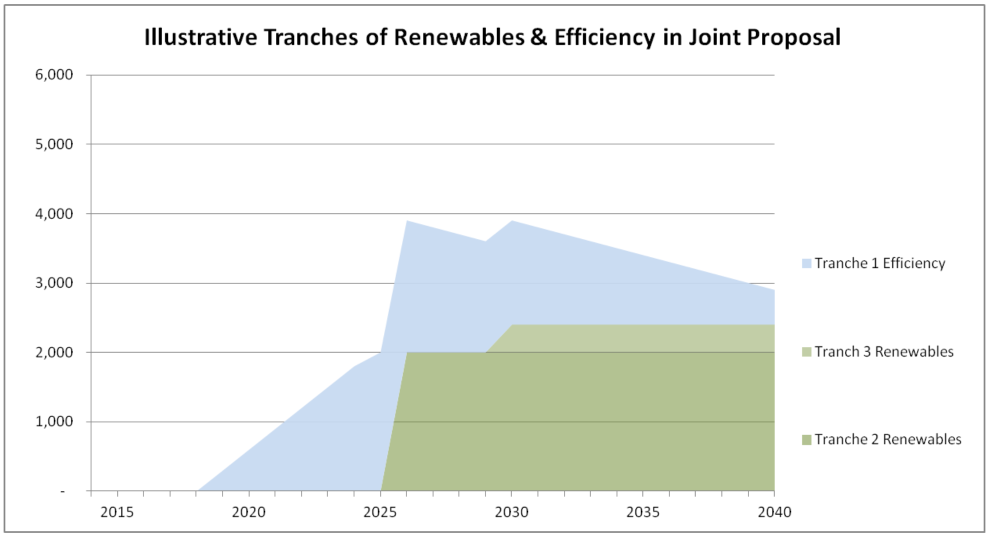
Scenario 1: Half Renewable Energy & Half Efficiency for Tranche 2



In this first scenario, the combined resources peak in 2030, replacing 28 percent of Diablo Canyon's normal electricity generation. However, the decay of energy efficiency rolls this back to about 20 percent over the next decade, if there is no commitment to maintain the savings after the period in which they are procured.

Another alternative is to procure only renewable electricity for the second tranche after 2025, so there is no additional second tranche of efficiency. In this case, less additional renewable energy must be procured to reach the extra 5 percent target in 2030, and less total efficiency is procured. The result is that the resource peak in 2030 is 1,000 gigawatt-hours less than when more efficiency is put into the mix in the first scenario.

Scenario 2: All Renewable Energy for Tranche 2 (next page)



These two scenarios show how relatively subtle assumptions about resource deployment can affect the outcome, even without changing the total amount of resources in each tranche.

Another important effect is the interaction between energy efficiency and the renewable energy target based on the percentage of retail sales, which is not reflected in the scenarios above. This effect is quite large when the renewable energy target reaches 50 and 55 percent. In these cases, every additional unit of efficiency will be half offset by a reduction in the amount of renewable energy needed to meet the target. So, adding 2,000 gigawatt-hours of efficiency will reduce the amount of renewable energy by about 1,000 gigawatt-hours. This avoided renewable energy purchase represents a cost savings that can be attributed to the additional efficiency.

The joint proposal also includes support for adding resources to replace the reliability of Diablo Canyon, which would be important if the main sources of renewable energy are likely to be solar and wind. The reliability resources could include demand response or energy storage. Storage can reduce the waste of excess renewable generation, but also incurs energy losses. These effects should be properly accounted for when determining the renewable energy requirements, since energy losses from storage and curtailment of renewable generation are not delivered to customers.

Utility Share of Electricity Market

Retirement of nuclear plants in California continues the long term trend of electric utilities in California pulling back from the business of generating electricity. This has important strategic implications for other providers of electricity that might have been perceived as "competing" with the investor-owned utilities (IOUs).

The two large nuclear plants in California constituted the primary utility-owned electrical generation remaining after most generation assets had been divested in the 1990s. The other electricity sources held as assets of the IOUs include some hydropower, a small fraction of in-state natural gas plants, and a minimal amount of renewable energy. Currently, PG&E owns power plants that produce 37% of the electricity that the utility supplies to its bundled customers.[51]

Total 2015 Actual Electricity Generated and Procured – 72,113 GWh(1):

	Percent of Bundled Retail Sales
Owned Generation Facilities	
Nuclear	22.6%
Small Hydroelectric	0.7%
Large Hydroelectric	4.6%
Fossil fuel-fired	8.9%
Solar	0.4%
Total	37.2%

The majority of the PG&E-owned supply is produced by the nuclear power plant. Once Diablo Canyon is retired, the share of electricity provided by PG&E-owned power plants will be reduced to only about 15 percent based on 2015 generation. However, this reflects a drought condition, so the amount of electricity generated would increase closer to 20% of PG&E's retail sales if it were a more normal hydropower year.

On the other hand, the market share of utility owned generation is even smaller if one looks at all electricity delivered to customers in PG&E's service territory, which is supplied from three other sources:

- Direct Access, where large commercial customers procure electricity from independent suppliers called Electric Service Providers

- Community Choice Aggregation, where local governments purchase electricity for customers in their jurisdiction

- Self Generation, where customers produce and consume their own electricity on-site

Nearly a quarter of the electricity in PG&E's service territory is provided by these other sources, with likelihood that this non-PG&E share will significantly increase in the future.[52,53]

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[51] 2015 Joint Annual Report to Shareholders, PG&E Corporation Pacific Gas and Electric Company, p. 13. http://s1.q4cdn.com/880135780/files/doc_financials/2015/2015-Annual-Report-Final.pdf

[52] Retail sales data from California Energy Commission, California Energy Demand Revised/Final Forecast 2016 - 2026, Mid Demand Baseline Case, Mid AAEE, docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN209989_20160127T094920_LSE_and_BA_Tables_Mid_Demand_Baseline__Mid_AAEE.xlsx

PG&E Planning Area Electricity Demand in 2015

Supplier	GWh	Share %
Pacific Gas and Electric Company (Bundled)	72,855	77%
Direct Access	9,520	10%
Marin Clean Energy CCA	1,701	2%
Sonoma Clean Power CCA	1,769	2%
Self Generation	8,626	9%
Total	94,472	100%

Measured against total electricity in PG&E's service territory, rather than just their bundled customers, the utility-owned generation currently provides a quarter of the electricity, and this would decrease to only about 10% if the nuclear plant is excluded. In other words, retirement of the nuclear plant will leave PG&E with only a marginal share of the electricity supply market. This is important because PG&E only makes a direct profit on electrical generation if the utility owns it. The other electricity that PG&E purchases, or that is provided by other suppliers, are costs that are passed through to customers on the electricity bill with no additional margin or profit for PG&E.

As a nuclear-free utility, PG&E will become almost entirely a company that provides the wires and customer services, leaving 90% of the electricity supply to other sources. From a strategic point of view, PG&E's future minimal role in the electric generation business is an important development for Community Choice programs and customers who generate their own electricity, because it means the utility interest as a competitor is only marginal.

PG&E's recognition of the evolving regulatory and market conditions, and its decreasing role in directly supplying electricity, partly explains why it is being cautious in making commitments to replacing only a portion of the energy provided by Diablo Canyon. This is a prudent business decision, and—in part— also responds to problems that arose from the retirement of San Onofre Nuclear Generating Station. In that case, additional expenses incurred have become a political, legal, regulatory, commercial, and financial risk to the utilities that own San Onofre, in which they are not assured full cost recovery.[54] This put shareholders on the hook for a portion

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[53] Self Generation data from California Energy Commission, California Energy Demand 2015 Revised - Mid Demand Case, December 2015; see table in Appendix B.
[54] CPUC Investigation of SONGS Settlement, ORA Withdrawal of Support, Office of Ratepayer Advocate, http://ora.ca.gov/general.aspx?id=3149

of excess costs—a situation that is highly problematic for risk averse utilities. In this context, purchasing extra electricity to replace the nuclear plant becomes a potential liability, rather than the utility's normal regulatory arrangement of passing through all the costs to customers. By limiting commitment to a fractional replacement of Diablo Canyon, PG&E is managing a variety of risks.

Cost Recovery & Alternatives

As stated earlier, the proposal binds the signatory parties to support recovery of costs associated with the replacement GHG-free energy resources through non-bypassable charges. For CCAs, the non-bypassable charges in the first phase to 2025 are entirely for energy efficiency measures that are placed on the Public Purpose Program (PPP) surcharge. This surcharge is not part of the energy supply portion of the bill with which CCAs directly compete, and the PPP appears as an equal charge on the utility bill for both CCA customers and PG&E bundled customers. However, there is a more general problem regarding the extent to which CCAs are able to access their fair share of this funding to plan energy efficiency within their own jurisdictions.

During the second phase from 2025 to 2030, additional energy efficiency procurement would also be placed on this public goods surcharge; however, new renewable electrical generation might potentially increase the Power Charge Indifference Adjustment exit fee, which can directly affect the competitiveness of CCA energy supplies. Procurement of replacement electricity through the voluntary 55 percent Renewable Portfolio Standard after 2030 could have a similar effect.

"2.6 Cost Recovery: Under the Joint Proposal, PG&E makes a commitment to procure GHG-free energy resources through 2030 and beyond for the benefit of all customers in its service territory. PG&E's commitment to replace Diablo Canyon energy with GHG-free energy resources under tranche 2 (Section 2.3) and tranche 3 (Section 2.4) is therefore conditioned upon CPUC pre-approval that any procurement PG&E makes associated with the Joint Proposal will be subject to a non-bypassable cost allocation mechanism....In the Joint Proposal Application, PG&E will ask the CPUC to pre-approve the non-bypassable cost allocation mechanism and the Parties will support approval of this proposal. Costs associated with EE in Tranche 1 or Tranche 2 will be recovered through the PPP on a non-bypassable basis, consistent with existing recovery mechanisms for EE costs."

While the Joint Proposal only quantifies a commitment to replace a portion of the energy from Diablo Canyon, there is no firm upper limit to what energy might be procured, and it is not clear whether excess procurement is also covered by the terms of the proposal. The preamble, which is not part of the main body specified as the "AGREEMENT", states that the parties recognize that "additional procurement will be needed on a system-wide basis to replace the output of Diablo Canyon and the Parties envision that this issue will primarily be addressed through the

CPUC's IRP process." On the other hand, the section called the "Agreement" could be read as only specifying the three tranches. Yet, section 2.3.3 also states that "PG&E may seek CPUC approval of cost-effective contracts from GHG-free resources in excess of the 2,000 GWh target,"[55] leaving open the question of whether that extra procurement is intended to be covered by the proposal.

This lack of a firm upper limit to procurement of renewable electricity supplies on long-term contracts potentially creates unclear upside risk of the joint parties supporting non-bypassable charges that could be imposed for many years on CCAs. Possible alternatives for mitigating the risks to CCAs could include:

1) Changing the terms to ensure that procurement of any renewable electricity under the proposal is only for bundled customers rather than procurement for the entire service territory

2) Clarification that only the specified amount of energy resources are covered by the terms of Joint Proposal

3) Allowing CCAs to access their fair share of the public goods funds for energy efficiency

4) Provide periodic review to adjust the replacement portfolio in response to changing load forecast, departing load, and future policy changes.

There are several reasons why CCA customers should not have to pay for PG&E's replacement electricity supplies:

- CCA customers do not receive any benefit from the nuclear plant, and already have to pay toward its decommissioning; this would be adding yet another charge with no benefit for these customers
- CCA customers already pay into a number of additional funds (public goods, DWR bonds, Competition Transition Charge, reliability resources, and PCIA) but CCAs do not have control over, and in many cases do not directly benefit from, their share of these funds
- CCAs already routinely procure more than the minimum requirement for renewable energy, and should not be double billed—effectively punished—for having extra renewable energy
- While the Joint Proposal claims that procurement of replacement resources would be "for the benefit of all customers in its service territory," it does not specify how this would be the case. PG&E's energy procurement is normally only for its own bundled customers

[55] PG&E Diablo Canyon Draft Joint Proposal, p. 7.

- Setting the renewable energy procurement in terms of a percentage of PG&E's retail sales assures that the target adjusts to the risks of departing load between now and 2030
- PG&E would get cost recovery in any case, through their own bundled customers who are directly benefiting from the additional carbon-free energy
- The modest fractional replacement is already calibrated to mitigate against the risk of stranded costs by aiming to meet only future bundled customer demand, so CCA customers should be permitted to benefit from the avoided over-procurement

The requirement regarding cost shifting in the State's renewable energy law, SB 350, is a two way street, that is also supposed to protect CCA customers from having to pay stranded costs for the utility's renewable energy procurement.[56] Furthermore, the only resources associated with renewable energy non-bypassable charges in SB 350 are for "net costs of any incremental renewable energy integration resources procured by an electrical corporation"[57] that are specifically identified as such by the CPUC. The additional renewable energy voluntarily procured according to the Joint Proposal would likely not meet any of these requirements in SB 350:

- Only net costs are eligible to become non-bypassable charges, not the full costs
- Only net costs for additional integration of renewable energy are eligible, not the renewable energy itself
- This procurement would be voluntary by PG&E, and beyond what is required pursuant to SB 350

The main resource that PG&E proposes to procure for resource integration is energy storage. Payment for this integration is proposed either through the Transmission Access Charge (TAC) or the Cost Allocation Mechanism (CAM), or other similar CAM mechanisms. Either of these would then effectively become non-bypassable charges for most purposes. The CPUC should insure that there is no "net cost" to these integration resources, mainly by 1) not over-procuring energy storage beyond what is necessary to integrate the additional 5 percent renewable energy, 2) purchasing a balanced portfolio of resources that requires less integration service, 3) making sure that the storage is cost-effective in order to avoid future stranded costs, and 4) allowing CCAs to procure their own share of energy storage, as occurred in the energy storage proceeding decision.

The modest amount of clean energy in the Joint Proposal only backfills a portion of the loss of Diablo Canyon. A higher RPS in legislation would probably be the best vehicle for balancing out

[56] SB 350, Section 14: Public Utilities Code 365.2. The commission shall ensure that bundled retail customers of an electrical corporation do not experience any cost increases as a result of retail customers of an electrical corporation electing to receive service from other providers. The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load. http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

[57] Public Utilities Code, Section 454.51.(a) and 454.51.(c).

the rest, because—unlike the Joint Proposal— 1) it would be enforceable, 2) it would cover other utilities in Southern California that have also yet to make up for lost nuclear power, 3) it would cover departing load from CCAs which prevents eroding the size of PG&E's commitment, 4) it would limit stranded costs and resulting exit fees.

A provisional alternative, pending a legislated higher RPS, would be agreement through the CPUC that CCAs match or exceed PG&E's additional renewable energy targets during Tranches 2 and 3, which they are generally doing in any case.

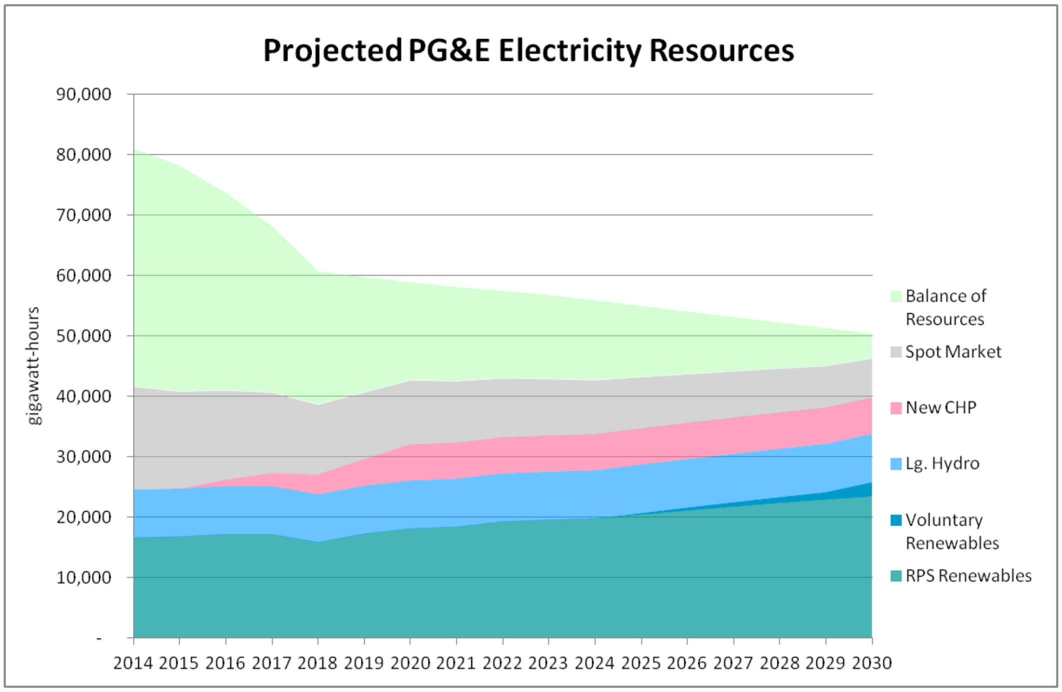
...

The further withdrawal of the state's investor owned utilities from the generation business potentially provides an opportunity for less conflict of commercial interest between utilities and customers who choose cleaner energy. Creating a new round of stranded costs would only prolong this conflict for decades into the future, and is unnecessary.

The long lead time of almost a decade before renewable energy procurement begins should allow great latitude to avoid excess procurement beyond the needs of bundled customers, and thus also avoid stranded costs.

Stranded costs simply mean that the CPUC allowed over-procurement beyond the need of PG&E, and allowed PG&E to spend more on those resources than what they will be worth. It should be incumbent upon the CPUC to avoid over-procurement and over-spending, and to insure that CCAs and their customers—who also happen to be PG&E distribution customers—are treated fairly.

Figure 12: PG&E's Diminishing Resource Gap



The chart above (Figure 12) adds a few elements of the energy resource portfolio that are not included in the graphs produced by PG&E's consultant (Figures 2 & 3):

Additional voluntary procurement of renewable energy in the Joint Proposal
Required procurement of new combined heat and power (CHP)
Spot market purchases that greatly decrease, but will probably remain necessary

This results in a much smaller gap for balance of resources. A significant margin of spot market and other—most likely natural gas—short term purchases are likely necessary as flexible padding to adjust to annual variations in hydropower. These flexible commitments also provide a portion of the resource portfolio that can be easily backed out in the case of more CCA departing load, or additional customer self-generation.

Appendix A: California Energy Demand Revised/Final Forecast 2016 - 2026, PG&E Planning Area, Mid Demand Baseline Case, Mid AAEE[58]

Form 1.1c - Statewide
California Energy Demand Revised/Final Forecast, 2016 - 2026, Mid Demand Baseline Case, Mid AAEE Savings
Electricity Deliveries to End Users by Agency (GWh)

Planning Area	Agency	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Average Annual Growth 2014 - 2026
PGE	Calaveras Public Power Agency	32	32	32	32	32	33	33	33	33	33	34	34	34	0.5%
	City of Alameda	351	351	350	352	354	356	357	359	362	365	366	368	369	0.4%
	City of Biggs	16	16	16	16	16	16	16	16	16	16	16	16	17	0.5%
	City of Gridley	36	36	36	36	36	36	36	36	37	37	37	37	37	0.2%
	City of Healdsburg	74	75	74	75	75	75	76	76	77	77	78	78	78	0.4%
	City of Hercules	12	12	12	12	12	12	12	12	12	12	12	12	12	0.0%
	City of Lodi	449	449	448	451	453	455	457	460	463	466	468	470	472	0.4%
	City of Lompoc	134	135	134	135	136	136	137	138	139	140	140	141	141	0.4%
	City of Palo Alto	962	962	960	965	970	974	979	985	992	999	1,004	1,008	1,012	0.4%
	City of San Francisco	1,021	1,021	1,019	1,025	1,030	1,034	1,039	1,045	1,053	1,061	1,065	1,070	1,074	0.4%
	City of Ukiah	109	109	109	109	110	110	111	112	112	113	114	114	115	0.4%
	Department of Water Resources (North)	837	1,614	1,614	1,614	1,614	1,614	1,614	1,614	1,614	1,614	1,614	1,614	1,614	5.6%
	Island Energy/Pittsburg	20	20	20	20	20	21	21	21	21	21	21	21	21	0.4%
	Lassen Municipal Utility District	132	132	131	132	133	133	134	135	136	137	137	138	138	0.4%
	Pacific Gas and Electric Company (Bundled)	75,421	72,855	71,879	71,660	71,209	70,917	70,753	70,619	70,669	70,648	70,447	70,188	69,911	-0.6%
	Pacific Gas and Electric Company (Direct Access)	9,520	9,520	9,520	9,520	9,520	9,520	9,520	9,520	9,520	9,520	9,520	9,520	9,520	0.0%
	Pacific Gas and Electric Company (Marin Clean Energy CCA)	1,255	1,701	1,802	1,793	1,781	1,774	1,768	1,761	1,756	1,750	1,744	1,739	1,733	2.7%
	Pacific Gas and Electric Company (Sonoma Clean Power CCA)	436	1,769	1,757	1,743	1,725	1,713	1,704	1,692	1,681	1,671	1,660	1,650	1,640	11.7%
	Plumas-Sierra Rural Electric Cooperation	149	149	149	150	150	151	152	153	154	155	156	156	157	0.4%
	Port of Oakland	48	48	48	49	49	49	49	49	50	50	50	51	51	0.5%
	Port of Stockton	20	20	19	20	20	20	20	20	20	20	20	20	21	0.4%
	Silicon Valley Power	3,024	3,026	3,018	3,036	3,052	3,064	3,079	3,097	3,120	3,142	3,156	3,169	3,181	0.4%
	Tuolumne County Public Power Agency	23	23	23	23	24	24	24	24	24	24	24	24	25	0.7%
	WAPA (CAISO)	1,493	1,493	1,490	1,498	1,506	1,512	1,519	1,528	1,540	1,551	1,558	1,564	1,570	0.4%
PGE Total		95,574	95,568	94,660	94,465	94,027	93,749	93,610	93,505	93,601	93,622	93,441	93,203	92,943	-0.2%

[58] docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN209989_20160127T094920_LSE_and_BA_Tables_Mid_Demand_Baseline__Mid_AAEE.xlsx

Appendix B: PG&E Planning Area Forecast Electricity Supply & Demand[59]

Form 1.2 - PGE Planning Area

California Energy Demand 2015 Revised - Mid Demand Case
Net Energy for Load (GWh)

Year	Total Consumption	Net Losses	Gross Generation	Non-PV Self Generation	PV	Total Private Supply	Net Energy for Load
1990	83,401	7,531	90,932	3,926	0	3,926	87,006
1991	82,954	7,528	90,482	3,778	0	3,778	86,704
1992	83,729	7,620	91,350	3,679	0	3,679	87,671
1993	84,500	7,574	92,074	4,521	0	4,521	87,553
1994	84,503	7,606	92,109	4,472	0	4,472	87,637
1995	85,218	7,674	92,892	4,511	0	4,511	88,381
1996	87,666	7,827	95,493	5,045	0	5,045	90,448
1997	90,719	8,122	98,841	5,126	0	5,126	93,715
1998	89,435	8,068	97,503	4,773	0	4,773	92,731
1999	85,902	7,704	93,606	4,746	0	4,747	88,859
2000	95,793	8,718	104,511	4,187	1	4,188	100,322
2001	91,613	8,299	99,912	4,341	3	4,344	95,568
2002	92,087	8,304	100,391	4,637	11	4,648	95,743
2003	93,116	8,332	101,449	5,097	28	5,125	96,324
2004	96,104	8,623	104,727	5,137	60	5,197	99,530
2005	96,919	8,685	105,604	5,056	97	5,153	100,450
2006	99,675	8,948	108,623	5,194	148	5,342	103,281
2007	103,099	9,218	112,317	5,185	224	5,409	106,908
2008	102,924	9,248	112,172	5,577	346	5,924	106,249
2009	100,973	9,048	110,022	5,425	512	5,937	104,084
2010	99,974	8,893	108,868	5,454	654	6,108	102,760
2011	100,855	8,927	109,782	5,567	878	6,445	103,337
2012	102,760	9,130	111,891	5,534	1,147	6,680	105,210
2013	102,940	9,148	112,089	5,374	1,516	6,889	105,199
2014	103,426	9,127	112,553	5,796	2,057	7,853	104,700
2015	104,245	9,086	113,331	5,896	2,731	8,626	104,705
2016	105,048	9,055	114,103	6,359	3,306	9,665	104,438
2017	106,234	9,099	115,333	6,519	3,778	10,297	105,035
2018	107,138	9,138	116,276	6,598	4,107	10,705	105,571
2019	107,948	9,166	117,114	6,671	4,458	11,129	105,985
2020	108,867	9,202	118,069	6,741	4,838	11,579	106,490
2021	109,953	9,247	119,201	6,804	5,288	12,092	107,109
2022	111,289	9,309	120,598	6,861	5,822	12,682	107,915
2023	112,638	9,365	122,002	6,909	6,440	13,349	108,654
2024	113,832	9,398	123,230	6,951	7,137	14,088	109,142
2025	115,027	9,426	124,453	6,986	7,900	14,886	109,567
2026	116,259	9,452	125,710	7,017	8,727	15,744	109,966

[59] PGE Mid Demand Case, Updated for Adoption SUPERCEDES TN 207249, IEPR 2016 Adoption 01-27-2016 Business Meeting, docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN210043_20160127T151452_PGE_Mid_Demand_Case.xls

Appendix C1: California Electric System Power for 2011[60]

2011 Total System Power in Gigawatt Hours						
Fuel Type	California In-State Generation (GWh)	Percent of California In-State Generation	Northwest Imports (GWh)	Southwest Imports (GWh)	California Power Mix (GWh)	Percent California Power Mix
Coal	3,120	1.6%	692	20,158	23,969	8.2%
Large Hydro	36,583	18.2%	74	1,430	38,088	13.0%
Natural Gas	91,233	45.4%	215	12,129	103,576	35.3%
Nuclear	36,666	18.2%	-	8,031	44,697	15.2%
Oil	36	0.0%	-	-	36	0.0%
Other	13	0.0%	-	-	13	0.0%
Renewables	33,336	16.6%	5,398	2,715	41,448	14.1%
Biomass	5,807	2.9%	419	-	6,226	2.1%
Geothermal	12,685	6.3%	-	574	13,259	4.5%
Small Hydro	6,148	3.1%	6	-	6,154	2.1%
Solar	1,097	0.5%	29	108	1,234	0.4%
Wind	7,598	3.8%	4,945	2,032	14,575	5.0%
Unspecified Sources of Power	N/A	N/A	28,840	12,985	41,825	14.2%
Total	200,987	100.0%	35,219	57,446	293,652	100.0%

Source: QFER and SB 1305 Reporting Requirements. In-state generation is reported generation from units 1 MW and larger

[60] Total System Power 2011, California Energy Commission, http://energyalmanac.ca.gov/electricity/system_power/2011_total_system_power.html

Appendix C2: California Electric System Power for 2012[61]

2012 Total System Power in Gigawatt Hours						
Fuel Type	California In-State Generation (GWh)	Percent of California In-State Generation	Northwest Imports (GWh)	Southwest Imports (GWh)	California Power Mix (GWh)	Percent California Power Mix
Coal	1,580	0.8%	561	20,545	22,685	7.5%
Large Hydro	23,202	11.7%	12	1,698	24,913	8.3%
Natural Gas	121,716	61.1%	37	9,242	130,995	43.4%
Nuclear	18,491	9.3%	-	8,763	27,254	9.0%
Oil	90	0.0%	-	-	90	0.0%
Other	14	0.0%	-	-	14	0.0%
Renewables	34,007	17.1%	9,484	3,024	46,515	15.4%
Biomass	6,031	3.0%	1,025	23	7,079	2.3%
Geothermal	12,733	6.4%	-	497	13,230	4.4%
Small Hydro	4,257	2.1%	204	-	4,461	1.5%
Solar	1,834	0.9%	-	775	2,609	0.9%
Wind	9,152	4.6%	8,254	1,729	19,135	6.3%
Unspecified Sources of Power	N/A	N/A	29,376	20,124	49,500	16.4%
Total	199,101	100.0%	39,470	63,396	301,966	100.0%

Source: QFER and SB 1305 Reporting Requirements. In-state generation is reported generation from units 1 MW and larger
Contact: Michael Nyberg, Mnyberg@energy.ca.gov
Data as of August 1, 2013

[61] Total System Power 2012, California Energy Commission, http://energyalmanac.ca.gov/electricity/system_power/2012_total_system_power.html

Appendix D1: California's Climate Scoping Plan Measures for the Electricity Sector[62]

Table 7: Energy Efficiency Recommendation - Electricity
($MMTCO_2E$ in 2020)

Measure No.	Measure Description	Reductions
E-1	Energy Efficiency (32,000 GWh of Reduced Demand) • Increased Utility Energy Efficiency Programs • More Stringent Building & Appliance Standards • Additional Efficiency and Conservation Programs	15.2
E-2	Increase Combined Heat and Power Use by 30,000 GWh	6.7
	Total	**21.9**

Table 9: Renewables Portfolio Standard Recommendation
($MMTCO_2E$ in 2020)

Measure No.	Measure Description	Reductions
E-3	Achieve a 33% renewables mix by 2020	21.3
	Total	**21.3**

Table 14: Million Solar Roofs Recommendation
($MMTCO_2E$ in 2020)

Measure No.	Measure Description	Reductions
E-4	Million Solar Roofs (including California Solar Initiative, New Solar Homes Partnership and solar programs of publicly owned utilities) • Target of 3000 MW Total Installation by 2020	2.1
	Total	**2.1**

The major Scoping Plan measures for the electric sector aimed to reduce GHG emissions in the electricity sector by 45 million metric tons of carbon dioxide equivalent (MMTCO2E) relative to business as usual. Peak emissions in the electricity sector reached 122 million metric tons in 2001, and decreased to 88 million metric tons by 2014 (see next table in Appendix D2)

[62] Climate Change Scoping Plan, California Air Resources Board, December 2008, pp. 44, 46, 53 https://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm

Appendix D2: California Greenhouse Gas Inventory for the Electricity Sector[63]

California Environmental Protection Agency
Air Resources Board

California Greenhouse Gas Inventory for 2000-2014
— by Category as Defined in the 2008 Scoping Plan

million tonnes of CO2 equivalent - (based upon IPCC Fourth Assessment Report's 100-yr Global Warming Potentials,

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Electric Power	**104.84**	**122.00**	**108.64**	**112.61**	**115.20**	**107.85**	**104.53**	**113.93**	**120.14**	**101.37**	**90.34**	**88.06**	**95.09**	**89.65**	**88.24**
In-State Generation	***58.94***	***62.98***	***49.68***	***48.05***	***49.15***	***45.05***	***49.85***	***54.12***	***54.32***	***53.33***	***46.75***	***41.20***	***51.02***	***49.47***	***51.72***
Natural Gas	50.92	55.46	42.17	40.92	42.40	38.11	43.07	47.12	48.02	46.08	40.59	35.92	45.77	45.66	46.43
Other Fuels	6.84	6.36	6.36	5.98	5.59	5.77	5.63	5.85	5.15	5.90	5.05	4.03	4.44	2.91	4.40
Fugitive and Process Emissions	1.17	1.16	1.15	1.15	1.16	1.16	1.15	1.16	1.14	1.35	1.10	1.25	0.82	0.90	0.90
Imported Electricity	***45.90***	***59.02***	***58.96***	***64.56***	***66.04***	***62.80***	***54.68***	***59.81***	***65.82***	***48.04***	***43.59***	***46.86***	***44.07***	***40.17***	***36.51***
Unspecified Imports	14.27	25.42	26.92	32.05	32.92	30.01	27.95	32.73	37.92	14.99	13.45	15.52	17.48	11.82	13.44
Specified Imports	31.64	33.59	32.04	32.51	33.13	32.79	26.73	27.08	27.90	33.05	30.14	31.34	26.59	28.35	23.07

63 https://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_scopingplan_2000-14.pdf

Appendix E1: Statewide Mid-Case Forecast for Electricity Demand

Form 1.2 - STATEWIDE

California Energy Demand 2015 Revised - Mid Demand Case
Net Energy for Load (GWh)

Year	Total Consumption	Net Losses	Gross Generation	Non-PV Self Generation	PV	Total Private Supply	Net Energy for Load
1990	227,606	18,431	246,037	8,234	0	8,234	237,802
1991	221,209	18,060	239,268	8,266	0	8,266	231,002
1992	224,967	18,404	243,371	8,081	0	8,081	235,290
1993	224,052	18,208	242,260	8,963	0	8,963	233,297
1994	227,424	18,373	245,798	9,289	1	9,290	236,507
1995	227,595	18,489	246,085	9,318	2	9,319	236,765
1996	235,654	19,014	254,668	9,849	3	9,851	244,817
1997	245,998	19,988	265,986	9,988	3	9,991	255,996
1998	239,998	19,477	259,475	9,620	4	9,623	249,851
1999	227,806	18,351	246,157	9,679	5	9,684	236,473
2000	261,037	21,182	282,219	8,856	7	8,864	273,355
2001	251,217	20,289	271,506	9,531	13	9,544	261,961
2002	256,379	20,479	276,859	10,928	34	10,961	265,897
2003	261,857	20,818	282,675	11,974	73	12,047	270,628
2004	271,144	21,529	292,673	12,038	141	12,179	280,494
2005	272,929	21,719	294,648	12,040	211	12,250	282,398
2006	281,612	22,406	304,018	12,199	303	12,502	291,516
2007	285,424	22,711	308,134	12,226	430	12,655	295,479
2008	285,468	22,854	308,323	12,626	669	13,295	295,028
2009	277,243	22,160	299,402	12,424	975	13,400	286,002
2010	272,658	21,642	294,300	12,634	1,279	13,913	280,387
2011	275,346	21,766	297,113	12,765	1,751	14,516	282,597
2012	280,836	22,254	303,089	12,552	2,391	14,944	288,146
2013	278,921	22,050	300,971	12,712	3,246	15,957	285,014
2014	280,536	22,201	302,737	13,014	4,502	17,516	285,221
2015	284,343	22,185	306,528	13,230	6,003	19,233	287,294
2016	287,256	22,201	309,457	14,197	7,398	21,595	287,862
2017	289,918	22,279	312,197	14,584	8,569	23,153	289,043
2018	291,961	22,344	314,304	14,742	9,466	24,209	290,096
2019	293,964	22,409	316,373	14,870	10,405	25,274	291,098
2020	296,244	22,498	318,742	14,994	11,345	26,339	292,403
2021	298,805	22,596	321,402	15,110	12,489	27,598	293,803
2022	302,315	22,752	325,067	15,216	13,841	29,057	296,010
2023	305,524	22,870	328,394	15,311	15,391	30,702	297,691
2024	308,579	22,961	331,541	15,393	17,118	32,511	299,030
2025	311,848	23,053	334,901	15,466	19,021	34,487	300,414
2026	314,970	23,124	338,094	15,531	21,085	36,616	301,479

Table shows statewide self-generation from solar photovoltaics (PV) reaching over 21,000 gigawatt-hours by 2026, increasing at the rate of about 2,000 gigawatt-hours per year. By 2030, at this rate, so-called "rooftop solar" should add another 8,000 gigawatt-hours, reaching 29,000 gigawatt-hours. That will amount to approximately 10% of the state's electricity generation, once additional energy efficiency is accounted for.

Appendix E2: Statewide Additional Achievable Energy Efficiency
SB 350 Baseline Retail Sales with No AAEE[64]

Form 1.1c - Statewide
California Energy Demand Updated Forecast, 2015 - 2025, Mid Demand Baseline Case, No AAEE Savings
Electricity Deliveries to End Users by Agency (GWh)

Planning Area	Agency	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Average Annual Growth 2014 - 2025
PGE	Calaveras Public Power Agency	33	33	33	34	34	35	35	35	36	36	37	37	38	1.3%
	Central Valley Project	2,516	2,358	2,368	2,395	2,424	2,451	2,470	2,488	2,506	2,527	2,543	2,559	2,577	0.8%
	City of Alameda	398	401	404	408	413	418	423	429	434	440	445	449	454	1.1%
	City of Biggs	17	17	17	17	17	17	18	18	18	18	18	18	18	0.5%
	City of Gridley	35	36	36	36	37	37	38	38	39	39	40	40	41	1.2%
	City of Healdsburg	75	76	76	77	78	79	80	81	82	83	84	85	86	1.1%
	City of Hercules	15	15	16	16	16	16	16	16	16	17	17	17	17	1.1%
	City of Lodi	436	440	443	447	453	457	462	468	472	477	481	485	490	1.0%
	City of Lompoc	130	132	133	134	135	137	139	141	143	145	147	149	150	1.2%
	City of Palo Alto	925	932	939	948	960	970	980	990	999	1,008	1,016	1,023	1,031	0.9%
	City of Redding	766	774	780	787	798	808	821	833	845	858	869	880	891	1.3%
	City of Roseville	1,179	1,191	1,199	1,210	1,225	1,238	1,254	1,270	1,285	1,301	1,314	1,327	1,341	1.1%
	City of San Francisco	1,017	1,026	1,031	1,040	1,051	1,060	1,068	1,076	1,084	1,100	1,112	1,120	1,132	0.9%
	City of Shasta Lake	188	191	192	193	194	195	196	197	198	198	199	199	199	0.4%
	City of Ukiah	106	107	108	109	111	112	114	115	117	119	120	121	123	1.3%
	Island Energy/Pittsburg	28	28	28	28	29	29	29	29	30	30	30	30	30	0.6%
	Lassen Municipal Utility District	131	133	134	135	137	138	141	143	145	148	150	152	154	1.3%
	Merced Irrigation District	449	453	456	460	465	468	472	475	478	481	483	486	488	0.7%
	Modesto Irrigation District	2,499	2,527	2,545	2,567	2,594	2,619	2,651	2,681	2,709	2,737	2,762	2,786	2,811	1.0%
	Pacific Gas and Electric Company (Bundled)	76,602	76,270	75,354	76,008	77,136	78,167	79,430	80,653	81,805	83,033	84,133	85,165	86,270	1.1%
	Pacific Gas and Electric Company (Direct Access)	8,868	9,085	9,303	9,520	9,520	9,520	9,520	9,520	9,520	9,520	9,520	9,520	9,520	0.4%
	Pacific Gas and Electric Company (Marin Clean Energy CCA)	1,043	1,580	1,617	1,614	1,611	1,607	1,604	1,601	1,598	1,594	1,591	1,588	1,585	0.0%
	Pacific Gas and Electric Company (Sonoma Clean Power CCA)	-	436	1,770	1,774	1,777	1,781	1,784	1,788	1,791	1,795	1,799	1,802	1,806	13.8%
	Plumas-Sierra Rural Electric Cooperation	129	130	131	132	134	136	138	140	142	144	146	148	150	1.3%
	Port of Oakland	46	46	47	47	47	48	48	48	48	49	50	50	50	0.8%
	Port of Stockton	19	19	19	20	20	20	20	20	20	21	21	21	21	0.9%
	Silicon Valley Power	2,994	3,019	3,041	3,069	3,102	3,127	3,153	3,174	3,194	3,215	3,230	3,245	3,261	0.7%
	Tuolumne County Public Power Agency	25	25	25	26	26	26	26	27	27	27	27	28	28	1.0%
	Turlock Irrigation District	2,040	2,065	2,081	2,101	2,126	2,150	2,179	2,208	2,235	2,264	2,290	2,314	2,341	1.1%
PGE Total		102,709	103,545	104,326	105,351	106,670	107,866	109,309	110,702	112,016	113,424	114,674	115,844	117,103	1.1%
SMUD	Sacramento Municipal Utility District	10,467	10,624	10,725	10,814	10,950	11,076	11,241	11,396	11,554	11,724	11,888	12,047	12,208	1.3%
SCE	Anza Electric Cooperative, Inc.	48	49	49	50	50	51	52	54	55	56	57	58	59	1.7%
	Azusa Light & Water	266	268	270	272	275	277	280	284	287	290	293	296	299	1.0%
	Bear Valley Electric Service	129	130	131	132	134	135	138	140	143	145	148	150	152	1.4%
	City of Anaheim	2,388	2,396	2,412	2,434	2,462	2,485	2,513	2,541	2,569	2,598	2,626	2,651	2,678	1.0%
	City of Banning	138	140	140	141	142	143	144	146	148	150	151	153	154	0.9%
	City of Colton	344	346	348	351	355	358	362	367	371	375	379	383	387	1.0%
	City of Corona	75	75	76	77	78	78	79	79	80	80	81	81	82	0.8%
	City of Rancho Cucamonga	74	74	74	75	75	76	77	77	78	79	79	80	80	0.7%
	City of Riverside	2,140	2,151	2,164	2,183	2,208	2,231	2,260	2,290	2,319	2,349	2,377	2,403	2,431	1.1%
	City of Vernon	1,137	1,138	1,148	1,155	1,161	1,165	1,170	1,173	1,177	1,181	1,184	1,187	1,191	0.4%
	Metropolitan Water District	1,985	1,736	1,715	1,695	1,675	1,674	1,674	1,673	1,673	1,674	1,675	1,676	1,678	-0.3%
	Moreno Valley Utilities	122	123	124	125	126	128	129	131	132	134	136	137	139	1.1%
	Southern California Edison Company (Bundled)	72,545	73,204	73,778	74,536	75,484	76,327	77,390	78,484	79,577	80,664	81,704	82,677	83,704	1.2%
	Southern California Edison Company (Direct Access)	11,903	11,710	11,710	11,710	11,710	11,710	11,710	11,710	11,710	11,710	11,710	11,710	11,710	0.0%
	Valley Electric Association, Inc.	10	10	10	10	10	10	10	10	10	10	10	10	10	0.0%
	Victorville Municipal	74	74	75	75	75	76	76	76	76	77	77	77	77	0.4%
SCE Total		93,378	93,624	94,224	95,021	96,020	96,924	98,064	99,235	100,405	101,572	102,687	103,729	104,831	1.0%
LADWP	Los Angeles Department of Water and Power	22,859	22,857	22,929	23,031	23,179	23,309	23,560	23,874	24,193	24,519	24,817	25,106	25,405	1.0%
BUGL	City of Burbank	1,057	1,053	1,058	1,065	1,074	1,082	1,092	1,105	1,118	1,130	1,139	1,147	1,156	0.9%
	City of Glendale	1,103	1,099	1,105	1,112	1,122	1,131	1,144	1,160	1,174	1,189	1,199	1,209	1,220	1.0%
BUGL Total		2,160	2,152	2,164	2,177	2,196	2,213	2,237	2,265	2,292	2,319	2,338	2,356	2,376	0.9%
PASD	City of Pasadena	1,128	1,115	1,115	1,117	1,122	1,126	1,133	1,144	1,157	1,170	1,185	1,198	1,211	0.8%
DWR	Department of Water Resources	5,923	7,176	7,176	7,176	7,176	7,176	7,176	7,176	7,176	7,176	7,176	7,176	7,176	0.0%
SDGE	San Diego Gas and Electric Company (Bundled)	16,459	16,661	16,745	16,859	17,087	17,297	17,591	17,829	18,052	18,281	18,486	18,692	18,907	1.2%
	San Diego Gas and Electric Company (Direct Access)	3,399	3,441	3,458	3,482	3,529	3,562	3,562	3,562	3,562	3,562	3,562	3,562	3,562	0.3%
SDGE Total		19,858	20,102	20,203	20,341	20,616	20,859	21,153	21,391	21,614	21,843	22,048	22,254	22,469	1.0%
IID	Imperial Irrigation District	3,363	3,428	3,495	3,563	3,643	3,725	3,820	3,921	3,914	3,980	4,061	4,140	4,221	1.9%
OTHER	California Pacific Electric Company, LLC	556	556	556	556	556	556	556	556	556	556	556	556	556	0.0%
	City of Needles	33	33	33	33	33	33	33	33	33	33	33	33	33	0.0%
	Kirkwood Meadows Public Utility District	7	7	7	7	7	7	7	7	7	7	7	7	7	0.0%
	PacifiCorp	788	800	806	812	818	824	830	836	843	849	856	849	856	0.6%
	Surprise Valley Electrification Corporation	104	105	105	106	106	106	107	107	108	108	109	108	109	0.3%
	Truckee-Donner Public Utility District	147	149	151	152	154	155	157	158	160	161	163	161	163	0.8%
OTHER Total		1,636	1,650	1,658	1,666	1,674	1,682	1,690	1,698	1,706	1,715	1,723	1,715	1,723	0.4%
Statewide Total		263,481	266,273	268,015	270,257	273,246	275,956	279,383	282,802	286,027	289,442	292,597	295,565	298,723	1.1%
Total Pumping Load		8,739	9,690	9,672	9,661	9,651	9,659	9,665	9,670	9,676	9,684	9,690	9,697	9,704	0.0%
Total Statewide Retail Deliveries excluding pumping		254,742	256,583	258,343	260,596	263,595	266,297	269,718	273,132	276,351	279,758	282,907	285,868	289,019	1.1%

This table includes retail sales and other deliveries only measured at the customer level. Losses and consumption served by self-generation are excluded. Table developed based on actual 2013 data.
Table includes sales from entities outside of California control areas. Thus, total sales in row 71 are higher than state totals given in Form 1.1b.
Pacific Gas and Electric Company (Direct Access) includes BART.

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64 California Energy Demand 2015-2025 Final Forecast LSE and Balancing Authority Forecasts, http://www.energy.ca.gov/2014_energypolicy/documents/demand_forecast_cmf/LSE_and_BA/

Appendix E2: Statewide Additional Achievable Energy Efficiency
SB 350 Baseline Retail Sales with AAEE

Form 1.1c - Statewide
California Energy Demand Updated Forecast, 2015 - 2025, Mid Demand Baseline Case, Mid AAEE Savings
Electricity Deliveries to End Users by Agency (GWh)

Planning Area	Agency	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Average Annual Growth 2014 - 2025
PGE	Calaveras Public Power Agency	33	33	33	34	34	35	35	35	36	36	37	37	38	1.3%
	Central Valley Project	2,516	2,358	2,368	2,395	2,424	2,451	2,470	2,488	2,506	2,527	2,543	2,559	2,577	0.8%
	City of Alameda	398	401	404	408	413	418	423	429	434	440	445	449	454	1.1%
	City of Biggs	17	17	17	17	17	17	18	18	18	18	18	18	18	0.5%
	City of Gridley	35	36	36	36	37	37	38	38	39	39	40	40	41	1.2%
	City of Healdsburg	75	76	76	77	78	79	80	81	82	83	84	85	86	1.1%
	City of Hercules	15	15	16	16	16	16	16	16	16	17	17	17	17	1.1%
	City of Lodi	436	440	443	447	453	457	462	468	472	477	481	485	490	1.0%
	City of Lompoc	130	132	133	134	135	137	139	141	143	145	147	149	150	1.2%
	City of Palo Alto	925	932	939	948	960	970	980	990	999	1,008	1,016	1,023	1,031	0.9%
	City of Redding	766	774	780	787	798	808	821	833	845	858	869	880	891	1.3%
	City of Roseville	1,179	1,191	1,199	1,210	1,225	1,238	1,254	1,270	1,285	1,301	1,314	1,327	1,341	1.1%
	City of San Francisco	1,017	1,026	1,031	1,040	1,051	1,060	1,068	1,076	1,084	1,100	1,112	1,120	1,132	0.9%
	City of Shasta Lake	188	191	192	193	194	195	196	197	198	198	199	199	199	0.4%
	City of Ukiah	106	107	108	109	111	112	114	115	117	119	120	121	123	1.3%
	Island Energy/Pittsburg	28	28	28	28	29	29	29	29	30	30	30	30	30	0.6%
	Lassen Municipal Utility District	131	133	134	135	137	138	141	143	145	148	150	152	154	1.3%
	Merced Irrigation District	449	453	456	460	465	468	472	475	478	481	483	486	488	0.7%
	Modesto Irrigation District	2,499	2,527	2,545	2,567	2,594	2,619	2,651	2,681	2,709	2,737	2,762	2,786	2,811	1.0%
	Pacific Gas and Electric Company (Bundled)	76,602	76,124	74,552	74,421	74,784	75,122	75,621	76,163	76,585	77,042	77,314	77,515	77,692	0.2%
	Pacific Gas and Electric Company (Direct Access)	8,868	9,068	9,203	9,321	9,230	9,149	9,064	8,990	8,913	8,833	8,748	8,665	8,573	-0.5%
	Pacific Gas and Electric Company (Marin Clean Energy CCA)	1,043	1,577	1,600	1,580	1,561	1,545	1,527	1,512	1,496	1,479	1,462	1,445	1,427	-0.9%
	Pacific Gas and Electric Company (Sonoma Clean Power CCA)	-	435	1,751	1,737	1,723	1,711	1,699	1,688	1,677	1,665	1,653	1,640	1,626	12.7%
	Plumas-Sierra Rural Electric Cooperation	129	130	131	132	134	136	138	140	142	144	146	148	150	1.3%
	Port of Oakland	46	46	47	47	47	48	48	48	48	49	50	50	50	0.8%
	Port of Stockton	19	19	19	20	20	20	20	20	20	21	21	21	21	0.9%
	Silicon Valley Power	2,994	3,019	3,041	3,069	3,102	3,127	3,153	3,174	3,194	3,215	3,230	3,245	3,261	0.7%
	Tuolumne County Public Power Agency	25	25	25	26	26	26	26	27	27	27	27	28	28	1.0%
	Turlock Irrigation District	2,040	2,065	2,081	2,101	2,126	2,150	2,179	2,208	2,235	2,264	2,290	2,314	2,341	1.1%
PGE Total		102,709	103,378	103,388	103,495	103,924	104,318	104,881	105,493	105,973	106,502	106,808	107,035	107,241	0.3%
SMUD	Sacramento Municipal Utility District	10,467	10,624	10,725	10,814	10,950	11,076	11,241	11,396	11,554	11,724	11,888	12,047	12,208	1.3%
SCE	Anza Electric Cooperative, Inc.	48	49	49	50	50	51	52	54	55	56	57	58	59	1.7%
	Azusa Light & Water	266	268	270	272	275	277	280	284	287	290	293	296	299	1.0%
	Bear Valley Electric Service	129	130	131	132	134	135	138	140	143	145	148	150	152	1.4%
	City of Anaheim	2,388	2,396	2,412	2,434	2,462	2,485	2,513	2,541	2,569	2,598	2,626	2,651	2,678	1.0%
	City of Banning	138	140	140	141	142	143	144	146	148	150	151	153	154	0.9%
	City of Colton	344	346	348	351	355	358	362	367	371	375	379	383	387	1.0%
	City of Corona	75	75	76	77	78	78	79	79	80	80	81	81	82	0.8%
	City of Rancho Cucamonga	74	74	74	75	75	76	77	77	78	79	79	80	80	0.7%
	City of Riverside	2,140	2,151	2,164	2,183	2,208	2,231	2,260	2,290	2,319	2,349	2,377	2,403	2,431	1.1%
	City of Vernon	1,137	1,138	1,148	1,155	1,161	1,165	1,170	1,173	1,177	1,181	1,184	1,187	1,191	0.4%
	Metropolitan Water District	1,985	1,736	1,715	1,695	1,675	1,674	1,674	1,673	1,673	1,674	1,675	1,676	1,678	-0.3%
	Moreno Valley Utilities	122	123	124	125	126	128	129	131	132	134	136	137	139	1.1%
	Southern California Edison Company (Bundled)	72,545	73,027	72,784	72,584	72,620	72,722	73,030	73,442	73,802	74,145	74,369	74,510	74,614	0.2%
	Southern California Edison Company (Direct Access)	11,903	11,682	11,552	11,403	11,266	11,157	11,050	10,958	10,860	10,764	10,659	10,553	10,438	-1.0%
	Valley Electric Association, Inc.	10	10	10	10	10	10	10	10	10	10	10	10	10	0.0%
	Victorville Municipal	74	74	75	75	75	76	76	76	76	77	77	77	77	0.4%
SCE Total		93,378	93,418	93,072	92,762	92,712	92,765	93,044	93,441	93,780	94,106	94,301	94,406	94,469	0.1%
LADWP	Los Angeles Department of Water and Power	22,859	22,857	22,929	23,031	23,179	23,309	23,560	23,874	24,193	24,519	24,817	25,106	25,405	1.0%
BUGL	City of Burbank	1,057	1,053	1,058	1,065	1,074	1,082	1,092	1,105	1,118	1,130	1,139	1,147	1,156	0.9%
	City of Glendale	1,103	1,099	1,105	1,112	1,122	1,131	1,144	1,160	1,174	1,189	1,199	1,209	1,220	1.0%
BUGL Total		2,160	2,152	2,164	2,177	2,196	2,213	2,237	2,265	2,292	2,319	2,338	2,356	2,376	0.9%
PASD	City of Pasadena	1,128	1,115	1,115	1,117	1,122	1,126	1,133	1,144	1,157	1,170	1,185	1,198	1,211	0.8%
DWR	Department of Water Resources	5,923	7,176	7,176	7,176	7,176	7,176	7,176	7,176	7,176	7,176	7,176	7,176	7,176	0.0%
SDGE	San Diego Gas and Electric Company (Bundled)	16,459	16,638	16,540	16,446	16,478	16,533	16,648	16,726	16,772	16,813	16,819	16,826	16,818	0.1%
	San Diego Gas and Electric Company (Direct Access)	3,399	3,436	3,416	3,397	3,403	3,405	3,371	3,342	3,309	3,276	3,241	3,206	3,168	-0.7%
SDGE Total		19,858	20,074	19,956	19,843	19,881	19,937	20,019	20,068	20,082	20,089	20,060	20,032	19,986	0.0%
IID	Imperial Irrigation District	3,363	3,428	3,495	3,563	3,643	3,725	3,820	3,921	3,914	3,980	4,061	4,140	4,221	1.9%
OTHER	California Pacific Electric Company, LLC	556	556	556	556	556	556	556	556	556	556	556	556	556	0.0%
	City of Needles	33	33	33	33	33	33	33	33	33	33	33	33	33	0.0%
	Kirkwood Meadows Public Utility District	7	7	7	7	7	7	7	7	7	7	7	7	7	0.0%
	PacifiCorp	788	800	806	812	818	824	830	836	843	849	856	849	856	0.6%
	Surprise Valley Electrification Corporation	104	105	105	106	106	106	107	107	108	108	109	108	109	0.3%
	Truckee-Donner Public Utility District	147	149	151	152	154	155	157	158	160	161	163	161	163	0.8%
OTHER Total		1,636	1,650	1,658	1,666	1,674	1,682	1,690	1,698	1,706	1,715	1,723	1,715	1,723	0.4%
Statewide Total		263,481	265,872	265,678	265,643	266,456	267,328	268,801	270,475	271,826	273,299	274,357	275,210	276,015	0.3%
Total Pumping Load		8,739	9,690	9,672	9,661	9,651	9,659	9,665	9,670	9,676	9,684	9,690	9,697	9,704	0.0%
Total Statewide Retail Deliveries excluding pumping		254,742	256,183	256,006	255,983	256,806	257,669	259,137	260,805	262,151	263,616	264,667	265,514	266,312	0.4%

This table includes retail sales and other deliveries only measured at the customer level. Losses and consumption served by self-generation are excluded. Table developed based on actual 2013 data.
Table includes sales from entities outside of California control areas.
Pacific Gas and Electric Company (Direct Access) includes BART.

Appendix E3: Statewide Additional Achievable Energy Efficiency
SB 350 Baseline Retail Sales Calculation for AAEE

Form 1.1c - Statewide
California Energy Demand Updated Forecast, 2015 - 2025, Mid Demand Baseline Case, Mid AAEE Savings
Electricity Deliveries to End Users by Agency (GWh)

Planning Area	Agency	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PGE	Calaveras Public Power Agency	-	-	-	-	-	-	-	-	-	-	-	-	-
	Central Valley Project	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Alameda	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Biggs	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Gridley	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Healdsburg	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Hercules	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Lodi	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Lompoc	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Palo Alto	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Redding	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Roseville	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of San Francisco	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Shasta Lake	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Ukiah	-	-	-	-	-	-	-	-	-	-	-	-	-
	Island Energy/Pittsburg	-	-	-	-	-	-	-	-	-	-	-	-	-
	Lassen Municipal Utility District	-	-	-	-	-	-	-	-	-	-	-	-	-
	Merced Irrigation District	-	-	-	-	-	-	-	-	-	-	-	-	-
	Modesto Irrigation District	-	-	-	-	-	-	-	-	-	-	-	-	-
	Pacific Gas and Electric Company (Bundled)	-	(146)	(803)	(1,586)	(2,353)	(3,045)	(3,809)	(4,491)	(5,220)	(5,991)	(6,819)	(7,649)	(8,579)
	Pacific Gas and Electric Company (Direct Access)	-	(17)	(99)	(199)	(290)	(371)	(456)	(530)	(607)	(687)	(772)	(855)	(947)
	Pacific Gas and Electric Company (Marin Clean Energy CCA)	-	(3)	(17)	(34)	(49)	(63)	(77)	(89)	(102)	(115)	(129)	(143)	(158)
	Pacific Gas and Electric Company (Sonoma Clean Power CCA)	-	(1)	(19)	(37)	(54)	(69)	(86)	(100)	(114)	(130)	(146)	(162)	(180)
	Plumas-Sierra Rural Electric Cooperation	-	-	-	-	-	-	-	-	-	-	-	-	-
	Port of Oakland	-	-	-	-	-	-	-	-	-	-	-	-	-
	Port of Stockton	-	-	-	-	-	-	-	-	-	-	-	-	-
	Silicon Valley Power	-	-	-	-	-	-	-	-	-	-	-	-	-
	Tuolumne County Public Power Agency	-	-	-	-	-	-	-	-	-	-	-	-	-
	Turlock Irrigation District	-	-	-	-	-	-	-	-	-	-	-	-	-
PGE Total		-	(167)	(938)	(1,856)	(2,746)	(3,548)	(4,428)	(5,209)	(6,043)	(6,922)	(7,866)	(8,809)	(9,862)
SMUD	Sacramento Municipal Utility District	-	-	-	-	-	-	-	-	-	-	-	-	-
SCE	Anza Electric Cooperative, Inc.	-	-	-	-	-	-	-	-	-	-	-	-	-
	Azusa Light & Water	-	-	-	-	-	-	-	-	-	-	-	-	-
	Bear Valley Electric Service	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Anaheim	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Banning	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Colton	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Corona	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Rancho Cucamonga	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Riverside	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Vernon	-	-	-	-	-	-	-	-	-	-	-	-	-
	Metropolitan Water District	-	-	-	-	-	-	-	-	-	-	-	-	-
	Moreno Valley Utilities	-	-	-	-	-	-	-	-	-	-	-	-	-
	Southern California Edison Company (Bundled)	-	(177)	(994)	(1,952)	(2,864)	(3,605)	(4,360)	(5,042)	(5,775)	(6,519)	(7,335)	(8,167)	(9,090)
	Southern California Edison Company (Direct Access)	-	(28)	(158)	(307)	(444)	(553)	(660)	(752)	(850)	(946)	(1,051)	(1,157)	(1,272)
	Valley Electric Association, Inc.	-	-	-	-	-	-	-	-	-	-	-	-	-
	Victorville Municipal	-	-	-	-	-	-	-	-	-	-	-	-	-
SCE Total		-	(206)	(1,152)	(2,259)	(3,308)	(4,159)	(5,020)	(5,794)	(6,625)	(7,466)	(8,386)	(9,323)	(10,362)
LADWP	Los Angeles Department of Water and Power	-	-	-	-	-	-	-	-	-	-	-	-	-
BUGL	City of Burbank	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Glendale	-	-	-	-	-	-	-	-	-	-	-	-	-
BUGL Total		-	-	-	-	-	-	-	-	-	-	-	-	-
PASD	City of Pasadena	-	-	-	-	-	-	-	-	-	-	-	-	-
DWR	Department of Water Resources	-	-	-	-	-	-	-	-	-	-	-	-	-
SDGE	San Diego Gas and Electric Company (Bundled)	-	(23)	(205)	(413)	(609)	(764)	(943)	(1,103)	(1,280)	(1,468)	(1,667)	(1,866)	(2,089)
	San Diego Gas and Electric Company (Direct Access)	-	(5)	(42)	(85)	(126)	(157)	(191)	(220)	(253)	(286)	(321)	(356)	(394)
SDGE Total		-	(28)	(247)	(498)	(735)	(922)	(1,134)	(1,323)	(1,532)	(1,754)	(1,988)	(2,222)	(2,483)
IID	Imperial Irrigation District	-	-	-	-	-	-	-	-	-	-	-	-	-
OTHER	California Pacific Electric Company, LLC	-	-	-	-	-	-	-	-	-	-	-	-	-
	City of Needles	-	-	-	-	-	-	-	-	-	-	-	-	-
	Kirkwood Meadows Public Utility District	-	-	-	-	-	-	-	-	-	-	-	-	-
	PacifiCorp	-	-	-	-	-	-	-	-	-	-	-	-	-
	Surprise Valley Electrification Corporation	-	-	-	-	-	-	-	-	-	-	-	-	-
	Truckee-Donner Public Utility District	-	-	-	-	-	-	-	-	-	-	-	-	-
OTHER Total		-	-	-	-	-	-	-	-	-	-	-	-	-
Statewide Total		-	(400)	(2,337)	(4,613)	(6,789)	(8,628)	(10,581)	(12,327)	(14,200)	(16,142)	(18,240)	(20,354)	(22,707)
Total Pumping Load		-	-	-	-	-	-	-	-	-	-	-	-	-
Total Statewide Retail Deliveries excluding pumping		-	(400)	(2,337)	(4,613)	(6,789)	(8,628)	(10,581)	(12,327)	(14,200)	(16,142)	(18,240)	(20,354)	(22,707)

This table includes retail sales and other deliveries only measured at the customer level. Losses and consumption served by self-generation are excluded. Table developed based on actual 2013 data.
Table includes sales from entities outside of California control areas.
Pacific Gas and Electric Company (Direct Access) includes BART.

This table, which is not supplied by the Energy Commission, takes the difference between the entries of the previous two spreadsheets, showing how much additional achievable energy efficiency (AAEE) is implied for each load serving entity. It can clearly be seen that only the three major investor-owned utilities and community choice programs have AAEE values provided by the forecast, and all the municipal utilities were not included. Savings embedded in the AAEE accrue from 2014, reaching 22,707 gigawatt-hours by 2025. Conservative extrapolation at slightly over 2,000 gigawatt-hours per year—the average incremental amount between 2015 and 2025— reaches savings of about 33,000 gigawatt-hours by 2030.

Appendix F: Demand Forecast and the 50% Renewable Requirement[65]

Form 1.1c - Statewide

California Energy Demand Revised/Final Forecast, 2016 - 2026, Mid Demand Baseline Case

Electricity Deliveries to End Users by Agency (GWh)

Planning Area	Label	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Total Statewide Retail Deliveries excluding pumping, Mid AAEE	Mid AAEE	258,561	256,392	254,951	253,808	251,995	250,857	250,201	249,729	250,042	249,876	249,475	249,154	248,534
Total Statewide Retail Deliveries excluding pumping No AAEE	Mid Case	258,561	256,935	257,471	258,585	259,581	260,522	261,742	263,052	265,095	266,657	267,908	269,199	270,194
Mid Case Additional Achievable Energy Efficiency (AAEE)		-	(543)	(2,520)	(4,777)	(7,586)	(9,665)	(11,541)	(13,323)	(15,053)	(16,781)	(18,433)	(20,045)	(21,660)
SB 350 Adjusted Retail Deliveries excluding pumping	SB 350	258,561	255,849	252,431	249,030	244,408	241,192	238,661	236,407	234,989	233,094	231,042	229,108	226,873
50% of Adjusted Retail Deliveries excluding pumping	50% RPS	129,281	127,924	126,216	124,515	122,204	120,596	119,330	118,203	117,494	116,547	115,521	114,554	113,437

The first two lines of the table show the mid-case demand forecast for electricity deliveries to end use customers from the California Energy Commission; the first line includes the mid-case Additional Achievable Energy Efficiency (AAEE), and the second line prior to the AAEE.

The next three lines are not published in the forecast itself, but show the effect of energy efficiency on the state's 50 percent renewable energy requirement for 2030.

The third line subtracts the second line from the first, to calculate the amount of AAEE implied by these forecasts. The fourth line shows the effect of doubling the AAEE on the demand forecast; this approximates the requirement of SB 350 in that it uses the most recent forecast to 2026, rather than the prior year forecast which only extends to 2025. The fifth line illustrates the decreasing amount of electricity supply that is needed to meet a 50 percent renewable portfolio standard (RPS) target. The actual 50 percent RPS is only required beyond 2030, by which time the target is projected to decrease to ~113,000 gigawatt-hours.

The actual amount of the AAEE target for SB 350 is subject to regulatory proceedings and may be further adjusted. For example, a lower efficiency target might be adopted for the investor-owned utilities if the full doubling is determined not to be feasible, cost-effective, or consistent with public health and safety. A lower efficiency target would have the effect of increasing electricity demand, and thus increasing the amount of renewable energy required to meet the 50 percent RPS. On the other hand, the AAEE does not include efficiency targets for publicly owned utilities, and there may be more self-generation than the forecast assumed. These factors would reduce retail electricity deliveries, and therefore reduce the amount of electricity required to meet the 50 percent RPS.

[65] LSE and BA Tables Mid Demand Baseline - Mid AAEE, IEPR 2016 Adoption 01-27-2016 Business Meeting; LSE and BA Tables Mid Demand Baseline - No AAEE, IEPR 2016 Adoption 01-27-2016 Business Meeting. CED 2015, California Energy Commission, Final Forecast, January 2016. https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03

Appendix G1: Committed Energy Efficiency Embedded in the Baseline Forecast Residential Sector[66]

Committed Electricity Efficiency/Conservation Consumption Savings* (GWh)

California Energy Demand 2015 Revised Forecast - Mid Demand Case
Residential

Year	Building Standards	Appliance Standards	Program and Price Effects	Total	Incremental from 2015
1990	2,811	2,751	3,306	8,868	
1991	2,985	3,146	3,706	9,837	
1992	3,242	3,722	3,800	10,764	
1993	3,425	4,225	3,845	11,495	
1994	3,636	4,781	3,887	12,304	
1995	3,829	5,317	3,872	13,018	
1996	4,022	5,850	3,648	13,519	
1997	4,184	6,321	3,653	14,158	
1998	4,449	6,938	3,147	14,534	
1999	4,541	7,275	3,284	15,100	
2000	4,715	7,782	3,542	16,040	
2001	4,814	8,072	4,430	17,316	
2002	4,971	8,802	4,856	18,630	
2003	5,114	9,466	4,691	19,271	
2004	5,230	10,127	5,022	20,378	
2005	5,284	10,667	5,623	21,574	
2006	5,657	11,345	7,031	24,033	
2007	5,940	12,524	7,424	25,888	
2008	6,160	13,644	7,870	27,674	
2009	6,192	14,445	9,178	29,815	
2010	6,454	15,972	10,009	32,435	
2011	6,748	17,339	10,559	34,647	
2012	7,028	18,530	11,486	37,044	
2013	7,170	20,306	12,069	39,546	
2014	7,552	22,468	12,226	42,246	
2015	7,915	24,609	12,269	44,793	2,547
2016	8,256	26,449	11,852	46,557	4,311
2017	8,573	28,139	11,269	47,982	5,736
2018	8,916	29,864	10,603	49,383	7,137
2019	9,269	30,844	10,052	50,164	7,918
2020	9,623	31,828	9,406	50,857	8,611
2021	9,938	32,758	8,650	51,346	9,100
2022	10,223	33,627	7,872	51,723	9,477
2023	10,495	34,459	7,202	52,155	9,909
2024	10,756	35,262	6,821	52,839	10,593
2025	11,021	36,049	6,534	53,604	11,358
2026	11,291	36,766	6,423	54,480	12,234

* Customer side of the meter

[66] Committed Electricity Efficiency Conservations Savings by Planning Area and Sector Mid CORRECTED
*** THIS DOCUMENT SUPERCEDES TN 207186 and TN 206992 ***
IEPR 2015-12-17 Workshop, CED 2015, California Energy Commission.
https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03

Appendix G2: Committed Energy Efficiency Embedded in the Baseline Forecast Non-Residential Sectors[67]

Committed Electricity Efficiency/Conservation Consumption Savings* (GWh)

California Energy Demand 2015 Revised Forecast - Mid Demand Case
Non-Residential

Year	Building Standards	Appliance Standards	Program and Price Effects	Total	Incremental from 2015
1990	1,568	845	12,924	15,337	
1991	1,752	960	13,209	15,921	
1992	1,988	1,106	13,623	16,717	
1993	2,117	1,198	13,113	16,428	
1994	2,213	1,275	13,178	16,666	
1995	2,360	1,384	12,994	16,739	
1996	2,554	1,500	11,666	15,720	
1997	2,793	1,638	12,027	16,459	
1998	3,050	1,789	11,675	16,513	
1999	3,406	1,957	12,053	17,417	
2000	3,866	2,179	12,890	18,935	
2001	4,062	2,261	19,938	26,261	
2002	4,496	2,444	21,412	28,351	
2003	4,998	2,671	20,436	28,104	
2004	5,414	2,872	18,528	26,814	
2005	5,836	3,054	18,849	27,740	
2006	6,271	3,224	20,491	29,986	
2007	6,891	3,461	20,593	30,945	
2008	7,508	3,701	20,782	31,990	
2009	7,882	3,826	24,426	36,133	
2010	8,246	3,929	25,078	37,253	
2011	8,720	4,073	25,265	38,058	
2012	9,205	4,209	25,795	39,210	
2013	9,617	4,517	27,722	41,856	
2014	10,116	4,838	29,675	44,630	
2015	11,120	5,456	30,237	46,813	2,183
2016	12,245	6,145	30,221	48,610	3,981
2017	13,455	6,824	30,321	50,600	5,970
2018	14,694	7,370	30,250	52,314	7,684
2019	15,849	7,826	30,515	54,190	9,560
2020	16,982	8,282	30,594	55,858	11,228
2021	18,079	8,737	30,415	57,232	12,602
2022	19,197	9,206	29,822	58,225	13,595
2023	20,265	9,659	29,291	59,216	14,586
2024	21,301	10,103	29,085	60,488	15,858
2025	22,315	10,555	28,775	61,646	17,016
2026	23,280	10,964	28,712	62,956	18,326

* Customer side of the meter

[67] Committed Electricity Efficiency Conservations Savings by Planning Area and Sector Mid CORRECTED
*** THIS DOCUMENT SUPERCEDES TN 207186 and TN 206992 ***
IEPR 2015-12-17 Workshop, CED 2015, California Energy Commission.
https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03