California Energy Commission

STAFF REPORT

Estimating Near-Term Grid Operation and Marginal Resource Efficiency for California Electricity

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ABSTRACT

This staff report describes the general operation of the grid and the order in which resources are dispatched to meet electric demand. The analysis concludes that a segment of natural gas-fired resources, divided into load-following and peaking generators, are the resources most likely to be displaced in the near-term. The trends in both resource categories show increased efficiency, which will most likely continue to improve. Challenges and uncertainties beyond the near-term, predominantly driven by increasing generation from variable renewable resources, will alter the way the grid is operated and the order in which resources are dispatched.

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

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EXECUTIVE SUMMARY

California's energy strategy is guided by the loading order, which calls first for reducing electricity demand with energy efficiency and demand response programs; then meeting remaining generation needs with renewable and distributed generation, including combined heat and power; and finally by 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. These methods are sufficient for some programs, but the differences in approaches and assumptions make program comparison difficult.

This report analyzes the generation resources that meet California's electric grid demand and comments on the operational properties of those resources. It reviews the general operation of the grid and organization of the resource stack (the order that resources are dispatched in to meet electric demand). Using general assumption, the average efficiency of the natural gas resources that are likely the last to be dispatched in the near-term (up to five years) is estimated.

Method Overview

Estimating the future composition of the natural gas-fired resource mix begins with cataloging 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, there is little certainty about retirements and new generation. The amount of new generation will depend on the outcome of preferred resource procurements (energy efficiency, demand response, renewable generation, distributed generation, and energy storage).

The addition of renewable resources and the increasing emphasis on flexible capacity requires resources that can ramp up and down more quickly and more frequently than in the past, increasing the uncertainty about the operating capacity and efficiency of new plants. It is unclear what effect new plants will have on the operation of older plants. This near-term estimate relies solely on historical heat rate data and trends, and does not make assumptions about unknown parameters.

Characterizing Electric Grid Generation Resources

Electric generation resources have technological and operational characteristics that allow them to be categorized. These characteristics guide 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 by the way they are operated. A common way to capture operational differences is by the capacity factor, 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 operate primarily during high demand or peak hours (peaking resources). High-capacity factor units operate continuously and follow net demand up and down (load-following resources).

Historical Heat Rate Trends

The Energy Commission collects generator data for facilities 1 MW in capacity or larger through the *Quarterly Fuels and Energy Report* as of February 23, 2001. Categories reported include 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 is summarized monthly, annual aggregation is also necessary to mitigate variability. Thus, heat rates are presented as annual averages.

Data from the *Quarterly Fuels and Energy Report* is screened to identify relevant generation resources, limiting the data set to natural gas-fired resources, and removing combined heat and power plants and grid stability resources. The data set is separated into load-following resources and peaking resources. Plants not classified as peaking or stability resources are categorized as load-following resources. These are mostly combined cycle combustion turbines. A summary of the average heat rates for load-following plants and associated capacity factors from 2001 to 2014 is presented in **Table 1**.

Peaking resources vary in capacity factor, the ratio of electricity produced over a given period divided by the amount of electricity the power plant could have produced if it operated at maximum permitted capacity for the same period, as shown in **Table 1**. While the electricity crisis in 2001 saw increased use of peaking resources, annual variability in the use of peaking resources is driven primarily by hydro availability, dependent on the previous winter's snowpack and summer heat.

The "Percentage of Load Balancing Energy From Peaking Resources" column in **Table 1** shows the amount of energy used by those resources. While peaking resources individually vary in annual capacity from one to ten percent, it is impossible to tell which and how many of these resources are operating at any particular time. It is assumed that most, if not all, are operating during peak system hours. As the resource stack and operation of the grid changes, research will be needed to inform the assumptions characterizing peaker plant operation.

Table 1: Average Heat Rates From Load-Following and Peaking Resources (British Thermal Units per Kilowatt Hour): 2001 to 2014

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%
2014	7,332	49.4%	10,402	5.8%	4.8%

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

Near-Term Heat Rate Trends

The historic heat rate data captures operational changes, including plant degradation and efficiency levels due to ramping variations, to peaker and load-following plants. Significant changes to California's resource mix, such as 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 historical heat rates for peaking and load-following resources from 2002 to 2014 yields a projection that takes into account recent electric grid trends as seen in **Table 2**. The year 2001 was not included in the regressions due to atypical power plant operation caused by the electricity crisis.

Table 2: Five-Year Heat Rate Estimates

Year	Load-Following	Peaking
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

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

Underlying factors, such as capacity factor and fleet efficiency are contingent on the intensity of summer heat and the amount of hydro production, are not fully delineated by the regression. Notwithstanding drought conditions during recent years, the trend in improved efficiency of load-following generation has leveled off. These system interdependencies add considerable uncertainty to future grid resource operation estimates.

Challenges of Looking Beyond the Near-Term

The challenges and uncertainties of making long-term estimates (10 to 15 years) are discussed throughout the report and summarized here.

- Peak hours for California load are shifting. Any method that attempts to identify reductions from avoiding grid use during peak hours will have to account for the possibility that peak demand may occur at different hours of the day or even times of year.
- Growth of renewable resources and uncontrolled generation from them is causing periods where their energy is not usable. This problem exists currently for a limited number of hours, but is increasing, which could affect the characterization of the resource and displacement estimates beyond the near-term.
- As renewables become the primary resource, the agreements under which they operate may change, resulting in new operational profiles that must be considered.
- Future construction of renewables may not just be driven by legislative mandate, but also by cost competition. In this environment, generation procurement and the mix of grid resources will change dramatically and alter the process of estimating grid displacement.
- New innovative technologies could change the operational profile of resources. Technologies such as electricity storage may drastically alter the operational landscape of the grid, rendering some of the characterizations invalid.
- Any method that estimates long-term resource displacement and operational changes must consider policy drivers that alter resource procurement and grid operation. Historic data can provide insight into electric grid trends and provide a starting place for future estimates.

CHAPTER 1: Introduction

California's energy strategy is guided by the *Energy Action Plan* and the loading order therein.[1] The loading order calls first for reducing electricity demand with energy efficiency and demand response programs; then by meeting remaining generation needs with renewable and distributed resources; and finally by 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 resulting from avoided generation vary substantially in approach and assumptions. Each method has been developed to fit a specific program or purpose. These methods are sufficient for some programs, but the differences in approaches and assumptions make program comparison difficult. A measurable, consistent, and widely applicable analytical approach will alleviate this conflict and lead to better policy making.

This report analyzes the generation resources that meet California's electric grid demand and comments on the operational properties of those resources. It reviews the general operation of the grid and organization of the resource stack (the order that resources are dispatched in to meet electric demand). Using general assumption, the average efficiency of the natural gas resources that are likely the last to be dispatched in the near-term (up to five years) is estimated.

The approach is designed to be policy-neutral, agnostic to the approaches and methods used to estimate emission reductions by programs that encourage the use of preferred resources. This is accomplished by looking at the current and historic operation of the grid and its resources. Assumptions were not made about the following:

- Retirement of existing resources
- Addition of new resources (preferred or otherwise)
- The impact current preferred resource procurement will have on future procurement
- The impact new resources will have on existing resource operation
- The emphasis on a "flexible" grid (requiring resources to ramp more quickly and more frequently)
- Future renewable procurement policy and legislation

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

Since the regression is based on historical data, the greater the extrapolation, the more uncertain the estimate. Combined with prospective grid developments, estimates beyond the near-term are speculative. In addition, since the regression is based on annual averages, day-to-day and seasonal variations are not detailed. Individual assumptions about the future of the electric grid and its resources are not made. Estimating the impacts of programs or policies that could cause large-scale changes to the grid and its resources may draw upon the information provided here, but should not rely solely on this analysis.

This staff report is based primarily on the staff paper *Proposed Near-Term Method for Estimating Generation Fuel Displaced by Avoided Use of Grid Electricity* published in June 2015. A summary paper of an emission displacement method was presented at an Energy Commission staff workshop on July 14, 2014.

Grid Operation and Marginal Grid Resources Beyond Five Years

In developing this approach, staff attempted to account for uncertainties associated with analyzing future events in complex systems. The changes to California's electric grid resources should have minimal impact on existing grid operation for the next three to five years; however, cumulative changes will gradually have greater influence on grid operation and alter associated emissions.

The challenges and uncertainties of making estimates over the long-term (10 to 15 years) are discussed throughout the report and are summarized here.

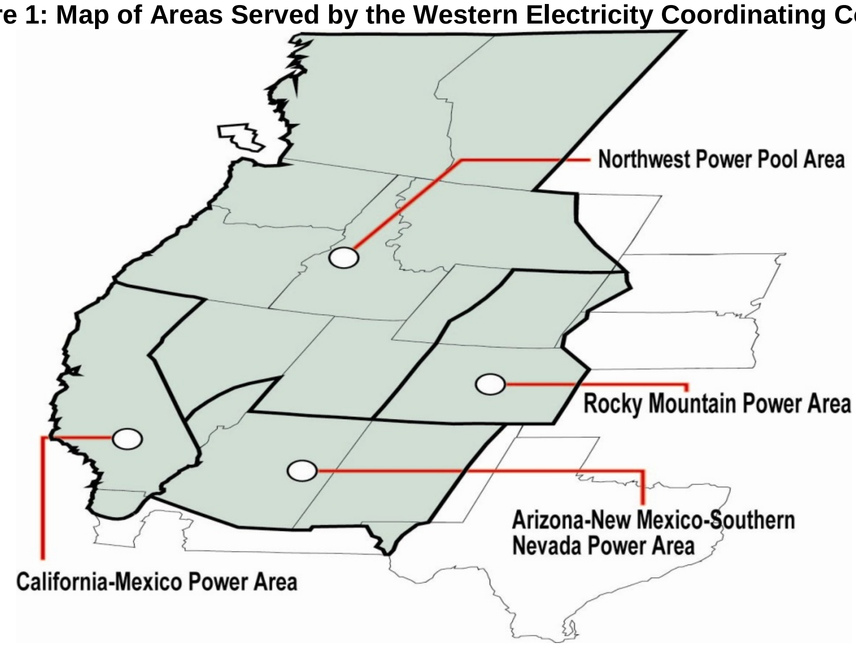
- Peak hours for California load are shifting. Any method that attempts to identify reductions from avoiding grid use during peak hours will have to account for the possibility that those peaks may occur at different hours of the day or even times of year.
- Growth of renewable resources and the uncontrolled generation from them is causing periods of time where their energy is not usable. This problem exists currently for a limited number of hours, but is increasing, which could affect the characterization of the resource and displacement estimates beyond the near-term.
- As renewables become the primary resource, the agreements under which they operate may change, resulting in new operational profiles that must be considered.
- Future construction of renewables may not just be driven by legislative mandate, but also by cost competition. In this environment, generation procurement and the mix of grid resources will change dramatically and alter the process of estimating grid displacement.
- New innovative technologies could change the operational profile of resources. Technologies such as electricity storage may drastically alter the operational landscape of the grid, rendering some of the characterizations invalid.

CHAPTER 2: Meeting California's Electricity Demand

The entities that operate California's electricity system must continually balance supply and demand to provide a reliable supply of electricity. To achieve this balance, the system relies on a portfolio of hydroelectric, natural gas, renewable, coal, and nuclear-powered generating power plants, which use different fuels and have different operating characteristics. Control area operators schedule and dispatch generation as needed to ensure power delivery and grid stability.

California's electricity system is part of a partnership known as the Western Electricity Coordinating Council (WECC), which serves 11 western states and areas of two additional countries: British Columbia and Alberta, Canada, and Baja California Norte, Mexico. The WECC provides California greater dispatch flexibility and allows the sharing of surplus generation capacity. **Figure 1** shows the areas served by WECC.

Figure 1: Map of Areas Served by the Western Electricity Coordinating Council

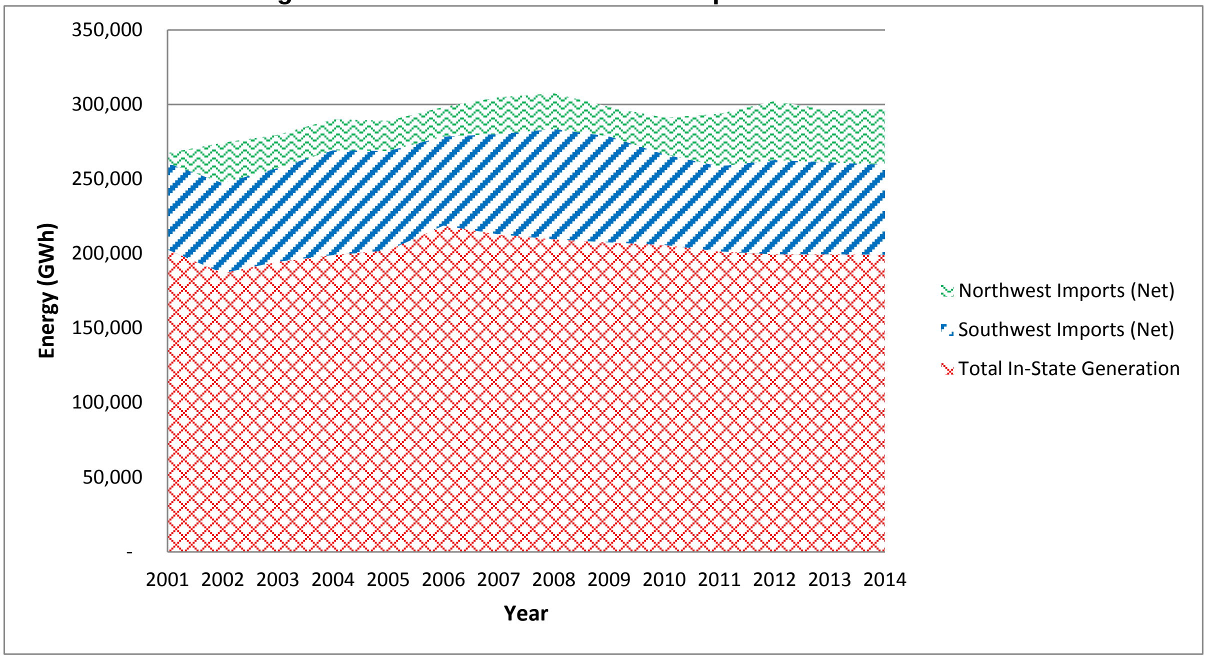


Source: Energy Commission.

Historical Trends

California meets approximately 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 from 2001 through 2014 are presented in **Figure 2**. In-state generation was at its highest in 2006, meeting more than 78 percent of 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 approximately 24 percent in 2008 before declining slightly.

Figure 2: In-State Generation and Imports: 2002 to 2014



Source: *Quarterly Fuels and Energy Report* and SB 1305 (Sher, Chapter 2.3 of Part 1 of the Public Utilities Code, Statutes of 1997) (SB 1305) 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.[2]

Averaging 14 percent of California's in-state generation, hydroelectric resources depend on annual rainfall and snowmelt. In 2012, 2013, and 2014, rainfall and snowpack were significantly lower than average. This was compounded by the retirement of the San Onofre Nuclear Generating Station (SONGS) early in 2012, which provided 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.

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.[3] This category includes spot market purchases, wholesale

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

3 The Power Source Disclosure Program was created to fulfill SB 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.

power marketing, purchases from pools of electricity where the original source is unspecified, and"null power." **Null power** is the generic electricity commodity that remains when renewable attributes (renewable energy credits) are stripped and sold separately. Most large hydro from the Northwest is reported as unspecified power because the short-term contracts these facilities operate under do not meet the regulatory requirements of "large hydro."

Table 3: California's Total System Power for 2012

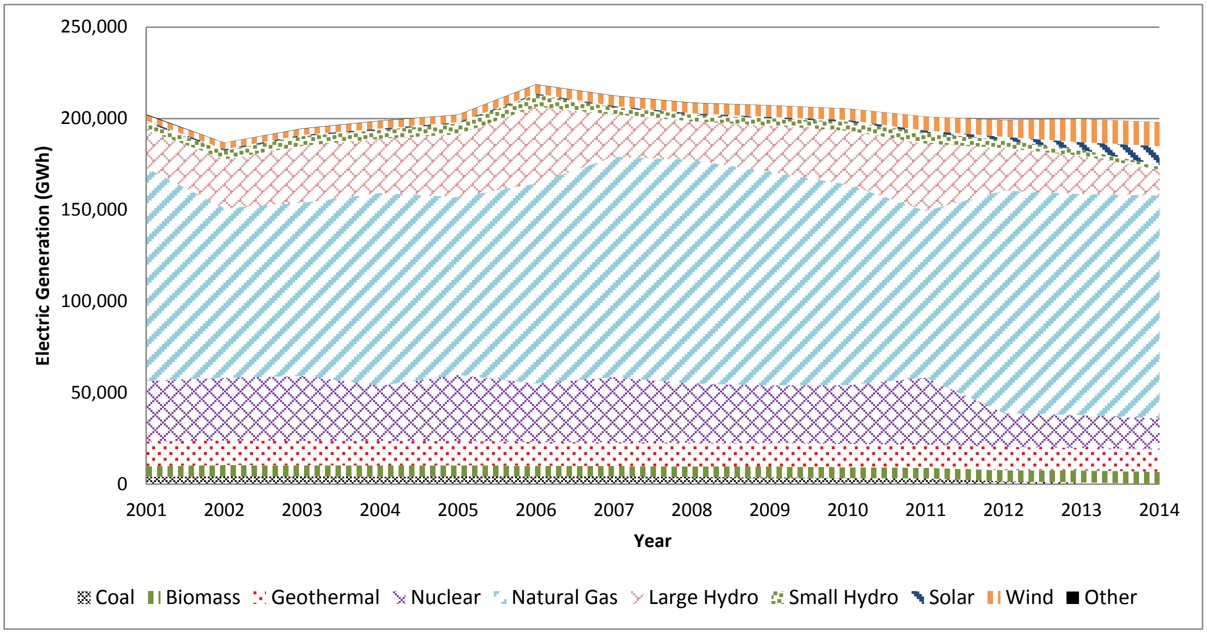
Fuel Type	California In-State Generation (GWh)	Percent of California In-State Generation	Northwest Imports (GWh)	Southwest Imports (GWh)	California Power Mix (GWh)	Percent California Power Mix
Coal	1,580	0.8%	561	20,545	22,685	7.5%
Large Hydro	23,202	11.7%	12	1,698	24,913	8.3%
Natural Gas	121,716	61.1%	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: *Quarterly Fuels and Energy Report* 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.

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

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

Figure 3: In-State Electric Generation by Fuel Type



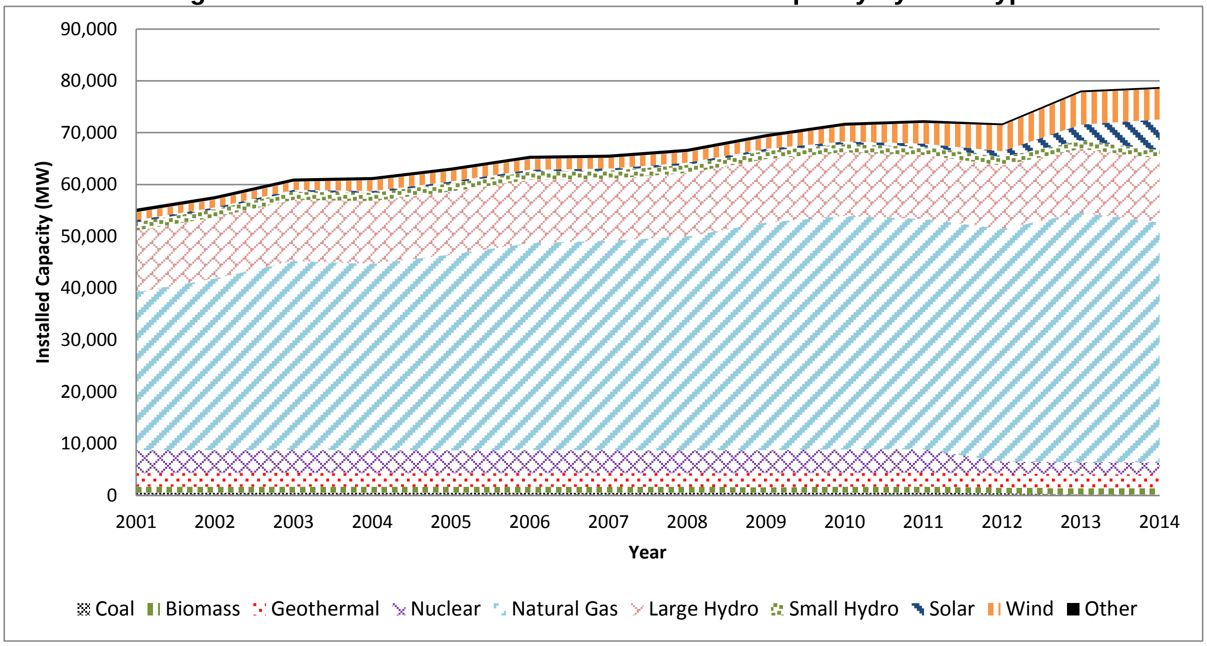
Source: Quarterly Fuels and Energy Report.

The closure of the SONGS and related impacts can be seen in both the generation (**Figure 3**) and capacity (**Figure 4**) of California's fuel supply mix; specifically, the decrease in energy from nuclear generation and corresponding increase from natural gas-fired generation. In addition, the high snowpack of 2011 shows the impact in reducing the use of in-state natural gas resources, while the less-than-average snowpack of 2012, 2013, and 2014 had the opposite impact. The increasing amount of renewable resources is also becoming more noticeable, specifically a higher amount of wind generation in 2012 and 2013, and the growth of solar generation in 2013 and 2014.

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 temporary replacement for energy from the retired SONGS). After the electricity crisis of 2001, there were extraordinary expansions of natural gas capacity in 2002 and 2003. The sizable amount of new natural gas resources has changed which units run at what times and for what purpose. Newer units are typically more efficient and run at higher capacity factors, which transitions generation away from older, less efficient generators. The sizable increase in renewable generation has started to affect the not only the operation, but also the total output from gas-fired generation.

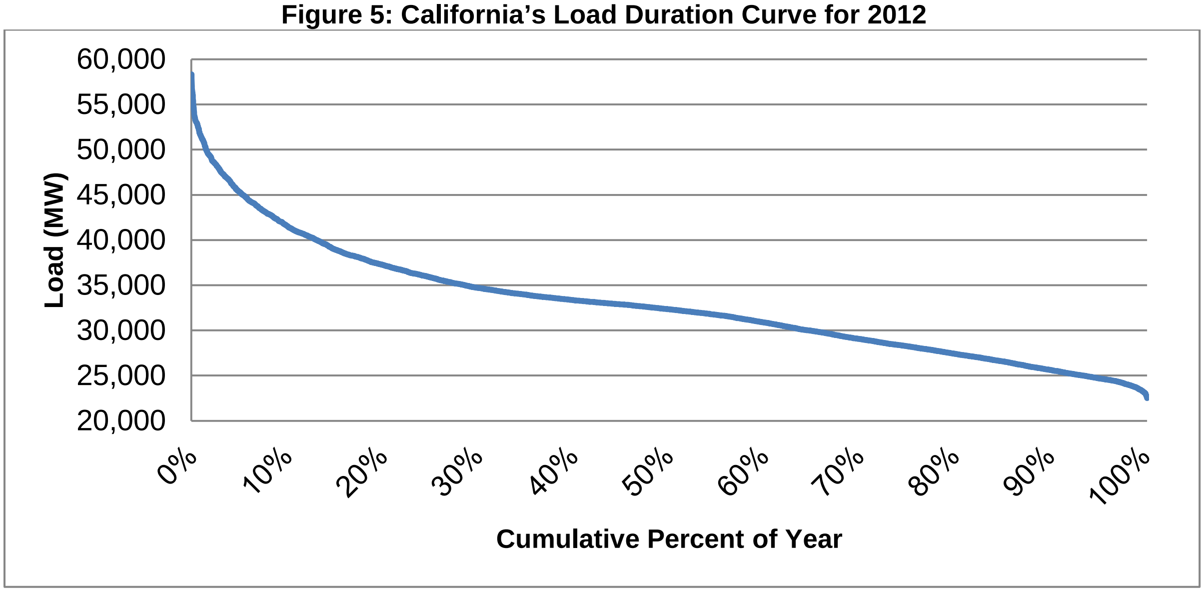
Sufficient capacity must be available to meet peak demand, even if it is only for a few hours a year. During the summer, capacity that sits idle for most of the year is needed to meet high demand. **Figure 5** shows the load duration curve for 2012.

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



Source: Quarterly Fuels and Energy Report.

Figure 5: California's Load Duration Curve for 2012

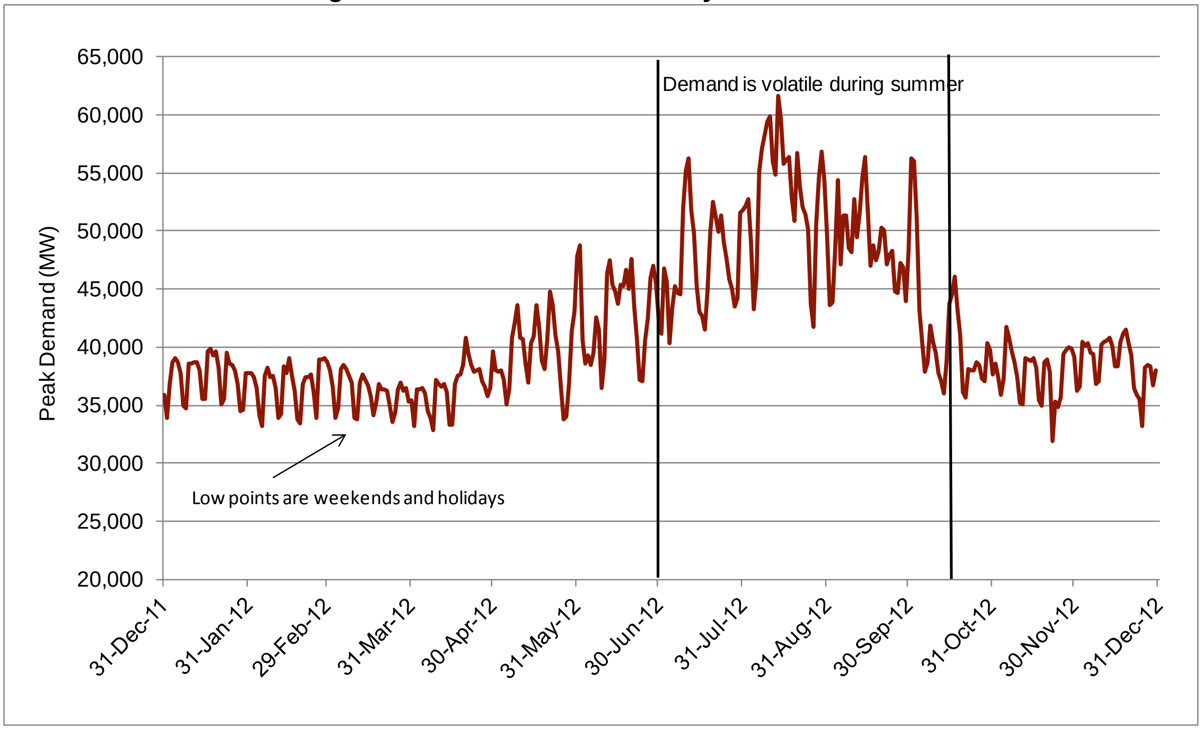


Source: Federal Energy Regulatory Commission Form 714, Part III, Schedule 2, United States Energy Information Administration 861, and Ventyx research.

Electricity use varies depending on the time of day and the season. On a typical day, demand increases 60 percent from the midnight low to the afternoon high. On a hot summer day (June through September), California's demand can spike 85 to 90 percent.

Figure 6 shows annual peak demand changes. The low points throughout the year are associated with weekends and holidays. Flexible resources and a system that can handle them are needed to meet the rapid swings in demand, especially during peak summer months.

Figure 6: Annual Pattern of Daily Peak Demand



Source: Federal Energy Regulatory Commission Form No. 714, Part III, Schedule 2.

Peak electricity demand increases dramatically in the summer due to air conditioning loads. The difference in peak demand between an average summer day and a very hot day is 6 percent. Although this may seem like a small percentage, it significantly impacts the amount of generation that is built to meet this demand. The system must be capable of adding or dropping generation from facilities to accommodate daily demand swings, peaks, weather variability, and economic growth cycles. Along with adapting to 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 have technological and operational characteristics that allow them to be categorized. These characteristics guide 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.

Baseload resources, such as geothermal, nuclear, and coal, typically run continuously except for maintenance or unscheduled outages. These resources have the lowest marginal cost and, even if prices drop below marginal costs, they are unable to reduce output. Coal plants can adjust production over a 24-hour period, such as over weekends, but cannot change output significantly between weekdays.

Electricity from renewable resources, such as wind and solar, are considered nondispatchable because they depend on the weather as their fuel source. Their output cannot be dispatched, but it can be curtailed or limited. For example, when solar generation decreases as the sun sets and increases as the sun rises, dispatchable resources must be available to balance the system. This dynamic may change in the future. Large amounts of cost-effective energy storage, and expanded application and use of inverters with renewable generation, which can provide reactive and partially-shaped power, will add flexibility to these resources and alter dispatchable resource operation.

Combined heat and power generation that is exported to the grid is also considered nondispatchable because of thermal demand at the host site. This demand determines how the combined heat and power system will operate, with electric generation being a secondary consideration. Therefore, this system is not used to maintain the supply/demand balance of the grid.

Hydroelectric power can be limitedly used to follow loads and provide power during peak times, but the total energy available fluctuates annually due to weather. Available hydropower is no longer sufficient to provide peak electricity because California's population and demand have surpassed its capacity. Ever increasing environmental constraints also limit hydro's availability. Electric generation is low on the list of priorities that includes flood control, public supply, maintaining water temperature and flows for fish spawning, and irrigation. Additionally, hydropower is incrementally less expensive than natural gas-fired electricity and not considered to be on the margin.[4, 5, 6]

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.

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

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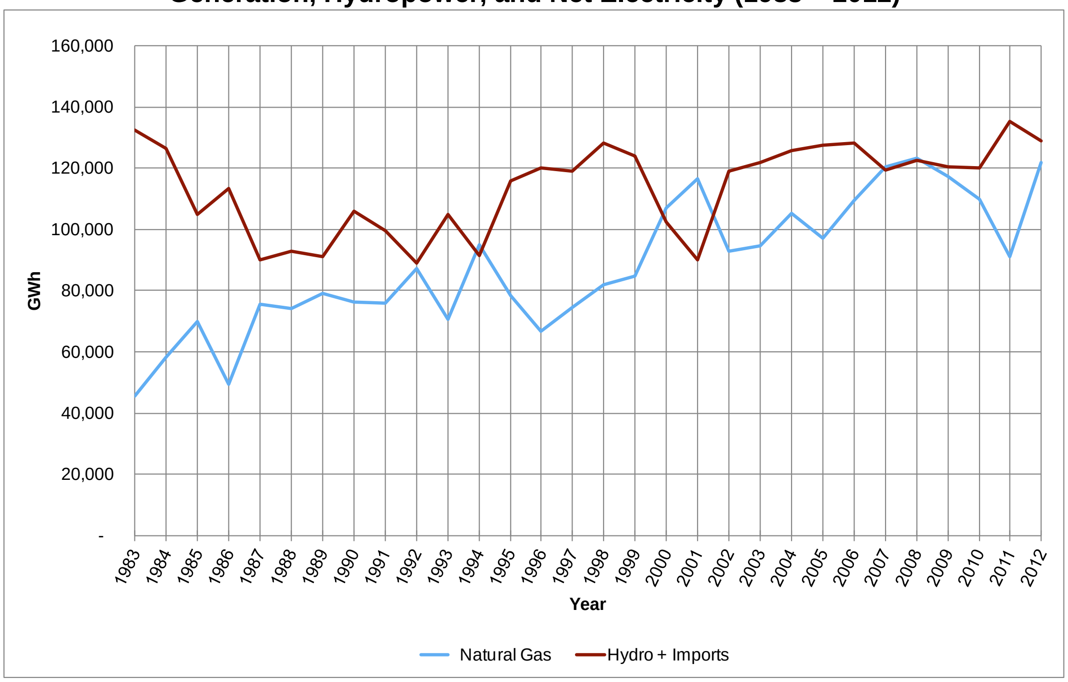
4 **On the margin** is a phrase used to describe the highest price resource that is dispatched to meet demand, which also sets the market clearing price.

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

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

turbines (CTs), and combined-cycle combustion turbines (CC CTs). The characteristics of these technologies can vary in thermal efficiency,[7] ramp rate,[8] and startup capability.[9] A common way to capture operational differences is by capacity factor, which is typically expressed as a percentage and is 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 minimally to meet peak electric demand are called **peaker plants**. They have the fastest startup and ramp rate, but lower thermodynamic efficiency. Peaker plants have the highest incremental cost due to the amount of fuel needed to provide an equivalent amount of energy, and also have the highest operational cost. Natural gas-fired plants with higher capacity factors, primarily CC CTs that were designed to run as baseload but that have ramping capabilities, are used as load-following resources on the grid. These peaking and load-following natural gas-fired resources provide flexible capacity to meet grid demand.

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



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.

Certain grid resources are run only for system stability. No other grid resources can provide the necessary product, be it energy, inertia, reactive power, or some other service, where it

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

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

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

is needed.[10] 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 can only be replaced with new transmission lines, new generation of comparable capability, or a combination of the two, they are not considered to be marginal generation resources. Thus, they are not included in the efficiency analysis found in this chapter.

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. 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. **Figure 8** shows the relationship between a decrease in demand and 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.[11])

Out-Of-State Natural Gas-Fired Generation

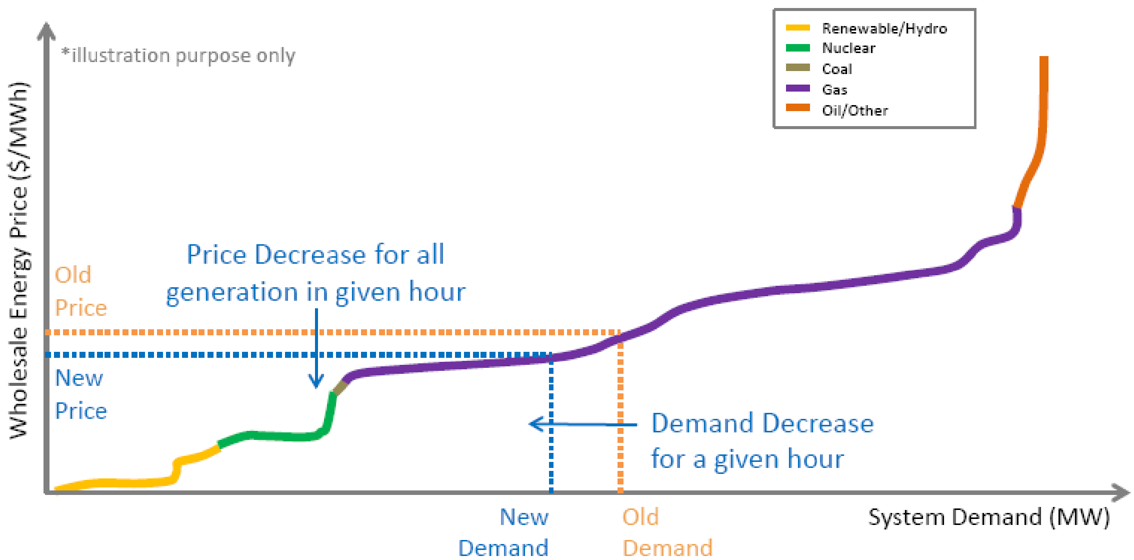
Operational data available to the Energy Commission about out-of-state generation provides some insight into the characteristics of out-of-state natural gas-fired generation.[12] It does not provide details on which facilities provided electricity to California, nor in what quantity. However, it allows an examination of trends outside of California.

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

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

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

Figure 8: Generator Supply Curve



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

Most of California's imports for natural gas-fired generation come from the Southwest, (predominantly Arizona and southern Nevada). Arizona built its modern CC natural gas-fired fleet between 2001 and 2006. Most modern plants are built with technology and operational characteristics, such as heat rate curves, similar to that of the CC plants developed in California during that time.

The Southwest also has a variety of natural gas-fired plants, simple-cycle CTs, gas turbines, and steam turbines that help meet its and California's peak demand. Modern peaker plants have heat rates at or below 10,000 Btu/kWh. The Southwest has a mix of modern peaker plants and older, less efficient plants. Electricity generated from these plants 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, 2013, and 2014 for low- and high-heat rate natural gas-fired facilities in Arizona and southern Nevada, as well as the percentage of the electricity generated from high heat rate (less efficient) plants.

Table 4: Average Heat Rates of Arizona and Southern Nevada's Natural Gas-Fired Fleet (British Thermal Units Per Kilowatt Hour [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%
2014	7,354	11,472	2.8%

Source: Ventyx Energy Velocity Suite Database.

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

Data on how much energy or which facilities import electricity into California is not available, but the average efficiency and heat rate curves of those resources are known. This approach assumes 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 with similar in-state resources. It is assumed that this will not significantly alter the trends of the average heat rates for peaking and load-following resources.

Generation Data Aggregation

Using an Annual Average

The Energy Commission collects generator data for facilities 1 MW in capacity or larger through the *Quarterly Fuels and Energy Report (QFER)*, which became effective February 23, 2001.[13] Data reported includes, but is not limited to, net electricity generation on the generator unit level, fuel type, and fuel consumption. Heat rates are calculated based on reported electricity generation and fuel consumption data. While the data reported is summarized monthly, annual aggregation is also necessary to mitigate variability. Thus, heat rates are presented as annual averages.

Energy Commission staff maintains that the *QFER* data provides an accurate, verifiable, and reliable source of information. This data provides direct measurement of electricity generation and fuel consumption over more than a decade. Its use is limited by the level of aggregation inherent in the reporting.

13 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.

There are other data sources that provide data on different time scales. The California ISO's Daily Integrated Forward Market Default Load Aggregation Point Market Implied Heat Rate creates an implied heat rate for each investor-owned utility using the daily energy weighted locational marginal price collected for each load aggregation point and divided this by the daily average natural price index.[14] The load aggregation points capture the price of electricity where it is delivered within the California ISO system and territory on five-minute intervals. This data is presented as marginal heat rates, the implied efficiency of the last unit dispatched, but does not provide information about the composition of the generation resources. Using these data requires accepting the assumptions that are built into the implied heat rate and calculation.[15] Information about resources that are not the marginal resource at any a particular time is not provided, nor is information on what the marginal resource in the future based on demand changes, the resource stack, and the operation of the grid and its resources.

Using a Statewide Resource Pool

Although generator location data is very specific, the regional connection between the generators and the load they serve is not a direct correlation. California ISO's *Annual Report on Market Issues and Performance* provides information on transmission constraints in both 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 quarterly frequency percentages for the time when transmission line congestion impacts price. Transmission constraints are highly affected by planned generation resource outages and transmission line de-rating and maintenance.[16] Natural disasters, such as wild fires, must also be accounted for to separate congestion during normal operation from congestion during extraordinary operation.

While there are short time segments when congestion causes electricity prices to rise, these are 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.

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14 Southern California Edison Company and San Diego Gas & Electric Company use the Southern California Border gas price.

15 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].

16 Transmission line de-rating reduces the maximum approved transmission capacity of the line.

Applying the Resource Constraints to *Quarterly Fuels and Energy Report* Data

Data from the *QFER* data set is screened to identify relevant generation resources, limiting the data set to natural gas-fired resources and removing combined heat factor plants and grid stability resources. The data is separated into load-following resources and peaking resources.

Peaker plants are plants that have a peak-cycle role, specifically, 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 increased to 71.

Plants not classified as peaking or stability resources fall into the category of load-following resources. These are mostly CC CTs. A summary of the average heat rates for load-following plants and associated from 2001 to 2014 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).*[17] Load-following resources include the units of once-through cooling plants that have been retrofitted or repowered with new CC CTs.[18] New CC CTs are defined in this report as 100 MW or larger and built in the late 1990s or after. They do not include repurposed turbines, only those with modern CC CT technology. Some of the plants in the *Thermal Efficiency Report* are categorized as "other" because they did not fall under any of the defined groups, and are included as load-following resources. Non-repowered or retrofitted once-through-cooling plants, and aging plants are included in either category (load-following and peaking) as those facilities are deemed necessary for system stability.

Capacity Factor and Energy from Peaking Resources

Peaking resources vary in capacity factor from year to year as shown in **Table 5**.[19] While the electricity crisis in 2001 saw increased use of peaking resources over previous years, annual variability in the use of peaking resources is driven primarily by the amount of hydro availability, which is dependent on the previous winter's snowpack and summer heat.

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

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

19 *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.

The "Percentage of Load Balancing Energy From Peaking Resources" column in **Table 5** allows for a determination of how much energy was used by those resources. While peaking resources usually vary individually in capacity factor from less than one to 10 percent, it is impossible to tell which and how many of them operate at any particular time. It is assumed that most, if not all peaking resources operate during peak system hours. Further research on the operation of peaker plants will be needed to accurately characterize the hours and quantity of their use in the long-term.

Table 5: Average Heat Rates From Load-Following and Peaking Resources (Btu/kWh): 2001 to 2014

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%
2014	7,332	49.4%	10,402	5.8%	4.8%

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

CHAPTER 3: Near-Term Gas-Fired Generation Heat Rate Trends

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,[20] there is little certainty about retirements and new generation. The amount of new generation will depend on the outcome of preferred resource procurements (energy efficiency, demand response, renewable generation, combined heat and power, and energy storage).

The addition of renewable resources and the increasing emphasis on flexible capacity requires resources that can ramp up and down more quickly and more frequently than in the past, increasing the uncertainty about the operating capacity and efficiency of new plants. It is unclear what effect new plants will have on the operation of older plants. This near-term estimate relies solely on historical heat rate data, and does not make assumptions about unknown parameters.

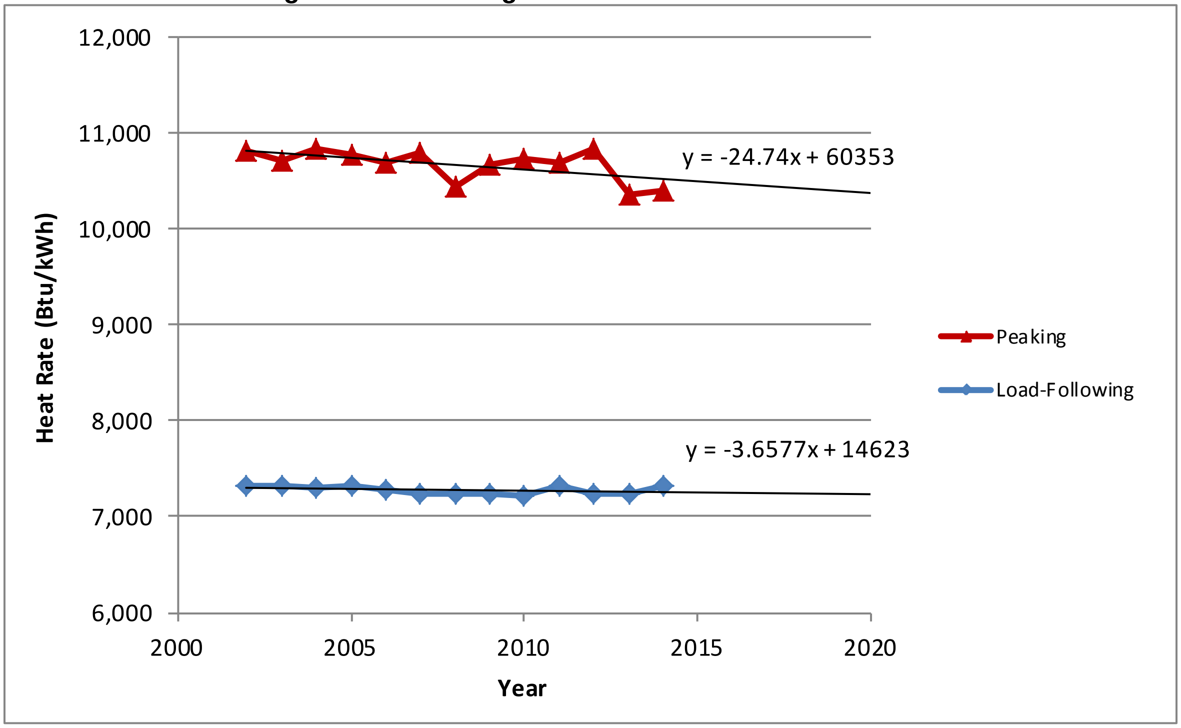
Heat Rate Trends

The historic heat rate data captures changes, including plant degradation and efficiency levels due to ramping variation, to peaker and load-following plants. Significant changes to California's resource mix, such as 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 peaking and load-following resources from 2002 to 2014 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 due to atypical power plant operation caused by the electricity crisis.

20 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
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

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

Underlying factors, such as capacity and fleet efficiency are contingent on the intensity of the summer heat and the amount of hydro production, are not fully delineated by the regression. Notwithstanding drought conditions during recent years, the trend in improved efficiency of load-following generation had leveled off. These system interdependencies add considerable uncertainty to future grid resource operation estimates.

Heat Rates in the Cost of Generation Model

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 7.**[21] 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 7: Heat Rates Used in Cost of Generation Report (Btu/kWh, Higher Heating Value)

Technology	Mid[22]	High	Low[23]
Conventional CT[24]	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: Energy Commission, CEC-200-2014-003-SD.

Line Loss Factors

Energy is lost during the transmission and distribution of electricity. Accordingly, consuming a megawatt-hour (MWh) of grid-provided energy requires that more than 1 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 combined heat and power) 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. Loss factors have been discussed in depth in a previous Energy Commission staff paper: *A Review of*

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

22 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.)

23 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.

24 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.

Transmission Losses in Planning Studies.[25] In summary, some programs rely on the line loss factor of 7.8 percent derived by the California Air Resources Board using the Energy Commission's *California Energy Demand 2008-2018 Staff Revised Forecast*[26] as a statewide loss factor for calculating avoided emissions in the California Air Resource Board's *Climate Change Scoping Plan,*[27] while the CPUC uses utility-specific transmission and distribution line loss factors in utility procurement planning and rate cases.

25 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].

26 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-SF

27 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].

CHAPTER 4: Conclusion

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

The expansion of renewable resources to supply the majority of California's electricity in 2030 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 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 effect to grid operation and the identification of marginal grid resources between early and later years.

ACRONYMS

Acronym	Definition
Btu/kWh	British thermal units per kilowatt hour
California ISO	California Independent System Operator
CC	Combined-cycle
CC CT	Combined-cycle combustion turbine
CT	Combustion turbine
Energy Commission	California Energy Commission
GHG	Greenhouse gas
ISO	Independent System Operator
KWh	Kilowatt-hour
MW	Megawatt
MWh	Megawatt-hour
QFER	*Quarterly Fuels and Energy Report*
SB 1305	Senate Bill 1305
SONGS	San Onofre Nuclear Generation Station
Thermal Efficiency Report	*Thermal Efficiency of Gas-Fired Generation in California: 2014 Update*
WECC	Western Electricity Coordinating Council