California Energy Commission

DRAFT STAFF REPORT

CALIFORNIA ENERGY DEMAND 2014-2024 PRELIMINARY FORECAST

Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency

CALIFORNIA
ENERGY COMMISSION

Edmund G. Brown Jr., Governor

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ABSTRACT

The *California Energy Demand 2014-2024 Preliminary Forecast, Volume 1: Statewide Electricity Demand and Methods, End-User Natural Gas Demand, and Energy Efficiency* describes the California Energy Commission's preliminary forecasts for 2014–2024 electricity consumption, peak, and natural gas demand for each of five major electricity planning areas and three natural gas distribution areas and for the state as a whole. This forecast supports the analysis and recommendations of the *2012 Integrated Energy Policy Report Update* and the *2013 Integrated Energy Policy Report.* The forecast includes three full scenarios: a *high energy demand* case, a *low energy demand* case, and a *mid energy demand* case. The *high energy demand* case incorporates relatively high economic/demographic growth, relatively low electricity and natural gas rates, and relatively low efficiency program and self-generation impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed rates, and higher efficiency program and self-generation impacts. The *mid* case uses input assumptions at levels between the *high* and *low* cases. Forecasts are provided at both the planning area and climate zone level.

Keywords:

Electricity, demand, consumption, forecast, weather normalization, peak, natural gas, self-generation, conservation, energy efficiency, climate zone, forecast methods

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EXECUTIVE SUMMARY

Introduction

This California Energy Commission staff report presents forecasts of electricity and end-user natural gas consumption and peak electricity demand for California and for each major utility planning area within the state for 2014-2024. The *California Energy Demand 2014-2024 Preliminary Forecast* (*CED 2013 Preliminary*) supports the analysis and recommendations of the *2012 Integrated Energy Policy Report Update* and the *2013 Integrated Energy Policy Report*, including electricity and natural gas system assessments and analysis of progress toward increased energy efficiency and distributed generation. This report details the historical and projected impacts of energy efficiency programs and standards as well as the effects of programs incentivizing distributed generation, continuing a major staff effort to improve the measurement and attribution of demand-side impacts within the energy demand forecast.

CED 2013 Preliminary includes three full scenarios: a *high energy demand* case, a *low energy demand* case, and a *mid energy demand* case. The *high energy demand* case incorporates relatively high economic/demographic growth, relatively low electricity and natural gas rates, and relatively low efficiency program and self-generation impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed rates, and higher efficiency program and self-generation impacts. The *mid* case uses input assumptions at levels between the *high* and *low* cases.

Electricity Forecast Results

Table ES-1 compares the *CED 2013 Preliminary* forecast for selected years with the adopted *California Energy Demand 2012-2022 Forecast* (*CED 2011*) mid demand case. For statewide electricity consumption, the new forecast begins about 1 percent below *CED 2011* in 2012, reflecting less actual economic growth in California than had been predicted in 2011. Consumption in the new mid scenario grows at a slower rate through 2022 compared to the *CED 2011* mid case as a result of lower projected population growth, higher projected rates, and the introduction of updated building standards under the state Title 24 regulations and new Title 20 appliance standards for battery chargers during the forecast period. By 2020, consumption is around 4 percent lower. The high demand case, with higher projected growth in consumption, matches the *CED 2011* mid case by 2022. Statewide noncoincident peak demand (sum of individual planning area peaks) in 2012 is almost 3 percent lower than predicted in the *CED 2011* mid case and grows at a slower rate from 2012-2022 for the same reasons as consumption, although the difference in growth rates is not as large.

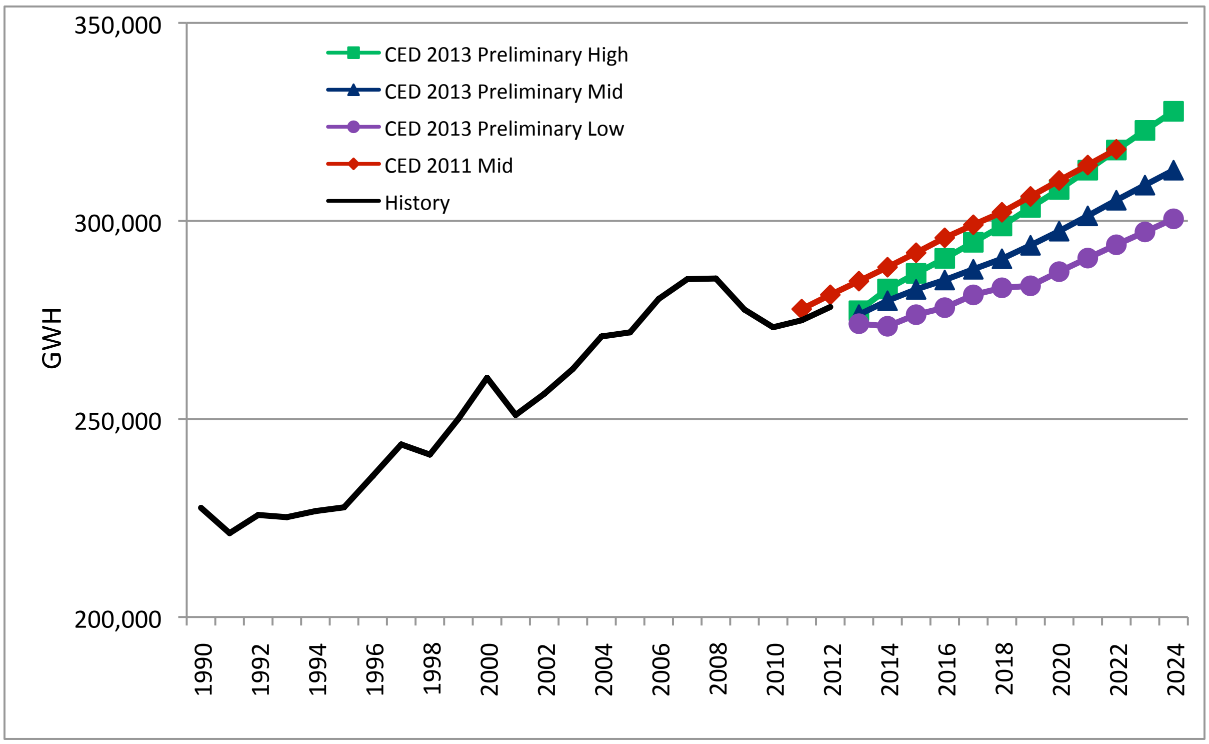
Table ES-1: Comparison of *CED 2013 Preliminary* and *CED 2011* Mid Demand Case Forecasts of Statewide Electricity Demand

Consumption (GWh)				
	CED 2011Mid Energy Demand	*CED 2013 Preliminary High Energy Demand*	*CED 2013 Preliminary Mid Energy Demand*	*CED 2013 Preliminary Low Energy Demand*
1990	227,586	227,576	227,576	227,576
2000	261,381	260,399	260,399	260,399
2012	281,347	278,282	278,282	278,282
2015	291,965	286,755	282,721	276,326
2020	310,210	307,944	297,422	287,192
2024	--	327,676	312,814	300,528
	Average Annual Growth Rates			
1990-2000	1.39%	1.36%	1.36%	1.36%
2000-2012	0.62%	0.56%	0.56%	0.56%
2012-2015	1.24%	1.00%	0.53%	-0.23%
2012-2022	1.20%	1.34%	0.93%	0.55%
2012-2024	--	1.37%	0.98%	0.64%
Noncoincident Peak (MW)				
	CED 2011Mid Energy Demand	*CED 2013 Preliminary High Energy Demand*	*CED 2013 Preliminary Mid Energy Demand*	*CED 2013 Preliminary Low Energy Demand*
1990	47,546	47,543	47,543	47,543
2000	53,700	53,702	53,702	53,702
2012		60,119	60,119	60,119
2012*	61,796	60,001	60,001	60,001
2015	65,036	63,815	63,166	60,598
2020	69,418	68,840	66,658	62,947
2024	--	73,054	69,627	65,158
	Average Annual Growth Rates			
1990-2000	1.22%	1.23%	1.23%	1.23%
2000-2012	1.18%	0.93%	0.93%	0.93%
2012-2015	1.72%	2.08%	1.73%	0.33%
2012-2022	1.38%	1.71%	1.30%	0.68%
2012-2024	--	1.65%	1.25%	0.69%
Historical values are shaded.				
*Weather normalized: *CED 2013 Preliminary* uses a weather-normalized peak value derived from the actual 2012 peak for calculating growth rates during the forecast period				

Source: California Energy Commission, Demand Analysis Office, 2013

Figure ES-1 shows statewide historical electricity consumption, projected *CED 2013 Preliminary* consumption for the three scenarios, and the *CED 2011* mid demand consumption forecast. Growth is flat or declining in 2013 in the new forecast because (1) the number of cooling degree days was historically high in 2012 and the forecast assumes a historical average in 2013; (2) new efficiency programs not included in *CED 2011* are introduced by utilities in 2013; and (3) rates are projected to increase significantly from 2012 to 2013. *CED 2013 Preliminary* consumption grows at a faster average annual rate from 2012 to 2022 in the high case (1.34 percent) and a slower rate in the mid scenario (0.93 percent) relative to *CED 2011* mid (1.20 percent).

Figure ES-1: Statewide Annual Electricity Consumption

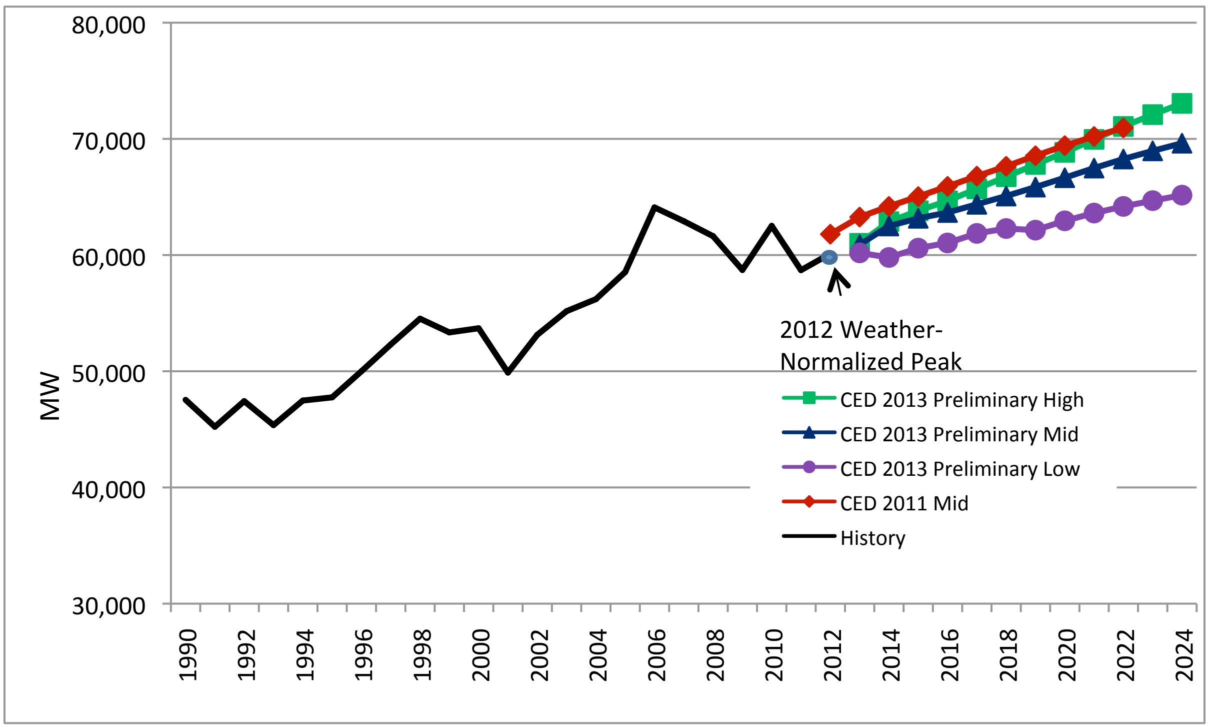


Source: California Energy Commission, Demand Analysis Office, 2013

Figure ES-2 compares *CED 2013 Preliminary* statewide noncoincident peak demand with the *CED 2011* mid demand case. Actual peak demand in 2012 was lower than projected in the *CED 2011* mid case, reflecting slower economic growth than was predicted in 2011. There is little growth in all three scenarios from 2012-2013, a result of efficiency improvements in 2013, rate increases, and low economic growth. As with consumption, growth in the *CED 2013 Preliminary* mid case is slower than in the *CED 2011* mid case from 2012-2022 because of lower population growth, higher rate growth, and additional efficiency initiatives. By

2022, the new mid case is almost 4 percent below the previous. With smaller increases in rates and higher population growth, the *CED 2013 Preliminary* high case reaches the *CED 2011* mid case level by 2022. **Figure ES-2** also shows the statewide weather-normalized peak in 2012, and growth rates in the forecast period are calculated relative to this weather-normalized total. However, this total is very close to the actual peak. Although 2012 was historically a relatively warm year on average, it was a fairly normal year for the highest temperatures.

Figure ES-2: Statewide Annual Noncoincident Peak Demand



Source: California Energy Commission, Demand Analysis Office, 2013

Natural Gas Forecast Results

Table ES-2 compares the three *CED 2013 Preliminary* demand scenarios for end-user natural gas consumption at the statewide level with the *CED 2011* mid demand case for selected years. The new forecasts begin at a lower point in 2012, as natural gas consumption in California was substantially lower in this year than was predicted in the *CED 2011* mid case, and grow at a slower rate in all three scenarios from 2012-2022. Key factors are slower projected population growth in the *CED 2013 Preliminary* mid and low cases, the introduction of climate change impacts in the mid and high cases, and new efficiency initiatives and higher projected natural gas rates for all three scenarios.

Table ES-2: Statewide End-User Natural Gas Forecast Comparison

Consumption (MM Therms)				
	CED 2011 Mid Case	*CED 2013 Preliminary High Energy Demand*	*CED 2013 Preliminary Mid Energy Demand*	*CED 2013 Preliminary Low Energy Demand*
1990	12,893	12,893	12,893	12,893
2000	13,913	13,913	13,913	13,913
2012	13,123	12,686	12,686	12,686
2015	13,503	12,613	12,631	12,353
2020	13,961	12,722	12,789	12,649
2024	--	12,779	12,804	12,719
	Average Annual Growth Rates			
1990-2000	0.76%	0.76%	0.76%	0.76%
2000-2012	-0.49%	-0.77%	-0.77%	-0.77%
2012-2015	0.96%	-0.19%	-0.15%	-0.88%
2012-2022	0.70%	0.05%	0.08%	-0.01%
2012-2024	--	0.06%	0.08%	0.02%
Historical values are shaded				

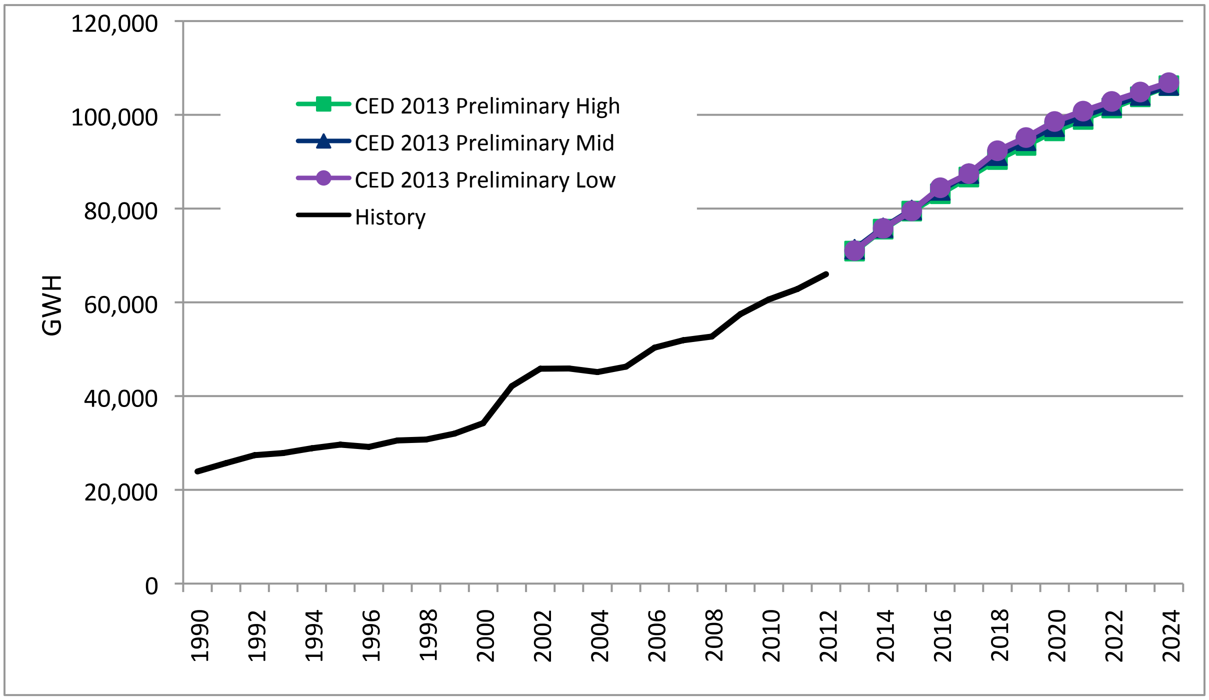
Source: California Energy Commission, Demand Analysis Office, 2013

Conservation/Efficiency

Energy Commission demand forecasts seek to account for efficiency and conservation reasonably expected to occur. Since the *1985 Electricity Report*, initiatives have been split into two types: committed and uncommitted. *CED 2013 Preliminary* continues that distinction. Committed initiatives include utility and public agency programs, codes and standards, legislation and ordinances that have final authorization, firm funding, and a design that can be readily translated into characteristics that can be evaluated and used to estimate future impacts (for example, a package of investor-owned utility incentive programs that has been funded by a California Public Utilities Commission order). In addition, committed impacts include price and other effects not directly related to a specific initiative. Uncommitted efficiency impacts are not estimated for this report; staff analysis for this purpose will follow later in 2013.

Figure ES-3 shows staff estimates of historical and projected committed savings impacts. Within the demand scenarios, higher demand yields more standards savings since new construction and appliance usage increase, while lower demand is associated with more program savings and higher rates (and therefore more price effects). The net result is that projected savings totals among the scenarios are very similar.

Figure ES-3: Total Statewide Committed Efficiency and Conservation Impacts



Source: California Energy Commission, Demand Analysis Office, 2013

Summary of Changes to Forecast

The previous long-run forecast, *CED 2011*, was based on 2011 peak demand and 2010 energy. For *CED 2013 Preliminary*, staff added 2011 and 2012 energy consumption data and 2012 peak data to the historical series used for forecasting. The peak demand forecast incorporates 2012 analysis of the temperature-peak demand relationship at the planning area level.

For *CED 2011*, econometric models were estimated for the residential, commercial, and industrial electricity sectors. *CED 2013 Preliminary* adds econometric models for the other electricity sectors (agriculture and water pumping; transportation, communications, and utilities; and street lighting) as well as for the major natural gas sectors. This means that forecasts were developed in two ways: through the Energy Commission's existing models and through econometric models. Adjustments were made to existing models based on the econometric estimations and results from existing models were compared to econometric results. In addition, staff is developing a new industrial end-use energy model. Although this model is not yet complete, enough progress has been made to allow use in *CED 2013 Preliminary*.

As part of the continuing effort to capture comprehensively the impacts of energy efficiency initiatives, *CED 2013 Preliminary* incorporates recent revisions to Energy Commission building codes and appliance standards, including projected effects from the 2013 updates to the Title 24 building standards and the battery charger standards, to be implemented in 2014. Utility program impacts were updated to include projected savings from the 2013-2014 California Public Utilities Commission efficiency program cycle for investor-owned utilities and from 2013 programs for the publicly owned utilities.

Staff used a predictive model to forecast residential adoption of photovoltaic systems and solar water heaters for the first time in *CED 2011*. *CED 2013 Preliminary* also includes a predictive model for the commercial sector that projects adoption of combined heat and power systems. These models are based on methods used by the U.S. Energy Information Administration, as part of its National Energy Modeling System, and the National Renewable Energy Laboratory.

CED 2011 included estimates of potential climate change impacts on peak demand. Along with an updated peak demand analysis, *CED 2013 Preliminary* incorporates estimates of climate change impacts on electricity and natural gas consumption. These impacts were developed using temperature scenarios developed by the Scripps Institute of Oceanography.

Stakeholders have expressed a strong interest in a more disaggregated demand forecast to better inform resource and infrastructure-related analyses and decisions. As a first step in this direction, staff developed results at the climate zone level for *CED 2013 Preliminary* in addition to the usual planning area forecasts. The appropriate level of disaggregation for future forecasts, given data and other resource constraints, will be determined through internal discussions and input from stakeholders after the *CED 2013* forecast cycle.

CHAPTER 1:
Statewide Forecast Results and Methods

Introduction

This California Energy Commission staff report presents forecasts of electricity and end-user natural gas consumption and peak electricity demand for California and for each major utility planning area within the state for 2014-2024. The *California Energy Demand 2014-2024 Preliminary Forecast* (*CED 2013 Preliminary*) supports the analysis and recommendations of the *2012 Integrated Energy Policy Report Update* and the *2013 Integrated Energy Policy Report* (*2013 IEPR*), including electricity and natural gas system assessments and analysis of progress toward increased energy efficiency. This report details the historical and projected impacts of energy efficiency programs and standards as well as the effects of programs incentivizing distributed generation, continuing a major staff effort to improve the measurement and attribution of demand-side impacts within the energy demand forecast.

The IEPR Lead Commissioner will conduct a workshop on May 30, 2013, to receive public comments on this forecast. Following the workshop, subject to the direction of the Lead Commissioner, staff will prepare a revised forecast for possible adoption by the Energy Commission. The revised forecast will include an assessment of incremental uncommitted efficiency impacts not included in *CED 2013 Preliminary*.

The final forecasts will be used in a number of applications, including the California Public Utilities Commission (CPUC) 2014 Long Term Procurement Plan (LTPP). The CPUC has identified the IEPR process as "the appropriate venue for considering issues of load forecasting, resource assessment, and scenario analyses, to determine the appropriate level and ranges of resource needs for load serving entities in California."[1] The final forecasts will also be an input to California Independent System Operator (California ISO) controlled grid studies and other transmission planning studies and in the *California Gas Report*[2] and electricity supply-demand (resource adequacy) assessments.

CED 2013 Preliminary includes three full scenarios: a *high energy demand* case, a *low energy demand* case, and a *mid energy demand* case. The *high energy demand* case incorporates relatively high economic/demographic growth, relatively low electricity and natural gas rates, and relatively low efficiency program and self-generation impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed rates, and

1 Peevey, Michael. September 9, 2004, *Assigned Commissioner's Ruling on Interaction Between the CPUC Long-Term Planning Process and the California Energy Commission Integrated Energy Policy Report Process.* Rulemaking 04-04-003.

2 California electric and gas utilities prepare the *California Gas Report* in compliance with California Public Utilities Commission Decision D.95-01-039.

higher efficiency program and self-generation impacts. The *mid* case uses input assumptions at levels between the *high* and *low* cases. Details on input assumptions for these scenarios are provided later in this chapter. The forecast comparisons presented in this report show the three *CED 2013 Preliminary* cases versus the adopted *California Energy Demand 2012-2022 Forecast*[3] (*CED 2011*) mid demand case, except where otherwise noted.

Summary of Changes to Forecast

The previous long-run forecast, *CED 2011*, was based on 2011 peak demand and 2010 energy. For the current forecast, staff added 2011 and 2012 energy consumption data and 2012 peak data to the historical series used for forecasting. The peak demand forecast incorporates 2012 analysis of the temperature-peak demand relationship at the planning area level.

For *CED 2011*, econometric models were estimated for the residential, commercial, and industrial electricity sectors. *CED 2013 Preliminary* adds econometric models for the other electricity sectors (agriculture and water pumping; transportation, communications, and utilities; and street lighting), as well as for the major natural gas sectors. This means that forecasts were developed in two ways: through the Energy Commission's existing models and through econometric models. Adjustments were made to existing models based on the econometric estimations, and results from existing models were compared to econometric results. In addition, staff is developing a new industrial end-use energy model. Although this model is not yet complete, enough progress has been made to allow use in *CED 2013 Preliminary*.

As part of the continuing effort to capture comprehensively the impacts of energy efficiency initiatives, *CED 2013 Preliminary* incorporates recent revisions to Energy Commission building codes and appliance standards, including projected effects from the 2013 updates to the Title 24 building standards and the battery charger standards, to be implemented in 2014. Utility program impacts were updated to include projected savings from the 2013-2014 CPUC efficiency program cycle for investor-owned utilities (IOUs) and from 2013 programs for the publicly owned utilities (POUs). Chapter 3 provides details on staff work related to efficiency impact measurement for this forecast.

Staff used a predictive model to forecast residential adoption of photovoltaic systems and solar water heaters for the first time in *CED 2011*. *CED 2013 Preliminary* also includes a predictive model for the commercial sector that projects adoption of combined heat and power (CHP) systems. These models are based on methods used by the U.S. Energy Information Administration, as part of its National Energy Modeling System, and the

3 California Energy Commission. June 2012. *California Energy Demand 2012–2022 Final Forecast*. CEC-200-2012-001-CMF (Volumes I and II). http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-CMF-V1.pdf and http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-CMF-V2.pdf.

National Renewable Energy Laboratory. Staff is also developing a predictive model for commercial PV and had hoped to incorporate this model in *CED 2013 Preliminary*, but determined that it required more testing. Details of the residential PV and commercial CHP models are provided in Appendix B.

CED 2011 included estimates of potential climate change impacts on peak demand. Along with an updated peak demand analysis, *CED 2013 Preliminary* incorporates estimates of climate change impacts on electricity and natural gas consumption. These impacts were developed using temperature scenarios developed by the Scripps Institute. The Scripps scenarios, and how they were included in the forecast, are discussed in Appendix A.

Stakeholders have expressed a strong interest in a more disaggregated demand forecast to better inform resource and infrastructure-related analyses and decisions. As a first step in this direction, staff developed results at the climate zone level for *CED 2013 Preliminary* in addition to the usual planning area forecasts. Climate zone results are provided in the planning area chapters in Volume II of this report. The appropriate level of disaggregation for future forecasts, given data and other resource constraints, will be determined through internal discussions and input from stakeholders after the *CED 2013* forecast cycle.

Statewide Forecast Results

Table 1-1 compares the *CED 2013 Preliminary* forecast for selected years with the *CED 2011* mid demand case. For statewide electricity consumption, the new forecast begins about 1 percent below *CED 2011* in 2012, reflecting less actual economic growth in California than had been predicted in 2011. Consumption in the new mid scenario grows at a slower rate through 2022 compared to the *CED 2011* mid case as a result of lower projected population growth, higher projected rates, and the introduction of updated Title 24 and new Title 20 standards during the forecast period. By 2020, consumption is around 4 percent lower. The high demand case, with higher projected growth in consumption, matches the *CED 2011* mid case by 2022. Statewide noncoincident[4] weather-normalized[5] 2012 peak demand is almost 3 percent lower than predicted in the *CED 2011* mid case and grows at a slower rate from 2012-2022 for the same reasons as consumption, although the difference in growth rates is not as large.

The historical data used for this forecast differs slightly from *CED 2011* as staff strives to improve processes to aggregate data submitted by utilities into the proper form required by the forecasting models. In addition, continuing review of self-generation data has found cases where on-site consumption was improperly estimated in the past.

4 The state's coincident peak is the actual peak, while the noncoincident peak is the sum of actual peaks for the planning areas, which may occur at different times.

5 Peak demand is weather-normalized in 2012 to provide the proper benchmark for comparison to future peak demand, which assumes either average (normalized) weather or hotter conditions measured relative to 2012 due to climate change.

Table 1-1: Comparison of *CED 2013 Preliminary* and *CED 2011* Mid Demand Case Forecasts of Statewide Electricity Demand

Consumption (GWh)				
	CED 2011Mid Energy Demand	*CED 2013 Preliminary High Energy Demand*	*CED 2013 Preliminary Mid Energy Demand*	*CED 2013 Preliminary Low Energy Demand*
1990	227,586	227,576	227,576	227,576
2000	261,381	260,399	260,399	260,399
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	Average Annual Growth Rates			
1990-2000	1.39%	1.36%	1.36%	1.36%
2000-2012	0.62%	0.56%	0.56%	0.56%
2012-2015	1.24%	1.00%	0.53%	-0.23%
2012-2022	1.20%	1.34%	0.93%	0.55%
2012-2024	--	1.37%	0.98%	0.64%
Noncoincident Peak (MW)				
	CED 2011Mid Energy Demand	*CED 2013 Preliminary High Energy Demand*	*CED 2013 Preliminary Mid Energy Demand*	*CED 2013 Preliminary Low Energy Demand*
1990	47,546	47,543	47,543	47,543
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2012		60,119	60,119	60,119
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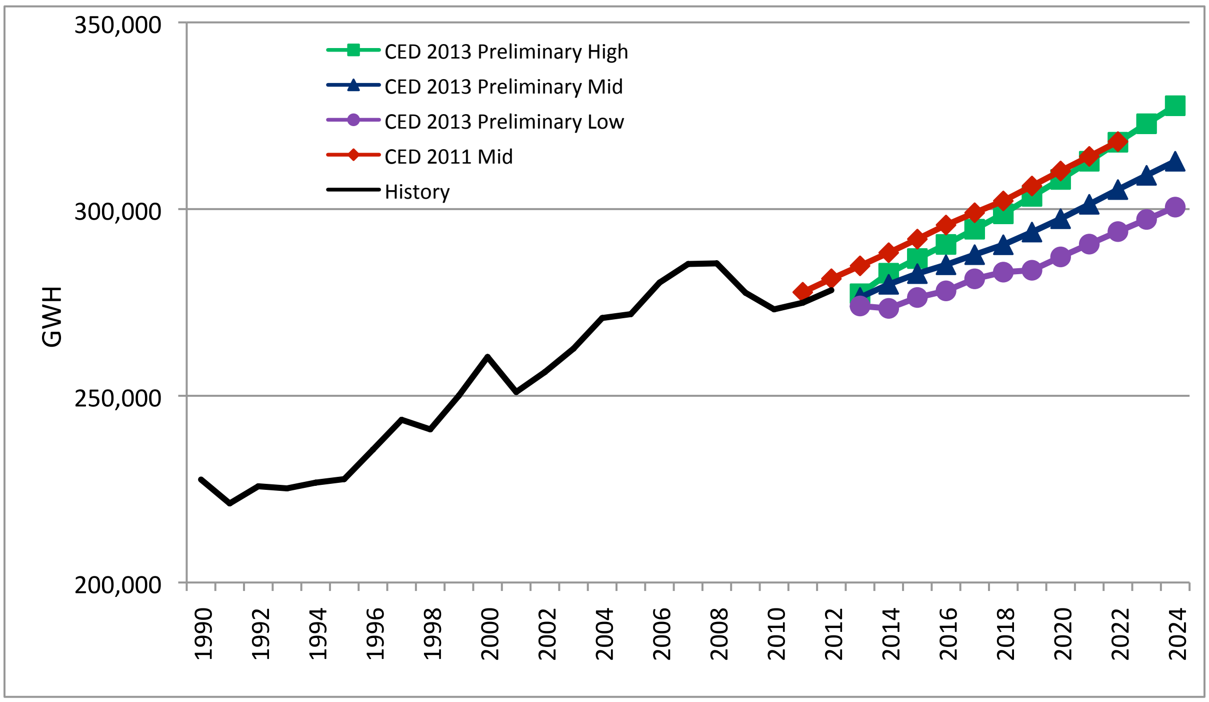
2024	--	73,054	69,627	65,158
	Average Annual Growth Rates			
1990-2000	1.22%	1.23%	1.23%	1.23%
2000-2012	1.18%	0.93%	0.93%	0.93%
2012-2015	1.72%	2.08%	1.73%	0.33%
2012-2022	1.38%	1.71%	1.30%	0.68%
2012-2024	--	1.65%	1.25%	0.69%
Historical values are shaded.				
*Weather normalized: *CED 2013 Preliminary* uses a weather-normalized peak value derived from the actual 2012 peak for calculating growth rates during the forecast period				

Source: California Energy Commission, Demand Analysis Office, 2013

Annual Electricity Consumption

Figure 1-1 shows statewide historical electricity consumption, projected *CED 2013 Preliminary* consumption for the three scenarios, and the *CED 2011* mid demand consumption forecast. Growth is flat or declining in 2013 in the new forecast because (1) the number of cooling degree days was historically high in 2012 and the forecast assumes a historical average in 2013; (2) new efficiency programs not included in *CED 2011* are introduced by utilities; and (3) rates are projected to increase significantly from 2012 to 2013. *CED 2013 Preliminary* consumption grows at a faster average annual rate from 2012 to 2022 in the high case (1.34 percent) and a slower rate in the mid scenario (0.93 percent) relative to *CED 2011* mid (1.20 percent).

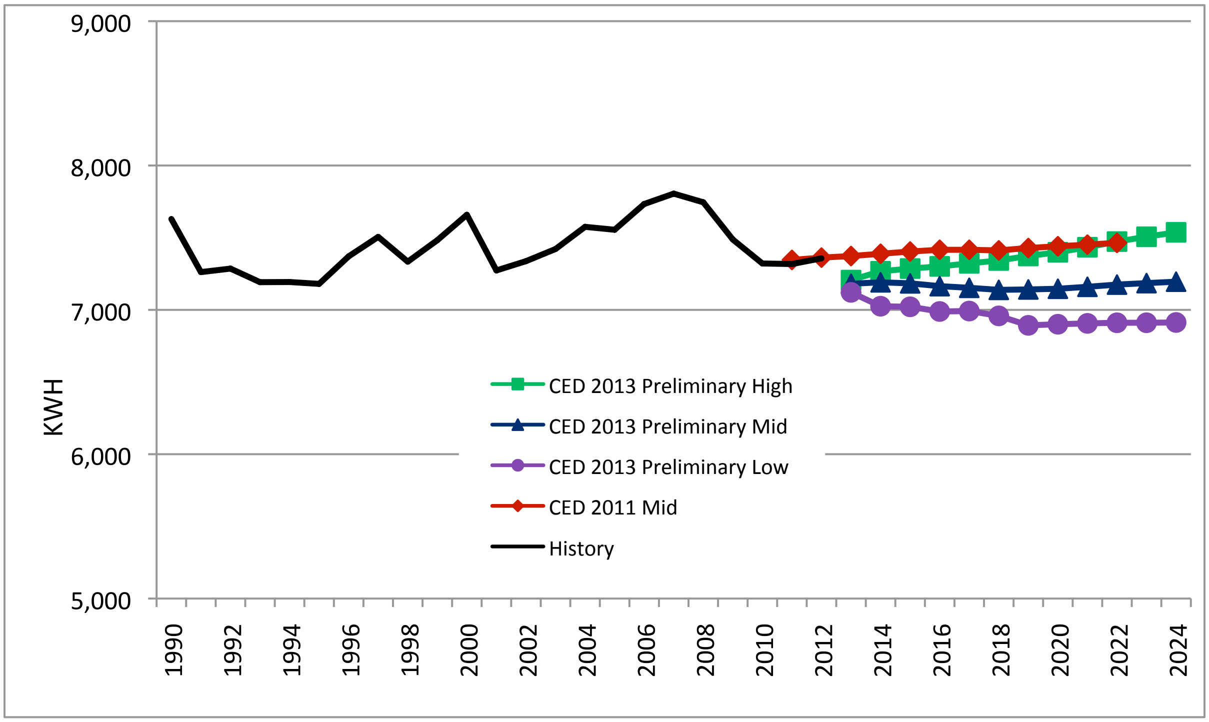
Figure 1-1: Statewide Annual Electricity Consumption



Source: California Energy Commission, Demand Analysis Office, 2013

As shown in **Figure 1-2**, *CED 2013 Preliminary* per-capita electricity consumption is projected to decrease from 2012 to 2013 because of flat total consumption growth combined with population increase. Thereafter, per-capita consumption declines in the mid and low scenarios before rising slightly toward the end of the forecast period due to increasing electric vehicle use. The projected impacts of new efficiency initiatives and higher rates lead to an increase in the difference between the *CED 2013 Preliminary* and *CED 2011* mid cases through 2022. Higher economic/demographic growth in the high demand case increases per-capita consumption throughout the forecast period, matching that in the *CED 2011* mid case by 2022.

Figure 1-2: Statewide Electricity Annual Consumption per Capita



Source: California Energy Commission, Demand Analysis Office, 2013

Table 1-2 compares projected annual consumption in each scenario for the three major economic sectors—residential, commercial, and industrial (manufacturing, construction, and resource extraction) – with the *CED 2011* mid demand case. Projected residential sector growth in the *CED 2013 Preliminary* mid case from 2012-2022 is slower compared to the *CED 2011* mid case, mainly because of a reversion to average weather at the beginning of the forecast period from a historically warm (in terms of cooling degree days) 2012. To compare across weather-normalized years, growth rates for 2013-2022 are also shown for the residential and commercial sectors; the rates of growth for the two residential mid cases are much closer when examining this period. The effect of lower population growth versus *CED 2011* on residential consumption is partially offset by higher per capita income, since personal income is projected to be about the same in the previous and new mid cases (see **Figure 1-7**, below), with a lower population in the latter. In addition, the *CED 2013 Preliminary* residential forecast includes projected consumption impacts from climate change.

Table 1-2: Electricity Consumption by Sector

Residential				
	CED 2011 Mid Energy Demand	*CED 2013 Preliminary High Energy Demand*	*CED 2013 Preliminary Mid Energy Demand*	*CED 2013 Preliminary Low Energy Demand*
2012	91,934	90,641	90,641	90,641
2015	95,520	95,791	93,870	91,296
2020	104,853	106,788	101,113	96,371
2024	--	118,102	110,207	104,459
Average Annual Growth, Residential Sector				
2012-2022	1.78%	2.18%	1.54%	1.02%
2013-2022	1.80%	2.45%	1.78%	1.37%
2012-2024	--	2.23%	1.64%	1.19%
Commercial				
	CED 2011 Mid Energy Demand	*CED 2013 Preliminary High Energy Demand*	*CED 2013 Preliminary Mid Energy Demand*	*CED 2013 Preliminary Low Energy Demand*
2012	103,641	101,685	101,685	101,685
2015	108,514	104,081	103,009	101,946
2020	116,658	112,195	109,895	107,248
2024	--	118,646	115,448	112,672
Average Annual Growth, Commercial Sector				
2012-2022	1.45%	1.29%	1.05%	0.81%
2013-2022	1.46%	1.45%	1.23%	0.98%
2012-2024	--	1.29%	1.06%	0.86%
Industrial				
	CED 2011 Mid Energy Demand	*CED 2013 Preliminary High Energy Demand*	*CED 2013 Preliminary Mid Energy Demand*	*CED 2013 Preliminary Low Energy Demand*
2012	47,943	47,689	47,689	47,689
2015	49,276	48,525	47,790	45,888
2020	49,194	47,415	45,154	46,940
2024	--	50,162	47,344	44,328
Average Annual Growth, Industrial Sector				
2012-2022	0.14%	0.40%	-0.06%	-0.63%
2012-2024	--	0.42%	-0.06%	-0.61%
Historical values are shaded				

Source: California Energy Commission, Demand Analysis Office, 2013

The same pattern applies to the commercial sector, although the differences in rates of growth for 2012-2022 and 2013-2022 between the *CED 2013 Preliminary* and *CED 2011* mid cases are significantly larger because the Title 24 update and the higher projected electricity rates have more of an effect in this sector.[6] Average annual growth in industrial consumption from 2012-2022 is slightly negative in the *CED 2013 Preliminary* mid case while slightly positive in the previous forecast, reflecting lower projected growth in resource extraction and construction.

Statewide Peak Demand

Figure 1-3 compares *CED 2013 Preliminary* statewide noncoincident peak demand with the *CED 2011* mid demand case. Actual peak demand in 2012 was lower than projected in the *CED 2011* mid case, reflecting slower economic growth than was predicted in 2011. There is little growth in all three scenarios from 2012-2013, a result of efficiency improvements in 2013, rate increases, and low economic growth. As with consumption, growth in the *CED 2013 Preliminary* mid case is slower than in *CED 2011* mid from 2012-2022 due to lower population growth, higher rate growth, and additional efficiency initiatives. By 2022, the new mid case is almost 4 percent below the previous. With smaller increases in rates and higher population growth, the *CED 2013 Preliminary* high case reaches the *CED 2011* mid case level by 2022.

Figure 1-3 also shows the statewide weather-normalized peak in 2012, and growth rates in the forecast period are calculated relative to this weather-normalized total. However, this adjusted total is very close to the actual peak; although 2012 was historically a relatively warm year on average, it was a fairly normal year for the highest temperatures.

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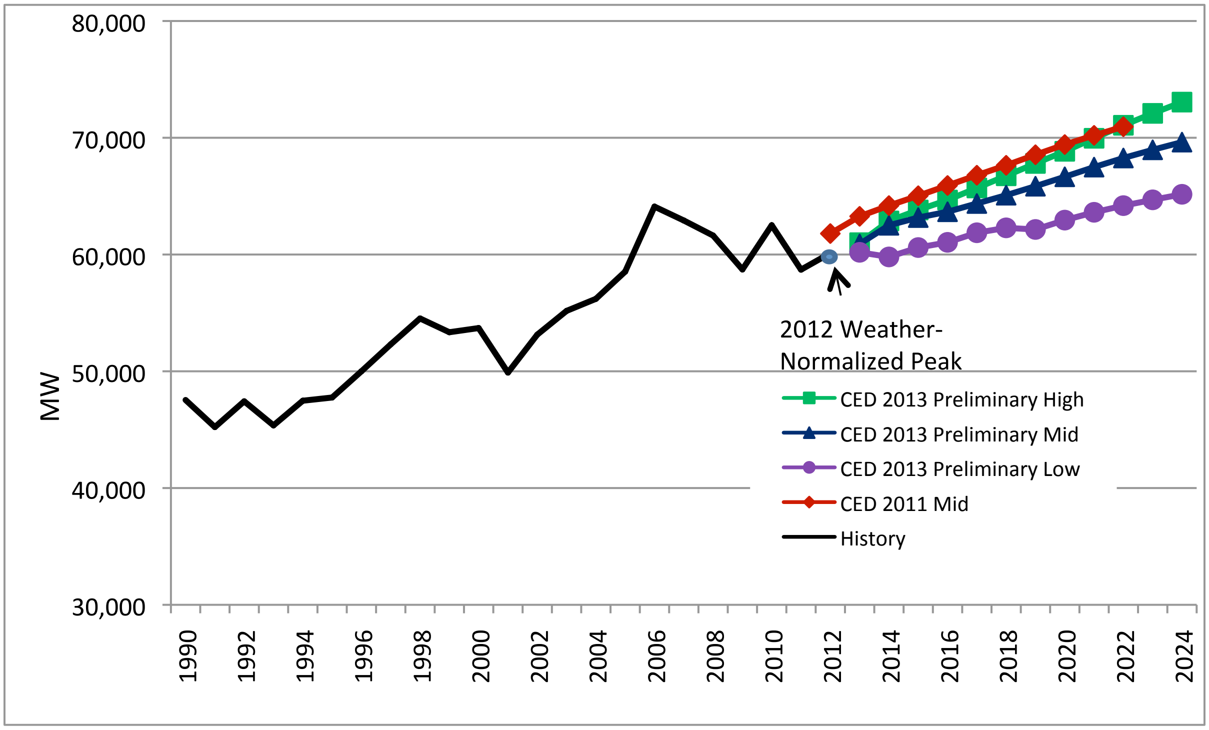
6 The price elasticity of demand is higher in the commercial model (-0.15) than in the residential (-0.08).

Figure 1-3: Statewide Annual Noncoincident Peak Demand

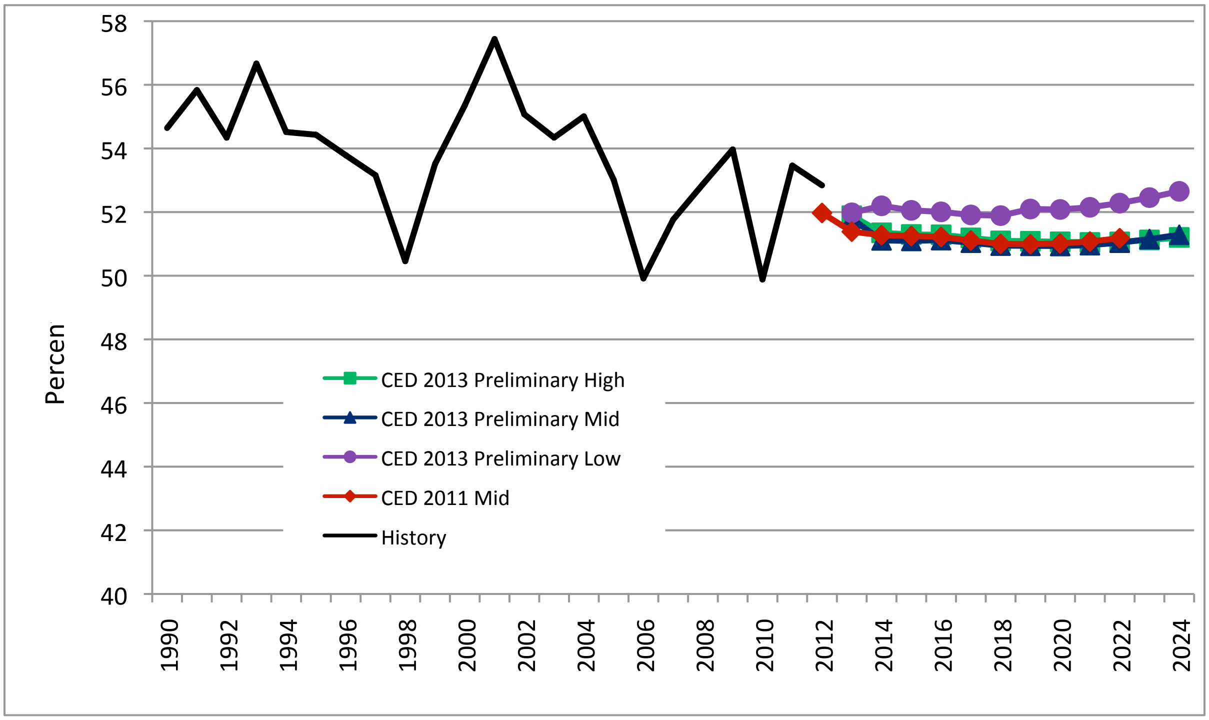


Source: California Energy Commission, Demand Analysis Office, 2013

Figure 1-4 shows load factors for the state as a whole. The load factor represents the relationship between average energy demand and peak. The smaller the load factor, the greater is the difference between peak and average hourly demand. The load factor varies with temperature; in years with extreme heat (1998, 2006), demand is "peakier," which results in lower system load factors.

The general declining trend in the load factor over the last 20 years indicates a greater proportion of homes and businesses with central air conditioning. These trends are projected to continue over most of the forecast period for all three demand scenarios (as in *CED 2011*). Energy efficiency measures, such as more efficient lighting, contribute to the declining load factor by reducing energy use while having an insignificant effect on peak. Late in the forecast period, projected increasing numbers of electric vehicles, which are assumed to affect consumption much more than peak demand, begin to push load factors upward.

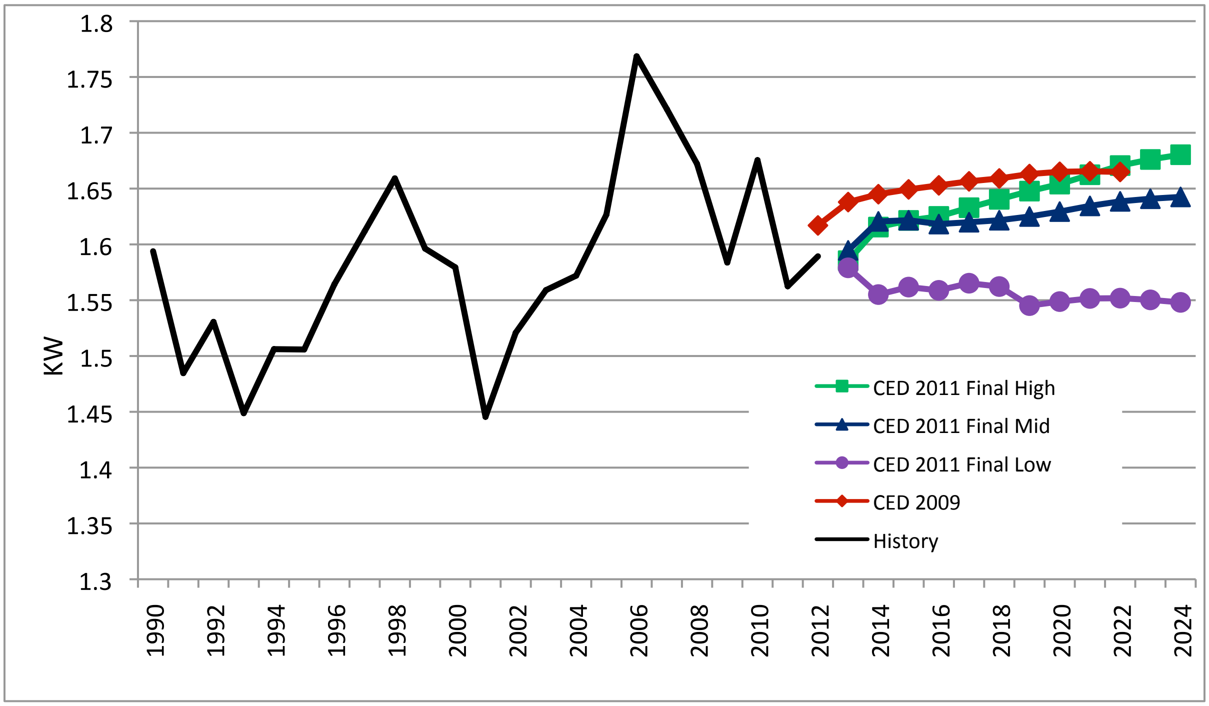
Figure 1-4: Statewide Noncoincident Peak Load Factors



Source: California Energy Commission, Demand Analysis Office, 2013

Figure 1-5 shows historical and projected noncoincident peak demand per capita and reflects the results for total peak demand in **Figure 1-3**. Continued increases in air conditioner usage yield growth through most of the forecast period in the *CED 2013 Preliminary* mid and high cases. In the low demand case, lower total peak demand combined with population projections that are relatively close to those in the mid case (see **Figure 1-9**) push peak per capita far below the other two demand cases.

Figure 1-5: Statewide Noncoincident Peak Demand per Capita



Source: California Energy Commission, Demand Analysis Office, 2013

Table 1-3 shows projected annual noncoincident peak demand for the major economic sectors. Peak demand in the *CED Preliminary 2013* mid case is projected to grow more slowly than in the *CED 2011* mid case in the residential and commercial sectors from 2012-2022. Growth is faster during this period in the new industrial mid case compared to the previous, reflecting high manufacturing growth projected for 2012 in the previous forecast that did not occur. However, the rate of industrial peak demand growth from 2013-2022 is slower in the *CED Preliminary* mid case than in the *CED 2011* mid case.

Table 1-3: Electricity Noncoincident Peak Demand by Sector

Residential				
	CED 2011 Mid Energy Demand	*CED 2013 Preliminary High Energy Demand*	*CED 2013 Preliminary Mid Energy Demand*	*CED 2013 Preliminary Low Energy Demand*
2012*	25,266	25,498	25,498	25,498
2015	26,698	27,272	26,997	25,920
2020	29,105	30,155	29,097	27,639
2024	--	32,810	31,154	29,418
Average Annual Growth, Residential Sector				
2012-2022	1.78%	2.13%	1.68%	1.13%
2012-2024	--	2.12%	1.68%	1.20%
Commercial				
	CED 2011 Mid Energy Demand	*CED 2013 Preliminary High Energy Demand*	*CED 2013 Preliminary Mid Energy Demand*	*CED 2013 Preliminary Low Energy Demand*
2012*	21,428	19,924	19,924	19,924
2015	22,642	21,444	21,275	20,618
2020	24,323	23,073	22,596	21,506
2024	--	24,350	23,642	22,424
Average Annual Growth, Commercial Sector				
2012-2022	1.53%	1.78%	1.52%	1.01%
2012-2024	--	1.69%	1.44%	0.99%
Industrial				
	CED 2011 Mid Energy Demand	*CED 2013 Preliminary High Energy Demand*	*CED 2013 Preliminary Mid Energy Demand*	*CED 2013 Preliminary Low Energy Demand*
2012*	7,317	6,922	6,922	6,922
2015	7,667	7,517	7,419	6,960
2020	7,670	7,710	7,408	6,851
2024	--	7,929	7,432	6,724
Average Annual Growth, Industrial Sector				
2012-2022	0.43%	1.22%	0.70%	-0.19%
2012-2024	--	1.14%	0.59%	-0.24%
*Weather-normalized Estimates of historical values are shaded				

Source: California Energy Commission, Demand Analysis Office, 2013

Natural Gas Demand Forecast

Table 1-4 compares the three *CED 2013 Preliminary* demand scenarios for end-user natural gas consumption at the statewide level with the *CED 2011* mid demand case for selected years. The new forecasts begin at a lower point in 2012, as natural gas consumption in California was substantially lower this year than was predicted in the *CED 2011* mid case, and grow at a slower rate in all three scenarios from 2012-2022. Key factors are slower projected population growth in the *CED 2013 Preliminary* mid and low cases, the introduction of climate change impacts in the mid and high cases, and new efficiency initiatives and higher projected natural gas rates for all three scenarios. More details are provided in Chapter 2 of this volume.

Table 1-4: Statewide End-User Natural Gas Forecast Comparison

Consumption (MM Therms)				
	CED 2011 Mid Case	*CED 2013 Preliminary High Energy Demand*	*CED 2013 Preliminary Mid Energy Demand*	*CED 2013 Preliminary Low Energy Demand*
1990	12,893	12,893	12,893	12,893
2000	13,913	13,913	13,913	13,913
2012	13,123	12,686	12,686	12,686
2015	13,503	12,613	12,631	12,353
2020	13,961	12,722	12,789	12,649
2024	--	12,779	12,804	12,719
	Average Annual Growth Rates			
1990-2000	0.76%	0.76%	0.76%	0.76%
2000-2012	-0.49%	-0.77%	-0.77%	-0.77%
2012-2015	0.96%	-0.19%	-0.15%	-0.88%
2012-2022	0.70%	0.05%	0.08%	-0.01%
2012-2024	--	0.06%	0.08%	0.02%
Historical values are shaded				

Source: California Energy Commission, Demand Analysis Office, 2013

Overview of Methods and Assumptions

Although the methods to estimate energy efficiency impacts and self-generation have undergone refinement, *CED 2013 Preliminary* uses essentially the same methods as earlier long-term staff demand forecasts. The one exception is in the industrial sector, where staff is developing an end-use model to replace the INFORM methodology used in previous forecasts. Although this model is still under development, enough progress has been made to allow use in this forecast. Appendix A describes the new model.

Models for the major economic sectors forecast annual energy consumption in each utility planning area. Electricity planning areas include Burbank/Glendale, Imperial Irrigation District, Los Angeles Department of Water and Power (LADWP), Pasadena, Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), and the Sacramento Municipal Utility District (SMUD). Natural gas planning areas include PG&E, SDG&E, and Southern California Gas (SoCalGas). After adjusting for historical weather and usage, the annual consumption forecast is used to project annual peak demand. The commercial, residential, and industrial sector energy models are structural models that attempt to explain how energy is used by process and end use. Structural models are critical in accounting for the forecasted impacts of mandatory energy efficiency standards and other energy efficiency programs that seek to encourage adoption of more efficient technologies by end users. The forecasts of agricultural and water pumping energy consumption are made using econometric methods for individual subsectors (for example, dairy and livestock). Projections for the transportation, communications, and utilities (TCU) and street lighting sectors rely on trend analyses. A detailed discussion of forecast methods and data sources is available in the 2005 *Methods Report*.[7] The commercial end-use forecast is supported by projections of floor space by building type (restaurant, retail, and so on), which are estimated using regressions that include various economic and demographic indicators as explanatory variables.[8]

In addition to existing models, staff incorporated econometric model estimation and forecast results from models estimated for total peak demand and for electricity and natural gas consumption in all sectors except for TCU gas, where the natural gas consumption data did not yield a parsimonious (simple formulation with high explanatory power) model. Estimation results for the econometric models are provided in Appendix C.

Results from the econometric estimations were applied to existing models in the following manner:

- Electricity price elasticities of demand[9] for the residential end-use and industrial models for both electricity and natural gas were changed to be consistent with elasticities estimated for the residential, manufacturing, and resource extraction/construction econometric models.
- The electricity forecast for the manufacturing sector was adjusted to reflect a trend in efficiency improvement estimated for the manufacturing econometric model.
- Results from the Hourly Electricity Load Model, used to forecast annual peak demand in each planning area, were adjusted to incorporate climate change scenarios using results from the peak econometric model.

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7 California Energy Commission. June 2005. *Energy Demand Forecast Methods Report,* CEC-400-2005-036. http://www.energy.ca.gov/2005publications/CEC-400-2005-036/CEC-400-2005-036.PDF.

8 As an example, projections for retail floor space are based on regressions that include personal income and retail employment.

9 Price elasticities of demand measure the responsiveness of demand to changes in price and are discussed further in Appendix A.

- Results for the residential, commercial, industrial, and agricultural forecasts were adjusted to incorporate climate change using results from the sector econometric models.
- High and low scenarios were developed for the agricultural/water pumping, TCU (electricity only), and street lighting sectors using the new econometric models benchmarked to the single scenarios output from the existing models. (*CED 2011* included only one scenario for these sectors.)
- Planning area forecasts for all sectors except commercial were broken out into climate zones using the econometric models. (The commercial end use model has been set up to produce climate zone as well as planning area results.) Econometric climate zone results were benchmarked to planning area totals by sector.

Estimation of new and updated econometric models is part of the Energy Commission's effort to incorporate a *multiresolution* modeling process, generating more aggregate "top down" results to compare with the detailed "bottom up" results from end-use models. Although staff used existing models for this forecast (except as noted in the bullets above), a comparison with econometric results is provided here at the statewide level and in Appendix A for individual planning areas.

For the high demand scenario, electricity consumption in the pure econometric forecast was 2.5 percent higher and peak demand 5 percent higher in 2024 compared to *CED 2013 Preliminary* statewide results shown in this chapter. The mid demand econometric scenario also yielded projected 2024 consumption 2.5 percent higher than *CED 2013 Preliminary*, while peak demand was 4.5 percent higher. The comparison for the low econometric demand scenario is similar, with statewide consumption projected to be 3 percent higher and peak 5.5 percent higher versus *CED 2013 Preliminary* in 2024.

Differences in results between the two methods are to be expected, not only due to aggregate versus disaggregate approaches, but because econometric models by their nature incorporate historical trends for demand-side impacts, such as efficiency and self-generation. Unlike with the existing forecasting models, staff did not adjust the econometric results to account for any future efficiency savings,[10] and this is likely one important source of the differences. If one presumes that energy efficiency efforts have intensified in recent years and into the near future, the econometric models, which project out average historical trends from 1980 onward, would likely understate future efficiency impacts and therefore overstate demand. Future work to explicitly capture efficiency impacts in econometric estimations at the Energy Commission and through the CPUC's macro consumption econometric project should allow better comparisons of end use and econometric results in the future.

10 The results were adjusted only to account for electric vehicles and, in the case of peak demand, photovoltaic adoption beyond 2012 levels.

Another important reason for the differences is the price elasticity of demand in the commercial sector used in each method. The elasticity for the econometric model (-0.02) is much lower than used in the end-use version (-0.10 to -0.20, depending on the building type and end use), so the impacts of higher rates are much lower for the econometric model. Applying an average commercial end-use elasticity (-0.15) to the econometric model reduces the differences in projected consumption by more than 50 percent in 2024.[11]

The natural gas full econometric forecast[12] is also higher than *CED 2013 Preliminary* in all three scenarios, by larger percentages. By 2024, the high demand econometric case is around 14 percent higher, and the mid and low econometric forecasts are about 8 percent higher. Almost all of the difference comes in the residential and construction/resource extraction sectors. As with electricity, the residential difference is likely partially from omission of explicit program and standards impacts in the econometric forecast, since this sector is affected most by efficiency initiatives. The differences in the construction/resource extraction sector result from aggregation in the econometric forecast. The sharp declines in resource extraction employment projected for all three scenarios reduce the end-use forecast, which projects energy use separately for construction and resource extraction, much more significantly than the econometric forecast, which projects demand for both subsectors combined.[13]

Economic and Demographic Assumptions

California's economy has been slowly recovering from the recession. In the last two years, the state has seen payroll gains, lower unemployment, fewer mortgage defaults, a dwindling inventory of homes for sale, and the return of tourism. Some characteristics of the current California economy include:[14]

- Expanding technology services are driving payroll gains.
- Construction and state government education have stabilized.
- The state unemployment rate is just under 10 percent and formerly discouraged workers are returning to the labor force.
- Housing prices are increasing with fewer homes for sale, and the median price of single-family homes appears to have hit bottom.
- The issuance of residential construction permits is increasing.

11 See discussion of price elasticities in Appendix A.

12 Excluding TCU gas, where the *CED 2013 Preliminary* forecast was used.

13 Unlike electricity demand, natural gas resource extraction demand is a significant component of industrial gas consumption.

14 Economic characteristics are based on summaries provided by Moody's Analytics and IHS Global Insight in February 2013.

- Despite the recent gains, employment in California's construction sector is still off nearly 40 percent from its prerecession boom level.
- Alternative-energy technologies may play a part in the recovery; California is well-suited to benefit from each part of that industry (research, design, and manufacturing).
- The economic slowdown of China, one of California's top export partners, has softened the state's export growth.
- Tourism is expanding.

In 2013, the state economy is anticipated to grow at a moderate pace with construction and business services posting the largest payroll gains. During this recovery, California should be the target for venture-capital investment because of California's highly educated workforce.

Moody's Analytics (Moody's) and IHS Global Insight provided economic projections. In general, the forecasting methods are similar for both. Econometric equations are developed at the sectoral level (for example, consumer spending), adjustments are made based on the latest economic news and professional judgment, a national forecast is generated, and individual state and county forecasts are broken out. Staff uses the county forecasts to generate projections at the planning area and climate zone levels.

These two companies update their long-term forecasts monthly; staff used the February 2013 projections for *CED 2013 Preliminary*. Other entities, such as UCLA (Anderson Forecast[15]) and the University of the Pacific,[16] also project the leading economic indicators for California but do not provide the detail and/or length of forecast period required by Energy Commission demand forecasts.

For its February 2013 economic forecast, Moody's generated seven scenarios, as follows:

- Baseline
- Stronger (compared to Baseline) Near-Term Rebound
- Mild Second Recession
- Deeper Second Recession
- Protracted Slump
- Below-Trend Long-Term Growth
- Oil Price Increase, Dollar Crash, Inflation

IHS Global Insight provided three scenarios for their February 2013 forecast:

- Optimistic
- Baseline

15 http://uclaforecast.com/

16 http://forecast.pacific.edu/

- Pessimistic

Staff selected the Global Insight *Optimistic* economic case for the high demand scenario and a mixture of Moody's *Mild Second Recession* and *Below-Trend Long-Term Growth* cases for the low demand scenario. The two Moody's cases were combined so that the *Second Recession* scenario drove the short-term results (through 2018) and the *Below-Trend Long-Term Growth* case the longer-term. The high and low demand scenarios as constructed, in general, project the highest and lowest rates of economic growth, respectively, of the various scenarios provided by the two companies throughout the forecast period. Moody's *Baseline* economic forecast was used for the mid energy demand scenario.

Table 1-5 provides the key assumptions used by the two companies to develop the three economic scenarios.

The probability assigned by Moody's to the mid demand scenario (Moody's *Baseline*) is 50 percent; that is, there is a 50 percent probability economic conditions will be worse than in this scenario. The equivalent probability for both Moody's scenarios used in the low demand scenario is 4-5 percent. Global Insight portrays the probabilities somewhat differently: "The probability of being near" the *Optimistic* economic scenario is 10 percent.[17]

17 E-mail communication with Jim Diffley, IHS Global Insight, January 24, 2012.

Table 1-5: Key Assumptions Embodied in Economic Scenarios

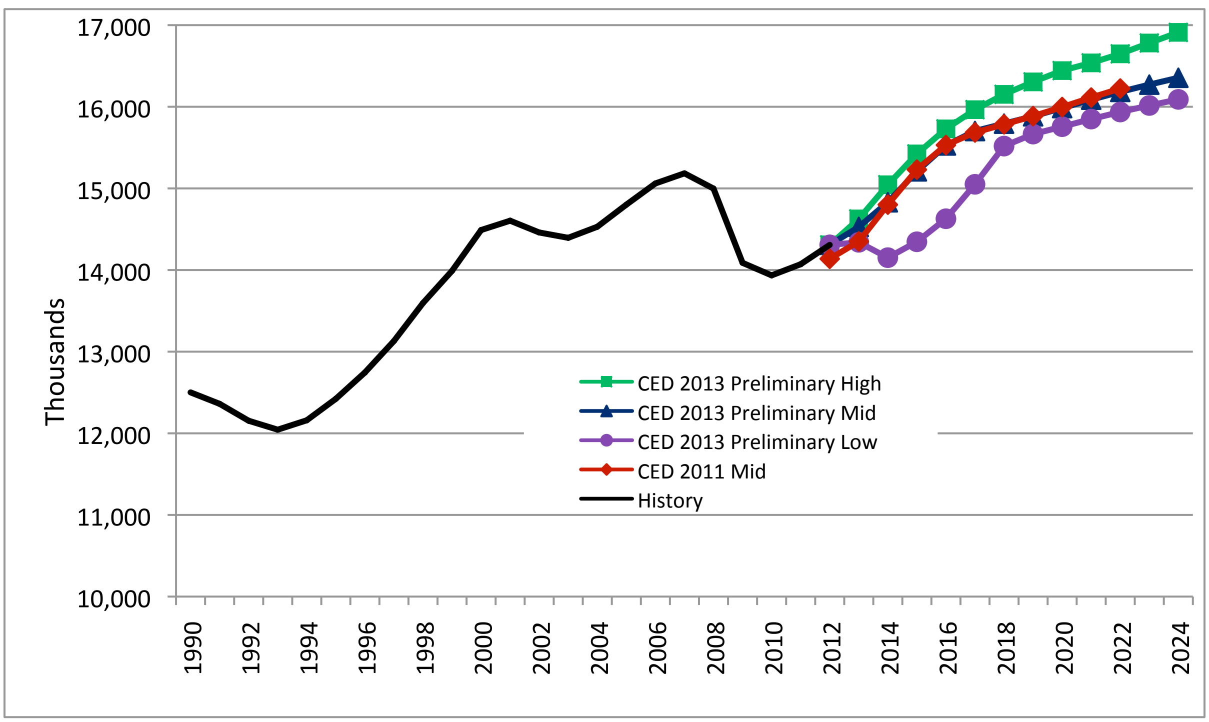
High Demand Scenario (IHS Global Insight *Optimistic* Scenario)	Mid Demand Scenario (Moody's Analytics *Baseline* Scenario)	Low Demand Scenario (Combination of Moody's Analytics *Second Recession* and *Below-Trend Long-Term Growth* Scenarios)
National unemployment rate falls below 7 percent by late 2013.	National unemployment rate stays below 8 percent through 2013.	The unemployment rate is expected to hit a peak of 10.6 percent in mid-2014.
There are no exits from the Eurozone, as members take decisive steps toward a banking and fiscal union that stabilize markets.	Continued turmoil in Europe and weaker growth in the emerging world.	European recession deepens as Greece leaves the Eurozone and investors worry about Portugal and Spain.
National light-duty vehicle sales above 17 million in 2014.	National light-duty vehicle sales above 16 million in 2014.	Unit auto sales decline throughout 2013 to a trough of only 13 million in early 2014.
National housing starts improve to near 1.3 million units by the end of 2013.	National housing starts are expected to break 2.0 million units by 2015.	House prices will experience a second decline, cumulatively falling 11 percent from the first quarter of 2013 to the first quarter of 2014.
	Oil and gas prices are expected to trend higher, just outpacing inflation.	Oil and gas prices fall more than in the baseline.
The Fed raises the federal funds rate in the first quarter of 2014.	The Fed is not expected to begin increasing interest rates until the unemployment rate has fallen to near 6.5 percent, around early 2015.	The Fed keeps the fed funds target rate near 0 percent until the fourth quarter of 2015.
Scheduled sequester spending cuts are replaced with credible long-term deficit reduction plan.	Policy makers are expected to reach an agreement to cut spending by close to $1 trillion over the next decade.	Uncertainty about whether U.S. policy makers will successfully address the national debt ceiling, sequestration, and spending in early 2013 rises significantly, causing the economy to descend into a second recession.

Sources: Moody Analytics and IHS Global Insight, 2013

Figure 1-6 and **Figure 1-7** compare projections for two key indicators used in the three scenarios, total statewide nonagricultural employment and statewide personal income, respectively, with those used in the *CED 2011* mid demand case. The historical numbers for each of the series appear to show resumption of growth after the recent recession. The *CED 2013 Preliminary* mid case for employment matches that from the previous forecast very closely, after beginning the forecast period slightly above—employment was higher in 2011 and 2012 compared to the forecast in 2011. The low case for employment shows a decrease in 2013 and 2014, consistent with an economic slump, before growth begins again in 2015. Employment growth rates from 2012-2024 in the three scenarios are projected to average 1.50 percent, 1.12 percent, and 0.98 percent in the high, mid, and low scenarios, respectively.

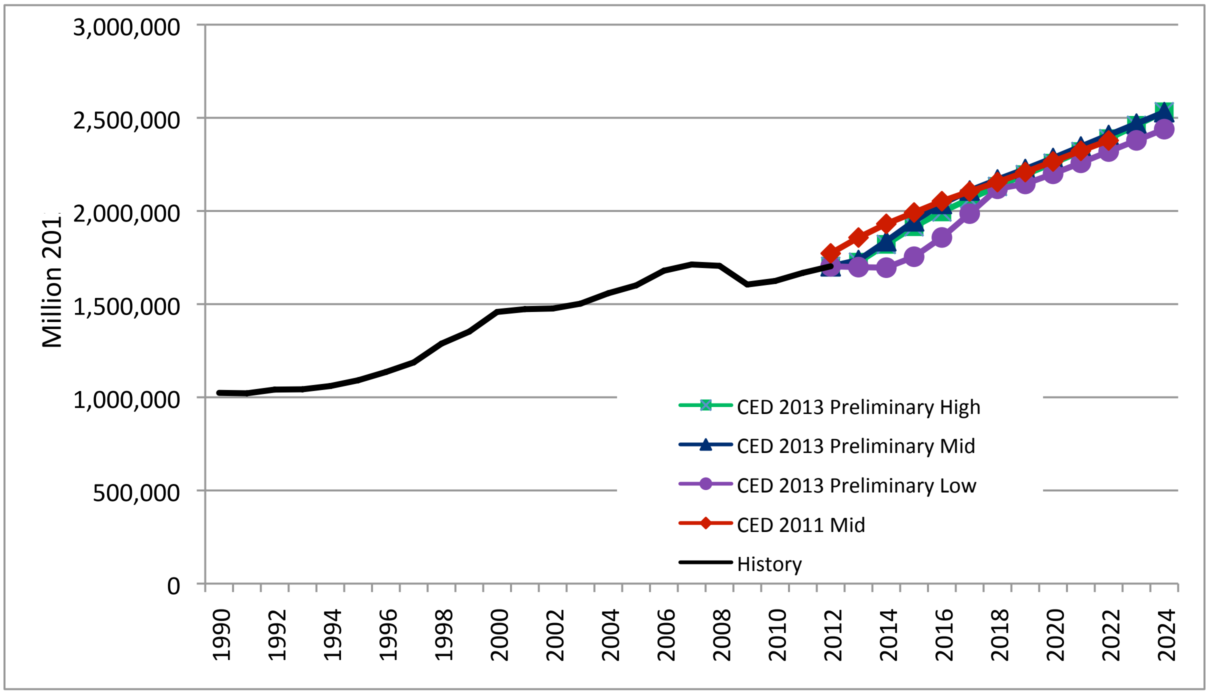
Unlike employment, personal income (**Figure 1-7**) did not reach the levels projected for 2011 and 2012 in the *CED 2011* mid case, and all three new series start the forecast below the *CED 2011* mid case income series. The *CED 2013 Preliminary* mid and high income cases reach the *CED 2011* mid case level by 2018 and are slightly higher thereafter. Projected average annual growth in personal income between 2012 and 2022 is 3.34 percent, 3.47 percent, and 3.08 percent in the high, mid, and low demand scenarios, respectively, compared to 3.25 percent in the *CED 2011* mid case.

Figure 1-6: Statewide Employment Projections



Sources: Moody's and IHS Global Insight, 2011 and 2013

Figure 1-7: Statewide Personal Income Projections

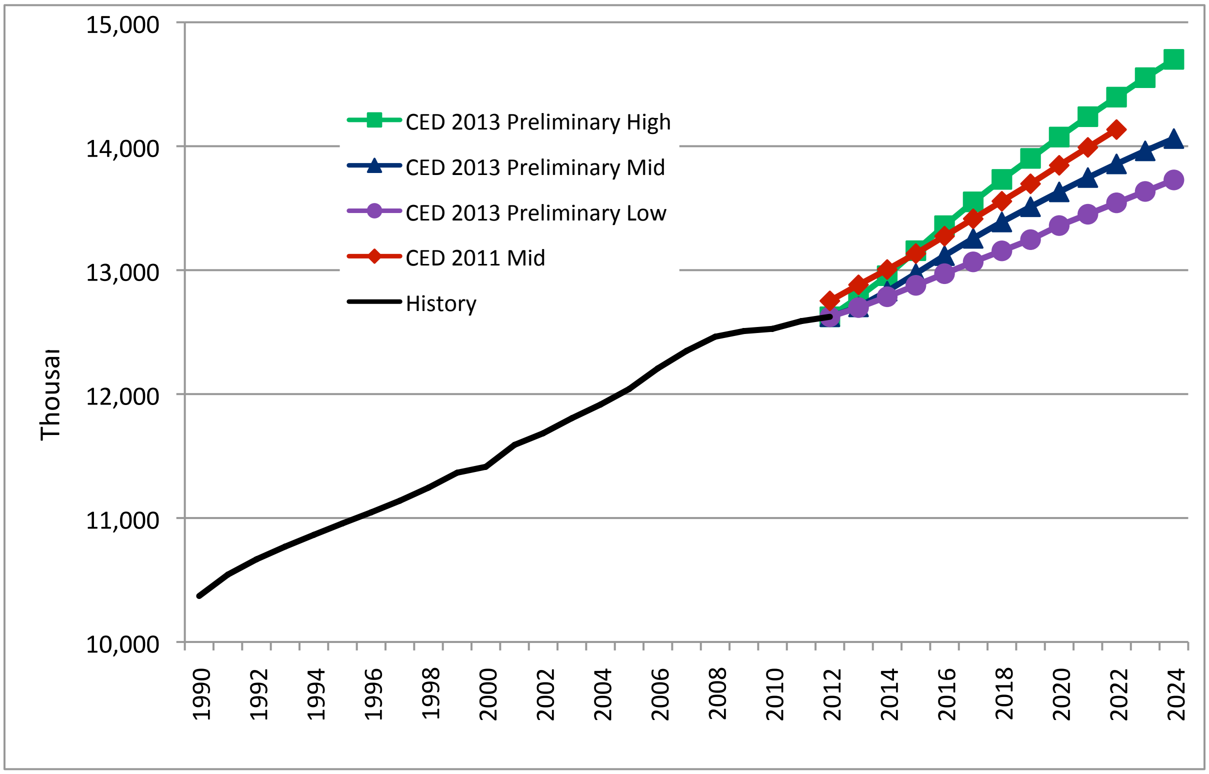


Sources: Moody's and IHS Global Insight, 2011 and 2013

Staff also developed scenario projections for number of households, shown in **Figure 1-8**, using the population projections discussed below and varying expected average persons per household. For the low demand case (higher persons per household), staff fit an exponential growth curve to historical persons per household for 1990-2010. The mid case assumed half of the growth of the low demand case and the high case (lower persons per household) used Moody's projections.[18]. The *CED 2013 Preliminary* number of households in the mid demand case grows more slowly than in *CED 2011* due to lower projected population growth.

18 Moody's projections for persons per household have typically been lower than historical trends.

Figure 1-8: Forecasts for Number of Households, Statewide

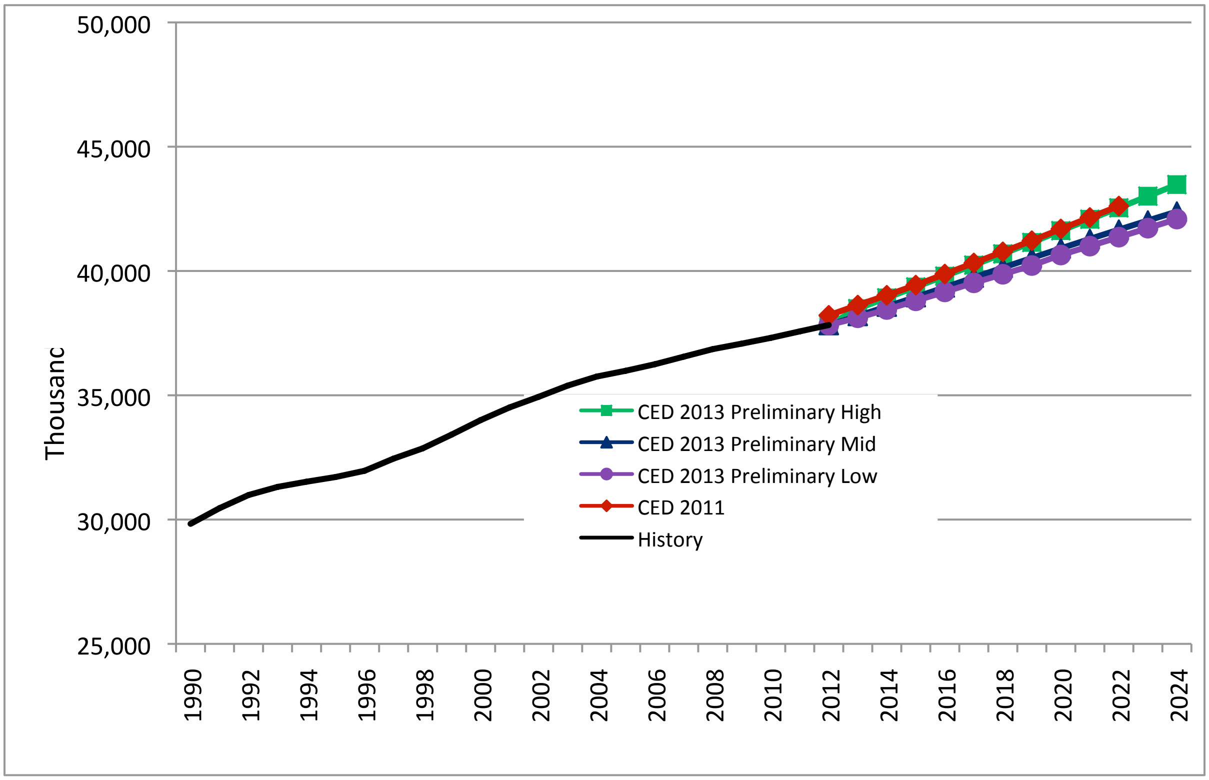


Source: California Energy Commission, Demand Analysis Office, 2013

Population growth is a key driver for residential energy consumption, as well as for commercial floor space and consumption for water pumping and other services. For CED *2013 Preliminary*, staff used three sets of population projections instead of just one, as in past forecasts. The low case comes from the California Department of Finance 2013 long-term population projections, the mid from IHS Global Insight, and the high from Moody's.[19] As shown in **Figure 1-9**, the *CED 2013 Preliminary* mid case population projections are well below those in *CED 2011,* which used only one scenario. The mid and low population scenarios reflect recent downward adjustments relative to past projections, based on state population trends in the last few years. State population growth rates from 2012-2022 in the three scenarios are projected to average 1.10 percent, 0.93 percent, and 0.86 percent annually in the high, mid, and low scenarios, respectively, compared to 1.10 percent in *CED 2011*.

19 IHS Global Insight and Moody's provide only one scenario for population, unlike other economic and demographic variables.

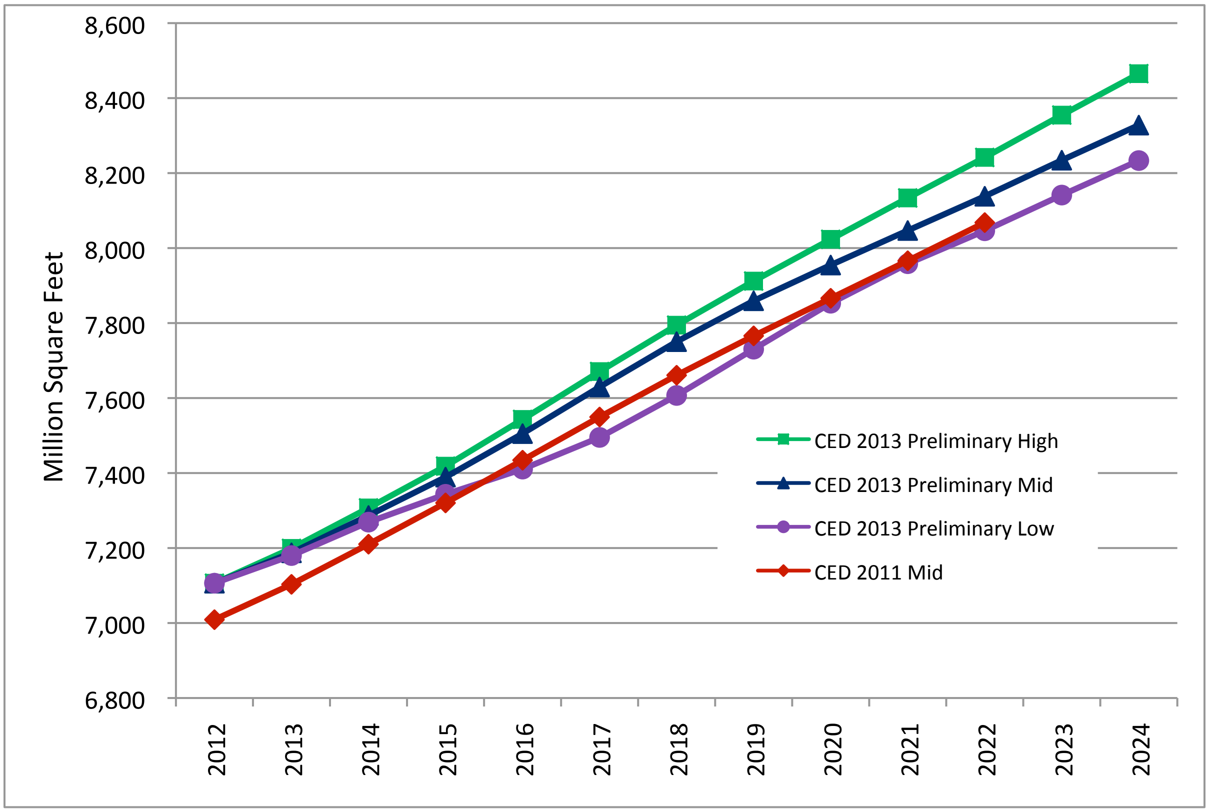
Figure 1-9: Historical and Projected Total Statewide Population



Sources: Moody's, IHS Global Insight, and California Department of Finance, 2013

Figure 1-10 compares the commercial floor space projections used for *CED 2013 Preliminary* with those used in the *CED 2011* mid case. Updates to the recent historical estimates of floor space yield 2012 statewide values higher than projected in *CED 2011*. The *CED 2013 Preliminary* mid and high cases remain above *CED 2011* throughout the forecast period, although the rate of growth in the new mid scenario is slightly lower than in the *CED 2011* mid case, due mainly to lower population growth. Projected average annual growth in commercial floor space between 2012 and 2022 is 1.25 percent, 1.37 percent, and 1.49 percent in the low, mid, and high demand scenarios, respectively, compared to 1.42 percent in the *CED 2011* mid case.

Figure 1-10: Projected Commercial Floor Space, Statewide



Source: California Energy Commission, Demand Analysis Office, 2013

Electricity and Natural Gas Rate Projections

Natural gas rate scenarios were developed by the Energy Commission's Electricity Analysis Office using the North American Gas-Trade Model (NAMGas). This model incorporates supply and demand components to generate equilibrium gas prices for California and sub-regions. The model was used to generate three scenarios, a reference case and high and low price scenarios.[20] Staff used percentage increases in these three scenarios versus 2012 actual prices in each planning area for the *CED 2013 Preliminary* forecasts, with the reference case used in the mid demand scenario, the high price scenario in the low demand case, and the low price scenario in the high demand case. Percentage increases varied slightly between Northern and Southern California planning areas. Projected prices show volatility in the early years, which is reflected in the gas forecasts, particularly in the low demand case.

20 The scenarios varied by demand and import source assumptions. For model and scenario details, see http://www.energy.ca.gov/2013_energypolicy/documents/2013-02-19_workshop/presentations/02_Brathwaite_Leon_NAMGas_IEPR2013_KeyDriversPlus_rev.pdf

As in *CED 2011*, the electricity price forecasts were generated using the Energy and Environmental Economics (E3) calculator.[21] The E3 calculator allows users to create electricity price scenarios by inputting assumptions for efficiency savings, natural gas rates, amount of renewables, amount of combined heat and power, penetration of PV systems, level of demand response, and price regime (cap and trade). **Table 1-6** provides the assumptions used to generate rate growth for each of the three demand scenarios. Efficiency and PV assumptions are based on *CED 2011* results. CHP assumptions come from work for the Energy Commission by ICF International.[22] Renewables numbers were taken from CPUC/Energy Commission joint scenario development for the 2012 LTPP.[23]

Table 1-6: Electricity Price Assumptions by Scenario

Assumption	High Demand Scenario (Lower Electricity Prices)	Mid Demand Scenario (Mid Electricity Prices)	Low Demand Scenario (Higher Electricity Prices)
Efficiency	Low CED 2011	Mid CED 2011	High CED 2011
Natural Gas Rates	NAMGas Low	NAMGas Reference	NAMGas High
PV	2,200 MW by 2020	2,300 MW by 2020	2,600 MW by 2020
Additional Renewables	12,000 by 2020	12,900 by 2020	13,500 by 2020
Demand Response	Current Levels	5 Percent Additional	5 Percent Additional
Combined Heat and Power	1,400 MW in 2020	3,000 MW in 2020	4,800 MW in 2020
Price Regime	\$20/metric ton of CO_2	\$29/metric ton of CO_2	\$50/metric ton of CO_2

Source: California Energy Commission, Demand Analysis Office, 2013

Resulting percentage growth by year for each scenario was applied to current (2012) planning area rates. E3 provided projections only for 2013-2020; staff used an annual growth rate of 1 percent for 2021 through 2024, which assumes no major change in state policies

21 Available at http://www.ethree.com/public_projects/cpuc2.html.

22 Hedman, Bruce, Ken Darrow, Eric Wong, Anne Hampson. ICF International, Inc. 2012. *Combined Heat and Power: 2011-2030 Market Assessment.* California Energy Commission. CEC-200-2012-002. http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

23 http://www.cpuc.ca.gov/NR/rdonlyres/1A44BC30-8C7A-4400-AEC8-4A33363352AC/0/2013TPPRPSPortfoliostransmittalletter.pdf

influencing electricity prices after 2020. Staff used the E3-projected percentage growth for each planning area, except in the case of LADWP, where E3 projects rate growth to be significantly higher than in the other planning areas due to expiration of current power contracts and relatively low load growth. Staff used a higher growth rate for LADWP but capped the growth so resulting LADWP rates remained at or below those of SCE.[24]

Table 1-7 provides statewide (planning area demand-weighted) averages for projected rate increases for electricity and natural gas for each scenario. Rates increase sharply from 2012 to 2013 (more than 1 cent per kWh in the mid demand case) as compliance obligations begin for cap and trade. Projections for each of the five major electricity planning areas and three natural gas planning areas are provided in the demand forms accompanying this report.

Table 1-7: Growth in Energy Rates, *CED 2013 Preliminary* Forecast

Period	% Change, High Demand Scenario	% Change, Mid Demand Scenario	% Change, Low Demand Scenario
Electricity			
2012-2015	12.2	14.4	16.0
2012-2020	26.2	33.7	41.6
2012-2024	31.3	39.2	47.3
Natural Gas			
2012-2015	42.4%	40.9%	45.8%
2012-2020	62.3%	63.7%	77.1%
2012-2024	72.9%	78.9%	92.2%

Source: California Energy Commission, Demand Analysis Office, 2013

Conservation/Efficiency Impacts

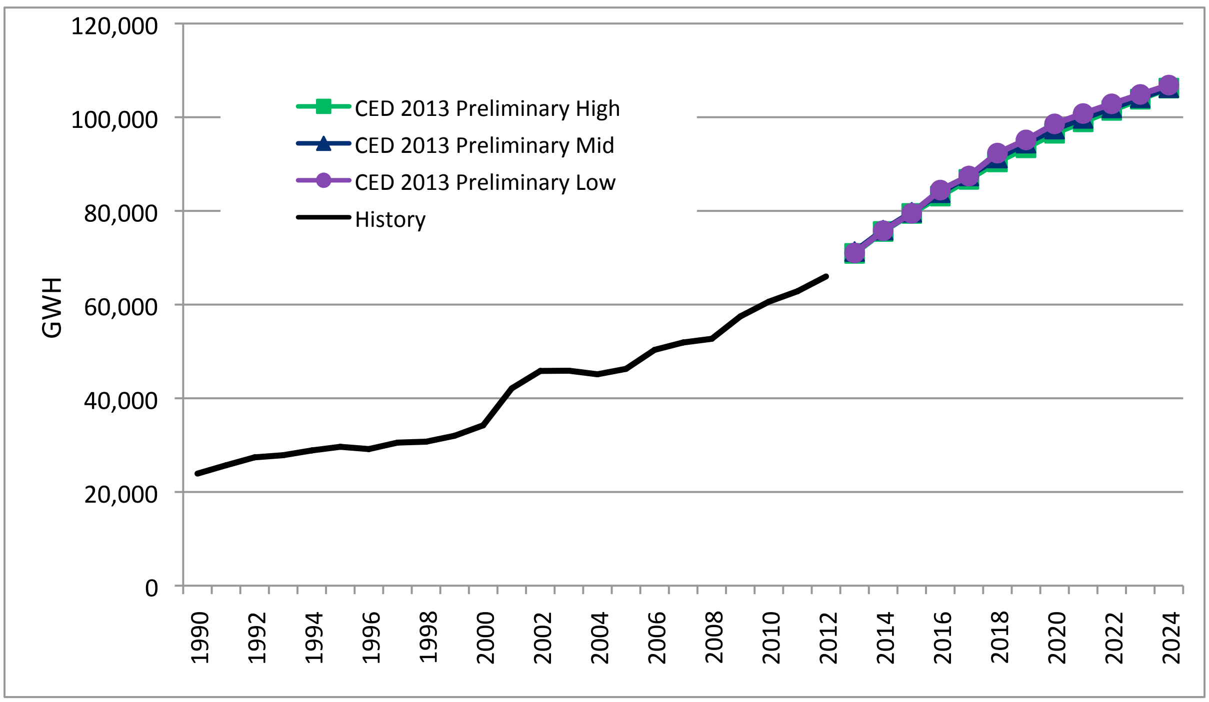
Energy Commission demand forecasts seek to account for efficiency and conservation *reasonably expected to occur.* Since the *1985 Electricity Report*, reasonably expected to occur initiatives have been split into two types: committed and uncommitted. *CED 2013 Preliminary* continues that distinction, with only committed efficiency included. Committed initiatives include utility and public agency programs, codes and standards, and legislation and ordinances having final authorization, firm funding, and a design that can be readily translated into characteristics capable of being evaluated and used to estimate future impacts (for example, a package of IOU incentive programs that has been funded by CPUC order). In addition, committed impacts include price and other market effects not directly

24 This assumption is based on the idea that, politically, a municipal utility could not offer rates higher than those of a neighboring investor-owned utility.

related to a specific initiative. Chapter 3 details the committed energy efficiency impacts projected for this forecast. Uncommitted efficiency impacts are not estimated for *CED 2013 Preliminary*; staff analysis for this purpose will follow this report and be included in the revised version of this forecast. Whether the revised forecast incorporates uncommitted impacts or these impacts are provided separately will be decided later in the IEPR process.

Figure 1-11 shows staff estimates of historical and projected committed savings impacts, which include those from programs, codes and standards, and price and other market effects. Within the demand scenarios, higher demand yields more standards savings since new construction and appliance usage increase, while lower demand is associated with more program savings and higher rates (and therefore more price effects). The net result is that savings totals among the scenarios are very similar.

Figure 1-11: Total Statewide Committed Efficiency and Conservation Impacts



Source: California Energy Commission, Demand Analysis Office, 2013

Demand Response

The term "demand response" encompasses a variety of programs, including traditional direct control (interruptible) programs and new price-responsive demand programs. A key distinction is whether the program is dispatchable, or event-based. Dispatchable programs, such as direct control, interruptible tariffs, or demand bidding programs, have triggering conditions that are not under the control of and cannot be anticipated by the customer. Energy or peak load saved from dispatchable programs is treated as a resource and, therefore, not accounted for in the demand forecast. Non-event-based programs are not activated using a predetermined threshold condition, which allows the customer to make the economic choice whether to modify its usage in response to ongoing price signals. Impacts from committed non-event-based programs should be included in the demand forecast.

Non-event-based program impacts are likely to increase in the coming years, and expected impacts incremental to the last historical year for peak (2012) affect the demand forecast.[25] Staff, in consultation with the IOUs and the CPUC, identified incremental (to 2012) impacts from current committed demand response programs in these planning areas, which include real-time or time-of-use pricing and permanent load shifting. Incremental impacts are shown in **Table 1-8**. CPUC proceedings on permanent load shifting programs are ongoing; demand response numbers will likely change in the revised version of this forecast.

Table 1-8: Estimated Demand Response Program Impacts Incremental to 2012

Year	PG&E	SCE	SDG&E
2013	7	18	2
2014	21	33	3
2015	21	33	3
2016	21	33	3
2017	20	33	3
2018	20	33	3
2019	20	33	3
2020	20	33	3
2021	20	33	3
2022*	20	33	3
2023*	20	33	3
2024*	20	33	3
*Program cycles end in 2021; 2022-2024 values assumed the same as 2021.			

Source: California Energy Commission, Demand Analysis Office, 2013

Self-Generation

This forecast accounts for all major programs designed to promote self-generation, building up from sales of individual systems. Incentive programs include:

- Emerging Renewables Program (ERP)
- New Solar Homes Partnership (NSHP)

25 Incremental impacts would only be counted since historical peaks would incorporate any reductions in demand that currently occur.

- California Solar Initiative (CSI)
- Self-Generation Incentive Program (SGIP)
- Incentives administered by public utilities such as SMUD, LADWP, Imperial Irrigation District, Burbank Water and Power, City of Glendale, and City of Pasadena.

The ERP and NSHP are managed by the Energy Commission and the CSI and SGIP by the CPUC. The forecast also accounts for power plants reporting information to the Energy Commission. The principal source is Form CEC 1304. Staff included only power plants that explicitly listed themselves as operating under cogeneration or self-generation mode.

The general strategy of the ERP, NSHP, CSI, and SGIP programs is to encourage demand for self-generation technologies, such as PV systems, with financial incentives until the size of the market increases to the point where economies of scale are achieved and capital costs decline. The extent to which consumers see real price declines will depend on the interplay of supplier expectations, the future level of incentives, and demand as manifested by the number of states or countries offering subsidies.

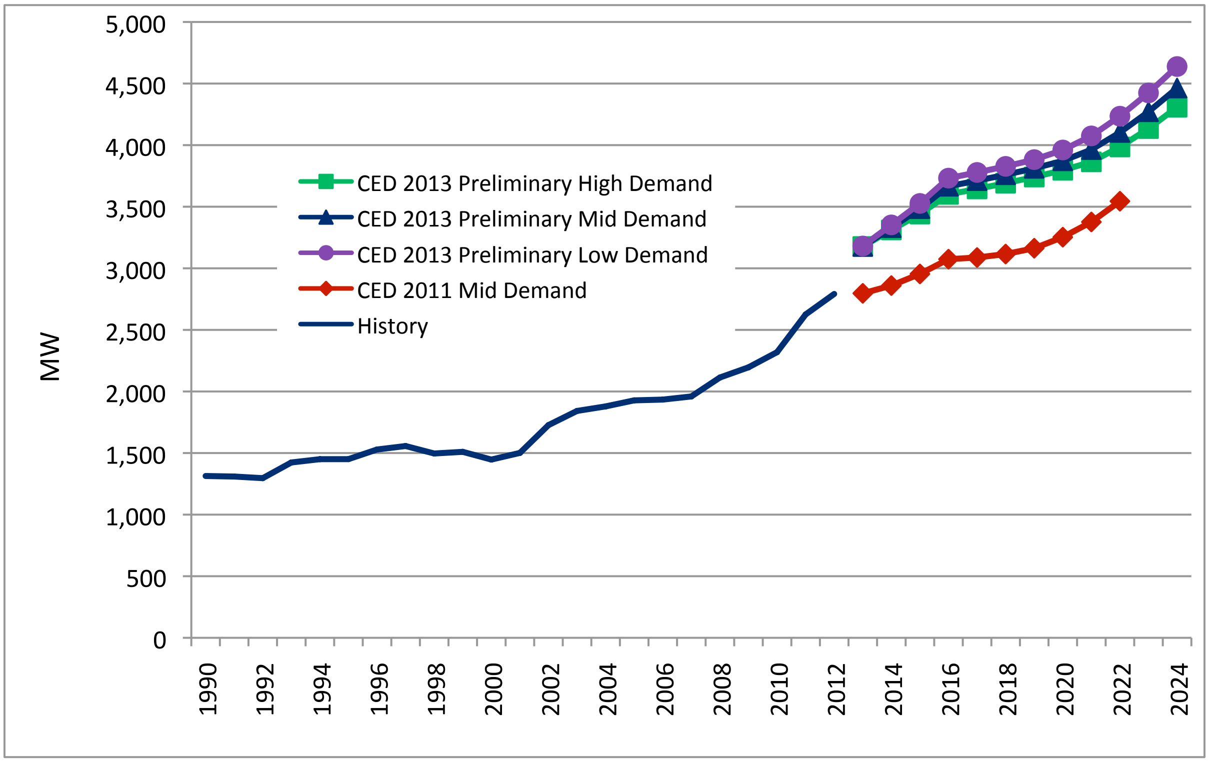
Residential PV adoption and solar water heating adoption are forecast using a predictive model developed by staff and used in *CED 2011*, based on estimated payback periods and cost-effectiveness, determined by upfront costs, energy rates, and incentive levels. Results for adoption differ by demand scenario since projected electricity and natural gas rates and number of homes vary across the scenarios. Lower electricity demand corresponds to higher adoptions; the effect from higher rates outweighs lower growth in households. For the commercial sector, staff has developed a similar predictive model for both PV and CHP. In the case of PV, staff did not incorporate model results for *CED 2013 Preliminary* because initial output did not always appear plausible. Further model testing is ongoing. Therefore, commercial PV was projected with a trend analysis, as in previous forecasts. Commercial CHP adoption from the new predictive model is included in *CED 2013 Preliminary* and is discussed in Appendix B. Self-generation for other technologies and sectors is projected using a trend analysis and does not vary by demand scenario. Appendix B provides more details.

Figure 1-12 shows historical and projected peak impacts of self-generation, which are projected to reduce peak load by more than 4,200 MW by 2024. Higher projections for PV peak impacts (shown in **Figure 1-13)** come from residential sector increases as a result of higher rates in *CED 2013 Preliminary* as well as a higher commercial trend resulting from incorporation of 2011 and 2012 adoptions. These drive total self-generation peak well above *CED 2011*mid levels in all three scenarios. The temporary flattening of the curve after 2016 comes from expiration of the CSI program and the federal tax credit for PV installation. The

PV peak impacts shown in **Figure 1-13** correspond to capacities that exceed the goal of 3,000 MW for 2017 set in Senate Bill 1 (Murray, Chapter 132, Statutes of 2006).[26]

The residential predictive model also projects residential electricity consumption statewide from solar water heating, which reaches around 210 GWh, 230 GWh, and 240 GWh in the high, mid, and low demand cases, respectively, by 2024.[27]

Figure 1-12: Statewide Peak Impacts of Self-Generation

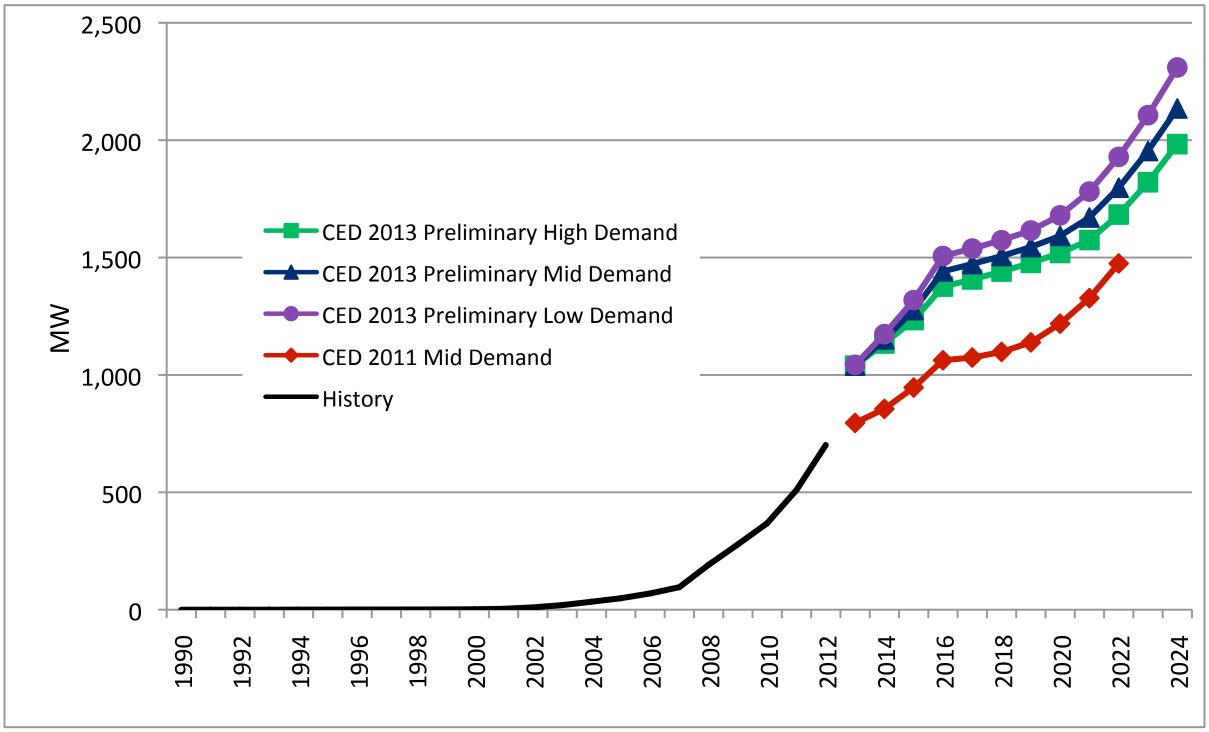


Source: California Energy Commission, Demand Analysis Office, 2013

26 In 2017, projected PV peak impacts correspond to capacities of around 3,030 MW, 3,165 MW, and 3,300 MW in the high, mid, and low demand cases, respectively. By 2024, capacities reach around 4,400 MW, 4,700 MW, and 5,100 MW.

27 "Peak impacts" cannot be defined for this technology.

Figure 1-13: Statewide Peak Impacts of PV Systems

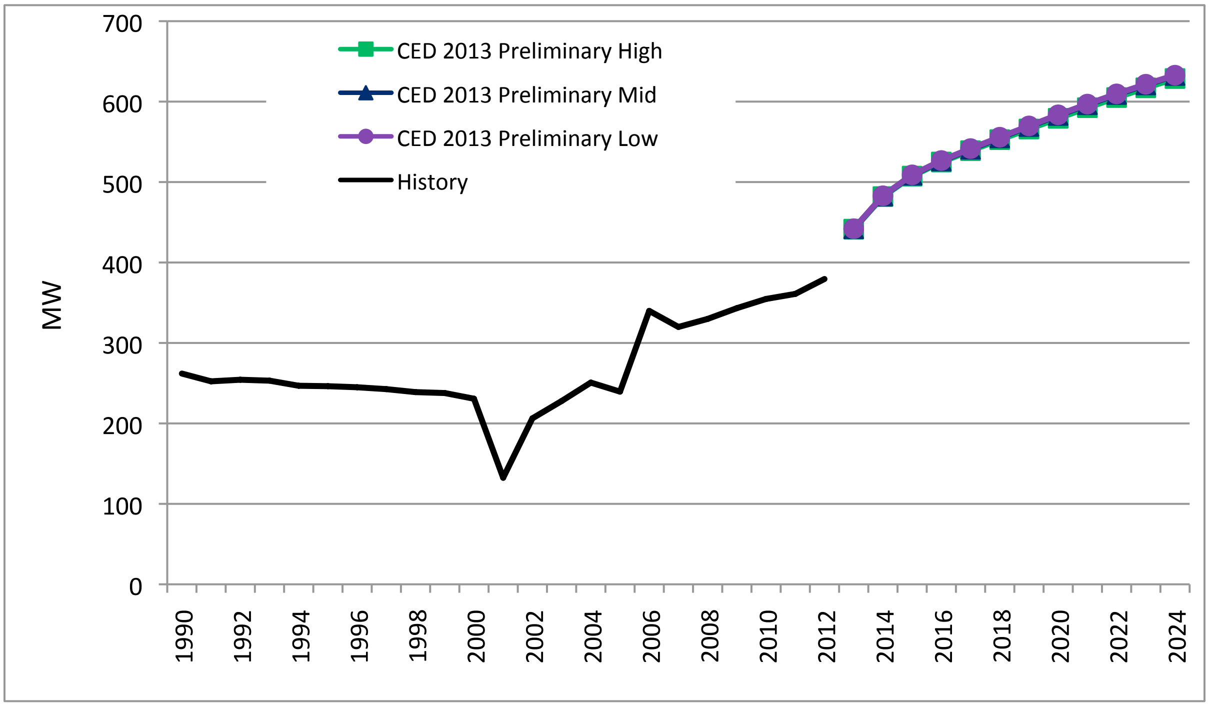


Source: California Energy Commission, Demand Analysis Office, 2013

Figure 1-14 gives historical and projected commercial CHP capacity from the new predictive model. Higher commercial floor space projections in the high demand case increase adoption relative to the other cases, while higher rates in the low case have the same effect. The net result is that all three scenarios are very similar throughout the forecast period. The roughly 630 MW of capacity projected for 2024 corresponds to about 3,200 annual GWh and a 540 MW peak impact.

Table 1-9 shows historical and projected statewide electricity consumption from self-generation, broken out into PV and non-PV applications. For traditional industrial CHP technologies, self-generation is assumed constant (no clear trend is evident in the historical data), so that retired CHP plants are replaced with new ones with no net change in generation. Growth in non-PV self-generation comes mainly from recent increases in the application of fuel cells projected forward and from commercial CHP.

Figure 1-14: Historical and Projected Commercial CHP Capacity



Source: California Energy Commission, Demand Analysis Office, 2013

Table 1-9: Electricity Consumption From Self-Generation

	1990	2000	2010	2015	2020	2024
Non-PV Self-Generation, High Demand	8,234	9,174	12,348	13,274	13,713	13,985
Non-PV Self-Generation, Mid Demand	8,234	9,174	12,348	13,283	13,740	14,017
Non-PV Self-Generation, Low Demand	8,234	9,174	12,348	13,287	13,751	14,032
PV, High Demand	0	6	2,166	4,363	5,427	7,266
PV, Mid Demand	0	6	2,166	4,544	5,739	7,920
PV, Low Demand	0	6	2,166	4,726	6,115	8,673
Total Self-Generation, High Demand	8,234	9,180	14,514	17,638	19,140	21,250
Total Self-Generation, Mid Demand	8,234	9,180	14,514	17,828	19,479	21,937
Total Self-Generation, Low Demand	8,234	9,180	14,514	18,014	19,867	22,704

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2013

Electric Light-Duty Vehicles

CED 2013 Preliminary incorporates scenarios for electric vehicle (EV) fuel consumption developed by the Energy Commission's Fuels Office in early 2012, the same scenarios used in *CED 2011*. The revised version of *CED 2013* will include a new set of scenarios from the Fuels Office. EV projections include both plug-in hybrid (PHEV) and dedicated electric vehicles (BEV). Details on this forecast are available in the report for the *California Energy Demand 2012-2022 Final Forecast*.[28] **Table 1-10** shows the projected number of BEVs and PHEVs on the road statewide in the high and low demand scenarios for selected years.

Table 1-10: Projected Number of Electric Vehicles on the Road, *CED 2013 Preliminary*

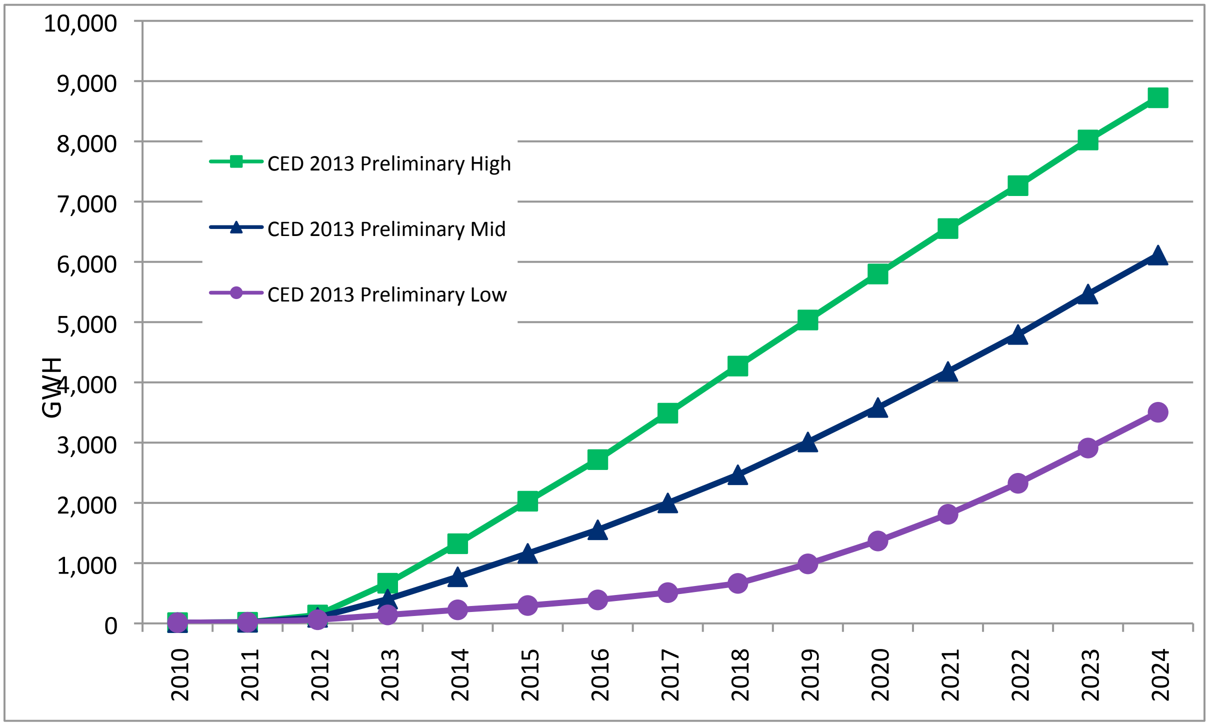
	High Scenario			Low Scenario		
Year	BEVs	PHEVs	Total EVs	BEVs	PHEVs	Total EVs
2012	11,908	42,506	54,415	9,249	6,644	15,893
2015	31,065	1,050,639	1,081,703	30,024	78,883	108,907
2018	63,325	2,145,769	2,209,095	62,409	183,038	245,447
2020	127,833	2,798,430	2,926,264	130,858	371,752	502,610
2024	346,068	3,869,948	4,216,016	361,827	883,775	1,245,602

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2013

Figure 1-15 shows projected statewide electricity consumption for EVs for all three demand scenarios (mid demand is the average of high and low), which reaches around 3,500 GWh by 2024 in the low demand case and more than 8,500 GWh in the high scenario. The majority of consumption is in the residential sector, as the Fuels Office vehicle choice simulation model typically predicts a much higher penetration of EVs in the residential sector versus the commercial, a result based on vehicle preference surveys in these two sectors. Forecasts for the five major planning areas are provided in Volume II of this report.

28 California Energy Commission. June 2012. *California Energy Demand 2012–2022 Final Forecast*. CEC-200-2012-001-CMF (Volume I, pp. 38-41). http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-CMF-V1.pdf.

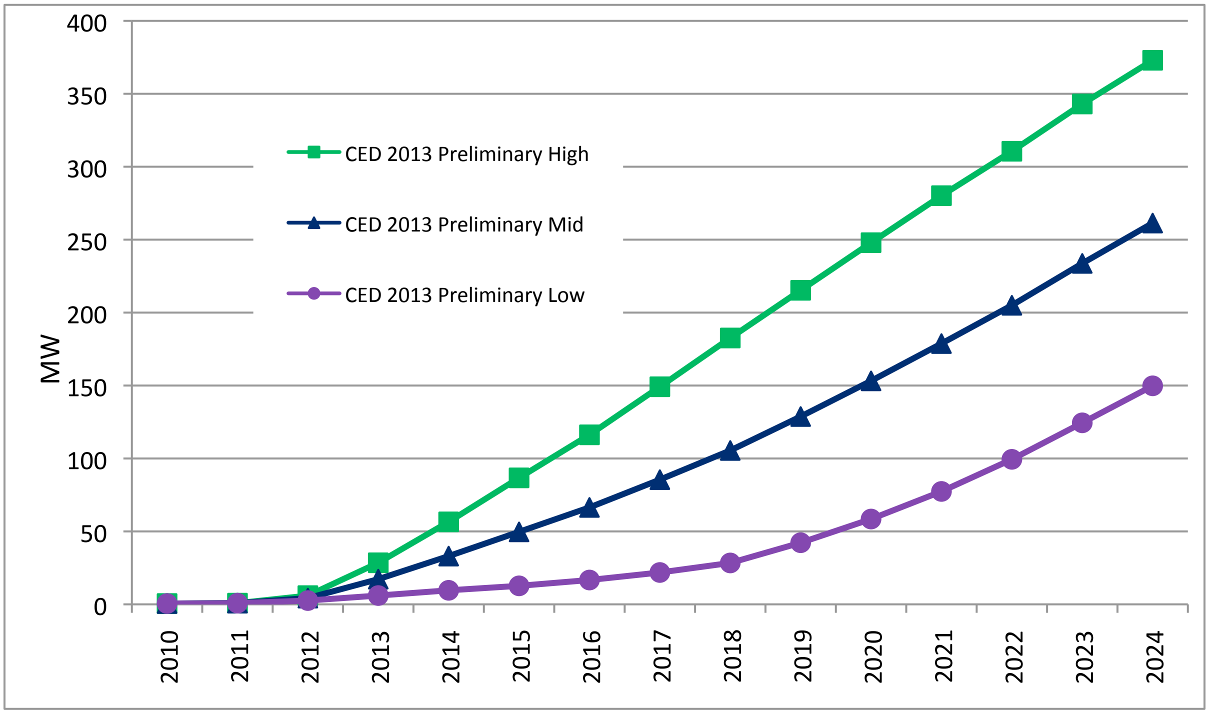
Figure 1-15: Statewide Electric Vehicle Consumption



Source: California Energy Commission, Fuels Office, 2012

To translate consumption to peak demand, as in previous forecasts, staff assumed 75 percent of recharging would take place during off-peak hours (10 p.m. – 6 a.m.), with the rest evenly distributed over the remaining hours. This recharging profile assumes some form of favored off-peak pricing for electric vehicle owners by utilities. **Figure 1-16** shows the projected EV contribution to statewide noncoincident peak. Peak impacts are relatively small compared to consumption due to recharging assumptions; EVs provide a slight increase to the statewide load factor.

Figure 1-16: Statewide Electric Vehicle Peak Demand



Source: California Energy Commission, Demand Analysis Office, 2013

Additional Electrification

Potentially significant increases in electricity use in California are expected to occur through port and truck stop electrification, electrification of commercial and industrial equipment (for example, forklifts), and high-speed rail. The Energy Commission's Fuels Office is involved in a comprehensive analysis of electrification, the results of which will be incorporated in the revised version of this forecast.

Natural Gas Light-Duty Vehicles

Natural gas vehicles and natural gas fuel consumption are forecast as part of the Fuels and Transportation Division's transportation energy demand forecasts. For *CED 2013 Preliminary*, staff used the same natural gas vehicle forecast as in *CED 2011*.[29] The revised version of *CED 2013* will include a new forecast from the Fuels Office. **Table 1-11** shows forecast natural gas vehicle consumption by major natural gas planning area and statewide for selected years.[30]

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29 http://www.energy.ca.gov/2011publications/CEC-600-2011-007/CEC-600-2011-007-SD.pdf.

30 The transportation energy demand forecast for the *2011 IEPR* included two scenarios, but there was almost no difference between the two for natural gas vehicles; Demand Analysis Office staff used the "low" forecast.

Table 1-11: *CED 2013 Preliminary* Natural Gas Consumption by Light-Duty Vehicles (MM therms)

Year	PG&E	Southern California Gas	SDG&E	Total
2012	10.36	12.32	1.93	24.60
2015	24.30	28.89	4.53	57.72
2018	35.68	42.42	6.66	84.77
2020	39.62	47.09	7.40	94.11
2024	45.05	53.54	8.43	107.02

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2013

Subregional Electricity Analysis

As discussed earlier in this chapter, staff intends to provide, to the extent possible, more granular results in future demand forecasts. An important reason is to support subregional electricity system analysis for CPUC/California ISO resource adequacy and other related proceedings. Staff currently disaggregates, or separates, the planning area and climate zone forecasts to correspond to control areas and congestion zones in a "top down" analysis. Further disaggregation of the demand forecast (beyond the climate zone level) would allow more refined, "bottom up" analyses for local congestion zones.

Subregional forecasts, for both energy and peak demand, are provided in spreadsheet files (Form 1.5) in the forms accompanying this forecast report.[31] To develop subregional peak demand forecasts, staff estimates weather-normalized peaks for the IOU transmission access charge (TAC) areas, as well as PG&E Bay and non-Bay subareas, using regression analysis and the latest hourly load data available. The regression results provide weather sensitivity for a reference year (in this case, 2012) so that peak demand can be normalized assuming average weather ("1 in 2") and extreme weather ("1 in 10") using 30-60 years of temperature data. Weather-normalized peaks are then projected in a manner consistent with the demand forecasts for the appropriate planning area.[32] Local area peaks within IOU TAC areas are estimated using the latest load data available and "trued up" (brought into alignment) to IOU TAC totals. More details about these methods are available in a 2011 Energy Commission Committee report.[33]

31 http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-30_workshop/spreadsheets/

32 For example, the PG&E TAC area peak demand is assumed to grow at the projected rate of the PG&E planning area.

33 Garcia-Cerrutti, Miguel, Tom Gorin, Chris Kavalec, Lynn Marshall. 2011. *Final Short-Term (2011-2012) Peak Demand Forecast* Committee Final Report. California Energy Commission, Electricity Supply Analysis Division. Available at: http://www.energy.ca.gov/2011publications/CEC-200-2011-002/CEC-200-2011-002-CTF.pdf.

Historical Electricity Consumption Estimates

Energy Commission demand forecasting models are organized by sector according to economic activity (that is, commercial, industrial, agricultural, and so on). Each of these models develops a forecast based on subactivities within the sector (for example, commercial building type or industrial activity). Under the Energy Commission's Quarterly Fuel and Energy Report (QFER) regulations, each load-serving entity (LSE) is required to file monthly and annual reports documenting energy consumption by activity group.

The quality of the QFER data is improving but is still occasionally undermined by LSE data coding errors, lack of adherence to regulations, and failure to provide economic classification for some of the data. Unclassified consumption, after declining from a high of almost 20,000 GWh in 2003 to less than 6,000 GWh in 2010, has increased to 10,000 GWh in 2012. Staff allocates unclassified consumption to economic sectors using professional judgment, relying on factors such as unrealistic changes in historical consumption.

Staff is developing a database system to automate QFER data collection and processing, which should facilitate more accurate LSE filings. A test version of this database is scheduled to be complete by the end of 2013.

Structure of Report

Chapter 2 of Volume I provides statewide results for the end-user natural gas forecast, along with results for the PG&E, SoCalGas, and SDG&E distribution areas. Chapter 3 presents committed energy efficiency and conservation savings estimated for the forecast. The appendices provide additional information about methods and econometric results, incorporation of climate change, self-generation, and regression results.

Volume II provides *CED 2013 Preliminary* electricity forecasts for the following planning areas: PG&E, SCE, SDG&E, SMUD, and LADWP, in that order. The planning areas included in this forecast are described in **Table 1-12**. The chapters for LADWP, PG&E, and SCE in Volume II provide results for the individual climate zones within these planning areas. **Figure 1-17** shows the Energy Commission's forecasting climate zones. Zones 1-5 correspond to PG&E, 7-10 to SCE, and 11-12 to LADWP. The other planning areas correspond to single climate zones. The areas labeled "Other" correspond to areas in California served (for electricity) by out-of-state entities and not included in the eight planning areas.

Forecast demand forms for each planning area are posted with this report. [34]

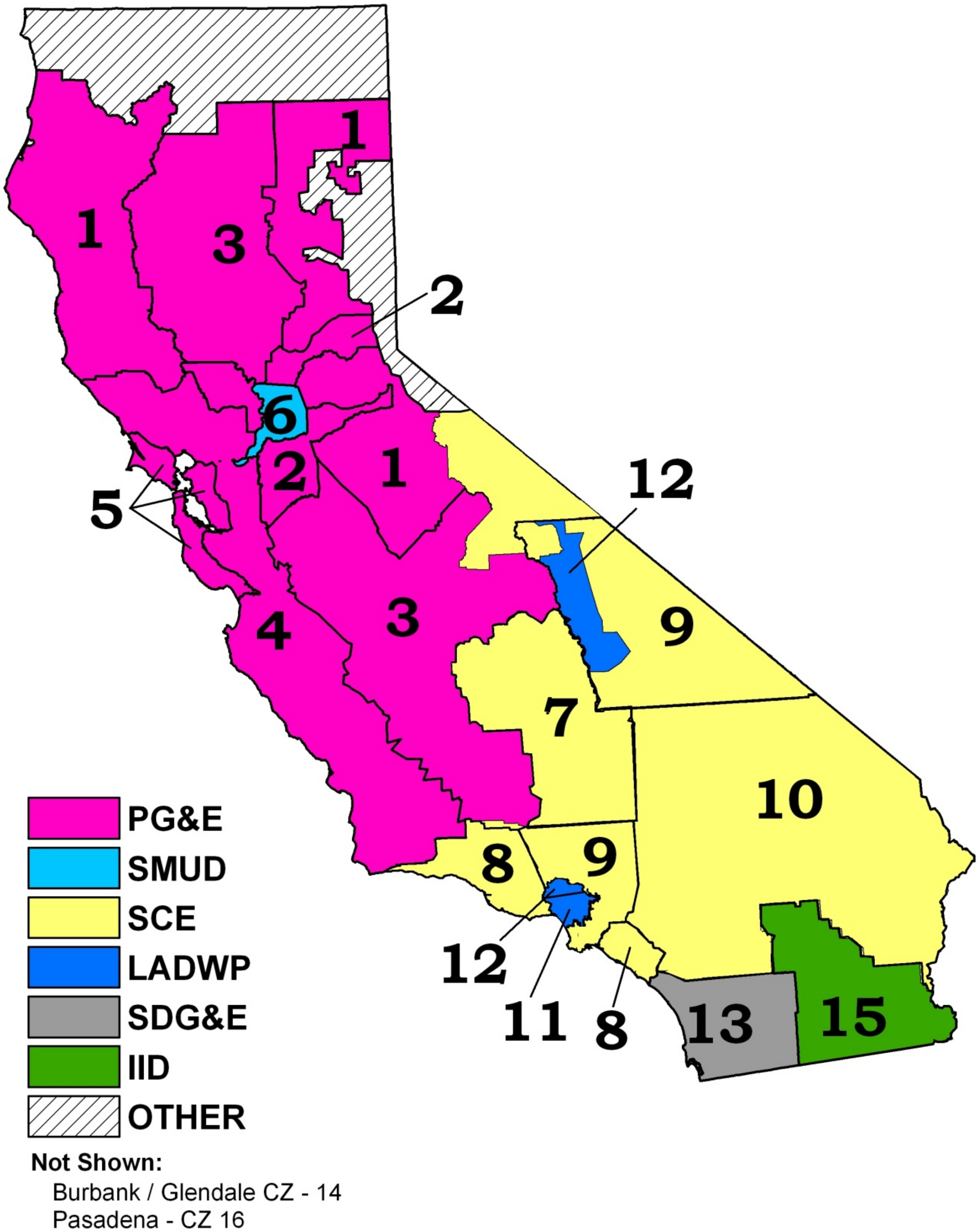
34 http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-30_workshop/spreadsheets/

Table 1-12: Utilities Within Forecasting Areas

Planning Area	Utilities Included
Electric Areas	
PG&E	PG&E Alameda Biggs Calaveras Gridley Healdsburg Hercules Island Energy (Pittsburg) Lassen Lodi Lompoc Merced Modesto Palo Alto Plumas – Sierra Port of Oakland Port of Stockton Power and Water Resources Pooling Authority Redding Roseville San Francisco Shasta Silicon Valley Tuolumne Turlock Irrigation District Ukiah US Bureau of Reclamation-Central Valley Project
SMUD	SMUD
SCE	Anaheim Anza Azusa Banning Bear Valley Colton Corona Metropolitan Water District Moreno Valley Rancho Cucamonga Riverside SCE US Bureau of Reclamation-Parker Davis Valley Electric Vernon Victorville
LADWP	LADWP
SDG&E	SDG&E
Cities of Burbank and Glendale (BUGL)	Burbank, Glendale
Pasadena (PASD)	Pasadena
Imperial (IID)	Imperial Irrigation District
Department of Water Resources (DWR)	DWR
Natural Gas Distribution Areas	
PG&E	PG&E, Palo Alto
SDG&E	SDG&E
SoCalGas	SoCalGas, Long Beach, Northwest Pipeline, Mojave Pipeline
OTHER	Southwest Gas Corporation, Avista Energy

Source: California Energy Commission, Demand Analysis Office, 2013

Figure 1-17: Energy Commission Forecasting Climate Zones



Source: California Energy Commission, Demand Analysis Office, 2013

CHAPTER 2: End-User Natural Gas Demand Forecast

This chapter presents preliminary forecasts of end-user natural gas demand for the PG&E, SoCalGas, and SDG&E natural gas planning areas. In addition, statewide results include sales from much smaller utilities, including Southwest Gas Corporation and Avista Energy, aggregated into the category "other." Detailed forecasts for the three major planning areas and "other" are provided in the electronic natural gas forms accompanying this forecast report.[35]

Staff prepares these forecasts in parallel with its electricity demand forecasts, with the same models, organized along electricity planning area boundaries. The gas demand forecasts presented here are the combination of gas demand in the corresponding electricity planning areas. These forecasts do not include natural gas used by utilities or others for electric generation but include projections for light-duty natural gas vehicle fuel use, as discussed in Chapter 1 of this volume.

CED 2013 Preliminary incorporates historical consumption data up through 2012. As in the case of electricity, three demand scenarios were forecast (high, mid, and low), with the same economic/demographic assumptions in each case. Also similar to electricity, the high, mid, and low scenarios incorporated low, mid, and high assumptions, respectively, for natural gas prices and efficiency program impacts. See Chapter 1 for a discussion of prices and economic and demographic inputs and Chapter 3 for a description of efficiency assumptions.

Statewide Forecast Results

Table 2-1 compares the three *CED 2013 Preliminary* demand scenarios at the statewide level with the *CED 2011* mid demand case for selected years. The new forecasts begin at a lower point in 2012, as natural gas consumption in California was substantially lower in this year than was predicted in the *CED 2011* mid case, and grow at a slower rate in all three scenarios from 2012-2022. Key factors are slower projected population growth in the *CED 2013 Preliminary* mid and low cases, the introduction of climate change impacts in the mid and high cases,[36] and new efficiency initiatives and higher projected natural gas rates for all three scenarios. Climate change affects the mid and high scenarios through projected decreases in heating degree days (see Appendix A). By 2024, climate change is projected to reduce end-user natural gas demand statewide by around 250 million therms in the mid

35 http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-30_workshop/spreadsheets/

36 Potential climate change impacts on end-user natural gas consumption were not estimated for *CED 2011*.

case and by roughly 640 million therms in the high case. Individual sector results are discussed in the planning area sections that follow.

Table 2-1: Statewide End-User Natural Gas Forecast Comparison

Consumption (MM Therms)				
	CED 2011 Mid Case	*CED 2013 Preliminary High Energy Demand*	*CED 2013 Preliminary Mid Energy Demand*	*CED 2013 Preliminary Low Energy Demand*
1990	12,893	12,893	12,893	12,893
2000	13,913	13,913	13,913	13,913
2012	13,123	12,686	12,686	12,686
2015	13,503	12,613	12,631	12,353
2020	13,961	12,722	12,789	12,649
2024	--	12,779	12,804	12,719
	Average Annual Growth Rates			
1990-2000	0.76%	0.76%	0.76%	0.76%
2000-2012	-0.49%	-0.77%	-0.77%	-0.77%
2012-2015	0.96%	-0.19%	-0.15%	-0.88%
2012-2022	0.70%	0.05%	0.08%	-0.01%
2012-2024	--	0.06%	0.08%	0.02%
Historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2013

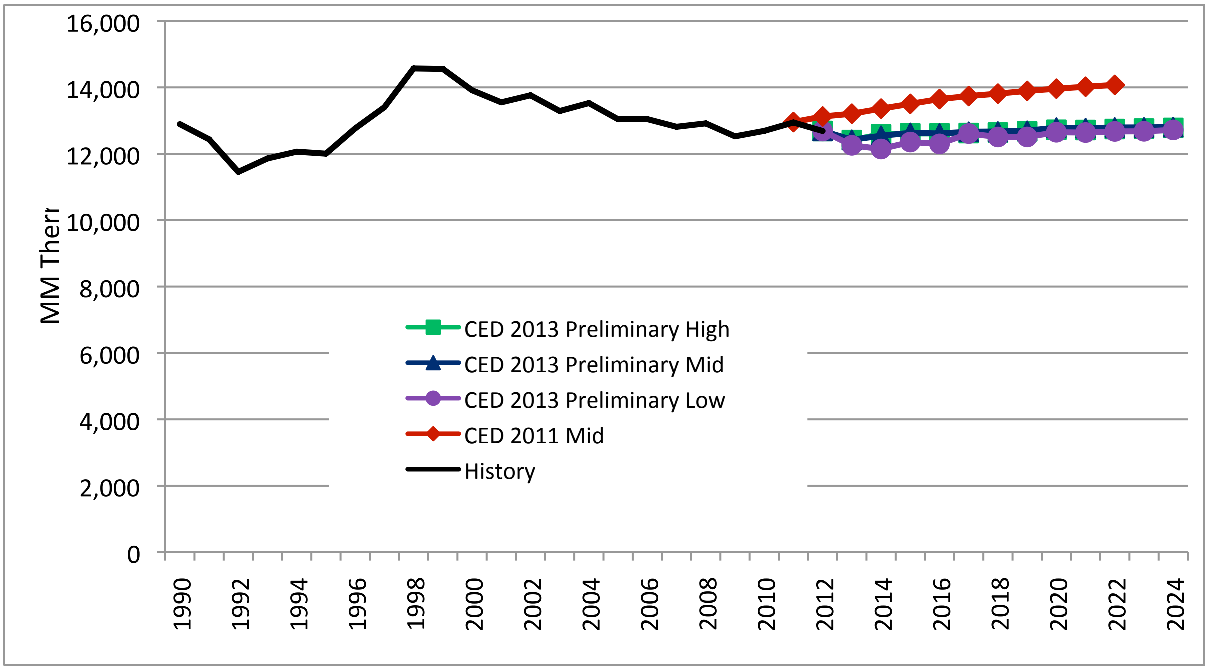
Figure 2-1 shows the forecasts. By 2022, demand in the *CED 2013 Preliminary* mid case is projected to be around 9 percent lower compared to the *CED 2011* mid case. The three scenarios are fairly close together as climate change impacts reduce consumption in the mid and high cases and resource extraction output[37] is lower in the high demand case. The difference in resource extraction gas consumption is enough to push the high demand case below the mid case by 2024. In general, growth rates for total consumption are lower compared to electricity, reflecting a historical trend for gas demand that is flat or declining for most of the previous decade, an indication of the effectiveness of building codes and standards.

Figure 2-2 compares *CED 2013 Preliminary* projected per capita natural gas consumption with the *CED 2011* mid case. Annual per capita demand varies in response to annual

37 Unlike industrial electricity demand, resource extraction contributes significantly to natural gas demand in the industrial sector.

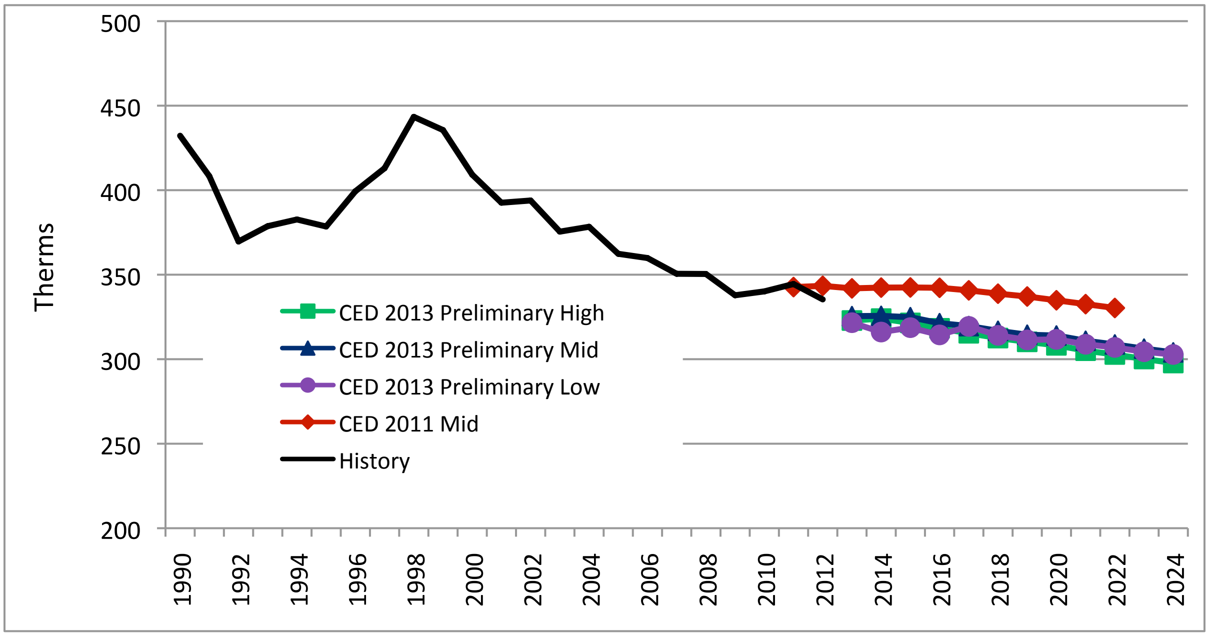
temperatures and business conditions but has been declining since the late 1990s. This trend is projected to continue as projected population grows faster than total natural gas demand. Per capita consumption in all three scenarios is lower in 2012 than projected in the *CED 2011* mid case due in part to a historically low number of heating degree days.

Figure 2-1: Statewide End-User Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013

Figure 2-2: Statewide End-User Per Capita Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013

Efficiency Impacts

New efficiency initiatives not incorporated in *CED 2011*, including the 2013-14 IOU programs and the 2013 Title 24 building standards update, contribute to a lower natural gas forecast. As discussed in Chapter 3, the new IOU programs are projected to reduce demand by almost 80 million therms by 2014, decaying to around 68 million therms in 2024. The Title 24 update adds additional savings of 46 million therms by the end of the forecast period. Staff was not able to prepare a full accounting of historical and forecast gas efficiency impacts as done with electricity (which include standards, programs, and price effects back to 1975) in time for this report; this will be provided with the revised version of this forecast.

Planning Area Results

This section presents forecasting results for each of the three natural gas planning areas, including sector-level projections.

Pacific Gas and Electric Planning Area

The PG&E natural gas planning area is defined as the combined PG&E and SMUD electric planning areas. It includes all PG&E retail gas customers and customers of private marketers using the PG&E natural gas distribution system.

Table 2-2 compares the *CED 2013 Preliminary* PG&E planning area forecasts with the *CED 2011* mid case. The new forecasts begin at almost the same level as projected in *CED 2011* mid but grow at a slower rate in all three scenarios. By 2020, demand is almost 4 percent lower in the mid case compared to *CED 2011*. Climate change impacts and slower growth in resource extraction output in the *CED 2013 Preliminary* high demand case reduce demand below that in *CED 2013 Preliminary* mid.

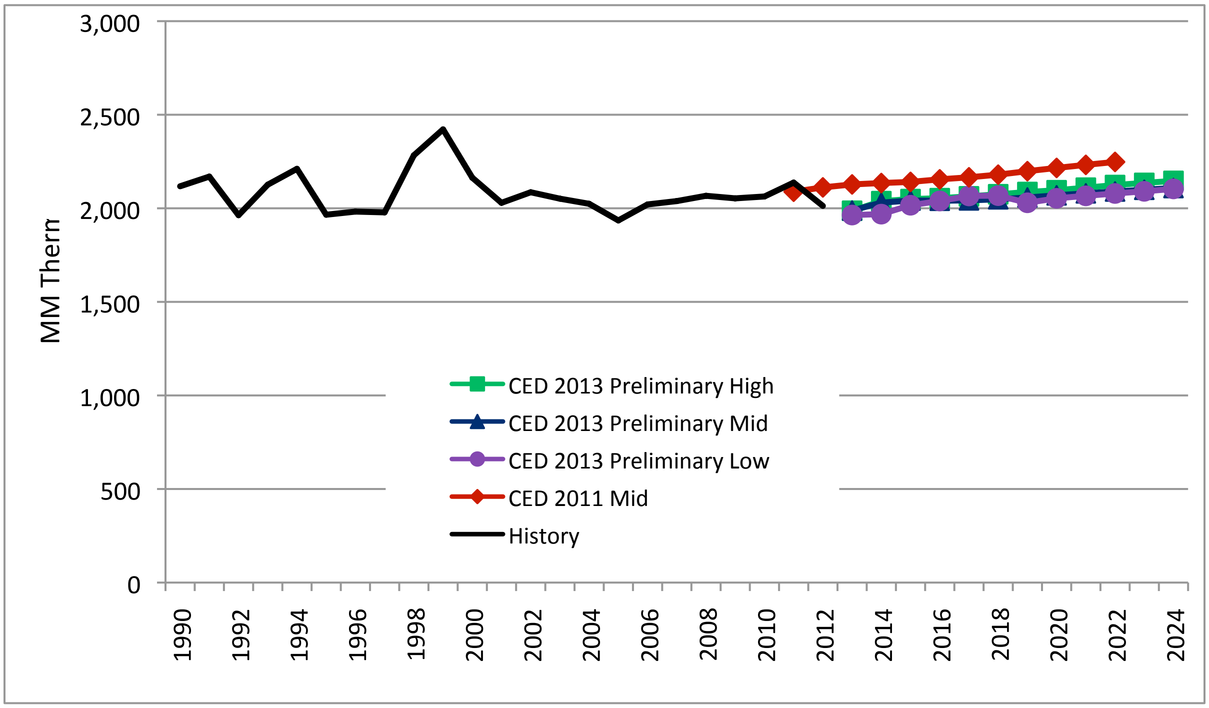
Table 2-2: PG&E Natural Gas Forecast Comparison

Consumption (MM Therms)				
	CED 2011 Mid Case	*CED 2013 Preliminary High Energy Demand*	*CED 2013 Preliminary Mid Energy Demand*	*CED 2013 Preliminary Low Energy Demand*
1990	5,275	5,275	5,275	5,275
2000	5,291	5,291	5,291	5,291
2012	4,746	4,761	4,761	4,761
2015	4,862	4,731	4,761	4,670
2020	5,035	4,814	4,849	4,783
2024	--	4,888	4,909	4,870
	Average Annual Growth Rates			
1990-2000	0.03%	0.03%	0.03%	0.03%
2000-2012	-0.90%	-0.88%	-0.88%	-0.88%
2012-2015	0.80%	-0.21%	0.00%	-0.64%
2012-2022	0.68%	0.20%	0.26%	0.15%
2012-2024	--	0.22%	0.26%	0.19%
Historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2013

Figure 2-3 compares *CED 2013 Preliminary* and *CED 2011* mid case PG&E residential forecasts. The new forecasts are lower throughout the forecast period as actual consumption recorded in 2012 was lower than predicted in the *CED 2011* mid case. Average annual growth from 2012-2022 in all three scenarios (0.54, 0.38, and 0.33 percent, respectively, for the high, mid, and low cases) is slower versus the *CED 2011* mid case (0.63 percent), reflecting the effect of lower population growth in the mid and low cases, climate change impacts in the mid and high cases, and higher projected rates and more efficiency savings in all three scenarios.

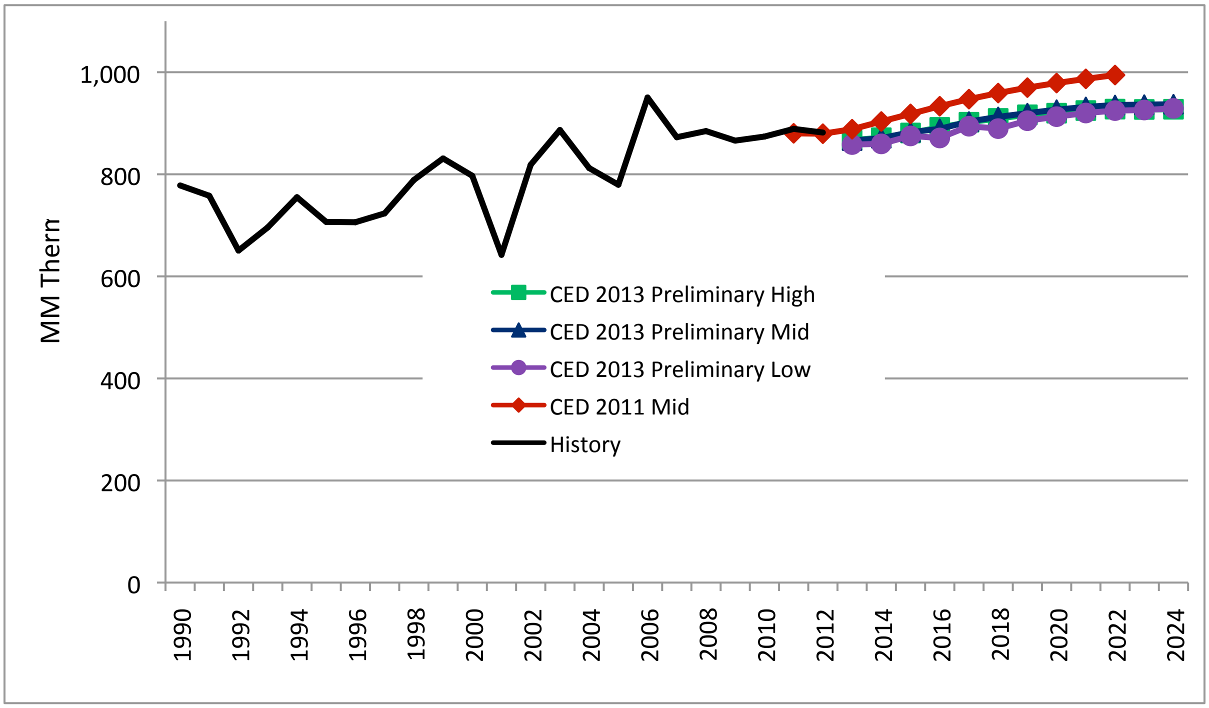
Figure 2-3: PG&E Planning Area Residential Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013

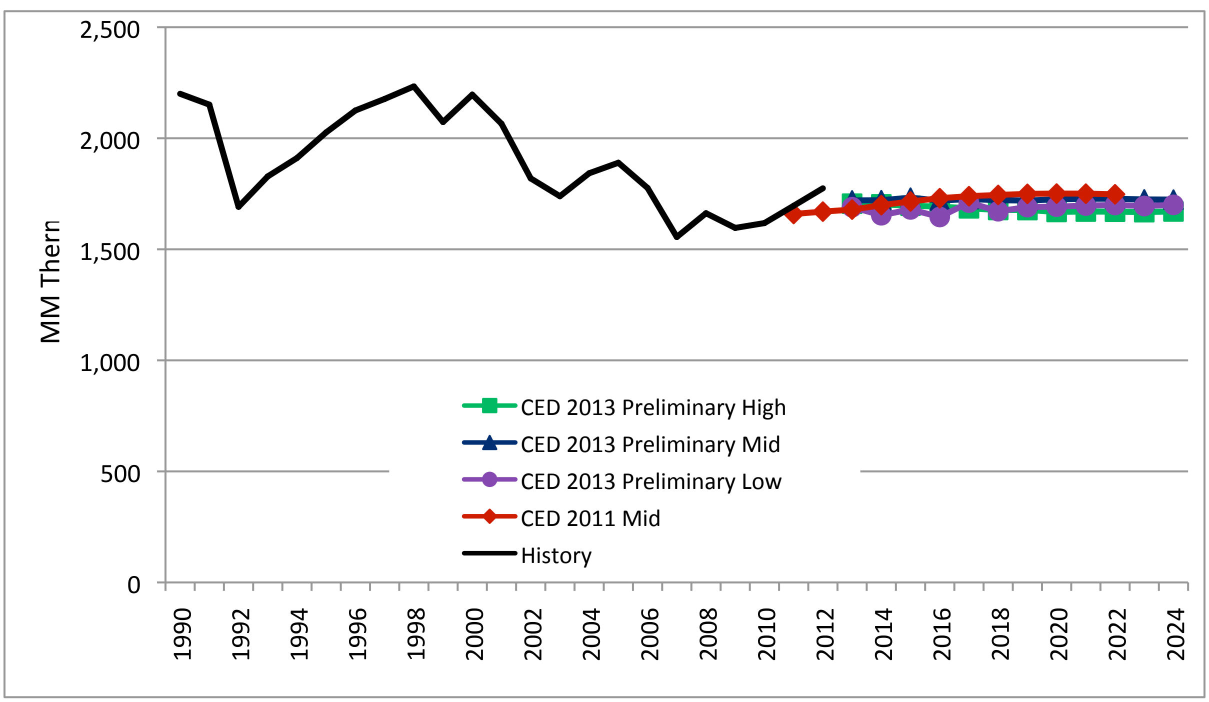
Figure 2-4 and **Figure 2-5** show the forecasts for the PG&E commercial and industrial sectors. Additional efficiency, climate change, and rate impacts result in lower growth in the commercial sector in all three scenarios versus the *CED 2011* mid case. By 2022, projected CED 2011 mid demand was around 6 percent higher than in the new forecast. The *CED 2013 Preliminary* high demand case falls below the mid case due to more pronounced climate change impacts. Projected industrial sector demand in the *CED 2013 Preliminary* mid case is virtually identical to the *CED 2011* mid case, as slightly higher manufacturing growth in the new forecast is offset by the introduction of climate change impacts. As in the commercial sector, *CED 2013 Preliminary* high demand climate change impacts, along with slower growth in resource extraction activity, push this scenario slightly below the mid case.

Figure 2-4: PG&E Planning Area Commercial Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013

Figure 2-5: PG&E Planning Area Industrial Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013

Southern California Gas Company Planning Area

The SoCalGas planning area is composed of the SCE, Burbank and Glendale, Pasadena, and LADWP electric planning areas. It includes customers of those utilities, plus customers of private marketers using the SoCalGas natural gas distribution system.

Table 2-3 compares the *CED 2013 Preliminary* SoCalGas planning area forecasts with the *CED 2011* mid case. In all three scenarios, average annual gas demand growth from 2012-2022 is below that of *CED 2011* mid. By 2020, demand in the new mid case is more than 10 percent lower than in the previous forecast. Slower growth in the *CED 2013 Preliminary* high demand scenario versus the *CED 2013 Preliminary* mid case comes from less growth in resource extraction activities and more pronounced climate change impacts.

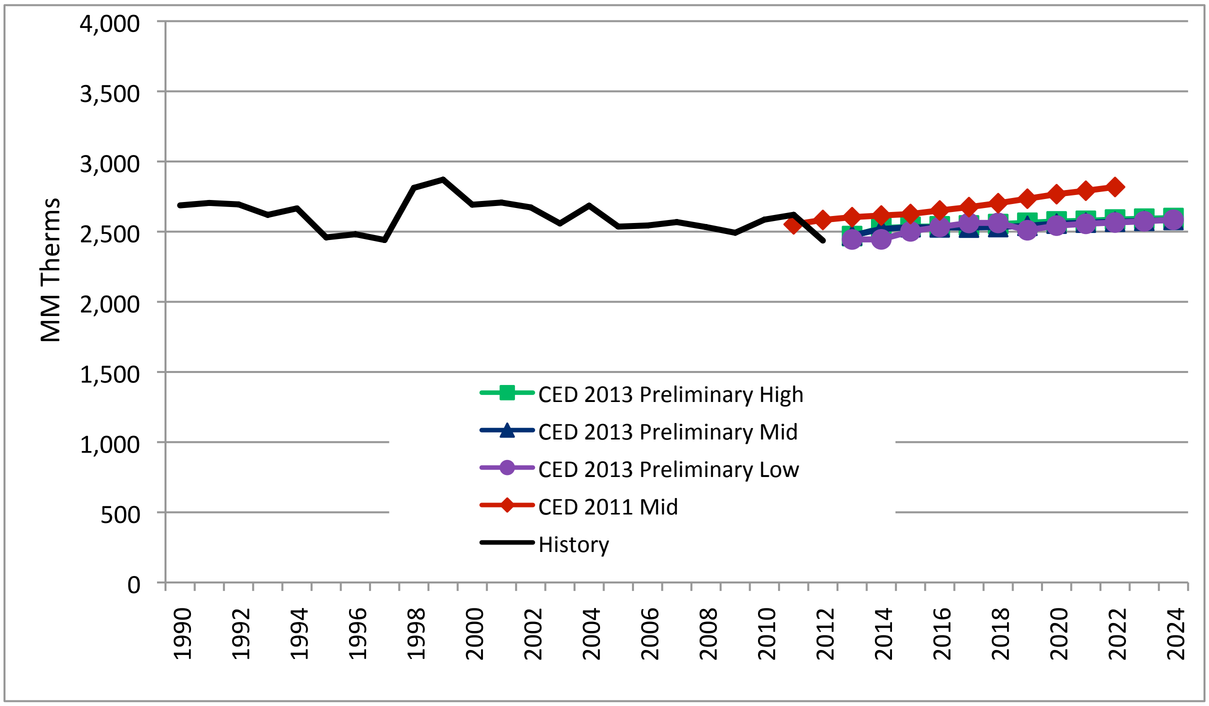
Table 2-3: SoCalGas Natural Gas Forecast Comparison

Consumption (MM Therms)				
	CED 2011 Mid Case	*CED 2013 Preliminary High Energy Demand*	*CED 2013 Preliminary Mid Energy Demand*	*CED 2013 Preliminary Low Energy Demand*
1990	6,806	6,806	6,806	6,806
2000	7,938	7,938	7,938	7,938
2012	7,656	7,275	7,275	7,275
2015	7,889	7,265	7,253	7,075
2020	8,109	7,302	7,334	7,263
2024	--	7,282	7,286	7,238
	Average Annual Growth Rates			
1990-2000	1.55%	1.55%	1.55%	1.55%
2000-2012	-0.30%	-0.72%	-0.72%	-0.72%
2012-2015	1.00%	-0.05%	-0.10%	-0.93%
2012-2022	0.63%	0.01%	0.03%	-0.06%
2012-2024	--	0.01%	0.01%	-0.04%
Historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2013

Figure 2-6 compares the *CED 2011* mid case and *CED 2013 Preliminary* SoCalGas residential forecasts. Average annual growth from 2012-2022 in all three scenarios (0.60, 0.54, and 0.52 percent, respectively, for the high, mid, and low cases) is slower versus the *CED 2011* mid case (0.87 percent), reflecting the effect of lower population growth in the mid and low cases, climate change impacts in the mid and high cases, and higher projected rates and more efficiency savings in all three scenarios.

Figure 2-6: SoCalGas Planning Area Residential Natural Gas Consumption

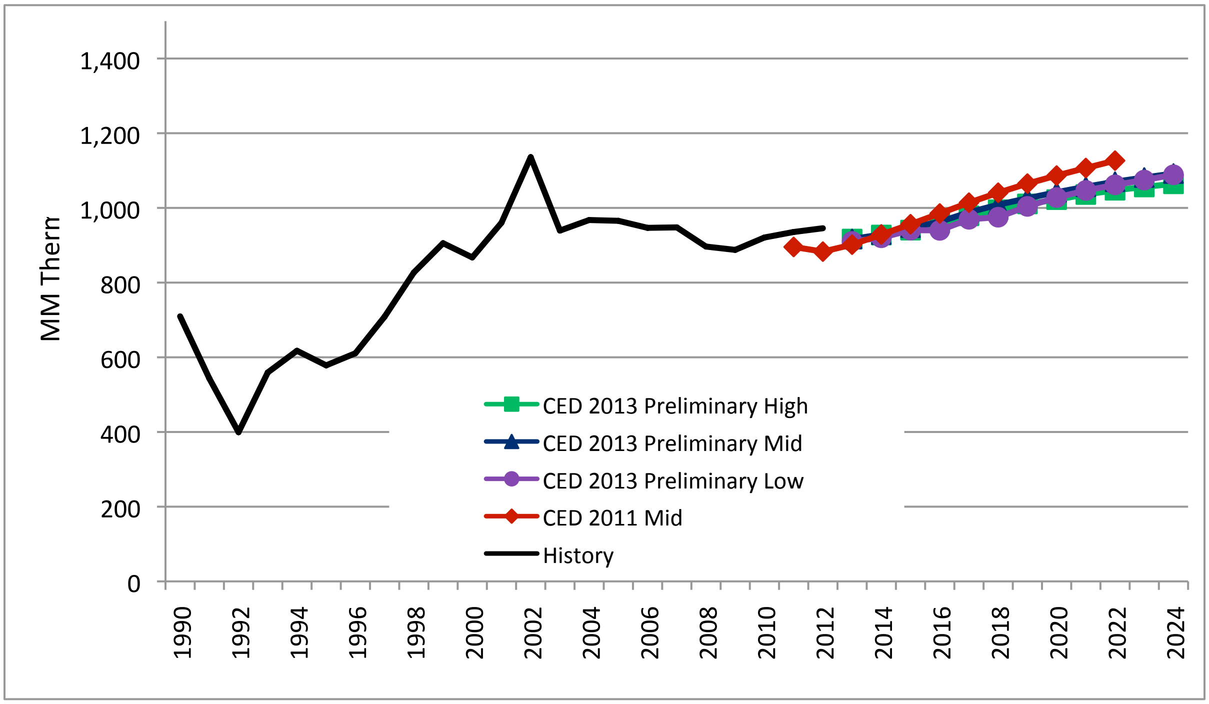


Source: California Energy Commission, Demand Analysis Office, 2013

Figure 2-7 and **Figure 2-8** show the forecasts for the SoCalGas commercial and industrial sectors, respectively. In the commercial sector, the three scenarios are similar to the *CED 2011* mid case through 2014, but then grow at a slower rate for the rest of the forecast period due to additional efficiency savings, climate change, and rate impacts. By 2022, demand is projected to be more than 5 percent lower in the new mid case relative to the old. As with PG&E, the *CED 2013 Preliminary* high demand case falls below the mid case because of more pronounced climate change impacts.

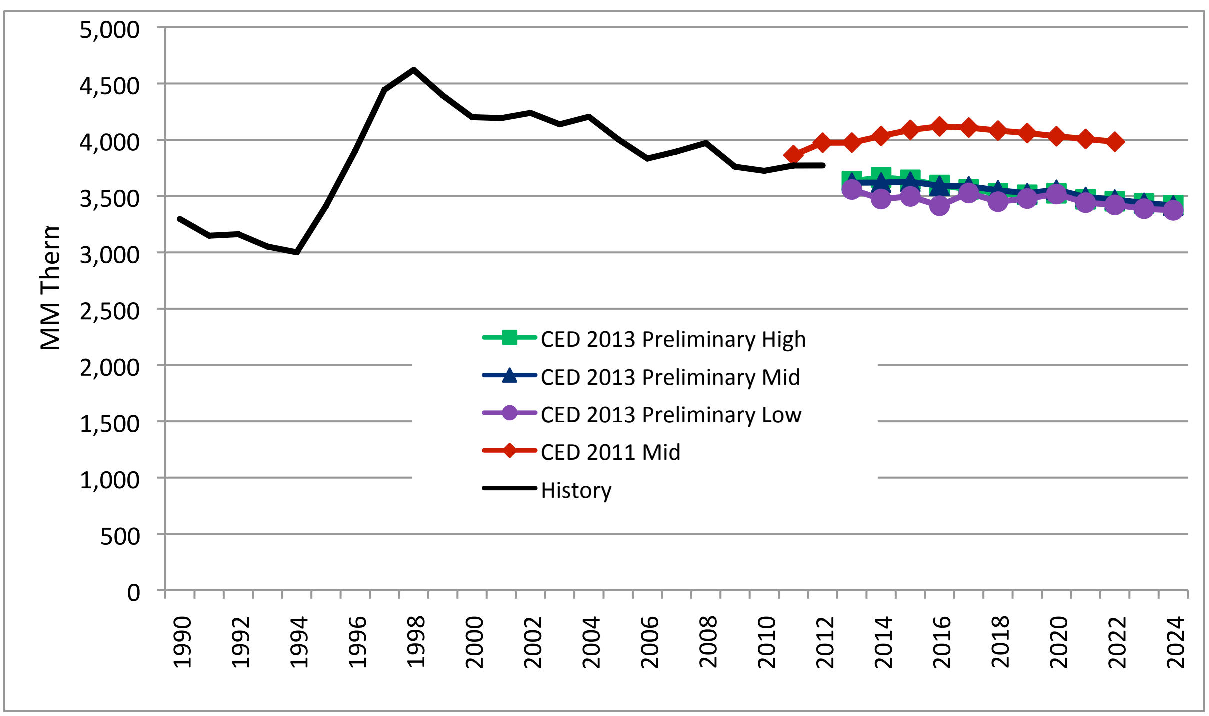
The projections for industrial natural gas consumption reflect an expected long-term decline in this sector's output in the Los Angeles region in all three *CED 2013 Preliminary* scenarios. Unlike *CED 2011*, gas demand is not projected to increase in the short term due to higher rates and the impacts of the 2013-14 IOU efficiency programs. By 2022, projected consumption is around 12 percent below that forecast in the *CED 2011* mid case.

Figure 2-7: SoCalGas Planning Area Commercial Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013

Figure 2-8: SoCalGas Planning Area Industrial Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013

San Diego Gas & Electric Planning Area

The SDG&E planning area contains SDG&E customers plus customers of private marketers using the SDG&E natural gas distribution system.

Table 2-4 compares the *CED 2013 Preliminary* SDG&E planning area forecasts with the *CED 2011* mid case. The new forecasts begin at a significantly lower level and grow at a slower rate from 2012-2022 in all three scenarios. By 2020, projected demand is almost 25 percent lower in the new mid case compared to *CED 2011*. A key reason for the large difference between the 2013 and 2011 forecasts in the early years (along with the introduction of the 2013-14 IOU efficiency programs) is that projected personal income growth was revised downward significantly for the new forecast. Climate change impacts and slower growth in resource extraction activities in the *CED 2013 Preliminary* high demand case reduce demand below that in the *CED 2013 Preliminary* mid and low cases.

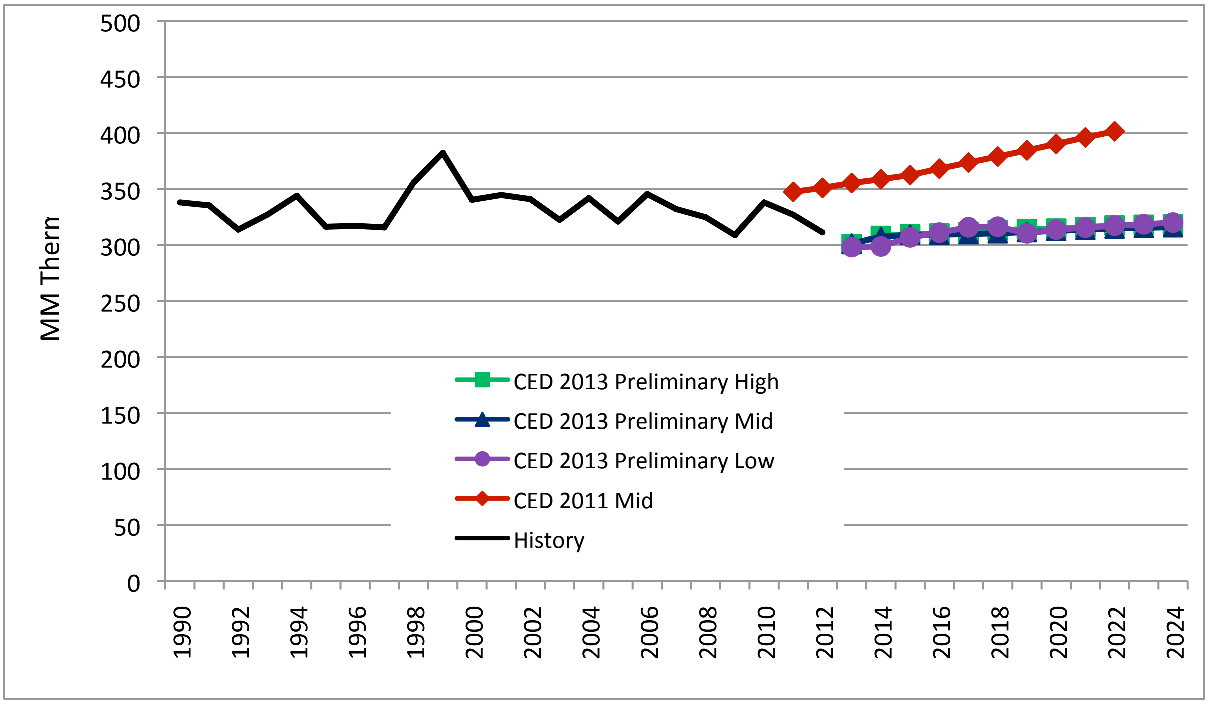
Table 2-4: SDG&E Natural Gas Forecast Comparison

Consumption (MM Therms)				
	CED 2011 Mid Case	*CED 2013 Preliminary High Energy Demand*	*CED 2013 Preliminary Mid Energy Demand*	*CED 2013 Preliminary Low Energy Demand*
1990	717	717	717	717
2000	565	565	565	565
2012	580	516	516	516
2015	609	513	513	507
2020	665	530	534	534
2024	--	539	545	552
	Average Annual Growth Rates			
1990-2000	-2.35%	-2.35%	-2.35%	-2.35%
2000-2012	0.22%	-0.75%	-0.75%	-0.75%
2012-2015	1.62%	-0.24%	-0.22%	-0.60%
2012-2022	1.69%	0.38%	0.46%	0.52%
2012-2024	--	0.37%	0.45%	0.56%
Historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2013

Figure 2-9 compares the *CED 2011* mid case and *CED 2013 Preliminary* SDG&E residential forecasts. Average annual growth from 2012-2022 in all three scenarios (0.19, 0.11, and 0.19 percent, respectively, for the high, mid, and low cases) is slower versus the *CED 2011* mid case (1.35 percent), reflecting the effect of lower population growth in the mid and low cases, climate change impacts in the mid and high cases, and higher projected rates and more efficiency savings in all three scenarios.

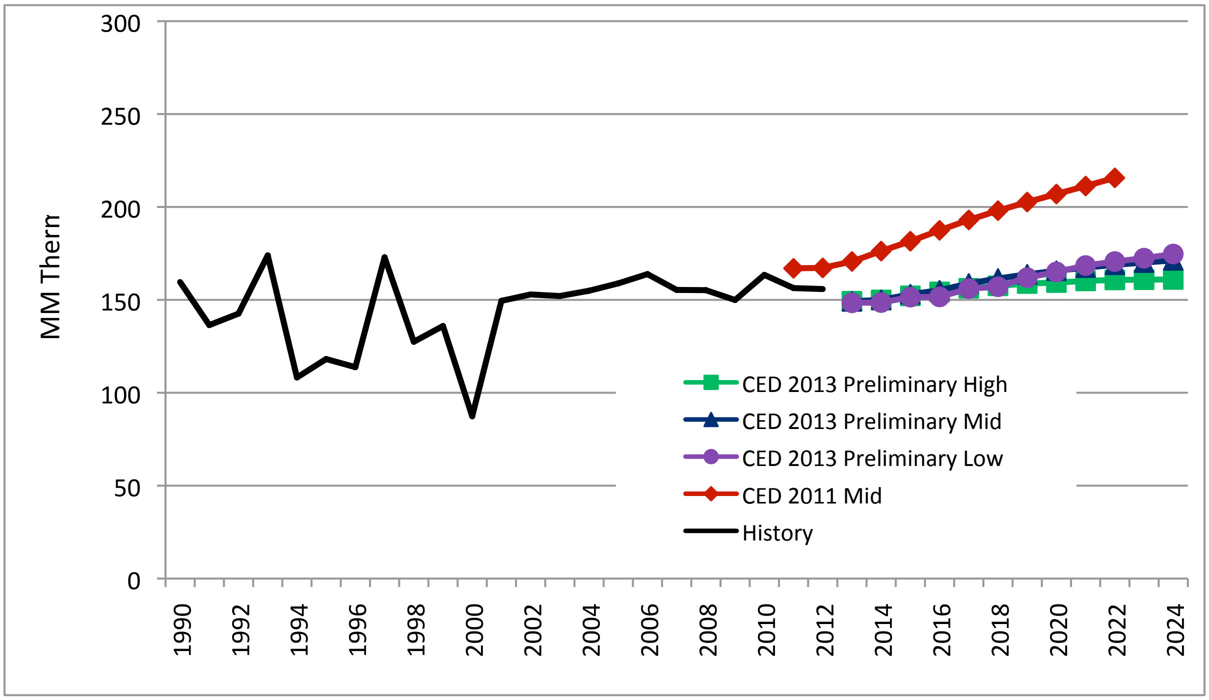
Figure 2-9: SDG&E Planning Area Residential Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013

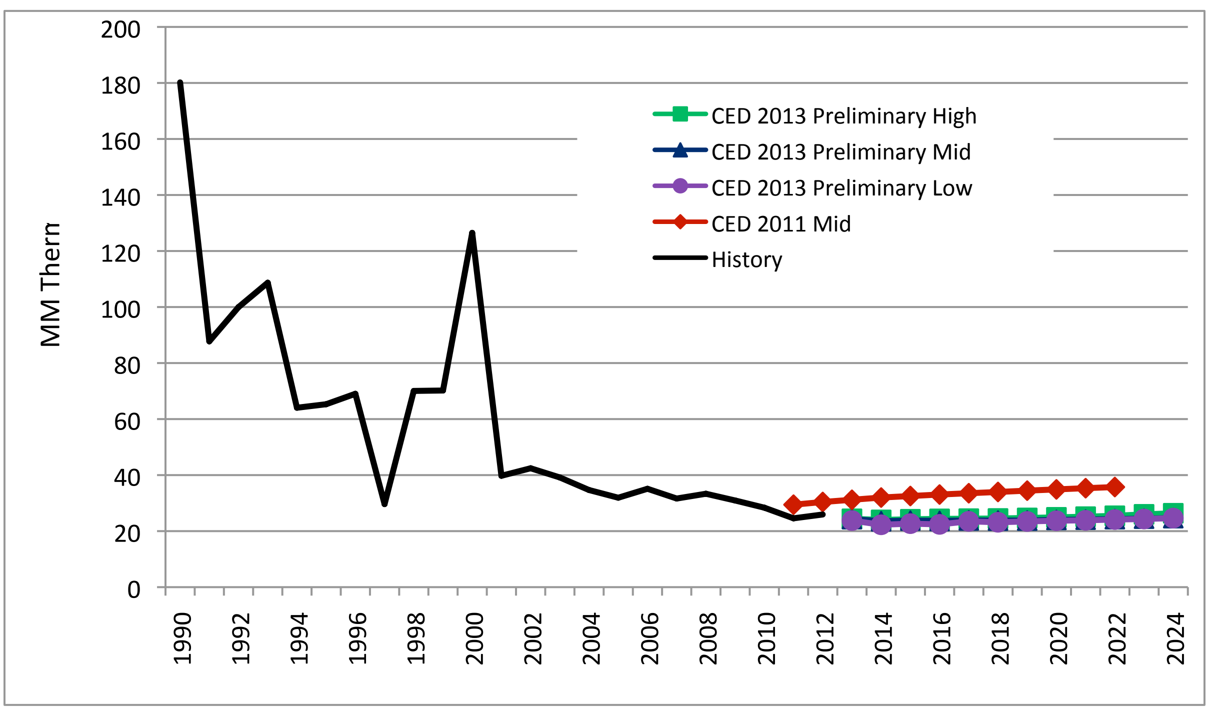
Figure 2-10 and **Figure 2-11** show the forecasts for the SDG&E commercial and industrial sectors. Additional efficiency, climate change, and rate impacts result in lower growth in the commercial sector in all three scenarios versus the *CED 2011* mid case. By 2022, projected *CED 2011* mid demand is almost 28 percent higher than in the new forecast. The *CED 2013 Preliminary* low demand case is above the mid and high cases by the end of the forecast period because climate change impacts are not assumed for this scenario. Projected industrial sector demand is flat throughout the forecast period and slightly below that predicted in the *CED 2011* mid case.

Figure 2-10: SDG&E Planning Area Commercial Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013

Figure 2-11: SDG&E Planning Area Industrial Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013

CHAPTER 3: Energy Efficiency and Conservation

Introduction

With the state's adoption of the first *Energy Action Plan (EAP)* in 2003, energy efficiency became the resource of first choice for meeting the state's future energy needs. Under Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006), the Energy Commission, in consultation with the CPUC, is responsible for periodically developing annual statewide efficiency potential estimates and setting savings targets in a public process using the most recent IOU and POU data. These targets, combined with California's greenhouse gas emission reduction goals, make it essential for the Energy Commission to account for energy efficiency impacts when forecasting future electricity and natural gas demand.

Starting with the *2009 IEPR* process, staff has undertaken a major effort to improve and refine efficiency measurement within the *IEPR* forecast and committed to examining methods for incorporating efficiency impacts in a public process that includes the CPUC staff, utilities, and other stakeholders. With this commitment in mind, Energy Commission staff continues its involvement in and support for the Demand Analysis Working Group (DAWG), which provides a forum for interaction among key organizations on topics related to demand forecasting and demand-side programs and policies. Membership in the DAWG includes staff from the Energy Commission, the CPUC Energy Division, the Department of Ratepayer Advocates, the California IOUs, several POUs, and other interested parties, including the California Air Resources Board, The Utility Reform Network, and the Natural Resources Defense Council. The member list has grown to include more than 100 participants.

With input from the DAWG, a substantial amount of work was dedicated to improving estimates of efficiency impacts incorporated in *CED 2009* and *CED 2011. CED 2013 Preliminary* builds on this work and incorporates the following elements:

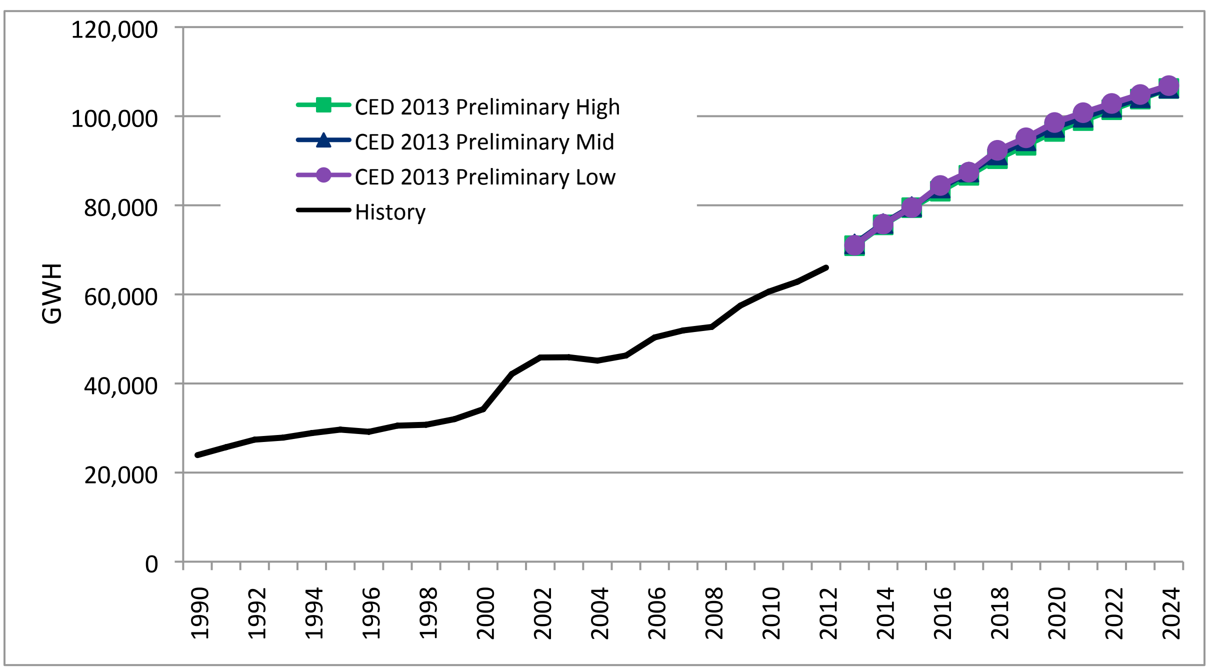
- New building and appliance standards, including impacts from the 2013 Title 24 building standards update and the 2011 battery charger standards
- IOU 2013-2014 efficiency programs
- Updated program savings for POUs, using estimated first-year savings through 2013
- Updated price elasticity estimates

Committed Energy Efficiency

Staff estimates the savings in energy demand associated with three sources: committed utility and public agency efficiency programs; finalized or implemented residential and commercial building and appliance standards; and residential, commercial, and industrial price and "other" effects, which are intended to capture the impacts from energy price changes and certain market trends not directly associated with programs or standards.[38]

Figure 3-1 and **Figure 3-2** show staff estimates of statewide historical and projected committed electricity consumption and peak savings, respectively. Savings are measured relative to a 1975 base and incorporate the simplifying assumption that "counterfactual" demand equals measured demand plus these savings. Within the demand scenarios, higher demand yields more standards savings since new construction and appliance usage increase, while lower demand is associated with more program savings and higher rates (and therefore more price effects). The net result is that savings totals among the scenarios are very similar, as shown in the two figures. For electricity consumption, total efficiency savings are around 66,000 GWh in 2012. Increasing rates, the addition of new programs, and the continuing impacts of existing standards (as buildings and appliances turn over) plus savings from new standards push total savings above 100,000 GWh in all three demand scenarios by the end of the forecast period. Peak demand savings increase above 25,000 MW in 2024, up from around 16,000 MW in 2012.

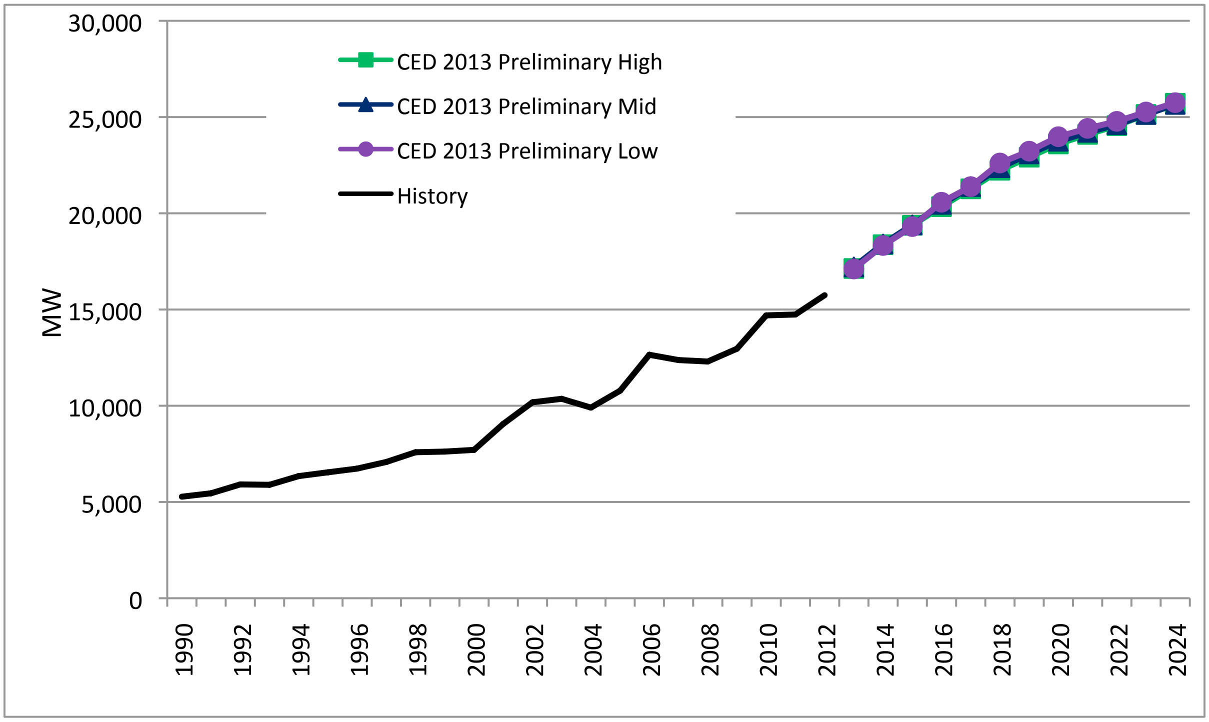
Figure 3-1: Historical and Projected Statewide Committed Efficiency Electricity Consumption Savings Impacts



Source: California Energy Commission, Demand Analysis Office, 2013

38 In practice, the vast majority of savings in this category since 1975 have come from price effects.

Figure 3-2: Historical and Projected Statewide Committed Electricity Efficiency Peak Savings Impacts



Source: California Energy Commission, Demand Analysis Office, 2013

Table 3-1 shows these savings as a percentage reduction[39] in consumption and peak for selected years. The increasing impact of standards relative to electricity use and increasing rates during the forecast period result in the percentages growing through 2024. Percentages increase across the scenarios as demand decreases since similar savings totals are divided by lower consumption and peak demand totals.

39 Efficiency savings divided by (consumption or peak total plus efficiency savings).

Table 3-1: Committed Electricity Efficiency Savings as a Percentage of Consumption and Peak Demand

	Consumption		
	CED 2013 Preliminary High Energy Demand	*CED 2013 Preliminary Mid Energy Demand*	*CED 2013 Preliminary Low Energy Demand*
1990	9.5%	9.5%	9.5%
2000	11.6%	11.6%	11.6%
2012	19.2%	19.2%	19.1%
2015	21.7%	22.0%	22.3%
2020	23.9%	24.7%	25.6%
2024	24.5%	25.4%	26.2%
	Peak Demand		
	CED 2011 Final High Energy Demand	*CED 2011 Final Mid Energy Demand*	*CED 2011 Final Low Energy Demand*
1990	10.0%	10.0%	10.0%
2000	12.6%	12.6%	12.6%
2012	20.7%	20.8%	20.6%
2015	23.3%	23.5%	24.2%
2020	25.5%	26.3%	27.6%
2024	26.0%	26.9%	28.3%

Source: California Energy Commission, Demand Analysis Office, 2013

As discussed in Chapter 2 of this volume, staff was not able to prepare a similar accounting for natural gas savings in time for this report, although estimated 2013-2014 IOU program impacts are provided later in this chapter. A full accounting of historical and projected natural gas savings will be provided with the revised version of this forecast.

Staff believes **Figure 3-1** through **Figure 3-3** provide reasonable estimates of total savings but acknowledges the uncertainty involved in attribution of savings among standards, programs, and price effects, especially during the historical period. Standards and programs are often designed to work together to reduce a targeted usage, and rate hikes increase the likelihood of participating in an incentive program or complying with a given standard. Therefore, no attribution among the three sources is shown, except for estimates of standards impacts and *future* program savings presented later in this chapter.

Committed Efficiency Programs

Historical electricity and natural gas program impacts were treated similarly to *CED 2011*,[40] with both POU and IOU savings through 2012 incorporating the most recent CPUC evaluation, measurement, and verification (EM&V) studies.[41] First-year utility-reported net savings are adjusted at the end-use level using realization rates[42] derived from these studies and then decayed (adjusted in each year by estimated rate of product failure) over the forecast period using expected useful measure lives from the most recent Database for Energy Efficient Resources (DEER) and applying an exponential decay function.

For the 2013-14 IOU programs, staff relied on utility projected net savings, translating measure-level detail to the appropriate end uses required for the forecast. Utilities were required to estimate measure impacts to be consistent with CPUC EM&V studies, so staff felt comfortable applying these savings without additional adjustments (such as realization rates), unlike past program cycles. Decay by end use was then reduced by 50 percent to reflect the CPUC's directive that one-half of measure decay be replaced through additional programmatic efforts.[43]

Figure 3-3 and **Figure 3-4** show resulting projected 2013-14 IOU cumulative program consumption savings for electricity and natural gas, respectively, over the forecast period. These savings were used in the mid demand case. Electricity savings for the combined IOUs reach almost 2,500 GWh in 2014 and decay to around 1,800 GWh by 2024. Combined savings for natural gas are estimated at around 80 million therms in 2014, decreasing to about 68 million therms in 2024. As alternative program scenarios for the other demand cases, staff assumed a 10 percent increase in savings for the low case and a 10 percent decrease for the high.[44]

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40 California Energy Commission. June 2012. *California Energy Demand 2012–2022 Final Forecast.* CEC-200-2012-001-CMF-V1. *Chapter 3: Efficiency and Conservation* http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-CMF-V1.pdf.

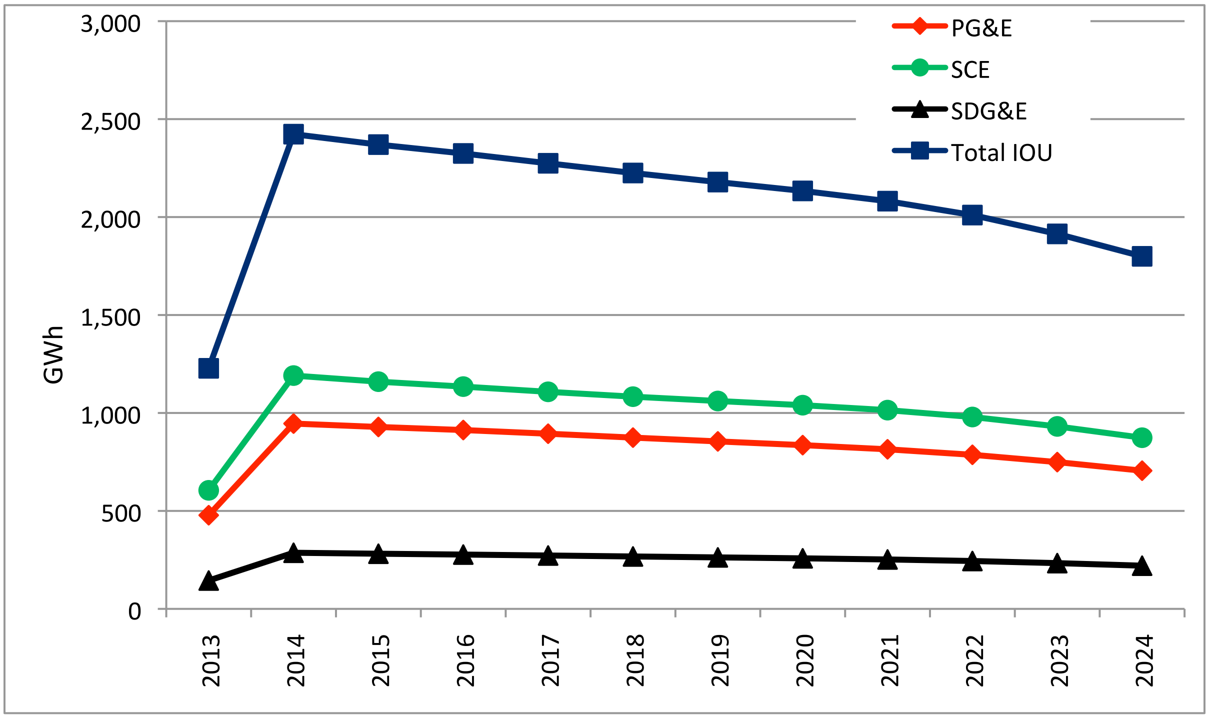
41 The CPUC is working on a review of 2010-12 program accomplishments. If this study is completed in time, the information will be applied to 2010-12 program savings for the revised version of this forecast.

42 Realization rates are meant to be an adjustment for real-world phenomena that may reduce measure savings. For example, CFLs that are purchased but never installed.

43 CPUC Decision 09-09-047, September 2009. This requirement applies to all IOU programs starting with 2006 first-year savings.

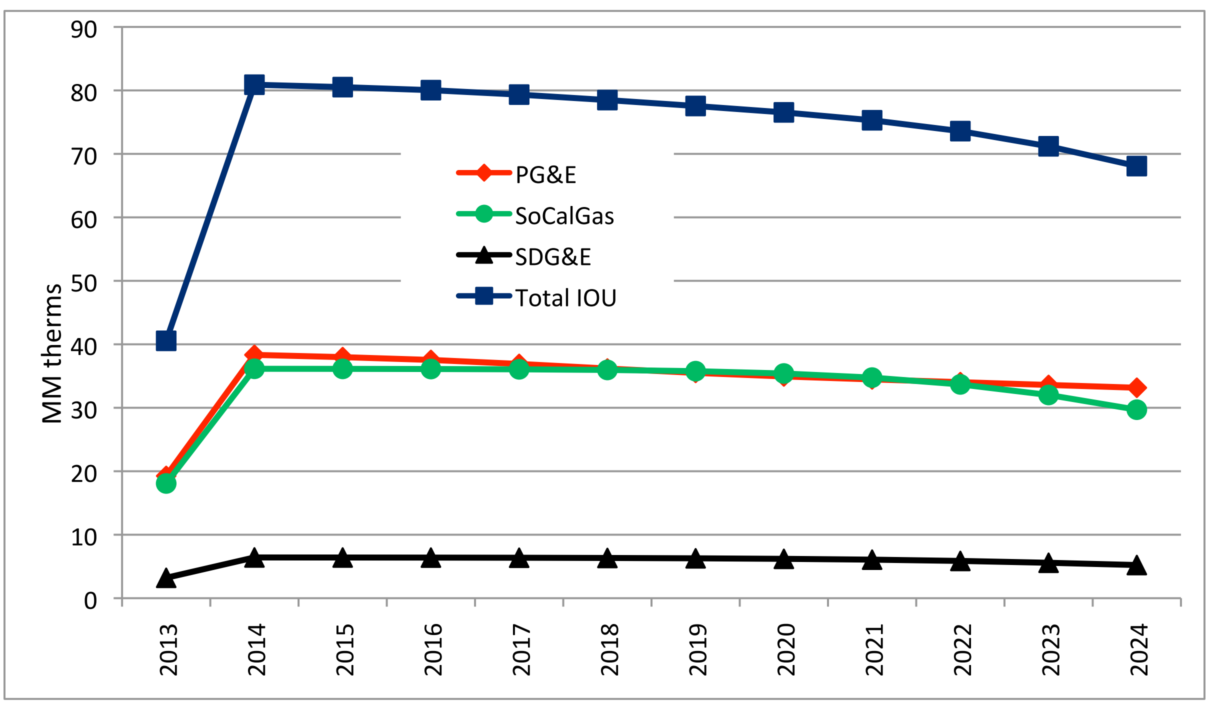
44 The 10 percent change is based on Navigant Consulting, Inc., analysis for the ongoing CPUC efficiency goals and potential studies. This informal analysis for the Energy Commission examined measure adoptions under differing rate and economic/demographic assumptions.

Figure 3-3: Projected Electricity Savings, 2013-14 IOU Programs, Mid Demand Case



Source: California Energy Commission, Demand Analysis Office, 2013

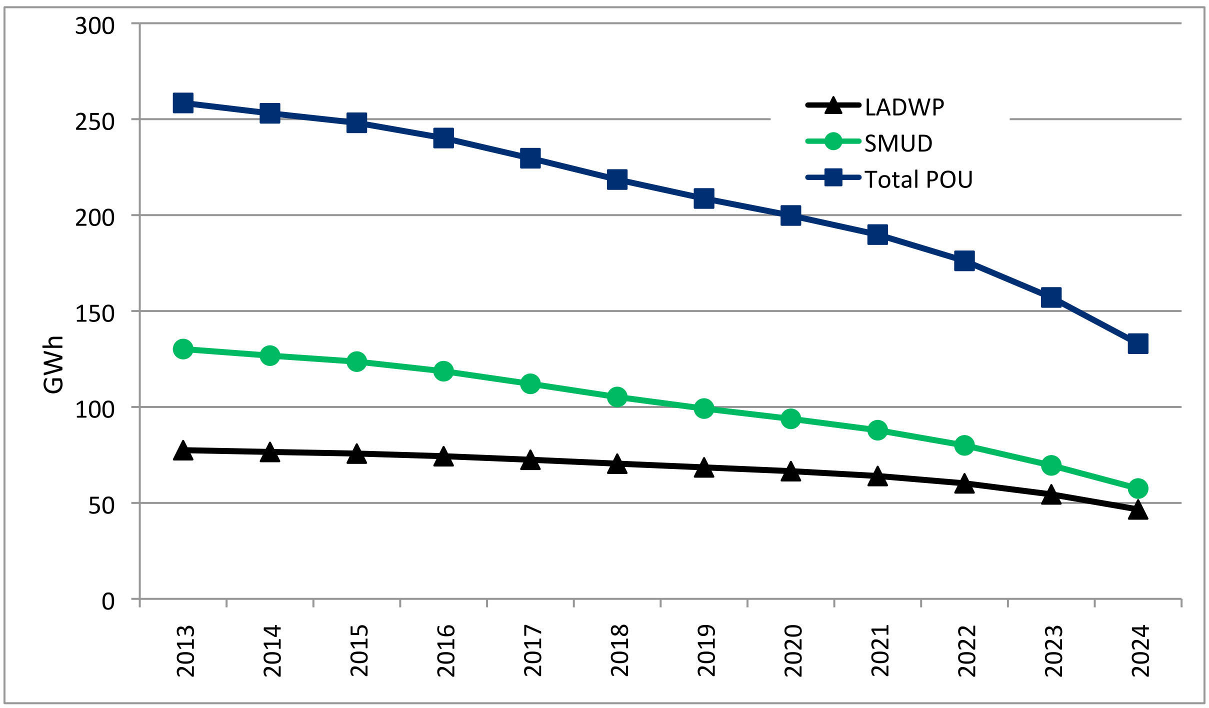
Figure 3-4: Projected Natural Gas Savings, 2013-14 IOU Programs, Mid Demand Case



Source: California Energy Commission, Demand Analysis Office, 2013

POU efficiency programs are funded through 2013 (and therefore committed), but estimated savings for 2013 will not be available until early 2014. Staff assumed that POUs would achieve the same level of savings as reported in 2012, with the same distribution across end uses. Realization rates for the high demand scenario were assumed to be similar at the end-use level to those estimated during the CPUC's evaluation of the 2006–2009 IOU programs. Realization rates for the low demand case were set at 100 percent and for mid case at an average of rates in the high and low cases. **Figure 3-5** shows projected cumulative statewide electricity consumption savings for POUs from 2013 programs in the mid demand case through 2024, along with savings for the two largest POUs, LADWP and SMUD. Projected savings in the low and high demand cases are around 10 percent higher and lower, respectively, compared to the mid case.

Figure 3-5: Projected Electricity Savings From 2013 POU Programs, Mid Demand Case



Source: California Energy Commission, Demand Analysis Office, 2013

Price Effects

Price effects are significantly higher in *CED 2013 Preliminary* compared to *CED 2011*, as rates are increased substantially in the new forecast. These effects are based on estimated price elasticities in the residential, commercial, and industrial sectors. On average, the price elasticity of electricity demand is around -0.1, which means that a doubling of rates reduces demand by about 10 percent.

Building Codes and Appliance Standards

Energy Commission forecasting models incorporate committed building codes and appliance standards through changes in end-use energy intensities that affect consumption per household in the residential sector and end-use consumption per square foot in the commercial sector. **Table 3-2** shows the codes and standards included in *CED 2013 Preliminary* by sector.

Table 3-2: Committed Building Codes and Appliance Standards Incorporated in *CED 2013 Preliminary*

Residential Model	
1975 HCD Building Standards 1978 Title 24 Residential Building Standards 1983 Title 24 Residential Building Standards 1991 Title 24 Residential Building Standards 1976-82 Title 20 Appliance Standards 1988 Federal Appliance Standards 1990 Federal Appliance Standards	1992 Federal Appliance Standards 2002 Refrigerator Standards 2005 Title 24 Residential Building Standards AB 1109 Lighting (Through Title 20) 2010 Title 24 Residential Building Standards 2011 Television Standards 2011 Battery Charger Standards 2013 Title 24 Residential Building Standards
Commercial Model	
1978 Title 24 Nonresidential Building Standards 1978 Title 20 Equipment Standards 1984 Title 24 Non-Residential Building Standards 1984 Title 20 Non-Res. Equipment Standards 1985-88 Title 24 Non-Residential Building Standards 1992 Title 24 Non-Residential Building Standards 1998 Title 24 Non-Residential Building Standards	2001 Title 24 Non-Residential Building Standards 2004 Title 20 Equipment Standards 2005 Title 24 Non-Residential Building Standards 2010 Title 24 Non-Residential Building Standards AB 1109 Lighting (Through Title 20) 2011 Television Standards 2011 Battery Charger Standards 2013 Title 24 Non-Residential Building Standards

Source: California Energy Commission, Demand Analysis Office, 2013

To measure the effect of each set of standards, staff removes the corresponding input effect one set at a time, beginning with the most recent standards, and calculates savings as the difference in energy demand output between model runs with the set of standards incorporated and without. This process is repeated until all standards are "removed" from the models.

Table 3-3 shows estimated electricity consumption and peak savings from appliance and building standards for the residential and commercial sectors in the mid demand scenario. Forecast standards impacts increase slightly in the high demand scenario due to more projected commercial floor space, home additions, and appliance usage and are slightly less in the low demand case. In 2024, projected standards impacts are around 2.5 percent above the mid forecast in the high demand case and 2.0 percent below in the low case.

Table 3-3: Estimated Electricity Savings From Building Codes and Appliance Standards: Mid Demand Scenario

	Consumption (GWh)						
	Residential			Commercial			Total Standards
	Building Standards	Appliance Standards	Total	Building Standards	Appliance Standards	Total	
1990	3,607	2,241	5,849	1,334	846	2,179	8,028
2000	6,023	7,243	13,265	3,363	2,391	5,754	19,019
2010	7,280	15,656	22,936	6,351	4,104	10,455	33,391
2015	8,671	23,709	32,381	7,963	5,246	13,209	45,590
2020	10,128	29,758	39,886	10,748	6,634	17,382	57,268
2024	11,148	32,306	43,454	12,822	7,391	20,214	63,668
	Peak (MW)						
	Residential			Commercial			Total Standards
	Building Standards	Appliance Standards	Total	Building Standards	Appliance Standards	Total	
1990	917	563	1,481	289	186	475	1,956
2000	1,494	1,727	3,220	696	496	1,193	4,413
2010	2,032	4,214	6,246	1,440	931	2,371	8,617
2015	2,536	6,694	9,230	1,679	1,107	2,786	12,015
2020	2,948	8,378	11,326	2,266	1,401	3,667	14,993
2024	3,186	8,930	12,115	2,703	1,562	4,265	16,380

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2013

Table 3-4 shows projected statewide electricity savings for electricity from the 2013 Title 24 building standards update and the 2011 battery charger standards (both to be implemented in 2014), the most recent standards introduced into the forecast. By the end of the forecast period, these standards are projected to produce savings of more than 2,000 GWh. Savings were derived to match estimates provided by the Energy Commission's Efficiency Division, adjusted for noncompliance (assumed to be 20 percent) and "naturally occurring" adoptions of relevant technologies.[45]

45 As estimated by Navigant Consulting, Inc., for the CPUC's 2012 efficiency potential study: *Analysis to Update Energy Efficiency Potential, Goals, and Targets for 2013 and Beyond: Track 1 Statewide Investor-Owned Utility Energy Efficiency Potential Study*, available at http://www.cpuc.ca.gov/NR/rdonlyres/6FF9C18B-CAA0-4D63-ACC6-F9CB4EB1590B/0/2011IOUServiceTerritoryEEPotentialStudy.pdf.

Table 3-4: Estimated Statewide Electricity Savings (GWh) From 2013 Title 24 Building Standards Update and 2011 Battery Charger Standards

Year	Title 24 Update	Battery Charger Standards	Total
2015	132	506	638
2018	471	856	1,328
2020	683	886	1,568
2024	1,084	940	2,024

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2013

Incremental Uncommitted Efficiency Savings

Staff plans to develop incremental uncommitted efficiency savings estimates for the revised version of this forecast. These estimates will be based on the CPUC's *2013 Efficiency Goals and Targets Study*, to be released later this year. Assessing incremental efficiency savings requires analysis of impacts that are uncommitted, and therefore not included in the Energy Commission's baseline forecasts, but still reasonably likely to occur given current overall strategies. This effort will involve Energy Commission, CPUC, and California ISO staff and is a critical step in developing a "managed" forecast for procurement, transmission need, and resource adequacy purposes.

GLOSSARY

Acronym	Definition
AB 2021	Assembly Bill 2021
CED	California Energy Demand
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
DG	Distributed generation
DOF	Department of Finance
EAP	*Energy Action Plan*
Energy Commission	California Energy Commission
ERP	Emerging Renewables Program
ESP	Electric service provider
GW/GWh	Gigawatt/gigawatt hours
HSR	High-speed rail
HELM	Hourly Electricity Load Model
IEPR	*Integrated Energy Policy Report*
IID	Imperial Irrigation District
IOU	Investor-owned utility
ISO	Independent system operator
KW/KWh	Kilowatt/Kilowatt hours
LADWP	Los Angeles Department of Water and Power
LSE	Load-serving entity
MW/MWH	Megawatt/megawatt hours
NSHP	New Solar Homes Partnership
PG&E	Pacific Gas and Electric Company
PV	Photovoltaic
QFER	Quarterly Fuel Energy Report
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SGIP	Self-Generation Incentive Program
SMUD	Sacramento Municipal Utility District
SoCalGas	Southern California Gas Company
TAC	Transmission Access Charge
TCU	Transportation, communications and utility sector
UEC	Unit energy consumption

APPENDIX A: Additional Methodology Documentation and Econometric Results

This appendix provides additional detail on forecasting methodology, including the new industrial model, incorporation of potential climate change impacts, and price elasticities of demand assumed for the forecast. In addition, the appendix provides a comparison of *CED 2013 Preliminary* results with the econometric forecasts.

Industrial Model

Until now, staff has used the Industrial End Use Forecasting Model (INFORM), developed by EPRI, to forecast industrial sector energy use. However, the model is no longer supported by EPRI, and the original contract agreement did not include the program code for the model, making improvements and revisions very difficult. Therefore, staff decided to develop a new model from the "ground up," based on the INFORM method, so that improvements, revisions, and augmentations could be made as needed.

As in the INFORM model, industrial (manufacturing, resource extraction, and construction) energy demand is forecast based on projected growth in dollar output or employment for 28 categories (for example, chemicals and paper), projected average industrial rates, and changes in end-use characteristics, including energy intensities.[46] In this context, energy intensity measures energy use per dollar of output. The marginal impact of economic growth on energy use in each of the 28 categories was estimated using regression analysis. Applying the estimated coefficients to the appropriate economic indicator provides a "business as usual" forecast for each industrial category. This forecast is adjusted for rate increases, using price elasticities estimated in the sector econometric models.[47] Finally, the forecast is adjusted to account for changes in end-use energy intensity.

Unfortunately, recent data on industrial end-use energy intensities and other characteristics to fully populate the model are not currently available for California. A full statewide industrial survey has not been administered for more than 20 years. For *CED 2013 Preliminary*, staff made simplifying assumptions for future end-use energy intensity trends using econometric analysis of historical data. For manufacturing as a whole, this analysis showed a roughly 1 percent annual energy intensity decrease on average (for all end uses combined) over the 1980–2012 period. For the *CED 2013 Preliminary* low demand scenario, this trend was assumed to continue for every subsector and end use through 2024. For the mid and high cases, the trend was reduced to 0.5 percent and 0.25 percent per year,

46 End uses include motors; thermal processes; other processes; lighting; heating, ventilation, and air conditioning; and miscellaneous.

47 See **Table A-6**, below.

respectively. Construction and resource extraction historical data showed no clear trend, and intensities were assumed constant over the forecast period.

Staff is populating end-use characteristics in the model using national data and smaller scale state surveys. Ultimately, however, the new model will require a full California industrial end-use survey to reach full potential as a forecasting tool.

Comparison of *CED 2013 Preliminary* and Full Econometric Forecasts

Table A-1 compares *CED 2013 Preliminary* electricity results for 2024 by major planning area and statewide with those from a full econometric forecast. More complete results are provided along with the demand forms posted with this report.[48] For consumption, differences range from almost zero to almost 5 percent above for the econometric forecasts. Peak demand differs by between around 3.5 percent higher to more than 7 percent higher. Likely reasons for these differences are discussed in Chapter 1 of this volume. Differences are largest for LADWP peak demand and smallest for SMUD consumption.

Table A-2 compares *CED 2013 Preliminary* end-user natural gas results for 2024 by major planning area and statewide with those from a full econometric forecast. Differences range from around 5 percent higher for the econometric forecast to almost 19 percent higher. Differences are largest for SoCalGas, reflecting the difference in forecasts for resource extraction, as discussed in Chapter 1.[49]

48 http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-30_workshop/spreadsheets/

49 Percentagewise, resource extraction gas demand for SoCalGas is highest among the planning areas.

Table A-1: Comparison of *CED 2013 Preliminary* and Full Econometric Electricity Forecasts, 2024

Planning Area	Demand Scenario	Consumption (GWh)			Peak (MW)		
		CED 2013 Preliminary	Econo-metric	% Difference	*CED 2013 Preliminary*	Econo-metric	% Difference
LADWP	High	30,473	29,560	3.09%	7,342	6,860	7.04%
	Mid	29,061	28,001	3.78%	6,886	6,463	6.54%
	Low	28,020	26,758	4.72%	6,440	6,019	6.99%
PG&E	High	129,764	125,272	3.59%	28,179	26,950	4.56%
	Mid	123,443	120,123	2.76%	27,063	25,892	4.52%
	Low	120,071	115,999	3.51%	25,799	24,390	5.78%
SCE	High	120,614	118,193	2.05%	27,889	26,602	4.84%
	Mid	115,060	112,729	2.07%	26,331	25,277	4.17%
	Low	111,340	107,929	3.16%	24,646	23,499	4.88%
SDG&E	High	26,739	26,376	1.37%	6,107	5,772	5.82%
	Mid	25,369	24,706	2.68%	5,651	5,432	4.04%
	Low	24,086	23,280	3.46%	5,217	5,032	3.67%
SMUD	High	12,673	12,704	-0.25%	3,908	3,698	5.67%
	Mid	12,160	12,071	0.74%	3,655	3,490	4.74%
	Low	11,757	11,631	1.08%	3,434	3,291	4.36%
State	High	335,955	327,676	2.53%	76,718	73,054	5.02%
	Mid	320,521	312,814	2.46%	72,796	69,627	4.55%
	Low	310,505	300,528	3.32%	68,658	65,158	5.37%

Source: California Energy Commission, Demand Analysis Office, 2013

Table A-2: Comparison of *CED 2013 Preliminary* and Full Econometric Natural Gas Forecasts, 2024

Planning Area	Demand Scenario	Consumption (MM therms)		
		CED 2013 Preliminary	Econometric	% Difference
PG&E	High	4,888	5,345	9.36%
	Mid	4,909	5,146	4.84%
	Low	4,870	5,117	5.07%
SoCalGas	High	7,282	8,658	18.89%
	Mid	7,286	8,040	10.34%
	Low	7,238	7,953	9.88%
SDG&E	High	539	584	8.32%
	Mid	545	590	8.18%
	Low	552	596	7.87%
State	High	12,779	14,742	15.36%
	Mid	12,804	13,931	8.80%
	Low	12,719	13,820	8.66%

Source: California Energy Commission, Demand Analysis Office, 2013

Impacts From Climate Change

CED 2013 Preliminary estimates the impacts of potential climate change for both energy (electricity and natural gas) and electricity peak demand. Energy impacts are estimated through changes in the number of annual heating and cooling degree days,[50] while peak demand impacts are simulated though increases in annual maximum daily average temperatures.

Econometric models for the residential, commercial, industrial, and agricultural sectors yielded significant coefficients for degree days, either for electricity, natural gas, or both (see Appendix C). Electricity consumption is affected by both heating and cooling degree days, while natural gas is affected by heating degree days only. For electricity, the impact of increases in the average annual number of cooling degree days as a result of climate change is tempered by decreasing average heating degree days, since both minimum and maximum temperatures increase. Because of heating degree day decreases, end-user natural gas demand drops, all else equal, due to climate change.

The econometric peak model re-estimated for *CED 2013 Preliminary* includes a coefficient for the annual maximum of *average631*, defined as follows:

Average631 =
Daily Average Temperature[51] × 0.6
+ *Previous Day's Average Temperature* × 0.3
+ *Two Days' Previous Average Temperature* × 0.1.

The adjustment from a simple daily average temperature to *average631* is meant to provide a better indicator of sustained temperature warming.[52]

To gauge the potential impact of climate change on annual degree days and *average631* temperatures through 2024, staff used a 2012 update of a climate change impact assessment by the California Climate Change Center, sponsored by the Energy Commission.[53] The update uses 24 climate change simulations for California consisting of two scenarios for each of 12 models, providing simulation results for daily maximum and minimum temperatures, average daily humidity, and sea level rises through 2099.

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50 Heating and cooling degree days measure the difference between daily average temperature and a reference temperature (for example, 65 degrees) summed over all days in a given year. An average temperature below the reference temperature adds to heating degree days and an average above the reference adds to cooling degree days.

51 Defined as maximum plus minimum daily temperature divided by 2.

52 Evidence shows that response to high temperatures increases if warming is sustained over a period of days, as customers do not always adjust immediately to changing weather.

53 Energy Commission., March 2009. *Climate Change Scenarios and Sea Level Rise Estimates for the California 2008 Climate Change Scenarios Assessment* .CEC-500-2009-014-D.

Climate change model simulations were performed for grids of 50 square miles within the state; staff used simulated daily maximum and minimum temperatures for grids corresponding to the 10 weather stations used for the 16 forecasting climate zones. Staff chose climate change scenarios that resulted in an average temperature impact over all scenarios for the mid demand case and a relatively high temperature impact for the high demand case.[54] For the low demand scenario, staff assumed no climate change impacts. Staff converted simulated daily averages for each weather station to degree days and *average631* indices for each planning area by weighting each climate zone either by estimated number of air conditioners (*average631* and cooling degree days) or population (heating degree days). Changes in annual degree days and maximum *average631* temperatures starting in 2013 were derived using long-term trends (2010-2040) from the two climate scenarios.[55]

Table A-3 shows the projected impacts of climate change in the mid and high demand scenarios on electricity consumption for the five major planning areas and for the state as a whole. By 2024, statewide consumption impacts reach almost 1,300 GWh in the mid demand case and over 1,800 GWh in the high demand case. Also shown are the simulated annual heating and cooling degree days (weighted by climate zone) for the two climate change scenarios used. Degree days in 2012 represent a historical 30-year average for the planning area.

The consumption increases shown in **Table A-3** are *net* impacts, representing increasing electricity consumption from cooling minus reduced usage from less heating need. Heating impacts are typically 10-40 percent of cooling increases, depending on the planning area and year. For the state as a whole in 2024, projected electricity consumption increases by over 1,500 GWh from more cooling need in the mid demand case, all else equal, and decreases by around 250 GWh from less heating. In the high demand case, the totals are approximately 2,400 GWh and 600 GWh, respectively. For the state as a whole, the largest portions of the consumption increase come from the commercial sector (50 percent and 60 percent in the mid and high cases, respectively), since the effect from warmer temperatures is not mitigated by decreasing heating degree days, as in the residential sector (see Appendix C).

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54 Staff wishes to thank Mary Tyree at the Scripps Institute of Oceanography for providing the simulation data.

55 A long-term trend was used rather than the actual temperatures in each scenario because year-to-year fluctuations simulated in the climate change models sometimes resulted in degree days or maximum temperatures in 2024 as low as or lower than in 2012.

Table A-3: Projected Electricity Consumption Impacts From Climate Change by Scenario and Planning Area

		Mid Demand Scenario		High Demand Scenario			
		Annual Cooling Degree Days (65° reference)	Annual Heating Degree Days (65° reference)	Annual Cooling Degree Days (65° reference)	Annual Heating Degree Days (65° reference)	Consump. Impact, Mid Scenario (GWh)	Consump. Impact, High Scenario (GWh)
LADWP	2012	1,275	1,410	1,275	1,410	--	--
	2015	1,310	1,382	1,343	1,339	27	47
	2020	1,369	1,334	1,458	1,219	74	126
	2024	1,417	1,296	1,550	1,123	112	187
PG&E	2012	1,387	2,464	1,387	2,464	--	--
	2015	1,424	2,432	1,442	2,389	115	148
	2020	1,484	2,379	1,533	2,264	315	402
	2024	1,533	2,336	1,606	2,164	482	609
SCE	2012	1,536	1,381	1,536	1,381	--	--
	2015	1,577	1,350	1,608	1,307	95	140
	2020	1,645	1,299	1,729	1,182	260	371
	2024	1,700	1,257	1,826	1,082	394	545
SDG&E	2012	800	1,177	800	1,177	--	--
	2015	840	1,137	876	1,101	53	91
	2020	906	1,070	1,002	974	140	230
	2024	960	1,016	1,103	872	206	329
SMUD	2012	1,267	2,586	1,267	2,586	--	--
	2015	1,307	2,565	1,332	2,523	17	25
	2020	1,374	2,529	1,441	2,417	46	68
	2024	1,428	2,501	1,528	2,332	70	103
State	2015	--	--	--	--	312	462
	2020	--	--	--	--	847	1,224
	2024	--	--	--	--	1,282	1,813

Source: California Energy Commission, Demand Analysis Office, 2013

Table A-4 shows projections of natural gas consumption reductions in the two climate change scenarios because of decreasing heating degree days, reductions that reach around 250 million therms in the mid demand case and about 640 million therms in the high case by 2024 for the state as a whole. At the statewide level, roughly 50 percent of the decrease occurs in the residential sector, with another 25 percent coming from commercial.

Table A-4: Projected Natural Gas Consumption Impacts (Decreases) From Climate Change by Scenario and Planning Area

		Annual Heating Degree Days (65° reference), Mid Demand Scenario	Annual Heating Degree Days (65° reference), High Demand Scenario	Consumption Impact, Mid Scenario (MM therms)	Consumption Impact, High Scenario (MM therms)
PG&E	2012	2,476	2,476	--	--
	2015	2,445	2,402	17	42
	2020	2,393	2,278	48	122
	2024	2,352	2,179	74	192
SoCalGas	2012	1,384	1,384	--	--
	2015	1,354	1,311	33	82
	2020	1,303	1,190	94	242
	2024	1,263	1,093	146	391
SDG&E	2012	1,177	1,177	--	--
	2015	1,137	1,101	5	11
	2020	1,070	974	16	32
	2024	1,016	872	25	54
State	2015	--	--	56	135
	2020	--	--	158	396
	2024	--	--	246	637

NOTE: Individual entries may not sum to total due to rounding.
Source: California Energy Commission, Demand Analysis Office, 2013

Table A-5 shows the projected impacts of climate change in the mid and high demand scenarios on peak demand for the five major planning areas and for the state as a whole. By 2024, statewide peak impacts reach more than 1,000 MW in the mid demand case and around 1,750 MW in the high demand case. Also shown are the simulated annual maximum *average631* temperatures in degrees Fahrenheit for the two climate change scenarios used. Temperatures in 2012 represent a historical 30-year average for the planning area.

Table A-5: Projected Peak Impacts From Climate Change by Scenario and Planning Area

		Annual Maximum *Average631* (°F), Mid Demand Scenario	Annual Maximum *Average631* (°F), High Demand Scenario	Peak Impact, Mid Scenario (MW)	Peak Impact, High Scenario (MW)
LADWP	2012	83.5	83.5	--	--
	2015	83.8	84.0	24	41
	2020	84.3	84.8	68	120
	2024	84.6	85.4	106	191
PGE	2012	85.7	85.7	--	--
	2015	86.0	86.1	92	136
	2020	86.4	86.7	266	398
	2024	86.8	87.3	420	634
SCE	2012	85.8	85.8	--	--
	2015	86.0	86.2	87	134
	2020	86.5	86.8	252	397
	2024	86.8	87.4	397	639
SDGE	2012	78.0	78.0	--	--
	2015	78.2	78.4	18	31
	2020	78.6	79.0	51	92
	2024	78.9	79.6	80	148
SMUD	2012	85.2	85.2	--	--
	2015	85.4	85.6	8	18
	2020	85.7	86.3	23	55
	2024	85.9	86.8	36	88
State	2015	--	--	233	369
	2020	--	--	672	1,089
	2024	--	--	1,061	1,745

Source: California Energy Commission, Demand Analysis Office, 2013

For the revised version of this forecast, scheduled to be released in August, staff plans to complete an analysis of how climate change might affect the distribution of temperatures and therefore the relationship between "1 in 10" (extreme weather) and "1 in 2" (normal weather) peak demand.

Price Elasticities

With at least some rate increases expected given California's energy policy, estimated price response within forecasting models becomes an increasingly important factor in predicting future demand. **Table A-6** shows the price elasticities of demand, which measure percentage changes in consumption given a 1 percent change in price, used in *CED 2013 Preliminary* by major sector. With the exception of the commercial sector, these elasticities were estimated in developing sector econometric models and replaced the elasticities that had been used in the existing models. The price elasticity of demand estimated in the commercial econometric model was not transferred to the end-use model because the end-use model requires elasticities at the building type and end-use level (-0.15 represents an average elasticity). In addition, the elasticity coefficient estimated in the econometric model (-0.02) was not statistically significant. The commercial econometric forecast differs from the end-use version mainly due to the difference in price elasticities.

Table A-6: Price Elasticities of Demand by Sector, CED 2013 Preliminary

Sector	Electricity	Natural Gas
Residential	-0.08	-0.035
Commercial	-0.15	-0.15
Industrial: Manufacturing	-0.10	-0.14
Industrial: Resource Extraction and Construction	-0.11	-0.11

Source: California Energy Commission, Demand Analysis Office, 2013

APPENDIX B: Self-Generation Forecasts

Compiling Historical Distributed Generation Data

The first stage of forecasting involved processing data from a variety of distributed generation (DG) incentive programs such as:

- The California Solar Initiative (CSI)[56]
- New Solar Homes Partnership (NSHP)[57]
- Self-Generation Incentive Program (SGIP)[58]
- CSI Thermal Program for Solar Hot Water (SHW)[59]
- Emerging Renewables Program (ERP)[60]
- POU programs[61]

In addition, power plants with a generating capacity of at least 1 MW are required to submit fuel use and generation data to the Commission under the Quarterly Fuel and Energy Report (QFER) Form 1304.[62] QFER data includes fuel use, generation, onsite use, and exports to the grid. These various sources of data were used to quantify DG activity in California and to build a comprehensive database to track DG activity. One concern in using incentive program data along with QFER data is the possibility of double-counting generation if the project has a capacity of at least 1 MW. This can occur since the publicly available incentive program data do not list the name of the entity receiving the DG incentive for confidentially reasons while QFER data collects information from the plant owner. Therefore, it is not possible to determine if a project from a DG incentive program is already reporting data to

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56 Downloaded on 2/27/13 from (http://www.californiasolarstatistics.org/current_data_files/)

57 Program data received on 1/28/13 from staff in the Commission's Renewables Office.

58 Downloaded on 01/10/13 from (https://energycenter.org/index.php/incentive-programs/self-generation-incentive-program/sgip-documents/sgip-documents). Data covers up to fourth quarter of 2012.

59 Downloaded on 2/28/13 from (http://www.gosolarcalifornia.org/solarwater/index.php)

60 Program data received on 1/18/13 from staff in the Commission's Renewables Office.

61 Program data submitted by POU's on June 2012 http://www.energy.ca.gov/sb1/pou_reports/index.html. Data covered additions occurring in 2011. Staff assumed that 2012 additions would be similar to 2011 since 2012 data will not be submitted to the Commission until June 2013.

62 Data received from Energy Commission's Electricity Analysis Office on March 6, 2013. For this preliminary forecast, data was not available for quarterly filers due to a misalignment in the overall schedule for the *IEPR* forecast and QFER reporting requirements. Missing monthly data used the average of prior months as a placeholder.

the Energy Commission under QFER. For example, the SGIP has 109 completed projects that are at least 1 MW and about 60 pending projects that are also 1 MW or larger. Given the small number of DG projects meeting QFER's reporting size threshold, double-counting may not be significant but could become an issue as an increasing amount of large SGIP projects come on-line.

QFER accounts for the majority of onsite generation in California with the representation of large industrial cogeneration facilities. With each forecast cycle, staff continues to refine QFER data to correct for mistakes in data collection and data entry. Given the self-reporting nature of QFER data, refinements to historical data will likely continue to occur in future forecast cycles.

Projects from incentive programs were classified as either completed or uncompleted. This was accomplished by examining the current status of a project. Each program varies in how it categorizes a project. CSI projects having the following statuses are counted as completed projects: "Completed," "PBI – In Payment," "Pending Payment," "Incentive Claim Request Review," and "Suspended – Incentive Claim Request Review." For the SGIP program, a project with the status "Completed" is counted as completed. For the ERP program, there was no field indicating the status of a project. However, there was a column labeled "Date_Completed," and this column was used to determine if a project was completed or uncompleted. For the NSHP, a project that has been approved for payment is counted as a completed project. For SHW, any project having the status "Paid" was counted as a completed project. POU PV data provided installations by sector. Staff then projected when uncompleted projects will be completed based on how long it has taken completed projects to move between the various application stages or, if available, made use of supplemental program data.[63]

The next step was to assign each project to a county and sector. For most projects, the mapping to a county is straightforward since either the county information is already provided in the data or a ZIP code is included. For nonresidential projects, when valid North American Classification System (NAICS) codes are provided in the program data, the corresponding NAICS sector description was used; otherwise, a default "Commercial" sector label was assigned. Each project was then mapped to one of 16 demand forecasting climate zones based on utility and county information. These steps were used to process data from all incentive programs in varying degrees to account for program-specific information. For example, certain projects in the SGIP program have an IOU as the program administrator but are interconnected to a POU; these projects were mapped directly to forecasting zones. For the ERP program, PV projects less than 10 kW were mapped to the residential sector while both non-PV and PV projects greater than 10 kW were mapped to

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63 Report available at (http://www.cpuc.ca.gov/NR/rdonlyres/D2C385B4-2EC3-4F9D-A2B9-48D06C41C1E3/0/DataAnnexQ42010.pdf). This quarterly progress report shows installation time for CSI projects that can be helpful in determining when uncompleted projects can be expected to be completed.

the commercial sector. Finally, capacity and peak factors from DG evaluation reports were used to estimate energy and peak impacts.[64] [65]

Staff then needed to make assumptions about technology degradation. PV output is assumed to degrade by 1 percent annually; this rate is consistent with other reports examining this issue.[66] Staff decided to not degrade output for non-PV technologies, given the uncertainty in selecting an appropriate factor and the implication of using these factors in a forecast with a 10-year horizon. This decision was based on information from a report focused on combined heat and power projects funded under the SGIP program[67]. The report found significant decline in energy production on an annual basis by technology; however, the reasons for the decline varied and ranged from improper planning during the project design phase, a lack of significant coincident thermal load (for combined heat and power applications), improper maintenance, and fuel price volatility. Also, some technologies, such as fuel cells and microturbines, were just beginning to be commercially sold in the market, and project developers did not have a full awareness of how these technologies would perform in a real-world setting across different industries. This does not mean that staff will not use degradation factors in future reports, and once better data have been collected, staff will revisit this issue.

Figure B-1 shows statewide energy use from PV and non-PV technologies. While PV constitutes a small share of total onsite usage, PV use begins to show a sharp increase as the CSI program started to gain momentum after 2007. Non-PV usage tends to be fairly constant starting in 2003. **Figure B-2** shows PV self-generation by sector from 2007 to 2012. PV adoption is generally concentrated in the residential and commercial sectors, and the growth in PV adoption is due almost solely to the CSI program. **Figure B-3** provides the statewide average costs and incentives (subsidies) associated with PV installation over all customer sectors on a per-kWh basis since 1998.

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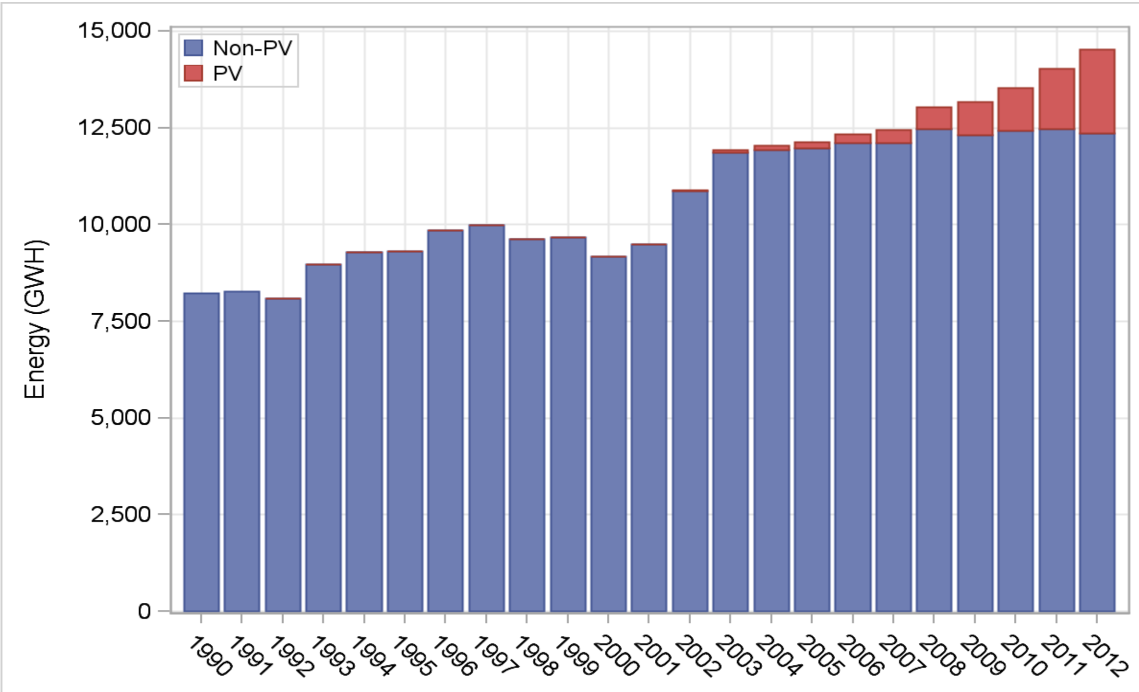
64 For SGIP program: Itron. June 2012. *CPUC Self-Generation Incentive Program Eleventh-Year Impact Evaluation*. Report available at (http://www. http://www.cpuc.ca.gov/NR/rdonlyres/EC6C16C5-9285-4424-87CF-4A55B0E9903E/0/SGIP_2011_Impact_Eval_Report.pdf)

65 For CSI program: Itron. June 2011. *CPUC California Solar Initiative 2010 Impact Evaluation.* Report available at (http://www.cpuc.ca.gov/NR/rdonlyres/E2E189A8-5494-45A1-ACF2-5F48D36A9CA7/0/CSI_2010_Impact_Eval_RevisedFinal.pdf)

66 Navigant Consulting. March 2010. *Self-Generation Incentive Program PV Performance Investigation*. Report available at (http://www.cpuc.ca.gov/PUC/energy/DistGen/sgip/sgipreports.htm). Annual degradation rate ranged from 0.4 percent to 1.3 percent.

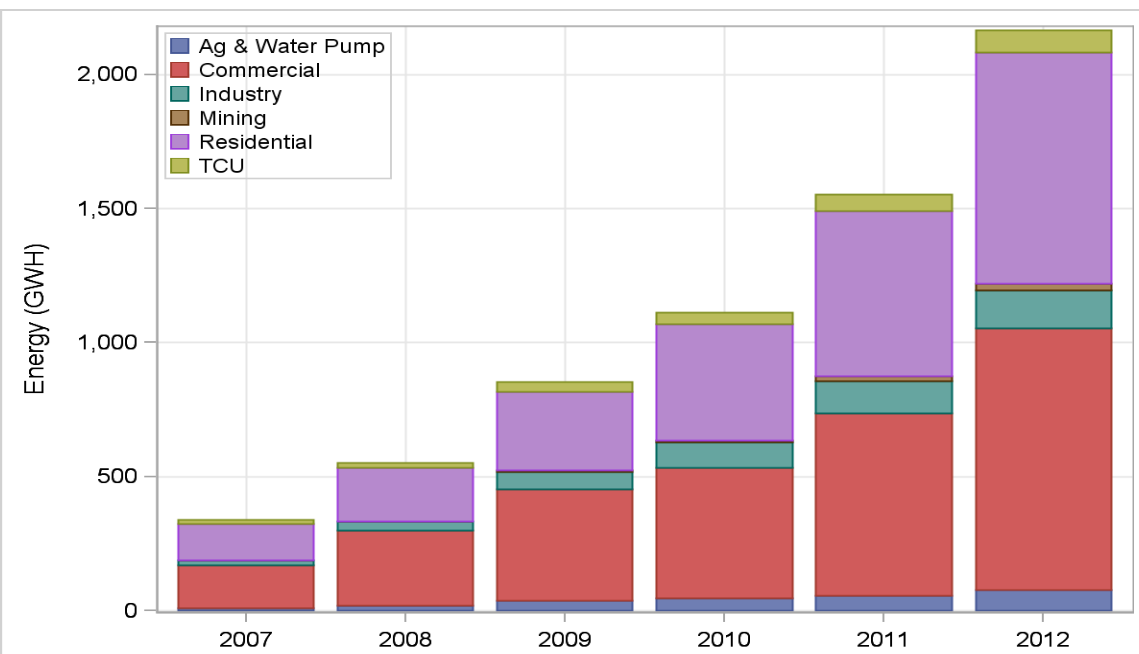
67 Navigant Consulting. April 2010. *Self-Generation Incentive Program Combined Heat and Power Performance Investigation.* Report available at (http://www.cpuc.ca.gov/NR/rdonlyres/594FEE2F-B37A-4F9D-B04A-B38A4DFBF689/0/SGIP_CHP_Performance_Investigation_FINAL_2010_04_01.pdf)

Figure B-1: Statewide Historical Distribution of Self-Generation, All Customer Sectors



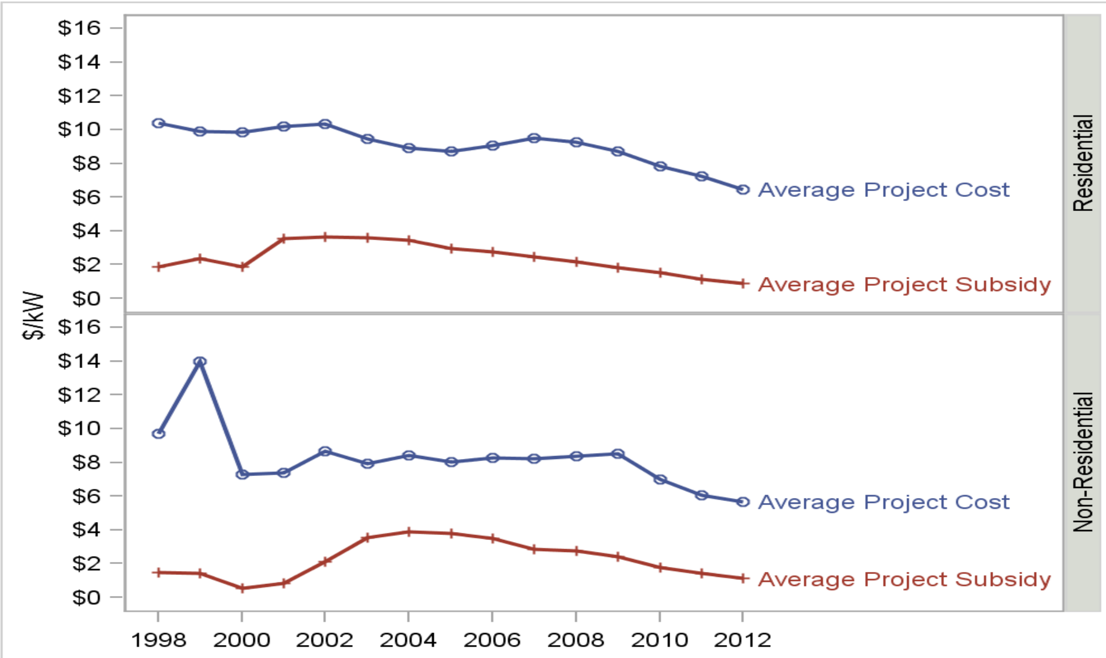
Source: California Energy Commission, Demand Analysis Office, 2013

Figure B-2: Statewide PV Self-Generation by Customer Sector



Source: California Energy Commission, Demand Analysis Office, 2013

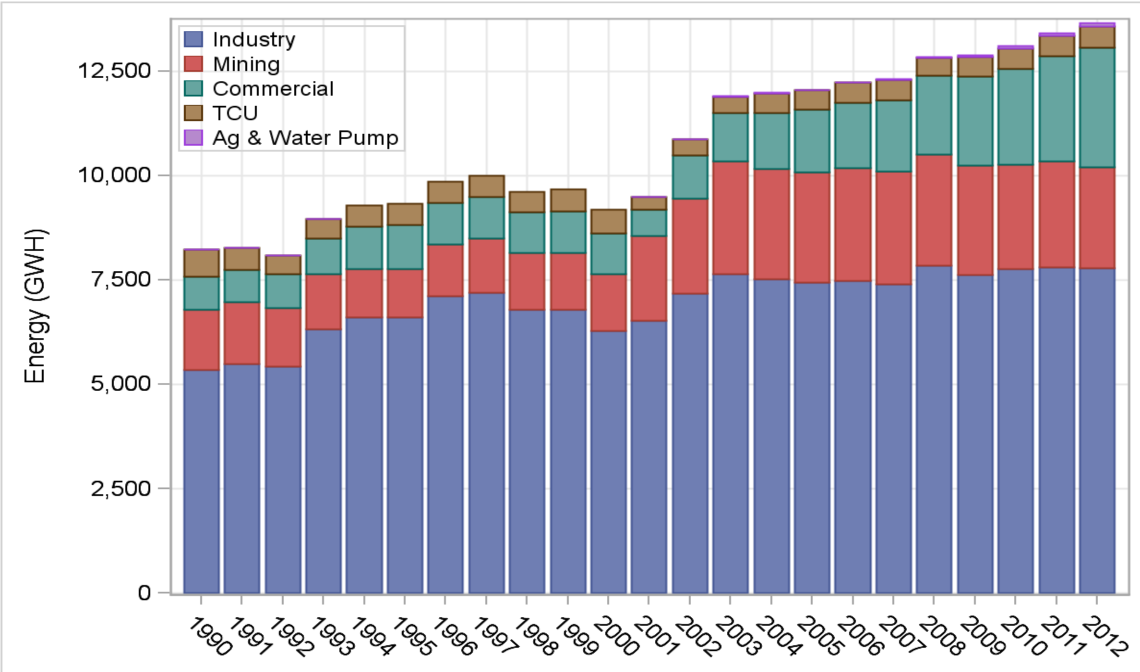
Figure B-3: Average PV Installation Costs and Subsidies, Statewide



Source: California Energy Commission, Demand Analysis Office, 2013

For self-generation as a whole, residential sector use is still a very small component of the total (around 5 percent in 2012). **Figure B-4** gives a breakout of self-generation by nonresidential category for the state and shows a continued overall dominance by the industrial and mining (resource extraction) sectors, although commercial adoptions are clearly trending upward in recent years.

Figure B-4: Statewide Historical Distribution of Self-Generation, Nonresidential Sectors



Source: California Energy Commission, Demand Analysis Office, 2013

Residential Sector Predictive Model

The residential sector self-generation model was designed to forecast PV and SHW adoption using estimated times for full payback, which depends on rate, cost, and performance assumptions. The model is similar in structure to the cash flow-based DG model in the National Energy Modeling System as used by the Energy Information Administration[68] and the *SolarDS* model developed by the National Renewable Energy Laboratory.[69]

PV cost and performance data were based on analysis performed by EIA for the 2013 Annual Energy Outlook (AEO) forecast report. Historical PV prices were developed from incentive program data. To forecast the installed cost of PV, staff adjusted the base year mean PV installed cost compiled from DG program data to be consistent with the PV price forecast developed by EIA. While this captures the overall trend in installed cost, staff feels that more attention needs to be devoted in future IEPR proceedings to untangle the changes in the major cost components of PV systems.

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68 Office of Integrated Analysis and Forecasting, United States Energy Information Administration. May 2010. *Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M067(2010).

69 Denholm, Paul, Easan Drury, and Robert Margolis. September 2009. *The Solar Deployment System (SolarDS) Model: Documentation and Sample Results.* NREL-TP-6A2-45832.

SHW cost and performance data was based on analysis conducted by ITRON in support of a California Public Utility Commission (CPUC) proceeding examining the costs and benefits of SHW systems.[70] Adjustments were made for incentives offered by the appropriate utility to obtain the net cost.

Residential electricity and gas rates consistent with those used in *CED 2013 Preliminary* were used to calculate the value of bill savings. The useful life for both PV and SHW was assumed to be 30 years, which is longer than the forecast period. Rates for years beyond 2024 were held constant. PV surplus generation was valued at a uniform rate of $0.06/kWh.[71]

The payback calculation was based on the internal rate of return (IRR) method used in the SolarDS model. The IRR approach takes an investment perspective and takes into account the full cash flow resulting from investing in the project. The IRR is defined as the rate that makes the net present value (the discounted stream of costs and benefits) of an investment equal to zero. In general, the higher the IRR of an investment, the more desirable it is to undertake. Staff compared the IRR to a required hurdle rate (5 percent) to determine if the technology should be adopted. If the calculated IRR was greater than the hurdle rate, then payback was calculated; otherwise, the payback was set to 40 years. The formula for converting the calculated IRR (if above 5 percent) to payback is:

$$Payback = \log 2 \log 1 + IRR$$

Estimated payback then becomes an input to a market share curve. The maximum market share for a technology is a function of the cost-effectiveness of the technology, as measured by payback, and was based on a maximum market share (fraction) formula defined as:

$$Maximum\ Market\ Fraction = e - Payback\ Sensitivity * Payback$$

Payback sensitivity was set to 0.3.[72] To estimate actual penetration, maximum market share was multiplied by an estimated adoption rate, calculated using a Bass Diffusion curve, to estimate annual PV and SHW adoption. The Bass Diffusion curve is often used to model adoption of new technologies and is part of a family of technology diffusion functions

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70 Spreadsheet models and documents available at (https://energycenter.org/index.php/incentive-programs/solar-water-heating/swhpp-documents/cat_view/55-rebate-programs/172-csi-thermal-program/321-cpuc-documents)

71 Annual residential energy use by housing type and water heater type from the Energy Commission’s Residential Model is used with the estimated PV generation to determine if any surplus generation occurs. The recent CPUC proposed decision on surplus compensation estimated that the surplus rate for PGE in 2009 would be roughly $0.04/kWh plus an environmental adder of $0.0183/kWh. See (http://docs.cpuc.ca.gov/word_pdf/AGENDA_DECISION/136635.pdf)

72 Based on an average fit of two empirically estimated market share curves by RW Beck. See R.W. Beck. *Distributed Renewable Energy Operating Impacts and Valuation Study,* January 2009. Prepared for Arizona Public Service by R.W. Beck, Inc.

characterized as having an "S" shaped curve to reflect the different stages of the adoption process.

The adoption rate is given by the following equation:

$$Adoption\ Rate=1-e-p+q*t1+qp*e-p+q*t$$

The terms p and q represent the impact of early and late adopters of the technology, respectively. Staff used mean values for p (0.03) and q (0.38), derived from a survey of empirical studies.[73]

Projected housing counts were allocated to two water heating types – electric and gas. The allocation is based on saturation levels used in the Energy Commission's residential model. For multifamily units, data from the most recent Residential Appliance Saturation Survey (RASS) are used to allocate multifamily units to two size categories: two to four units and five or more units. PV systems were sized to each housing type based on RASS floor space data, assumptions regarding roof slope, and factors to account for shading and orientation.[74] PV system size was constrained to be no more than 4 kW for single-family homes, 7 kW for two- to four-unit multifamily units, and 15 kW for five or more multifamily units. For PV systems, hourly generation over the life of the system was estimated based on data provided to staff by the Energy Commission's Efficiency and Renewable Energy Division.[75] For SHW systems, energy saved on an annual basis was used directly to estimate bill savings. PV and SHW energy output were degraded at the same rate based on the PV degradation factor estimated by ICF for EIA. From year to year, available housing stock was reduced by penetration from existing programs in previous years and increased by the projected amount of new residential construction.

The different discounted cost and revenue streams were then combined into a final cash flow table so that the IRR and project payback could be calculated. Revenues include incentives, the avoided grid purchase of electricity or natural gas, tax savings on the loan interest, and depreciation benefits. Costs include loan repayment, annual maintenance and operation expense, and inverter replacement cost.

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73 Meade, Nigel and Towidul Islam. 2006. "Modeling and forecasting the diffusion of innovation – A 25-year review," *International Journal of Forecasting*, Vol. 22, Issue 3.

74 Navigant Consulting Inc. September 2007. *California Rooftop Photovoltaic (PV) Resource Assessment and Growth Potential By County.* Report available at (http://www.energy.ca.gov/2007publications/CEC-500-2007-048/CEC-500-2007-048.PDF)

75 Data come from the NSHP Incentive calculator.

Self-Generation Forecast, Nonresidential Sectors

Commercial CHP Forecast

For *CED 2013 Preliminary*, staff incorporated a newly developed predictive model for commercial CHP adoption, which uses the same basic payback framework as in the residential predictive model. Staff began by allocating energy use to different building types using the 2006 Commercial End-Use Survey (CEUS).[76] The survey contains information on each site that participated in the survey, including:

- Site floor space.
- Site roof area.
- Electricity and natural gas use per square foot.
- Grouping variables and weights for building type, building size, and forecasting climate zone.

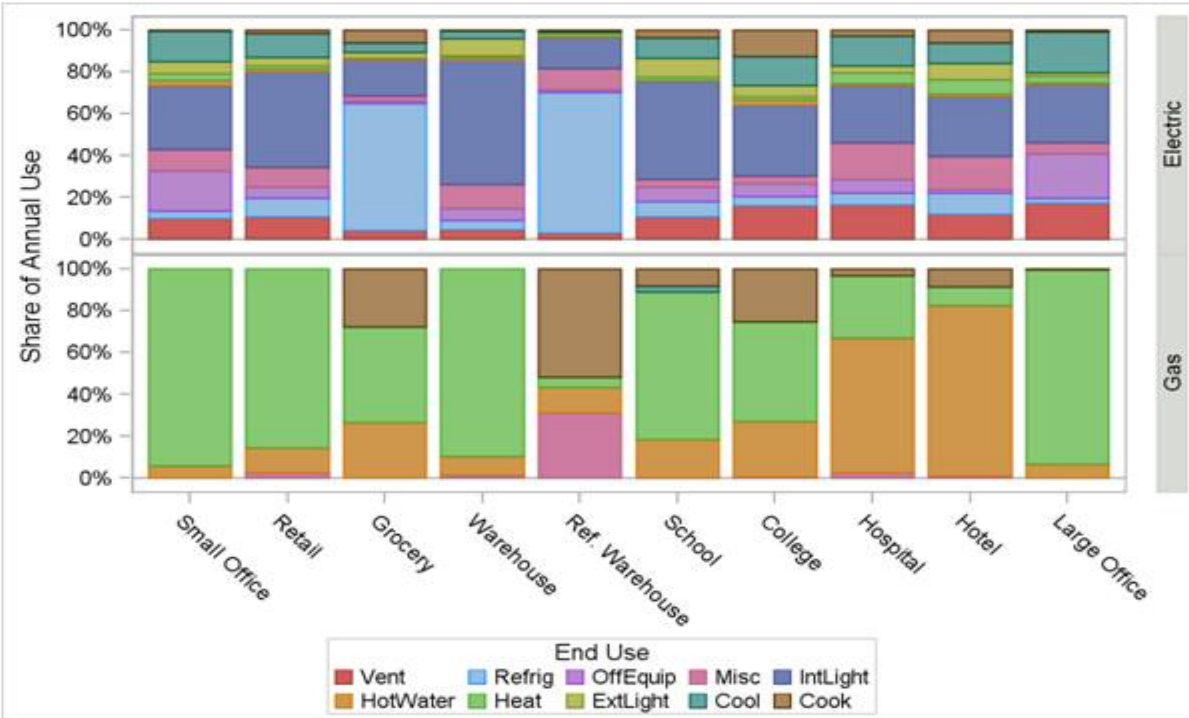
Building sizes were grouped into four size categories based on annual electricity use. Fuel intensities (use per square foot) were then calculated for each building type and size for electricity and natural gas.

Next, the "DrCEUS" building energy use simulation tool, developed in conjunction with the CEUS, was used to create load shapes by fuel type and end use. DrCEUS uses the eQUEST building energy use software tool as a "front-end" to the considerably more complex Department of Energy DOE 2.2 building energy use simulation tool, which does much of the actual building energy demand simulation.

Staff grouped small and medium-size buildings together since the CEUS survey had a limited number of samples of these building sizes. Also because of small sample sizes, staff grouped inland and coastal climate zones together. Four geographic profiles were created: north inland, north coastal, south inland, and south coastal. These profiles were used to create prototypical building energy use load profiles that could then be used to assess the suitability of different CHP technologies in meeting onsite demand for heat and power. As examples, **Figure B-5** shows the distribution of annual consumption among end uses for electricity and natural gas for the north coastal climate zones for small/medium-size buildings, and **Figure B-6** shows hourly electricity loads for south coastal large schools.

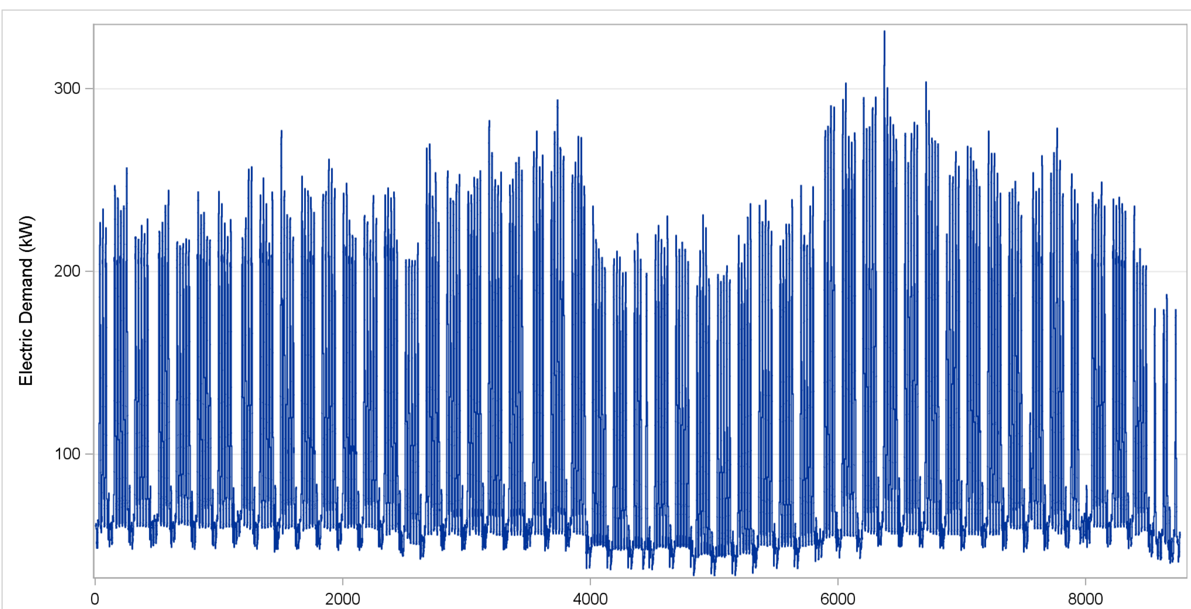
76 Itron. March 2006. Report available at http://www.energy.ca.gov/2006publications/CEC-400-2006-005/CEC-400-2006-005.PDF.

Figure B-5: Distribution of Annual End-Use Consumption by Fuel Type – North Coastal Small/Medium Buildings



Source: California Energy Commission, Demand Analysis Office, 2013

Figure B-6: Hourly* Electricity Demand for Large Schools, South Coastal Climate Zones



*In chronological order.
Source: California Energy Commission, Demand Analysis Office, 2013

Next, the commercial sector model output from the current forecast cycle was benchmarked to the 2012 QFER data. The distribution of energy use by fuel type and end use was then applied to the CEUS site level data and expanded by the share of floor space stock represented by the site. This essentially "grows" the site level profile from the CEUS survey to match the QFER calibrated commercial model output by end use, fuel type, forecast zone, demand scenario, and year.

For CHP, staff assumed that waste heat will be recovered to meet the site demand for hot water and space heating and that this will displace gas used for these two purposes.[77] Based on this assumption, the power-to-heat ratio was then calculated for each building type and size category by forecast climate zone and demand scenario.

System sizing was determined by the product of the thermal factor, which is the ratio of the power-to-heat ratio of the CHP system to the power-to-heat ratio of the application, and the average electrical demand of the building type. A thermal factor less than one would indicate that the site is thermally limited relative to its electric load, while a thermal factor greater than one would indicate that the site is electrically limited relative to its thermal load. Thermal factors greater than one mean that the site can export power to the grid if the CHP system is sized to meet the base load thermal demand. Thermal factors were less than one for most building types.

Finally, cost and benefits were developed to derive payback. Staff applied the same set of assumptions used in a prior Energy Commission-sponsored report[78] to characterize CHP technology operating characteristics such as heat rate, useful heat recovery, installed capital cost, and operating costs. Avoided retail electric and gas rates were derived from utility tariff sheets and based on estimated premise-level maximum demand. Current rates were escalated based on the rates of growth developed for the *CED 2013 Preliminary* scenarios. In addition, CHP technologies may face additional costs such as standby and departing load charges. Details for these charges were also collected and used in the economic assessment. Staff examined details surrounding the applicability of these charges and applied them as appropriate. The rate for gas used by the CHP technology also had to be estimated. Staff began with border prices and then added a transportation charge. Staff from the Energy Commission's Electricity Analysis Office supplied the historical border prices. The Malin border price was used for PG&E, and the Southern California border price was used for both SoCalGas and SDG&E. For the forecast period, staff escalated average 2012 border prices at a rate consistent with the *CED 2013 Preliminary* gas rate scenarios. Staff also identified federal tax credits for CHP and assessed the eligibility for utility rebate programs such as the SGIP.

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77 ICF International. February 2012. *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment.* Report available at http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf

78 See footnote 77.

The cash flow analysis and payback/adoption modeling were performed similarly to the residential sector PV model process, described earlier.

Other Commercial Self-Generation

Staff had also hoped to incorporate a predictive model for commercial PV in *CED 2013 Preliminary* but determined that the model required more testing. Therefore, staff used a trend analysis for commercial PV as well as the other non-CHP self-generation technologies. Using CSI incentive program data, staff calculated the average annual growth rate for each DG technology by sector and forecast climate zone for 2008-2012. Given strong growth for some technologies, namely fuel cells and PV, the maximum annual growth rate was capped at 12 percent. Installed capacity was allowed to grow at this rate until 2016, when the growth rate was reduced by half to account for expiration of federal tax credits. For SHW, staff assumed that nonresidential sector adoption would follow a ratio similar to residential versus nonresidential PV adoption.

APPENDIX C: Regression Results

This appendix provides estimation results for the econometric models used in the analysis for *CED 2013 Preliminary*.

Table C-1: Residential Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Persons per Household	0.3868	0.1205	3.21
Per capita income (2012$)	0.1414	0.0423	3.35
Unemployment Rate	-0.0034	0.0009	-3.95
Residential Electricity Rate (2012¢/kWh)	-0.0832	0.0134	-6.20
Median Home Price/Average Household Income	0.0143	0.0073	1.96
Number of Cooling Degree Days (70^{o})	0.0387	0.0038	10.21
Number of Heating Degree Days (60^{o})	0.0137	0.0050	2.72
Dummy: 2001	-0.0534	0.0064	-8.32
Dummy: 2002	-0.0391	0.0063	-6.17
Constant: Burbank/Glendale	-0.5656	0.0216	-26.21
Constant: IID	0.1472	0.0292	5.04
Constant: LADWP	-0.5920	0.0203	-29.19
Constant: Pasadena	-0.6738	0.0297	-22.67
Constant: PG&E	-0.3585	0.0186	-19.27
Constant: SCE	-0.4931	0.0222	-22.19
Constant: SDG&E	-0.4657	0.0239	-19.51
Overall Constant	7.2560	0.4468	16.24
Trend Variables			
Time: Burbank/Glendale	0.0094	0.0018	5.29
Time Squared: Burbank/Glendale	-0.0001	0.0000	-2.40
Time: IID	0.0066	0.0007	9.54
Time: LADWP	0.0063	0.0007	8.77
Time: Pasadena	0.0199	0.0033	6.03
Time Squared: Pasadena	-0.0003	0.0001	-3.19
Time: PG&E	0.0016	0.0008	2.06
Time: SCE	0.0050	0.0008	6.45
Time: SDG&E	0.0032	0.0009	3.79
Time: SMUD	-0.0042	0.0022	-1.91
Time Squared: SMUD	0.0001	0.0001	1.34
Adjusted for autocorrelation and cross-sectional correlation Wald chi squared = 24,371 Dependent variable = natural log of electricity consumption per household by planning area, 1980-2012 All variables in logged form except time and unemployment rate			

Source: California Energy Commission, Demand Analysis Office, 2013

Table C-2: Commercial Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Commercial Floor Space (mm. sq. ft.)	0.8879	0.0661	13.44
% of Floor Space Refrigerated	0.2801	0.0356	7.87
Commercial Employment/Floor Space	0.4836	0.0794	6.09
Personal Income (billion 2012$)	0.1320	0.0595	2.22
Commercial Electricity Rate (2012¢/kWh)	-0.0207	0.0162	-1.28
Natural Gas Rate: except SMUD (2012$/mm. BTU)	0.0085	0.0075	1.13
Number of Cooling Degree Days (65^{o})	0.0482	0.0076	6.33
Dummy: 2001 (LADWP)	-0.0459	0.0201	-2.28
Dummy: 2001 (PG&E)	-0.0345	0.0151	-2.28
Dummy: 2001 (SDG&E	-0.0766	0.0198	-3.86
Constant: IID	0.1498	0.0440	3.40
Constant: LADWP	-0.1197	0.0341	-3.51
Constant: Pasadena	0.4151	0.0861	4.82
Constant: PG&E	-0.2964	0.0606	-4.90
Constant: SCE	-0.3023	0.0603	-5.01
Overall Constant	2.0303	0.2019	10.06
Trend Variables			
Time	0.0082	0.0016	5.05
Time Squared	-0.0002	0.0000	-5.56
Additional Time Impact: Burbank/Glendale	0.0314	0.0037	8.44
Additional Time Squared Impact: Burbank/Glendale	-0.0006	0.0001	-6.37
Additional Time Impact: IID	0.0140	0.0031	4.51
Additional Time Squared Impact: IID	-0.0003	0.0001	-3.13
Additional Time Impact: IID	0.0071	0.0010	7.26
Additional Time Impact: Pasadena	0.0064	0.0039	1.63
Additional Time Impact: SCE	0.0034	0.0007	5.29
Adjusted for autocorrelation and cross-sectional correlation Wald chi squared = 358,173 Dependent variable = natural log of commercial consumption by planning area, 1980-2012 All variables in logged form except time and % of floor space refrigerated			

Source: California Energy Commission, Demand Analysis Office, 2013

Table C-3: Manufacturing Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Manufacturing Output (million 2012$)	0.4873	0.0635	7.67
Manufacturing Output/Manufacturing Employment	-0.3579	0.0475	-7.54
Output Textiles, Fiber, Printing/Manufacturing Output	0.8962	0.3235	2.77
Output Chemicals, Energy, Plastic/Manufacturing Output	-0.3680	0.1430	-2.57
Industrial Electricity Rate (2012¢/kWh)	-0.1024	0.0240	-4.26
Industrial Gas Rate (2012$/Therm)	0.0277	0.0149	1.85
Constant: Burbank/Glendale	0.6658	0.1796	3.71
Constant: IID	-0.2138	0.2008	-1.07
Constant: LADWP	1.4350	0.2264	6.34
Constant: PASD	-0.3533	0.1670	-2.12
Constant: PG&E	2.7295	0.2659	10.27
Constant: SCE	2.5408	0.2820	9.01
Constant: SDG&E	0.6206	0.1732	3.58
Overall Constant	3.8197	0.3027	12.62
Trend Variables	3.3431	0.2805	11.92
Time: Burbank/Glendale	-0.0433	0.0061	-7.05
Time: IID	-0.0589	0.0168	-3.51
Time Squared: IID	0.0023	0.0005	4.93
Time: Pasadena	-0.0697	0.0150	-4.65
Time Squared: Pasadena	0.0008	0.0004	1.79
Time: PG&E	-0.0045	0.0029	-1.53
Time: SDG&E	0.0406	0.0046	8.80
Time Squared: SDG&E	-0.0011	0.0001	-9.33
Time: SMUD	0.0766	0.0160	4.78
Time Squared: SMUD	-0.0014	0.0004	-3.26
Adjusted for autocorrelation and cross-sectional correlation Wald chi squared = 38,113 Dependent variable = natural log of industrial consumption by planning area, 1980-2012 All variables in logged form except time, output textiles, fiber, printing/manufacturing output and output chemicals, energy, plastic/manufacturing output			

Source: California Energy Commission, Demand Analysis Office, 2013

Table C-4: Resource Extraction and Construction Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Output, Resource Extraction (million 2005$)	0.1374	0.0447	3.07
Employment in Construction (thousands)	0.3079	0.0790	3.90
Percent Employment Resource Extraction	2.7076	0.9870	2.74
Industrial Electricity Rate (2012 cents/kWh)	-0.1138	0.0615	-1.85
Dummy: 2002	-0.0605	0.0336	-1.80
Dummy: 1997 SDG&E	-1.0975	0.1165	-9.42
Dummy: 1980 and 1981 PG&E	-1.1028	0.0848	-13.01
Constant: BUGL	-1.2694	0.1619	-7.84
Constant: IID	-1.5375	0.2846	-5.40
Constant: LADWP	0.8669	0.2565	3.38
Constant: PASD	-3.5706	0.3045	-11.73
Constant: PG&E	2.8330	0.3730	7.59
Constant: SCE	2.5825	0.3694	6.99
Overall Constant	2.6513	0.3246	8.17
Trend Variables			
Time: BUGL	0.1186	0.0122	9.69
Time squared: BUGL	-0.0026	0.0003	-8.14
Time: IID	0.1081	0.0312	3.46
Time squared: IID	-0.0014	0.0009	-1.60
Time: PASD	0.3316	0.0358	9.26
Time squared: PASD	-0.0085	0.0010	-8.51
Time: PG&E	-0.0512	0.0146	-3.51
Time squared: PG&E	0.0016	0.0004	4.14
Time: SDG&E	0.1152	0.0256	4.50
Time Squared: SDG&E	-0.0030	0.0008	-3.83
Time: SMUD	0.0474	0.0174	2.72
Time Squared: SMUD	-0.0007	0.0005	-1.40
Adjusted for autocorrelation and cross-sectional correlation Wald chi squared = 25,467 Dependent variable = natural log of construction & resource extraction consumption by planning area 1980-2012 All variables in logged form except time and percentage employment resource extraction			

Source: California Energy Commission, Demand Analysis Office, 2013

Table C-5: Agriculture and Water Pumping Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Agricultural Output per Capita (2005$)	0.4165	0.0728	5.72
Agricultural Electricity Rate (2012 cents/kWh)	-0.3255	0.1286	-2.53
Number of Cooling Degree Days (65^{o})	0.1596	0.0776	2.06
Number of Heating Degree Days (65^{o})	0.0925	0.0628	1.47
Dummy: Pasadena (2001-2008)	-2.8740	0.2837	-10.13
Constant: IID	0.7300	0.2304	3.17
Constant: LADWP	-0.4390	0.1491	-2.94
Overall Constant	2.0851	0.9765	2.14
Trend Variables			
Time: LADWP	-0.0112	0.0036	-3.12
Time: PASD	0.0636	0.0310	2.05
Time Squared: PASD	-0.0020	0.0011	-1.84
Time: PG&E	0.0191	0.0085	2.25
Time: SCE	0.0158	0.0102	1.54
Time: SDG&E	-0.0771	0.0143	-5.38
Time Squared: SDG&E	0.0019	0.0005	4.22
Adjusted for autocorrelation and cross-sectional correlation Wald chi squared = 4,892 Dependent variable = natural log of agriculture and water pumping electricity consumption per capita by planning area 1980-2012 All variables in logged form except time			

Source: California Energy Commission, Demand Analysis Office, 2013

Table C-6: Transportation, Communications, and Utilities (TCU) Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Total Employment (thousands)	0.7973	0.0455	17.54
Dummy: 2001	-0.0604	0.0192	-3.14
Dummy: 2002	-0.0458	0.0192	-2.38
Number of Heating Degree Days (65^{o})	0.0925	0.0628	1.47
Constant: Burbank/Glendale	-1.8113	0.2440	-7.42
Constant: IID	1.1085	0.2926	3.79
Constant: LADWP	-0.3350	0.0871	-3.85
Constant: Pasadena	-1.6215	0.1978	-8.20
Constant: SDG&E	0.1163	0.0603	1.93
Overall Constant	1.5947	0.3749	4.25
Trend Variables			
Time: BUGL	-0.0549	0.0355	-1.54
Time Squared: BUGL	0.0060	0.0014	4.19
Time: IID	-0.0928	0.0406	-2.29
Time Squared: IID	0.0018	0.0016	1.13
Time: LADWP	0.0270	0.0136	1.99
Time Squared: LADWP	-0.0006	0.0005	-1.01
Time: Pasadena	0.0247	0.0035	7.14
Time: PG&E	0.0124	0.0033	3.74
Time: SCE	0.0038	0.0026	1.46
Time: SMUD	-0.0224	0.0063	-3.57
Adjusted for autocorrelation and cross-sectional correlation Wald chi squared = 33,538 Dependent variable = natural log of TCU electricity consumption by planning area 1980-2012 All variables in logged form except time			

Source: California Energy Commission, Demand Analysis Office, 2013

Table C-7: Street Lighting Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Total Population (thousands)	0.8437	0.0116	72.82
Per Capita Income (2012$)	0.2828	0.1194	2.37
Constant: IID	-1.5467	0.1800	-8.59
Constant: LADWP	0.3089	0.0794	3.89
Constant: SCE	0.2899	0.0765	3.79
Constant: SDG&E	-0.8648	0.1046	-8.27
Overall Constant	-4.5615	1.2201	-3.74
Trend Variables			
Time: BUGL	-0.0454	0.0161	-2.81
Time Squared: BUGL	0.0013	0.0008	1.56
Time: IID	0.0754	0.0337	2.24
Time Squared: IID	-0.0024	0.0014	-1.75
Time: LADWP	0.0337	0.0146	2.31
Time Squared: LADWP	-0.0023	0.0006	-3.94
Time: Pasadena	0.0105	0.0036	2.91
Time: PG&E	-0.0143	0.0028	-5.12
Time: SCE	-0.0207	0.0051	-4.05
Time: SDG&E	0.0251	0.0076	3.32
Time: SMUD	-0.0061	0.0019	-3.25
Adjusted for autocorrelation and cross-sectional correlation Wald chi squared = 27,333 Dependent variable = natural log of street lighting electricity consumption by planning area 1980-2012 All variables in logged form except time			

Source: California Energy Commission, Demand Analysis Office, 2013

Table C-8: Peak Demand Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Per Capita Income (2012$)	0.3416	0.0337	10.14
Unemployment Rate	-0.0022	0.0009	-2.56
Number of Households/Population	2.9921	0.5342	5.60
Residential Electricity Rate (2012¢/kWh)	-0.0703	0.0205	-3.44
Annual Max *Average631* Temperature	1.2290	0.0557	22.06
Dummy: 2001	-0.0843	0.0091	-9.25
Dummy: 2002	-0.0219	0.0091	-2.42
Constant: Burbank/Glendale	-0.1173	0.0192	-6.11
Constant: IID	0.2645	0.0380	6.96
Constant: LADWP	-0.3094	0.0189	-16.37
Constant: Pasadena	-0.2005	0.0239	-8.38
Constant: PG&E	-0.2607	0.0145	-17.95
Constant: SCE	-0.2615	0.0232	-11.25
Constant: SDG&E	-0.5257	0.0281	-18.74
Overall Constant	-9.2382	0.5395	-17.12
Trend Variables			
Time: Burbank/Glendale	0.0116	0.0023	5.07
Time Squared: Burbank/Glendale	-0.0002	0.0001	-3.37
Time: Imperial Irrigation District	0.0046	0.0007	6.54
Time: LADWP	0.0110	0.0022	4.48
Time Squared: LADWP	-0.0003	0.0001	-4.16
Time: Pasadena	0.0304	0.0031	9.03
Time Squared: Pasadena	-0.0007	0.0001	-7.45
Time: SCE	0.0100	0.0024	3.38
Time Squared: SCE	-0.0002	0.0001	-2.87
Time: SDG&E	0.0056	0.0011	5.19
Adjusted for autocorrelation and cross-sectional correlation Wald chi squared = 13,447 Dependent variable = natural log of annual peak per capita by planning area, 1980-2012 All variables in logged form except time, unemployment rate, and numbers of households/population			

Source: California Energy Commission, Demand Analysis Office, 2013

Table C-9: Residential Sector Natural Gas Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Income per Household (2012$)	0.2175	0.0970	2.24
Residential Gas Rate (2012¢/therm)	-0.0350	0.0216	-1.62
Number of Heating Degree Days (65^{o})	0.2858	0.0198	14.44
Dummy: 2001	-0.0311	0.0188	-1.66
Constant: Southern California Gas	-0.5656	0.0216	-26.21
Overall Constant	1.8884	1.0578	1.79
Trend Variables			
Time: PG&E	-0.0258	0.0035	-7.45
Time Squared: PG&E	0.0002	0.0001	2.93
Time: Southern California Gas	-0.0296	0.0038	-7.82
Time Squared: Southern California Gas	0.0003	0.0001	3.23
Time: SDG&E	-0.0355	0.0037	-9.70
Time Squared: SDG&E	0.0004	0.0001	3.82
Adjusted for autocorrelation and cross-sectional correlation Wald chi squared = 2,110 Dependent variable = natural log of natural gas consumption per household by planning area, 1980-2012 All variables in logged form except time			

Source: California Energy Commission, Demand Analysis Office, 2013

Table C-10: Commercial Sector Natural Gas Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Personal Income (billion 2012$)	0.4773	0.0828	5.77
Commercial Gas Rate (2012$/mmBTU)	-0.0101	0.0374	-0.27
Number of Heating Degree Days (60^{o})	0.2234	0.0395	5.65
Dummy: 2001	-0.2229	0.0427	-5.23
Constant: PG&E	0.6939	0.1402	4.95
Constant: Southern California Gas	0.8836	0.1602	5.52
Overall Constant	1.5643	0.3752	4.17
Trend Variables			
Time	-0.0691	0.0295	-2.35
Adjusted for autocorrelation and cross-sectional correlation Wald chi squared = 358,173 Dependent variable = natural log of commercial gas consumption by planning area, 1980-2012 All variables in logged form			

Source: California Energy Commission, Demand Analysis Office, 2013

Table C-11: Manufacturing Sector Natural Gas Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Manufacturing Output (2005$)	0.9585	0.3266	2.93
Manufacturing Output/Manufacturing Employment	-0.8302	0.2867	-2.90
Industrial Gas Rate (2012$/therm)	-0.1442	0.0771	-1.87
Number of Heating Degree Days (65^{o})	0.2832	0.1249	2.27
Dummy: SDG&E (1990)	1.1710	0.2911	4.02
Dummy: PG&E (1980 and 1981)	0.4000	0.0994	4.02
Constant: PG&E	2.0677	0.7107	2.91
Constant: Southern California Gas	1.8245	0.8818	2.07
Overall Constant	-3.5530	1.9031	-1.87
Trend Variables			
Time: Southern California Gas	-0.0533	0.0227	-2.35
Time Squared: Southern California Gas	0.0019	0.0007	2.86
Time: SDG&E	0.0550	0.0428	1.28
Time Squared: SDG&E	-0.0023	0.0012	-1.93
Adjusted for autocorrelation and cross-sectional correlation Wald chi squared = 1,255 Dependent variable = natural log of natural gas consumption by planning area, 1980-2012 All variables in logged form except time			

Source: California Energy Commission, Demand Analysis Office, 2013

Table C-12: Resource Extraction and Construction Sector Natural Gas Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Sector Employment	0.4927	0.2313	2.13
Dummy: PG&E (1991)	0.7990	0.5049	1.58
Constant: PG&E	3.8388	0.4885	7.86
Constant: Southern California Gas	4.9226	0.4045	12.17
Overall Constant	-0.9467	0.9580	-0.99
Trend Variables			
Time: PG&E	-0.0490	0.0197	-2.49
Time: Southern California Gas	0.0788	0.0339	2.32
Time Squared: Southern California Gas	-0.0490	0.0197	-2.49
Adjusted for autocorrelation and cross-sectional correlation Wald chi squared = 1,167 Dependent variable = natural log of natural gas consumption by planning area, 1980-2012 All variables in logged form except time			

Source: California Energy Commission, Demand Analysis Office, 2013

Table C-13: Agriculture and Water Pumping Sector Natural Gas Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Sector Employment	0.8855	0.0472	18.74
Per Capita Income (2012$)	1.4905	0.5345	2.79
Commercial Gas Rate (2012$ per mmBTU)	-0.0917	0.0890	-1.03
Dummy: 2001	-0.1249	0.0840	-1.49
Overall Constant	-15.5599	5.3555	-2.91
Trend Variables			
Time: PG&E	-0.0367	0.0096	-3.82
Time: Southern California Gas	0.0190	0.0084	2.26
Time: SDG&E	-0.0406	0.0120	-3.40
Adjusted for autocorrelation and cross-sectional correlation Wald chi squared = 1,833 Dependent variable = natural log of natural gas consumption by planning area, 1980-2012 All variables in logged form except time			

Source: California Energy Commission, Demand Analysis Office, 2013