STAFF PAPER

Proposed Near-Term Method for Estimating Generation Fuel Displaced by Avoided Use of Grid Electricity

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ABSTRACT

As preferred resources – including energy efficiency, renewable generation, and distributed generation – have become increasingly important in California's electricity system, so has the need to evaluate the programs that support them. A primary metric used in evaluating preferred resource programs is greenhouse gas emissions reduction. Methods for calculating emissions reduction, which results from avoided generation, vary substantially in approaches and assumptions. Each method has been developed to fit a specific program or purpose. While these methods suffice for individual programs, the differences in approaches and assumptions make program comparison difficult.

This paper proposes a common method for estimating the amount of generation fuel displaced by avoided use of grid electricity over the next five years by using these preferred resources, with discussion of the challenges to producing longer-term estimates. This paper identifies California's average dispatchable grid resources and the associated fuel efficiency, presents a method for calculating how much grid electricity was avoided and illustrates how this numerical representation can be applied to help evaluate four of California's preferred resources: energy efficiency, demand response, renewable electricity generation, and combined heat and power systems. This paper also contains initial discussion with the aid of public comments, of the considerations that must take place to design a long-term displacement method.

California Energy Commission staff seeks public comments and feedback on this proposed method.

Keywords: Displacement method, greenhouse gas emissions, heat rate, energy efficiency, demand response, renewable generation, combined heat and power

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EXECUTIVE SUMMARY

California's energy strategy is guided by the "loading order," which first calls for reducing electricity demand with energy efficiency and demand response programs, then meeting remaining generation needs first with renewable and distributed generation, including combined heat and power, and finally with using clean fossil-fueled generation. A primary metric used in evaluating preferred resource programs is greenhouse gas emissions reduction.

Methods for calculating emissions reduction resulting from avoided generation vary substantially in approach and assumptions. Each method has been developed to fit a specific program or purpose. While these methods are sufficient for some programs, the differences in approaches and assumptions makes program comparison difficult. This paper proposes a common method for estimating the amount of generation fuel displaced from avoided use of grid electricity over the next five years, with discussion of the challenges to producing longer-term estimates, for California's preferred resources: energy efficiency, demand response, renewable electricity generation, and combined heat and power systems. This paper also comments on the considerations that must take place to design a long-term displacement method.

Method Overview

This approach is designed to use policy-neutral assumptions and methods used to estimate emission reductions by the various programs that encourage preferred resources. This is accomplished by applying any energy reduction to a common set of dispatchable resources. This method relies solely on historical heat rate data and the trend found within these data. Using historical data remains a feasible starting place; however, significant changes affecting the resource mix and the increasingly dynamic operation of the electric grid may require future updates to this approach. In addition, the application of this method may be insufficient for analyzing subannual increments, such as daily displacement patterns or seasonal variation.

Characterizing Electric Grid Generation Resources

Electric generation resources all have technological and operational characteristics that allow them to be grouped into a limited set of categories. These characteristics provide a general guide for the role they play in the generation portfolio and how they operate as a system to meet demand. To balance supply and demand almost instantaneously and accommodate nondispatchable resources, such as nuclear generation and variable renewable generation, the electricity system needs dispatchable resources that are capable of being cycled up and down to follow load. In California, natural gas-fired generation is the predominant resource used to maintain the supply-demand balance.

Natural gas-fired plants can also be categorized based on the technology that is used and/or the way they are operated. A common way to capture these operational differences is by the capacity factor, which is typically expressed as a percentage determined by dividing the actual electric generation output by the generation that would occur if the generator ran at full output year round. Low capacity factor units primarily operate during high demand or peak hours and are known as peaking resources. High capacity factor units operate through the entire day and follow the net demand up and down and are known as load-following resources.

Determining Heat Rates

In general, the amount of fuel displaced by an energy reduction measure or onsite generation depends on the amount and type of generation that it displaces, which in turn determines the amount of greenhouse gas emission reductions that can be attributed to any particular preferred resource. Greenhouse gas emission reductions are a function of the amount of carbon in the fuel that is converted to carbon dioxide through combustion. As a result, the fuel efficiency of a generator, known as heat rate, is an important factor in determining the amount of generation and the associated fuel that is being displaced, along with the amount of greenhouse gas emission reductions that is achieved. Heat rate is measured as a ratio of fuel used to electricity generated, expressed in British thermal units per kilowatt-hour.

The proposed approach for estimating fuel reduction outlined in this report uses generator reporting data from the Quarterly Fuel and Energy Report to provide historical heat rates from 2002 to 2013. The data are screened to identify relevant generation resources, limiting the data set to natural gas-fired resources and removing CHP plants and grid stability resources, and separated into two categories, load-following resources and peaking resources. The data are then extrapolated to provide statewide average annual heat rate estimates for the marginally dispatched resource classes. The year 2001 was not included in the regressions as the effect of California's electricity crisis forced atypical power plant operation during that year. These regressions assume that recent trends in technological improvement will continue as newer, more efficient turbines replace some of the energy from the current natural gas fleet.

The onsite equivalent heat rates are calculated using a line loss factor of 7.8 percent. Energy is lost during the transmission and distribution of electricity. Accordingly, a megawatt-hour (MWh) of consumption of grid provided energy requires that more than 1 MWh be generated. A line loss factor is needed to account for this additional electricity and the fuel needed to generate it; onsite equivalent represents the reduced efficiency caused by the transmission and distribution of electricity. It is not applied when another grid-connected generator is the source of displacement, as energy from that resource experiences line losses as well.

Combining the results of the regression analysis and the line loss factor yields heat rate estimates for load-following and peaking resources, as shown in **Table 1.** Peaking resources produce only 2.8 percent of the total annual energy on average and, thus, are limited to a maximum of 2.8 percent of the energy from load-balancing gas-fired plants displaced annually.

Table 1: Five-Year Heat Rate Estimates

Year	Export		Onsite	
	Load-Following	Peaking	Load-Following	Peaking
2014	7,221	10,554	7,832	11,446
2015	7,214	10,534	7,824	11,426
2016	7,200	10,515	7,817	11,405
2017	7,193	10,496	7,809	11,384
2018	7,186	10,477	7,801	11,363

Source: California Energy Commission, Supply Analysis Office, Energy Assessments Division.

Determining the Amount of Fuel Displaced

The proposed method to determine the equivalent displaced fuel from reduced electric grid use is to take the number of kilowatt-hours of avoided grid electricity consumption multiplied by the applicable heat rate.

In general terms, the calculation for both load-following and peaking resources is:

> (electricity displaced) x (applicable heat rate) = displaced electric grid fuel equivalent

For each year of the estimate, the portion of the savings that occurs during peak hours is calculated using the peaking heat rate. All other savings are calculated using the load-following heat rate. Once the savings for each year are calculated, they can be summed and averaged to produce an average carbon savings per megawatt hour. Because this is just an estimate, it is not, nor is it intended to replace, direct measurement of emission reductions. It provides uniformity and a common approach to estimating the potential avoided use of fuel by reduced or displaced grid electricity.

Displacement Estimate Examples

Staff applied the method using four illustrative scenarios to demonstrate how this estimation may be applied in a given policy, with a set of assumptions, to yield a numerical result. The specifics of each example are generic, meant only to illustrate the application of the method. Each example uses the same carbon content conversion metric as provided by the U.S. Energy Information Administration, 117 pounds of carbon dioxide (CO_2) emitted per million British thermal units of natural gas consumed. These examples estimate the total avoided grid energy and corresponding avoided emissions for the first five years of the heat rate estimates and calculate the avoided carbon intensity on an average of those five years.

Table 2 summarizes the examples for avoided energy, displaced fuel equivalent, carbon content, and carbon intensity. Since the specifics in the examples are generic, the resulting avoided carbon intensities are not definitive of the reduction types. The difference between the two renewable generation examples illustrates the impact line losses have on the calculation.

Table 2: Five–Year Displacement Totals and Average Carbon Intensity

Illustrative Example	Five-Year Total CO_2 Conversion (metric tonnes CO_2)	Five-Year Total Avoided Grid Energy (MWh)	Average Avoided Carbon Intensity (kg CO_2/MWh)
Renewable (export)	2,920	37,885	386
Combined Heat and Power	14,299	176,523	405
Renewable (onsite)	3,167	37,885	418
Energy Efficiency	737	8,765	420
Demand Response	149	1,227	605

Source: California Energy Commission, Supply Analysis Office, Energy Assessments Division.

Energy Commission staff seeks public comments and feedback on this proposed method through June 19, 2015. This analysis is meant to prompt discussion of the framework needed to design a standardized approach for estimating electric grid fuel displacement. This project seeks to identify a reasonable and consistent displacement accounting method that can be used for renewable generation, combined heat and power systems, demand response, and energy efficiency program evaluations at California's energy agencies. The Energy Commission will use this feedback to update an approach that is consistent with stakeholder feedback and to produce a separate report detailing the best available parameters and time horizon for estimating fuel displacement.

Limitations and Questions for Stakeholders

Since this method relies on numerous simplifying assumptions, it depends on the validity of those assumptions, and pertinent changes to those assumptions may significantly alter the outcome. It does not make any specific assumptions about the retirement of existing resources, the addition of new resources (preferred or otherwise), the impact today's preferred resource procurement will have on future procurement, the impact the operation of these new resources will have on existing resource operation, the emphasis on a "flexible" grid (requiring resources that will be tasked with ramping more quickly and more frequently than in the past), and future renewable procurement policy and legislation. This method relies solely on historical heat rate data and the trend found within those data.

While the near-term future of the resources comprising California's generation resources and associated operation is expected to be relatively similar to today, rapid changes in the electric grid makes estimates beyond five years problematic. Changes in technologies, such as energy storage, may alter the dispatch behavior of existing resources. In addition, renewable resources in excess of those currently mandated may magnify the operational issues associated with integrating variable generation. For these reasons, the Energy Commission has limits its quantitative analysis to the next five years.

The Energy Commission requests that parties address the following questions in their written comments:

- Is a uniform statewide method appropriate for evaluating emissions displacement factors over a long-term (10-15 year) planning horizon? If not, please explain.
- Are the assumptions used to calculate the avoided generation for energy efficiency, demand response, renewables, and combined heat and power (and other distributed generation) correct? If not, what changes need to be made?
- Is the treatment of onsite generation and associated electric grid displacement appropriate? Please explain.
- How might this method be applied in program planning and comparison or program impacts? In what circumstances do you see the State using a method like this?
- What programs and/or situations would this method be inappropriate to apply? (For example, would it be inappropriate to use this method to estimate emissions avoided by geothermal plants that operate as base load?)
- Do you think the approach (as a whole or specific elements of the method) will result in accurate estimate, or will it overestimate/underestimate grid displacement? Please explain.
- What do you think are the appropriate levels of granularity necessary in order to provide a reasonable estimate of electric grid fuel displacement? Please use the discussion of Method Parameters section in Chapter 5 as a starting place for discussion.

CHAPTER 1: Introduction

California's energy strategy is guided by the state's *Energy Action Plan* and the "loading order" contained therein.[1] The loading order calls first for reducing electricity demand with energy efficiency and demand response programs, then meeting remaining generation needs first with renewable and distributed resources, and finally with using clean fossil-fueled generation. With the exception of fossil-fueled generation, these resources are called *preferred resources*. As preferred resources have become increasingly important in California's electricity system, so has the need to evaluate the programs that support them. A primary metric used in evaluating preferred resource programs is greenhouse gas (GHG) emissions reduction.

Methods for calculating GHG emissions reduction, which results from avoided generation, vary substantially in approach and assumptions. Each method has been developed to fit a specific program or purpose. While these methods are sufficient for individual programs, the differences in approaches and assumptions makes program comparison difficult. A measurable, consistent, and widely applicable analytical approach will help alleviate this conflict and lead to better policy making.

This paper proposes a common method for estimating the amount of generation fuel displaced by avoided use of grid electricity over the next five years, with discussion of the challenges to producing longer-term estimates. This paper identifies California's average dispatchable grid resources and the associated fuel efficiency, presents a method for calculating grid electricity displacement, and illustrates how this numerical representation can be applied to help evaluate four of California's preferred resources: energy efficiency, demand response, renewable electricity generation, and combined heat and power (CHP) systems. This paper also contains initial discussion, with the aid of previous public comments, of the considerations that must take place to design a long-term displacement method.

This approach is designed to be policy-neutral, agnostic to the approaches and methods used to estimate emission reductions by various programs that encourage preferred resources. This is accomplished by applying any energy reduction to a common set of dispatchable resources. To extend this policy-neutral nature to the estimates this method produces, it does not make any specific assumptions about the retirement of existing resources, the addition of new resources (preferred or otherwise), the impact today's preferred resource procurement will have on future procurement, the impact the operation of these new resources will have on existing resource operation, the emphasis on a "flexible" grid (requiring resources that will be tasked with ramping more quickly and more

1 http://www.energy.ca.gov/energy_action_plan/.

frequently than in the past), and future renewable procurement policy and legislation. This method relies solely on historical heat rate data and the trend found within those data.

The scope and assumptions used in this method limit its application. For example, this method does not include analysis on the embedded energy or emissions it takes to reduce grid use, such as the energy and associated emissions to manufacture and install a solar panel. Moreover, this method is not intended to be an end-to-end analysis of resources, including manufacturing, construction, fuel acquisition and transport, and infrastructure costs. Each of these areas is broad in scope with unique sets of parameters and assumptions that may be looked at individually without affecting the approach of another area. Furthermore, since this method uses annual averages, it is inappropriate for estimating short-term grid variations, including day-to-day operational changes and seasonal variation. Since this method relies on numerous simplifying assumptions, it depends on the validity of those assumptions, and pertinent changes to those assumptions may significantly alter the outcome. This method is also not appropriate for estimating large-scale changes to the electric grid, actions that result in the displacement of terawatt-hours, such as those envisioned by the California Air Resources Board's (ARB) *Draft Scoping Plan,*[2] since these programs may have a nontrivial effect on what resources are dispatched and when. In certain circumstances, direct comparison of new and old emissions may be a more appropriate and accurate measure of emission reductions when generation resources are replaced on a one-for-one basis.

Staff presented and made available a summary paper of this method at an Energy Commission staff workshop on CHP held on July 14, 2014. Written comments were received on the summary paper and the questions presented therein. A discussion based on these questions and the comments received is presented in Chapter 5, Preliminary Discussion and Public Comments. This discussion is presented at the end, rather than interspersed in the body of the paper, to provide a clear, concise analysis of this approach and its parameters. Additional questions are contained at the end of that chapter to provide the opportunity for stakeholders to comment on the staff paper and build upon existing discussions to determine the best available parameters for a standardized approach to estimating electric grid fuel displacement.

Displacement Calculations Beyond Five Years

In developing this approach, staff identified and attempted to deal with a number of uncertainties associated with analyzing future events in complex systems. While the changes in the California's electric grid are likely to be generally predictable for the next three to five years, beyond that, several forces may combine to change the operational and emissions landscape.

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2 http://www.arb.ca.gov/cc/scopingplan/document/draftscopingplan.htm.

While the challenges and uncertainties are addressed separately in the preceding chapters, it is appropriate here to summarize the reasons why this paper only attempts to calculate displacement over the next five years rather than make estimates out over a longer time horizon, such as 10 to 15 years.

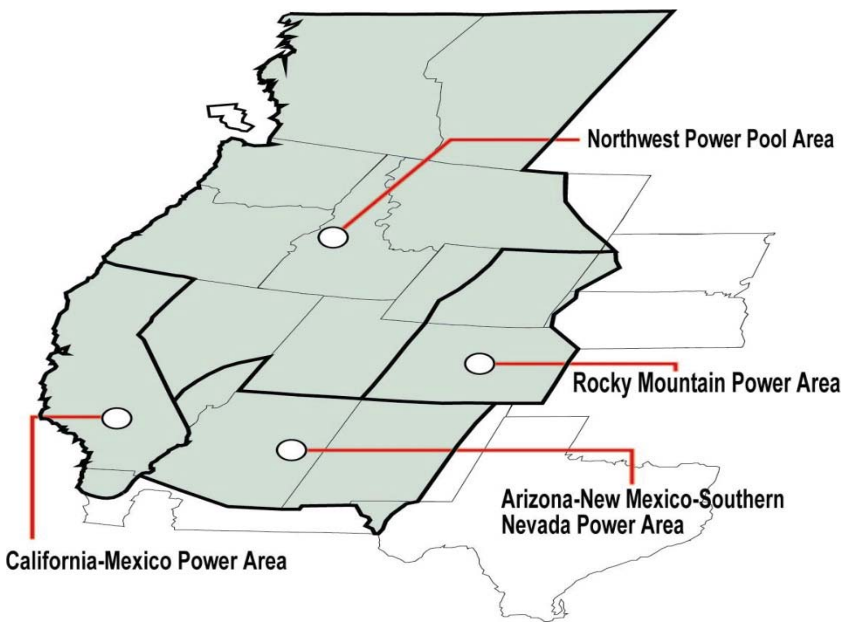
- The peak hours for California load are shifting. This means that any method attempting to identify reductions from peak load shaving will have to account for the possibility that those peaks will happen at different hours of the day or even perhaps times of year.
- Continued growth of renewable resources and the uncontrolled generation from them is causing periods of time where their energy is not usable. While this problem exists today for a very small number of hours, it is increasing and will likely effect the displacement of future resources beyond the next five years.
- Life-cycle changes in program savings are not fixed. For the first few years of a program, the savings are often large. But as a program continues, the effective savings will decline.
- New disruptive technologies are likely to change the operational profile of key resources. Technologies such as electricity storage may drastically alter the operational landscape of the grid, rendering the assumptions this approach is based on obsolete.
- Renewable operational agreements may change. As renewables become a mainstream resource, the agreements under which they operate may change. These changes could result in new operational profiles that must be considered.
- The future construction of renewables beyond the next five years may no longer be driven by legislative mandate, but rather by cost competition. In this environment, generation procurement and the mix of grid resources will change dramatically, altering the process of estimating grid displacement.

CHAPTER 2: Meeting California's Electricity Demand

To provide a reliable supply of electricity, the entities that operate California's electricity system must balance supply and demand at every moment of the day. To match supply with demand, electricity systems rely on a portfolio of power plants that use different fuels and have different operating characteristics. Control area operators, responsible for maintaining grid stability and reliability, schedule and dispatch generation when needed and ensure that the power quality is maintained. California's electricity supply comes from a mix of hydroelectric, natural gas, renewable, coal, and nuclear-powered generating plants.

California's electricity system is part of a larger grid that serves 11 western states and parts of two countries: British Columbia and Alberta in Canada and Baja California Norte in Mexico. This interconnection is mutually beneficial by allowing greater dispatch flexibility and sharing of surplus generation capacity. **Figure 1** shows this area defined as the Western Electricity Coordinating Council.

Figure 1: Map Showing Western Electricity Coordinating Council

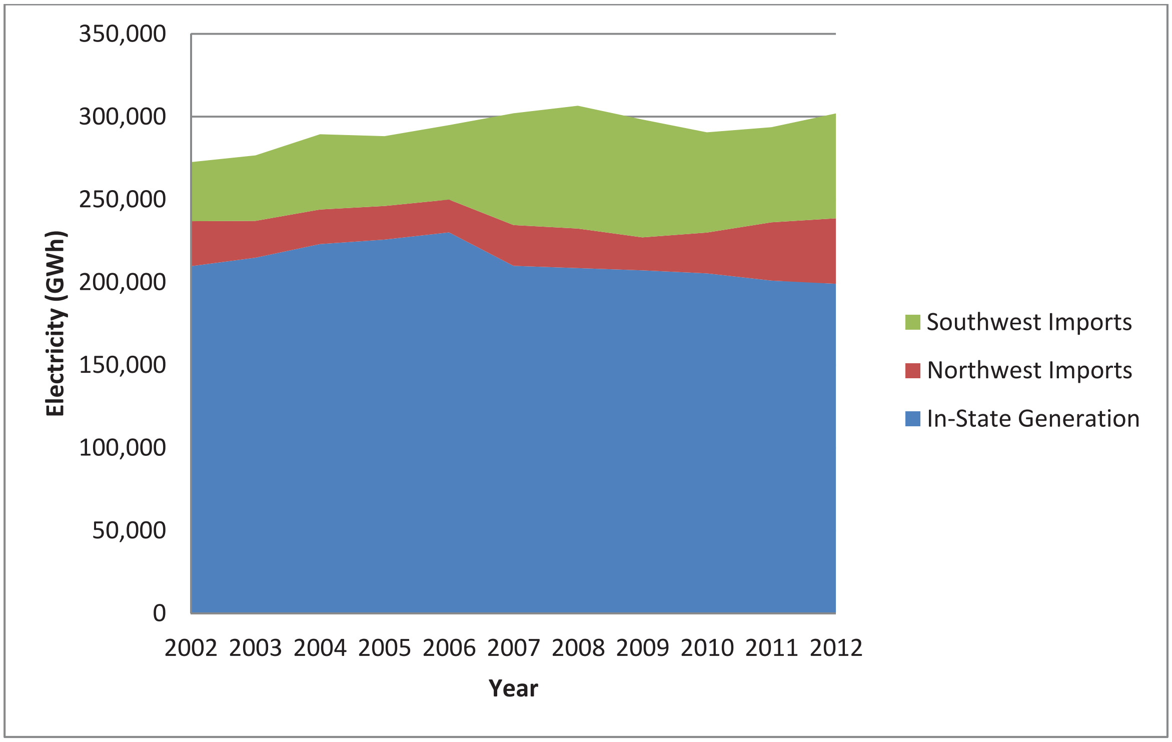


Source: Energy Commission.

Historical Trends

California meets roughly two-thirds of its electric demand with in-state resources. Imported electricity is classified as coming from either the Southwest or the Northwest. Historical trends for California's total system power for 2002 to 2012 are presented in **Figure 2**. In-state generation was at its highest in 2006, meeting more than 78 percent of California's demand. Northwest imports have been around 8 percent for more than a decade but have increased in recent years with growing wind generation development. Southwest imports increased in the early 2000s, reaching a high of roughly 24 percent in 2008 before declining slightly.

Figure 2: In-State Generation and Imports: 2002 to 2012



Source: Quarterly Fuels and Energy Report (QFER) and Senate Bill 1305 (Sher, Chapter 2.3 of Part 1 of the Public Utilities Code, Statutes of 1997) Power Source Disclosure Reporting Requirements.

Each of these regions has resource mix characteristics. **Table 3** shows the total system power mix that met California's needs in 2012.[3]

Averaging 14 percent of California's in-state generation, hydroelectric resources depend greatly on annual snowpack. In the recent years 2012, 2013, and 2014, snowpack has been significantly lower than average, necessitating larger amounts of imports and in-state natural gas resources. This issue was compounded with the retirement of the San Onofre Nuclear Generating Station early in 2012, which was responsible for serving about 7 percent of California's electricity demand. As a result, California reached its lowest level of in-state generation in more than a decade, generating only 66 percent of its total energy consumption in 2012.

3 http://energyalmanac.ca.gov/electricity/system_power/2012_total_system_power.html.

Table 3: California's Total System Power for 2012

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 (Sher, Chapter 2.3 of Part 1 of the Public Utilities Code, Statutes of 1997) Power Source Disclosure Reporting Requirements. In-state generation is reported generation from units 1 MW and larger.

Identified imports from the Northwest are mostly from renewable resources, with the largest sources of renewable electricity being wind, biomass, and small hydro, as shown in **Table 3**. However, the largest amount of electricity comes from "unspecified sources of power." *Unspecified power* is energy not specifically claimed by a utility under the Power Source Disclosure Program.[4] This category includes spot market purchases, wholesale power marketing, and purchases from pools of electricity where the original source is

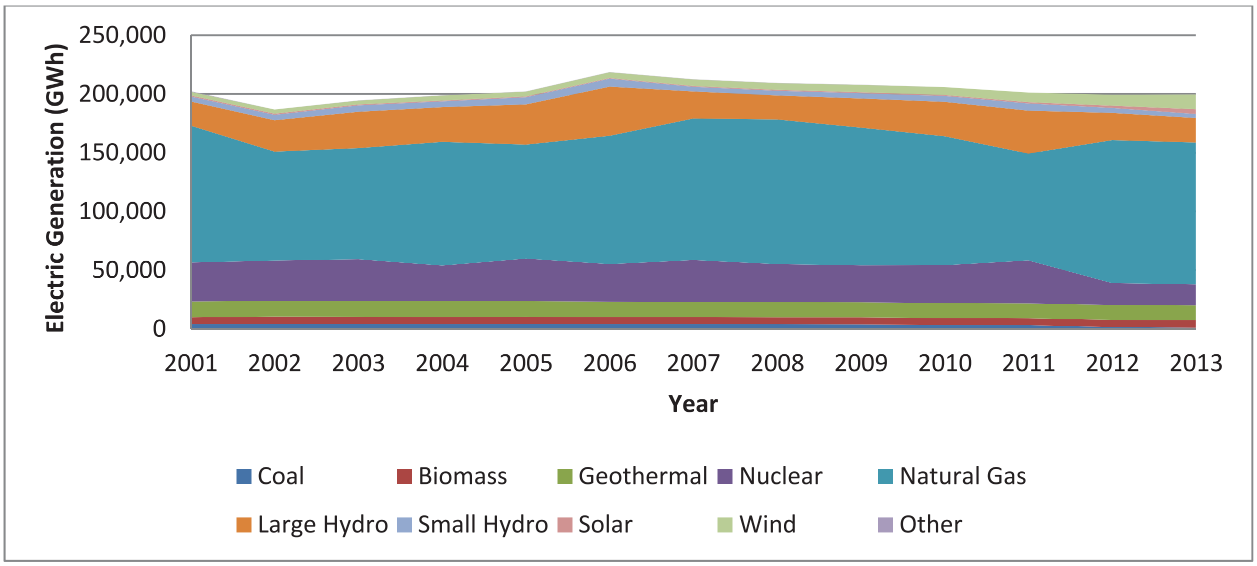
4 The Power Source Disclosure Program was created to fulfill Senate Bill 1305 (Sher, Statutes of 1997), requiring retail suppliers of electricity to disclose to consumers accurate, reliable, and simple-to-understand information on the sources of energy that are being used.

unspecified, and "null power." *Null power* is the generic electricity commodity that remains when the renewable attributes (Renewable Energy Credits) are sold separately. Most large hydro from the Northwest is reported as unspecified power because the short-term contracts these facilities choose to operate under are not sufficiently long to fulfill the regulatory requirement to be classified as "large hydro."

Electricity from the Southwest is roughly a third from coal, followed by a sixth from natural gas and a sixth from nuclear energy. The remaining third comes from unspecified sources, renewable energy, and large hydro resources, in that descending order. Unspecified sources also may include coal and other resources without long-term contracts.

California's in-state generation has remained relatively flat over the last decade (see **Figure 3**), while the in-state generation capacity has increased by more than 20 percent (see **Figure 4**).

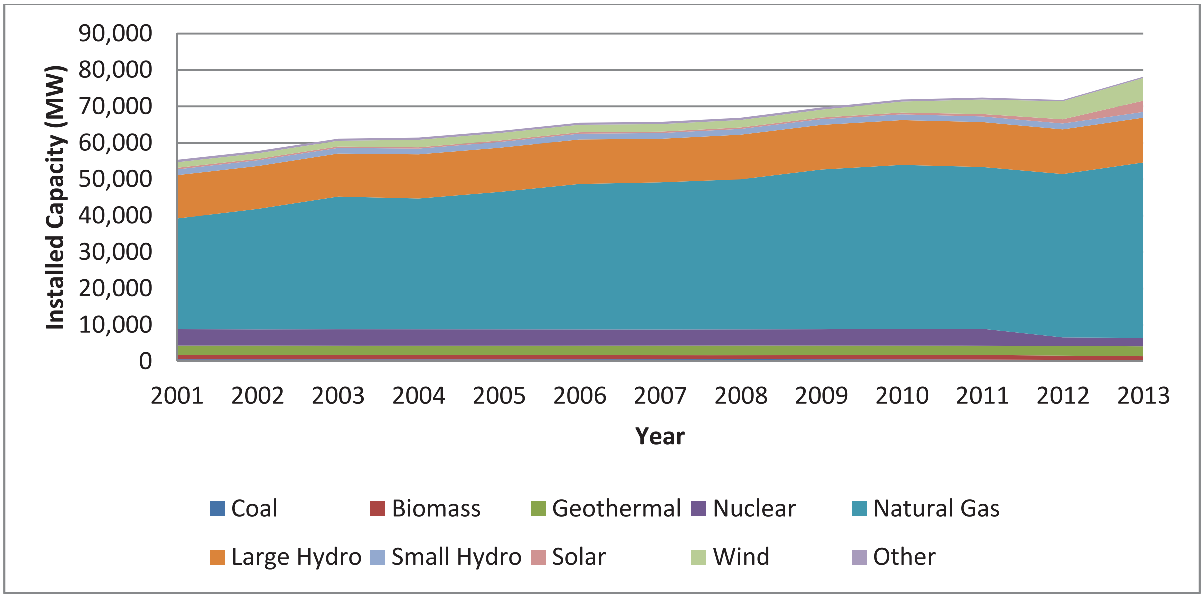
Figure 3: In-State Electric Generation by Fuel Type



Source: QFER.

The closure of the San Onofre Nuclear Generating Station and related direct impacts can be clearly seen in both the energy (see **Figure 3**) and capacity (see **Figure 4**) of California's fuel supply mix. Specifically, the decrease in energy from nuclear generation corresponded with an increase in energy from natural gas-fired generation. In addition, the high snowpack of 2011 clearly shows the impact in reducing the use of in-state natural gas resources, while the less-than-average snowpacks of 2012 and 2013 had the opposite impact. The increasing amount of renewable resources is also becoming more noticeable, specifically this higher amount of wind generation in 2012 and 2013.

Figure 4: Installed In-State Electric Generation Capacity by Fuel Type

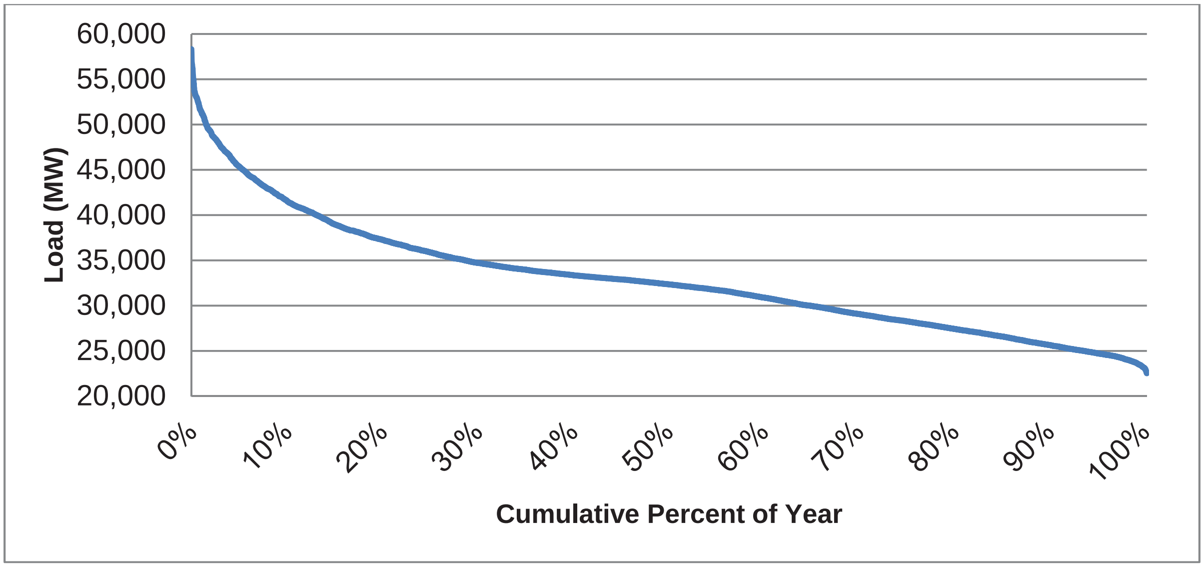


Source: QFER.

While the installed capacity of natural gas resources has increased over the last decade, the amount of electricity from natural gas has remained relatively constant (with the exception of natural gas being the primary replacement for energy from the retired San Onofre Nuclear Generating Station). In response to the electricity crisis in 2001, there were extraordinary expansions of natural gas capacity in 2002 and 2003. The sizable amount of new natural gas resources has shifted which units run at what times and for what purpose. Newer units are typically more efficient and run at higher capacity factors, shifting generation away from older, less efficient generators.

California and the desert Southwest have surplus capacity available for most hours in the year. For a small number of hours during the summer, capacity that sits idle for most of the year is needed to meet high demand. **Figure 5** is the load duration curve for 2012.

Figure 5: California's Load Duration Curve for 2012

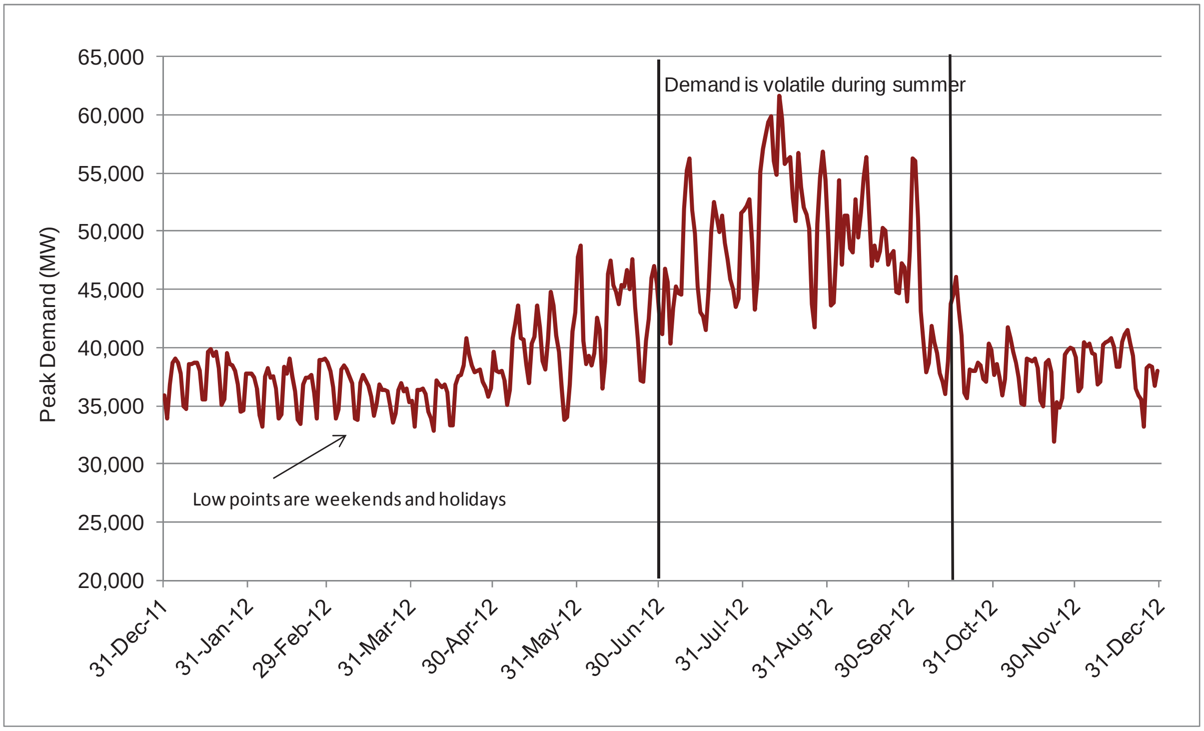


Source: Federal Energy Regulatory Commission Form 714 Part III Schedule 2, United States Energy Information Administration 861, and Ventyx research.

Electricity use varies widely over the time of day and time of year. On a typical day, demand increases 60 percent from the midnight low to the afternoon high. On a hot summer day, this increase can be 85 percent to 90 percent, corresponding to California's greatest daily demand spikes during the summer months (June, July, August, and September).

Figure 6 shows how peak demand changes over the year. This variable load requires a generation system that is extremely flexible. The full available capacity of the electric system needs to be dispatched for only a few hours annually to meet peak demand.

Figure 6: Annual Pattern of Daily Peak Demand



Source: FERC Form No. 714, Part III, Schedule 2.

Peak electricity demand dramatically increases in the summer due to air conditioning loads. The difference in peak demand between an average summer day and a very hot peak day is 6 percent. While this may seem like a small percentage, it causes a significant impact on the amount of generation that is built to meet this peak, but used infrequently. The generation system must be capable of adding or dropping generation from some facilities to accommodate daily swings in demand, high summer peaks, weather variability, and economic growth cycles. Along with adapting to these shifts in demand and changes in consumer habits, the system must accommodate the varying availability of generation, pipelines, transmission lines, storage facilities, and fuel sources.

California's Grid Resources and Operating Characteristics

Electric generation resources all have technological and operational characteristics that allow them to be grouped into a limited set of categories. These characteristics provide a general guide for the role they play in the generation portfolio and how they operate as a system to meet demand. To balance supply and demand on a nearly instantaneous basis and accommodate nondispatchable resources, such as nuclear generation and variable renewable generation, the electricity system needs dispatchable resources that are capable of being cycled up and down to follow load. In California, natural gas-fired generation is the predominant resource used to maintain the supply-demand balance.

Baseload resources, such as geothermal and nuclear, run as much as possible, typically around the clock, all year, except for maintenance or unscheduled outages. These resources have the lowest marginal cost and, even if prices dropped below marginal costs for a short period, would be unable to reduce output to adapt that situation. This is also the case with coal resources. Coal plants have the ability to adjust production over a 24-hour period, enabling reduced output on weekends, but are unable to significantly change output between weekdays.

Electricity from renewable resources, such as wind and solar, are considered nondispatchable because they depend on the weather as their fuel source and their output cannot be dispatched, though it can be curtailed. For example, when large-scale solar generation decreases as the sun sets and increases as the sun rises, dispatchable resources must be available to balance the system. This situation may change in the future for reasons such as the cost of storage becoming cost-effective and integrated into the grid, and the expanded application of inverters with renewable generation to provide reactive power and partially shaped power.

CHP generation that is exported to the grid is also considered nondispatchable generation because of the role in meeting thermal demand for the host site. Traditionally, the thermal demands of the host site determine how the CHP system will operate, with the electric generation being a secondary consideration. Thus, CHP in the traditional role is not used to maintain the supply-demand balance of the grid.

Hydroelectric power, both in-state and imported, can be used to help follow loads and provide peaking power, but the total energy available fluctuates annually due to weather. Hydropower, once a large source of peaking power, is no longer sufficient to provide critical peak electricity as California's population and demand have greatly surpassed its capacity. However, hydropower is incrementally less expensive than natural gas-fired electricity, is generally not considered to be *on the margin,*[5] and, therefore, does not affect displacement calculations.[6, 7] **Figure 7** illustrates the inverse relationship between in-state natural gas-fired generation and hydropower plus out-of-state imports, showing that when hydropower is readily available, gas-fired resources are used less.

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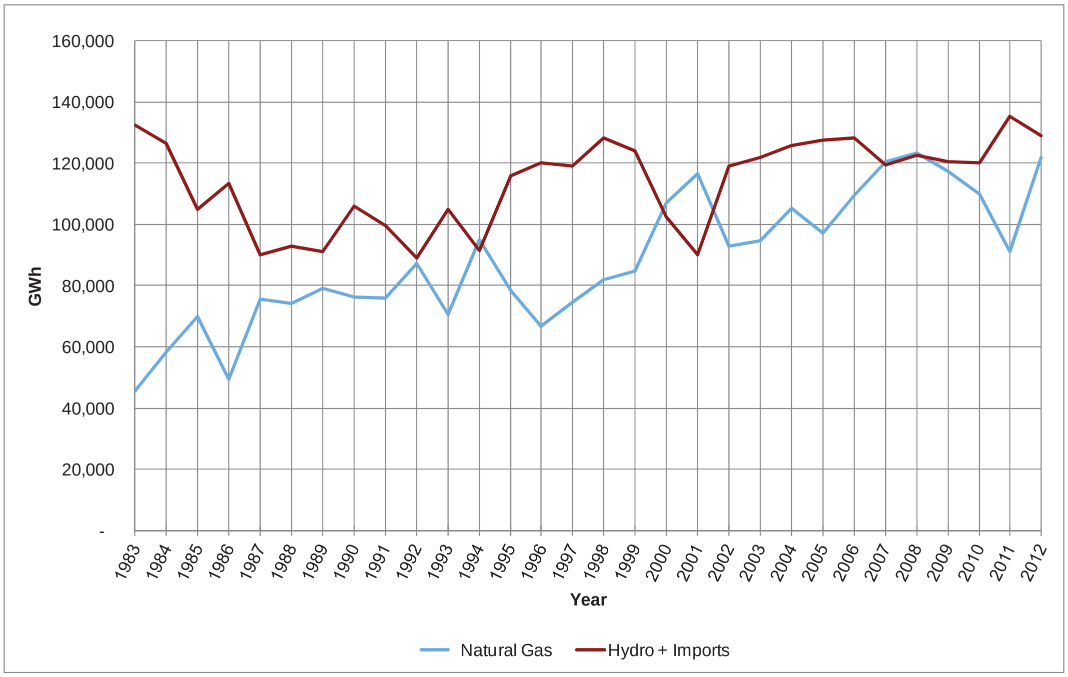
5 *On the margin* is a phrase used to describe the highest price resource that is dispatched to meet demand, which also sets the market clearing price.

6 In electric system dispatch, the resource on the margin is the final generator needed to meet load.

7 Imported hydropower is still less expensive even when considering transmission losses.

Figure 7: Correlation of the Annual California Natural Gas Generation, Hydropower and Net Electricity (1983 – 2012)



Source: QFER and Senate Bill 1305 (Sher, Chapter 2.3 of Part 1 of the Public Utilities Code, Statutes of 1997) Power Source Disclosure Reporting Requirements. In-state generation is reported generation from units 1 MW and larger.

Natural gas-fired plants fall under several categories based on technology or the way they are operated. Some common technologies are steam turbines, simple-cycle combustion turbines (CTs), and combined-cycle combustion turbines (CC CTs). The characteristics of these technologies can vary in thermal efficiency,[8] ramp rate,[9] and startup capability.[10] A common way to capture the operational differences is by capacity factor, which is typically expressed as a percentage determined by dividing the actual electric generation output by the generation that would occur if the generator ran at full output year round. Natural gas-fired plants with low capacity factors that run a minimal amount of time each year to meet peak electric demand are called *peaker plants*. They have the fastest startup and ramp rate, but lower thermodynamic efficiency. Thus, they have the highest incremental cost due to needing more fuel to provide an equivalent amount of energy, and are, therefore, have the highest operational cost. Natural gas-fired plants with higher capacity factors, primarily CC CTs that were originally designed to run as baseload but that have ramping capabilities, are

8 *Thermal efficiency* is a measure of the conversion of energy from one form to another, in this case natural gas to electricity.

9 *Ramp rate* is the ratio of change in electrical output over the time it takes to make that change.

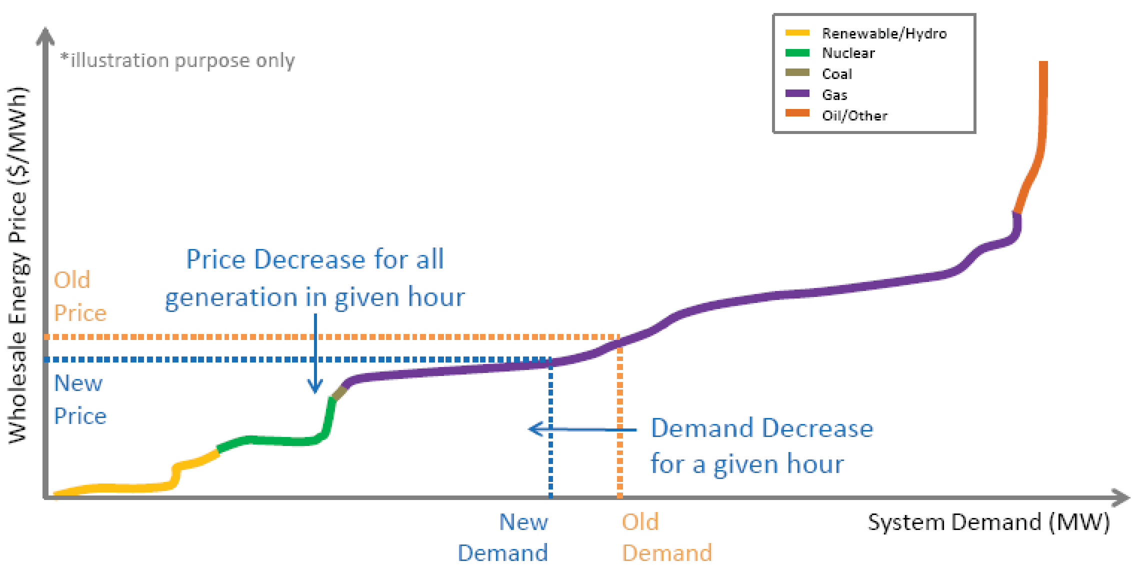
10 *Startup* is the actions required to safely reach a predefined output from an off-line state.

used as load-following resources on the grid. These peaking and load-following natural gas-fired resources provide the flexible capacity to meet grid demand.

Certain grid resources are run only for system stability. There are no other electric grid resources that can provide the necessary product, be it energy, inertia, reactive power, or some other service, where it is needed.[11] Many resources that fulfill these roles are less efficient, older natural gas-fired generators that are in need of, or are being replaced or renovated. Since these resources cannot be displaced, they are removed from the analysis.

A supply curve relating price and energy generation can be approximated using the relative fuel efficiency of generation resources. Higher-priced resources are on the upper end of the supply curve, while lower-priced resources are on the lower end. Imports from out-of-state resources compete for participation based on the associated heat rate relative to all other resources in the supply curve. A reduction in demand will reduce the price of electricity. This is illustrated in **Figure 8**, which shows the relationship between a decrease in demand with a decrease in energy price. Even though all resources compete in the energy markets on price, many of these resources are price takers (plants that submit low bids to ensure that they are scheduled).[12]

Figure 8: Generator Supply Curve



Source: EtaGen Inc., based on California ISO data as reported by Dynegy Inc.

11 http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf.

12 Since all resources are paid the market clearing price, it makes sense for many plants to behave in this manner.

Out-Of-State Natural Gas-Fired Generation

Operational data available to the Energy Commission about out-of-state generation provide some insight into the characteristics of out-of-state natural gas-fired generation.[13]

The data do not provide details of which facilities provided electricity to California, nor in what quantity. However, they allow an examination of the trends that have occurred outside California.

Most of California's imports for natural gas-fired generation come from the Southwest, predominantly from Arizona and Southern Nevada. These data show that Arizona built its modern CC natural gas-fired fleet between 2001 and 2006, with average heat rates in 2012 and 2013 of 7,232 Btu/kWh and 7,282 Btu/kWh, respectively. These modern plants are built with similar technology to that of the CC plants developed in California during that time and with similar operational characteristics, such as similar heat rate curves.

The Southwest also has a variety of other natural gas-fired plants, simple-cycle CTs, gas turbines, and steam turbines that help meet its and California's peak demand. The modern peaker plants have heat rates at or below 10,000. While the Southwest has some of these modern peaker plants, they also have older, less efficient plants. The amount of electricity generated from peaker plants in the Southwest can be presented as a percentage of the total amount of electricity generated by the Southwest's natural gas-fired fleet. **Table 4** shows the heat rates for 2012 and 2013 for low and high heat rate natural gas-fired facilities of Arizona and Southern Nevada.as well as the percentage of the electricity generated from the high heat rate (less efficient) plants.

Table 4: Average Heat Rates of Arizona and Southern Nevada's Natural Gas-Fired Fleet (Btu/kWh)

Year	Average Heat Rate of Low Heat Rate Plants	Average Heat Rate of High Heat Rate Plants	Percentage of Electricity From High Heat Rate Plants
2012	7,232	11,071	2.9%
2013	7,282	11,604	3.1%

Source: Ventyx Energy's Velocity Suite Database.

Electric Grid Generation Data

In general, the amount of fuel displaced by an energy reduction measure or onsite generation depends on the amount and type of generation that it displaces, which in turn determines the amount of GHG emission reductions that can be attributed to any particular preferred resource. Carbon dioxide (CO_2) emissions, a key component of GHG emissions, is a function of the amount of carbon in the fuel that is converted to CO_2 when consumed. As a result, the fuel efficiency of a generator, commonly expressed as a heat rate, is an important

13 The Energy Commission uses Ventyx Energy's Velocity Suite Database.

factor in determining the amount of generation and the associated fuel that is being displaced, along with the amount of CO_2 emission reductions that are achieved.

Since a purpose of this paper is to determine the average heat rates California's displaced electric grid resources, staff considered the various sources of data including, but not limited to, the California Independent System Operator (California ISO) compiled Daily Integrated Forward Market Default Load Aggregation Point Market Implied Heat Rate, the Energy Commission's QFER,[14] and data from the ARB GHG emissions reporting.

The California ISO's Daily Integrated Forward Market Default Load Aggregation Point Market Implied Heat Rate creates an implied heat rate for each IOU using the daily energy weighted locational marginal price aggregated, or collected, for each load aggregation point and divided this by the daily average natural price index.[15] The load aggregation points capture the price of electricity where it is delivered within the California ISO's system and territory on five-minute intervals. The data are presented as marginal heat rates, the implied efficiency of the last unit dispatched, but do not provide information about the composition of the generation resources. Further, using these data would require accepting the assumptions that are built into the implied heat rate and calculation.[16] Since these data do not provide information about resources that are not the marginal resource at any a particular time, they do not provide information on what may be the marginal resource in the future based on changes to demand, the resource stack, and the operation of the grid and its resources. This inhibits their use without making additional assumptions.

Data collected by the ARB in its GHG emission reporting contains some similar information to that collected by the Energy Commission QFER. However, these data are tailored to emissions and do not provide as much generation data detail as QFER. In addition, the Energy Commission collects the QFER data. This aggregation not only allows for ease of access and quality assurance, but analysis of system trends, plant operational changes, and resource stack evaluation.

Energy Commission staff maintains that the QFER data provide an accurate, verifiable, and robust source of information. QFER data provides direct measurement of electricity generation and fuel consumption over more than a decade. Use of the data is limited by the level of aggregation inherent in the reporting. However, these limits have a negligible effect on the method proposed here, making it a reasonable data source.

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14 See http://energyalmanac.ca.gov/electricity/web_qfer/.

15 SCE and SDG&E use the Southern California Border gas price.

16 Nelson, Jeffrey. April 22, 2014. *Concerns Over Price Formation and Interpretation*. Southern California Edison. Available at: [http://www.caiso.com/Documents/11_ConcernsOverPriceFormation-Interpretation.pdf]

Using Quarterly Fuels and Energy Report Data: Limits and Assumptions

The Energy Commission collects generator data for facilities 1 MW in capacity or larger through the QFER, which became effective February 23, 2001.[17] Categories reported include, but are not limited to, net electricity generation on the generator unit level, fuel type, and fuel consumption. Heat rates are calculated based on reported data on electricity generation and fuel consumption. While the data reported to the Energy Commission are summarized to monthly totals, aggregation on an annual basis proved necessary to mitigate the noise of month-to-month variability between years. Thus, heat rates are presented as annual averages.

A price reduction will tend to produce a proportional reduction in energy from plants with similar heat rate curves since they will have similar costs to produce energy. If the heat rates of one group of resources are similar to the heat rates of a second group of resources and there is sufficient variation in those heat rates, then it could be assumed that the first group will have limited effect on the calculation of the average heat rates of the second group.

While data are not available regarding how much energy or which facilities import their electricity into California, the average efficiency and heat rate curves of those resources are known. This approach relies on the assumptions that out-of-state natural gas-fired generators are similar to California's natural gas-fired fleet, have a variety of heat rates that are distributed among California's natural gas-fired resources, and are dispatched on an economical basis along with the economic dispatch of in-state resources of similar characteristics. It is assumed that this will not significantly alter the calculation of the average heat rates for peaking and load-following resources.

Using a Statewide Resource Pool

Although generator location data are very specific, the regional connection between the generators and the load they serve is not a direct correlation. The California ISO's *Annual Report on Market Issues and Performance* provides information on transmission constraints in both the day-ahead and real-time markets, and can be used to provide insight into the geographical boundaries that should be applied.

The information contained in the report provides frequency percentages for the time during each quarter when transmission line congestion impacted price. These transmission constraints are highly affected by planned generation resource outages and transmission line derating and maintenance.[18] Natural disasters, such as wild fires, must also be

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17 To adapt to the changing energy industry, several amendments were passed over the years that altered the data collection regulations. The current draft forms and instructions were adopted by the Energy Commission on January 2, 2008.

18 Transmission line derating reduces the maximum approved transmission capacity of the line.

accounted for to separate congestion under normal operation from congestion during extraordinary operation.

While there are short time segments when congestion causes electricity prices to rise, these are far surpassed by periods of uncongested operation, under both constrained and unconstrained conditions. As a result, this analysis uses a statewide heat rate curve assumption rather than attempting to estimate localized heat rate curves for areas experiencing congestion. In addition, QFER data, being collected monthly, are insufficient to provide the necessary granularity for localized estimates.

Applying the Resource Constraints to Quarterly Fuel and Energy Report Data

Data from the QFER data set are screened to identify relevant generation resources, limiting the data set to natural gas-fired resources and removing CHP plants and grid stability resources. The data are separated into two categories, load-following resources and peaking resources.

Peaker plants are those plants that have a peak-cycle role, specifically, those plants that are called upon to meet peak demand loads for a few hours on short notice. These plants typically use a fast-ramping, simple cycle CT and are usually restricted in total hours of operation annually by air quality and environmental regulations. Individually, peaker plants generally have capacity factors of less than 10 percent. There were 34 peaker plants identified in 2001; by 2013, the number of peaker plants had grown to 71.

The remaining plants not classified as peaking or stability resources fall into the main category of load-following resources. These are mostly CC CTs. A summary of the average heat rates for load-following plants and associated capacity factors from 2001 to 2013 is presented in **Table 5**.

This resource categorization differs from that used in the Energy Commission's *Thermal Efficiency of Gas-Fired Generation in California Report (Thermal Efficiency Report)*.[19] Load-following resources include the units of once-through cooling plants that have been retrofitted or repowered with new CC CTs.[20] New CC CTs are defined in this paper as 100 MW or larger and built in the late 1990s or thereafter. They do not include repurposed turbines, only those with modern CC CT technology. Some of the plants in the *Thermal Efficiency Report* categorized as "other," because they did not fall under any of the defined groups, are included as load-following resources. Nonrepowered or retrofitted once-

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19 Nyberg, Michael. 2014. *Thermal Efficiency of Gas-Fired Generation in California: 2014 Update.* California Energy Commission. CEC-200-2014-005.

20 See http://www.energy.ca.gov/renewables/tracking_progress/documents/once_through_cooling.pdf.

through cooling plants and none of the aging plants are included in either category (load-following and peaking) as those facilities are deemed necessary for system stability.

Table 5: Average Heat Rates From Load-Following and Peaking Resources (Btu/kWh): 2001 to 2013

Year	Heat Rate of Load-Following Plants	Capacity Factor of Load-Following Plants	Heat Rate of Peaker Plants	Capacity Factor of Peaker Plants	Percentage of Load Balancing Energy From Peaking Resources
2001	8,048	24.1%	11,725	8.9%	36.4%
2002	7,323	36.5%	10,822	5.0%	10.4%
2003	7,329	42.4%	10,716	3.6%	4.0%
2004	7,291	49.4%	10,830	4.3%	3.5%
2005	7,320	39.2%	10,773	3.7%	2.7%
2006	7,279	50.4%	10,694	3.4%	1.9%
2007	7,233	58.7%	10,786	3.7%	1.9%
2008	7,239	61.0%	10,437	4.1%	2.2%
2009	7,242	53.7%	10,671	3.8%	2.3%
2010	7,216	46.9%	10,741	3.0%	1.9%
2011	7,331	35.4%	10,698	3.4%	3.1%
2012	7,239	51.4%	10,838	4.8%	2.9%
2013	7,244	48.5%	10,363	4.5%	3.9%

Source: Energy Commission, Supply Analysis Office, Energy Assessments Division.

CHAPTER 3:
Estimating Changes to the Electric Grid Resource Mix and the Impact on Average Heat Rates

Estimating the future composition of the natural gas-fired resource mix begins with cataloging the existing resources, and then adjusting for retirements and new generation. With the exception of once-through-cooling plants being phased out, retrofitted, or repowered as required by the California State Water Resources Control Board,[21] there is little certainty about retirements and new generation. The amount of new generation that comes onto the system will depend on the outcome of preferred resource procurements (energy efficiency, demand response, renewable generation, CHP, and energy storage). Further, the addition of renewable resources and the increasing emphasis on “flexible capacity” requires resources that can ramp more quickly and more frequently than in the past, increasing the uncertainty about the operating capacity and efficiency of new plants. In addition, it is unclear what effect new plants will have on the operation of older plants. Instead of making assumptions about unknown parameters, this estimate relies solely on historical heat rate data and the trend found within those data.

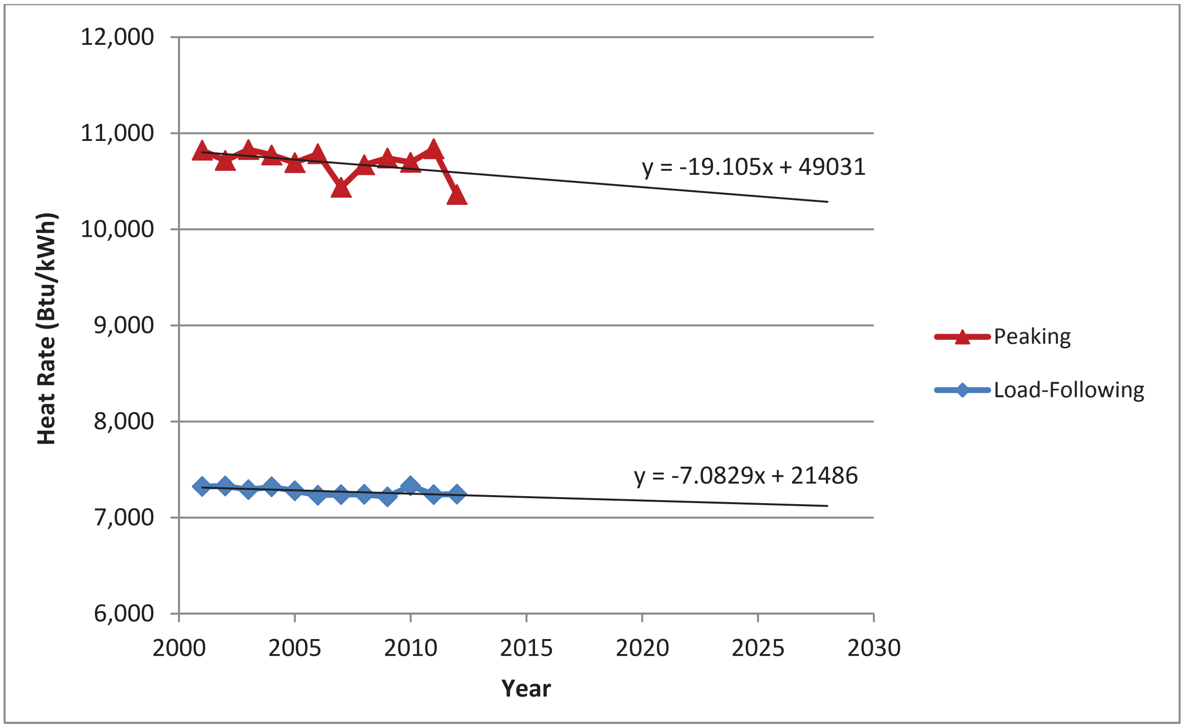
Heat Rate Trends

The historic heat rate data capture changes to the plants that constitute the two resource groups, as well as operational changes of those plants. Operational changes, for example, include plant degradation and changes in efficiency due to variation in ramping. Significant changes to California’s resource mix, such as the extensive development of solar power, may alter grid operation in unknown and unforeseen ways that are not captured in historical trends.

Fitting a linear regression to the historical heat rates for load-following and peaking resources from 2002 to 2013 yields a projection that takes into account recent electric grid trends as seen in **Figure 9** and **Table 6**. The year 2001 was not included in the regressions as the effect of California’s electricity crisis forced atypical power plant operation during that year.

21 See
http://www.energy.ca.gov/renewables/tracking_progress/documents/once_through_cooling.pdf.

Figure 9: Linear Regression of Historical Heat Rates



Source: Energy Commission, Supply Analysis Office, Energy Assessments Division.

Table 6: Annual Average Heat Rates From Regression (Btu/kWh)

Year	Load-Following	Peaking
2014	7,221	10,554
2015	7,214	10,534
2016	7,207	10,515
2017	7,200	10,496
2018	7,193	10,477
2019	7,186	10,458
2020	7,179	10,439
2021	7,171	10,420
2022	7,164	10,401
2023	7,157	10,382
2024	7,150	10,362
2025	7,143	10,343
2026	7,136	10,324
2027	7,129	10,305
2028	7,122	10,286
2029	7,115	10,267
2030	7,108	10,248

Source: Energy Commission, Supply Analysis Office,
Energy Assessments Division.

Line Loss Factor and Onsite Adjusted Heat Rates

Energy is lost during the transmission and distribution of electricity. Accordingly, consuming a megawatt-hour (MWh) of grid-provided energy requires that more than a MWh be generated. A 1 MWh reduction in consumption (due to energy efficiency or demand response) or a 1 MWh of onsite generation (rooftop solar, distributed generation including CHP) reduces the need for grid-provided energy by more than 1 MWh. A line loss factor is needed to account for this additional electricity and the fuel needed to generate it; onsite equivalent represents the reduced efficiency caused by the transmission and distribution of electricity. It is not applied when another grid-connected generator is the source of displacement, as energy from that resource experiences line losses as well.

Loss factors in use differ among programs and even within the same agency.[22] However, determining a loss factor is not in the scope of this paper. Lacking a publicly vetted value, this paper relies on a 7.8 percent line loss percentage derived by the California ARB using the Energy Commission's *California Energy Demand 2008-2018 Staff Revised Forecast*[23] as a statewide loss factor for calculating avoided emissions in the ARB's *Climate Change Scoping Plan*.[24]

The following formula is used to convert line losses into a loss factor and then estimate the additional energy that would have been needed to overcome line losses.

Avoided Line Loss = X/(1 – 0.078), where X is the reduced grid demand.

Using the formula to convert loss rate into a loss factor, line losses of 7.8 percent equals a loss factor of 1.08460. **Table 7** shows the adjusted heat rates from the regression to show the equivalent heat rates for demand side resources.

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22 The discussion of loss factors in planning studies was the topic of an Energy Commission staff paper, which concludes with several outstanding issues that have yet to be addressed in a public process. Wong, Lana. 2011. *A Review of Transmission Losses in Planning Studies*. California Energy Commission. CEC-200-2011-009, available at [http://www.energy.ca.gov/2011publications/CEC-200-2011-009/CEC-200-2011-009.pdf].

23 Marshall, Lynn and Tom Gorin, 2007. *California Energy Demand 2008-2018, Staff Revised Forecast*. California Energy Commission. CEC-200-2007-015-SF2, available at [http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF].

24 California Air Resources Board, *Climate Change Scoping Plan* and *Climate Change Scoping Plan Appendices*, December 2008, available at [http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm].

Table 7: Onsite Adjusted Annual Average Heat Rates From Regression (Btu/kWh)

Year	Onsite Equivalent	
	Load-Following	Peaking
2014	7,832	11,446
2015	7,824	11,426
2016	7,817	11,405
2017	7,809	11,384
2018	7,801	11,363
2019	7,794	11,343
2020	7,786	11,322
2021	7,778	11,301
2022	7,770	11,281
2023	7,763	11,260
2024	7,755	11,239
2025	7,747	11,218
2026	7,740	11,198
2027	7,732	11,177
2028	7,724	11,156
2029	7,717	11,136
2030	7,709	11,115

Source: Energy Commission, Supply Analysis Office, Energy Assessments Division.

Peaking Resources

Peaking resources vary in capacity factor from year to year as shown in **Table 5**.[25] While the electricity crisis in 2001 saw increased use of peaking resources than in previous years, annual variability in the use of peaking resources is primarily driven by the amount of hydro availability, which is dependent on the previous winter's snowpack and summer heat. To draw consistency out of this variability, an average of the energy from peaking natural gas-fired resources is calculated using the historical average with the highest year, lowest year, and 2001 data removed. This yields an average of 2.8 percent for energy from peaking resources provided by California's flexible natural gas resources.

25 *Capacity factor* is the ratio of electricity produced over a period divided by the amount of electricity the power plant could have produced if it had been operated at its maximum permitted capacity for the same period of measurement.

Limitations of Heat Rate Trends

These regressions assume recent trends in technological improvement will continue as more efficient turbines replace some of the current natural gas fleet. This projection of decreasing average heat rates stays within the range of available technologies for the length of the estimate, as analyzed and recommended for use in the Cost of Generation Model by the Energy Commission's *Estimated Cost of New Renewable and Fossil Generation in California Final Staff Report*, referenced in **Table 8**.[26] Since the projection does not exceed current technological limitations, considerations to limit the regressions, such as using a "heat rate floor" below which the heat rate trend is ignored and heat rates do not decline further, are not discussed further at this time.

Table 8: Heat Rates Used in Cost of Generation Report (Btu/kWh, Higher Heating Value)

Technology	Mid[27]	High	Low[28]
Conventional CT[29]	10,585	11,890	9,980
Advanced CT	9,880	10,200	9,600
Conventional CC	7,250	7,480	7,030
Conventional CC With Duct Firing	7,250	7,480	7,030

Source: See Energy Commission, CEC-200-2014-003-SD.

The length of the forecast increases the many unknowns. Driven by new policy, California's electric system will continue to change and evolve over the next 15 years. Continued development of renewable resources and the implementation of emerging technologies, such as energy storage and plug-in electric vehicles (PEVs), will alter the resource stack and grid operation.

The expansion of renewable resources beyond 33 percent in 2020 will come with significant changes to the operation of these resources to accommodate the increasing quantity. These changes may include contract structure, peak generation leveling using inverters, trading energy generation for other system benefits like reactive power, additional curtailment to accommodate even more renewable resource capacity, and changes to the must-take

26 See CEC-200-2014-003-SF, March 2015.

27 Mid and high cost recommended values are based on an analysis of mid and high QFER heat rates and current turbine technology. (For example, the mid cost heat rate for the conventional CT is based on new projects installing the next generation of LM6000 gas turbine.)

28 Low cost recommended values are based on heat rates from turbine manufacturers. Mid cost heat rates in Cost of Generation Model are presented as a regression formula based on QFER data.

29 The conventional CT values are recommended for both the single-turbine (49.9 MW) and two-turbine (100 MW) cases and are based on NXGen LM6000 gas turbine efficiencies that are higher than most of the existing LM6000-powered plants.

priority resource designation. In addition, renewable resources are changing the way the grid operates. High quantities of solar power will shift the time of day when peak demand occurs and alter the grid's demand profile.

Changes to the natural gas-fired resource fleet must also be considered. Beyond resource retirements and additions, and trends in increasing efficiency, there will be a preference for fast ramping turbines to accommodate variable renewable resources and the effect increased frequency of ramping has on operational efficiency to consider.

Projects or programs that span 10 to 15 years will have to account for these changes and how to differentiate the emission reductions between the early and later years.

CHAPTER 4: Application of Heat Rate Estimates and Displacement Examples

California has supported the loading order with numerous pieces of legislation and various programs to support the preferred electricity alternatives of energy efficiency measures, demand response, renewable generation, and distributed generation including CHP. The following examples are intended to illustrate the possible use of the average heat rates in estimating electric grid displacement for these preferred resources.

Energy storage has recently become a preferred resource, not originally contained in the loading order. It is unclear how energy storage will be integrated into grid operations. Energy storage could significantly change how the grid is operated, resulting in the need to reevaluate this method. On the other hand, energy storage may play a more traditional generation-style role if paired with renewable resources. Under these circumstances this method may continue to be applicable with only minor updates. Any calculation of heat rates for energy storage is going to depend on where the electricity that charges it comes from and the efficiency at which the energy storage unit operates. Energy storage systems charged from renewable generation could undergo a similar analysis as that of renewable generation as long as the efficiency of the energy storage system is taken into account. Evaluating alternative applications of energy storage, such as in the ancillary services market,[30] are beyond the scope of this paper.

Because this is just an estimate, it is not, nor is it intended to, replace direct measurement of emission reductions. It is a means to provide uniformity and a common approach to estimating and evaluating different types of resources that avoid use of grid electricity.

The proposed method to determine the equivalent generation fuel displaced by not using grid electricity is to take the number of kilowatt-hours (kWh) of avoided grid electricity consumption multiplied by the annual average heat rate. In general terms, the generation fuel displacement calculation for both load-following and peaking resources is:

(electricity avoided) x (heat rate) = avoided electricity fuel equivalent

Because this method does not consider the daily electric grid load profile in the analysis, it follows that the load profile is not considered in the displacement calculation. Since peaking resources make up an average of 2.8 percent of the energy displaced on an annual average, the limit to applying the peaking heat rate is limited to a maximum of 2.8 percent of the total energy displaced per year. For example, a resource that avoids grid power for all hours of the year will avoid 97.2 percent of load- following resources and 2.8 percent of peaking resources, not 100 percent load-following resources. If this method was altered so that it

30 Ancillary services are specialty functions necessary to facilitate and support the transmission of electric power, and maintain grid stability.

would take into consideration a resource place in the load profile, it would have to consider the total benefit and cost of the resource operational profile. For example, a resource operating as baseload would then avoid only baseload resources, while resources with operational profiles similar to peaker plants could avoid peaking resources. Renewable resources would therefore have to account for the associated impact on the efficiency of gas-fired generation used to balance the intermittent/variable output. These issues are worthy of careful consideration; however, this approach does not allow for this level of comparison.

Staff applied the above method using four sample scenarios to illustrate how this estimation may be applied to a given policy, with a set of assumptions, to yield a numerical result. The specifics of each example are generic, meant only to illustrate the application of the method. Each example uses the same conversion metric based on the carbon content of the fuel as provided by the United States Energy Information Administration, 117 pounds of carbon dioxide (CO_2) emitted per million British thermal units (Btu) of natural gas consumed.[31] Heat rate estimates for five years, from 2014 to 2018, are taken from **Table 6** for exported energy and **Table 7** for onsite energy.

Each example is calculated from user-defined criteria. For energy efficiency and demand response, the user defines the capacity factor equivalent for on-peak and off-peak hours. For renewable generation and CHP, the user defines the capacity factor for on-peak and off-peak hours, as well as the percentage of exported electricity during those times.

Energy Efficiency

For this example, assume that the energy efficiency measure alters the operation of an appliance that operates roughly uniformly throughout the year, such as a refrigerator. For ease of calculation, assume that a refrigerator replacement program reduces demand by 2,000 kW. However, since refrigerators only run part of the time, assume that only 10 percent of the refrigerator compressors will be running at the same time, resulting in a 10 percent capacity factor equivalent throughout the year as shown in **Table 9**.

Table 9: Inputs for Energy Efficiency Example

Quantity Subscribed (kW)	**2,000**
Off-Peak Capacity Factor Equivalent (Percentage)	**10%**
On-Peak Capacity Factor Equivalent (Percentage)	**10%**

Source: Energy Commission, Supply Analysis Office, Energy Assessments Division.

Over a five-year period, this measure yields a total energy savings of 737 metric tonnes[32] CO_2 for 8,765 MWh of avoided electricity generation. These two factors combine to make an

31 See http://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11.

32 One metric tonne is equal to 1000 kg.

avoided emissions displacement factor for this example of 420 kg CO_2/MWh, shown in **Table 10**.

Table 10: Five-Year Results From Energy Efficiency Example

Average Annual Emissions Equivalent (metric tonnes CO_2)	**737**
Total kWh Savings	**8,764,800**
Avoided Emissions Displacement Factor (kg CO_2/MWh)	**420**

Source: Energy Commission, Supply Analysis Office, Energy Assessments Division.

Demand Response

For this example, assume a demand response program is implemented that reduces load during the entire time that peaking resources are being used. Also assume that the reduction is a uniform 1 MW (or 1,000 kilowatts) when it occurs. The inputs are the maximum capacity reduction, the off-peak capacity factor equivalent, and the on-peak capacity factor equivalent, as shown in **Table 11**.

Table 11: Inputs for Demand Response Example

Maximum Capacity Reduction (kW)	**1,000**
Off-Peak Capacity Factor Equivalent (Percentage)	**0%**
On-Peak Capacity Factor Equivalent (Percentage)	**100%**

Source: Energy Commission, Supply Analysis Office, Energy Assessments Division.

Over a five-year period, this measure yields a total energy savings of 149 metric tonnes CO_2 for about 1,227 MWh of avoided electricity generation. These two factors combine to make an avoided emissions displacement factor for this example of 605 kg CO_2/MWh, as shown in **Table 12**.

Table 12: Five-Year Results From Demand Response Example

Average Annual Emissions Equivalent (metric tonnes CO2)	**149**
Total kWh Savings	**1,227,072**
Avoided Emissions Displacement Factor (kg CO2/MWh)	**605**

Source: Energy Commission, Supply Analysis Office, Energy Assessments Division.

Renewable Generation

For this example, assume the simplified operation of a wind generator, a 2.5 MW (2,500 kilowatts) turbine. Also assume that the generator has a 20 percent capacity factor during peak hours, and that operates at a 35 percent capacity factor during off peak hours. These inputs of capacity factor will yield a total capacity factor of 32.8 percent. Below are two examples, one with 100 percent electricity export, and one with no electricity export. **Table 13** shows the inputs for 100 percent electricity export.

Table 13: Inputs for Export Renewable Generation Example

Generator Size (kW)	2,500
Off-Peak Capacity Factor (Percentage)	35.0%
Off-Peak Export (Percentage)	100%
On-Peak Capacity Factor (Percentage)	20.0%
On-Peak Export (Percentage)	100%
Total Capacity Factor	32.8%

Source: Energy Commission, Supply Analysis Office, Energy Assessments Division.

Over a five-year period, this measure yields a total energy savings of 2,920 metric tonnes CO_2 for 37.9 gigawatt-hours (GWh) of avoided electricity generation. These two factors combine to make an avoided emissions displacement factor for this example of 385 kg CO_2/MWh, shown in **Table 14**.

Table 14: Five-Year Results From Export Renewable Generation Example

Average Annual Emissions Equivalent (metric tonnes CO2)	2,920
Total kWh Savings	37,885,848
Avoided Emissions Displacement Factor (kg CO2/MWh)	385

Source: Energy Commission, Supply Analysis Office, Energy Assessments Division.

To demonstrate the effect line losses have on the calculation, this renewable example can be repeated with the assumption that the energy is all used onsite, with the inputs shown in **Table 15**.

Table 15: Inputs for Onsite Renewable Generation Example

Generator Size (kW)	2,500
Off-Peak Capacity Factor (Percentage)	35.0%
Off-Peak Export (Percentage)	0%
On-Peak Capacity Factor (Percentage)	20.0%
On-Peak Export (Percentage)	0%
Total Capacity Factor	32.8%

Source: Energy Commission, Supply Analysis Office, Energy Assessments Division.

Over a five-year period, this measure yields a total energy savings of 3,167 metric tonnes CO_2 for 37.9 gigawatt-hours (GWh) of avoided electricity generation. These two factors combine to make an avoided emissions displacement factor for this example of 418 kg CO_2/MWh, shown in **Table 16**.

Table 16: Five-Year Results From Onsite Renewable Generation Example

Average Annual Emissions Equivalent (metric tonnes CO2)	3,167
Total kWh Savings	37,885,848
Avoided Emissions Displacement Factor (kg CO2/MWh)	418

Source: Energy Commission, Supply Analysis Office, Energy Assessments Division.

Combined Heat and Power

This example assumes a 5 MW (5000 kWh) facility that operates with an 80 percent off-peak capacity factor and a 100 percent on-peak capacity factor. These inputs of capacity factor will yield a total capacity factor of 80.6 percent. To illustrate both onsite and export together in an example, assume that 50 percent of the power is exported to the grid, as shown in **Table 17**.

Table 17: Inputs for Combined Heat and Power Example

Generator Size (kW)	5,000
Off Peak Capacity Factor (Percentage)	80%
Off Peak Export (Percentage)	50%
On Peak Capacity Factor (Percentage)	100%
On Peak Export (Percentage)	50%
Total Capacity Factor	80.6%

Source: Energy Commission, Supply Analysis Office, Energy Assessments Division.

Over a five-year period, this measure yields a total energy savings of 14,299 metric tonnes CO_2 for nearly 177 gigawatt-hours (GWh) of avoided electricity generation. These two factors combine to make an avoided emissions displacement factor for this example of 405 kilograms CO_2/MWh, shown in **Table 18**.

Table 18: Five-Year Results From Combined Heat and Power Example

Average Annual Emissions Equivalent (metric tonnes CO2)	14,299
Total kWh Savings	176,523,072
Avoided Emissions Displacement Factor (kg CO2/MWh)	405

Source: Energy Commission, Supply Analysis Office, Energy Assessments Division.

This calculation accounts for only the generation fuel displaced by avoided use of grid electricity from this hypothetical CHP generator. Since the operating efficiency of CHP systems and boilers is out of the scope of this paper, this calculation does not take into account how much fuel the CHP unit used or the avoided boiler fuel. Real-world calculations should take these variables into account. Distributed generation that provides only electric power, such as some fuel cells, would follow the same approach as CHP in calculating generation fuel displacement. Since this method does not comment on the efficiency of distributed generators, the fuel consumed by the generator would need to be accounted for to determine the net avoided fuel.

Summary of Displacement Examples

Table 19 summarizes the examples used in this paper for carbon content, avoided grid energy, and carbon intensity.[33] The values depend on the assumptions used in the examples, resulting in unique displaced carbon intensities, but do not represent all reduction measures of that particular type.

These examples are meant to illustrate the application of this method and the drivers that yield a variety of displaced carbon intensities. Since the examples are generic, the resulting avoided carbon intensities are not definitive of the reduction type but instead show the consequence of the assumptions. Line losses and the ratio of peak to off-peak energy drive the variations. The difference between the two renewable generation examples illustrates the impact line losses have on the calculation. A renewable generator used onsite will have a higher displacement carbon intensity. The difference in displaced carbon intensity in the energy efficiency and the onsite renewable examples is attributable to the ratio of peak to off-peak electricity. For the carbon intensity in the CHP example, neither the carbon intensity of the CHP generator nor the avoided boiler fuel is included.

Table 19: Illustrative Calculation of Emissions Displacement (and Carbon Intensities) Using 2014 Heat Rates

Illustrative Example	Five-Year Total CO_2 Conversion (metric tonnes CO_2)	Five-Year Total Avoided Grid Energy (MWh)	Average Avoided Carbon Intensity (kg CO_2/MWh)
Energy Efficiency	737	8,765	420
Demand Response	149	1,227	605
Renewable (export)	2,920	37,885	386
Renewable (onsite)	3,167	37,885	418
Combined Heat and Power	14,299	176,523	405

Source: Energy Commission, Supply Analysis Office, Energy Assessments Division.

33 *Carbon intensity* is the average amount of emissions per unit of electricity, typically expressed in pounds CO_2 per MWh.

CHAPTER 5: Preliminary Discussion and Public Comments

The straightforward policy- and program-neutral approach of this method has benefits and limits. The proposed approach for estimating displaced electricity outlined in this report is designed to create a uniform standard that can be applied across programs and may be used by multiple state agencies and outside organizations.

Among the strengths of this approach, changes to the composition of each resource class will not affect this approach to determining heat rates. This allows for easy updating using QFER data periodically. The way this method defines peak hours, by not being tied to specific hours of the year, allows for flexibility to capture changes to these resources. This characteristic means that those who apply this method will need to be aware of when the peak hours of electric demand occur and how they may change over time as California's electricity system continues to evolve.

On the other hand, the electricity system is becoming more complex, given renewable development obligations, local capacity requirements, and a number of environmental policies that will be implemented throughout the decade. Preferred resource additions will likely shift the amounts, time of day, and seasons that conventional thermal generation may need to operate. Local capacity requirements and changes to the transmission system could significantly impact real resource displacement. The changing dynamics of the grid and associated operation may necessitate major changes to this method and could eventually render it invalid.

A summary paper of this method was made available and presented at an Energy Commission staff workshop on CHP held on July 14, 2014. Written comments were received on the summary paper from the following parties:[34]

- Bloom Energy (Bloom)
- California Clean Distributed Generation Coalition (CCDC)
- California Cogeneration Council (CCC)
- Energy Producers and Users Coalition and the Cogeneration Association of California (EPUC & CAC)
- Etagen, Inc. (Etagen)
- Los Angeles Department of Water and Power (LADWP)
- Pacific Gas and Electric (PG&E)
- San Diego Gas & Electric (SDG&E)
- Southern California Gas Company (SoCal Gas)

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34 http://www.energy.ca.gov/chp/documents/2014-07-14_workshop/comments/.

- Steve Uhler

This chapter uses these stakeholders' views to present the issues associated with creating an electric grid fuel displacement method. The end of this chapter contains questions to solicit additional public comments. This provides the opportunity for stakeholders to comment on the staff paper and build upon existing discussions to determine the best available parameters for a standardized approach to estimating electric grid fuel displacement.

The general consensus in the written comments is that the proposed method is a worthwhile starting point for the discussion of a displacement method, but nearly all the stakeholders take issue with one or more of the assumptions. There is a wide range of directions and possible methods that could be developed, yet the underlying goal of determining a simple, tractable method to estimate avoided grid fuel consumption remains. Parameters such as the granularity, or level of detail, of a fuel displacement calculation and the perceived accuracy of such a calculation have to be weighed against the ease of producing displacement estimates and the incremental usefulness of increasingly complex analysis.

Method Application

CCDC expressed the need for "a consistent State-wide methodology on [displacement] and energy policy in general" because it is "important to end users and energy solution providers who need to plan 10 to 15 years out for prospective energy infrastructure investments." Bloom agreed that the proposed method, with some modifications, should be used with existing and future programs that identify GHG reduction as a goal of the program. However, SoCal Gas raised an important point: "Programs are usually created to meet specific goals. Creating a methodology that could be applied across programs will not necessarily take the specific goals of a program into account. At most, the Energy Commission methodology should be use[d] to supplement existing program evaluations, not replace them." This belief that each program could have a unique displacement method runs counter to having a standardized approach. Such an opinion is voiced by Steve Uhler in his comments: "This method is agnostic to the approaches and methods used by those programs to estimate emission reductions. If this interferes with existing program-specific displacement metrics, maybe those metrics need adjusting."

It is staff's position that there are numerous existing programs where altering the existing displacement method is not possible or would have questionable benefit, such as in the American Recovery and Reinvestment Act of 2009. It makes sense for these programs to separately apply a standard method with any necessary caveats. Looking forward to new programs, a standardized displacement method has significant benefit for policy planners, energy solution providers, and end users. If a forward-looking, universal standard is going to be applied, what levels of granularity are necessary to provide a reasonable estimate of electric grid fuel displacement without giving false precision?

Method Considerations

In creating a displacement metric, one of the first issues to be addressed is whether to use a historical approach or a production cost model. Does a production cost model provide substantial value that would significantly alter a displacement analysis? Do the benefits of using a production cost model and the added complexity outweigh that of a simple historical-based method?

Numerous comments touched on this discussion, even if some did not directly call out the use of a production cost model.

The joint comments from EPUC & CAC get straight to the heart of the matter. "There are two preferable methods for determining the effective heat rate of the displaced grid electricity. One is a historical-based method, and the other is a well-vetted and auditable production simulation modeling approach."

The comments continue: "Of these two preferred methods, the most straightforward and less controversial is the historical method." EPUC & CAC reference the California ISO day-ahead locational marginal price at generation nodes and aggregation points[35] as a way to get the necessary level of detail to fulfill desires for more granular location and time of delivery data in a transparent manner.

EPUC & CAC go on to discuss the alternative of a production simulation model method.

> "[This] typically employs a proprietary computer model that is costly to acquire and very complex to operate. While the major computational advantage of this method is the ability to simulate the impact of future projected changes in system resource configuration as well as load growth on the effective heat rate, the disadvantage is that the method requires hundreds, if not thousands of data inputs, with virtually all of these inputs subject to dispute. Moreover, underlying modeling assumptions and the manner that certain system aspects are represented in the model's list of options can significantly influence the results of such models."

The Energy Commission uses a production cost model, PLEXOS®, to support work performed by the Energy Assessments Division, such as in its natural gas outlook report. This production cost model may be repurposed to aid in a displacement analysis; however, any production cost model is going to have the issues of uncertainty and sensitivity to inputs, especially in the later years of an estimate. The model, a complex algorithm that is solved using multiple simultaneous equations, dispatches plants on an incremental, iterative basis to meet projected demand. Overgeneration is a system constraint problem that occurs when the model is unable to solve given the parameters of the run. Some of

35 **http://www.caiso.com/docs/2004/02/13/200402131607358643.pdf**.

these parameters may be limiting export energy, minimum gas-fired generation in local reliability areas, load profile, transmission constraints, and scheduled generator maintenance outages. For example, renewable resources, as regulatory must-take generation,[36] are dispatched prior to natural gas-fired generation. This means that renewables are never curtailed in the model. It also means that when there is overgeneration, the energy is available for export to neighboring states.

Etagen and Bloom both expressed concern over the weighting percentage for peaker plants, arguing that the applicable percentage should be applied whenever a peaking unit is operating. This in itself may not require a production cost model but would require additional analysis of hourly dispatch data.

CCC argues that existing CHP does not displace the marginal resource, but resources that are less efficient than the marginal resource, since those generators would be generating if not for existing CHP. CCC suggests use of a complete incremental system heat rate for estimating fuel displacement. This view is shared by EPUC & CAC as well, that the fuel displacement factor understates the benefits of existing CHP.

PG&E does not specifically favor one approach over the other but does recommend benchmarking the proposed method against production simulation model-based analysis so that the approach accounts for the presence of renewables and other GHG policies.

Even if the use of historical data was not challenged, using a regression analysis was contested. The main concern was failure to incorporate operational changes to gas-fired generation over the long-term.

SoCal Gas commented that the proposed method is inappropriate, that it "will miss the major changes in the operation of [new gas-fired] resources, especially as more variable energy resources are integrated into the grid." SoCal Gas also agrees with Etagen and Bloom that this will result in an increase in the share of energy from peaking resources.

CCDC expressed a similar concern. "In the longer term, most fossil generation will be dispatched to firm renewable generation resulting in more cycling and higher heat rates. CCDC does not feel that decreasing heat rate trends continue for the longer term situation in California."

SDG&E does not call out a preferred method but states that the

> "proposed [historically-based] method would have no consideration of SDG&E's addition of over 1,000 MW of renewables in the next three years to its portfolio and no consideration of SDG&E's near flat load forecast through 2024 due to increased energy efficiency, and no consideration of

36 Must-take resources have scheduling priority and receive a higher level of protection from curtailment than that given to resources with self-schedules and economic bids.

> the Federal or State's future goals for GHG reduction from SDG&E's electricity generation portfolio."

SDG&E continues its explanation of the inappropriateness of the proposed method:

> "For SDG&E, with relatively no CAISO market imports other than firming-and-shaping contracts, with no coal in its portfolio, and reaching 33% RPS in the near future, all out-of-the-local-area must-take topping cycle CHP generation will increase the GHG content of SDG&E's portfolio."

However, SDG&E also posits that "displaced grid electricity for SDG&E is two-thirds gas-fired and one-third renewable energy regardless of whether the CHP electricity is used behind the meter or is sold to the grid." Further nuancing its position, SDG&E also believes in a more detailed approach "if applied to energy efficiency or renewable energy with different patterns of saving/production throughout the day or across months in response to weather."

Staff believes that it is unclear that a production cost model would be the best way to achieve the goal of creating a single displacement method that could be broadly applied and allow for program comparison, particularly in the time frame being considered. Using historical data remains a feasible starting place; however, significant changes taking place to the resource mix and the increasingly dynamic operation of the electric grid may require future updates to this approach. In addition, the application of this method may be insufficient by itself for analysis of subannual increments, such as daily displacement patterns or seasonal variation. While the grid will continue to be operated in the near term (3-5 years) in a way consistent with current practices, additions of renewable resources, changes in operational characteristics, and evolutions of energy technology make the mid- to long-term operation of the grid unclear.

As California moves past its 33 percent renewable energy target and its electric system continues to change, so will the metric traditionally used in planning. For example, the traditional peak demand period was driven by the use of air conditioning during the hottest months of the year. However, the addition of solar resources that generate during the same time frame, but that stop production suddenly as the sun sets, is changing the time window within which the peak occurs. This change has also shifted focus to flexible resources capable of quick dispatch and fast-ramping capabilities. New technologies, such as energy storage, can help meet these new system needs but could also alter the operational patterns for both renewable and nonrenewable resources, which will alter the assumptions of what may be displaced from further pursuit of preferred resources. Finally, curtailing renewable resources will allow for greater renewable capacity on the system, albeit with decreasing incremental benefit. Demand-side reductions will also experience this decreasing incremental benefit when measured solely by the ability to reduce GHG emissions.

Method Parameters

The parameters for an evaluation method are intended to add value for decision makers, program designers, and evaluators. At a certain point, the marginal benefit of greater specificity will be outweighed by complexity and application. The benefit of increased detail and complexity has to be measured against transparency and false precision, in addition to the cost and effort to create, maintain, and apply such standards. This section discusses the various parameters used in this paper and possible alternatives taken from public comments received on the summary of staff's proposed method that was presented at the July 14, 2014, staff workshop on CHP.

Treatment of Renewable Resources

While some parties agree with the proposed method that renewable generation will not be displaced, many commentators believe that renewable generation should be included and analyzed. PG&E stated that it "believes that the staff approach should account for the overgeneration hours where renewables (instead of thermal resources) can be on the margin." Steve Uhler raises an important point in his comments, noting that the effect renewable resources have on grid operation, whether for spinning reserves or to cover generation fluctuations, should be attributed to that renewable resource and factored into the net fuel displacement for that resource.

There is a lack of historical data available to significantly address this issue. PG&E and SDG&E both reference Energy and Environmental Economic Inc.'s report *Investigating a Higher Renewables Portfolio Standard in California*[37] and its estimate for percentage of time and energy when renewable generation would cause over-generation. Curtailment is seldom done and, when it occurs, it is for local reliability purposes. It has been widely recognized as a growing issue that needs addressing.

In a production cost model, the specific hours of the year when overgeneration occurs could be quantified. However, as PG&E notes, overgeneration

> "occurs when 'must-run' generation (such as non-dispatchable renewables, CHP, nuclear generation, run-of-river hydro) and thermal generation which is needed for grid reliability is greater than load plus exports."

It is staff's position that no single generator or resource type is solely responsible for overgeneration. Rather, it is a system issue. There is no clear answer for how the hours in which overgeneration occurs should be treated in a displacement analysis.

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37 See https://ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf.

Staff recognizes that reductions in demand influence the Energy Commission's California Energy Demand Forecast and, thus, the projected amount of retail sales that is used to calculate the IOU's renewable resource procurement targets to meet California's Renewables Portfolio Standard (RPS). The demand forecast incorporates economic/demographic growth, electricity and natural gas rates, committed efficiency programs, self-generation impacts, and achievable energy efficiency into electricity demand scenarios. Reductions in demand, specifically from energy efficiency and onsite generation, do not automatically correlate with reductions in the amount of electricity generated by renewable resources. First, the three content categories in the Renewables Portfolio Standard allow for the inclusion of renewable electricity that may not be delivered to California, thus not affect the operation of California's grid resources. Second, the translation from projected demand reductions to reduced capacity procurement to reduced electricity generation from renewables is tenuous at best, given the frequently repeated viewpoint that the 33 percent Renewables Portfolio Standard goal is a floor to procurement rather than a ceiling. Third, since renewables are must-take resources, this energy is not currently curtailed during standard operation. The existing RPS accounting methods, the inexact nature of the planning processes, and the current operation of renewable resources makes accurately evaluating the impact of energy efficiency and demand reduction on annual renewable generation totals difficult at best. Doing so at this time within this proposed method is impractical.

Annual Heat Rate Values

Half of the commentators thought the use of annual displaced heat rate value averages were sufficient, with one party questioning the long-term adequacy of this use. The other half thought using annual averages was insufficient, calling for seasonal and/or hourly heat rate estimates. CCC had an additional concern that the marginal heat rate would not properly account for the displaced fuel of the less efficient generators that are not running because of alternatives such as CHP. CCC views the marginal resource as the most efficient resource being displaced, and that the group resources truly displaced by the entire CHP fleet are less efficient than the marginal resource. Thus, adjustments should be made to account for the lesser efficiency of the displaced resources.

Single Heat Rate Projection

A majority of the commentators thought that use of a statewide heat rate projection is appropriate to meet the stated goals and needs. However, SDG&E, EPUC & CAC, and CCC presented arguments to the contrary. SDG&E stated that its portfolio has an emissions rate well below that of the proposed method and that adding CHP would increase emissions, as opposed to the proposed method showing a benefit by adding CHP. EPUC & CAC and CCC both cite the substantial differences between the California ISO's market heat rates for North Path 15 and South Path 15. All three parties argue that a statewide heat rate is not appropriate and additional geographically detailed analysis is needed to develop more accurate approximations.

Heat Rate Categories

Some commentators supported the use of two heat rate categories (peaking and load-following), while others thought this only a good starting point. SoCal Gas generally approved with a caveat: “[A]s long as each category is representative of how the units are actually operated. New quick-start combustion turbines used specifically for ramping may require the creation of a third category.” PG&E and SDG&E expressed desire for a third heat rate category for times when renewable resources are on the margin. Bloom commented that imported electricity should be included as a third heat rate category. EPUC & CAC expressed two concerns: 1) averaging tends to understate marginal values, and 2) system conditions often result in peaking resources being dispatched during hours of the day or months of the year that are not considered to be peak-related. CCC was least in favor of this two category approach, stating, “To be clear, the average and market heat rate estimated above are just a component of, and should be view[ed] as the starting point for, the complete incremental heat rate that should be used in estimated fuel displacement.”

Imported Electricity

Several parties were unclear with the assumptions that were used and the treatment of imported electricity. EPUC & CAC and CCC both considered California ISO market data in their comments, which incorporate imports because they are sales data, not generation data. PG&E stated, “…[S]taff’s current approach of looking primarily at instate gas-fired generation is a reasonable proxy for displaced grid resources, with the qualification that the impact from overgeneration conditions should also be considered.” Bloom took a slightly different stance, stating, “[T]he heat rate for imported power should be based upon the default emissions factor for unspecified imports previously determined…”

Line Loss Factor

While the majority of the parties thought the proposed line loss factor a reasonable estimate, some did not. Steve Uhler stated that the loss factor should be based on empirical data. SGD&E said that the line loss factor was probably too high for its service area, stating that in 2013 the total generation and purchases exceeded retail sales by 5.5 percent. CCC cited and suggested using the line loss factors from an IOU’s general rate case, which are provided at the various levels of the transmission and distribution system and are utility-specific. PG&E expressed concern over the lack of an updated estimate for line losses and recommended study of how line losses are expected to change over time.

Heat Rate Floor

Opinions on the application of a heat rate floor are split. Bloom "agree[s] that a heat rate floor based on natural gas-fired generation is appropriate, and that the Energy Commission has proposed a reasonable estimate." Etagen added that the heat rate floor should be updated when newer, more efficient technology is installed. CCDC and SoCal Gas disagree, stating that the floor does not take into account the expected operation changes to gas-fired generation and that the change in unit operation will affect the heat rate floor. PG&E and SDG&E both state that over-generation needs to be examined and accounted for.

Request for Public Comments

The discussions in this paper outline the issues that need to be dealt with to create a standardized approach for evaluating electric grid displacement. The Energy Commission will use this feedback to update an approach that is consistent with stakeholder feedback and produce a separate report detailing the best available parameters for estimating fuel displacement. The Energy Commission is accepting written comments on this proposed method through June 19, 2015. The Energy Commission requests that parties address the following questions in their written comments:

- Is a uniform statewide method appropriate for evaluating emissions displacement factors over a long-term (10-15 year) planning horizon? If not, please explain.
- Are the assumptions used to calculate the avoided generation for energy efficiency, demand response, and combined heat and power (and other distributed generation) correct? If not, what changes need to be made?
- Is the treatment of onsite generation and associated electric grid displacement appropriate? Please explain.
- How might this method be applied in program planning and comparison or program impacts? In what circumstances do you see the state using a method like this?
- What programs and/or situations would this method be inappropriate to apply? (For example, would it be inappropriate to use this method to estimate the emissions avoided by geothermal plants that operate as base load?)
- Do you think the approach (as a whole or specific elements of the method) will result in accurate estimate, or will it overestimate/underestimate grid displacement? Please explain.
- What do you think are the appropriate levels of granularity, such as geographic or temporal, are necessary to provide a reasonable estimate of electric grid fuel displacement? Please use the discussion of method parameters section in Chapter 5 as a starting place for discussion.

ACRONYMS

Acronym	Definition
ARB	California Air Resources Board
Bloom	Bloom Energy
Btu	British thermal units
CC	Combined cycle
CCDC	California Clean Distributed Generation Coalition
CCC	California Cogeneration Council
CHP	Combined heat and power
CT	Combustion turbine
CO_2	Carbon dioxide
Energy Commission	California Energy Commission
EPUC & CAC	Energy Producers and Users Coalition and the Cogeneration Association of California
Etagen	Etagen, Inc.
GHG	Greenhouse gas
ISO	Independent System Operator
KWh	Kilowatt-hour
MWh	Megawatt-hour
PG&E	Pacific Gas and Electric Company
PEVs	Plug-in Electric Vehicles
QFER	Quarterly Fuels and Energy Report
RPS	Renewables Portfolio Standard
SB 1305	Senate Bill 1305
SDG&E	San Diego Gas & Electric Company
So Cal Gas	Southern California Gas Company