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STAFF FINAL REPORT

CALIFORNIA ENERGY DEMAND 2012-2022 FINAL FORECAST

Volume 1: Statewide Electricity Demand and Methods, 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 2012-2022 Final Forecast Volume 1: Statewide Electricity Demand and Methods, End-User Natural Gas Demand, and Energy Efficiency* describes the California Energy Commission staff's final forecasts for 2012–2022 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 *Integrated Energy Policy Report 2011* and *2012 Integrated Energy Policy Report Update*. 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.

Keywords

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

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EXECUTIVE SUMMARY

Introduction

The *California Energy Demand 2012-2022 Final Forecast* (*CED 2011 Final*) forecasts electricity and end-user natural gas consumption and peak electricity demand for the State of California and for each major utility planning area within the state for 2012-2022. *CED 2011 Final* supports the analysis and recommendations of the *2011 Integrated Energy Policy Report (2011 IEPR)* and *2012 Integrated Energy Policy Report Update (2012 IEPR Update)*, including electricity and natural gas system assessments and analysis of progress toward increased energy efficiency. It provides detail on the impacts of energy efficiency programs and standards, continuing a major staff effort to improve the measurement and attribution of efficiency impacts within the energy demand forecast.

CED 2011 Final 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 *CED 2011 Final* for selected years with the *California Energy Demand 2010-2020 Adopted Forecast (CED 2009)*, the forecast used in the *2009 IEPR*. The new forecast begins almost 3 percent below *CED 2009* in 2010, reflecting a significant drop in actual electricity consumption in 2009 and 2010 as the recent recession worsened relative to the outlook in 2009, combined with a relatively mild weather year in 2010. Consumption in the mid scenario grows at a slightly faster rate and the high scenario at a significantly faster rate through 2020 compared to *CED 2009*. By 2020, consumption is around 2 percent higher in the high case, with the mid scenario around 2 percent lower. Statewide noncoincident weather-normalized (adjusted to reflect "average" historical weather) 2011 peak demand is almost 5 percent lower than predicted in *CED 2009* but grows at a faster rate in the mid and high cases from 2011-2020 as a result of projected economic recovery and an adjustment to account for climate change.

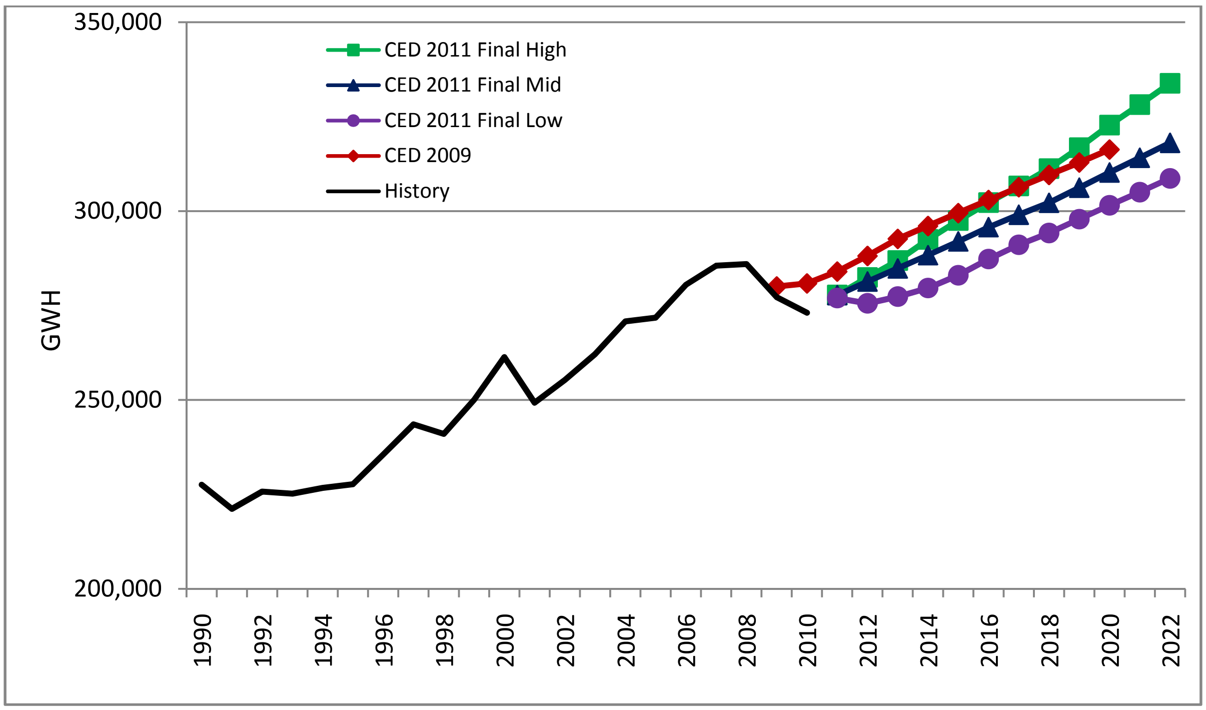
Table ES-1: Comparison of *California Energy Demand 2010-2020 Adopted Forecast (CED 2009)* and *California Energy Demand 2012-2022 Final Forecast Volume 1: Statewide Electricity Demand and Methods, End-User Natural Gas Demand, and Energy Efficiency* (*CED 2011*) Statewide Electricity Demand

Consumption (GWh)				
	CED 2009	*CED 2011 Final High Energy Demand*	*CED 2011 Final Mid Energy Demand*	*CED 2011 Final Low Energy Demand*
1990	228,473	227,586	227,586	227,586
2000	264,230	261,381	261,381	261,381
2010	280,843	273,103	273,103	273,103
2015	299,471	297,509	291,965	283,011
2020	316,280	322,760	310,210	301,535
2022	--	333,838	318,071	308,677
	Average Annual Growth Rates			
1990-2000	1.46%	1.39%	1.39%	1.39%
2000-2010	0.61%	0.44%	0.44%	0.44%
2010-2015	1.29%	1.73%	1.34%	0.72%
2010-2020	1.20%	1.68%	1.28%	1.00%
2010-2022	--	1.69%	1.28%	1.03%
Noncoincident Peak (MW)				
	CED 2009	*CED 2011 Final High Energy Demand*	*CED 2011 Final* Mid Energy Demand	*CED 2011 Final Low Energy Demand*
1990	47,521	47,546	47,546	47,546
2000	53,703	53,700	53,700	53,700
2011	--	58,737	58,737	58,737
2011*	63,282	60,310	60,310	60,310
2015	66,868	65,950	65,036	61,791
2020	71,152	71,701	69,418	65,884
2022	--	74,049	70,946	66,916
	Average Annual Growth Rates			
1990-2000	1.23%	1.23%	1.23%	1.23%
2000-2011	1.50%	0.82%	0.82%	0.82%
2011-2015	1.39%	2.33%	1.93%	0.72%
2011-2020	1.31%	1.97%	1.58%	1.05%
2011-2022	--	1.91%	1.50%	1.00%
Historical values are shaded.				
*Weather-normalized: *CED 2011 Final* uses a weather-normalized peak value derived from the actual 2011 peak for calculating growth rates during the forecast period				

Source: California Energy Commission, Demand Analysis Office, 2012

Figure ES-1 shows statewide historical electricity consumption, projected consumption for the three scenarios, and the *CED 2009* consumption forecast. Consumption grows at a faster average annual rate from 2010 to 2020 in the high case (1.68 percent) and a slower rate in the low scenario (1.00 percent) relative to *CED 2009* (1.20 percent). All three scenarios grow at a faster average annual rate than *CED 2009* toward the end of the forecast period, from 2015-2020, driven by higher growth in the commercial sector. Forecast consumption reaches *CED 2009* projected 2020 levels by 2017 in the high demand scenario and by 2022 in the mid case.

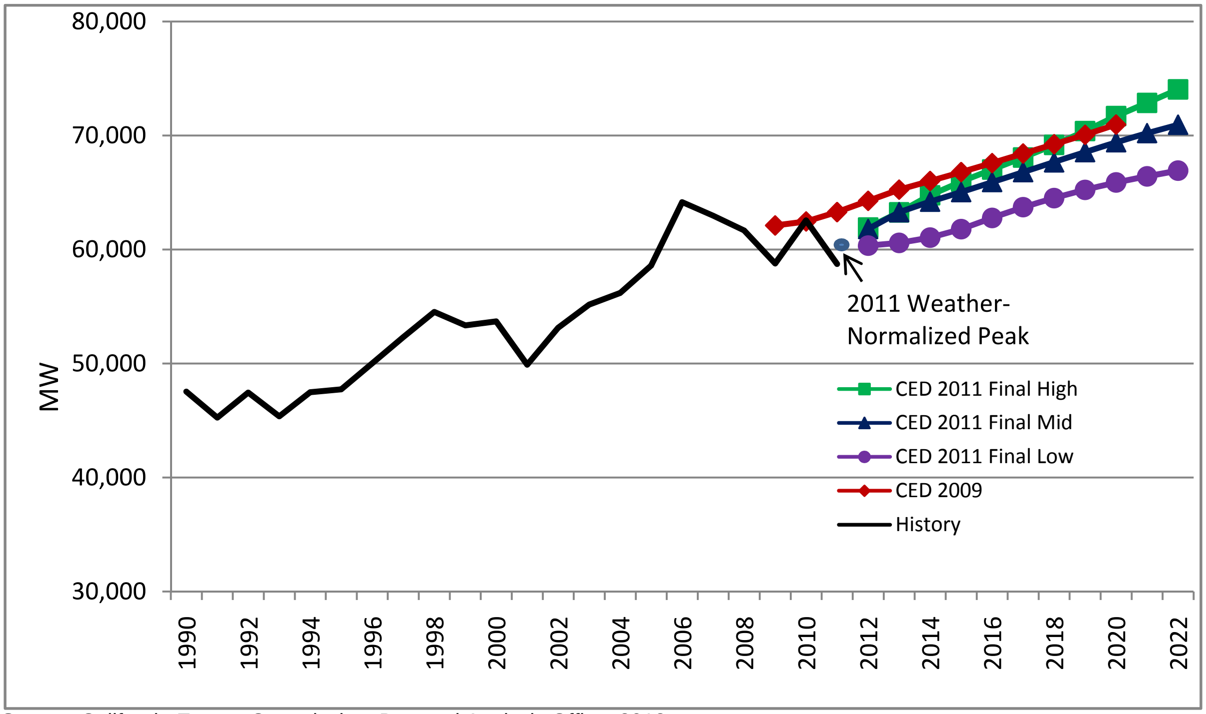
Figure ES-1: Statewide Annual Electricity Consumption



Source: California Energy Commission, Demand Analysis Office, 2012

Figure ES-2 compares *CED 2011 Final* statewide noncoincident peak demand with *CED 2009*. Unlike consumption, peak over all sectors in 2010 was very close to the *CED 2009* statewide projection; although 2010 was a mild weather year overall, a heat storm event (extended heat wave) in September 2010 yielded a relatively high peak. The figure also indicates noncoincident weather-normalized peak demand in 2011, higher than the actual total since this was a relatively cool year. Growth rates in the forecast period are calculated relative to this weather-normalized total, which is significantly lower than the peak predicted in *CED 2009*. Peak demand is projected to grow faster in the mid and high demand scenarios relative to *CED 2009*; by 2020, demand in the high case is 1 percent higher in the high case and 2.2 percent lower in the mid case (after beginning the forecast period almost 5 percent below).

Figure ES-2: Statewide Annual Noncoincident Peak Demand



Source: California Energy Commission, Demand Analysis Office, 2012

Natural Gas Forecast Results

Table ES-2 compares three *CED 2011 Final* end-user natural gas demand forecasts at the statewide level with *CED 2009* for selected years. The new forecasts begin at a higher point in 2010, as natural gas consumption in California was substantially higher than predicted in *CED 2009* and grows at a faster rate in the mid case from 2010-2020. This results mainly from higher projected demand in the industrial sector versus *CED 2009*.

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

Consumption (MM Therms)				
	CED 2009	*CED 2011 Final High Energy Demand*	*CED 2011 Final Mid Energy Demand*	*CED 2011 Final Low Energy Demand*
1990	12,893	12,893	12,893	12,893
2000	13,913	13,913	13,913	13,913
2010	12,162	12,774	12,774	12,774
2015	12,751	13,265	13,503	12,877
2020	12,997	13,648	13,961	13,588
2022	--	13,929	14,075	13,688
	Average Annual Growth Rates			
1990-2000	0.76%	0.76%	0.76%	0.76%
2000-2010	-1.34%	-0.85%	-0.85%	-0.85%
2010-2015	0.95%	0.76%	1.12%	0.16%
2010-2020	0.67%	0.66%	0.89%	0.62%
2010-2022	--	0.72%	0.81%	0.58%
Historical values are shaded				

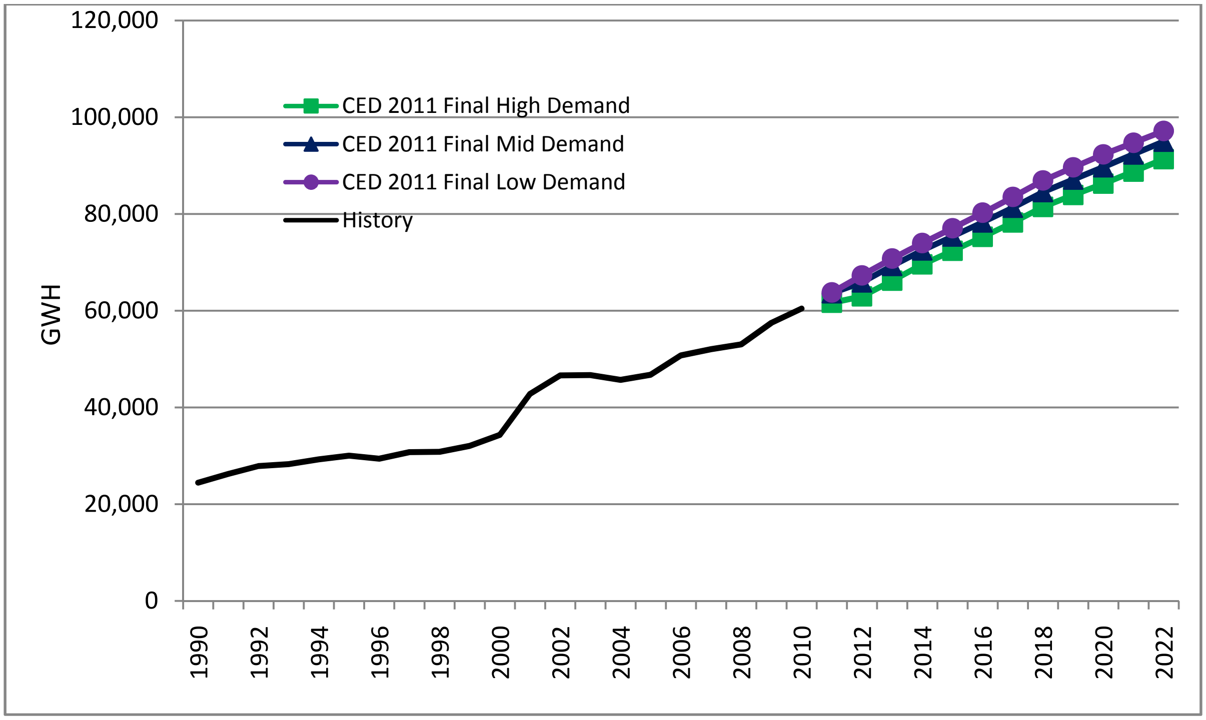
Source: California Energy Commission, Demand Analysis Office, 2012

Conservation/Efficiency

Energy Commission demand forecasts seek to account for efficiency and conservation expected to occur. Since the *1985 Electricity Report*, initiatives have been split into two types: committed and uncommitted. *CED 2011 Final* 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. Chapter 3 gives details regarding the committed energy efficiency impacts projected for this forecast. Uncommitted efficiency impacts are not estimated for this report; staff analysis for this purpose will follow later in 2012.

Figure ES-3 shows staff estimates of historical and projected committed consumption savings impacts, which include programs, codes and standards, price, and other effects. Projected savings impacts are higher the lower the demand scenario, since price and program effects are inversely related to the demand outcome.

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



Source: California Energy Commission, Demand Analysis Office, 2012

Summary of Changes to Forecast

The previous long-run forecast, *CED 2009*, was based on 2008 peak demand and energy. For the current forecast, staff added 2009 and 2010 energy consumption data to the historical series used for forecasting. The peak demand forecast incorporates recent analysis of 2010 and 2011 temperatures and peak demand at the planning area level.

CED 2011 Final 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. Details on input assumptions for these scenarios are provided in Chapter 1.

For the residential, commercial, and industrial (a combination of manufacturing and resource extraction and construction) sectors, forecasts were developed in two ways: through the Energy Commission's existing models and through econometric models developed by staff in 2011 and re-estimated for *CED 2011 Final*. Adjustments were made to existing models based on the econometric estimations, and results from existing models were compared to econometric results.

As part of the continuing effort to capture comprehensively the impacts of energy efficiency initiatives, *CED 2011 Final* incorporates recent revisions to Energy Commission building codes and appliance standards, including effects from Assembly Bill 1109 (AB 1109, Huffman, Chapter 534, Statutes of 2007) and the television standards implemented in 2011, as well as an update to natural gas efficiency program impacts. Staff focused on electricity programs in *CED 2009*, and time and resources did not permit any revision to natural gas program impacts. Chapter 3 details staff work related to efficiency impact measurement for this forecast.

Residential adoption of photovoltaic systems and solar water heaters was forecast using a predictive model rather than a trend analysis as in previous forecasts. This model is 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. Details of the model are provided in Appendix B.

Finally, potential climate change was incorporated in the forecast, using temperature scenarios developed by the Scripps Institute. These scenarios, and how they were included in the forecast, are discussed in Appendix A.

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 the State of California and for each major utility planning area within the state for 2012-2022. The *California Energy Demand 2012-2022 Final Forecast* (*CED 2011 Final*) supports the analysis and recommendations of the *2011 Integrated Energy Policy Report (2011 IEPR)* and *2012 Integrated Energy Policy Report Update (2012 IEPR Update)*, including electricity and natural gas system assessments and analysis of progress toward increased energy efficiency. This report details the impacts of energy efficiency programs and standards, continuing a major staff effort to improve the measurement and attribution of efficiency impacts within the energy demand forecast.

The IEPR Lead Commissioner held a workshop on February 23, 2012, to receive public comments on this forecast. Following the workshop, under the direction of the Lead Commissioner, staff prepared revisions to this forecast for adoption by the Energy Commission.

The final forecasts will be used in a number of applications, including the California Public Utilities Commission (CPUC) 2012 Long Term Procurement Plan. 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 assessments.

Summary of Changes to Forecast

The previous long-run forecast, *California Energy Demand 2010-2020 Adopted Forecast*[3] (*CED 2009*), was based on 2008 peak demand and energy. For the current forecast, staff added

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

3 California Energy Commission. *California Energy Demand 2010–2020 Adopted Forecast,* December 2009. CEC-200-2009-012-CMF. http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html.

2009 and 2010 energy consumption data to the historical series used for forecasting. The peak demand forecast incorporates recent analysis of 2010 and 2011 temperatures and peak demand at the planning area level.

CED 2011 Final 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. Details on input assumptions for these scenarios are provided later in this chapter.

For the residential, commercial, and industrial (a combination of manufacturing and resource extraction and construction) sectors, forecasts were developed in two ways: through the Energy Commission's existing models and through econometric models developed by staff in 2011 and re-estimated for *CED 2011 Final*. Adjustments were made to existing models based on the econometric estimations and results from existing models were compared to econometric results.

As part of the continuing effort to capture comprehensively the impacts of energy efficiency initiatives, *CED 2011 Final* incorporates recent revisions to Energy Commission building codes and appliance standards, including effects from Assembly Bill 1109 (AB 1109, Huffman, Chapter 534, Statutes of 2007) and the television standards implemented in 2011, as well as an update to natural gas efficiency program impacts. Staff focused on electricity programs in *CED 2009*, and time and resources did not permit any revision to natural gas program impacts. Chapter 3 provides details on staff work related to efficiency impact measurement for this forecast.

Residential adoption of photovoltaic (PV) systems and solar water heaters was forecast using a predictive model rather than a trend analysis as in previous forecasts. This model is 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. Details of the model are provided in Appendix B.

Finally, potential climate change was incorporated in the forecast, using temperature scenarios developed by the Scripps Institute. These scenarios, and how they were included in the forecast, are discussed in Appendix A.

The forecast comparisons presented in this report show *CED 2011 Final* versus the adopted *CED 2009* forecast, except for a discussion of the preliminary version of *CED 2011* provided in the next section.

Changes From Revised to Final Forecast

Staff prepared a revised forecast[4] (*CED 2011 Revised*), presented in a workshop on February 23, 2012. The analysis for *CED 2011 Final* reflects the following updates and changes:

- Estimates for electricity savings from the 2011 television standards were revised after discussions with appliance standards experts within the Energy Commission as well as examination of additional studies from other sources.
- Estimates for peak demand savings from non-event-based demand response programs were incorporated into the forecast.[5]
- A revised light-duty electric vehicle forecast from the Fuels Office at the Energy Commission was incorporated.
- A forecast for light-duty natural gas vehicle fuel usage was added to the end-user natural gas forecast.
- Additional electrification at ports and from other sources in the Southern California Edison (SCE) planning area was added to the forecast.
- The SCE manufacturing sector forecast was replaced with the econometric version.

The first update is discussed further in Chapter 3 of this volume, while the next three are discussed later in this chapter; the changes affecting SCE are explained in the chapter for this planning area in Volume II of this report.

At the statewide level, projected results for electricity consumption in all three demand scenarios are slightly higher (less than 1 percent by 2022) than in the revised forecast, as the impacts from the new electric vehicle forecast, electrification in Southern California, and a higher industrial forecast for SCE outweigh the effects from higher projected savings from the television standards. Consumption forecasts for individual planning areas differ most for SCE for reasons described above (1.2 percent higher in the mid case in 2022) and San Diego Gas & Electric (SDG&E) due to a relatively high share of electric vehicle ownership assumed in the new forecast (mid case consumption is 2.1 percent higher in 2022). Peak demand is down very slightly (0.5 percent or less) at the statewide level in all three scenarios, mainly because electric vehicle usage is assumed to have relatively little impact on peak demand, and therefore the additive factors versus the revised forecast are outweighed by increased peak savings from the television standards as well as the incorporation of demand response. SDG&E and SCE peak demands are projected to increase in 2022 in the mid demand case for the same reasons as the consumption increase,

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4 Kavalec, Chris, Nicholas Fugate, Tom Gorin, Bryan Alcorn, Mark Ciminelli, Asish Gautam, Glen Sharp, and Kate Sullivan, 2012. *Revised California Energy Demand Forecast 2012-2022.* California Energy Commission, Electricity Supply Analysis Division. CEC-200-2012-001-SD.

5 Non-event demand response provides wholesale and retail electricity customers with the ability to choose to respond to time-based prices and other incentives by reducing or shifting electricity use, particularly during peak-demand periods.

but by a smaller percentage. The end-user natural gas demand forecast increases by the projected additional light-duty natural gas vehicle fuel usage, around 90 million therms statewide by 2022 (less than 1 percent).

Statewide Forecast Results

Table 1-1 compares the *CED 2011 Final* forecast for selected years with *CED 2009*, the forecast used in the *2009 IEPR*. The new forecast begins almost 3 percent below *CED 2009* in 2010, reflecting a significant drop in actual electricity consumption in 2009 and 2010 as the recent recession worsened relative to the outlook in 2009, combined with a relatively mild weather year in 2010. Consumption in the mid scenario grows at a slightly faster rate and the high scenario at a significantly faster rate through 2020 compared to *CED 2009*. By 2020, consumption is around 2 percent higher in the high case, with the mid scenario around 2 percent lower. Statewide (noncoincident) weather-normalized[6] 2011[7] peak demand is almost 5 percent lower than predicted in *CED 2009* but grows at a faster rate in the mid and high cases from 2011-2020 as a result of projected economic recovery and an adjustment to account for climate change.

The historical data used for this forecast differs slightly from *CED 2009* due to revised data submitted by utilities and because a detailed review of self-generation data found that on-site consumption had been improperly estimated in the past. Differences are largest in the restructuring period through the electricity crisis in 2001 and are due mainly to updates to the self generation data.

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6 Peak demand is weather-normalized in 2011 to provide the proper benchmark for comparison to future peak demand, which assumes average, or normalized, weather. The process for normalization is described in the section Subregional Electricity Analysis later in this chapter.

7 The year 2011 serves as the last historical year for the peak forecast; unlike consumption, full data is available for utility peaks in 2011, since these occurred months ago.

Table 1-1: Comparison of *CED 2009* and *CED 2011 Final* Forecasts of Statewide Electricity Demand

Consumption (GWh)				
	CED 2009	*CED 2011 Final High Energy Demand*	*CED 2011 Final Mid Energy Demand*	*CED 2011 Final Low Energy Demand*
1990	228,473	227,586	227,586	227,586
2000	264,230	261,381	261,381	261,381
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1990-2000	1.46%	1.39%	1.39%	1.39%
2000-2010	0.61%	0.44%	0.44%	0.44%
2010-2015	1.29%	1.73%	1.34%	0.72%
2010-2020	1.20%	1.68%	1.28%	1.00%
2010-2022	--	1.69%	1.28%	1.03%
Noncoincident Peak (MW)				
	CED 2009	*CED 2011 Final High Energy Demand*	*CED 2011 Final* Mid Energy Demand	*CED 2011 Final Low Energy Demand*
1990	47,521	47,546	47,546	47,546
2000	53,703	53,700	53,700	53,700
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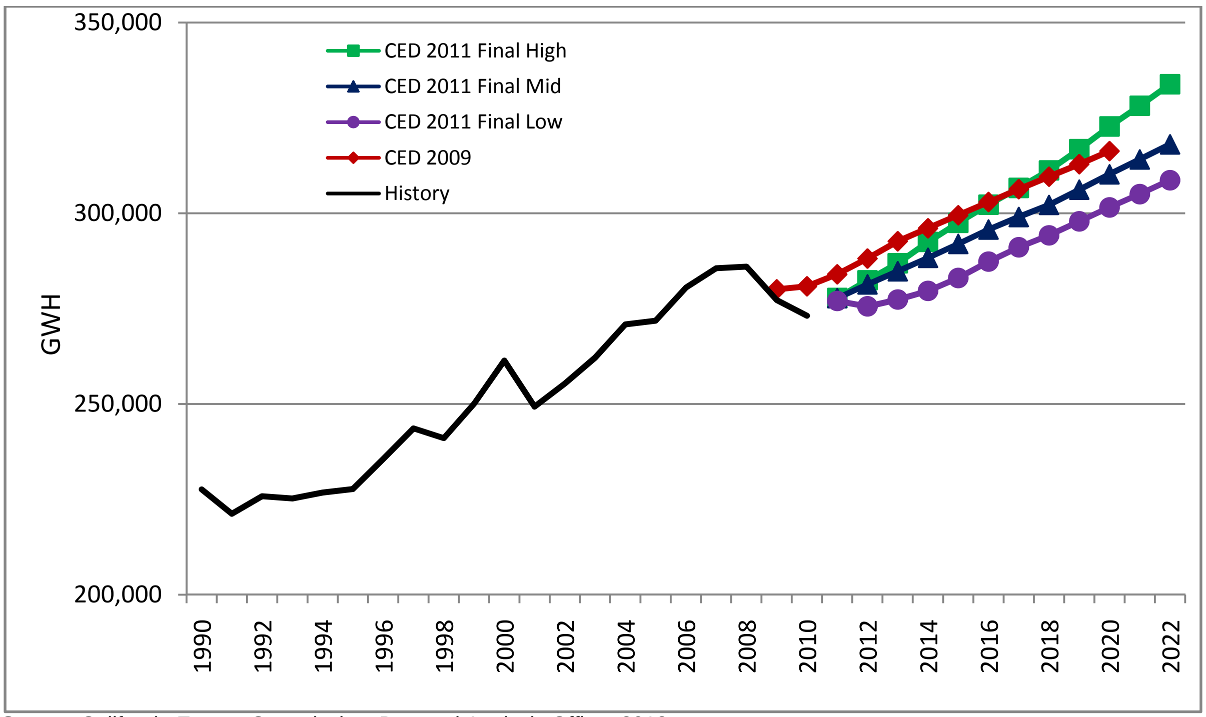
2022	--	74,049	70,946	66,916
	Average Annual Growth Rates			
1990-2000	1.23%	1.23%	1.23%	1.23%
2000-2011	1.50%	0.82%	0.82%	0.82%
2011-2015	1.39%	2.33%	1.93%	0.72%
2011-2020	1.31%	1.97%	1.58%	1.05%
2011-2022	--	1.91%	1.50%	1.00%
Historical values are shaded.				
*Weather normalized: *CED 2011 Final* uses a weather-normalized peak value derived from the actual 2011 peak for calculating growth rates during the forecast period				

Source: California Energy Commission, Demand Analysis Office, 2012

Annual Electricity Consumption

Figure 1-1 shows statewide historical electricity consumption, projected *CED 2011 Final* consumption for the three scenarios, and the *CED 2009* consumption forecast. *CED 2011 Final* consumption grows at a faster average annual rate from 2010 to 2020 in the high case (1.68 percent) and a slower rate in the low scenario (1.00 percent) relative to *CED 2009* (1.20 percent). All three scenarios grow at a faster average annual rate than *CED 2009* toward the end of the forecast period, from 2015-2020, driven by higher growth in the commercial sector. Forecast consumption reaches *CED 2009* projected 2020 levels by 2017 in the high demand scenario and by 2022 in the mid case.

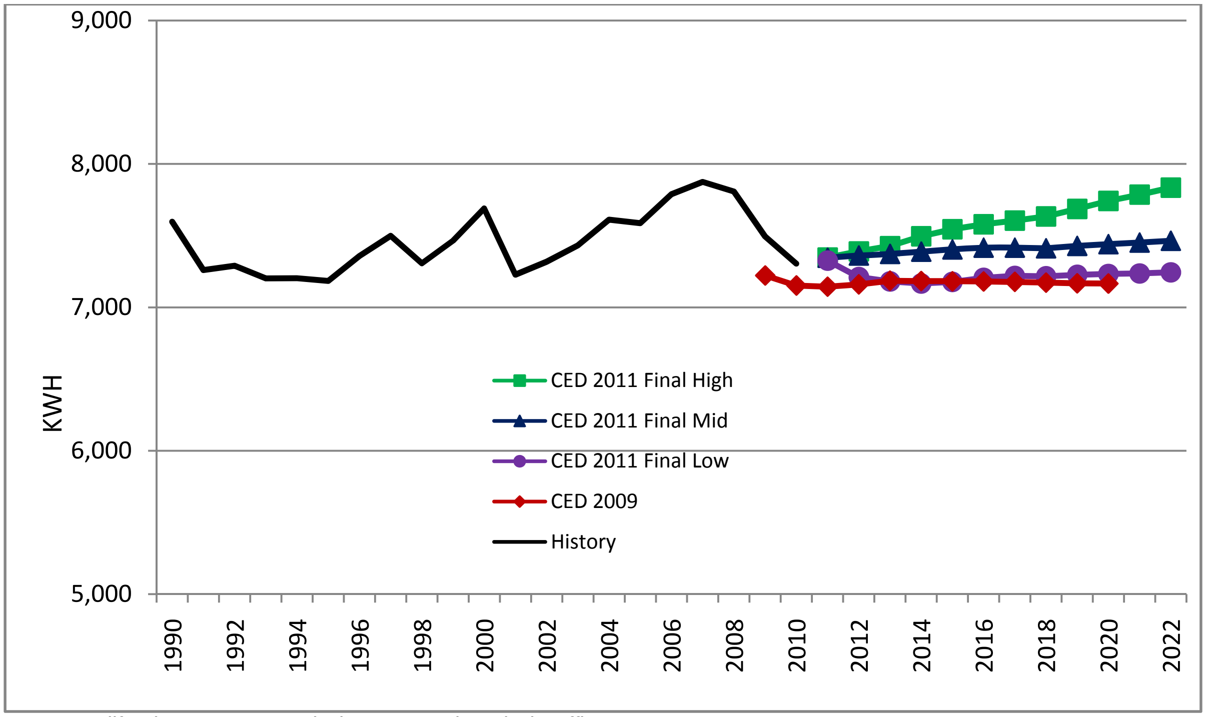
Figure 1-1: Statewide Annual Electricity Consumption



Source: California Energy Commission, Demand Analysis Office, 2012

As shown in **Figure 1-2**, per capita electricity consumption is relatively flat throughout the forecast period in the mid case and from 2017 on in the low case, which assumes a longer delay for economic recovery. Both forecasts increase slightly toward the end of the forecast period due to increasing electric vehicle use. Higher economic/demographic growth in the high demand case increases per capita consumption throughout the forecast period. Per-capita consumption in all three scenarios is higher in 2010 than projected in *CED 2009* because of a downward adjustment to California's population estimates in the latest census.

Figure 1-2: Statewide Electricity Annual Consumption per Capita



Source: California Energy Commission, Demand Analysis Office, 2012

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 *CED 2009*. Projected residential sector growth in the mid and high scenarios from 2010-2020 is faster compared to *CED 2009*, mainly because of a reversion to average weather in the forecast period from a historically mild 2010. Projected commercial sector consumption growth is higher in all three scenarios compared to *CED 2009* due to the reversion to average weather as well as from faster projected commercial floor space growth in the mid and high scenarios.[8] To compare across weather-normalized years, growth rates for 2011-2020 are also shown for the residential and commercial sectors. (Consumption is much less weather-sensitive in the industrial sector.) Industrial consumption growth from 2010-2020 is slower in the mid and low cases compared to *CED 2009*; although manufacturing output is projected to grow faster in the mid scenario compared to *CED 2009* projections, this is offset by a labor productivity adjustment made by staff (discussed later in this chapter). In the high demand case, much higher growth in manufacturing than in the mid and low cases results in a 2010-2020 growth rate significantly above that in *CED 2009*.

8 In addition, impacts from the Huffman lighting and television standards are projected to have much less impact in the commercial sector compared to the residential.

Table 1-2: Electricity Consumption by Sector (GWh)

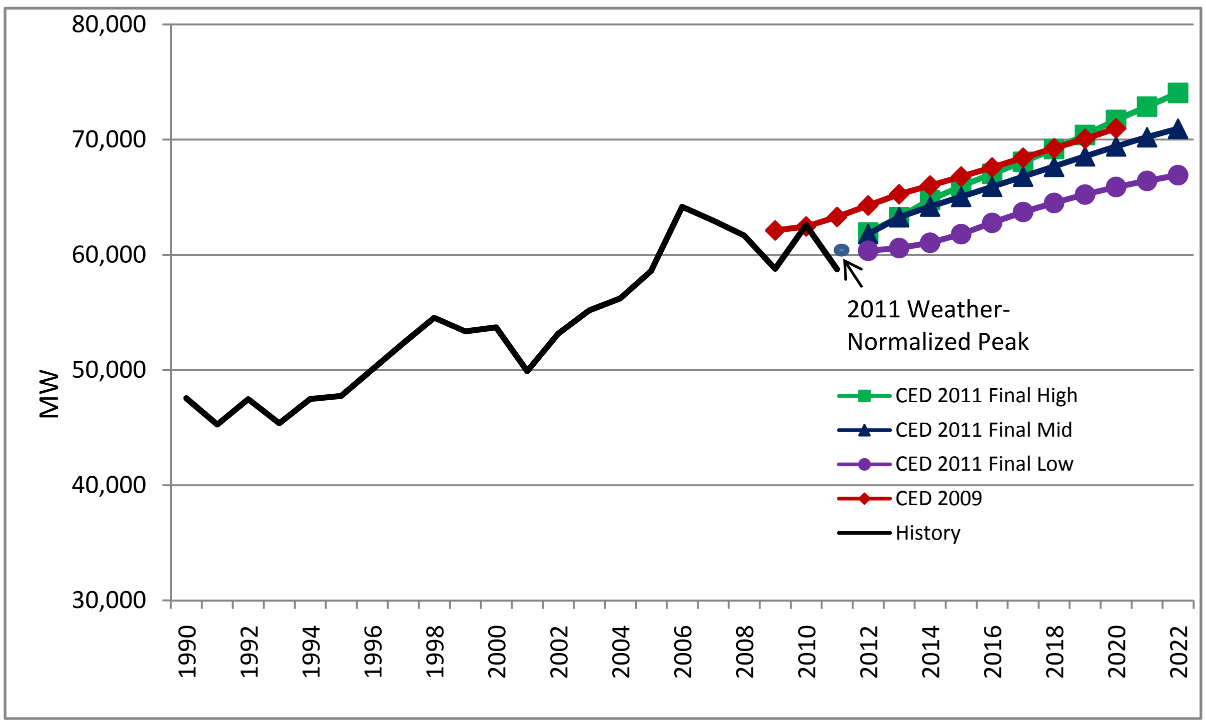
Residential				
	CED 2009	*CED 2011 Final High Energy Demand*	*CED 2011 Final Mid Energy Demand*	*CED 2011 Final Low Energy Demand*
2010	90,712	87,378	87,378	87,378
2015	97,353	98,015	95,520	92,566
2020	108,529	109,498	104,853	101,621
2022	--	114,684	109,659	105,415
Average Annual Growth, Residential Sector				
2010-2020	1.81%	2.28%	1.84%	1.52%
2011-2020	1.91%	2.16%	1.69%	1.37%
2010-2022	--	2.29%	1.91%	1.58%
Commercial				
	CED 2009	*CED 2011 Final High Energy Demand*	*CED 2011 Final Mid Energy Demand*	*CED 2011 Final Low Energy Demand*
2010	103,143	100,375	100,375	100,375
2015	110,313	109,284	108,514	105,985
2020	116,278	117,282	116,658	113,301
2022	--	120,505	119,640	116,593
Average Annual Growth, Commercial Sector				
2010-2020	1.21%	1.57%	1.51%	1.22%
2011-2020	1.20%	1.49%	1.45%	1.14%
2010-2022	--	1.53%	1.47%	1.26%
Industrial				
	CED 2009	*CED 2011 Final High Energy Demand*	*CED 2011 Final Mid Energy Demand*	*CED 2011 Final Low Energy Demand*
2010	49,315	47,528	47,528	47,528
2015	52,546	51,469	49,276	45,880
2020	52,162	56,081	48,916	46,940
2022	--	58,357	48,597	46,609
Average Annual Growth, Industrial Sector				
2010-2020	0.56%	1.67%	0.29%	-0.12%
2010-2022	--	1.73%	0.19%	-0.16%
Historical values are shaded				

Source: California Energy Commission, Demand Analysis Office, 2012

Statewide Peak Demand

Figure 1-3 compares *CED 2011 Final* statewide noncoincident[9] peak demand with *CED 2009*. Unlike consumption, peak in 2010 was very close to the *CED 2009* statewide projection over all sectors; although 2010 was a generally a mild weather year, a heat storm in September 2010 yielded a relatively high peak. The figure also indicates noncoincident weather-normalized peak demand in 2011, higher than the actual total since this was a relatively cool year. Growth rates in the forecast period are calculated relative to this weather-normalized total, which is significantly lower than the peak predicted in *CED 2009*. Peak demand is projected to grow faster in the mid and high demand scenarios relative to *CED 2009*; by 2020, demand in the high case is 1 percent higher in the high case and 2.2 percent lower in the mid case (after beginning the forecast period almost 5 percent below).

Figure 1-3: Statewide Annual Noncoincident Peak Demand



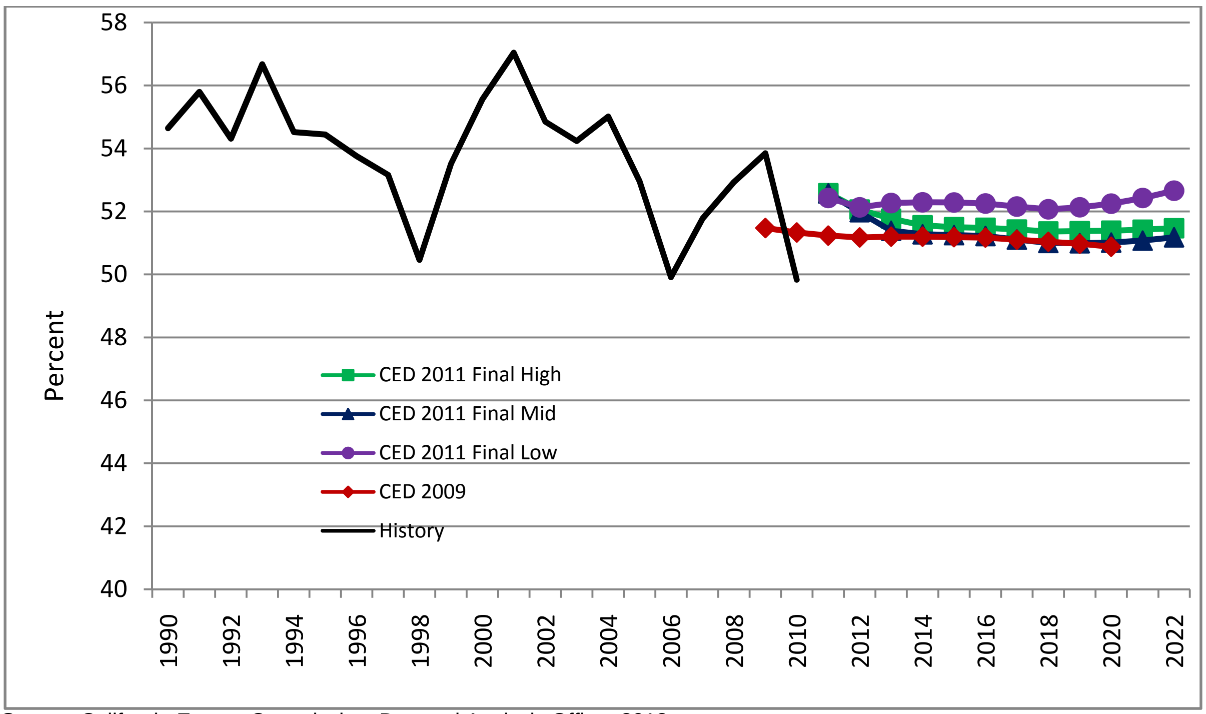
Source: California Energy Commission, Demand Analysis Office, 2012

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

9 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.

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 2009*) through 2020. 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.

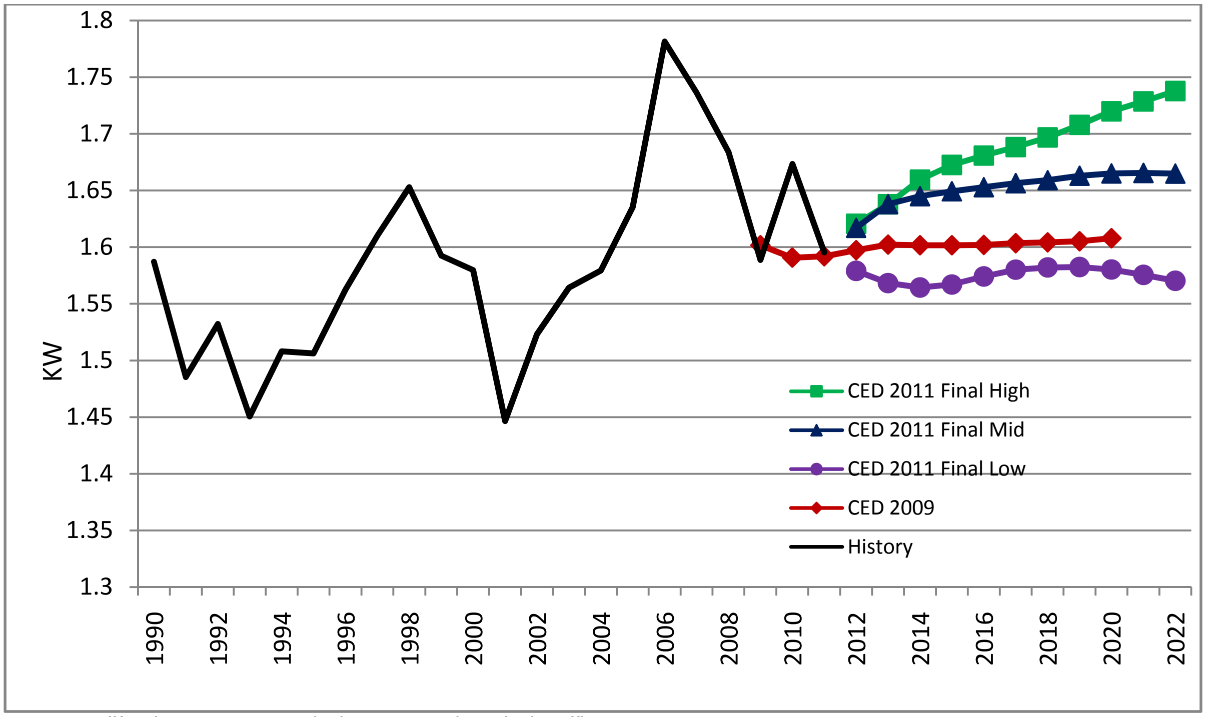
Figure 1-4: Statewide Noncoincident Peak Load Factors



Source: California Energy Commission, Demand Analysis Office, 2012

Figure 1-5 shows historical and projected noncoincident peak demand per capita. Unlike total peak, per capita demand in 2011 (using a weather-normalized peak) is roughly equal to that predicted in *CED 2009* due to a downward adjustment to California's population per the 2010 census. (This adjustment also affects historical values from 2000-2010.) Per capita demand increases at the beginning of the forecast period in all three scenarios as the California economy recovers. Afterward, demand flattens out and begins to decline toward the end of the forecast period in the mid and low demand scenarios, reflecting efficiency improvements and PV system adoption. Stronger economic growth in the high demand case, along with less efficiency improvement and PV adoption relative to the other scenarios, is enough to keep per capita demand increasing.

Figure 1-5: Statewide Noncoincident Peak Demand per Capita



Source: California Energy Commission, Demand Analysis Office, 2012

Table 1-3 shows projected annual noncoincident peak demand by the major economic sectors. All three sectors show a significant decline in weather-normalized peak compared to *CED 2009*, but, as with total peak, growth is faster in the mid and high cases from 2011-2022.

Table 1-3: Electricity Noncoincident Peak Demand by Sector (GWh)

Residential				
	CED 2009	*CED 2011 Final High Energy Demand*	*CED 2011 Final Mid Energy Demand*	*CED 2011 Final Low Energy Demand*
2011*	25,680	24,420	24,420	24,420
2015	27,689	27,228	26,698	25,608
2020	30,567	30,072	29,105	28,007
2022	--	31,205	30,131	28,710
Average Annual Growth, Residential Sector				
2011-2020	1.95%	2.34%	1.97%	1.53%
2011-2022	--	2.25%	1.93%	1.48%
Commercial				
	CED 2009	*CED 2011 Final High Energy Demand*	*CED 2011 Final Mid Energy Demand*	*CED 2011 Final Low Energy Demand*
2011*	21,589	20,935	20,935	20,935
2015	22,621	22,791	22,642	21,764
2020	23,676	24,514	24,323	23,102
2022	--	25,202	24,939	23,699
Average Annual Growth, Commercial Sector				
2011-2020	1.03%	1.77%	1.68%	1.10%
2011-2022	--	1.70%	1.60%	1.13%
Industrial				
	CED 2009	*CED 2011 Final High Energy Demand*	*CED 2011 Final Mid Energy Demand*	*CED 2011 Final Low Energy Demand*
2011*	7,835	7,148	7,148	7,148
2015	8,214	7,796	7,667	6,811
2020	8,154	8,511	7,670	7,041
2022	--	8,999	7,638	6,966
Average Annual Growth, Industrial Sector				
2011-2020	0.44%	2.10%	0.74%	-0.03%
2011-2022	--	2.23%	0.55%	-0.12%
*Weather-normalized Estimates of historical values are shaded				

Source: California Energy Commission, Demand Analysis Office, 2012

Natural Gas Demand Forecast

Table 1-4 compares the three *CED 2011 Final* natural gas demand forecasts at the statewide level with *CED 2009* for selected years. The new forecasts begin at a higher level in 2010, as natural gas consumption in California was substantially higher in this year than was predicted in *CED 2009*, and grows at a faster rate in the mid case from 2010-2020. This results mainly from higher projected demand in the industrial sector versus *CED 2009*. Growth in the high demand scenario is lower than in the mid case because of Global Insight's lower forecast for resource extraction and construction in the Southern California Gas Company (SoCalGas) service territory. Sector results are discussed further in Chapter 2.

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

Consumption (MM Therms)				
	CED 2009	*CED 2011 Final High Energy Demand*	*CED 2011 Final Mid Energy Demand*	*CED 2011 Final Low Energy Demand*
1990	12,893	12,893	12,893	12,893
2000	13,913	13,913	13,913	13,913
2010	12,162	12,774	12,774	12,774
2015	12,751	13,265	13,503	12,877
2020	12,997	13,648	13,961	13,588
2022	--	13,929	14,075	13,688
	Average Annual Growth Rates			
1990-2000	0.76%	0.76%	0.76%	0.76%
2000-2010	-1.34%	-0.85%	-0.85%	-0.85%
2010-2015	0.95%	0.76%	1.12%	0.16%
2010-2020	0.67%	0.66%	0.89%	0.62%
2010-2022	--	0.72%	0.81%	0.58%
Historical values are shaded				

Source: California Energy Commission, Demand Analysis Office, 2012

Overview of Methods and Assumptions

Although the methods to estimate energy efficiency impacts and self-generation have undergone refinement, *CED 2011 Final* uses essentially the same methods as earlier long-term staff demand forecasts. Models for the major economic sectors forecast annual energy consumption in each utility planning area. 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 and 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*.[10]

In addition to existing models, staff incorporated econometric model estimation and forecast results from models estimated for total peak demand and for electricity consumption in the three major sectors: residential, commercial, and industrial. The latter sector includes separate models for manufacturing and for resource extraction and construction. Estimation results for the econometric models are provided in Appendix D.

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

- Electricity price elasticities of demand[11] for the residential end-use and industrial (INFORM) models were changed to be consistent with elasticities estimated for the residential and industrial econometric models.

- The weather adjustment made to commercial end-use model electricity consumption results was changed to be consistent with the coefficient for cooling degree days in the commercial econometric model.

- The INFORM electricity forecast for the manufacturing sector was adjusted downward to reflect a negative impact from increasing labor productivity 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.

These adjustments, as well as the climate change scenarios, are discussed further in Appendix A. In addition, the resource extraction and construction econometric model forecast was used instead of the results from the INFORM model. Staff judged the INFORM results to be suspect: Projected electricity consumption growth decreased for some planning areas in a manner inconsistent with the economic drivers behind the forecast. Staff will look into revamping this portion of the INFORM methodology. Finally, staff replaced the manufacturing sector forecast for SCE with the econometric version for *CED 2011 Final*. Unlike in the other planning areas, the INFORM model predicted a significant decline in manufacturing energy use in 2011, a decline not evident in the year-to-date (through September 2011) Quarterly Fuel and Report (QFER) sales data. The econometric forecast predicted no such decline.

Estimation of new econometric models is part of the Energy Commission's effort to incorporate a *multiresolution* modeling process, generating more aggregate "tops down"

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

11 Price elasticities of demand measure the responsiveness of demand to changes in price.

results to compare with the detailed "bottoms up" results from end-use models. Although staff used existing models for this forecast (with the exception of resource extraction and construction and SCE's manufacturing), 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, consumption in the pure econometric forecast was almost 2 percent lower and peak demand 0.60 percent higher in 2022 compared to high demand *CED 2011 Final* statewide results shown in this chapter. The mid demand econometric scenario yielded projected 2022 consumption almost identical to *CED 2011 Final*, while peak demand was 1.8 percent higher. In the low econometric demand scenario, statewide consumption was projected to be 0.3 percent higher and peak 1.9 percent higher versus *CED 2011 Final* in 2022.

Differences in results between the two methods are to be expected, not only because of aggregate versus disaggregate approaches, but because econometric models by their nature incorporate historical trends for demand-side impacts such as efficiency and self-generation. End-use models, on the other hand, incorporate such impacts explicitly. Staff adjusted the econometric results to account for electric vehicles, the television standards, and incremental (to the last historical year) PV system adoptions, which, it could reasonably be argued, would not be captured in historical trends. For other demand impacts with at least some historical track record, differences between the two methods should be expected with changes in trends. For example, the effects of efficiency programs implicitly increase in the forecast period at historical rates in the econometric models, while end-use projections incorporate a substantial increase in 2011 and 2012 and reductions afterward as committed efficiency savings decay. Continued work on explicitly capturing 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.

Economic and Demographic Assumptions

Moody's Analytics (Moody's) and IHS Global Insight (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. These two companies update their long-term forecasts monthly; staff used the October 2011 projections for *CED 2011 Final*. Other entities, such as UCLA (Anderson Forecast) and the University of the Pacific, 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 October 2011 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

Global Insight provided three scenarios for their October 2011 forecast:

- Optimistic
- Baseline
- Pessimistic

Staff selected the Global Insight *Optimistic* economic case for the high demand scenario and a mixture of Moody's *Protracted Slump* and *Below-Trend Long-Term Growth* cases for the low demand scenario. The two Moody's cases were combined so that the *Protracted Slump* scenario drove the short-term results (through 2014) 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. Moody's base case 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.

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 *Protracted Slump* and *Below-Trend Long-Term Growth* Scenarios)
National unemployment rate falls below 6 percent by the end of 2015	National unemployment rate falls to around 6 percent by the end of 2015	National unemployment rate remains above 7 percent through 2015
European debt crises resolved	Policy makers urge more monetary quantitative easing	European debt crises worsens
National light-duty vehicle sales above 17 million in 2015	National light-duty vehicle sales above 16 million in 2015	National light-duty vehicle sales below 14 million in 2015
Home foreclosure rate declines; housing starts rise	Low/zero interest policy through mid 2013	Home foreclosures remain high and accelerate
Consumer and investment spending increases	Federal deficit is reduced to a "long-term structural" level by 2015	Continued cuts in state and local services
	Oil prices remain below $100/barrel in the short term	No decrease in oil prices
	Natural gas prices remain relatively low in the next several years	
	Current payroll tax holiday extended through 2012	

Sources: Moody Analytics and IHS Global Insight, 2011

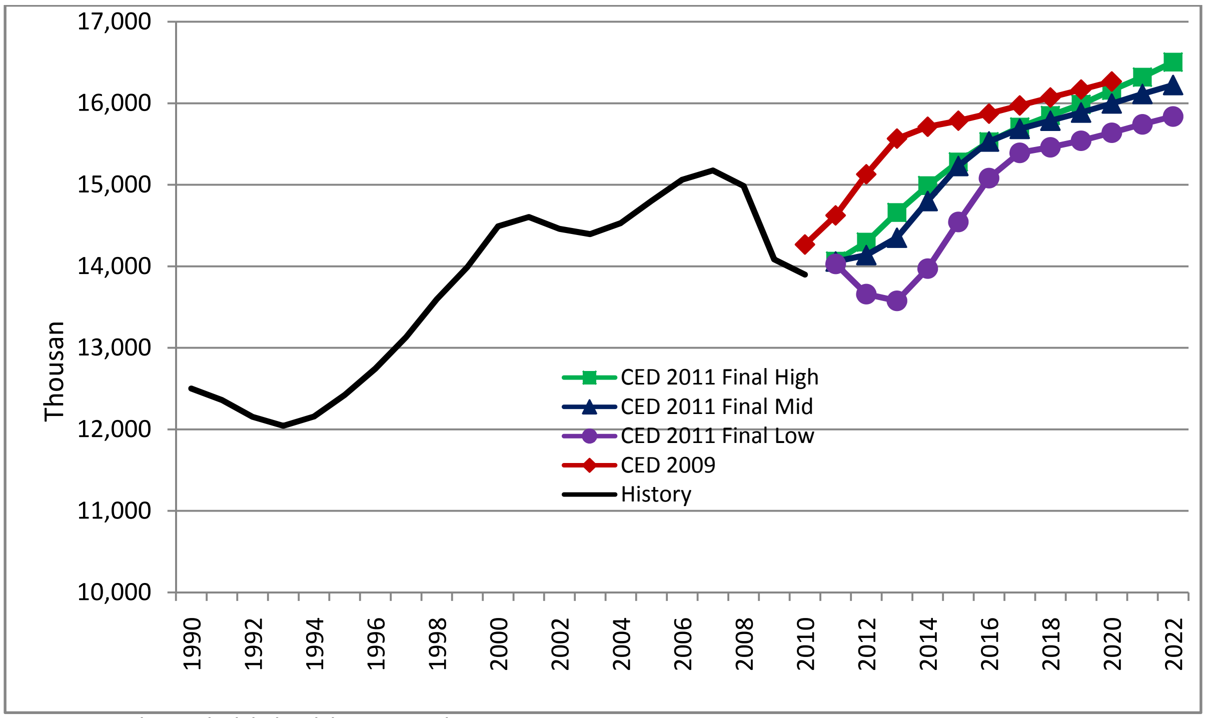
The probability assigned by Moody's to the mid demand scenario (Moody's *Baseline*) is 50 percent; that is, there is a 50 percent probability economic conditions will be worse than in this scenario. The equivalent probability for both Moody's scenarios used in the low demand scenario is 4 percent. Global Insight portrays the probabilities somewhat differently: "The probability of being near" the *Optimistic* economic scenario is 10 percent.[12]

Figure 1-6 and **Figure 1-7** compare projections for two key indicators used in the three scenarios, total statewide employment and statewide household personal income, respectively, with those used in *CED 2009*. Employment projections for all three scenarios remain below corresponding *CED 2009* projections through 2020, with high case projections almost reaching the *CED 2009* level in this year. The economic forecasts reflect more severe employment impacts from the recent recession than projected for *CED 2009*. Employment begins significantly below the 2010 projection for *CED 2009* but grows at a faster average annual rate from 2010-2020 in the mid and high cases (1.42 percent and 1.52 percent,

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

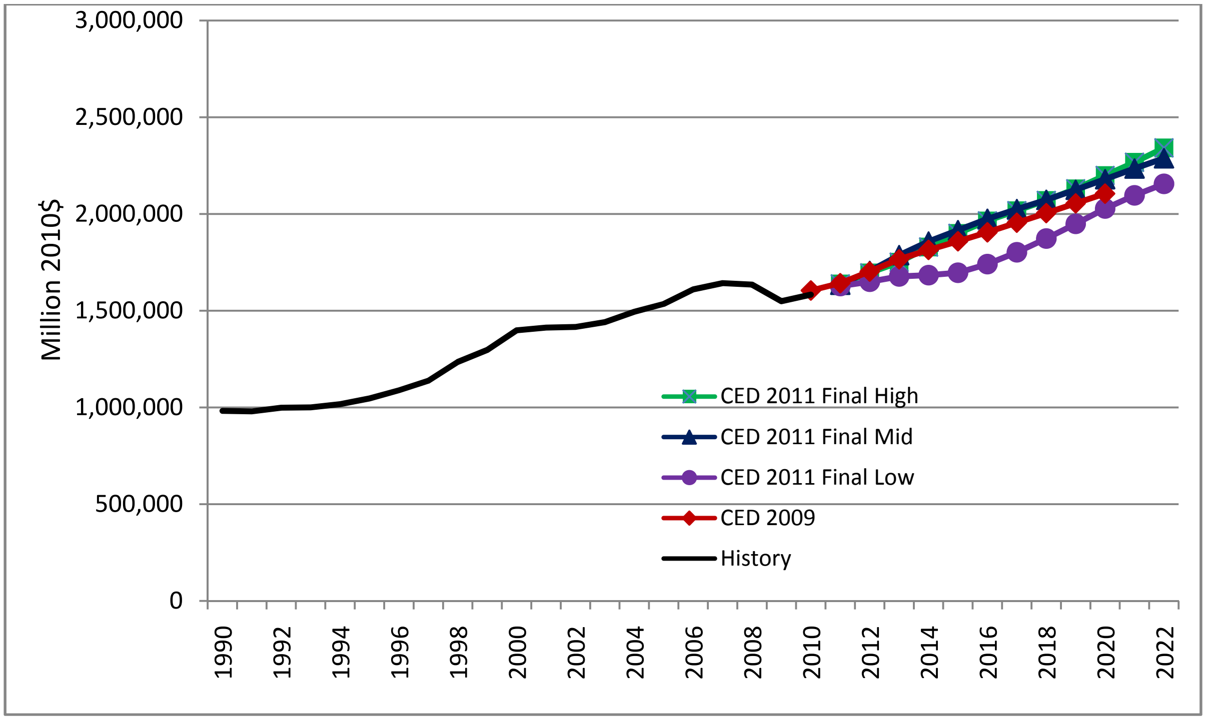
respectively, versus 1.32 percent in *CED 2009*). Dollar output, reflected by projected statewide personal income in **Figure 1-7**, is more in line with 2009 short-term projections, with growth from 2010-2020 in the mid and high demand scenarios higher than in *CED 2009*. Projected average annual growth in personal income between 2010 and 2020 is 3.34 percent, 3.25 percent, and 2.52 percent in the high, mid, and low scenarios, respectively, compared to 2.75 percent in *CED 2009*.

Figure 1-6: Statewide Employment Projections



Sources: Moody's and Global Insight, 2009 and 2011

Figure 1-7: Statewide Household Personal Income Projections

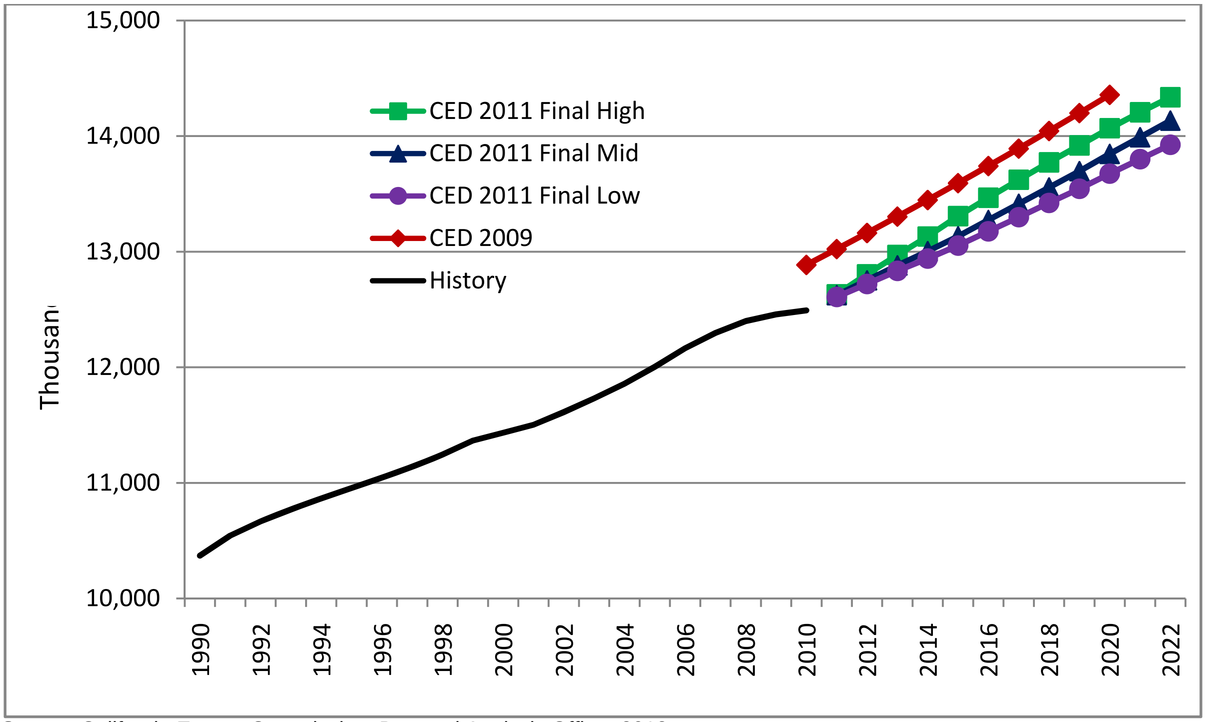


Sources: Moody's and Global Insight, 2009 and 2011

Staff also developed scenario projections for number of households, shown in **Figure 1-8**, by 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 2000-2010. The high case used Moody's projections.[13] The mid case assumed changes in persons per household halfway between the high and low. The *CED 2011 Final* number of households in 2010 is well below *CED 2009* due to adjustments to historical population, as discussed below.

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

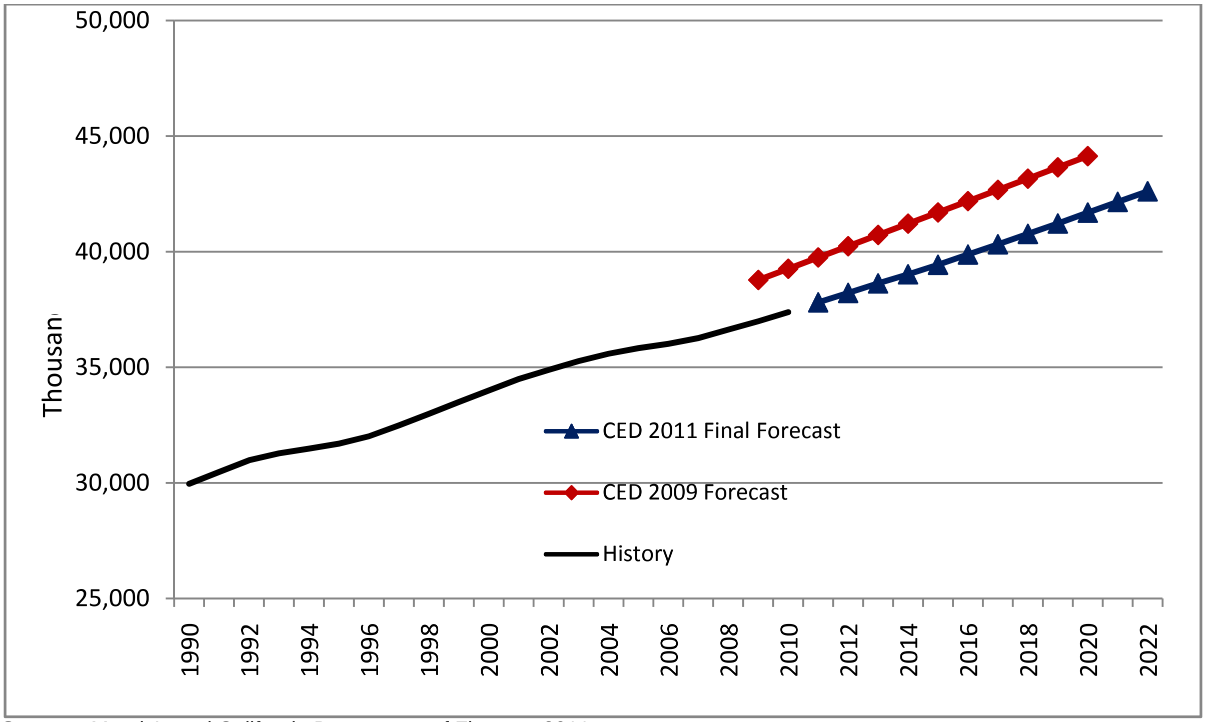
Figure 1-8: Forecasts for Number of Households, Statewide



Source: California Energy Commission, Demand Analysis Office, 2012

Population growth is a key driver for residential energy consumption, as well as for commercial growth and consumption for water pumping and other services. Energy Commission demand forecasts typically use California Department of Finance (DOF) population projections. However, the DOF has not yet updated its long-term population forecast since the 2010 census. Therefore, staff used growth rates from the Moody's population forecast, which has been updated, applied to DOF historical estimates. The DOF historical estimates have been revised downward for the 2000-2010 period, based on 2010 census counts. As shown in **Figure 1-9**, this leads to a lower statewide population forecast compared to *CED 2009.* (Both DOF and Moody's provide only one population scenario.)

Figure 1-9: Historical and Projected Total Statewide Population

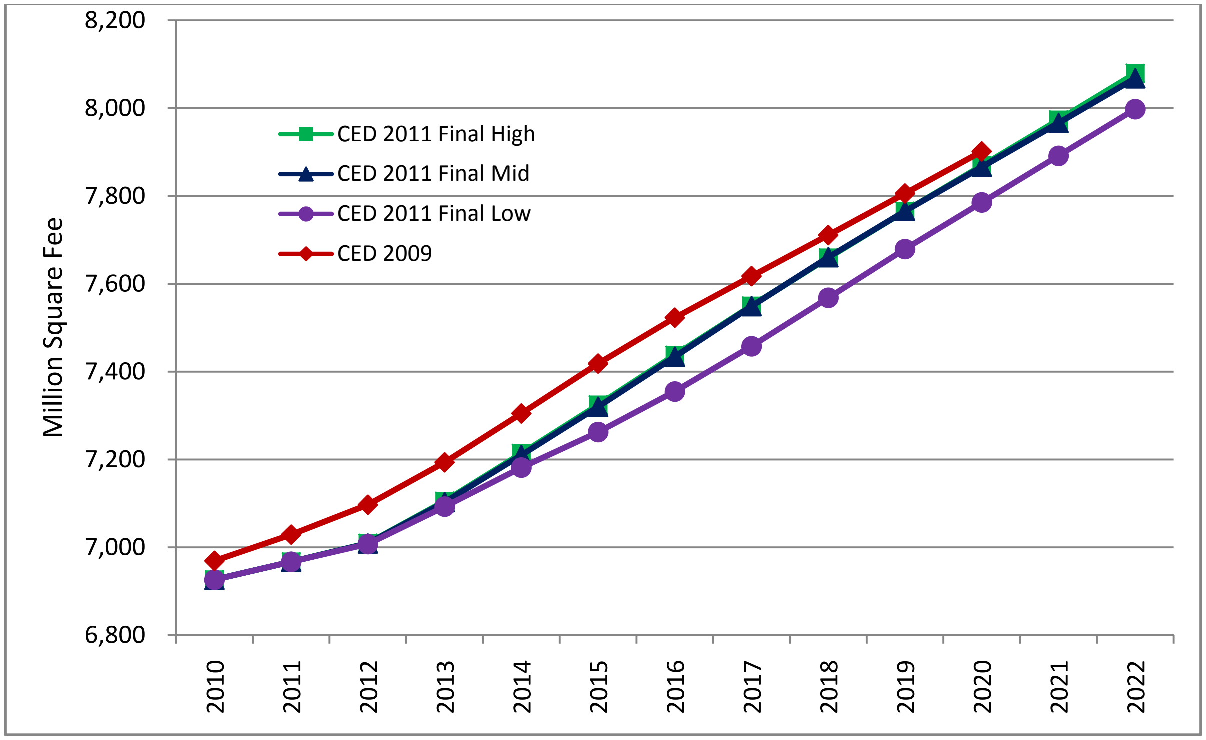


Sources: Moody's and California Department of Finance, 2011

Figure 1-10 compares the floor space projections used for *CED 2011 Final* with those used in *CED 2009*. Since the floor space projections rely heavily on employment, the forecast mirrors **Figure 1-6**, so the three scenario projections remain at or below *CED 2009* through 2020. Projected average annual growth in commercial floor space between 2010 and 2020 is 1.2 percent, 1.3 percent, and 1.3 percent in the low, mid, and high scenarios, compared to 1.25 percent in *CED 2009*.

Appendix C provides additional information on the economic outlook for California and regions within the state.

Figure 1-10: Projected Commercial Floor Space, Statewide



Source: California Energy Commission, Demand Analysis Office, 2012

Electricity and Natural Gas Rate Projections[14]

Natural gas rates were projected using recent Henry Hub price forecasts from the U.S. Energy Information Administration (EIA) and Bentek, as well as Henry Hub[15] futures prices. For the mid demand case, staff used the 2011 EIA *reference case* forecast, with the first three years (2011-2014) replaced by average current futures prices for these years. The low demand scenario used the EIA 2010 *no shale* natural gas price scenario, which assumes no further development of shale reserves beyond what is approved (and therefore higher prices). For the high demand scenario, staff used a first quarter 2011 forecast from Bentek[16] for 2011-2015, with 2016-2022 projections held constant at the 2015 level.

The electricity price forecasts were generated using the Energy and Environmental Economics (E3) calculator.[17] The E3 calculator allows users to create electricity price

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14 Rates are the same as used in the *CED 2011 Preliminary* and *Revised* forecasts.

15 Henry Hub refers to a natural gas pipeline located in Louisiana that serves as the official delivery location for futures contracts on the NYMEX.

16 http://www.bentekenergy.com/ForwardCurveQuarterly.aspx.

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

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 1-16** provides the assumptions used to generate rate growth for each of the three demand scenarios.

Table 1-16: Electricity Price Assumptions by Scenario

Assumption	Low Demand Scenario (Higher Electricity Prices)	Mid Demand Scenario (Mid Electricity Prices)	High Demand Scenario (Lower Electricity Prices)
Efficiency	High CPUC Goals	Mid CPUC Goals	Current Programs Only
Natural Gas Rates	High (EIA *No Shale*)	Mid (EIA *Reference*)	Low (Bentek)
PV	3000 MW by 2020	*2009 IEPR* Forecast Levels	Current Levels
Renewables	33 Percent by 2020	20 Percent by 2020	Current Levels
Demand Response	5 Percent Additional	5 Percent Additional	Current Levels
Combined Heat and Power	Additional 4,300 MW	*2009 IEPR* Forecast Levels	*2009 IEPR* Forecast Levels
Price Regime	Cap and Trade ($30/ton CO_2)	Current	Current

Source: California Energy Commission, Demand Analysis Office, 2011

Resulting percentage growth by year for each scenario from the natural gas and electricity price forecasts was applied to current planning area rates and is shown in **Table 1-7**. In the case of electricity, E3 provided projections for 2012-2020, so staff assumed 2010 rates for 2011 and extrapolated rates for 2021 and 2022 using average growth rates for 2015-2020. Staff used the E3-projected state average for percentage growth for each planning area, except in the case of Los Angeles Department of Water and Power (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 least 10 percent lower those of SCE.[18] Resulting rate projections for each of the five major planning areas are provided in the forms accompanying this report.

18 This assumption is based on the idea that, politically, a municipal utility could not offer rates as high as those of a neighboring investor-owned utility. LADWP rates by sector are provided in the forms accompanying this forecast, and residential rates are projected to increase by 24 percent, 20 percent, and 18 percent in the three scenarios, respectively, over 2010-2022. This assumption of a growth cap resulted in commercial and industrial rates increasing at the same rate as in the other planning areas.

Table 1-17: Growth in Energy Rates, *CED 2011 Final* Forecast

Period	% Change, Low Demand Scenario	% Change, Mid Demand Scenario	% Change, High Demand Scenario
Electricity			
2010-2015	9.6	1.9	-1.8
2010-2020	18.8	8.8	2.3
2010-2022	22.5	13.1	5.8
Natural Gas			
2010-2015	28.0	10.6	-8.6
2010-2020	34.4	19.2	-8.6
2010-2022	38.1	26.3	-8.6

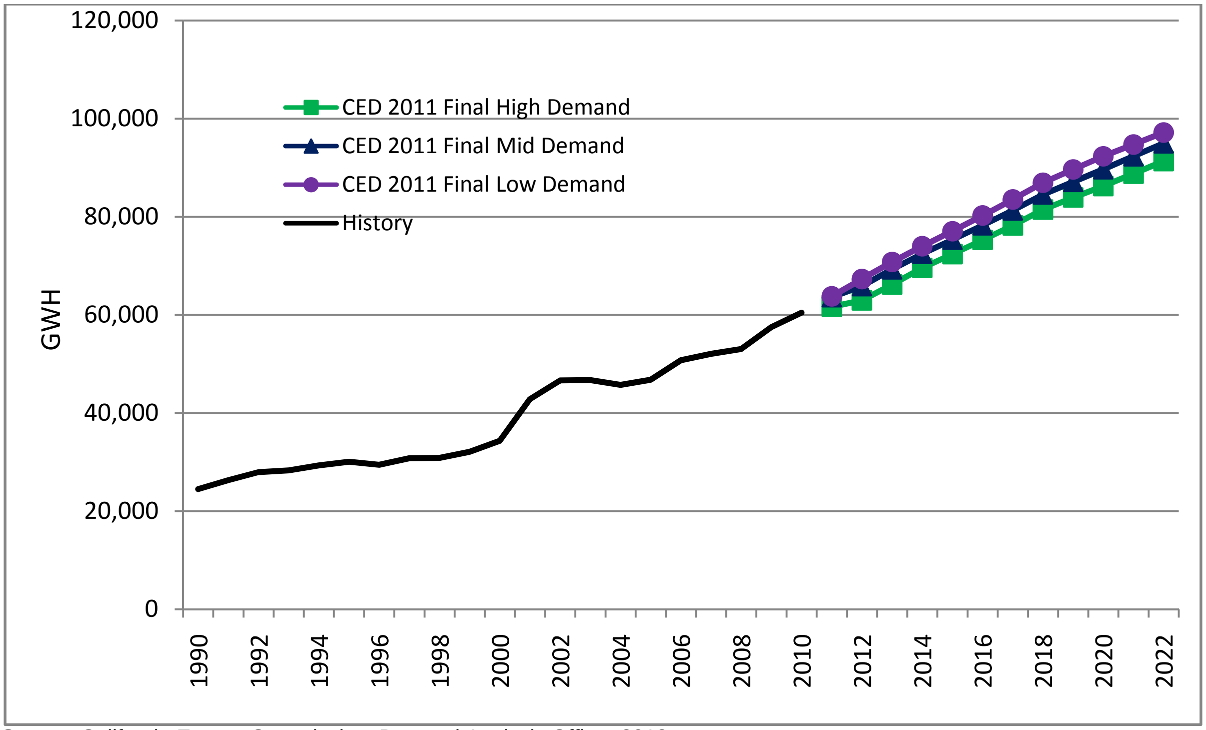
Source: California Energy Commission, Demand Analysis Office, 2011

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 2011 Final* continues that distinction, with only committed efficiency included in *CED 2011 Final.* 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 investor-owned utility (IOU) incentive programs that has been funded by CPUC order). In addition, committed impacts include price and other market effects not directly related to a specific initiative. Chapter 3 details the committed energy efficiency impacts projected for this forecast. Uncommitted efficiency impacts are not estimated for this report; staff analysis for this purpose will follow later in 2012.

Figure 1-11 shows staff estimates of historical and projected committed savings impacts, which include programs, codes and standards (including AB 1109 lighting and television standards savings), and price and other market effects. Projected savings impacts are higher the lower the demand scenario, since price and program effects are inversely related to the demand outcome.

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



Source: California Energy Commission, Demand Analysis Office, 2012

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 (2011) affect the demand forecast.[19] Staff, in consultation with Pacific Gas and Electric Company (PG&E) and SCE staff, identified incremental impacts from current committed programs in these planning areas,

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

which include real-time or time-of-use pricing and permanent load shifting. Incremental impacts are shown in **Table 1-8**.

Table 1-8: Estimated Demand Response Program Impacts Incremental to 2011 (MW)

Year	PG&E	SCE	Total
2012	29	0	29
2013	36	11	47
2014	50	20	70
2015	50	20	70
2016	50	20	70
2017	49	20	69
2018	49	20	69
2019	49	20	69
2020	49	20	69
2021	49	20	69
2022*	49	20	69
*Program cycles end in 2021; 2022 values assumed the same as 2021.			

Source: California Energy Commission, Demand Analysis Office, 2012

Self-Generation

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

- Emerging Renewables Program (ERP). This program is managed by the Energy Commission.
- California Solar Initiative (CSI). This program is managed by the CPUC.
- Self-Generation Incentive Program (SGIP). This program is managed by the CPUC.
- New Solar Homes Partnership (NSHP). This program is managed by the Energy Commission.
- Incentives administered by public utilities such as Sacramento Municipal Utility District (SMUD), LADWP, Imperial Irrigation District, Burbank Water and Power, City of Glendale, and City of Pasadena.

The forecast also accounts for power plants reporting information to the Energy Commission. The principal source is Form CEC 1304, and staff included only power plants that explicitly listed themselves as operating under cogeneration or self-generation mode.

The general strategy of the ERP, CSI, SGIP, and NSHP 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 recently developed by staff, which is 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. Self-generation for other technologies and sectors is projected using a trend analysis and does not vary by demand scenarios. Appendix B provides details on these methods.

Figure 1-12 shows historical and projected peak impacts of self-generation, which are projected to reduce peak load by more than 3,500 MW by 2022 in the mid demand scenario. Higher projections for PV peak impacts (shown in **Figure 1-13)** in both the residential and commercial sectors drive total self-generation peak well above *CED 2009* levels by 2020 in all three scenarios.[20] The temporary flattening of the curve after 2016 corresponds to expiration of the CSI program and the federal tax credit. Most of the difference in PV peak comes from a significant increase in residential adoption, a result from application of the predictive model.[21] **Figure 1-14** shows projected PV peak impacts in the residential sector. Staff is working on a commercial PV predictive model, so future *IEPR* forecasts could show a similar increase in commercial adoption if this model projects adoptions above current trends, as in the residential case. The predictive model also projects residential electricity consumption statewide from solar water heating to reach 250 GWh and 285 GWh in the high and low demand cases, respectively, by 2022.[22]

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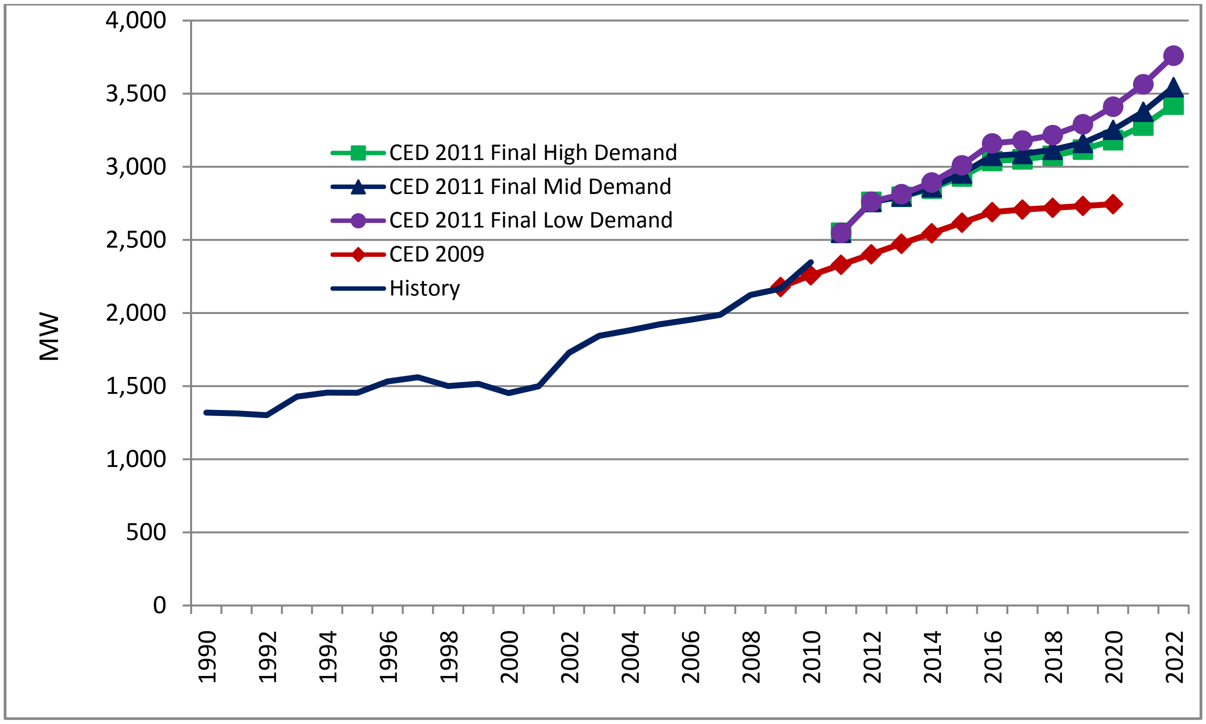
20 In 2015, projected PV peak impacts correspond to capacities of around 1,700 MW, 1,750 MW, and 1,850 MW in the high, mid, and low demand cases, respectively. By 2022, capacities reach around 2,600 MW, 2,800 MW, and 3,150 MW.

21 Previous forecasts have used a trend analysis for residential PV adoption. The predictive model projects growth in adoptions above the historical trend.

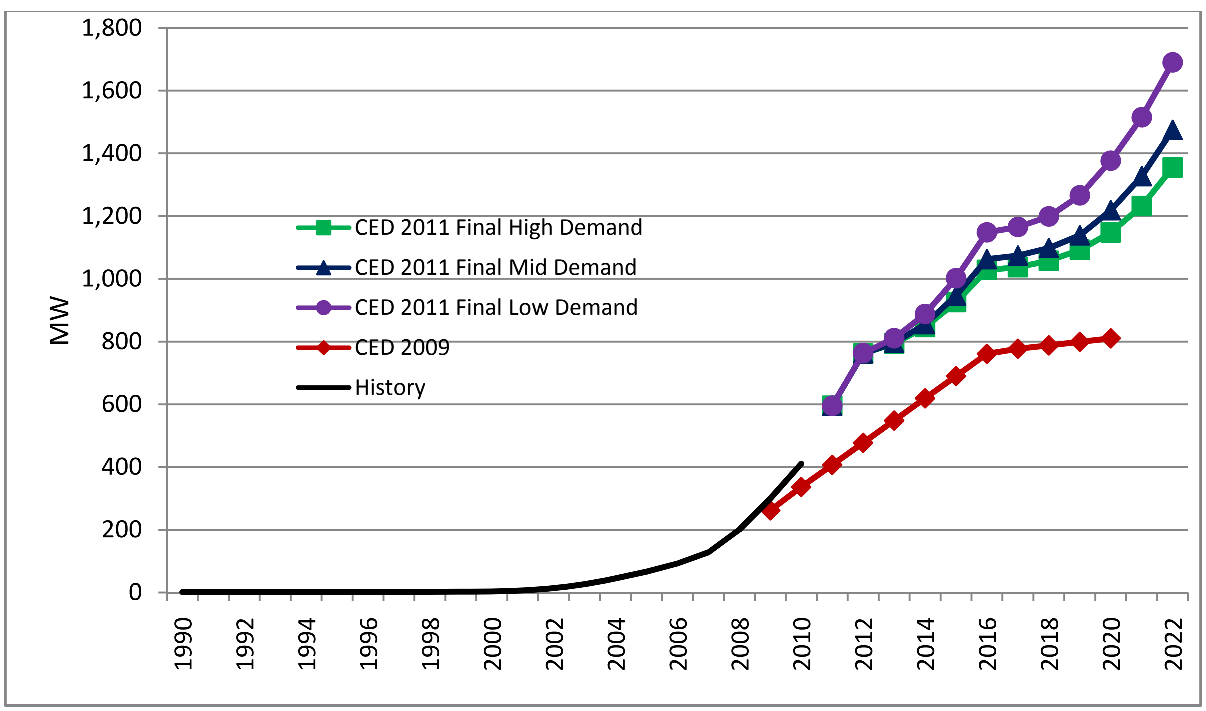
22 "Peak impacts" cannot be defined for this technology.

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



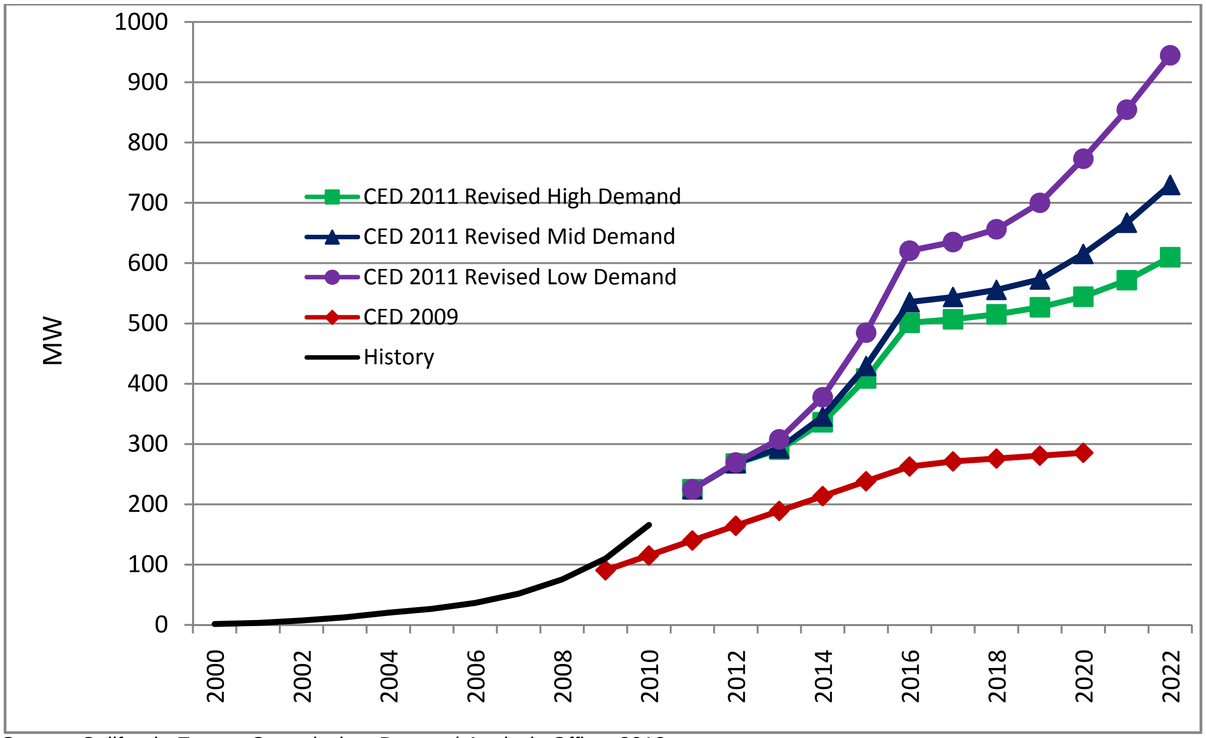
Source: California Energy Commission, Demand Analysis Office, 2012

Figure 1-13: Statewide Peak Impacts of PV Systems



Source: California Energy Commission, Demand Analysis Office, 2012

Figure 1-14: Statewide Peak Impacts of Residential PV Systems



Source: California Energy Commission, Demand Analysis Office, 2012

Table 1-9 shows historical and projected statewide electricity consumption from self-generation, broken out into PV and non-PV applications. For traditional combined heat and power (CHP) technologies, self-generation is assumed constant, 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 historical growth in engines and recent increases in the application of fuel cells projected forward.

Table 1-9: Electricity Consumption From Self-Generation, GWh

	1990	2000	2010	2015	2020	2022
Non-PV Self-Generation, Low Demand	8,258	9,204	12,385	13,244	13,519	13,796
Non-PV Self-Generation, Mid Demand	8,258	9,204	12,385	13,233	13,491	13,762
Non-PV Self-Generation, High Demand	8,258	9,204	12,385	13,227	13,479	13,744
PV, Low Demand	3	10	1,093	3,130	4,429	5,465
PV, Mid Demand	3	10	1,093	2,933	3,870	4,701
PV, High Demand	3	10	1,093	2,858	3,619	4,278
Total Self-Generation, Low Demand	8,261	9,214	13,478	16,374	17,949	19,262
Total Self-Generation, Mid Demand	8,261	9,214	13,478	16,166	17,361	18,464
Total Self-Generation, High Demand	8,261	9,214	13,478	16,085	17,097	18,022

Source: California Energy Commission, Demand Analysis Office, 2012

Electric Light-Duty Vehicles

CED 2011 Final incorporates scenarios for electric vehicle (EV) fuel consumption developed by the Energy Commission's Fuels Office in early 2012, which include both plug-in hybrid (PHEV) and dedicated electric vehicles (BEVs). The low scenario, used for the low energy demand case, is consistent with the revised Zero-Emission Vehicle mandates adopted in January 2012[23] and is based on a "most-likely" compliance case developed for the mandates by California Air Resources Board staff.[24] For this scenario, Fuels Office staff ran its vehicle choice simulation model,[25] adjusting inputs to the model until the number of BEVs and

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23 Further information about California's Zero-Emission Vehicle mandates is available at: http://www.arb.ca.gov/msprog/zevprog/2011zevreg/2011zevreg.htm.

24 The compliance case was presented at the Energy Commission's demand forecasting workshop on February 23, 2012, by Analisa Bevan, Air Resources Board Zero-Emission Vehicle program director. http://www.energy.ca.gov/2012_energypolicy/documents/2012-02-23_workshop/presentations/02_Bevan_ARB_ZEV_Forecasts.pdf.

25 For more information on the vehicle choice and other transportation forecasting methods, see Appendix A of the Fuels Office report for the *2011 IEPR*: http://www.energy.ca.gov/2011publications/CEC-600-2011-007/CEC-600-2011-007-SD.pdf.

PHEVs roughly matched the compliance case in each year. Electricity consumption is calculated in the model using vehicle miles traveled and efficiency predicted for each vehicle type. A high scenario for EVs was developed for the high energy demand case by assuming approximately the same number of BEVs as in the low scenario but allowing the vehicle choice model to predict PHEVs with no change in inputs, resulting in much higher projections for this type of vehicle. A mid scenario was developed as the average (in terms of electricity consumption) of the high and low. **Table 1-10** shows the projected number of BEVs and PHEVs on the road in the high and low scenarios for selected years.

Table 1-10: Projected Number of Electric Vehicles on the Road, *CED 2011 Final*

	High Scenario			Low Scenario		
Year	BEVs	PHEVs	Total EVs	BEVs	PHEVs	Total EVs
2011	7,698	2,701	10,399	7,698	2,284	9,982
2013	18,437	314,122	332,559	18,375	24,738	43,113
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
2022	227,733	3,346,937	3,574,670	235,719	598,770	834,489

Source: California Energy Commission, Demand Analysis Office, 2012

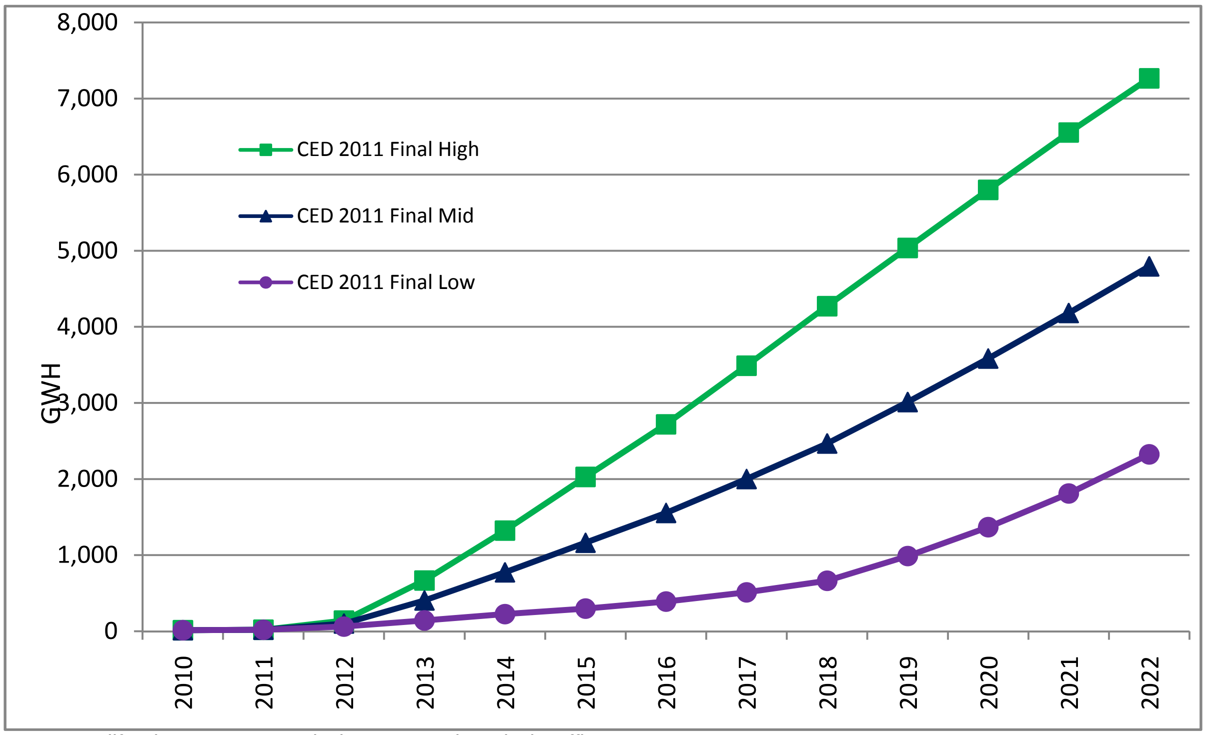
These scenarios provide statewide totals only, so staff needed to distribute the results among the eight planning areas. For this purpose, staff developed shares by first adding electric vehicles registered in each county in 2009[26] (from Department of Motor Vehicles data) and the number of vehicles participating in the California Air Resources Board Clean Vehicle Rebate program in 2010 and 2011. The county numbers were then weighted by average annual miles traveled per vehicle from 2010 California Department of Transportation data.[27] The weighted numbers were then aggregated to the planning area level and divided by statewide weighted totals to give the share of electricity consumption for each planning area. Past demand forecasts have used total (all fuel type) DMV registrations to develop planning area shares; the method used for this forecast is meant to capture some of the geographic differences specific to EV ownership. For example, very few EVs have been purchased in the Imperial Irrigation District planning area, presumably because of its rural nature and EV range limitations. This area therefore was assigned a lower share relative to one using total vehicle registrations. The SDG&E planning area, where EVs have been promoted heavily (and is more urban), was assigned a relatively high share.

26 The most recent year available to the Fuels Office.

27 This adjustment was made to account for varying driving behavior among counties. For example, average miles traveled are generally higher in Southern California counties.

Figure 1-15 shows projected statewide electricity consumption for EVs for all three scenarios, which reaches around 2,200 GWh by 2020 in the low case and more than 7,000 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.

Figure 1-15: Statewide Electric Vehicle Consumption

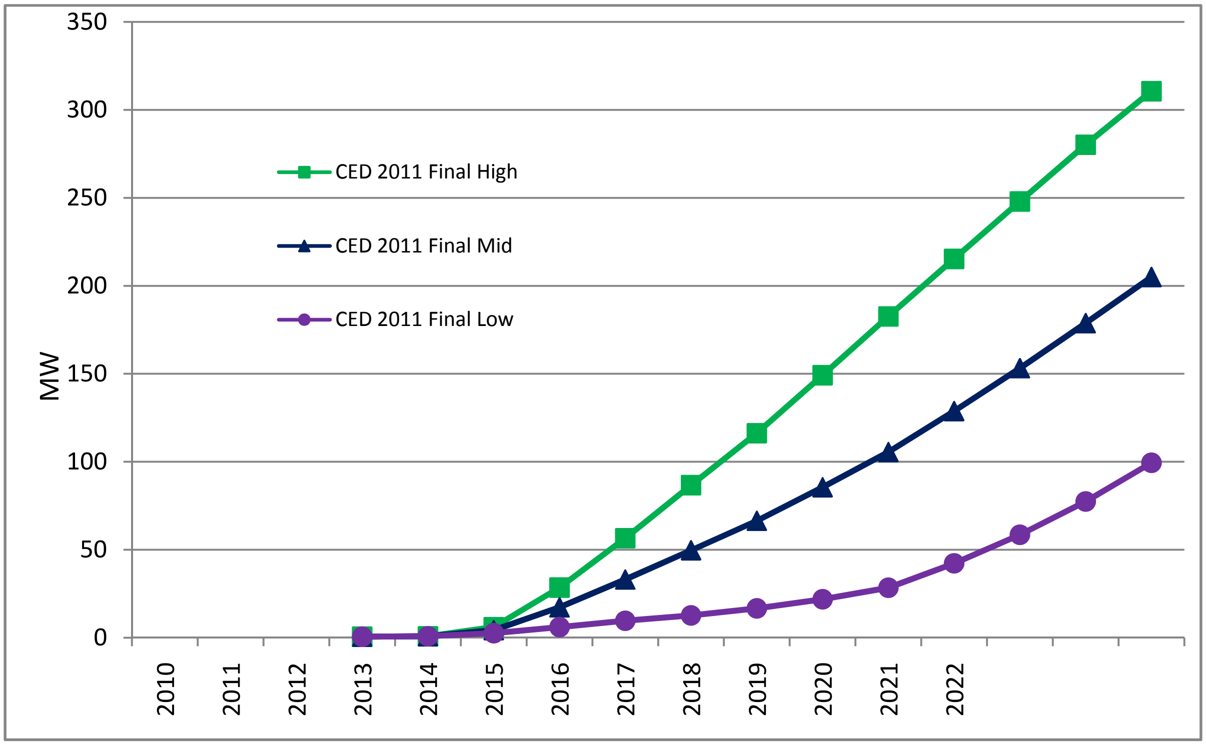


Source: California Energy Commission, Demand Analysis Office, 2012

To translate consumption to peak demand, as in *CED 2009*, 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.[28] 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 because of recharging assumptions, and EVs provide a slight increase to the statewide load factor.

28 This is consistent with "reference case" assumptions made in a recent Electric Power Research Institute study, *Environmental Assessment of Plug-in Hybrid Electric Vehicles, Volume 1: Nationwide Greenhouse Gas Emissions*, Electric Power Research Institute, July 2007.

Figure 1-16: Statewide Electric Vehicle Peak Demand



Source: California Energy Commission, Demand Analysis Office, 2012

Additional Electrification

As discussed earlier in this chapter, additional[29] electrification impacts in the ports and for other equipment were projected and added to electricity consumption in the SCE planning area. Staff plans a more comprehensive analysis of electrification in future forecasts, building on preliminary discussions of electrification potential in the Demand Analysis Working Group.[30] Included in this potential is high-speed rail. Staff did not include estimates of electricity usage by high-speed rail for this forecast, since the California High Speed Rail Authority recently revised its business plan,[31] and this plan is still at the draft stage.[32]

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29 Beyond that assumed in *CED 2011 Revised*.

30 See page 61 for further description of this working group.

31
http://www.cahighspeedrail.ca.gov/uploadedFiles/Document_Repository/Business_Plans/Draft%20Revised%202012%20Business%20Plan%282%29.pdf.

32 As an indication of the magnitude of electricity consumption by HSR, the Fuels Office of the Energy Commission provided a preliminary projection of statewide usage, based on the previous HSR business plan, of around 2,500 GWH in 2022, increasing to almost 3,000 GWH in 2030.

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 2011 Final*, staff incorporated the most recent projections for light-duty natural gas vehicles from the transportation energy demand forecast in support of the *2011 IEPR*.[33] The penetration of light-duty natural gas vehicles is forecast using the Fuels Office's vehicle choice simulation model, where these vehicles compete with other fuel types, including gasoline, electric (dedicated and plug-in hybrids vehicles), diesel, and ethanol. There is currently no policy mandate to directly incentivize the production of more natural gas vehicles, so penetration of these vehicles in the light-duty sector is relatively low compared to other alternative fuel technologies. Fuel consumption was distributed to the three major planning areas in a manner similar to that used for electric vehicles: Shares were determined by the number of registered light-duty vehicles in each area, weighted by average vehicle miles traveled. **Table 1-11** shows forecast natural gas vehicle consumption by major natural gas planning area and statewide for selected years.[34]

Table 1-11: *CED 2011 Final* Natural Gas Consumption by Light-Duty Vehicles (MM therms)

Year	PG&E	Southern California Gas	SDG&E	Total
2010	5.38	6.40	1.00	12.78
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
2022	42.41	50.41	7.93	100.74

Source: California Energy Commission, Demand Analysis Office, 2012

Subregional Electricity Analysis

To support subregional electricity system analysis for CPUC/California ISO resource adequacy and other proceedings, staff disaggregates, or separates, the planning area forecasts to correspond to control areas and congestion zones. These forecasts, for both consumption and peak demand, are provided in spreadsheet files (Form 1.5) in the forms accompanying this forecast report.

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 sub-

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

34 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; staff used the "low" forecast.

areas, using regression analysis and the latest hourly load data available. The regression results provide weather sensitivity for a reference year (in this case, 2011) 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 out in a manner consistent with the demand forecasts for the appropriate planning area.[35] 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.[36] Regression results for this analysis are provided in Appendix D.

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 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 continues to be undermined by LSE data coding errors, lack of adherence to regulations by some LSEs, and failure to provide economic classification for some of the data. However, unclassified consumption has declined significantly in recent years. From a high of almost 20,000 GWh in 2003, unclassified energy use dropped to fewer than 6,000 GWh in 2010, a result of reporting obligations revised in 2006 that now require IOUs to provide an economic classification for direct access customers. Staff allocated remaining unclassified consumption to economic sectors using professional judgment, relying on factors such as unrealistic changes in historical consumption.

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 adjustments to existing models, incorporation of climate change, self-generation, and regression results. Volume II provides *CED 2011 Final* electricity forecasts for the following planning areas: PG&E, SCE, SDG&E,

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

36 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.

SMUD, and LADWP, in that order. The planning areas included in this forecast are described in **Table 1-12**.

In addition, forecast demand forms for each planning area are posted[37] with this report, along with an attachment to this report written by a panel of outside technical experts. The attachment provides an initial assessment of current Energy Commission forecasting models as well as recommendations for future improvements in forecasting methodology.

Table 1-12: Utilities Within Forecasting Areas

Planning Area	Utilities Included
Electric Areas	
PG&E	PG&E Alameda Biggs Calaveras Gridley Healdsburg Hercules Lassen Lodi Lompoc Merced Modesto Palo Alto Plumas – Sierra Port of Oakland Port of Stockton PWRPA Redding Roseville San Francisco Shasta Silicon Valley Tuolumne Turlock Irrigation District Ukiah USBR-Central Valley Project
SMUD	SMUD
SCE	Anaheim Anza Azusa Banning Bear Valley Colton Corona Metropolitan Water District Moreno Valley Rancho Cucamonga Riverside SCE USBR-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, 2012

37 At http://www.energy.ca.gov/2012_energypolicy/documents/index.html#no-meeting.

CHAPTER 2:
End-User Natural Gas Demand Forecast

This chapter presents final 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 the "other" are provided in the natural gas forms accompanying this forecast report.

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. Unlike the electricity forecast, new econometric models have not been estimated for natural gas demand. 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 2011 Final incorporates historical consumption data up through 2010. 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 2011 Final* demand scenarios at the statewide level with *CED 2009* for selected years. The new forecasts begin at a higher point in 2010, as natural gas consumption in California was substantially higher in this year than was predicted in *CED 2009* and grows at a faster rate in the mid case from 2010-2020. This results mainly from higher projected demand in the industrial sector versus *CED 2009*. Growth in the high demand scenario is lower than in the mid case because of Global Insight's lower forecast for mining and construction in the Southern California Gas service territory. Sector results are discussed further in the planning area sections that follow.

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

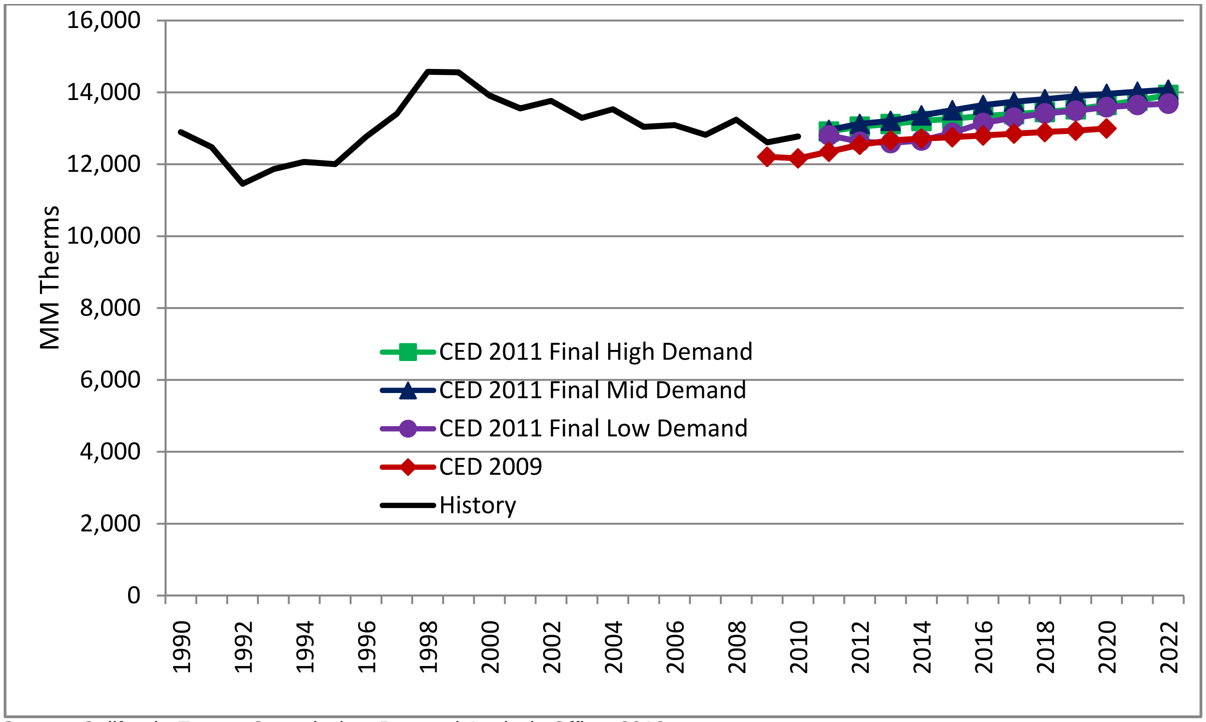
Consumption (MM Therms)				
	CED 2009	*CED 2011 Final High Energy Demand*	*CED 2011 Final Mid Energy Demand*	*CED 2011 Final Low Energy Demand*
1990	12,893	12,893	12,893	12,893
2000	13,913	13,913	13,913	13,913
2010	12,162	12,774	12,774	12,774
2015	12,751	13,265	13,503	12,877
2020	12,997	13,648	13,961	13,588
2022	--	13,929	14,075	13,688
	Average Annual Growth Rates			
1990-2000	0.76%	0.76%	0.76%	0.76%
2000-2010	-1.34%	-0.85%	-0.85%	-0.85%
2010-2015	0.95%	0.76%	1.12%	0.16%
2010-2020	0.67%	0.66%	0.89%	0.62%
2010-2022	--	0.72%	0.81%	0.58%
Historical values are shaded				

Source: California Energy Commission, Demand Analysis Office, 2012

Figure 2-1 shows the forecasts. By 2020, because of the higher starting point in 2010, demand in the mid case is projected to be around 7.4 percent higher and around 4.5 percent higher in the low case compared to the 2009 forecast. Growth rates for total demand are lower compared to electricity, reflecting a historical trend that is flat or declining for most of the previous decade, an indication of the effectiveness of building codes and standards (discussed further in Chapter 3).

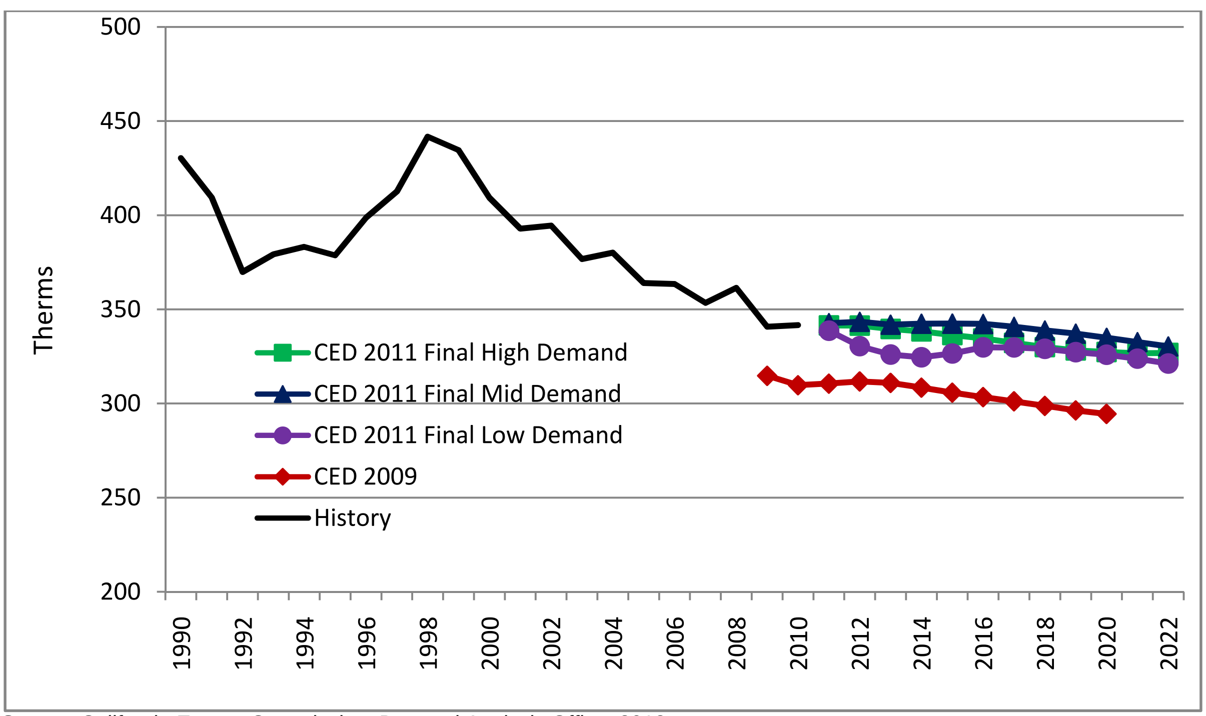
Figure 2-2 compares *CED 2011 Final* projected per capita natural gas consumption with *CED 2009*. Annual per capita demand varies in response to annual temperatures and business conditions but has been declining since the late 1990s. This trend is projected to continue in all four forecasts as population is projected to grow faster than total natural gas demand. Per capita consumption in all three scenarios is higher in 2010 than projected in *CED 2009* due to higher total consumption combined with a downward adjustment to California's population estimates based on the latest census.

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



Source: California Energy Commission, Demand Analysis Office, 2012

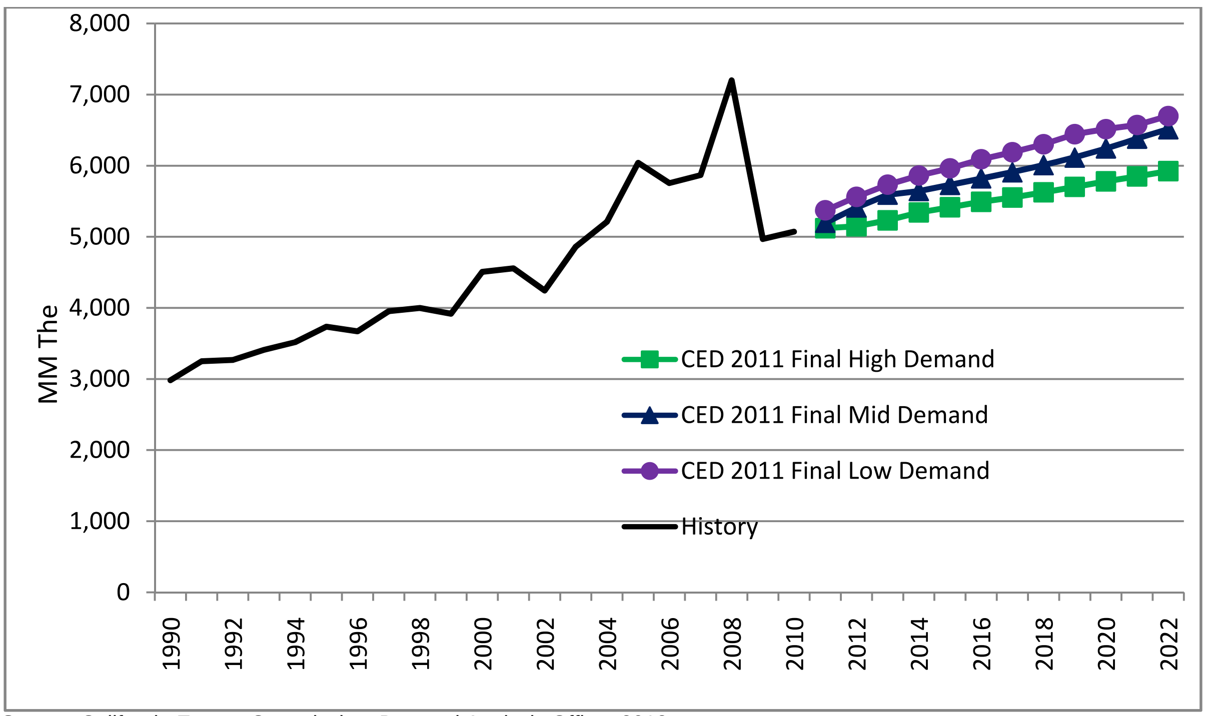
Figure 2-2: Statewide End-User Per Capita Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2012

Figure 2-3 shows estimated historical and forecast impacts of committed efficiency on state natural gas consumption from building and appliance standards, utility and public agency programs, and price and other effects, or savings associated with rate changes and certain market trends not directly related to programs or standards. Savings are measured against a 1975 baseline, so they incorporate more than 30 years of impacts from rate changes and standards. Projected savings impacts are higher the lower the demand scenario, since price and program effects are inversely related to the demand outcome. The large increase in impacts seen in 2008 comes from a sharp rise in natural gas prices. In 2022, accumulated efficiency impacts are expected to correspond to around a 32 percent decrease in consumption in the mid demand case relative to use, assuming no efficiency impacts since 1975.

Figure 2-3: State Natural Gas Consumption Efficiency Impacts



Source: California Energy Commission, Demand Analysis Office, 2012

Planning Area Results

This section presents forecasting results for each of the three 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 final PG&E planning area forecasts with *CED 2009*. As in the statewide case, the new forecasts begin at a higher level and grow at a faster rate in the mid and high scenarios. By 2020, demand is almost 17 percent higher in the high case and 11 percent higher in the low case compared to *CED 2009*.

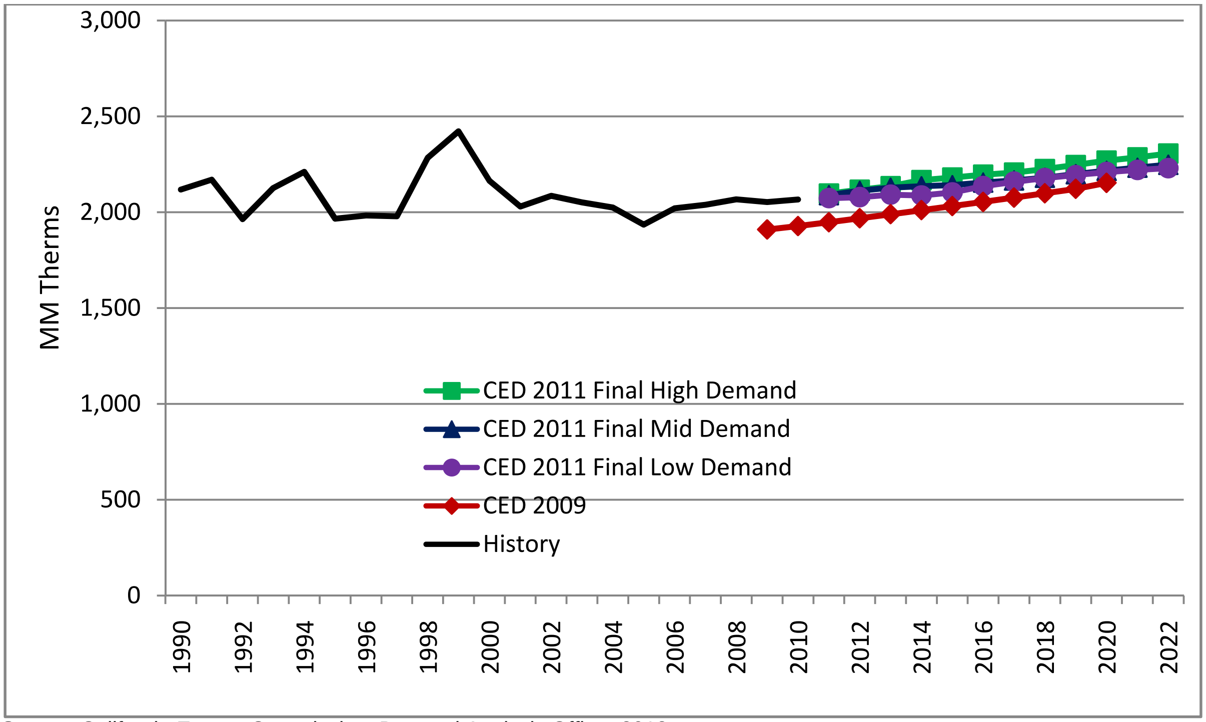
Table 2-2: PG&E Natural Gas Forecast Comparison

Consumption (MM Therms)				
	CED 2009	*CED 2011 Final High Energy Demand*	*CED 2011 Final Mid Energy Demand*	*CED 2011 Final Low Energy Demand*
1990	5,275	5,275	5,275	5,275
2000	5,291	5,291	5,291	5,291
2010	4,186	4,643	4,643	4,643
2015	4,315	4,866	4,862	4,616
2020	4,388	5,133	5,035	4,877
2022	--	5,267	5,081	4,908
	Average Annual Growth Rates			
1990-2000	0.03%	0.03%	0.03%	0.03%
2000-2010	-2.31%	-1.30%	-1.30%	-1.30%
2010-2015	0.61%	0.95%	0.93%	-0.11%
2010-2020	0.47%	1.01%	0.81%	0.49%
2010-2022	--	1.06%	0.75%	0.46%
Historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2012

Figure 2-4 compares *CED 2011 Final* and *CED 2009* PG&E residential forecasts. The new forecasts are higher throughout the entire forecast period as actual consumption recorded in 2010 was higher than predicted in *CED 2009*. Average annual growth from 2010-2020 in all three scenarios (0.94, 0.70, and 0.68 percent, respectively, for the high, mid, and low cases) is slower versus *CED 2009* (1.11 percent), reflecting the effect of higher natural gas rates in the mid and low scenarios and updated natural gas efficiency program impacts.

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

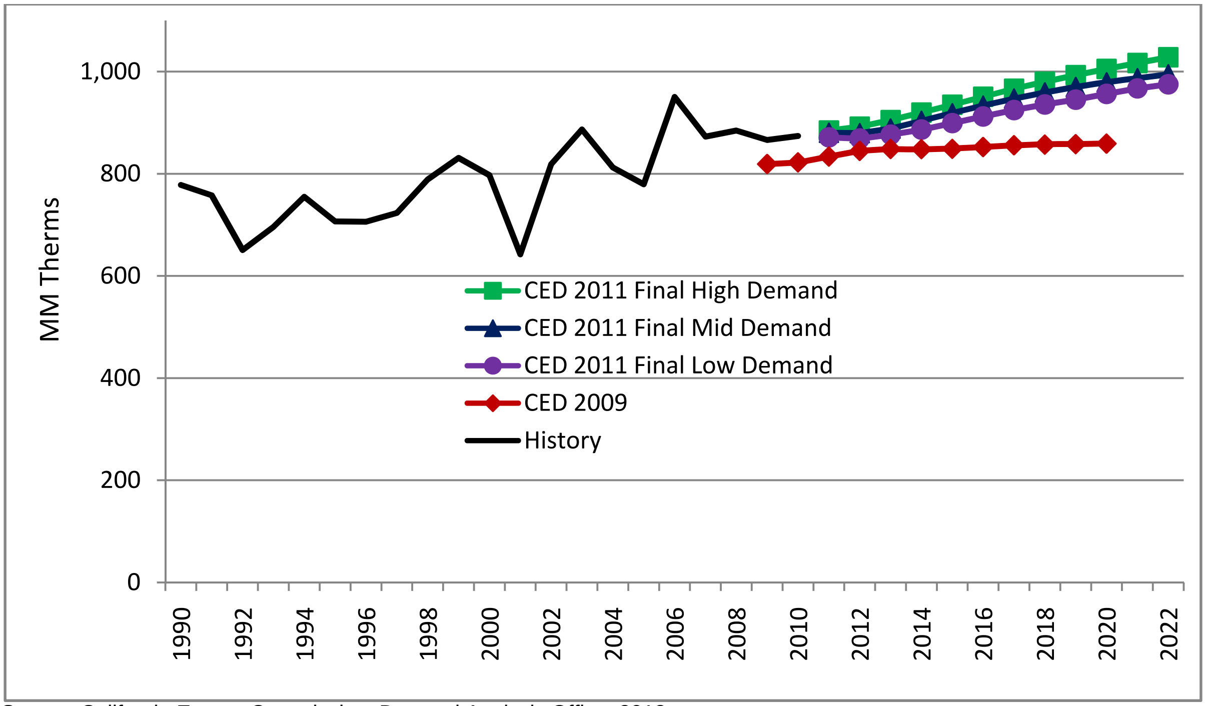


Source: California Energy Commission, Demand Analysis Office, 2012

Figure 2-5 and **Figure 2-6** show the forecasts for the PG&E commercial and industrial sectors. Faster growth in all three demand scenarios for projected floor space in the commercial sector and manufacturing output[38] in the industrial sector yield faster growth in gas demand compared to *CED 2009*. A higher 2010 starting point for *CED 2011 Final* in both sectors, combined with faster demand growth, results in projected 2020 demand 14 percent higher than *CED 2009* in the commercial mid case and 38 percent higher in the industrial mid case.

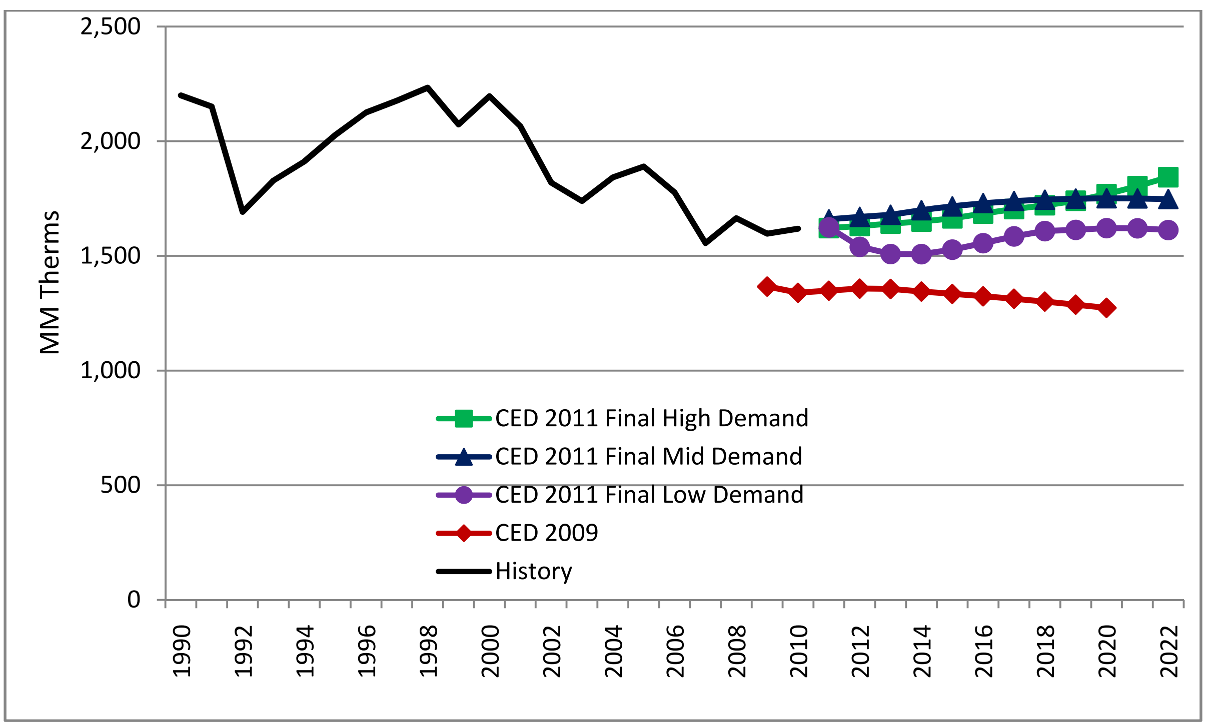
38 The faster growth in manufacturing output in the mid case versus *CED 2009* (which also relied on Moody's *baseline* scenario) comes from a lower starting point in 2010, increasing to roughly the same output as in the 2009 forecast by 2020.

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



Source: California Energy Commission, Demand Analysis Office, 2012

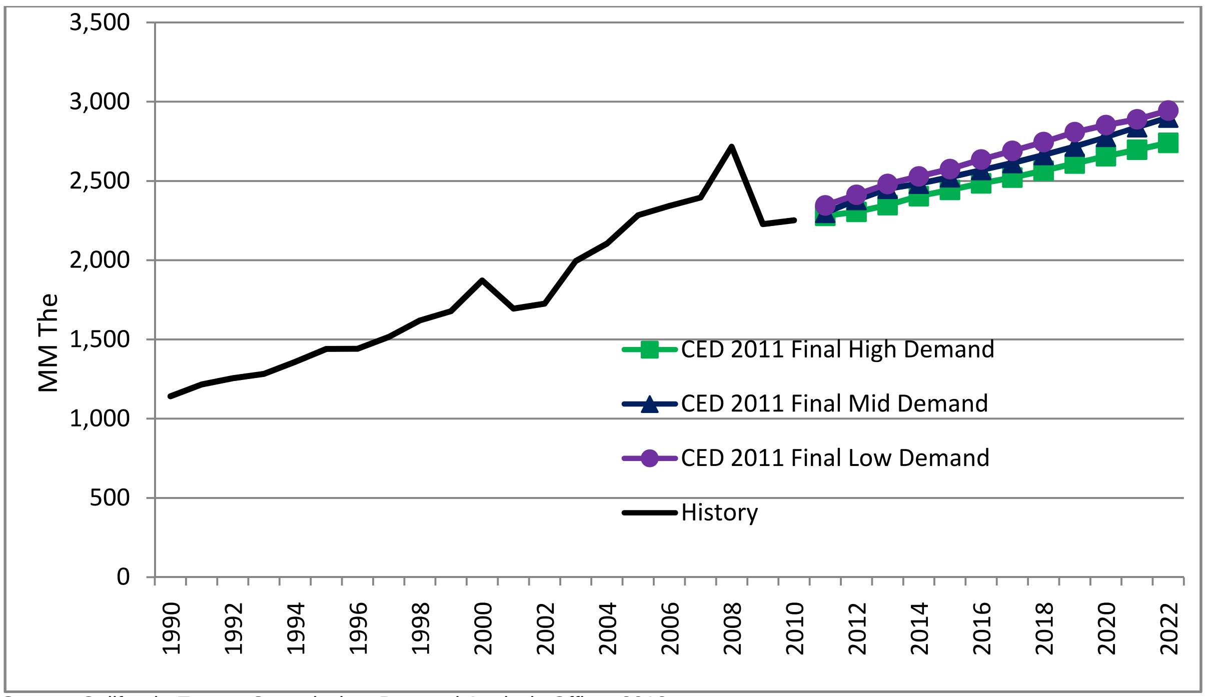
Figure 2-6: PG&E Planning Area Industrial Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2012

Figure 2-7 shows estimated historical and forecast impacts of committed efficiency on PG&E natural gas consumption from building and appliance standards, utility and public agency programs, and price and other effects. Projected savings impacts are higher the lower the demand scenario, since price and program effects are inversely related to the demand outcome. The large increase in impacts seen in 2008 comes from a sharp rise in natural gas prices. In 2022, accumulated efficiency impacts are expected to correspond to around a 37 percent decrease in consumption in the mid demand scenario relative to use, assuming no efficiency impacts since 1975.

Figure 2-7: PG&E Planning Area Natural Gas Consumption Efficiency Impacts



Source: California Energy Commission, Demand Analysis Office, 2012

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 2011 Final* SoCalGas planning area forecasts with *CED 2009*. Average annual gas demand growth from 2010-2020 is above that of *CED 2009* for the mid demand scenarios and below for the high and low scenarios. The lower growth in the high demand scenario comes from a sharp projected decline in Global Insight's forecast of the resource extraction and construction sector (discussed further below). A higher starting point in 2010 is enough to keep total gas demand above the *CED 2009* level in 2020 in the mid and low cases.

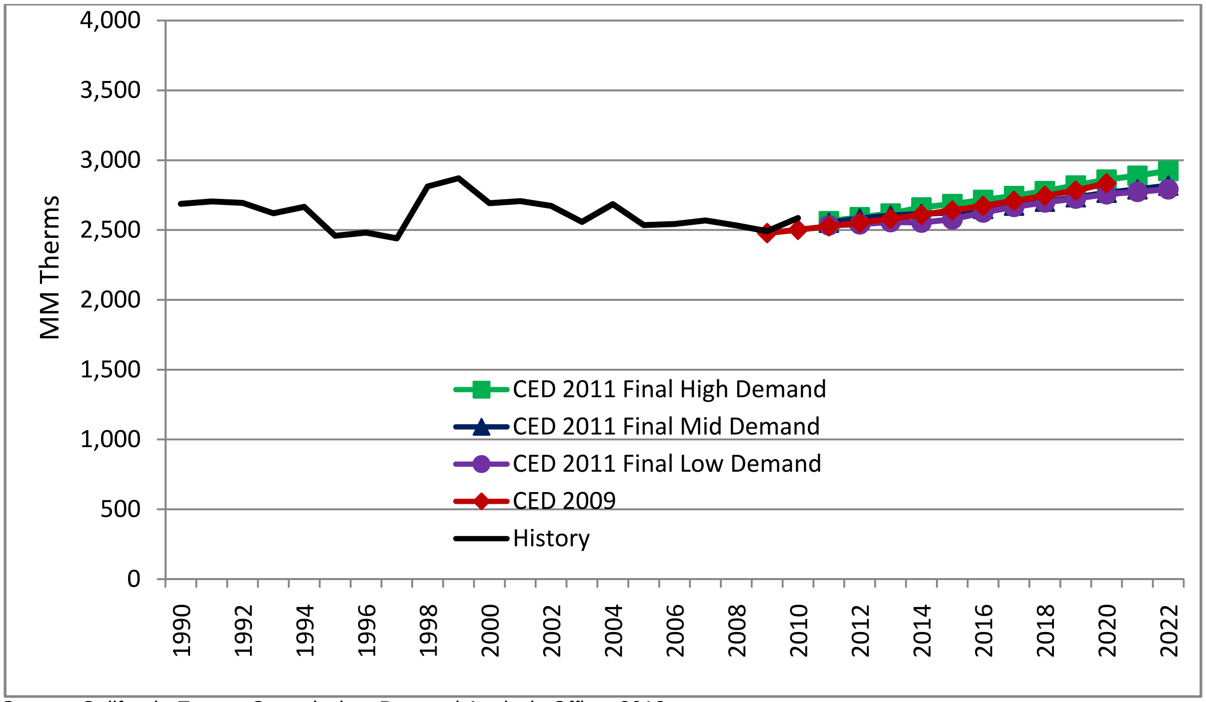
Table 2-3: SoCalGas Natural Gas Forecast Comparison

Consumption (MM Therms)				
	CED 2009	*CED 2011 Final High Energy Demand*	*CED 2011 Final Mid Energy Demand*	*CED 2011 Final Low Energy Demand*
1990	6,806	6,806	6,806	6,806
2000	7,938	7,938	7,938	7,938
2010	7,290	7,431	7,431	7,431
2015	7,698	7,632	7,889	7,527
2020	7,829	7,681	8,109	7,905
2022	--	7,798	8,153	7,951
	Average Annual Growth Rates			
1990-2000	1.55%	1.55%	1.55%	1.55%
2000-2010	-0.85%	-0.66%	-0.66%	-0.66%
2010-2015	1.10%	0.54%	1.20%	0.26%
2010-2020	0.72%	0.33%	0.88%	0.62%
2010-2022	--	0.40%	0.78%	0.57%
Historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2012

Figure 2-8 compares *CED 2009* and *CED 2011 Final* SoCalGas residential forecasts. The new forecasts grow more slowly from 2010-2020 (average annual growth of 1.01, 0.68, and 0.64 percent, respectively, in the high, mid, and low scenarios) versus *CED 2009* (1.25 percent), a result of faster projected natural gas rate growth in the mid and high cases and a decline in demand from 2010 to 2011 in all three scenarios due to the economy.

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

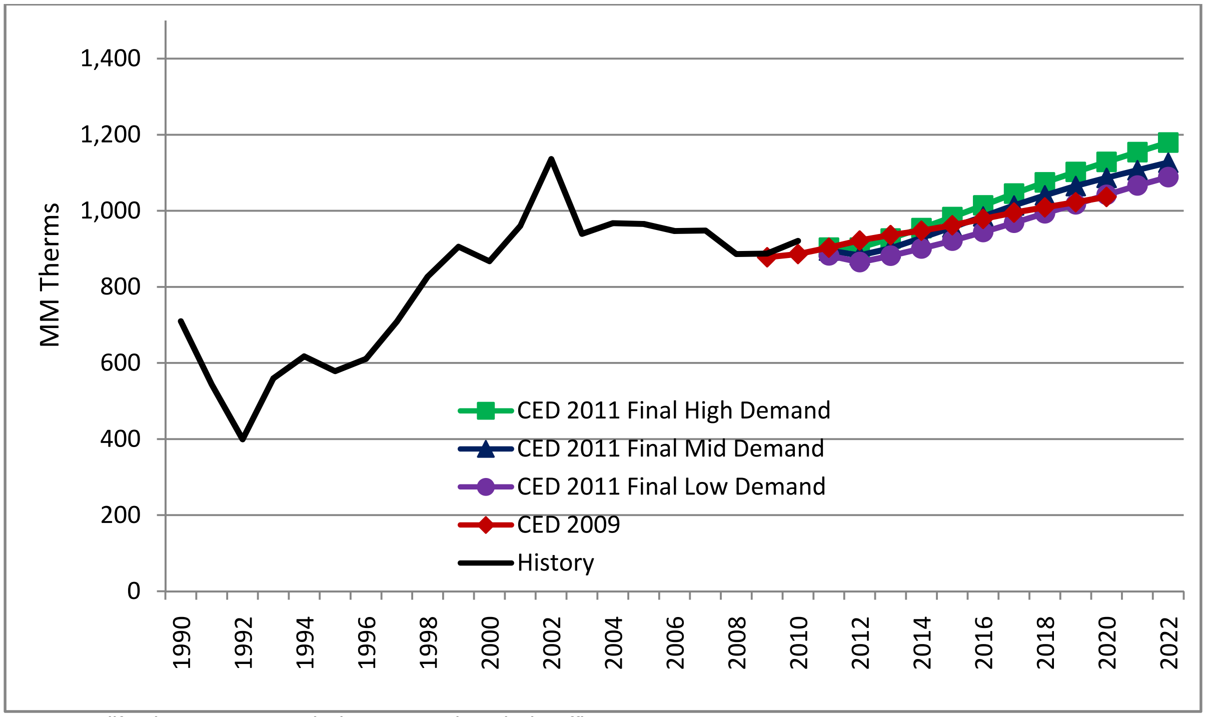


Source: California Energy Commission, Demand Analysis Office, 2012

Figure 2-9 and **Figure 2-10** show the forecasts for the SoCalGas commercial and industrial sectors, respectively. As the economy is projected to recover in 2012 and beyond, natural gas demand is forecast to increase at a faster rate from 2012-2020 compared to *CED 2009*. By 2020, demand is projected to be almost 9 percent higher in the high demand scenario and almost 5 percent higher in the mid case versus *CED 2009*.

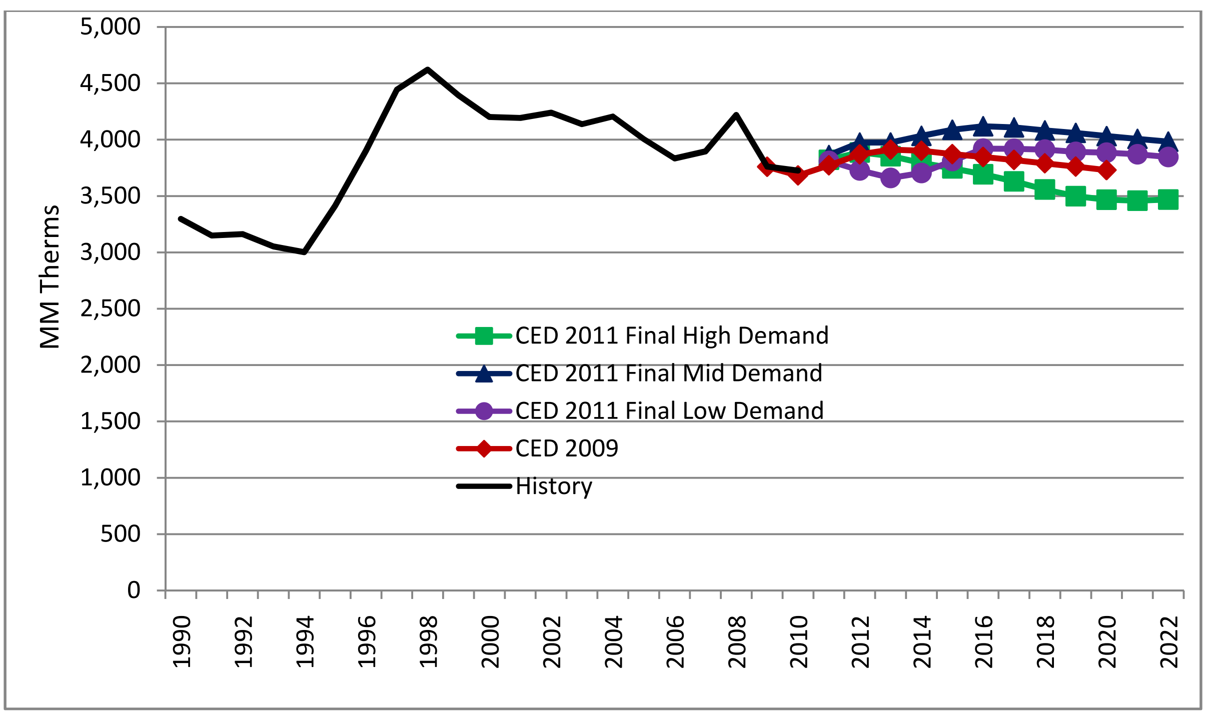
The projections for industrial output growth reflect an expected long-term decline in this sector in the Los Angeles region after recovery in the next few years. Resource extraction, a significant portion of gas demand in the SoCalGas service territory, is projected to decline at a faster rate in the high demand case than in the mid and low, so projected gas demand in the high case is lower than in the other two demand scenarios by 2013.

Figure 2-9: SoCalGas Planning Area Commercial Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2012

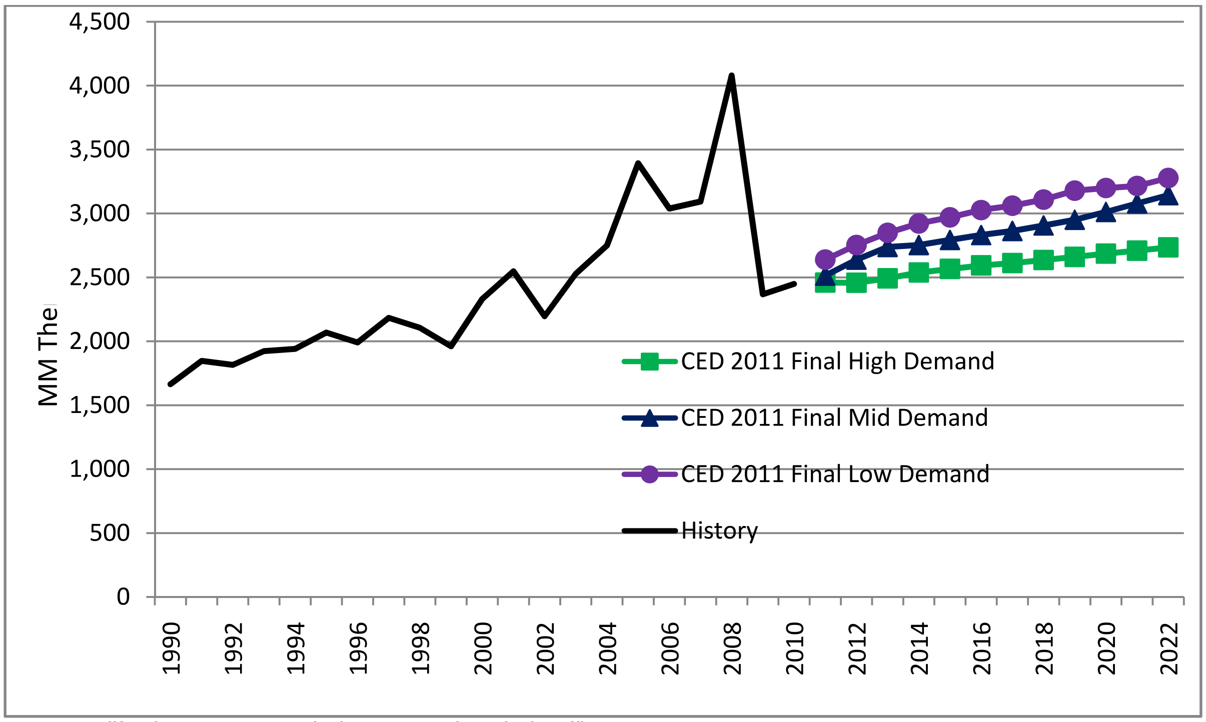
Figure 2-10: SoCalGas Planning Area Industrial Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2012

Figure 2-11 shows estimated historical and forecast impacts of committed efficiency on SoCalGas natural gas consumption from building and appliance standards, utility and public agency programs, and price and other effects. Projected savings impacts are higher the lower the demand scenario, since price and program effects are inversely related to the demand outcome. The large increase in impacts seen in 2008 comes from a sharp rise in natural gas prices. In 2022, accumulated efficiency impacts are expected to correspond to around a 29 percent decrease in consumption in the mid demand scenario relative to use, assuming no efficiency impacts since 1975.

Figure 2-11: SoCalGas Planning Area Natural Gas Consumption Efficiency Impacts



Source: California Energy Commission, Demand Analysis Office, 2012

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 2011 Final* SDG&E planning area forecasts with *CED 2009*. The new forecasts begin at a higher level and grow at a faster rate from 2010-2020 in all three scenarios. By 2020, demand is more than 11 percent higher in the high case and around 7.5 percent higher in the low case compared to *CED 2009*.

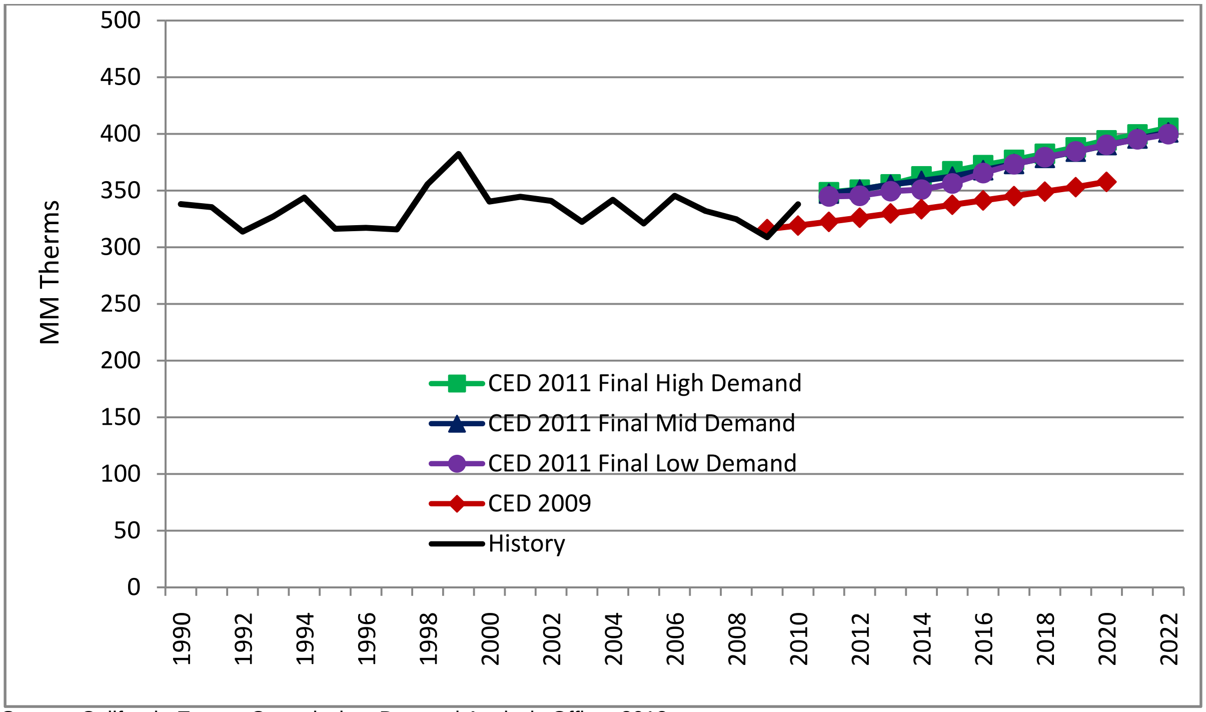
Table 2-4: SDG&E Natural Gas Forecast Comparison

Consumption (MM Therms)				
	CED 2009	*CED 2011 Final High Energy Demand*	*CED 2011 Final Mid Energy Demand*	*CED 2011 Final Low Energy Demand*
1990	717	717	717	717
2000	565	565	565	565
2010	531	561	561	561
2015	574	620	609	594
2020	611	680	665	657
2022	--	705	686	677
	Average Annual Growth Rates			
1990-2000	-2.35%	-2.35%	-2.35%	-2.35%
2000-2010	-0.64%	-0.08%	-0.08%	-0.08%
2010-2015	1.60%	2.02%	1.67%	1.15%
2010-2020	1.43%	1.94%	1.72%	1.59%
2010-2022	--	1.93%	1.70%	1.58%
Historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2012

Figure 2-12 compares *CED 2009* and *CED 2011 Final* SDG&E residential forecasts. The new forecasts are higher throughout the entire forecast period as actual consumption recorded in 2010 was higher than predicted in *CED 2009*. Faster projected growth in number of households in all three demand scenarios and as well as income in the mid and high cases versus *CED 2009* push 2010-2020 demand growth rates in the high, mid, and low scenarios (1.56 percent, 1.45 percent, and 1.45 percent, respectively) above that projected in *CED 2009* (1.15 percent).

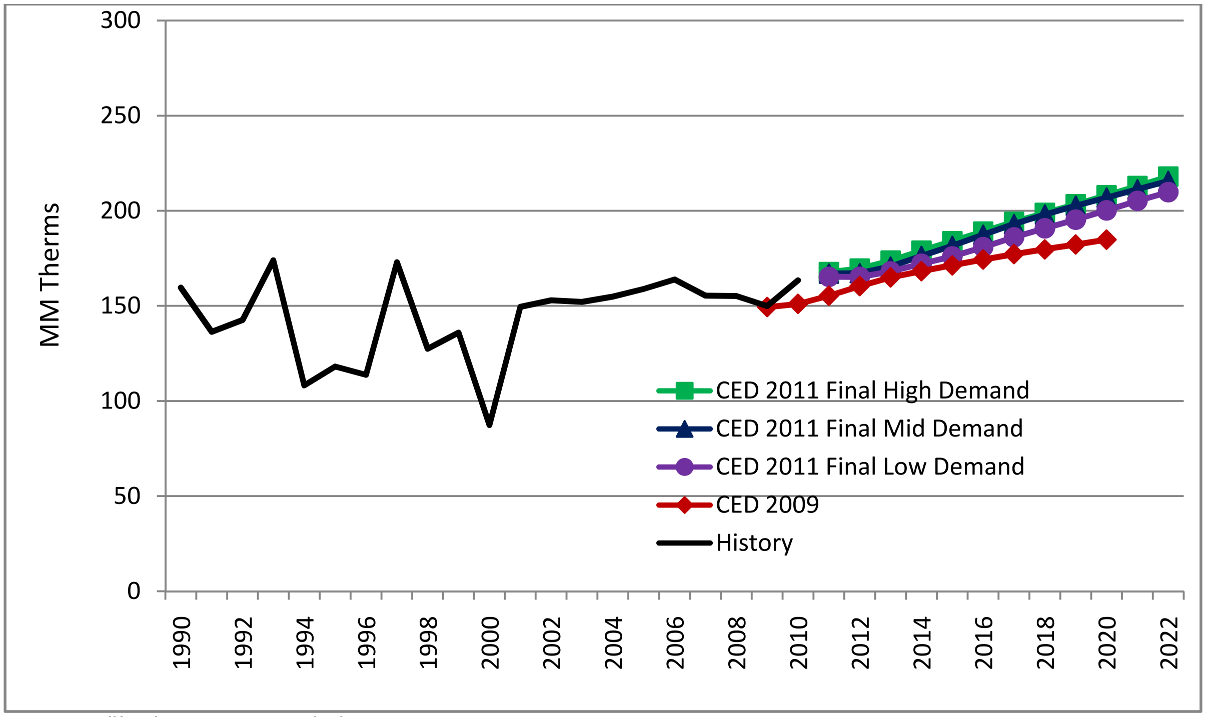
Figure 2-12: SDG&E Planning Area Residential Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2012

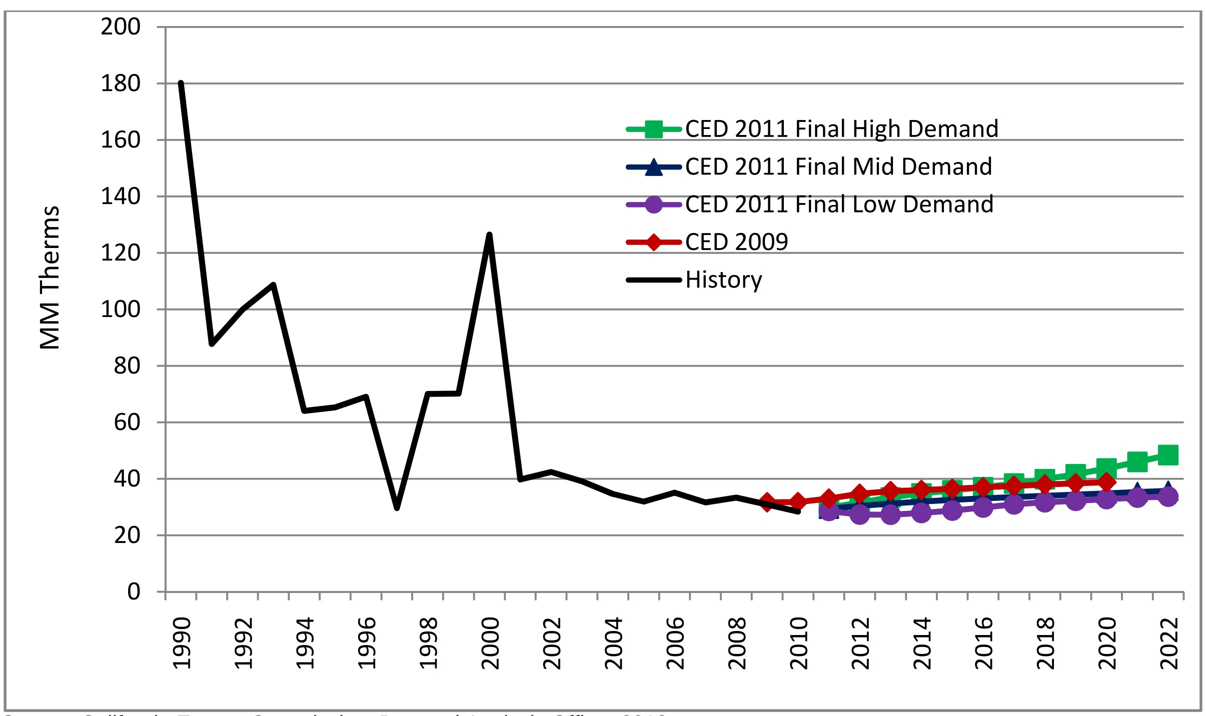
Figure 2-13 and **Figure 2-14** show the forecasts for the SDG&E commercial and industrial sectors. Faster growth in all three demand scenarios for projected floor space in the commercial sector and manufacturing output in the industrial sector yield faster growth in gas demand compared to *CED 2009* in all three cases. Projected 2020 demand is almost 12 percent higher than *CED 2009* in the commercial mid case. The new industrial demand forecasts begin at a lower point in 2010, so only the high case yields higher demand in 2020 versus *CED 2009*.

Figure 2-13: SDG&E Planning Area Commercial Natural Gas Consumption



Source: California Energy Commission, 2012

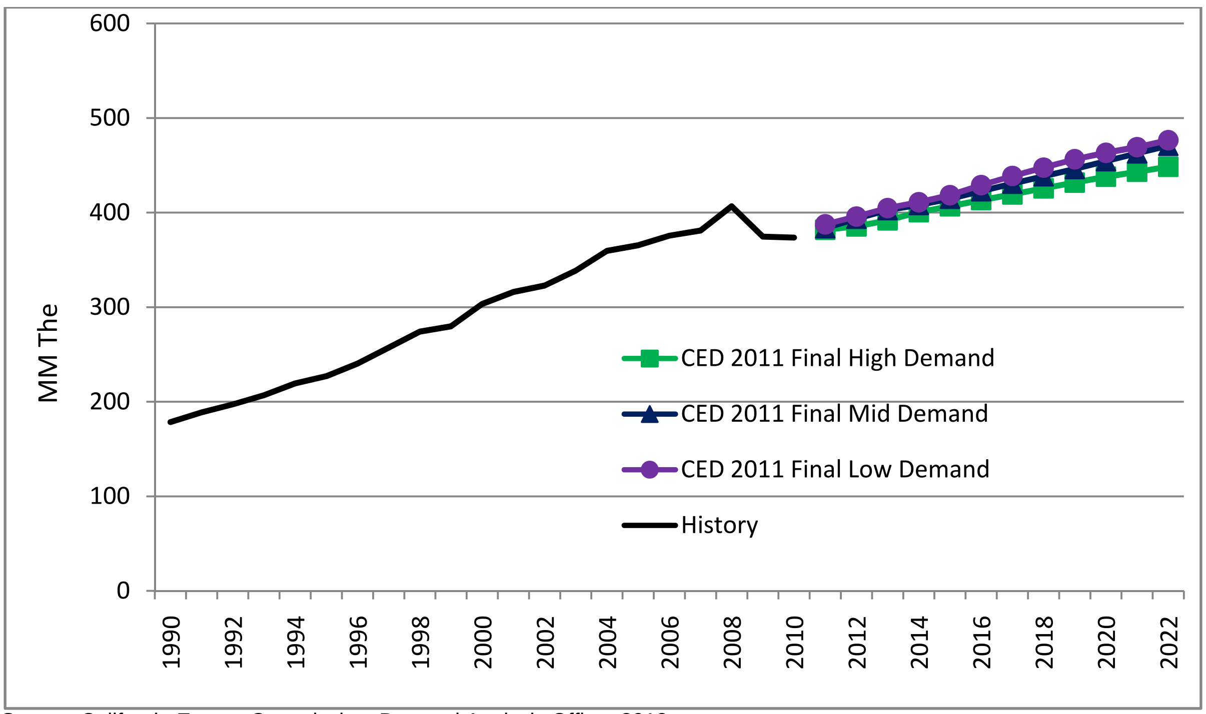
Figure 2-14: SDG&E Planning Area Industrial Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2012

Figure 2-15 shows estimated historical and forecast impacts of committed efficiency on SDG&E natural gas consumption from building and appliance standards, utility and public agency programs, and price and other effects. Projected savings impacts are higher the lower the demand scenario, since price and program effects are inversely related to the demand outcome. The large increase in impacts seen in 2008 comes from a sharp rise in natural gas prices (although not as sharp as in the PG&E and SoCalGas planning areas). In 2022, accumulated efficiency impacts are expected to correspond to around a 40 percent decrease in consumption in the mid demand scenario relative to use, assuming no efficiency impacts since 1975.

Figure 2-15: SDG&E Planning Area Natural Gas Consumption Efficiency Impacts



Source: California Energy Commission, Demand Analysis Office, 2012

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. Assembly Bill 2021(Levine, Chapter 734, Statutes of 2006) set a statewide goal of reducing total forecasted electricity consumption by 10 percent over the next 10 years. Under AB 2021, the Energy Commission, in consultation with the CPUC, is responsible for setting annual statewide efficiency potential estimates and targets in a public process every three years using the most recent IOU and publicly owned utility 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.

Since the *2007 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 formed the Demand Analysis Working Group (DAWG)[39] to provide a forum for interaction among key organizations on topics related to energy efficiency, demand forecasting, and energy procurement. Membership in the DAWG includes staff from the California Energy Commission, the CPUC Energy Division, the Department of Ratepayer Advocates, the California IOUs, several publicly owned utilities, 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 program impacts to be incorporated in *CED 2009.*[40] *CED 2011 Final* builds on the work done during the *2009 IEPR* process with the following elements:

- Incorporation of new building and appliance standards, including impacts from AB 1109 lighting regulations and television standards.

39 The first incarnation of DAWG, in 2008 and 2009, was referred to as the Demand Forecasting Energy Efficiency Quantification Project (DFEEQP).

40 The effort for *CED 2009* is detailed in Chapter 8 of Kavalec, Chris and Tom Gorin, 2009. *California Energy Demand 2010-2020, Adopted Forecast*. California Energy Commission. CEC-200-2009-012-CMF. http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF.

- Refinement of 2006-2009 efficiency program impacts through incorporation of the CPUC's 2006-2008 and 2009 evaluation, measurement, and verification (EM&V) studies.
- Updated price elasticity estimates.
- Inclusion of industrial price effects along with residential and commercial.
- Updated committed natural gas efficiency program impacts, starting in 2006.
- Presentation of alternative scenarios for 2011-2012 projected committed efficiency program impacts, consistent with the high, mid, and low demand scenarios.

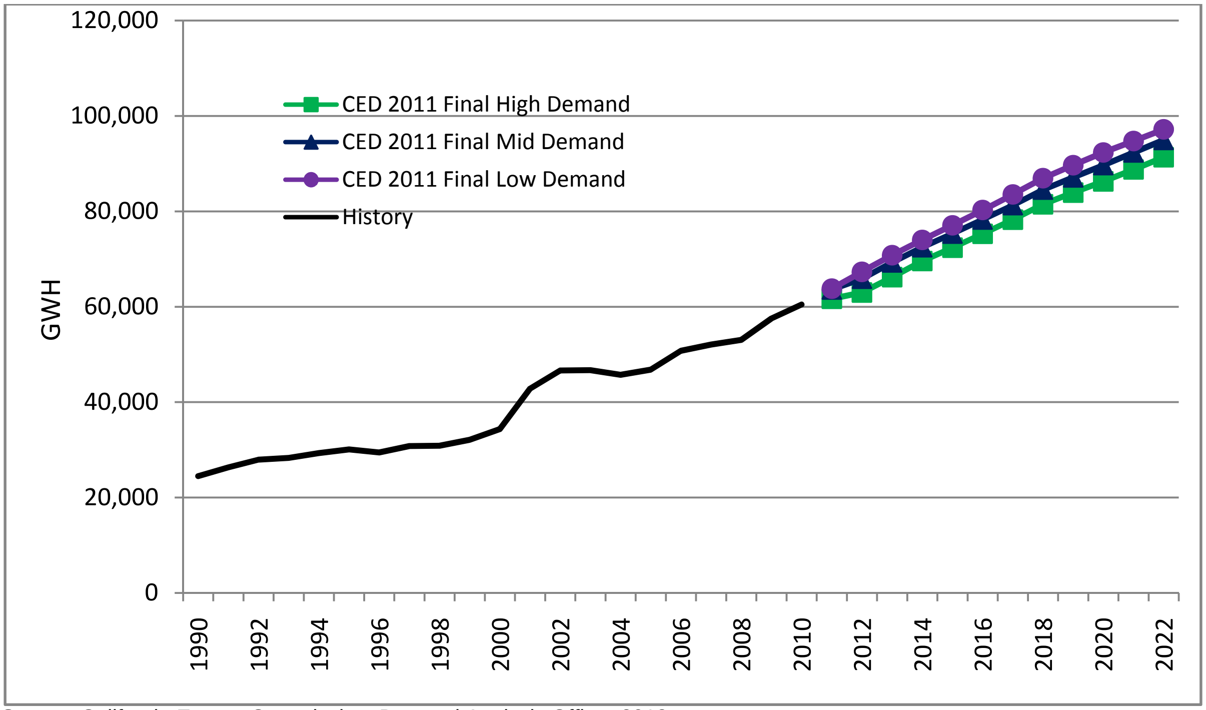
Committed Energy Efficiency

Staff estimates the savings in energy demand associated with three sources: committed utility and public agency efficiency programs in the residential, commercial, industrial, and agricultural sectors; 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.

Figure 3-1 and **Figure 3-2** show staff estimates of statewide historical and projected committed electricity consumption and peak savings, respectively. Projected savings impacts are higher the lower the demand scenario; although standards impacts increase with demand, price and program effects (for 2011 and beyond) are inversely related to the demand outcome. Peak results show less difference among the scenarios, since residential consumption savings totals[41] are very similar and the residential sector has a disproportionately large effect on peak demand.

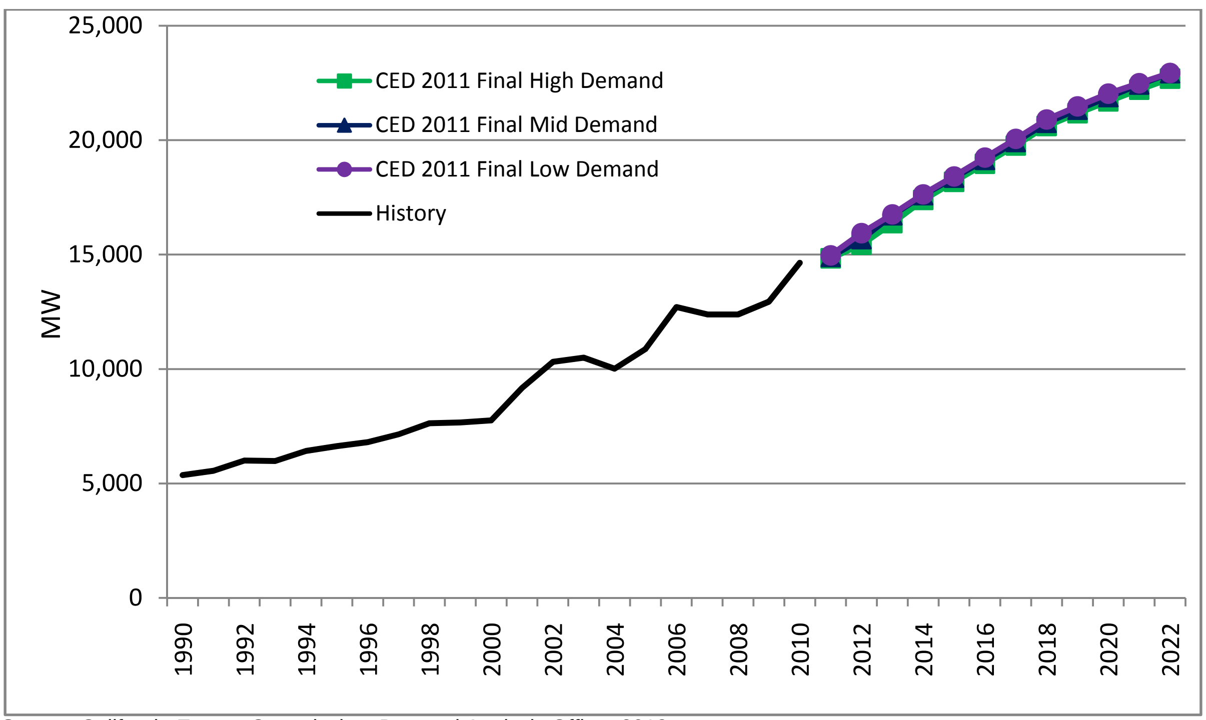
41 A result of the almost equal (but opposite) impact of standards savings versus price and program effects.

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



Source: California Energy Commission, Demand Analysis Office, 2012

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



Source: California Energy Commission, Demand Analysis Office, 2012

Table 3-1 shows these savings as a percentage reduction[42] 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 2022. Since price and program effects are inversely related to the demand outcome, percentages increase as demand decreases.

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

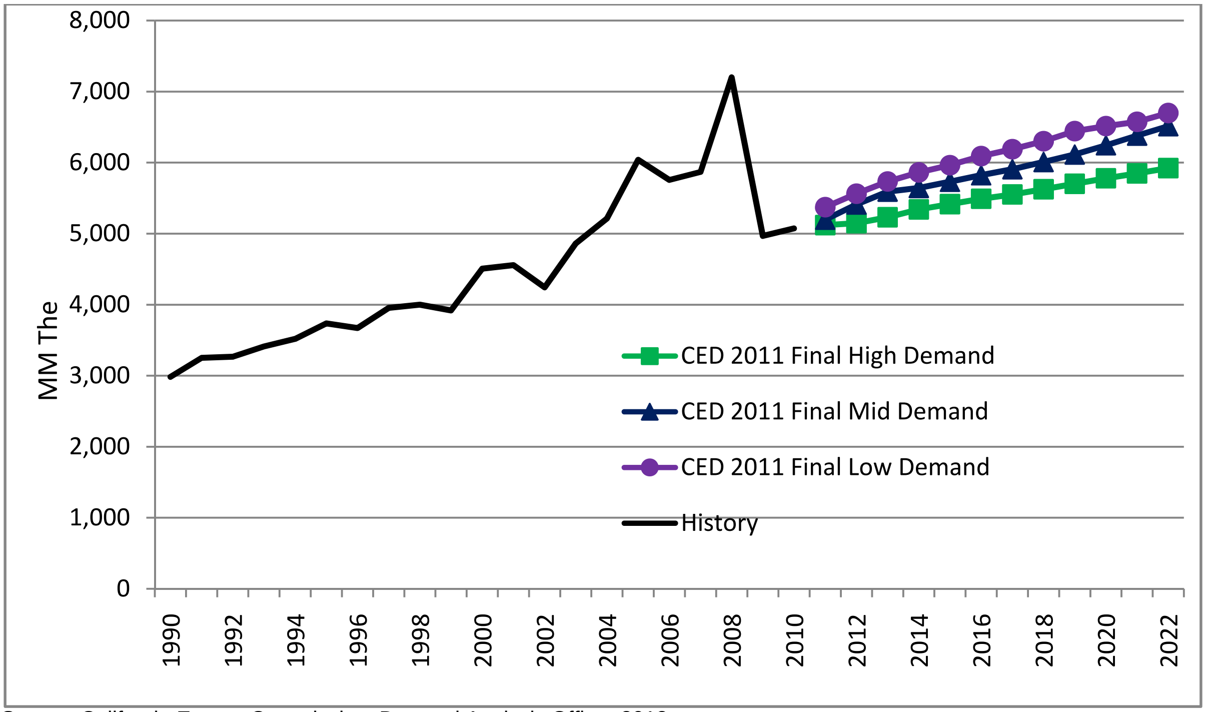
	Consumption		
	CED 2011 Final High Energy Demand	*CED 2011 Final Mid Energy Demand*	*CED 2011 Final Low Energy Demand*
1990	9.7%	9.7%	9.7%
2000	11.6%	11.6%	11.6%
2010	18.1%	18.1%	18.1%
2015	19.6%	20.5%	21.5%
2020	21.1%	22.4%	23.5%
2022	21.5%	23.0%	24.0%
	Peak Demand		
	CED 2011 Final High Energy Demand	*CED 2011 Final Mid Energy Demand*	*CED 2011 Final Low Energy Demand*
1990	10.1%	10.1%	10.1%
2000	12.6%	12.6%	12.6%
2010	19.0%	19.0%	19.0%
2015	21.6%	22.0%	23.0%
2020	23.2%	24.0%	25.1%
2022	23.5%	24.4%	25.5%

Source: California Energy Commission, Demand Analysis Office, 2012

Figure 3-3 shows estimated historical and forecast impacts of committed efficiency on state natural gas consumption. As with electricity, projected savings impacts are higher the lower the demand scenario, since price and program effects are inversely related to the demand outcome. The large increase in impacts seen in 2008 comes from a sharp rise in natural gas prices.

42 That is, efficiency savings divided by (consumption or peak total plus efficiency savings).

Figure 3-3: Historical and Projected Statewide Natural Gas Consumption Efficiency Impacts



Source: California Energy Commission, Demand Analysis Office, 2012

Table 3-2 shows these savings as a percentage reduction in consumption for selected years. Percentages are higher compared to electricity mainly because the relatively few gas end uses are covered by standards to a greater degree than electricity end uses. In particular, standards related to heating (a source of a much larger proportion of natural gas use relative to electricity) have had a much greater relative impact on gas consumption.

Table 3-2: Committed Natural Gas Efficiency Savings as a Percentage of Consumption

	CED 2011 Final High Energy Demand	*CED 2011 Final Mid Energy Demand*	*CED 2011 Final Low Energy Demand*
1990	18.8%	18.8%	18.8%
2000	24.5%	24.5%	24.5%
2010	28.4%	28.4%	28.4%
2015	29.1%	29.9%	31.7%
2020	29.9%	31.0%	32.5%
2022	30.0%	31.8%	33.0%

Source: California Energy Commission, Demand Analysis Office, 2012

Because a clear, consistent record of evaluated efficiency program achievements is not readily available, there is a great deal of uncertainty around any estimate of historical program impacts. This uncertainty, along with uncertainty around attribution of savings among standards, programs, and price effects, has been the subject of debate in recent DAWG meetings. Some parties have suggested that historical program impacts incorporated in Energy Commission demand forecasts are vastly underestimated and/or too much savings is credited to standards and price effects, especially before 1998.

Staff believes **Figure 3-1** through **Figure 3-3** provide reasonable estimates of total savings but acknowledges and shares the concerns voiced by stakeholders about savings attribution. For *CED 2011 Final*, therefore, no attribution among the three sources is shown, except for estimates of standards impacts presented later in this chapter. In other words, no specific estimates of program and price effects are provided. Staff will continue to work with stakeholders on these issues, with the goal of showing attribution for at least some years in future forecasts.

Committed Program and Price Effects

In general, historical electricity program impacts were treated similarly to *CED 2009*,[43] with the following differences. First, 2006-2009 IOU program savings were adjusted to incorporate the CPUC's 2006-2008 and 2009 EM&V studies.[44] Second, IOU industrial program savings were included and adjusted using the 2006-2009 study results. The adjustment to 2006-2009 program savings varied by end use but overall resulted in a lower realization rate (around 60 percent) compared to *CED 2009* (70 percent). In addition, efficiency measure savings decay (the rate of "burnout" for measures) was reduced by 50 percent, starting with 2006 programs to reflect the CPUC's directive that one-half of measure decay be replaced through additional programmatic efforts.[45]

Natural gas efficiency program savings were updated for *CED 2011 Final*, starting with the 2006 program year, with realization rates derived from the same 2006-2008 and 2009 EM&V studies.

Alternative committed efficiency program scenarios for both electricity and natural gas, consistent with the high, mid, and low demand cases, were developed for 2011 and 2012 for

43 See Chapter 8 in Kavalec, Chris and Tom Gorin, 2009. *California Energy Demand 2010-2020, Adopted Forecast*. California Energy Commission. CEC-200-2009-012-CMF. In general, for program savings back to 1998, net-to-gross ratios of 80 percent were applied to reported gross savings, along with a realization rate of 70 percent.

44 Results from these studies remain controversial among stakeholders. The IOUs criticize the general approach to the 2006-2008 study as noncooperative, with interim results not properly vetted among stakeholders. However, staff believes that this work provides the best available estimates of realized savings over 2006-2009.

45 Given in D.09-09-047, CPUC, 2009.

the IOUs and for 2011 for the publicly owned utilities.[46] For the low demand case (higher efficiency program savings), staff adjusted the forecast using utility-reported net savings.[47] In the high demand case, these savings were reduced to be consistent with the 2006-2008 and 2009 CPUC EM&V studies, yielding an average realization rate of around 70 percent. The mid case realization rate relied on an average between the high and low cases, around 85 percent.

Residential price effects are significantly higher in *CED 2011 Final* compared to *CED 2009*, based on the price elasticity estimated in the residential econometric model (See Appendix A). Price effects in the industrial sector were estimated and incorporated in *CED 2011 Final*, also based on econometric estimation.

Building Codes and Appliance Standards

Energy Commission forecasting models incorporate building codes and appliance standards through changes in inputs estimated end-use consumption per household in the residential sector and end-use consumption per square foot in the commercial sector. **Table 3-3** shows the codes and standards currently included in the energy demand forecast by sector.

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46 IOU programs operate in three-year cycles, so that current funding extends through 2012. Therefore, 2011 and 2012 projected program impacts are considered committed for this forecast. Publicly owned utilities typically fund one year ahead, so only 2011 program impacts are considered committed.

47 IOUs have been adjusted slightly since *CED 2009* to reflect the most recent Database for Energy Efficient Resources (DEER) revisions.

Table 3-3: Committed Building Codes and Appliance Standards Incorporated in *CED 2011 Final*

Residential Model	
1975 HCD Building Standards 1978 Title 24 Residential Building Standards 1983 Title 24 Residential Building Standards 1991 Title 24 Residential Building Standards 2005 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) 2011 Television 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

Source: California Energy Commission, Demand Analysis Office, 2012

AB 1109 lighting regulations, now coded in Title 20 Appliance Standards, were introduced into the residential end-use model through reductions in average household lighting use, so that electricity consumption for this end use was reduced 50 percent from 2007 levels by 2018.[48] Staff resources did not permit incorporating AB 1109 into the commercial end-use model for *CED 2011 Final*, and so staff substituted the savings estimated in the 2010 incremental uncommitted efficiency work.[49] Estimates were made only for IOUs in the 2010 study; staff estimated impacts for publicly owned utility planning areas by applying a ratio of lighting savings to consumption over the three IOUs.[50] The 2010 (formerly 2008) Residential Title 24 Standards were not included due to lack of resources and time. However, staff believes (confirmed in the incremental uncommitted efficiency study) residential impacts from this update to Title 24 are much less significant than in the commercial sector.

48 Average lighting use decreases for single-family homes from 1,800 kilowatt hour (kWh) per year to 900 kWh by 2017, and remains constant thereafter. For multifamily homes, the decrease is from 1,000 KWh to 500 KWh.

49 Electricity and Natural Gas Committee. *Incremental Impacts of Energy Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast*. CEC-200-2010-001-CTF. http://www.energy.ca.gov/2010publications/CEC-200-2010-001/CEC-200-2010-001-CTF.PDF.

50 This is meant to give only a rough approximation of impacts for the non-IOU planning areas: Lighting savings from AB 1109 were estimated for the IOUs, controlling for efficiency programs that might overlap. To the extent that publicly owned utility efficiency programs differ in scope and magnitude from IOU programs, potential overlap would be different in these planning areas.

For the television standards, staff used information provided in the Energy Commission's 2009 Appliance Efficiency Rulemaking proceeding (Docket # 09-AAER-1C) for the existing saturation and power use of televisions by technology type. The characteristics of existing technology types formed the foundation of forecasted energy use. Although size, features, and display technologies continue to change rapidly, several simplifying assumptions were made to characterize the energy consumption of televisions under the standards throughout the forecast period. First, it was assumed that no new cathode ray tube (CRT) televisions would enter the market after 2011 and all stock turnover would first occur with these televisions. Once the CRTs have been removed, older, prestandard Liquid Crystal Display (LCD) and plasma televisions would be replaced, followed by Tier 1 standard televisions, and finally Tier 2 standard televisions.[51] Average screen size by technology type was assumed to increase at a rate of 2 percent per year, following recent trends. The average annual unit energy consumption (UEC) by technology type was calculated from the power usage by average size multiplied by an annual usage estimate and weighted to give an overall UEC under the standards. Usage estimates in the residential sector were derived by examining 7 recent government and consumer research studies,[52] which provided a range of average daily viewing hours (across all televisions in the home) of between around 7 and 13 hours. Staff applied the average over these studies, 9.29 hours, in this forecast.[53] An average of 12 hours per day for commercial use was provided in the Energy Commission staff report for the Rulemaking Proceeding[54] and was used for the commercial sector. Saturations of televisions in the residential sector are based on historical values and marginal saturation estimates derived from the *Residential Appliance Saturation Survey*, Residential Energy Consumption Survey, and other appliance research data. For the commercial sector, the saturations of televisions were estimated by using the *2004 Commercial End Use Survey* data as a baseline, and projecting the growth in the number of televisions using the growth in forecast commercial electricity consumption. Total projected savings from television standards reach around 4,500 GWH by 2022,[55] varying slightly by demand scenario, since higher demand means more homes and commercial floor space, and therefore more televisions and more savings.

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51 The television standards are "ramped up" with Tier 1 and Tier 2 in 2011 and 2013, respectively.

52 Includes studies by the Energy Information Administration, the Natural Resources Defense Council, TIAX, Nielsen, and the Energy Commission (residential appliance saturation surveys).

53 CED 2011 Revised assumed average usage of around 7 hours per day, based on a recent Energy Information Administration study. The Rulemaking Proceeding for the television standards assumed around 13 hours per day, but more recent studies show lower usage.

54 Appliances and Process Energy Office, 2009. *Staff Report for Proposed Efficiency Standards for Televisions. California Energy Commission,* CEC-400-2009-024. http://www.energy.ca.gov/2009publications/CEC-400-2009-024/CEC-400-2009-024.PDF.

55 Compared to around 2,600 GWH in *CED 2011 Revised.*

To measure the impact of each set of included standards, staff removed the input effect from standards one set at a time, beginning with the most recent standards, and calculated savings as the difference in energy demand output between model runs with the set of standards incorporated and without. For example, for the commercial sector, staff began by running the Commercial Model with all sets of standards included and then ran the model excluding changes in inputs associated with the 2010 Title 24 Nonresidential Building Standards (the most recent standards). The difference in output between the two model runs gives an estimate of the electricity savings associated with the 2010 standards. Next, staff removed the input changes associated with the next-most recent set of standards, the 2005 Title 24 Nonresidential Building Standards, and compared the results from model runs without the 2010 standards and without both the 2010 and 2005 standards, which estimated the impact of the 2005 standards. The process was repeated until all sets of standards had been "removed" from the model.

Table 3-4 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 and home additions and are slightly less in the low demand case.

Table 3-4: 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	1,304	834	2,138	7,987
2000	6,023	7,243	13,265	3,281	2,331	5,611	18,877
2010	6,891	15,656	22,546	6,267	4,028	10,295	32,841
2015	8,257	23,472	31,730	8,205	5,377	13,582	45,312
2020	9,736	29,378	39,114	10,706	7,422	18,128	57,242
2022	10,203	30,709	40,912	11,652	7,810	19,462	60,374
	Peak (MW)						
	Residential			Commercial			Total Standards
	Building Standards	Appliance Standards	Total	Building Standards	Appliance Standards	Total	
1990	917	563	1,481	282	183	465	1,946
2000	1,494	1,727	3,220	678	483	1,162	4,382
2010	1,927	4,214	6,141	1,419	913	2,332	8,472
2015	2,421	6,626	9,047	1,728	1,134	2,862	11,909
2020	2,844	8,268	11,112	2,252	1,563	3,815	14,926
2022	2,927	8,486	11,413	2,452	1,645	4,097	15,510

Source: California Energy Commission, Demand Analysis Office, 2012

Table 3-5 shows estimated statewide natural gas consumption savings from appliance and building standards for the residential and commercial sectors in the mid demand scenario. As with electricity, forecast standards impacts increase slightly in the high demand scenario due to more projected commercial floor space and home additions and are slightly less in the low demand case.

Table 3-5: Estimated Natural Gas Savings From Building Codes and Appliance Standards: Mid Demand Scenario

	Consumption Savings by Sector (MM Therms)						
	Residential			Commercial			
	Building Standards	Appliance Standards	Total	Building Standards	Appliance Standards	Total	Total Standards
1990	724	680	1,404	35	31	66	1,470
2000	1,322	1,225	2,547	70	63	133	2,680
2010	1,711	1,514	3,225	109	95	204	3,429
2015	1,847	1,641	3,487	130	115	245	3,732
2020	2,026	1,750	3,775	156	136	291	4,067
2022	2,093	1,791	3,884	166	143	309	4,193

Source: California Energy Commission, Demand Analysis Office, 2012

Incremental Uncommitted Efficiency Savings

Staff had intended to develop a full revision to the incremental uncommitted savings results estimated for the *2009 IEPR* using a new CPUC Goals Study currently underway. However, completion of this study has been delayed until summer 2012. Therefore, this report does not include potential incremental uncommitted efficiency impacts, but staff plans to develop new estimates as a separate product in two analyses: one based on the CPUC's recently completed efficiency Potential Study to be provided to the CPUC for its long-term procurement process and a more complete examination once the Goals Study is complete.

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: Adjustments to Existing Models From Econometric Estimations

The econometric forecasting models for residential, commercial, industrial, and peak were re-estimated between *CED 2011 Preliminary* and *CED 2011 Final*. Estimation results are given in Appendix D. Results from the econometric estimations were used to adjust the following model assumptions:

- Electricity price elasticities for the residential end-use and industrial (INFORM) models.
- The weather adjustment made to commercial end-use model electricity consumption.
- The INFORM electricity forecast for the manufacturing sector was adjusted to reflect the impact from increasing labor productivity.
- Peak results from the Hourly Electricity Load Model (HELM) were adjusted to incorporate climate change scenarios.

Residential and Industrial Price Elasticities

Electricity price elasticities of demand that have been used in the residential end-use model and in the industrial INFORM models are very low, on the order of 1-3 percent[56], and very dated. For *CED 2011 Final*, staff replaced these elasticities with those estimated in fall 2011 for the residential, manufacturing, and resource extraction/construction econometric models. This meant increasing the residential end-use model elasticity to around 8 percent and the INFORM elasticity to 10 percent. The elasticity estimated for the commercial econometric model (3 percent) was significantly lower than that currently used in the commercial end-use model (around 15 percent) but was barely significant statistically. Therefore, the commercial end-use model price elasticity was not changed.

Commercial Weather Adjustment

In the Summary Model, which collects and calibrates the sector model results, adjustments are made to account for actual weather, by using the ratio of degree days in a given year to a 30-year average. For the commercial results (from the end-use model), the adjustment for

56 Price elasticity of demand measures the percentage change in quantity demand given a 1 percent change in price. Thus, an elasticity of -0.5 means that a 1 percent change in price leads to a decrease in quantity demanded of -0.5 percent.

cooling degree days resulted in a much higher effect (about twice as much) as would be applied using the estimated coefficient for cooling degree days in the commercial econometric model. Therefore, staff reduced the cooling adjustment in the Summary Model by 50 percent. The residential adjustment for cooling degree days in the Summary Model is consistent with the econometric results.

Industrial Labor Productivity Adjustment

In the INFORM model, manufacturing energy demand is forecast based primarily on projected growth in output for 28 categories (for example, chemicals and paper). In estimating the manufacturing econometric model, staff found that, in addition to output, the ratio of output to employment has had a very significant[57] effect on electricity demand. That is, as output per labor unit has increased, total energy use has declined, all else equal. The coefficient can be construed as an indicator of the effect of more efficient manufacturing processes and may also be capturing changes in the makeup of manufacturing industries. Staff used the estimated coefficient for output/labor to adjust the INFORM results, yielding a lower (and in staff's view, a more realistic) forecast for manufacturing consumption.

Comparison of *CED 2011 Final* and Full Econometric Forecasts

Table A-1 compares *CED 2011 Final* results for 2022 by planning area and statewide with those from a full econometric forecast; that is, with residential, commercial, industrial, and peak econometric model results substituted for the residential and commercial end-use models, INFORM, and the HELM peak model, respectively. More complete results are provided along with the demand forms posted with this report. Differences range from almost zero to more than 4.5 percent above or below, and the reasons for these differences are discussed in Chapter 1 of this volume. Statewide consumption in the mid demand case is almost identical to *CED 2011 Final*.

Consumption results are generally higher in the econometric forecasts except for SDG&E and SMUD, and peak results are generally higher except for SDG&E. Although staff recommends adopting the forecast results as presented in this report, given the detail and specific accounting for demand impacts in the end-use models, the econometric results may be useful as an alternative scenario. For example, peak econometric results in the high demand case (with the exception of SDG&E) could be used to provide a broader range for the peak forecasts.

57 A t-statistic of -7.8.

Table A-1: Comparison of *CED 2011 Final* and Full Econometric Forecasts, 2022

Planning Area	Demand Scenario	Consumption (GWh)			Peak (MW)		
		CED 2011 Final	Econo-metric	% Difference	*CED 2011 Final*	Econo-metric	% Difference
LADWP	High	29,207	29,797	2.02%	7,194	7,300	1.47%
	Mid	28,333	29,016	2.41%	6,937	7,079	2.05%
	Low	27,447	28,050	2.20%	6,550	6,682	2.00%
PGE	High	132,056	126,766	-4.01%	27,466	27,385	-0.30%
	Mid	123,364	122,678	-0.56%	26,161	26,812	2.49%
	Low	119,526	119,384	-0.12%	24,724	25,339	2.49%
SCE	High	116,637	117,455	0.70%	26,739	27,153	1.55%
	Mid	112,535	113,717	1.05%	25,591	25,984	1.54%
	Low	109,350	110,147	0.73%	24,056	24,447	1.63%
SDG&E	High	27,228	25,956	-4.67%	5,699	5,483	-3.79%
	Mid	25,967	25,286	-2.62%	5,536	5,438	-1.76%
	Low	24,992	24,338	-2.62%	5,202	5,118	-1.62%
SMUD	High	12,666	12,070	-4.70%	3,691	3,781	2.42%
	Mid	12,109	11,801	-2.54%	3,540	3,635	2.68%
	Low	11,794	11,486	-2.61%	3,343	3,419	2.27%
State	High	333,838	327,781	-1.81%	74,049	74,489	0.59%
	Mid	318,071	318,060	0.00%	70,946	72,233	1.81%
	Low	308,677	308,768	0.03%	66,916	68,162	1.86%

Source: California Energy Commission, Demand Analysis Office, 2012

Peak Impacts of Climate Change

The Energy Commission demand forecasting process incorporates the potential impacts of global climate change by adjusting upward the number of cooling and heating degree days for each climate zone in the forecast period, based on the historical ratio of degree days in the last 12 years to that of the last 30 years. The result of this adjustment is typically[58] an increase in the projected amount of cooling and a reduction in projected heating relative to the historical period. This correction attempts to account for the likelihood of a general warming trend. However, temperatures assumed in the peak forecast, an average of daily temperatures over a 30-year period, are not affected by the adjustment. Therefore, the

58 This is not always the case: In some climate zones, the last 12 years have been slightly cooler on average than the 30-year period.

forecast may not fully capture the impact on peak demand of possibly more frequent heat storms reflected in higher maximum or average temperatures in a given year.

Staff used the econometric peak model re-estimated for *CED 2011 Final* to estimate the potential impacts of climate change on annual peaks, and then added these estimated impacts to the Energy Commission's HELM end-use peak model results. The econometric model includes a coefficient for the annual maximum of *average631*, defined as follows:

Average631 =
Daily Average Temperature[59] × 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.[60]

To gauge the potential impact of climate change on *average631* temperatures through 2022, staff used a 2011 update of a climate change impact assessment by the California Climate Change Center, sponsored by the Energy Commission.[61] The update is based on eight climate change model simulations for California using four models, providing scenario results for daily maximum and minimum temperatures, average daily humidity, and sea level rises through 2099.

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 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 in a relatively high temperature impact for the high demand case.[62] For the low demand scenario, staff assumed no climate change impacts. Staff converted simulated daily averages for each weather station to *average631* indices for each planning area by weighting each climate zone by estimated number of air conditioners.

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

60 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.

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

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

Growth in annual maximum *average631* temperatures starting in 2011 was derived using long-term trends (1990-2020) from the two climate scenarios.[63]

Table A-2 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 2022, statewide peak impacts reach almost 1,000 MW in the mid demand case and around 1,300 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 2011 represent a historical 30-year average for the planning area.

Table A-2: Projected Peak Impacts of 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	2011	83.7	83.7	--	--
	2015	84.0	84.2	35	54
	2020	84.5	85.0	83	131
	2022	84.7	85.2	105	165
PGE	2011	85.7	85.7	--	--
	2015	86.0	86.1	114	143
	2020	86.4	86.6	277	349
	2022	86.6	86.8	348	440
SCE	2011	85.8	85.8	--	--
	2015	86.2	86.3	121	171
	2020	86.6	87.0	293	421
	2022	86.8	87.2	368	533
SDGE	2011	78.2	78.2	--	--
	2015	78.6	78.6	27	28
	2020	79.0	79.1	66	70
	2022	79.2	79.3	84	88
SMUD	2011	85.1	85.1	--	--
	2015	85.4	85.6	13	23
	2020	85.7	86.2	31	57
	2022	85.9	86.5	39	72
State	2015	--	--	316	430
	2020	--	--	768	1,056
	2022	--	--	965	1,334

Source: California Energy Commission, Demand Analysis Office, 2012

63 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 2022 maximum temperatures as low or lower than 2011 maximums.

For future *IEPR* forecasts, staff plans to examine the potential impact of climate change on electricity consumption, in addition to peak demand, through econometric analysis. In addition, staff will investigate 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.

APPENDIX B: Self-Generation Forecasts

Compiling Historical Distributed Generation Data

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

- The California Solar Initiative (CSI)[64]
- New Solar Homes Partnership (NSHP)[65]
- Self-Generation Incentive Program (SGIP)[66]
- CSI Thermal Program for Solar Water Heating (SWH)[67]
- Emerging Renewables Program (ERP)[68]
- Publicly owned utility program (POU)[69]

In addition, power plants with a generating capacity of at least 1 MW are required to submit fuel use and generation data to the Energy Commission under the Quarterly Fuel and Energy Report (QFER) Form 1304.[70] QFER data includes fuel use, total generation, onsite use, and exports to the grid. QFER accounts for the majority of onsite generation in California given the large representation of industrial cogeneration facilities. With each forecast cycle, staff continues to refine QFER data to correct for mistakes in data collection and data entry. In this cycle, staff spent time separating third-party sales ("wheeling" or "over the fence sales") from onsite generation. Also, an attempt was made to allocate third-party sales to the North American Industrial Classification System (NAICS) code reported by the form preparer. In situations where a NAICS code was not reported for a third-party sale, staff assigned the third-party sales transaction to the same NAICS category as generation. This is not an unreasonable assumption given that it is most likely that firms engaged in similar industries tend to be clustered together and that these "over-the-fence"

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64 Downloaded on 10/25/11 from (http://www.californiasolarstatistics.org/current_data_files/).

65 Program data received on 11/16/11 from staff in the Energy Commission's Renewable Energy Office.

66 Downloaded on 05/09/11 from (https://energycenter.org/index.php/incentive-programs/self-generation-incentive-program/sgip-documents/sgip-documents). Data covers up to 4th Quarter of 2010.

67 Downloaded on 10/25/11 from (http://www.gosolarcalifornia.org/solarwater/index.php).

68 Downloaded on 01/20/11 from (http://www.energy.ca.gov/renewables/emerging_renewables/index.html).

69 Program data submitted by POU's for June 2011 reporting period. http://www.energy.ca.gov/sb1/pou_reports/index.html.

70 Data received from Commissions Electricity Analysis Office on 11/15/11.

sales generally occur with the buyer and seller located close to one another. Staff also examined the classification of plants to NAICS groups and assignment of plants to planning area. Given the self-reporting nature of QFER data, refinements to historical data will likely continue to occur in future forecast cycles.

These various sources of data are used to quantify distributed generation (DG) activity in the state 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 a project if the project has a generating capacity of at least 1 MW. This can occur since the publicly available incentive program data does not list the name of the entity receiving the incentive for investing in DG due to confidentially reasons while QFER data collects information from the plant owner. Thus, it is not possible to determine if a project from a DG incentive program is already reporting data to the Commission under QFER. For example, the SGIP has 93 completed and around 50 pending projects that are at least 1 MW. Given the small number of DG projects meeting QFER's reporting size threshold, double-counting may not be significant but could become an issue in the future as an increasing number of large SGIP projects come on-line.

Projects from incentive programs are classified as either completed or uncompleted. This is accomplished by examining the current status of a project. Each program varied in how it categorized a project as being completed. 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 projects when uncompleted projects will be completed based on how long it took completed projects to move between the various application stages or make use of supplemental program data.[71]

The next step is to assign each project to a county and sector. For the minority of records that cannot be mapped to a county due to missing or invalid county or ZIP code, staff distributes these records to a county based on the distribution of records that have been mapped to a county. Sector mapping for nonresidential projects can be a challenge.[72] When

71 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.

72 For example, the SGIP program uses both the old Standard Industrial Classification (SIC) codes and the now standard NAICS codes.

valid NAICS codes are provided in the program data, the corresponding NAICS sector description is used; otherwise, a default "Commercial" sector label is used. The next step for each program is to aggregate capacity additions by county to one of 16 demand forecasting climate zones. These steps are 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 investor-owned utility (IOU) as the program administrator but are interconnected to a POU; these projects are mapped directly to forecasting zones. For the ERP program, PV projects less than 10 kW are mapped to the residential sector while both non-PV and PV projects greater than 10 kW are mapped to the commercial sector. Finally, capacity and peak factors from DG evaluation reports are used to estimate energy and peak impacts.[73] [74]

Figure B-1 shows the statewide historical distribution of self-generation between the residential and nonresidential sectors, reflecting relatively recent (and small, although growing) residential contributions to the total. **Figure B-2** gives a breakout by non-residential category for the state and shows a continued overall dominance in self – generation use by the industrial (manufacturing) and mining (resource extraction) sectors, although commercial applications are clearly trending upward in recent years.

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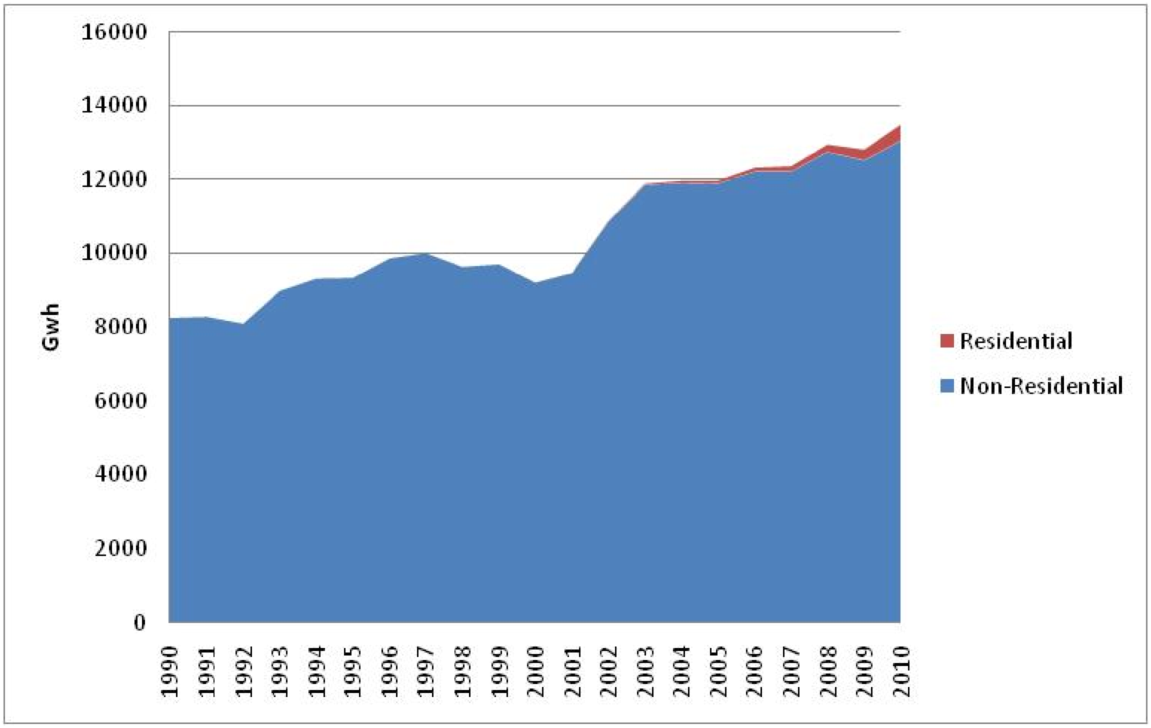
73 For SGIP program: Itron. CPUC *Self-Generation Incentive Program Tenth-Year Impact Evaluation*, June 2010. Report available at http://www.cpuc.ca.gov/NR/rdonlyres/CF952F3B-0C3C-481D-968A-420F92FC2901/0/SGIP_2010_Impact_Eval_Report.pdf.

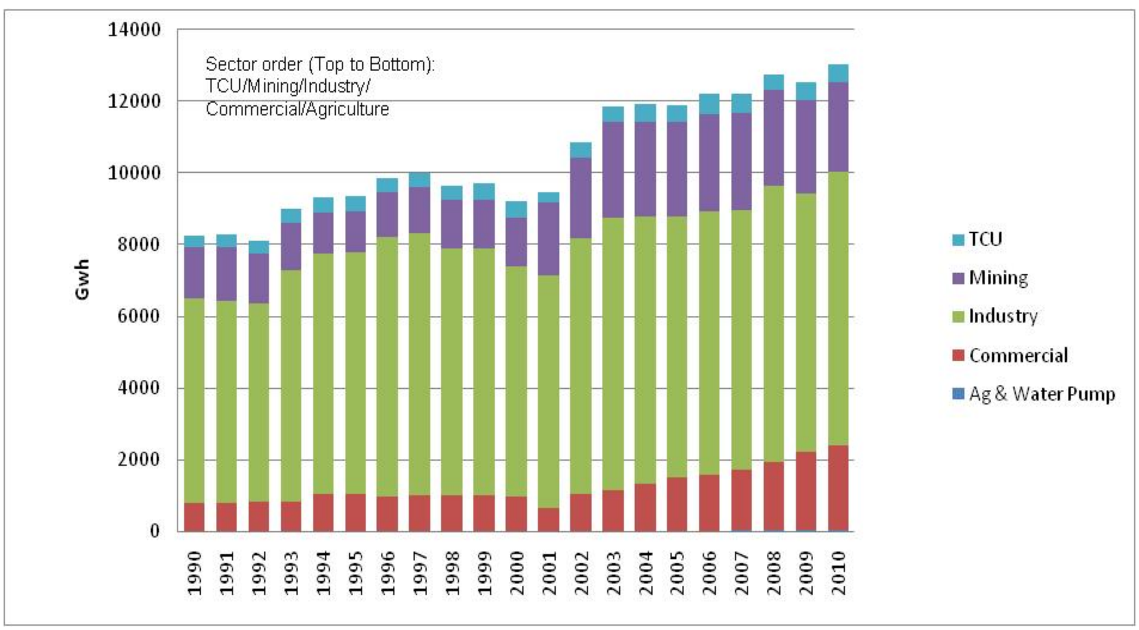
74 For CSI program: Itron. CPUC *California Solar Initiative 2010 Impact Evaluation*, June 2011. Report available at (http://www.cpuc.ca.gov/NR/rdonlyres/E2E189A8-5494-45A1-ACF2-5F48D36A9CA7/0/CSI_2010_Impact_Eval_FinalFinal.pdf.

Figure B-1: Statewide Historical Distribution of Self-Generation



Source: California Energy Commission, Demand Analysis Office, 2012

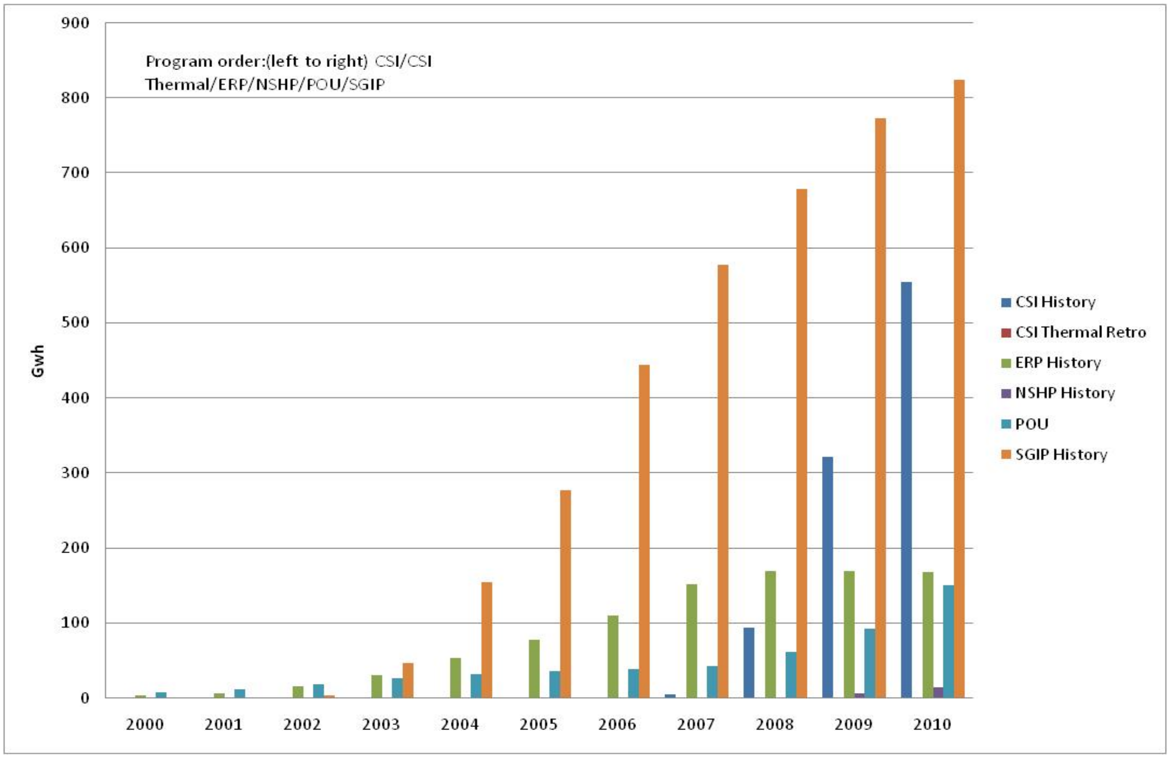
Figure B-2: Statewide Historical Distribution of Self-Generation, Nonresidential



Source: California Energy Commission, Demand Analysis Office, 2012

Figure B-3 shows the growing impact from self-generation incentive programs over the last 10 years. The SGIP program has historically had the largest impacts, although CSI is rapidly closing the gap.

Figure B-3: Statewide Self-Generation by Program



Source: California Energy Commission, Demand Analysis Office, 2012

Self-Generation Forecast, Nonresidential Sectors

Staff has begun to develop a predictive model for the commercial sector, but it has not yet been completed. For this forecast, staff used a method similar to the one used in *CED 2009*. Using DG incentive program data, staff calculated the mean growth rate in DG technology stock by sector and forecast zone for 2007 to 2010. Given strong growth for some technologies, namely fuel cells and PV, the maximum annual growth rate was capped at 7 percent. This mean growth rate was applied to the installed capacity in 2010. The installed capacity was allowed to grow at the mean rate until 2016 when the growth rate was reduced by half.[75] It was not feasible to forecast SWH in this manner for the nonresidential sector since the SWH program is relatively new. Therefore, staff assumed that the residential and nonresidential sector SWH adoption would follow a ratio similar to residential and nonresidential PV adoption. Staff used data from the CSI program to estimate this ratio,

75 This is a somewhat arbitrary assumption meant to account for CSI program expiration.

which was then applied to SWH penetration estimated for the residential sector with the predictive model. Due to the lack of an in-house model, staff is unable to consider the effect of technology cost, incentives, electricity and gas rates, and general improvements in DG technology on nonresidential DG technology adoption. As a result, there is only one scenario for the nonresidential sector. Capacity and peak factors from DG program evaluation reports were used to estimate energy and peak impacts.[76]

In the fall of 2010, an agreement was reached between the CPUC, utilities, and other stakeholders regarding the establishment of a statewide combined heat and power (CHP) program.[77] A major emphasis of this settlement is to re-sign contracts for existing qualifying facilities (QF). The settlement has a goal to have 3,000 MW of CHP under contract by 2020. Currently, based on QFER data and DG program data, staff can identify roughly 7,900 MW of installed CHP capacity as of 2010. This includes 2,800 MW of QFER CHP counted in the demand forecast,[78] 190 MW of DG from program data,[79] and 5,050 MW of QFER CHP not counted in the demand forecast since these plants sell generation back to the grid. At this early stage after the settlement, it is difficult to know how many existing plants will be re-signed to a contract and how many new plants will have to come on-line for the MW (and greenhouse gas emissions reduction) goals to be met. In *CED 2011 Final*, onsite use from historical non-PV technologies is held constant over the forecast horizon and is set to the level observed or estimated in the last historical year. Non-PV technologies make up about 3,200 MW of the total installed capacity in all three scenarios. The Energy Commission plans to hold workshops in early 2012 to better gauge the potential of CHP, and future forecasts will incorporate analyses that result from these workshops.

Residential Sector Predictive Model

The residential sector self-generation model was designed to forecast PV and SWH adoption using estimated times for full payback that depend 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[80] and the *SolarDS* model developed by the National Renewable Energy Laboratory.[81]

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76 See notes 55 and 56.

77 http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/128624.PDF.

78 Some of these plants use a portion of their generation onsite and sell any excess back to the utility.

79 Staff assumes that all projects from SGIP using natural gas operate in CHP mode.

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

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

The payback calculation is 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 compares the IRR to a required hurdle rate (5 percent) to determine if the technology should be adopted. If the calculated IRR is greater than the hurdle rate, then payback is calculated; otherwise, the payback is set to 30 years. The formula for converting the calculated IRR (if above 5 percent) to payback is:

$$Payback = \frac{\log(2)}{\log(1 + IRR)}$$

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 is based on a maximum market share (fraction) formula defined as:

$$Maximum\ Market\ Fraction = e^{-Payback\ Sensitivity * Payback}$$

Payback sensitivity is set to 0.3.[82] To estimate actual penetration, maximum market share is multiplied by an estimated adoption rate, calculated using a Bass Diffusion curve, to estimate annual PV and SWH adoption. The Bass Diffusion curve is often used to model adoption of new technologies and is part of a family of technology diffusion functions 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:

$$Adoption\ Rate = \frac{1 - e^{-(p+q)*t}}{1 + \left(\frac{q}{p}\right) * e^{-(p+q)*t}}$$

The terms p and q represent the impact of early and late adopters of the technology, respectively. Staff uses mean values for p (0.03) and q (0.38), derived from a survey of empirical studies.[83]

PV cost and performance data are based on analysis performed by ICF International in support of EIA's 2011 *Annual Energy Outlook* forecast report.[84] SWH cost and performance

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82 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.

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

84 ICF International. *Photovoltaic (PV) Cost and Performance Characteristics for Residential and Commercial Applications,* June 2010.

data are based on analysis conducted by ITRON in support of a CPUC proceeding examining the costs and benefits of SWH systems.[85]

Projected housing counts are 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 are sized to each housing type based on RASS floor space data, assumptions regarding roof slope, and factors to account for shading and orientation.[86] PV system size is 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 is estimated based on data provided to staff by the Energy Commission's Efficiency and Renewable Energy Division.[87] For SWH systems, energy saved on an annual basis is used directly to estimate bill savings. PV and SWH energy output are degraded at the same rate based on the PV degradation factor estimated by ICF for EIA. From year to year, available housing stock is reduced by penetration from existing programs in previous years and increased by the projected amount of new residential construction.

Staff uses the residential electricity and natural gas rates developed for *CED 2011 Final* to estimate bill savings, with rates held constant over the life of PV and SWH systems. Useful life is assumed to be 30 years for both technologies. For PV, surplus generation is valued at a uniform rate of $0.06/kWh.[88] Once the revenue stream for the two types of technology has been estimated, the initial cost of each technology is calculated with adjustments made for incentives offered by a utility to obtain the net cost. As in the *SolarDS* simulations, staff assumes PV systems will cost 10 percent less in new residential construction. Staff also assumes that the system owner will be able to claim the federal investment tax credit and that PV and SWH systems are financed rather than purchased outright.[89] Tax savings on the

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85 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).

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

87 Data comes from the NSHP Incentive calculator.

88 Annual residential energy use by housing type and water heater type is an output from the residential model. This data is used with the estimated PV generation to estimate if any surplus generation occurs. Note that the recent CPUC proposed decision on surplus compensation estimated that the surplus rate for PG&E 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)

89 Staff assumes a 30-year loan period for new construction and a 15-year period for retrofit.

loan interest is also taken into account by assuming a uniform marginal tax rate of 35 percent. Owners of multifamily units are assumed to claim the five-year Modified Accelerated Cost Recovery System (MACRS) depreciation benefit.

The different discounted cost and revenue streams are then combined into a final cash flow table so that the IRR and project payback can 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.

Appendix C: Statewide and Regional Economic and Demographic Outlook

This appendix provides additional information on the economic and demographic outlook for California using information provided by Moody's, IHS Global Insight, the University of California, Los Angeles (UCLA), the California Department of Finance, and the United States Census Bureau.

The recent recession in California started earlier, was deeper, and lasted longer compared to the rest of the nation. Payrolls in the state began to decrease in mid-2008, six months before national levels began to fall. From the economic peak in 2007, California lost 9 percent of total payroll through the "trough" of the recession, compared to 6.4 percent in the rest of the nation. The collapse of the real estate market defined California's experience, a collapse that occurred earlier and was more severe than outside the state. Global Insight does not expect the state to recover all of the jobs lost in the recession until 2016, nearly two years after the rest of the United States.

Moody's, Global Insight, and UCLA do not expect a second recession in California or in the nation as a whole, but 2012 is projected to be a time of relatively slow growth. All three forecasting groups expect California's economy to grow at a faster rate than the rest of the nation beginning in 2013 or 2014. They predict this growth will be driven by high-tech industries and continued rapid economic growth in Asia, given California's role as the primary port of entry and exit for imports and exports.

Although a primary cause of the recent recession, housing markets may turn from a negative to a positive factor for California's economy. First, the state's population growth has been relatively steady (compared to other nearby states), meaning that there has been a steady buildup of pent-up demand for housing in California, at least in the larger coastal, metro areas. Second, affordability (housing prices relative to income) in most of California's housing markets is at a 30-year high in many of California's larger metro areas, being highest in the Central Valley. Given stable demographic patterns, according to Moody's, there is a good chance that once house prices are perceived to be steady and job growth accelerates, first time homebuyers will return to housing markets, driving additional consumer spending via furnishings, home alterations, and renovations.

On the negative side, California faces continued budget difficulties and uncertainties with respect to tax and revenue polices. State spending on services and higher education will remain weak for some time, according to Moody's, probably longer than many other states. Additionally, the decline of home prices, by around 40 percent on average compared to the peak in 2006, means that even when home values begin to rise again, local property tax revenue will remain well below prerecession levels.

California's population growth, unlike in past economic downturns, was fairly steady through the recent recession and early recovery period, around 1 percent per year since

2008. In fact, the annual population growth rate has edged up slightly from 2009-2011, a result of increased international migration and an end to the decline in birth rates that occurred during the recession. Other states with hard-hit housing markets, such as Arizona, Florida, and Nevada, slowed to one-third of their prerecession growth rates. However, the cost of living in California may renew the pattern of population outflow seen before the recession to neighboring, lower-cost states, particularly if housing prices begin to rise.

Regional Outlook

Los Angeles Region

The unemployment rate remains relatively high in the Los Angeles metro area, particularly in Los Angeles (12 percent) and Riverside/San Bernardino (13 percent). Housing prices are expected to continue declining in these two areas in 2012, acting as a drag on the local economies. The recovery in Los Angeles will be spurred by infrastructure expansion, the entertainment industry, and trade out of the ports. In Riverside/San Bernardino, residential construction permits are trending upward, and economic growth will be led by transportation and natural resources.

Oxnard/Ventura and Orange County are in somewhat better shape, with the unemployment rate below 10 percent in both areas. Oxnard/Ventura has seen a gain in high-paying manufacturing jobs, and this gain is expected to continue, according to Moody's. The recovery in Orange County is expected to continue as growth in jobs in retail and visitor-dependent industries offset losses in construction and aerospace. As in Los Angeles and Riverside/San Bernardino, continued declines in housing prices should be a drag on these economies in 2012, with the situation improving in 2013.

Net outmigration has fallen in Los Angeles due to increased international migration and a reduction in domestic outmigration as neighboring states remain in poor economic shape. Once housing prices stabilize and begin to rise, the historical trend in migration from coastal to inland areas should continue.

Bay Area

The recovery is strongest in San Francisco and Marin counties, fueled by rapid growth in high tech and an unemployment rate below the United States and California averages. In contrast to other parts of the state, housing prices are stable in these two counties, and construction permits are growing. In San Jose, the recovery is being boosted by not only high tech but health care and education. Housing prices in Santa Clara County are expected to continue decline in 2012.

On the other hand, Oakland/Alameda, Contra Costa County, and Santa Rosa may be slipping back into recession. The unemployment rate remains higher than 10 percent in Alameda and Contra Costa counties, little changed since the middle of last year. This area has recently suffered significant job losses in high tech and education. In Santa Rosa, employment growth has slowed, and the area has lost jobs in nondurable manufacturing and in higher education. However, if these areas suffer another recession, it is expected to be much milder than the recession that began in 2008.

Booming high tech will push population growth in San Francisco and Marin, and these counties have seen increased population growth each in the last two years. Because of still-high housing prices, however, the rate of population growth will be lower than California and United States averages, at least in the next five years. In San Jose, the tech-driven recovery may not be sufficient to prevent the return of a longer-term pattern of net outmigration. Better housing affordability in Oakland/Alameda compared to the rest of the Bay Area should help stem a pattern of net outmigration occurring in the early 2000s.

San Diego County

Recovery is also strong in San Diego, boosted by high tech and other manufacturing, tourism, and health care. The labor force has returned to prerecession levels faster than in the United States as a whole. Housing sales and construction permits are trending upward, and the county has a relatively low share of "distress" home sales.

San Diego has a relatively high cost of living, and this is expected to slow population growth slightly in the next few years, although a promising job market should limit out-migration.

Sacramento Region

The unemployment rate in Sacramento remains around 12 percent, a figure higher than California and national averages. However, the home foreclosure rate is decreasing, and residential construction permits are increasing. Reliance on state government and a lack of high value-added industry are likely to keep economic growth at or below the statewide average in the near term. Sacramento has suffered net outmigration during the recession, but movement of both residents and businesses from the Bay Area is expected to resume, returning the region to positive net migration.

APPENDIX D: Regression Results

This appendix provides estimation results for regressions used in the analysis for *CED 2011 Final,* including results used to develop subregional forecasts.

Table D-1: Residential Sector Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Persons per Household	0.4530	0.0997	4.54
Per capita income (2010$)	0.1641	0.0468	3.50
Unemployment Rate	-0.0020	0.0008	-2.49
Residential Electricity Rate (2010¢/kWh)	-0.0788	0.0134	-5.89
Number of Cooling Degree Days (65^o)	0.0476	0.0082	5.80
Number of Heating Degree Days (65^o)	0.0140	0.0085	1.65
Dummy: 2001	-0.0507	0.0053	-9.65
Dummy: 2002	-0.0283	0.0053	-5.33
Additional Income Effect: LADWP	0.1959	0.0708	2.77
Additional Income Effect: SCE	0.1793	0.1034	1.73
Additional Cooling Degree Day Impact: IID	0.2045	0.0348	5.87
Additional Cooling Degree Day Impact: LADWP	0.0580	0.0124	4.67
Additional Cooling Degree Day Impact: SCE	0.0656	0.0172	3.81
Additional Cooling Degree Day Impact: SMUD	0.0817	0.0176	4.63
Additional Heating Degree Day Impact: SMUD	0.1234	0.0257	4.79
Constant: Burbank/Glendale	0.8979	0.2832	3.17
Constant: LADWP	-1.4916	0.7802	-1.91
Constant: Pasadena	0.8649	0.2839	3.05
Constant: PG&E	1.2257	0.2833	4.33
Constant: SCE	-1.2402	1.0928	-1.13
Constant: SDG&E	1.0604	0.2823	3.76
Overall Constant	5.1914	0.5588	9.29
Trend Variables			
Time: Burbank/Glendale	0.0102	0.0022	4.59
Time Squared: Burbank/Glendale	-0.0002	0.0001	-2.57
Time: IID	0.0057	0.0009	5.98
Time: LADWP	0.0036	0.0010	3.63
Time: Pasadena	0.0125	0.0033	3.77
Time Squared: Pasadena	-0.0001	0.0001	-1.24
Time: PG&E	0.0013	0.0010	1.31
Time: SCE	0.0025	0.0015	1.73
Time: SDG&E	0.0031	0.0010	3.15
Time: SMUD	-0.0020	0.0009	-2.20
Adjusted for autocorrelation and cross-sectional correlation Wald chi squared = 21,694 Dependent variable = natural log of electricity consumption per household by planning area, 1980-2010 All variables in logged form except time and unemployment rate			

Source: California Energy Commission, Demand Analysis Office, 2012

Table D-2: Commercial Sector Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Commercial Floor Space (mm. sq. ft.)	0.7035	0.0713	9.87
% of Floor Space Refrigerated	16.4421	2.2871	7.19
Commercial Employment/Floor Space	0.3489	0.0912	3.83
Gross Product (billion 2010$)	0.2038	0.0714	2.86
Commercial Electricity Rate (2010¢/kWh)	-0.0308	0.0163	-1.89
Natural Gas Rate: except SMUD (2010$/mm. BTU)	0.0136	0.0073	1.86
Number of Cooling Degree Days (65^{o})	0.0526	0.0084	6.23
Dummy: 2001	-0.0361	0.0077	-4.67
Constant: Burbank/Glendale	-0.2126	0.0365	-5.83
Constant: Pasadena	0.1049	0.0844	1.24
Constant: SCE	-0.0210	0.0175	-1.2
Overall Constant	2.8337	0.1974	14.36
Trend Variables			
Time: Except Burbank/Glendale and SCE	0.0113	0.0015	7.41
Time Squared: Except Burbank/Glendale and SCE	-0.00028	0.00004	-7.15
Time: Burbank/Glendale	0.0412	0.0045	9.11
Time Squared: Burbank/Glendale	-0.0008	0.0001	-6.19
Time: SCE	0.0135	0.0020	6.79
Time Squared: SCE	-0.0002	0.0001	-3.59
Additional Time Impact: IID	0.0071	0.0010	7.26
Additional Time Impact: Pasadena	0.0087	0.0044	1.99
Additional Time Impact: PG&E	0.0024	0.0009	2.76
Additional Time Impact: SDG&E	0.0027	0.0007	3.65
Adjusted for autocorrelation and cross-sectional correlation Wald chi squared = 320,179 Dependent variable = natural log of commercial consumption by planning area, 1980-2010 All variables in logged form except time and % of floor space refrigerated			

Source: California Energy Commission, Demand Analysis Office, 2012

Table D-3: Manufacturing Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Manufacturing Output (million 2010$)	0.5270	0.0550	9.58
Manufacturing Output/Manufacturing Employment	-0.3562	0.0495	-7.19
Output Text.,Paper, and Metals*/Manufacturing Output	0.8923	0.2805	3.18
Industrial Electricity Rate (2010¢/kWh)	-0.1277	0.0261	-4.90
Constant: Burbank/Glendale	0.7289	0.1832	3.98
Constant: LADWP	1.3997	0.2349	5.96
Constant: Pasadena	-0.3835	0.1305	-2.94
Constant: PG&E	2.6133	0.2794	9.35
Constant: SCE	2.4707	0.2857	8.65
Constant: SDG&E	0.7602	0.1918	3.96
Overall Constant	3.2820	0.2712	12.10
Trend Variables	3.3431	0.2805	11.92
Time: Burbank/Glendale	-0.0432	0.0067	-6.49
Time: IID	-0.0820	0.0164	-4.99
Time Squared: IID	0.0031	0.0005	5.70
Time: Pasadena	-0.0451	0.0039	-11.55
Time: SDG&E	0.0313	0.0053	5.94
Time Squared: SDG&E	-0.0008	0.0001	-5.74
Time: SMUD	0.0916	0.0189	4.84
Time Squared: SMUD	-0.0018	0.0006	-3.14
Adjusted for autocorrelation and cross-sectional correlation Wald chi squared = 34,019 Dependent variable = natural log of industrial consumption by planning area, 1980-2010 All variables in logged form except time and output textiles, paper, and metals/manufacturing output *Includes textiles, fiber, printing, and metal and machine manufacturing			

Source: California Energy Commission, Demand Analysis Office, 2012

Table D-4: Resource Extraction and Construction Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Output, Resource Extraction (million 2010$)	0.2604	0.0528	4.93
Employment in Construction (thousands)	0.1807	0.0772	2.34
Industrial Electricity Rate (2010$/kWh)	-0.2366	0.1083	-2.18
Constant: BUGL	1.7381	0.2109	-5.08
Constant: IID	1.3677	0.2718	-5.30
Constant: LADWP	3.4591	0.1763	3.69
Constant: PASD	-0.2759	0.2457	-12.56
Constant: PG&E	5.7893	0.2828	10.54
Constant: SCE	5.2073	0.2981	8.04
Constant: SDG&E	3.2042	0.2231	1.77
Constant: SMUD	2.8092	0.3922	7.16
Dummy: 1997 SDGE	-1.1351	0.2247	-5.05
Time: BUGL	0.0819	0.0199	4.12
Time squared: BUGL	-0.0018	0.0006	-2.85
Time: IID	0.1060	0.0228	4.65
Time squared: IID	-0.0019	0.0007	-2.74
Time: PASD	0.3003	0.0201	14.97
Time squared: PASD	-0.0090	0.0006	-13.91
Time: PGE	-0.1016	0.0217	-4.69
Time squared: PGE	0.0032	0.0007	4.71
Time squared: SDGE	0.0999	0.0245	4.08
Time: SDGE	-0.0033	0.0008	-4.33
Time: SMUD	0.0272	0.0055	4.93
Procedure: SAS Least Square Dummy Variable model Root MSE = 0.2148 Dependent variable = natural log of construction & resource extraction consumption by planning area 1982-2010 All variables in logged form except time			

Source: California Energy Commission, Demand Analysis Office, 2012

Table D-5: Peak Demand Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Per capita income (2010$)	0.3478	0.0364	9.55
Unemployment Rate	-0.0016	0.0009	-1.79
Number of Households/Population	2.6792	0.5402	4.96
Residential Electricity Rate	-0.0647	0.0218	-2.97
Annual Max *Average631* Temperature	1.1932	0.0554	21.53
Dummy: 2001	-0.0816	0.0090	-9.03
Dummy: 2002	-0.0196	0.0090	-2.19
Constant: Burbank/Glendale	-0.2736	0.0284	-9.63
Constant: IID	0.3717	0.0391	9.50
Constant: LADWP	-0.3608	0.0186	-19.45
Constant: Pasadena	-0.2842	0.0267	-10.66
Constant: PG&E	-0.2644	0.0149	-17.79
Constant: SCE	-0.2374	0.0270	-8.78
Constant: SDG&E	-0.5336	0.0278	-19.18
Overall Constant	-9.0345	0.5536	-16.32
Trend Variables			
Time: Burbank/Glendale	0.0102	0.0025	4.07
Time Squared: Burbank/Glendale	-0.0001	0.0001	-1.92
Time: Imperial Irrigation District	0.0115	0.0026	4.47
Time Squared: Imperial Irrigation	-0.0002	0.0001	-2.44
Time: LADWP	0.0114	0.0027	4.18
Time Squared: LADWP	-0.0003	0.0001	-3.67
Time: Pasadena	0.0263	0.0032	8.33
Time Squared: Pasadena	-0.0007	0.0001	-7.08
Time: SCE	0.0072	0.0024	2.97
Time Squared: SCE	-0.0001	0.0001	-2.05
Time: SDG&E	0.0056	0.0012	4.66

Adjusted for autocorrelation and cross-sectional correlation

Wald chi squared = 14,339

Dependent variable = natural log of annual peak per capita by planning area, 1980-2010

All variables in logged form except time, unemployment rate, and numbers of households/population

Source: California Energy Commission, Demand Analysis Office, 2012

Table D-6: SubRegional Analysis—Regression Results for PG&E

Variable	Estimated Coefficient	Standard Error	t-statistic
Max631 Temperature	0.0178	0.001344	13.25
Minimum Temperature	0.001757	0.002014	0.87
Dummy Constant: Weekend	-0.0900	0.006681	-13.47
Constant	8.02	0.0943	85.08
Adjusted for autocorrelation: rho = 0.441, Durbin-Watson statistic = 1.7987 R- Squared = 0.9185 Dependent variable = natural log of daily afternoon peak, June 15 - September 15, 2011			

Source: California Energy Commission, Demand Analysis Office, 2012

Table D-7: SubRegional Analysis—Regression Results for PG&E Bay Area

Variable	Estimated Coefficient	Standard Error	t-statistic
Max631 Temperature	0.0139	0.000835	16.63
Minimum Temperature	0.004630	0.001621	2.86
Dummy Constant: Weekend	-0.1506	0.006854	-21.97
Constant	7.4542	0.0915	81.45
Adjusted for autocorrelation: rho = 0.2545, Durbin-Watson statistic = 1.9465 R- Squared = 0.9268 Dependent variable = natural log of daily afternoon peak, June 15 - September 15, 2011			

Source: California Energy Commission, Demand Analysis Office, 2012

Table D-8: SubRegional Analysis—Regression Results for PG&E Non-Bay Area

Variable	Estimated Coefficient	Standard Error	t-statistic
Max631 Temperature	0.0182	0.001590	11.44
Minimum Temperature	0.001586	0.002004	0.79
Dummy Constant: Weekend	-0.0562	0.007992	-7.03
Constant	7.3739	0.1046	70.47
Adjusted for autocorrelation: rho = 0.4713, Durbin-Watson statistic = 1.7057 R- Squared = 0.8954 Dependent variable = natural log of daily afternoon peak, June 15 - September 15, 2011			

Source: California Energy Commission, Demand Analysis Office, 2012

Table D-9: SubRegional Analysis—Regression Results for SCE

Variable	Estimated Coefficient	Standard Error	t-statistic
Max631 Temperature	300.5114	19.2851	15.58
Minimum Temperature	93.0387	30.9853	3.00
Dummy Constant: Weekend	-1732	145.9877	-11.86
Constant	-14362	1498	-9.58
Adjusted for autocorrelation: rho = 0.2667, Durbin-Watson statistic = 1.977 R- Squared = 0.9325 Dependent variable = daily afternoon peak, June 15 - September 15, 2011			

Source: California Energy Commission, Demand Analysis Office, 2012

Table D-10: SubRegional Analysis—Regression Results for SDG&E

Variable	Estimated Coefficient	Standard Error	t-statistic
Max631 temperature<=80 degrees	49.69	5.45	9.12
80<Max631<=85	97.14	9.35	10.39
Max631>85	73.02	8.49	9.33
Minimum Temperature	14.48	5.24	2.77
Dummy Constant: Weekend	-373.01	19.68	-18.95
Constant	-1696.48	510.35	-3.32
Adjusted for autocorrelation: rho = 0.402, Durbin-Watson statistic = 1.859 R- Squared = 0.944 Dependent variable = daily afternoon peak, June 15 - September 15, 2011			

Source: California Energy Commission, Demand Analysis Office, 2012