California Energy Commission

COMMISSION FINAL REPORT

CALIFORNIA ENERGY DEMAND 2014–2024 FINAL FORECAST

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

CALIFORNIA
ENERGY COMMISSION

Edmund G. Brown Jr., Governor

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ABSTRACT

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

Keywords: Electricity, demand, consumption, forecast, weather normalization, peak, natural gas, self-generation, conservation, energy efficiency, climate zone, forecast methods, additional achievable energy efficiency.

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EXECUTIVE SUMMARY

Introduction

The *California Energy Demand 2014 – 2024 Final Forecast* (*CED 2013 Final*) report describes 10-year forecasts for electricity and end-user natural gas in California and for major utility planning areas within the state. The report supports electricity and natural gas system assessments and analysis of progress toward demand-side policy goals. Work described in this report continues a major staff effort to improve the measurement of energy efficiency, distributed generation, and other demand-side impacts within the energy demand forecast.

CED 2013 Final includes three baseline scenarios designed to capture a reasonable range of demand outcomes over the next 10 years. The *high energy demand* case incorporates relatively high economic/demographic growth, relatively low electricity and natural gas rates, and relatively low committed efficiency program, self-generation, and climate change impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed rates, and higher committed efficiency program and self-generation impacts. The *mid* case uses input assumptions at levels between the *high* and *low* cases.

Staff also developed estimates of additional achievable energy efficiency impacts for the investor-owned utilities that are incremental to (do not overlap with) committed efficiency savings included in the *CED 2013 Final* baseline scenarios. Forecasts adjusted to reflect these additional savings are presented in this report.

Baseline Electricity Forecast Results

Table ES-1 compares the *CED 2013 Final* baseline forecast for selected years with the mid demand scenario from the previous Energy Commission adopted forecast, *California Energy Demand 2012 – 2022 Final Forecast* (*CED 2011).* Statewide electricity consumption begins the forecast period about 0.3 percent below *CED 2011*, as actual economic growth in California was slower than had been predicted in 2011. By 2022, consumption is around 1.4 percent lower in the mid demand case. The high demand case, with higher projected growth in consumption, matches the *CED 2011* mid case by 2016. Statewide noncoincident peak demand, adjusted to account for atypical weather, is around 3 percent lower than predicted in the *CED 2011* mid case in 2012 but grows at a higher rate from 2012 – 2022 in the mid case.

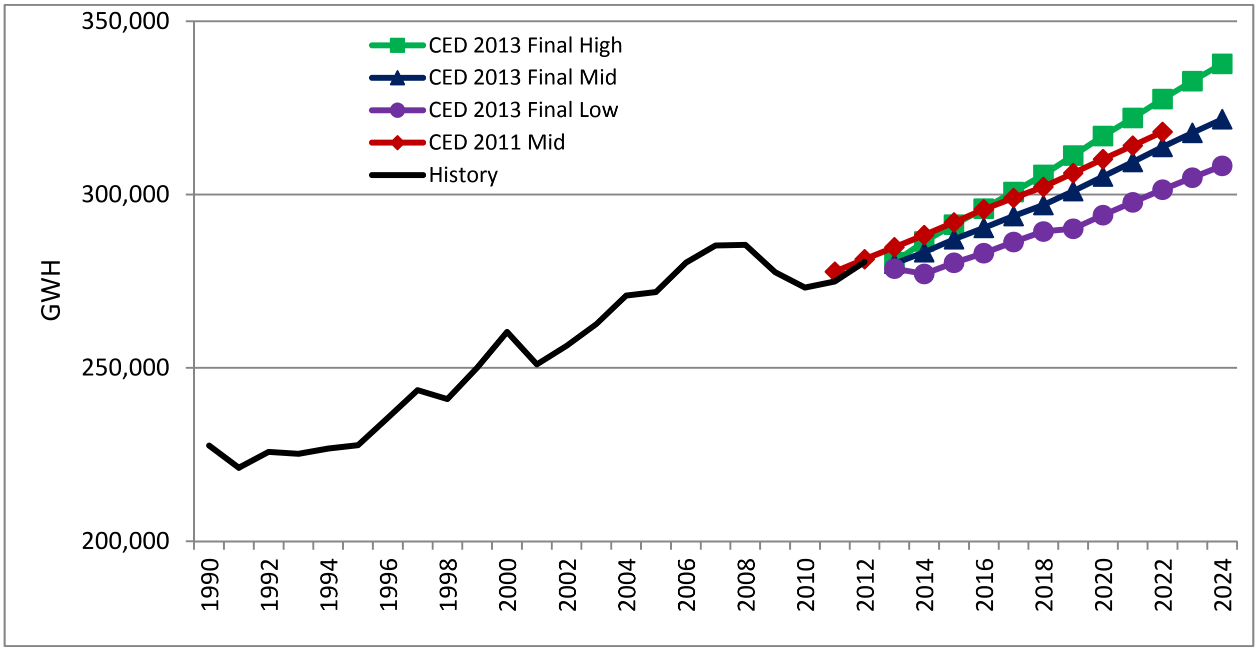
Table ES-1: Comparison of *CED 2013 Final* and *CED 2011* Mid-Demand Baseline Forecasts of Statewide Electricity Demand

Consumption (GWh)				
	CED 2011Mid Energy Demand	***CED 2013 Final High Energy Demand***	***CED 2013 Final Mid Energy Demand***	***CED 2013 Final Low Energy Demand***
1990	227,586	227,576	227,576	227,576
2000	261,381	260,399	260,399	260,399
2012	281,347	280,561	280,561	280,561
2015	291,965	291,307	287,104	280,314
2020	310,210	316,874	305,218	294,056
2024	--	337,713	321,734	308,277
	Average Annual Growth Rates			
1990-2000	1.39%	1.36%	1.36%	1.36%
2000-2012	0.62%	0.62%	0.62%	0.62%
2012-2015	1.24%	1.26%	0.77%	-0.03%
2012-2022	1.20%	1.56%	1.12%	0.72%
2012-2024	--	1.56%	1.15%	0.79%
Noncoincident Peak (MW)				
	CED 2011Mid Energy Demand	***CED 2013 Final High Energy Demand***	***CED 2013 Final Mid Energy Demand***	***CED 2013 Final Low Energy Demand***
1990	47,546	47,543	47,543	47,543
2000	53,700	53,702	53,702	53,702
2012		59,931	59,931	59,931
2012*	61,796	59,811	59,811	59,811
2015	65,036	64,941	64,121	61,899
2020	69,418	70,933	68,321	65,029
2024	--	75,153	71,312	67,203
	Average Annual Growth Rates			
1990-2000	1.22%	1.23%	1.23%	1.23%
2000-2012	1.18%	0.90%	0.90%	0.90%
2012-2015	1.72%	2.78%	2.35%	1.15%
2012-2022	1.38%	2.03%	1.58%	1.03%
2012-2024	--	1.92%	1.48%	0.98%
Historical values are shaded.				
*Weather normalized: *CED 2013 Final* uses a weather-normalized peak value derived from the actual 2012 peak for calculating growth rates during the forecast period.				

Source: California Energy Commission, Demand Analysis Office, 2013.

Figure ES-1 shows projected *CED 2013 Final* electricity consumption for the three baseline scenarios compared to the *CED 2011* mid demand consumption forecast. Growth is flat or declining in 2013 in the new forecast because (1) the number of cooling degree days was historically high in 2012 and the forecast assumes a historical average in 2013; and (2) new efficiency programs not included in *CED 2011* are introduced by utilities. From 2013 onward, *CED 2013 Final* consumption grows at a faster average annual rate through 2022 in the high case, at the same rate in the mid case, and at a slower rate in the low scenario compared to the mid scenario from *CED 2011*.

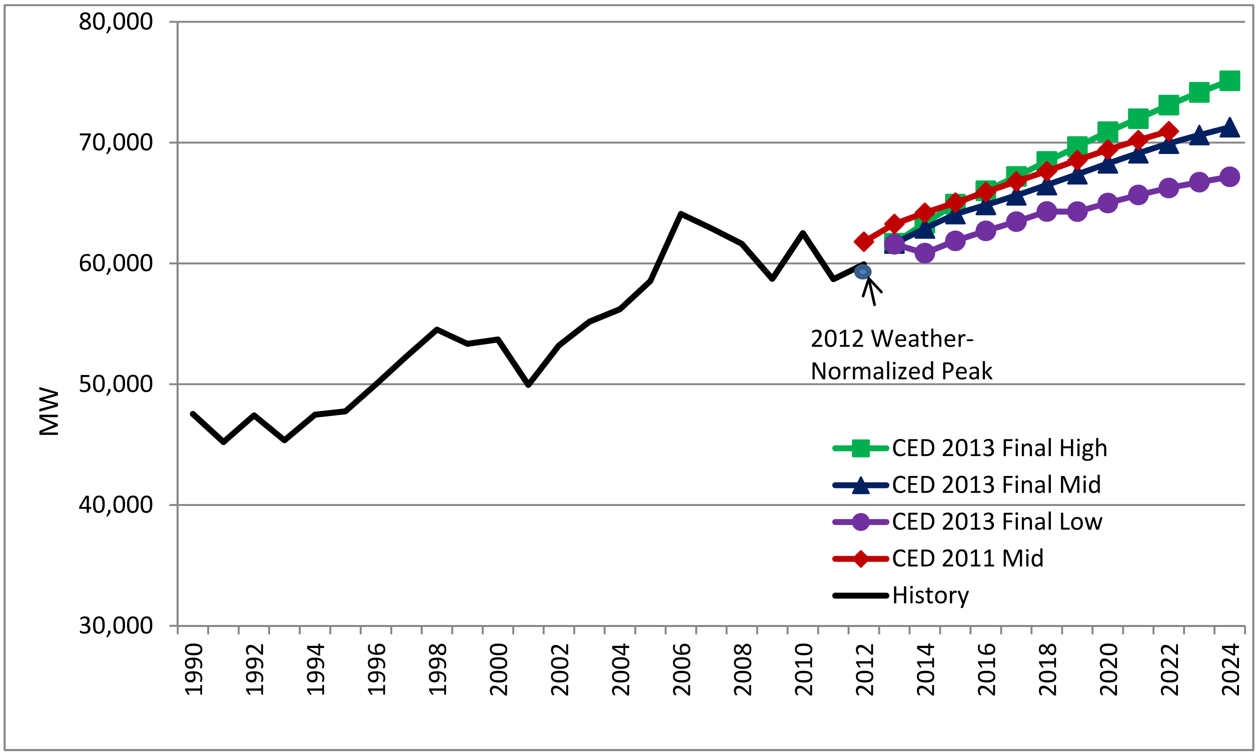
Figure ES-1: Statewide Baseline Annual Electricity Consumption



Source: California Energy Commission, Demand Analysis Office, 2013.

Figure ES-2 shows *CED 2013 Final* baseline statewide noncoincident peak demand compared with the *CED 2011* mid demand case. The figure also shows the statewide weather-normalized peak in 2012. This adjusted total is very close to the actual peak; although 2012 was historically a relatively warm year on average, it was a fairly normal year for the highest temperatures, which typically determine annual peak demand. Weather-adjusted peak demand in 2012 was lower than projected in the *CED 2011* mid case, reflecting slower economic growth than was predicted in 2011. The *CED 2013 Final* high case reaches the *CED 2011* mid case level by 2016. From 2013 onward, peak demand grows at about the same rate in the new mid case and *CED 2011* mid case.

Figure ES-2: Statewide Baseline Annual Noncoincident Peak Demand



Source: California Energy Commission, Demand Analysis Office, 2013.

At a statewide level, projected baseline electricity results in *CED 2013 Final* are slightly higher than in the revised version of this forecast released in September 2013 because of revisions to historical consumption for the PG&E planning area and to 2013 peaks for PG&E and SCE, along with a change in the accounting method for efficiency program savings decay for the investor-owned utilities.

Baseline Natural Gas Forecast Results

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

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

Consumption (MM Therms)				
	CED 2011 Mid Case	***CED 2013 Final High Energy Demand***	***CED 2013 Final Mid Energy Demand***	***CED 2013 Final Low Energy Demand***
1990	12,893	12,893	12,893	12,893
2000	13,913	13,913	13,913	13,913
2012	13,123	12,767	12,767	12,767
2015	13,503	12,736	12,687	12,176
2020	13,961	12,816	12,774	12,423
2024	--	12,801	12,806	12,569
	Average Annual Growth Rates			
1990-2000	0.76%	0.76%	0.76%	0.76%
2000-2012	-0.49%	-0.71%	-0.71%	-0.71%
2012-2015	0.96%	-0.08%	-0.21%	-1.57%
2012-2022	0.70%	0.06%	0.04%	-0.19%
2012-2024	--	0.02%	0.03%	-0.13%
Historical values are shaded.				

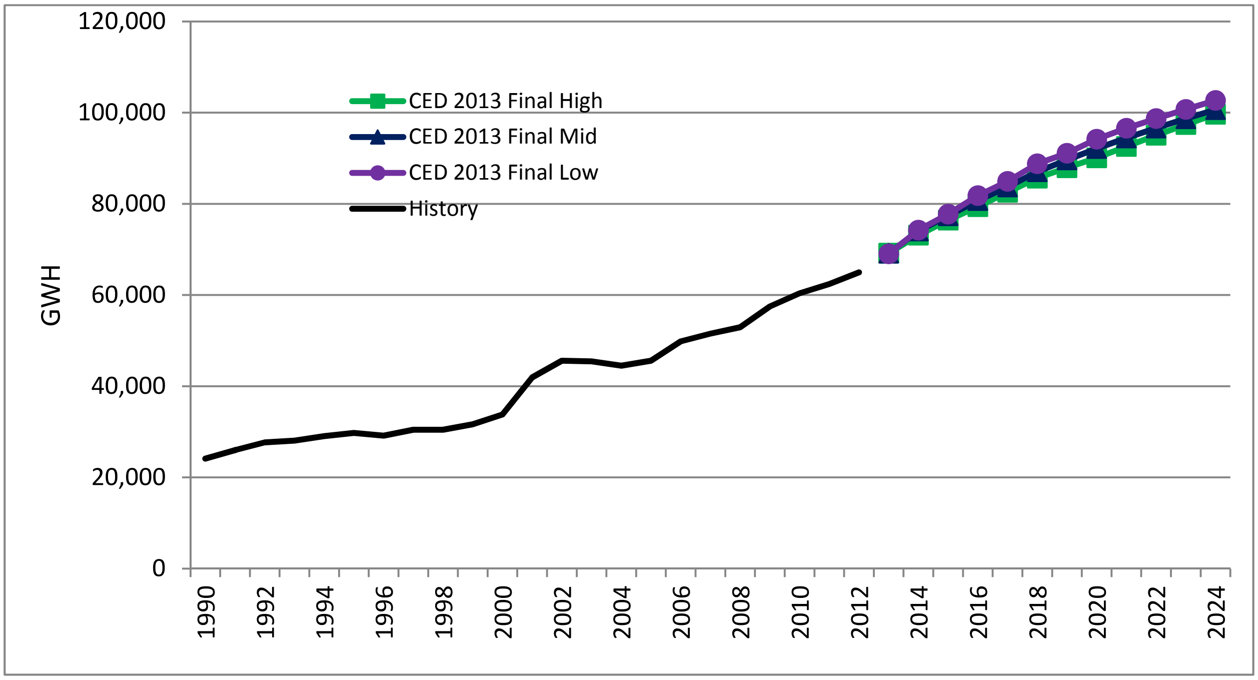
Source: California Energy Commission, Demand Analysis Office, 2013.

Committed Conservation/Efficiency

Energy Commission demand forecasts seek to account for efficiency and conservation that has or is likely to occur. Traditionally, the forecasts have made a distinction between committed and uncommitted, or achievable, efficiency impacts. The baseline forecasts in *CED 2013 Final* continue that distinction, with only committed efficiency included. Committed initiatives include those having final authorization, firm funding, and a program plan. Committed impacts also include price and other market effects not directly related to a specific initiative.

Figure ES-3 shows staff estimates of historical and projected committed savings impacts, which include those from programs, codes and standards, and price and other market effects. Within the demand scenarios, higher demand yields more standards savings since new construction and appliance usage increase, while lower demand is associated with more program savings and higher rates (and therefore more price effects). The net result is that savings vary inversely with demand outcome, although the totals are very similar.

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

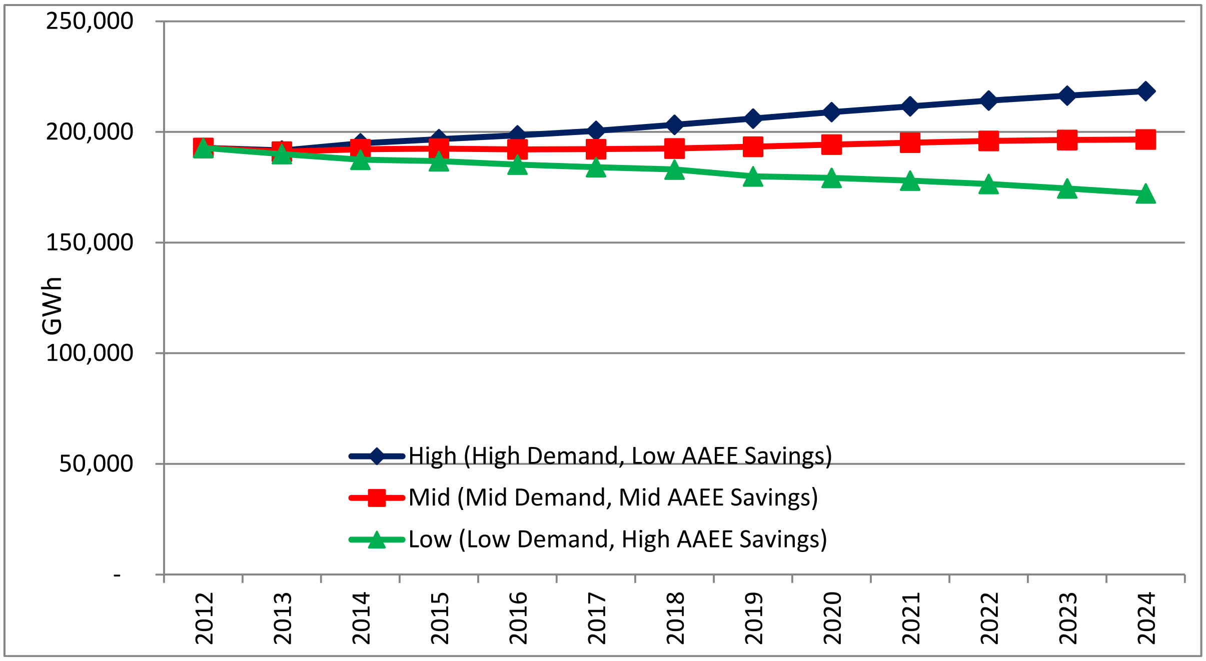


Source: California Energy Commission, Demand Analysis Office, 2013.

Additional Achievable Energy Efficiency

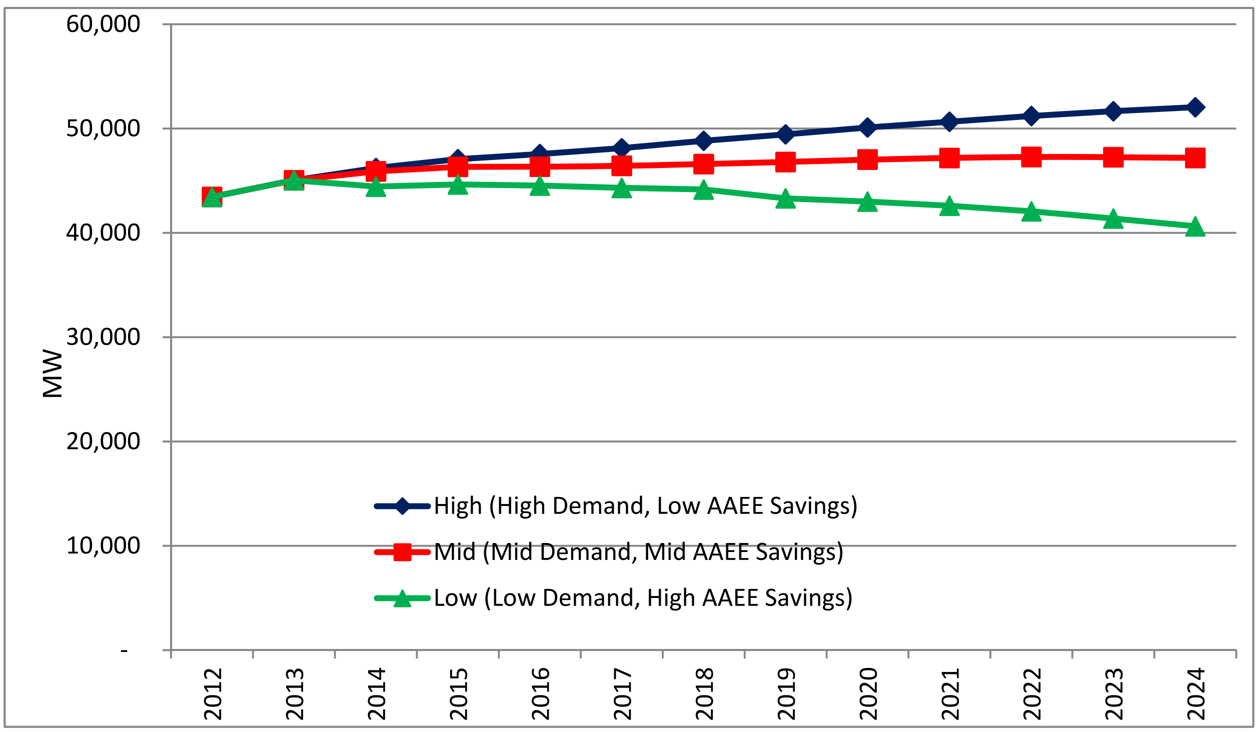
CED 2013 Final includes estimates of additional achievable (uncommitted) energy efficiency for the investor-owned utility service territories. These savings are not yet considered committed but are deemed reasonably likely to occur, and include impacts from future updates of building codes and appliance standards and utility efficiency programs expected to be implemented after 2014. Five different savings scenarios were developed. This report shows the impact of additional achievable electricity consumption, peak demand, and natural gas consumption savings incorporated in adjusted (relative to the baseline) forecasts for these service territories. **Figure ES-4** and **Figure ES-5** show adjusted forecasts for electricity sales and peak demand, respectively, for the combined investor-owned utility service territories, where additional achievable savings from the low scenario are combined with the high demand baseline case, savings from the high scenario are combined with the low demand baseline case, and mid scenario savings are paired with the mid demand baseline case. These savings have a significant impact on projected sales and peak: the adjusted mid case totals for sales and peak are around 10 percent lower (about 21,000 GWh and 5,200 MW, respectively) than the baseline mid demand case by 2024.

Figure ES-4: Adjusted Demand Scenarios for Electricity Sales, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2013.

Figure ES-5: Adjusted Demand Scenarios for Peak, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2013.

Summary of Changes to Forecast

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

For *CED 2011*, econometric models were estimated for the residential, commercial, and industrial electricity sectors. *CED 2013 Final* adds econometric models for the other electricity sectors (agriculture and water pumping; transportation, communications, and utilities; and street lighting), as well as for the major natural gas sectors. Adjustments were made to existing models based on the econometric estimations. In addition, staff is developing a new industrial end-use energy model. Although this model is not yet complete, enough progress has been made to allow use in *CED 2013 Final*.

As part of the continuing effort to capture comprehensively the impacts of energy efficiency initiatives, *CED 2013 Final* incorporates recent revisions to Energy Commission building codes and appliance standards and projected savings from the 2013–2014 California Public Utilities Commission efficiency program cycle for investor-owned utilities and from 2013 programs for the publicly owned utilities. Along with these new committed efficiency initiatives, *CED 2013 Final* provides estimates of additional achievable energy efficiency savings for the investor-owned utility service territories. This report presents both baseline and adjusted forecasts for these areas.

In addition to a predictive model to forecast residential adoption of photovoltaic systems and solar water heaters used in *CED 2011*, *CED 2013 Final* employs a predictive model for the commercial sector that projects adoption of combined heat and power and photovoltaic systems. These models are based on methods used by the United States Energy Information Administration, as part of its National Energy Modeling System, and the National Renewable Energy Laboratory.

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

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

CHAPTER 1: Statewide Baseline Forecast Results and Methods

Introduction

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

CED 2013 Final was submitted for adoption by the Energy Commission at a business meeting on December 11, 2013. The final forecasts will be used in a number of applications, including the California Public Utilities Commission (CPUC) 2014 Long Term Procurement Plan (LTPP). The CPUC has identified the *Integrated Energy Policy Report (IEPR)* process as "the appropriate venue for considering issues of load forecasting, resource assessment, and scenario analyses, to determine the appropriate level and ranges of resource needs for load serving entities in California."[1] The final forecasts will also be an input to California Independent System Operator (California ISO) controlled grid studies and other transmission planning studies and in the *California Gas Report*[2] and electricity supply-demand (resource adequacy) assessments.

CED 2013 Final includes three full baseline 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. The baseline forecast comparisons presented in this report show the three *CED*

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

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

2013 Final cases versus the adopted *California Energy Demand 2012 – 2022 Final Forecast*[3] (*CED 2011*) mid demand case, except where otherwise noted.

This report also documents estimates of additional achievable energy efficiency (AAEE) impacts for the investor-owned utility (IOU) service territories that are incremental to (do not overlap with) committed efficiency savings included in the baseline *CED 2013 Final* forecasts. Adjusted forecasts for these service territories that combine the three baseline demand forecasts with five AAEE scenarios are provided. At the December 11 business meeting, stakeholders will be asked to provide their recommendation for a single planning forecast for the IOUs that combines baseline and AAEE elements.

Summary of Changes to Forecast

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

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

As part of the continuing effort to capture comprehensively the impacts of energy efficiency initiatives, *CED 2013 Final* incorporates recent revisions to Energy Commission building codes and appliance standards, including projected effects from the 2013 updates to the Title 24 building standards and the battery charger standards, to be implemented in 2014. Utility program impacts were updated to include projected savings from the 2013 – 2014 CPUC efficiency program cycle for IOUs and from 2013 programs for the publicly owned utilities (POUs). Along with these new committed efficiency initiatives, *CED 2013 Final* provides estimates of AAEE savings for the investor-owned utility service territories. This report presents both baseline and AAEE-adjusted forecasts for these areas. Chapter 3 provides details on staff work related to committed efficiency impact measurement. Chapter 4 of this volume and the

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3 California Energy Commission. June 2012. *California Energy Demand 2012 – 2022 Final Forecast.* CEC-200-2012-001-CMF (Volumes 1 and 2). http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-CMF-V1.pdf and http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-CMF-V2.pdf.

IOU electricity planning area chapters in Volume 2 provide AAEE estimates and adjusted IOU forecasts. Chapter 2 of this volume gives AAEE estimates for the natural gas planning areas.

Staff used a predictive model to forecast residential adoption of photovoltaic systems (PV) and solar water heaters for the first time in *CED 2011*. *CED 2013 Final* also employs a predictive model for the commercial sector that projects adoption of combined heat and power (CHP) and PV systems. These models are based on methods used by the United States Energy Information Administration (U.S. EIA), as part of its National Energy Modeling System (NEMS), and the National Renewable Energy Laboratory (NREL). Details of the residential PV and commercial CHP and PV models are provided in Appendix B.

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

Stakeholders have expressed a strong interest in a more disaggregated demand forecast to better inform resource and infrastructure-related analyses and decisions. As a first step in this direction, staff developed results at the climate zone level for *CED 2013 Final* in addition to the usual planning area forecasts. Climate zone results are provided in the planning area chapters in Volume 2 of this report. The appropriate level of disaggregation for future forecasts, given data and other resource constraints, will be determined through internal discussions and input from stakeholders after the *CED 2013* forecast cycle.

Changes From Revised to Final Forecast

Staff prepared a revised forecast[4] (*CED 2013 Revised*), presented in a workshop on October 1, 2013. In addition to incorporation of AAEE savings, the analysis for *CED 2013 Final* reflects the following updates and changes:

- Updated historical consumption data for 2012 for the Pacific Gas and Electric (PG&E) planning area, which raises the forecast starting point by around 2,200 GWh.
- Updated, weather-normalized 2013 peak demand estimates for the IOU planning areas, based on actual 2013 electricity loads. Note that additional changes to peak demand have been made for the PG&E and Southern California Edison (SCE) planning areas since *CED 2013 Final* was submitted for adoption on December 11, 2013.[5]

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4 Kavalec, Chris, Nicholas Fugate, Bryan Alcorn, Mark Ciminelli, Asish Gautum, Kate Sullivan, and Malachi Weng-Gutierrez, 2013. *California Energy Demand 2014–2024 Revised Forecast, Volumes 1 and 2.* California Energy Commission, Electricity Supply Analysis Division. CEC-200-2013-004 SD-V1-REV and CEC-200-2013-004 SD-V2-REV.

5 These final changes are a result of discussions both internally and with the utilities on weather normalization methods for peak demand, particularly the specification of a proper historical period to be used to develop “normal” temperatures for peak weather normalization. Based on these discussions, staff

- Eliminated the assumption that 50 percent of IOU efficiency program savings decay is made up for with additional savings, based on input from CPUC Energy Division staff.
- Updated electric vehicle forecast.

At the statewide level, projected baseline electricity results are slightly higher than in *CED 2013 Revised* because of the higher starting point for PG&E and less projected committed efficiency program savings as a result of a more savings decay. In addition, the updated 2013 peak demand estimates for the PG&E and SCE planning areas are slightly higher. For the state as a whole, electricity consumption is 1.0 percent higher, peak demand less than 0.1 percent higher, and end-user natural gas consumption 0.5 percent higher by 2024 in the mid demand baseline. The electric vehicle forecast is lower than in *CED 2013 Revised*, so some of the electricity planning areas show slightly lower baseline forecasts.

Statewide Baseline Forecast Results

Table 1 compares the *CED 2013 Final* baseline forecast for selected years with the *CED 2011* mid demand case. For statewide electricity consumption, the new forecast begins about 0.3 percent below *CED 2011* in 2012, reflecting less actual economic growth in California than had been predicted in 2011. Consumption in the new mid scenario grows at a slower rate through 2022 compared to the *CED 2011* mid case as a result of lower projected population growth and the introduction of updated Title 24 and new Title 20 standards during the forecast period. By 2022, consumption is around 1.4 percent lower. In addition, consumption growth referenced to 2012 will be slower, all else equal, because this was a relatively warm year on average—warmer in general than forecasted years, which are based on historical average weather. The high demand case, with higher projected growth in consumption, matches the *CED 2011* mid case by 2016. Statewide noncoincident[6] weather-normalized[7] peak demand is around 3 percent lower than predicted in the *CED 2011* mid case in 2012 but grows at a higher rate from 2012-2022 in the mid case. IOU peak demands were rescaled from *CED 2013 Revised* estimates so that 2013 projections match newly estimated 2013 weather-normalized peaks.[8] Differences were non-trivial for PG&E and SCE planning areas, where 2013 peak demands (and

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agreed to reduce the historical period to 30 years (down from 64 years for PG&E and 54 years for SCE), recognizing that given the impacts of climate change, a shorter, more recent historical period may serve as a better indicator of current "normal" temperatures. Incorporating a 30-year historical period raised estimated 2013 weather-normalized peaks by around 300 MW for both PG&E and SCE.

6 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.

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

8 2013 summer hourly loads for the IOUs became available in October 2013.

therefore demand for the rest of the forecast period) were increased by around 500 MW in each case.

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

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

Consumption (GWh)				
	CED 2011 Mid Energy Demand	***CED 2013 Final High Energy Demand***	***CED 2013 Final Mid Energy Demand***	***CED 2013 Final Low Energy Demand***
1990	227,586	227,576	227,576	227,576
2000	261,381	260,399	260,399	260,399
2012	281,347	280,561	280,561	280,561
2015	291,965	291,307	287,104	280,314
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	Average Annual Growth Rates			
1990-2000	1.39%	1.36%	1.36%	1.36%
2000-2012	0.62%	0.62%	0.62%	0.62%
2012-2015	1.24%	1.26%	0.77%	-0.03%
2012-2022	1.20%	1.56%	1.12%	0.72%
2012-2024	--	1.56%	1.15%	0.79%
Noncoincident Peak (MW)				
	CED 2011 Mid Energy Demand	*CED 2013 Final High Energy Demand*	*CED 2013 Final Energy Demand*	*CED 2013 Final Low Energy Demand*
1990	47,546	47,543	47,543	47,543
2000	53,700	53,702	53,702	53,702
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2012*	61,796	59,811	59,811	59,811
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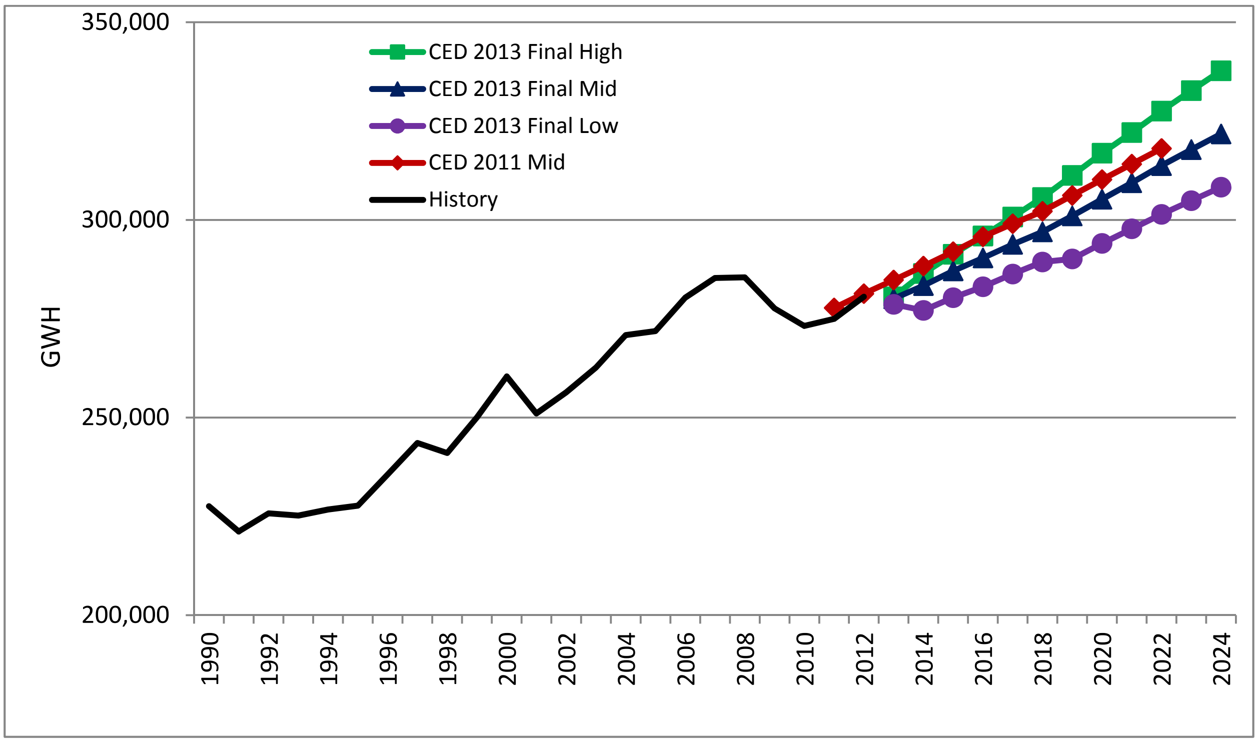
2024	--	75,153	71,312	67,203
	Average Annual Growth Rates			
1990-2000	1.22%	1.23%	1.23%	1.23%
2000-2012	1.18%	0.90%	0.90%	0.90%
2012-2015	1.72%	2.78%	2.35%	1.15%
2012-2022	1.38%	2.03%	1.58%	1.03%
2012-2024	--	1.92%	1.48%	0.98%
Historical values are shaded.				
*Weather normalized: *CED 2013 Final* uses a weather-normalized peak value derived from the actual 2012 peak for calculating growth rates during the forecast period				

Source: California Energy Commission, Demand Analysis Office, 2013.

Annual Electricity Consumption

Figure 1 shows statewide historical electricity consumption, projected *CED 2013 Final* baseline consumption for the three scenarios, and the *CED 2011* mid case demand consumption forecast. Growth is flat or declining in 2013 in the new forecast because (1) the number of cooling degree days was historically high in 2012 and the forecast assumes a historical average in 2013; and (2) new efficiency programs not included in *CED 2011* are introduced by utilities. From 2013 onward, *CED 2013 Final* consumption grows at a faster average annual rate through 2022 in the high case (1.74 percent), at about the same rate in the mid case (1.27 percent), and at a slower rate in the low scenario (0.88 percent) compared to *CED 2011* mid case (1.24 percent).

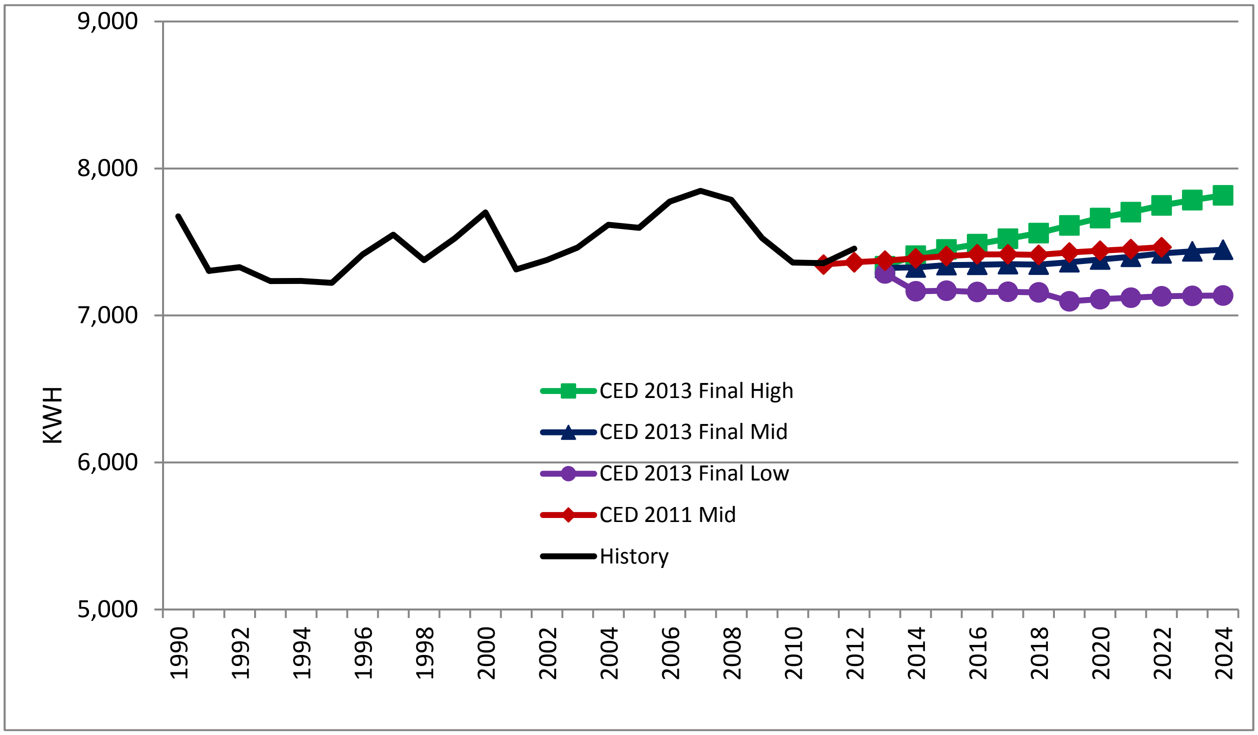
Figure 1: Statewide Baseline Annual Electricity Consumption



Source: California Energy Commission, Demand Analysis Office, 2013.

As shown in **Figure 2**, *CED 2013 Final* baseline per capita electricity consumption is projected to decrease from 2012 to 2013 because of flat total consumption growth combined with population increase. Thereafter, per capita consumption remains flat in the mid case scenario and declines in the low before rising slightly toward the end of the forecast period due to increasing electric vehicle use. The projected impacts of new efficiency initiatives keep the *CED 2013 Final* mid case below *CED 2011* through 2022. Higher economic/demographic growth in the high demand case increases per-capita consumption throughout the forecast period, surpassing that in the *CED 2011* mid case by 2015.

Figure 2: Statewide Baseline Electricity Annual Consumption per Capita



Source: California Energy Commission, Demand Analysis Office, 2013.

Table 2 compares projected baseline annual consumption in each scenario for the three major economic sectors—residential, commercial, and industrial (manufacturing, construction, and resource extraction)—with the *CED 2011* mid demand case. Projected residential and commercial sector growth in the *CED 2013 Final* mid case from 2012-2022 is slower compared to the *CED 2011* mid case, mainly because of a reversion to normal weather at the beginning of the forecast period from 2012, which was a historically warm year on average.

Table 2: Baseline Electricity Consumption by Sector

Residential Consumption (GWh)				
	CED 2011 Mid Energy Demand	***CED 2013 Final High Energy Demand***	***CED 2013 Final Mid Energy Demand***	***CED 2013 Final Low Energy Demand***
2012	91,934	90,651	90,651	90,651
2015	95,520	95,013	93,452	91,362
2020	104,853	107,291	101,475	97,060
2024	--	118,842	110,910	105,314
Average Annual Growth, Residential Sector				
2012-2022	1.78%	2.24%	1.59%	1.09%
2013-2022	1.80%	2.56%	1.84%	1.38%
2012-2024	--	2.28%	1.70%	1.26%
Commercial Consumption (GWh)				
	CED 2011 Mid Energy Demand	***CED 2013 Final High Energy Demand***	***CED 2013 Final Mid Energy Demand***	***CED 2013 Final Low Energy Demand***
2012	103,641	102,932	102,932	102,932
2015	108,514	107,305	105,788	104,116
2020	116,658	117,766	114,381	110,761
2024	--	124,574	120,179	116,450
Average Annual Growth, Commercial Sector				
2012-2022	1.45%	1.67%	1.34%	1.02%
2013-2022	1.46%	1.80%	1.46%	1.13%
2012-2024	--	1.60%	1.30%	1.03%
Industrial Consumption (GWh)				
	CED 2011 Mid Energy Demand	***CED 2013 Final High Energy Demand***	***CED 2013 Final Mid Energy Demand***	***CED 2013 Final Low Energy Demand***
2012	47,943	48,113	48,113	48,113
2015	49,276	49,364	48,491	46,363
2020	49,194	50,424	48,438	45,884
2024	--	51,247	48,331	45,003
Average Annual Growth, Industrial Sector				
2012-2022	0.14%	0.54%	0.06%	-0.56%
2012-2024	--	0.53%	0.04%	-0.56%
Historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2013.

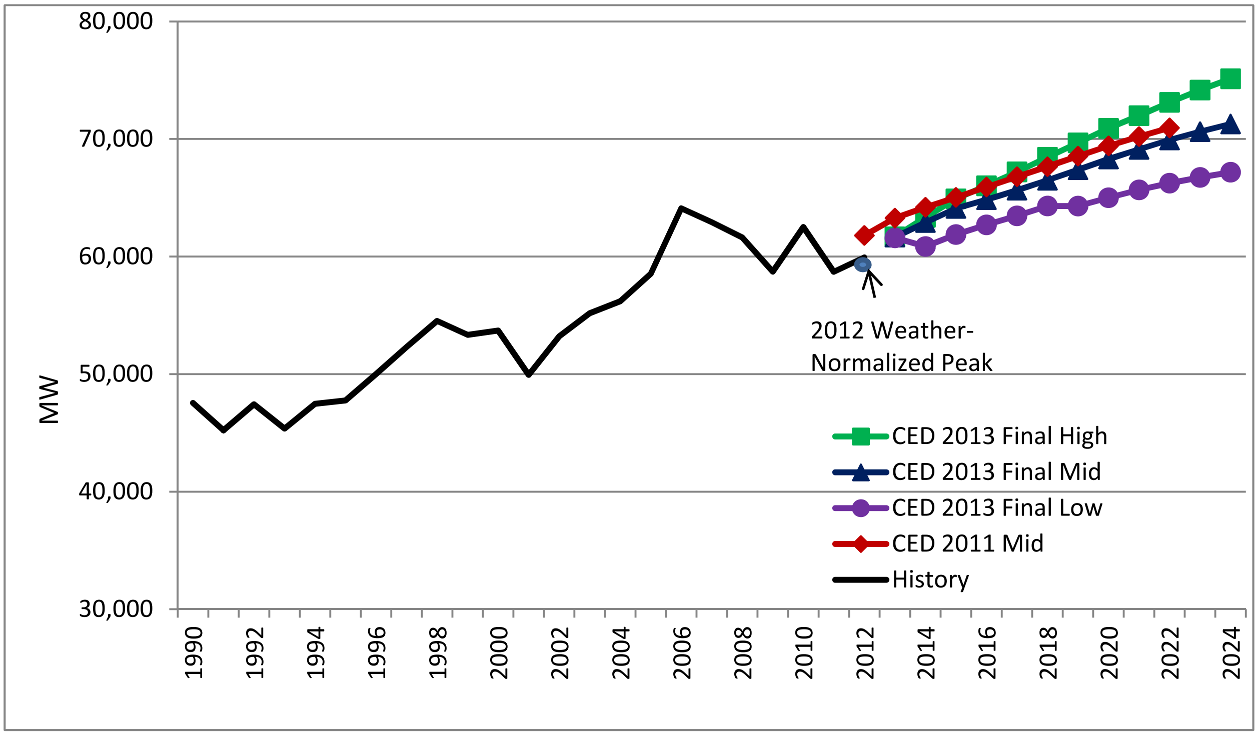
To compare across weather-normalized years, growth rates for 2013 – 2022 are also shown for the residential and commercial sectors; the rates of growth for the two residential and commercial mid cases are much closer when examining this period. The effect of lower population growth versus *CED 2011* on residential consumption is partially offset by higher per capita income, since personal income is projected to be about the same in the previous and new mid cases (see **Figure 7**), with a lower population in the latter. In addition, unlike *CED 2011*, the *CED 2013 Final* residential and commercial forecasts include projected consumption impacts from climate change that are increasing throughout the forecast period. Average annual growth in industrial consumption from 2012 – 2022 is slightly lower in the *CED 2013 Final* mid case than in the previous forecast, reflecting lower projected growth in resource extraction and construction.

Statewide Baseline Peak Demand

Figure 3 compares *CED 2013 Final* baseline statewide noncoincident peak demand with the *CED 2011* mid demand case. The figure also shows the statewide weather-normalized peak in 2012, and growth rates in the forecast period are calculated relative to this weather-normalized total. However, this adjusted total is very close to the actual peak; although 2012 was historically a relatively warm year on average, it was a fairly normal year for the highest temperatures, which typically determine annual peak demand.

Weather-adjusted peak demand in 2012 was lower than projected in the *CED 2011* mid case, reflecting slower economic growth than was predicted in 2011. As with consumption, growth in the *CED 2013 Final* mid case is similar to that in *CED 2011* mid case from 2013 onward. The *CED 2013 Final* high case reaches the *CED 2011* mid case level by 2016, with average annual growth of 1.92 percent from 2012-2024. Peak demand in the low demand case averages 0.97 percent per year over the same period.

Figure 3: Statewide Baseline Annual Noncoincident Peak Demand

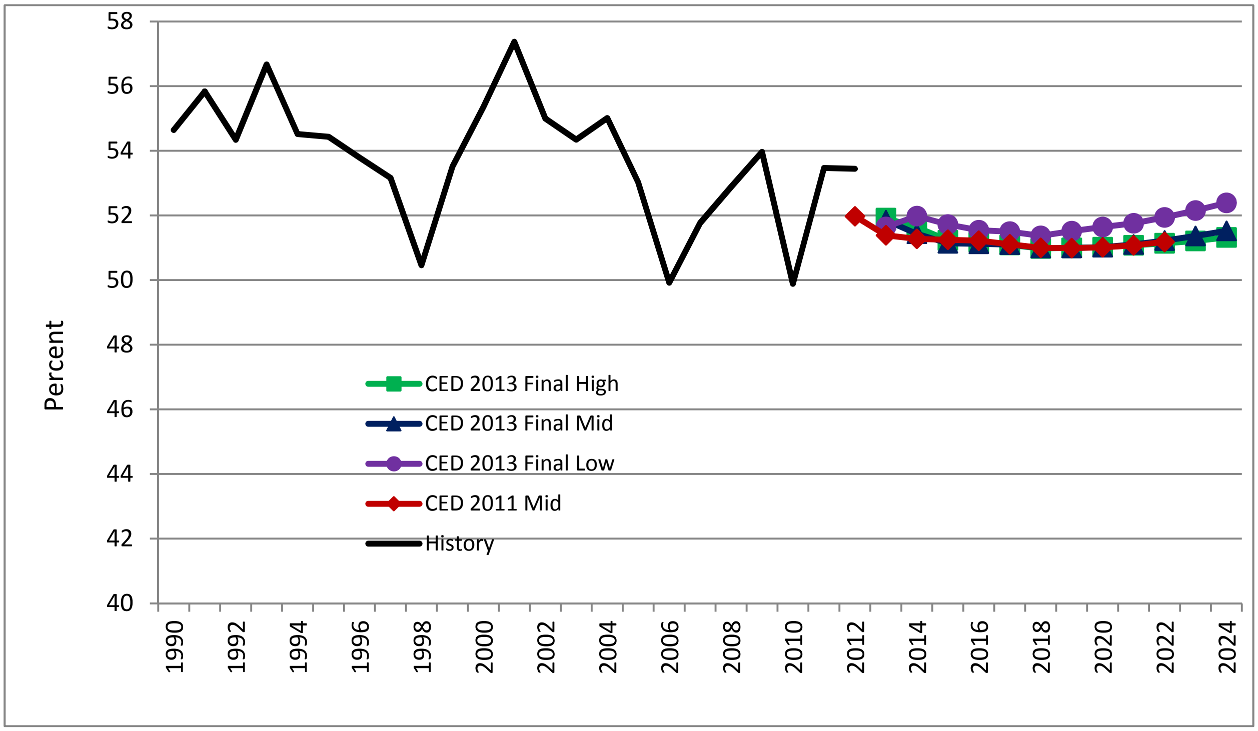


Source: California Energy Commission, Demand Analysis Office, 2013.

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

The general declining trend in the load factor over the last 20 years indicates a greater proportion of homes and businesses with central air conditioning. These trends are projected to continue over most of the forecast period for all three demand scenarios (as in *CED 2011*). Energy efficiency measures, such as more efficient lighting, contribute to the declining load factor by reducing energy use while having an insignificant effect on peak. This efficiency effect is also responsible for load factors slightly higher than in the previous forecast. 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.

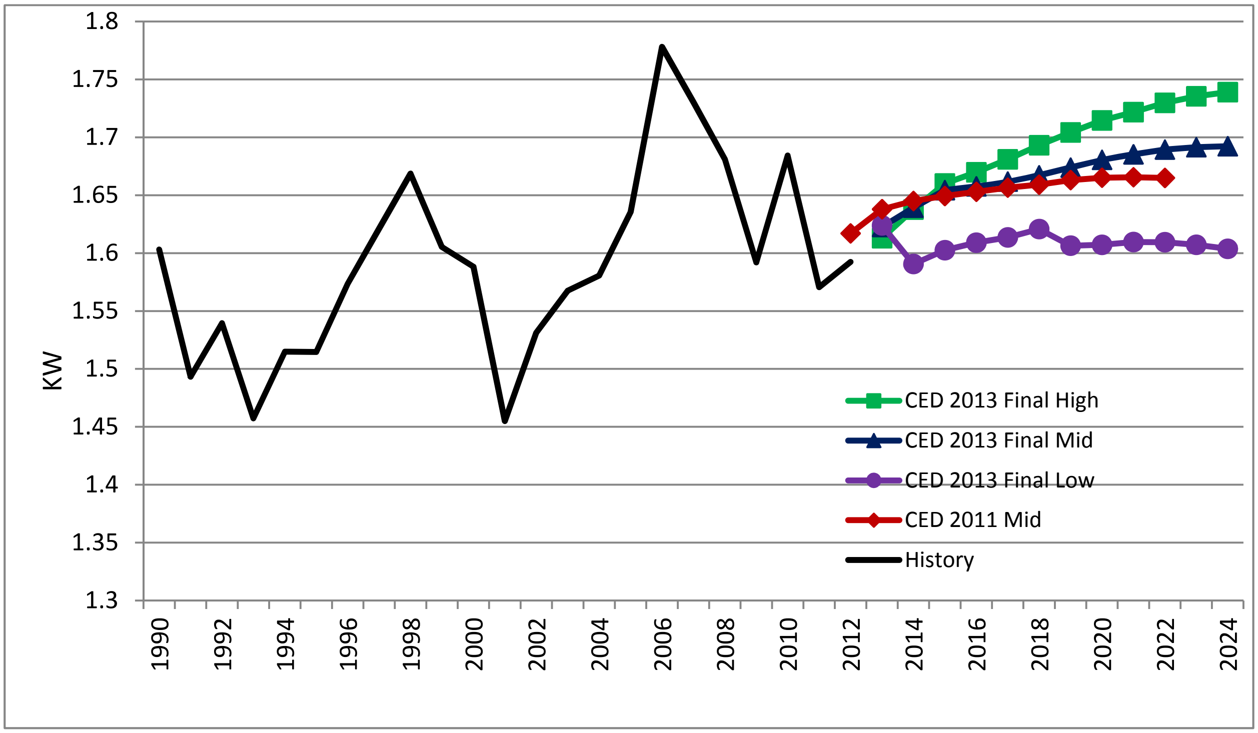
Figure 4: Statewide Baseline Noncoincident Peak Load Factors



Source: California Energy Commission, Demand Analysis Office, 2013.

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

Figure 5: Statewide Baseline Noncoincident Peak Demand per Capita



Source: California Energy Commission, Demand Analysis Office, 2013.

Table 3 shows projected baseline annual noncoincident peak demand for the major economic sectors. Peak demand in the *CED Final 2013* mid case is projected to grow at about the same rate from 2012 – 2022 for the residential sector compared to the *CED 2011* mid case and at a slightly higher rate in the commercial sector. Growth is also faster during this period in the new industrial mid case compared to *CED 2011*, reflecting high manufacturing growth projected for 2012 in the previous forecast that did not occur; the rate of industrial peak demand growth from 2013 – 2022 is about the same in the *CED 2013 Final* and *CED 2011* mid cases.

Table 3: Electricity Baseline Noncoincident Peak Demand by Sector

Residential Peak (MW)				
	CED 2011 Mid Energy Demand	***CED 2013 Final High Energy Demand***	***CED 2013 Final Mid Energy Demand***	***CED 2013 Final Low Energy Demand***
2012*	25,266	25,260	25,260	25,260
2015	26,698	27,460	27,137	26,173
2020	29,105	30,565	29,406	28,250
2024	--	33,017	31,403	30,011
Average Annual Growth, Residential Sector				
2012-2022	1.78%	2.32%	1.87%	1.44%
2012-2024	--	2.26%	1.83%	1.45%
Commercial Peak (MW)				
	CED 2011 Mid Energy Demand	***CED 2013 Final High Energy Demand***	***CED 2013 Final Mid Energy Demand***	***CED 2013 Final Low Energy Demand***
2012*	21,428	19,921	19,921	19,921
2015	22,642	22,012	21,744	21,197
2020	24,323	24,144	23,458	22,442
2024	--	25,504	24,568	23,454
Average Annual Growth, Commercial Sector				
2012-2022	1.53%	2.25%	1.91%	1.46%
2012-2024	--	2.08%	1.76%	1.37%
Industrial Peak (MW)				
	CED 2011 Mid Energy Demand	***CED 2013 Final High Energy Demand***	***CED 2013 Final Mid Energy Demand***	***CED 2013 Final Low Energy Demand***
2012*	7,317	6,901	6,901	6,901
2015	7,667	7,656	7,530	7,113
2020	7,670	7,905	7,563	7,042
2024	--	8,097	7,577	6,903
Average Annual Growth, Industrial Sector				
2012-2022	0.43%	1.48%	0.93%	0.11%
2012-2024	--	1.34%	0.78%	0.00%
*Weather-normalized. Estimates of historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2013.

Baseline Natural Gas Demand Forecast

Table 4 compares the three *CED 2013 Final* baseline demand scenarios for end-user natural gas consumption at the statewide level with the *CED 2011* mid demand case for selected years. The new forecasts begin at a lower point in 2012, as natural gas consumption in California was substantially lower this year than was predicted in the *CED 2011* mid case, and grow at a slower rate in all three scenarios from 2012 – 2022. Key factors are (1) slower projected population growth in the *CED 2013 Final* mid and low cases, (2) the introduction of climate change impacts in the mid and high cases, (3) new efficiency initiatives, and (4) higher projected natural gas rates for all three scenarios. More details are provided in Chapter 2 of this volume.

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

Consumption (MM Therms)				
	CED 2011 Mid Case	***CED 2013 Final High Energy Demand***	***CED 2013 Final Mid Energy Demand***	***CED 2013 Final Low Energy Demand***
1990	12,893	12,893	12,893	12,893
2000	13,913	13,913	13,913	13,913
2012	13,123	12,767	12,767	12,767
2015	13,503	12,736	12,687	12,176
2020	13,961	12,816	12,774	12,423
2024	--	12,801	12,806	12,569
	Average Annual Growth Rates			
1990-2000	0.76%	0.76%	0.76%	0.76%
2000-2012	-0.49%	-0.71%	-0.71%	-0.71%
2012-2015	0.96%	-0.08%	-0.21%	-1.57%
2012-2022	0.70%	0.06%	0.04%	-0.19%
2012-2024	--	0.02%	0.03%	-0.13%
Historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2013.

Overview of Methods and Assumptions

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

Models for the major economic sectors forecast annual energy consumption in each utility planning area. Electricity planning areas include Burbank/Glendale, Imperial Irrigation District (IID), Los Angeles Department of Water and Power (LADWP), Pasadena, PG&E, SCE, San

Diego Gas & Electric (SDG&E), and the Sacramento Municipal Utility District (SMUD). Natural gas planning areas include PG&E, SDG&E, and the Southern California Gas Company (SoCalGas). After adjusting for historical weather and usage, the annual consumption forecast is used to project annual peak demand. The commercial, residential, and industrial sector energy models are structural models that attempt to explain how energy is used by process and end use. Structural models are critical in accounting for the forecasted impacts of mandatory energy efficiency standards and other energy efficiency programs that seek to encourage adoption of more efficient technologies by end users. The forecasts of agricultural and water pumping energy consumption are made using econometric methods for individual subsectors (for example, dairy and livestock). Projections for the transportation, communications, and utilities (TCU) and street lighting sectors rely on trend analyses. A detailed discussion of forecast methods and data sources is available in the 2005 *Methods Report*.[9] The commercial end-use forecast is supported by projections of floor space by building type (restaurant, retail, and so on), which are estimated using regressions that include various economic and demographic indicators as explanatory variables.[10]

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

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

- Electricity price elasticities of demand[11] for the residential end-use and industrial models for both electricity and natural gas were changed to be consistent with elasticities estimated for the residential, manufacturing, and resource extraction/construction econometric models.
- The electricity forecast for the manufacturing sector was adjusted to reflect a trend in efficiency improvement estimated for the manufacturing econometric model.
- Results from the Hourly Electricity Load Model, used to forecast annual peak demand in each planning area, were adjusted to incorporate climate change scenarios using results from the peak econometric model.
- Results for the residential, commercial, industrial, and agricultural forecasts were adjusted to incorporate climate change using results from the sector econometric models.

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

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

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

- High and low scenarios were developed for the agricultural/water pumping, TCU (electricity only), and street lighting sectors using the new econometric models benchmarked to the single scenarios output from the existing models. (*CED 2011* included only one scenario for these sectors.)
- Planning area forecasts for all sectors were broken out into climate zones using the econometric models. Econometric climate zone results were benchmarked to planning area totals by sector.

Although staff used existing models for this forecast (except as noted in the bullets previously listed), 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 in 2024, electricity consumption in the pure econometric forecast was 0.8 percent higher and peak demand 2.3 percent higher compared to *CED 2013 Final* statewide results shown in this chapter. The mid demand econometric scenario yielded projected 2024 consumption 1.4 percent higher than *CED 2013 Final*, while peak demand was 2.5 percent higher. Differences were slightly higher in the low demand case, with statewide consumption projected to be 2.6 percent higher and peak demand projected to be 3.3 percent higher than *CED 2013 Final* in 2024.

Given the manner efficiency is treated in each method, these results are to be expected. The end-use models used in *CED 2013 Final* account for historical and projected efficiency impacts explicitly while the econometric models implicitly account for historical efficiency trends that are then projected forward.[12] If one presumes that energy efficiency efforts have intensified in recent years and into the near future, the econometric models, accounting for average trends from 1980 onward, would likely understate future efficiency impacts and therefore overstate demand. Future work to explicitly capture efficiency impacts in econometric estimations at the Energy Commission and through the CPUC's macro consumption econometric project[13] should allow better comparisons of end use and econometric results in the future.

The natural gas full econometric forecast[14] is higher than *CED 2013 Final* in all three scenarios by larger percentages. By 2024, the high demand econometric case is around 8 percent higher, the mid econometric forecast about 6 percent higher, and the low econometric case around 7 percent higher. As with electricity, the difference is likely from omission of explicit program and standards impacts in the econometric forecast. As a percentage of usage, natural gas efficiency savings are higher compared to electricity; therefore, it is not surprising that the

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12 Econometric results were adjusted to account for only electric vehicles and other electrification and, in the case of peak demand, photovoltaic adoption beyond 2012 levels.

13 CPUC. October 28, 2010. *Decision on Evaluation, Measurement, and Verification of California Energy Efficiency Programs*. Decision 10-10-033.

14 Excluding TCU gas, where the *CED 2013 Revised* forecast was used.

econometric forecasts should overstate consumption relative to *CED 2013 Final* by larger percentages.

Economic and Demographic Assumptions

California's economy has been slowly recovering from the recession. In the last two years, the state has seen payroll gains, lower unemployment, fewer mortgage defaults, a dwindling inventory of homes for sale, and the return of tourism. Some characteristics of the current California economy include:[15]

- California's recovery is gaining momentum on the strength of real estate, tech, and other services.
- Construction is pushing growth in payrolls. Construction employment is up almost 20,000 from a year earlier on a seasonally unadjusted basis.
- The unemployment rate is below 9 percent.
- Reinvigorated housing-related industries should help push the unemployment rate below 8 percent.
- There is a significant reduction of distressed housing throughout the state.
- The inventory of houses for sale is at the lowest level since the middle of 2005 and is driving housing price gains.
- Improving labor markets and renewed household formations will drive new residential construction in the near term.
- The economic slowdown of China has softened the state's exports.
- Alternative-energy technologies are expected to play a part in the recovery. California is well suited to benefit from each part of the industry.

For 2014, the state's economy is anticipated to grow at a faster pace than in previous years with construction and business services posting the largest payroll gains. During this recovery, California should be the target for venture-capital investment because of California's highly educated workforce.

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

15 Economic characteristics are based on summaries provided by Moody's and IHS Global Insight in August 2013.

These two companies update their long-term forecasts monthly; staff used the May 2013 projections for *CED 2013 Final*. Other entities, such as University of California, Los Angeles (Anderson Forecast[16]) and the University of the Pacific,[17] also project the leading economic indicators for California but do not provide the detail or length of forecast period required by Energy Commission demand forecasts.

For its May 2013 economic forecast, Moody's generated seven scenarios:

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

IHS Global Insight provided three scenarios for its May 2013 forecast:

- Optimistic
- Baseline
- Pessimistic

As in *CED 2013 Preliminary*, staff selected the Global Insight *Optimistic* economic case for the high demand scenario and a mixture of Moody's *Mild Second Recession* and *Below-Trend Long-Term Growth* cases for the low demand scenario. The two Moody's cases were combined so that the *Second Recession* scenario drove the short-term results (through 2018) and the *Below-Trend Long-Term Growth* case the longer-term. The high and low demand scenarios as constructed, in general, project the highest and lowest rates of economic growth, respectively, of the various scenarios provided by the two companies throughout the forecast period. Moody's *Baseline* economic forecast was used for the mid energy demand scenario.

Table 5 provides the key assumptions used by the two companies to develop the three economic scenarios. The probability assigned by Moody's to the mid demand scenario (Moody's *Baseline*) is 50 percent; that is, there is a 50 percent probability economic conditions will be worse than in this scenario. The equivalent probability for both Moody's scenarios used

16 http://uclaforecast.com/.

17 http://forecast.pacific.edu/.

in the low demand scenario is 4 – 5 percent. Global Insight portrays the probabilities somewhat differently: "The probability of being near" the *Optimistic* economic scenario is 10 percent.[18]

Table 5: Key Assumptions Embodied in Economic Scenarios

High Demand Scenario (IHS Global Insight *Optimistic* Scenario), May 2013	**Mid Demand Scenario (Moody's Analytics *Baseline* Scenario), May 2013**	**Low Demand Scenario (Combination of Moody's Analytics *Second Recession* and *Below-Trend Long-Term Growth* Scenarios), May 2013**
National unemployment rate falls to 6.5 percent by early 2014.	National unemployment rate stays below 8 percent through 2017.	The unemployment rate is expected to hit a peak of 10.6 percent at the end of 2014.
There are no exits from the Eurozone, as members take decisive steps toward a banking and fiscal union that stabilize markets.	Some continued turmoil in Europe and weaker growth in the emerging world.	European recession deepens as Greece leaves the Eurozone and investors continue to worry about Portugal and Spain.
National light-duty vehicle sales reach more than 17 million in 2014.	National light-duty vehicle sales are above 16 million in 2014.	Unit auto sales decline throughout 2013 to a trough of only 13 million in early 2014.
National housing starts improve to near 1.25 million units by the end of 2013.	National housing starts are expected to break 2 million units by 2015.	House prices will experience a second decline, cumulatively falling 9 percent from the second quarter of 2013 to the third quarter of 2014.
Same as in mid demand scenario.	Oil and gas prices are expected to trend higher, just outpacing inflation.	Oil and gas prices fall in the short term.
The Federal Reserve halts its latest quantitative easing program before the end of 2013 and raises the federal funds rate in the second quarter of 2014.	The Federal Reserve is not expected to begin increasing interest rates until the unemployment rate has fallen to near 6.5 percent, around early 2015.	The Fed keeps the fed funds target rate near 0 percent until the fourth quarter of 2015.
The sequester spending cuts remain in place through the second quarter, but Congress agrees on a credible long-term deficit-reduction plan, replacing the automatic cuts.	The sequester will reduce outlays in 2013 by $58 billion and by $1.2 trillion over the next decade. Fiscal policy will subtract 1.4 percentage points from 2013 real GDP growth.	The negative impacts from longer-term spending issues rise significantly, causing the economy to descend into a second recession in the third quarter of 2013.

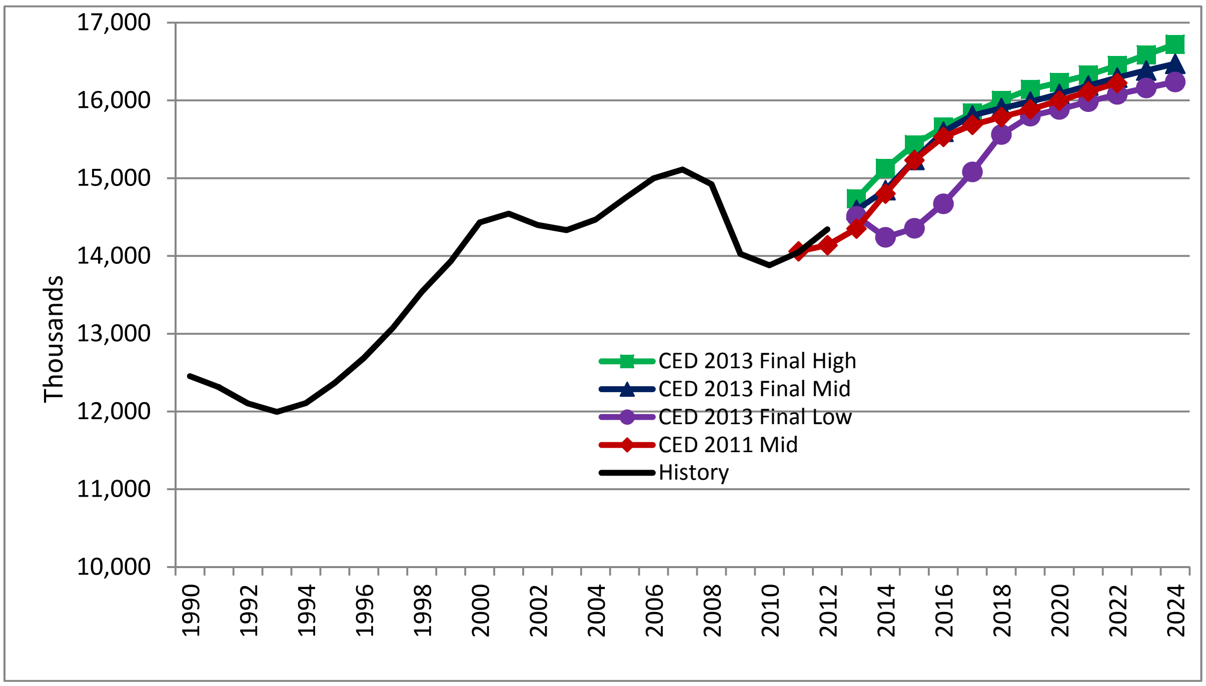
Source: Moody's and IHS Global Insight, 2013.

Figure 6 and **Figure 7** compare projections for two key indicators used in the three scenarios, total statewide nonagricultural employment and statewide personal income, respectively, with those used in the *CED 2011* mid demand case. The historical numbers for each of the series appear to show resumption of growth after the recent recession. The *CED 2013 Final* mid case

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

for employment matches that from the previous forecast very closely, after beginning the forecast period slightly above—employment was higher in 2011 and 2012 compared to 2011 projections. The low case for employment shows a decrease in 2013 and 2014, consistent with an economic slump, before growth begins again in 2015. Employment growth rates from 2012-2022 in the three scenarios are projected to average 1.15 percent, 1.07 percent, and 0.96 percent in the high, mid, and low scenarios, respectively, compared to 1.39 percent in the *CED 2011* mid case.

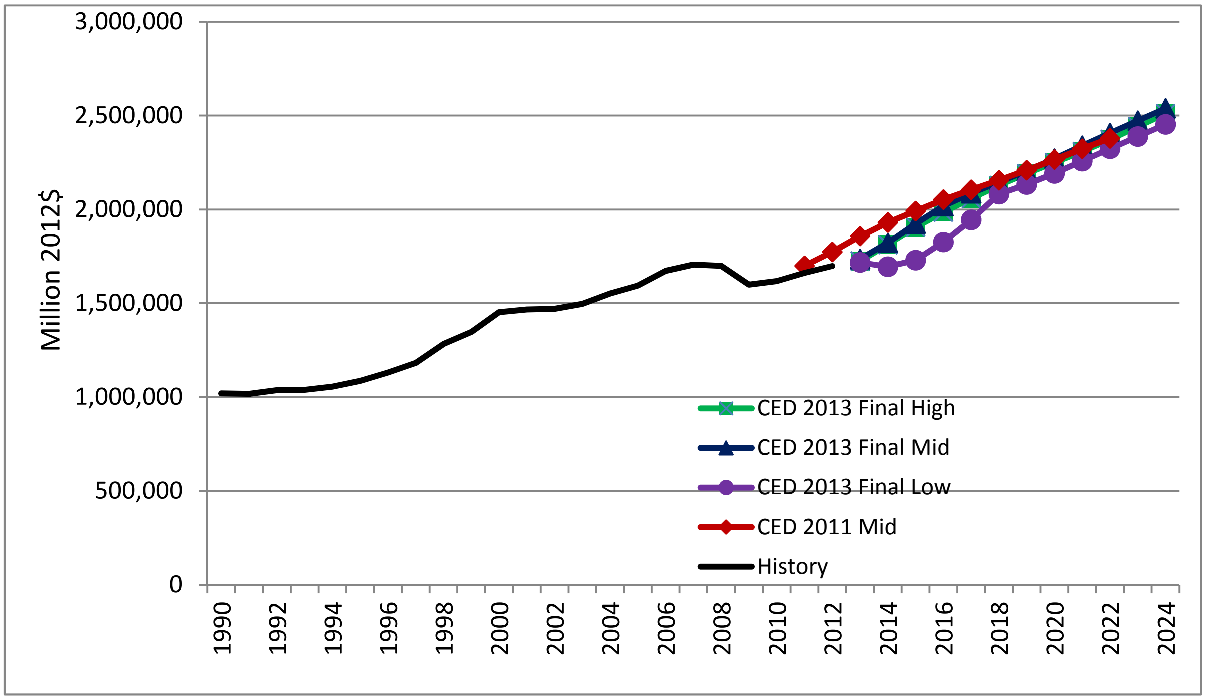
Figure 6: Statewide Employment Projections



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

Unlike employment, personal income (**Figure 7**) did not reach the levels projected for 2011 and 2012 in the *CED 2011* mid case, and all three new series start the forecast below the *CED 2011* mid case income series. The *CED 2013 Final* mid case reaches the *CED 2011* mid case level by 2019 and is slightly higher thereafter. Income in the high scenario is slightly below that in the new mid case for most of the forecast period. Projected average annual growth in personal income between 2012 and 2022 is 3.36 percent, 3.45 percent, and 3.09 percent in the high, mid, and low demand scenarios, respectively, compared to 3.25 percent in the *CED 2011* mid case.

Figure 7: Statewide Personal Income Projections

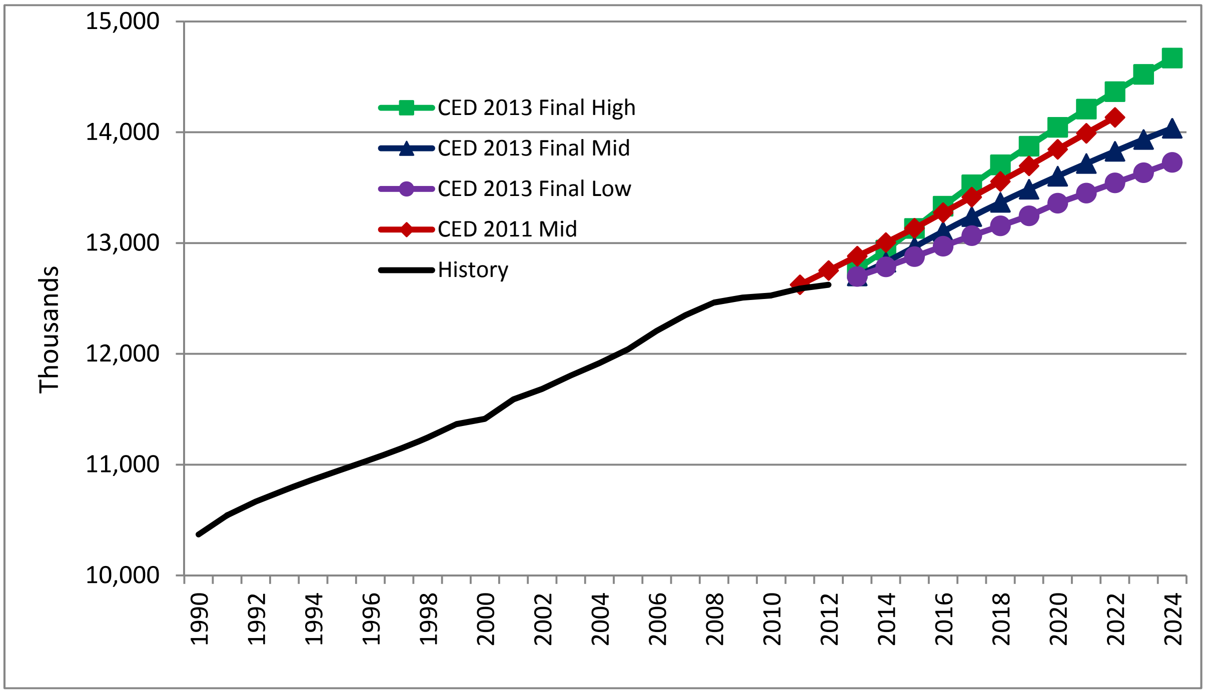


Sources: Moody's and IHS Global Insight, 2011 and 2013.

Staff also developed scenario projections for number of households, shown in **Figure 8**, using the population projections discussed below and varying expected average persons per household. For the low demand case (higher persons per household), staff fit an exponential growth curve to historical persons per household for 1990-2010. The mid case assumed half of the growth of the low demand case and the high case (lower persons per household) used Moody's projections.[19] The *CED 2013 Final* number of households in the mid demand case grows more slowly than in *CED 2011* due to lower projected population growth.

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

Figure 8: Statewide Number of Households Projections

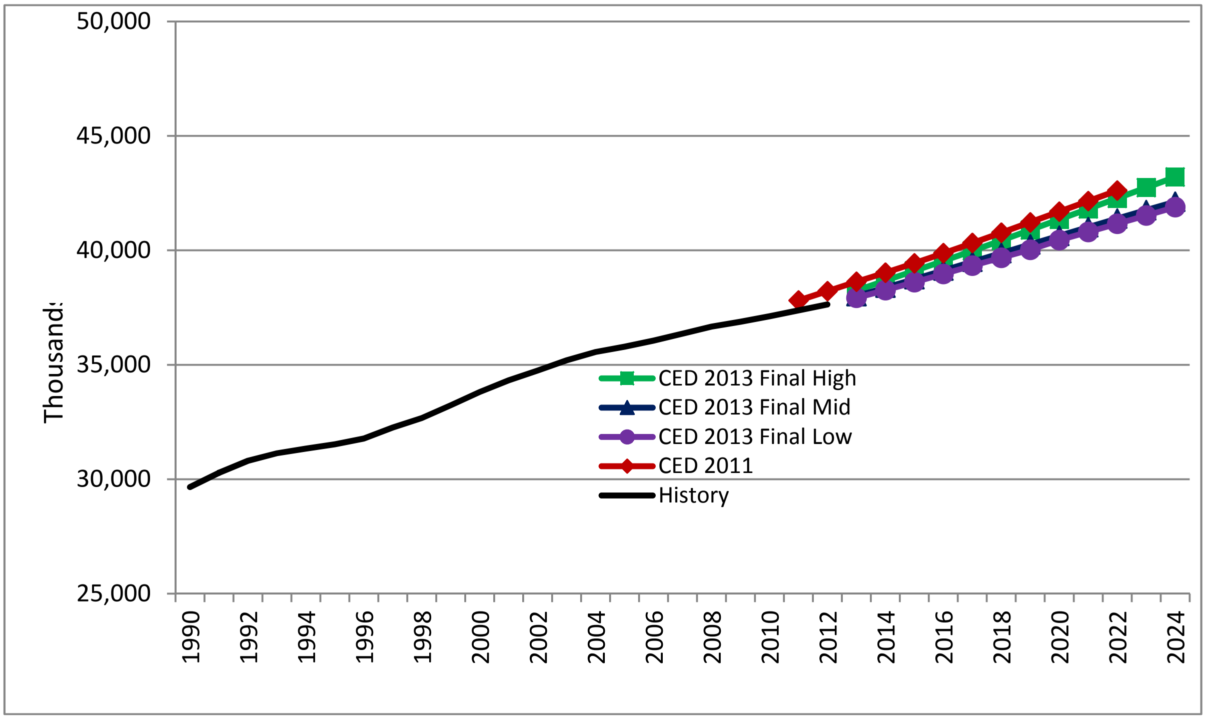


Source: California Energy Commission, Demand Analysis Office, 2013.

Population growth is a key driver for residential energy consumption, as well as for commercial floor space and energy consumption for water pumping and other services. For CED *2013 Final* (as well as *CED 2013 Preliminary*), staff used three sets of population projections instead of just one, as in past forecasts. The low case comes from the California Department of Finance 2013 long-term population projections, the mid case from IHS Global Insight, and the high from Moody's.[20] As shown in **Figure 9**, the *CED 2013 Final* mid case population projections are well below those in *CED 2011,* which used only one scenario. The mid and low population scenarios reflect recent downward adjustments relative to past projections based on state population trends in the last few years. Between the preliminary and final versions of this forecast, IHS Global Insight adjusted their population forecast downward, so that mid and low scenarios are almost identical. State population growth rates from 2012-2022 in the three scenarios are projected to average 1.09 percent, 0.91 percent, and 0.86 percent annually in the high, mid, and low scenarios, respectively, compared to 1.10 percent in *CED 2011*.

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

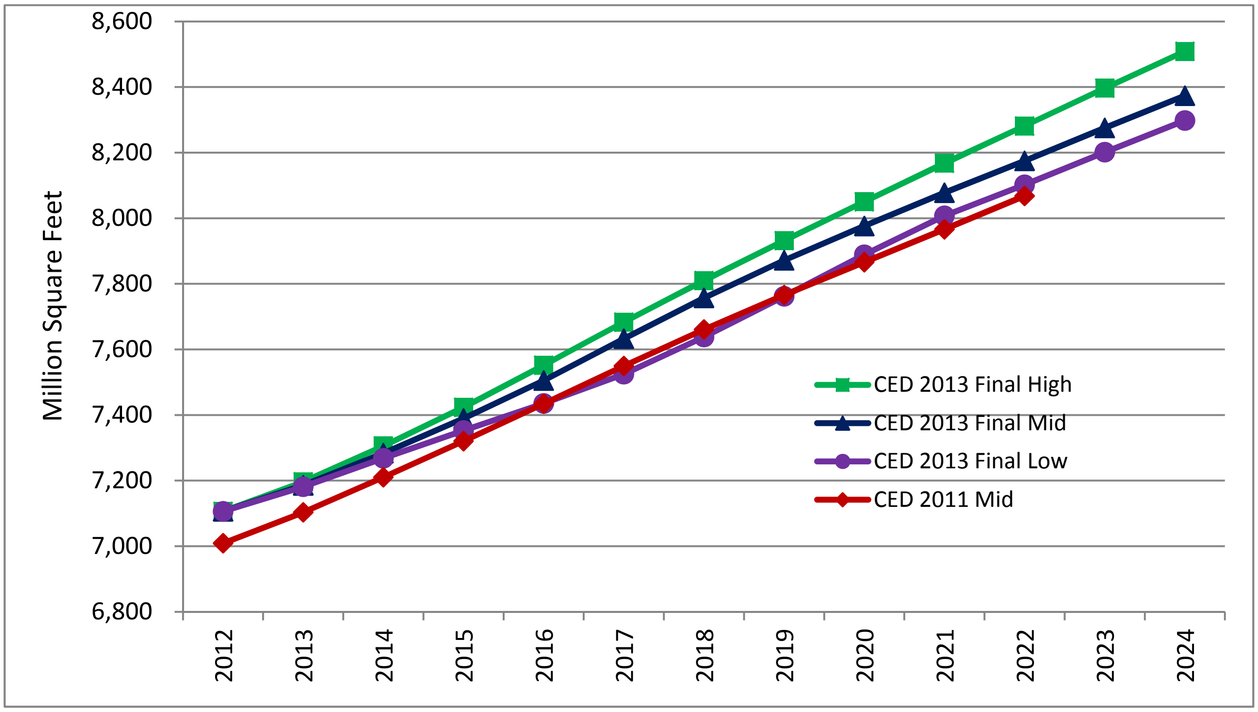
Figure 9: Historical and Projected Statewide Population



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

Figure 10 compares the commercial floor space projections used for *CED 2013 Final* with those used in the *CED 2011* mid case. Updates to the recent historical estimates of floor space yield 2012 statewide values higher than projected in *CED 2011*. The *CED 2013 Final* mid and high cases remain above *CED 2011* throughout the forecast period, although the rate of growth in the new mid scenario is slightly lower than in the *CED 2011* mid case, due mainly to lower population growth. Projected average annual growth in commercial floor space between 2012 and 2022 is 1.54 percent, 1.41 percent, and 1.32 percent in the high, mid, and low demand scenarios, respectively, compared to 1.42 percent in the *CED 2011* mid case.

Figure 10: Statewide Projected Commercial Floor Space



Source: California Energy Commission, Demand Analysis Office, 2013.

Electricity and Natural Gas Rate Projections

Natural gas rate scenarios were developed by the Energy Commission's Electricity Analysis Office using the North American Gas-Trade Model (NAMGas). This model incorporates supply and demand components to generate equilibrium gas prices for California and sub-regions. The rate scenarios used in *CED 2013 Final* are updated versions, based on stakeholder comments, of the scenarios presented at the May 30 *IEPR* workshop and used in *CED 2013 Preliminary*.[21] Staff used percentage increases in these three new scenarios versus 2012 actual prices in each planning area for the *CED 2013 Final* forecasts, with the reference case used in the mid demand scenario, the high price scenario in the low demand case, and the low price scenario in the high demand case. Percentage increases varied slightly between Northern and Southern California planning areas. Projected prices show volatility in the early years, which is reflected in the gas forecasts, particularly in the low demand case.

As in *CED 2013 Preliminary*, the electricity price forecasts were generated using the Energy and Environmental Economics (E3) calculator.[22] The E3 calculator allows users to create electricity

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21 The newest scenarios have not yet been published. For model and scenario details presented on May 30, 2013, see http://www.energy.ca.gov/2013_energypolicy/documents/2013-02-19_workshop/presentations/02_Brathwaite_Leon_NAMGas_IEPR2013_KeyDriversPlus_rev.pdf.

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

price scenarios by inputting assumptions for efficiency savings, natural gas rates, amount of renewables, amount of combined heat and power, penetration of PV systems, level of demand response, and price regime (cap and trade). Between *CED 2013 Preliminary* and *CED 2013 Final*, staff updated various inputs to the model, resulting in significantly lower projected electricity rates compared to the preliminary forecast. Modifications made by staff include:

- Updating the auction price estimates for cap and trade.
- Reducing the estimates of renewable resources needed for Renewables Portfolio Standard compliance and assigning scenarios to be consistent with demand outcomes.
- Incorporating the distribution of carbon allowance auction revenues back to ratepayers.
- Reducing transmission and distribution costs to reflect growth rates more consistent with other analyses, including California ISO Transmission Planning and the CPUC LTPP.

Table 6 summarizes the assumptions used to generate rate growth for each of the three demand scenarios. Efficiency and PV assumptions are based on *CED 2011* results. CHP assumptions come from work for the Energy Commission by ICF International.[23] Renewables numbers were taken from CPUC/Energy Commission joint scenario development for the 2012 LTPP.[24]

Table 6: *CED 2013 Final* Electricity Price Assumptions by Scenario

Assumption	High Demand Scenario (Lower Electricity Prices)	Mid Demand Scenario (Mid Electricity Prices)	Low Demand Scenario (Higher Electricity Prices)
Efficiency	Low CED 2011	Mid CED 2011	High CED 2011
Natural Gas Rates	NAMGas Low	NAMGas Reference	NAMGas High
PV	2,200 MW by 2020	2,300 MW by 2020	2,600 MW by 2020
Additional Renewables	11,800 MW by 2020	10,150 MW by 2020	7,200 MW by 2020
Demand Response	Current Levels	5 Percent Additional	5 Percent Additional
Combined Heat and Power	1,400 MW in 2020	3,000 MW in 2020	4,800 MW in 2020
Price Regime	\$17/metric ton of CO_2	\$25/metric ton of CO_2	\$50/metric ton of CO_2

Source: California Energy Commission, Demand Analysis Office, 2013.

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

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

Resulting percentage growth by year for each scenario was applied to current (2012) planning area rates. E3 provided projections only for 2013-2020; staff used an annual growth rate of 1 percent for 2021 through 2024, which assumes no major change in state policies influencing electricity prices after 2020. Staff used the model-projected percentage growth for each planning area, except in the case of LADWP, where E3 projects rate growth to be significantly higher than in the other planning areas due to expiration of current power contracts and relatively low load growth. Staff used a higher growth rate for LADWP but capped the growth so resulting LADWP rates remained at or below those of SCE.[25]

Table 7 provides statewide (planning area/sector demand-weighted) averages for projected rates and rate increases for electricity and natural gas for each scenario. Projections for each of the five major electricity planning areas and three natural gas planning areas are provided in the demand forms accompanying this report.[26]

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

26 See http://www.energy.ca.gov/2013_energypolicy/documents/#reportsnomeeting.

Table 7: Energy Prices, *CED 2013 Final* Forecast

Electricity			
Year/Period	**High Demand Scenario**	**Mid Demand Scenario**	**Low Demand Scenario**
	Average Price (2012 cents/kWh)		
2012	13.4	13.4	13.4
2015	14.0	14.6	15.2
2020	14.2	15.7	17.2
2024	14.9	16.4	18.0
	Percentage Change vs. 2012		
2012-2015	4.4%	8.8%	13.3%
2012-2020	5.8%	16.7%	27.8%
2012-2024	10.5%	21.9%	33.6%
Natural Gas			
Year/Period	**High Demand**	**Mid Demand**	**Low Demand**
	Average Delivered Cost (2012$/therm)		
2012	0.64	0.64	0.64
2015	0.86	0.92	1.10
2020	0.91	1.08	1.34
2024	1.02	1.18	1.42
	Percentage Change vs. 2012		
2012-2015	33.8%	43.5%	70.8%
2012-2020	41.6%	67.1%	108.0%
2012-2024	58.1%	83.6%	119.9%

Source: California Energy Commission, Demand Analysis Office, 2013.

Conservation/Efficiency Impacts

Energy Commission demand forecasts seek to account for efficiency and conservation *reasonably expected to occur*. Since the *1985 Electricity Report*, reasonably expected to occur initiatives have been split into two types: committed and uncommitted, or achievable. The baseline forecasts in *CED 2013 Final* continue that distinction, with only committed efficiency included. Committed initiatives include utility and public agency programs, codes and standards, and legislation and ordinances having final authorization, firm funding, and a design that can be readily translated into characteristics capable of being evaluated and used to estimate future impacts (for example, a package of IOU incentive programs that has been funded by CPUC order). In addition, committed impacts include price and other market effects not directly related to a specific initiative. Chapter 3 details the committed energy efficiency impacts projected for this forecast.

CED 2013 Final also includes estimates of AAEE savings for the investor-owned utility service territories. These savings are not yet considered committed but are deemed reasonably likely to occur, and include impacts from future updates of building codes and appliance standards and utility efficiency programs expected to be implemented after 2014. Five different savings scenarios were developed. Chapter 4 shows the impact of additional achievable electricity consumption and peak savings as well as natural gas consumption savings incorporated in adjusted (relative to the baseline) forecasts for these service territories.

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. Non-event-based programs are not activated using a predetermined threshold condition, which allows the customer to make the economic choice whether to modify its usage in response to ongoing price signals. Impacts from committed non-event-based programs should be included in the demand forecast.

Non-event-based program impacts are likely to increase in the coming years, and expected impacts incremental to the last historical year for peak (2012) affect the demand forecast.[27] Staff, in consultation with the IOUs and the CPUC, identified impacts from current committed demand response programs in these planning areas, which include real-time or time-of-use pricing and permanent load shifting. Impacts are shown in **Table 8**.

Table 8: Estimated Non-Event-Based Demand Response Program Impacts (MW)

Year	PG&E	SCE	SDG&E
2012	16	5	3
2013	11	9	2
2014	15	9	2
2015	17	12	2
2016	17	12	2
2017	17	12	2
2018	17	12	2
2019	17	12	2
2020	17	12	2
2021	17	11	2
2022	17	11	2
2023	17	11	2
2024*	17	11	2
*Program cycles end in 2023; 2024 values assumed the same as 2023.			

Source: California Energy Commission, Demand Analysis Office, 2013.

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

Energy or peak load saved from dispatchable or event-based programs has traditionally been treated as a resource and, therefore, is not accounted for in the demand forecast. However, the California ISO's perspective on reliability and resource needs requires a level of certainty on the triggering and dispatch of resources. Two types of event-based programs, critical peak pricing and peak time rebates, require an action to be taken by an individual or business based on a predefined price. This source of action is in contrast to other event-based demand response programs where the event is triggered by a reliability or system cost event and load reductions are achieved by direct load control or incentives. For this reason, resource adequacy analyses will no longer include these two programs as a resource, which means they must be accounted for in the demand forecast.

In consultation with CPUC staff and based on IOU studies, staff developed projected peak impacts from critical peak pricing and peak time rebate programs, shown in **Table 9** by IOU. Combined impacts from these two programs and non-event based reductions reach 122 MW for PG&E, 36 MW for SCE, and 46 MW for SDG&E by 2024. The total (noncoincident) reduction over all utilities from critical peak pricing, peak-time rebate, and non-event programs amounts to 204 MW in 2024.

Table 9: Estimated Demand Response Program Impacts: Critical Peak Pricing and Peak-Time Rebate Programs (MW)

Year	PG&E	SCE	SDG&E
2012	38	42	19
2013	35	24	21
2014	41	25	39
2015	64	25	39
2016	75	25	40
2017	107	25	40
2018	102	25	41
2019	103	25	42
2020	103	25	42
2021	104	25	43
2022	104	25	43
2023	105	25	44
2024*	105	25	44
*Program cycles end in 2023; 2024 values assumed the same as 2023.			

Source: California Energy Commission, Demand Analysis Office, 2013.

Self-Generation

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

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

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

The ERP and NSHP are managed by the Energy Commission and the CSI and SGIP by the CPUC. The forecast also accounts for power plants reporting information to the Energy Commission. The principal source is Form CEC 1304.[28] Staff included only power plants that explicitly listed themselves as operating under cogeneration or self-generation mode.

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

Residential PV adoption and solar water heating adoption are forecast using a predictive model developed for *CED 2011*, based on estimated payback periods and cost-effectiveness, determined by upfront costs, energy rates, and incentive levels. Results for adoption differ by demand scenario since projected electricity and natural gas rates and number of homes varies across the scenarios. Lower electricity demand corresponds to higher adoptions; the effect from higher rates outweighs lower growth in households. Staff applied a predictive model that includes commercial PV adoption for the first time in *CED 2013 Final*, a model similar in principle to the residential model, with adoptions developed by building type (hospitals, schools, and so on). The same predictive model is used to forecast commercial CHP, employing estimated load shapes by building type. Staff developed these two models, which are discussed further in Appendix B. Self-generation for other technologies and sectors is projected using a trend analysis and does not vary by demand scenario. Appendix B provides more details.

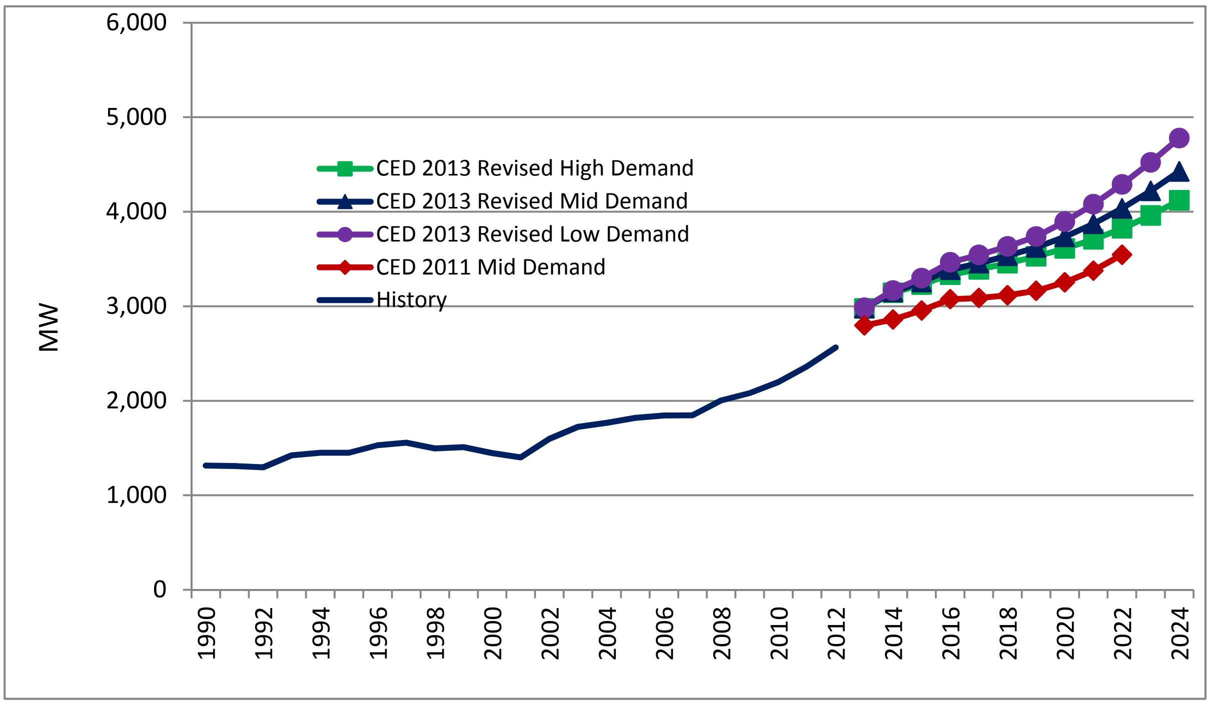
Figure 11 shows historical and projected peak impacts of self-generation, which are projected to reduce peak load by more than 4,400 MW in the mid demand scenario by 2024. Higher projections for PV peak impacts (shown in **Figure 12)** come from incorporating 2011 and 2012 actual and pending adoptions and the use of a commercial predictive model that projects higher penetrations compared to previous trend analyses (see Appendix B). PV adoptions drive total self-generation peak well above *CED 2011* mid levels in all three scenarios. The temporary flattening of the curve after 2016 comes from expiration of the CSI program and the federal tax credit for PV installation. The PV peak impacts shown in **Figure 12** correspond to capacities that

28 See http://www.energy.ca.gov/forms/cec-1304.html.

meet or exceed the goal of 3,000 MW for 2017 set in Senate Bill 1 (Murray, Chapter 132, Statutes of 2006).[29]

The residential predictive model for PV also projects residential electricity consumption statewide from solar water heating, which reaches around 245 gigawatt hours (GWh), 270 GWh, and 300 GWh in the high, mid, and low demand cases, respectively, by 2024.[30]

Figure 11: Statewide Peak Impacts of Self-Generation

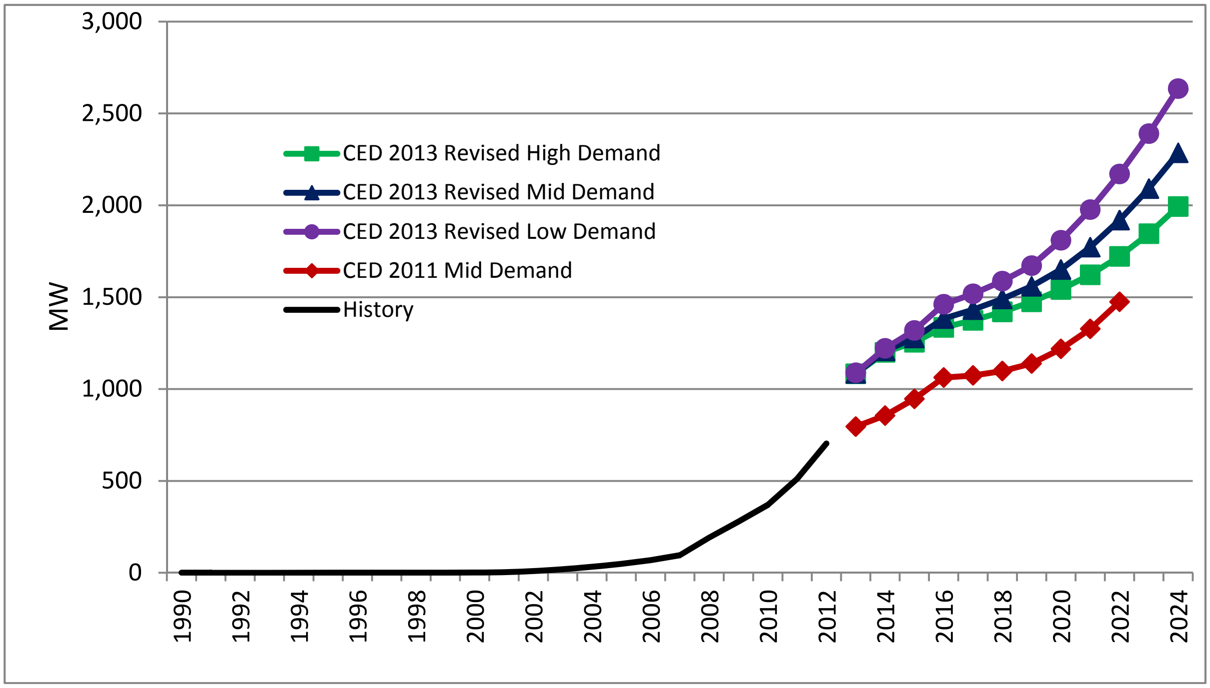


Source: California Energy Commission, Demand Analysis Office, 2013.

29 In 2017, projected PV peak impacts correspond to capacities of around 2,950 MW, 3,070 MW, and 3,245 MW in the high, mid, and low demand cases, respectively. By 2024, capacities reach around 4,370MW, 4,970 MW, and 5,690 MW.

30 “Peak impacts” cannot be defined for this technology.

Figure 12: Statewide Peak Impacts of PV Systems



Source: California Energy Commission, Demand Analysis Office, 2013.

Table 10 shows historical and projected statewide electricity consumption from self-generation, broken out into PV and non-PV applications. For traditional industrial CHP technologies, self-generation is assumed constant (no clear trend is evident in the historical data), so that retired CHP plants are replaced with new ones with no net change in generation. Growth in non-PV self-generation comes mainly from recent increases in the application of fuel cells projected forward and from commercial CHP.

Table 10: Electricity Consumption From Self-Generation (GWh)

	1990	2000	2010	2015	2020	2024
Non-PV Self-Generation, High Demand	8,234	9,174	12,445	13,394	14,027	14,384
Non-PV Self-Generation, Mid Demand	8,234	9,174	12,445	13,418	14,110	14,480
Non-PV Self-Generation, Low Demand	8,234	9,174	12,445	13,429	14,142	14,514
PV, High Demand	-	6	2,166	4,409	5,466	7,213
PV, Mid Demand	-	6	2,166	4,500	5,899	8,403
PV, Low Demand	-	6	2,166	4,668	6,549	9,846
Total Self-Generation, High Demand	**8,234**	**9,180**	**14,611**	**17,803**	**19,494**	**21,597**
Total Self-Generation, Mid Demand	**8,234**	**9,180**	**14,611**	**17,919**	**20,009**	**22,883**
Total Self-Generation, Low Demand	**8,234**	**9,180**	**14,611**	**18,097**	**20,691**	**24,360**

Source: California Energy Commission, Demand Analysis Office, 2013.

NOTE: Individual entries may not sum to total due to rounding.

Electric Light-Duty Vehicles

CED 2013 Final incorporates scenarios for electric vehicle (EV) fuel consumption based on those developed by the Energy Commission's Transportation Energy Office (TEO) in early 2012. These scenarios were used in *CED 2011* and in the *CED 2013 Preliminary* and *CED 2013 Revised* forecasts. Details on these scenarios are available in the report for the *CED 2011*.[31] The TEO was not able to complete a new EV forecast in time for this report, so staff updated these projections by incorporating the latest California sales numbers for EVs and considering the latest information on credit allowances available within the California Air Resources Boards Zero-Emission Vehicle (ZEV) mandates.

The low case for EVs was developed to be consistent with a scenario that just meets the ZEV mandates related to EV sales, based on a "most-likely" compliance case developed by California Air Resources Board (CARB) staff, presented at the Energy Commission's demand forecasting

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

workshop on February 23, 2012.[32] However, since *CED 2011*, CARB staff has developed scenarios that more fully incorporate greenhouse gas over-compliance credits and other credit allowances. These credits would directly affect the potential number of vehicles required to comply with ZEV mandates after 2017. CARB staff provided estimates of the impact of these updated credit assumptions, which were incorporated in *CED 2013 Final*. The end result is a reduction of around 25,000 battery electric vehicles (BEVs) and 200,000 plug-in electric vehicles (PHEVs) by the end of the forecast period in the low scenario compared to previous forecasts, reducing projected statewide EV consumption by around 17 percent in this year.

The high EV scenario was rescaled downward to match 2012 EV vehicle totals (provided by the TEO) combined with 2013 sales-to-date derived from California electric vehicle rebate program data. Thereafter, annual growth in vehicle sales matched the *CED 2011* EV forecast. Total number of EVs projected on the road declined by around 500,000 in 2024, reducing projected consumption by around 10 percent compared to previous forecasts.

Table 11 shows the projected number of BEVs and PHEVs on the road statewide in the new high and low demand scenarios for selected years. As in previous forecasts, the mid demand scenario assumes an average of the high and low.

Table 11: Projected Number of Electric Vehicles on the Road

	High Scenario			Low Scenario		
Year	**BEVs**	**PHEVs**	**Total EVs**	**BEVs**	**PHEVs**	**Total EVs**
2012	11,807	16,690	28,497	11,807	16,690	28,497
2015	30,995	312,504	343,499	29,960	78,427	108,386
2018	63,100	1,397,607	1,460,707	58,737	151,214	209,950
2020	127,295	2,135,277	2,262,572	112,577	262,541	375,118
2024	344,489	3,330,826	3,675,315	335,536	688,593	1,024,129

Source: California Energy Commission, Demand Analysis Office, 2013.

NOTE: Individual entries may not sum to total due to rounding.

To allocate the EV forecast across the eight electricity planning areas, electric vehicle ownership was estimated for each county based on the electric vehicle rebate program data. EV growth in each county was assigned based on projected county populations. County projections were then aggregated into planning areas (as well as climate zones). Forecasts for the five major planning areas are provided in Volume 2 of this report.

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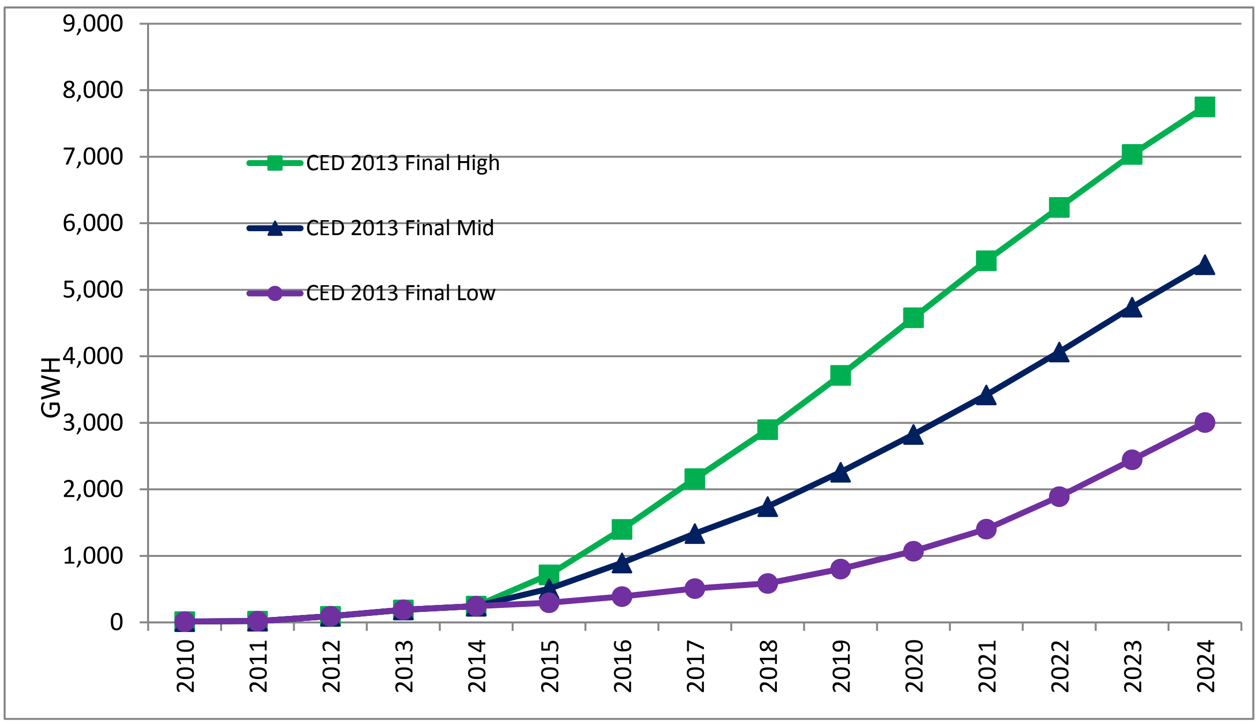
32 Presentation by Analisa Bevan, Air Resources Board Zero-Emission Vehicle program director. http://www.energy.ca.gov/2012_energypolicy/documents/2012-02-23_workshop/presentations/02_Bevan_ARB_ZEV_Forecasts.pdf.

Figure 13 shows projected statewide electricity consumption for EVs for all three demand scenarios, developed using TEO projections for average efficiency and annual miles traveled. EV consumption reaches around 3,000 GWh by 2024 in the low demand case and more than 7,750 GWh in the high scenario. The majority of consumption is in the residential sector, as the Transportation Energy 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.

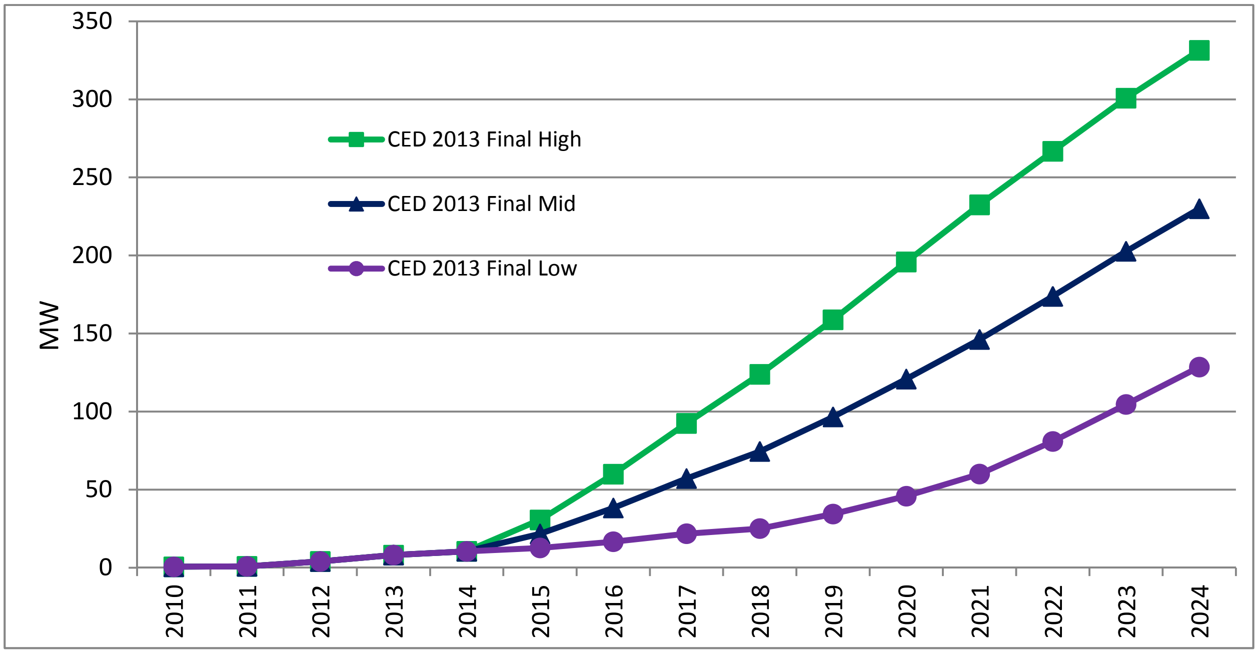
Figure 13: Statewide Electric Vehicle Consumption



Source: California Energy Commission, Demand Analysis Office, 2013.

To translate consumption to peak demand, as in previous forecasts, staff assumed 75 percent of recharging would take place during off-peak hours (10 p.m. – 6 a.m.), with the rest evenly distributed over the remaining hours. This recharging profile assumes some form of favored off-peak pricing for electric vehicle owners by utilities. **Figure 14** shows the projected EV contribution to statewide noncoincident peak. Peak impacts are relatively small compared to consumption due to recharging assumptions; EVs provide a slight increase to the statewide load factor.

Figure 14: Statewide Electric Vehicle Peak Demand



Source: California Energy Commission, Demand Analysis Office, 2013

Additional Electrification

Potentially significant increases in electricity use in California are expected to occur through port electrification and operation of a high-speed rail system. Regulations implemented by the California Air Resources Board[33] are aimed at reducing emissions from container, passenger, and refrigerated cargo vessels docked at California ports. The regulations specifically require obligated vessels to use electric shore power to perform services that would normally be provided by onboard auxiliary diesel engines or to implement other equivalent emission reduction strategies. The percentage of port visits required to be electrified increases from 50 percent in 2014 to 80 percent in 2020 and should lead to a corresponding increase in associated electric load.

To estimate electricity consumption impacts, staff assumed a load of 10.5 MW for passenger ships[34] and 2.5 MW for container and refrigerated cargo vessels.[35] Berthing times were assumed

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33 "Airborne Toxic Control Measure For Auxiliary Diesel Engines Operated On Ocean-Going Vessels At-Berth in a California Port." Adopted in 2007.

34 Port of Los Angeles cruise ships currently demand between 8 and 13 MW, although capable of demand up to 20 MW. See http://www.portoflosangeles.org/environment/alt_maritime_power.asp.

35 Personal correspondence with Vahik Haddadian, Port of Los Angeles, Chief Electrical Engineer, October 2, 2012; and Unified Port of San Diego, *Tenth Avenue Marine Terminal Shore Power Project, Final Mitigated Negative Declaration*, UPD #MND-2012-20, February 2013, page 11.

to be 9 hours for passenger vessels,[36] 17 to 20 hours for container vessels,[37] and 62 hours for refrigerated cargo vessels.[38] Staff developed high and low scenarios for port electrification based on projected growth in annual number of visits, with a mid case calculated as an average of the high and low. Low case growth was assumed flat. High case growth was assumed to be 5 percent per year for passenger ships[39] and 4 – 5 percent (depending on the year) for container and refrigerated cargo vessels.[40]

Planning area electricity forecasts were increased by the projected amount of electrification above 2012 levels[41] for the corresponding ports (Oakland, San Francisco, Los Angeles, Long Beach, and San Diego). The planning area chapters in Volume 2 of this report show these amounts. For the state as a whole, increased port electrification adds 322 GWh in the high demand case, 266 GWh in the mid case, and 211 GWh in the low scenario by 2024.[42]

The Energy Commission's Transportation Energy Office provided projections of electricity consumed by the initial operating section of the high-speed rail system (Bakersfield to Merced), scheduled to begin service in 2022. The projections, a function of train miles and average efficiencies, were based on the California High-Speed Rail Authority's 2012 Business Plan,[43] using the associated environmental impact report (EIR).[44] The Transportation Energy Office provided a single scenario, using the "medium" case examined in the EIR. The total electricity consumed is projected to be 223 GWh by 2024. Staff used the electricity source allocation

36 Staff analysis of cruise ship arrival and departure times at California ports.

37 Personal correspondence with Jill Borner-Brown, Port of Oakland, Port Principle Engineer/Department Manager, August 30, 2013.

38 Unified Port of San Diego, *Tenth Avenue Marine Terminal Shore Power Project, Final Mitigated Negative Declaration*, UPD #MND-2012-20, February 2013, page 10. See http://www.portofsandiego.org/component/docman/doc_download/4878-tamt-shore-power-final-mnd.html?Itemid=104.

39 Port of San Francisco, Memorandum to Authorize Pier 27 Terminal Management Agreement, June 7, 2013, page 7. See http://www.sfport.com/modules/showdocument.aspx?documentid=6314.

40 This is consistent with the Energy Commission's Transportation Energy Office most recent freight forecast and is based on the U.S. Department of Transportation Federal Highway Administration Freight Analysis Framework, Origin-Destination Data, 2007 – 2040.

41 Port electrification in 2012 is captured in the historical electricity consumption data.

42 There are significant uncertainties associated with estimating annual port electricity consumption related to port activities and regulation compliance. Changes in port tenants, diversion of products to other ports, and variability of vessel freight will influence the electricity consumption. The first complete year of required reporting for the berthing regulations is 2014, so a more accurate measure of consumption (at least in the short term) will be possible in future forecasts.

43 See http://californiastaterailplan.dot.ca.gov/docs/1a6251d7-36ab-4fec-ba8c-00e266dadec7.pdf.

44 See http://www.hsr.ca.gov/Programs/Environmental_Planning/final_merced_fresno.html.

provided in the EIR to assign consumption to the PG&E and SCE planning areas for 2022 – 2024. **Table 12** shows projected high-speed rail electricity consumption by planning area.

Table 12: Estimated High-Speed Rail Electricity Impacts by Planning Area (GWh)

Year	PG&E	SCE	Total
2022	93	35	**128**
2023	155	58	**213**
2024	162	61	**223**

Source: California Energy Commission, Demand Analysis Office, 2013.

Natural Gas Light-Duty Vehicles

Natural gas vehicles and natural gas fuel consumption are forecast as part of the Fuels and Transportation Division's transportation energy demand forecasts. For *CED 2013 Final*, staff used the same natural gas vehicle forecast as in *CED 2011*.[45] As with EVs, staff expects the final version of *CED 2013* to include a new forecast from the Transportation Energy Office. **Table 13** shows forecasted natural gas vehicle consumption by major natural gas planning area and statewide for selected years.[46]

Table 13: *CED 2013 Final* Natural Gas Consumption by Light-Duty Vehicles (MM therms)

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

Source: California Energy Commission, Demand Analysis Office, 2013.

NOTE: Individual entries may not sum to total due to rounding.

Subregional Electricity Analysis

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

45See http://www.energy.ca.gov/2011publications/CEC-600-2011-007/CEC-600-2011-007-SD.pdf.

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

disaggregation of the demand forecast (beyond the climate zone level) would allow more refined, "bottom up" analyses for local congestion zones.

Subregional forecasts for both energy and peak demand are provided in spreadsheet files (Form 1.5) in the forms accompanying this forecast report.[47] To develop subregional peak demand forecasts, staff estimates weather-normalized peaks for the IOU transmission access charge (TAC) areas, as well as PG&E Bay and non-Bay subareas, using regression analysis and the latest hourly load data available.[48] The regression results provide weather sensitivity for a reference year (in this case, both 2012 and 2013) so that peak demand can be normalized, assuming average weather ("1 in 2") and extreme weather ("1 in 10") using 30 years of temperature data. Weather-normalized peaks are then projected in a manner consistent with the demand forecasts for the appropriate planning area.[49] 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.[50] In the past, Energy Commission and utility forecasters have sometimes disagreed on the best methods to weather normalize peak demand. For the next forecast cycle, utility and Energy Commission staffs will attempt to agree upon a consistent method to be used by both.

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 model develops a forecast based on subactivities within the sector (for example, commercial building type or industrial activity). Under the Energy Commission's Quarterly Fuel and Energy Report (QFER) regulations, each load-serving entity (LSE) is required to file quarterly reports documenting energy consumption by activity group.

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

47 See http://www.energy.ca.gov/2013_energypolicy/documents/#reportsnomeeting.

48 The TAC areas include the IOUs and, for Pacific Gas and Electric and Southern California Edison, publicly owned utilities utilizing the IOU's transmission system.

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

50 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.

unclassified consumption to economic sectors using professional judgment, relying on factors such as unrealistic changes in historical consumption.

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

Structure of Report

Chapter 2 of Volume 1 provides statewide results for the end-user natural gas forecast, along with results for the PG&E, SoCalGas, and SDG&E distribution planning areas as well as AAEE results at the service territory level. Chapter 3 presents committed energy efficiency and conservation savings estimated for the forecast. Chapter 4 provides estimates of AAEE savings, a discussion of the methods used to develop these estimates, and resulting adjusted combined IOU service territory forecasts. The appendices provide additional information about methods and econometric results, incorporation of climate change, self-generation, and regression results.

Volume 2 provides *CED 2013 Final* electricity forecasts for the following planning areas: PG&E, SCE, SDG&E, SMUD, and LADWP. The planning areas included in this forecast are described in **Table 14** below. For PG&E and SCE, service territories are a subset of the planning areas. The chapters for LADWP, PG&E, and SCE in Volume 2 provide results for the climate zones within these planning areas. **Figure 15** shows the Energy Commission's forecasting climate zones. Zones 1 − 5 correspond to PG&E, 7 – 10 to SCE, and 11 – 12 to LADWP. The other planning areas correspond to single climate zones. The areas labeled "Other" correspond to areas in California served (for electricity) by out-of-state entities and not included in the eight planning areas. The chapters for PG&E, SCE, and SDG&E also provide estimates of AAEE savings for these service territories and show resulting adjusted forecasts. Forecast demand forms for each planning area are posted with this report.[51]

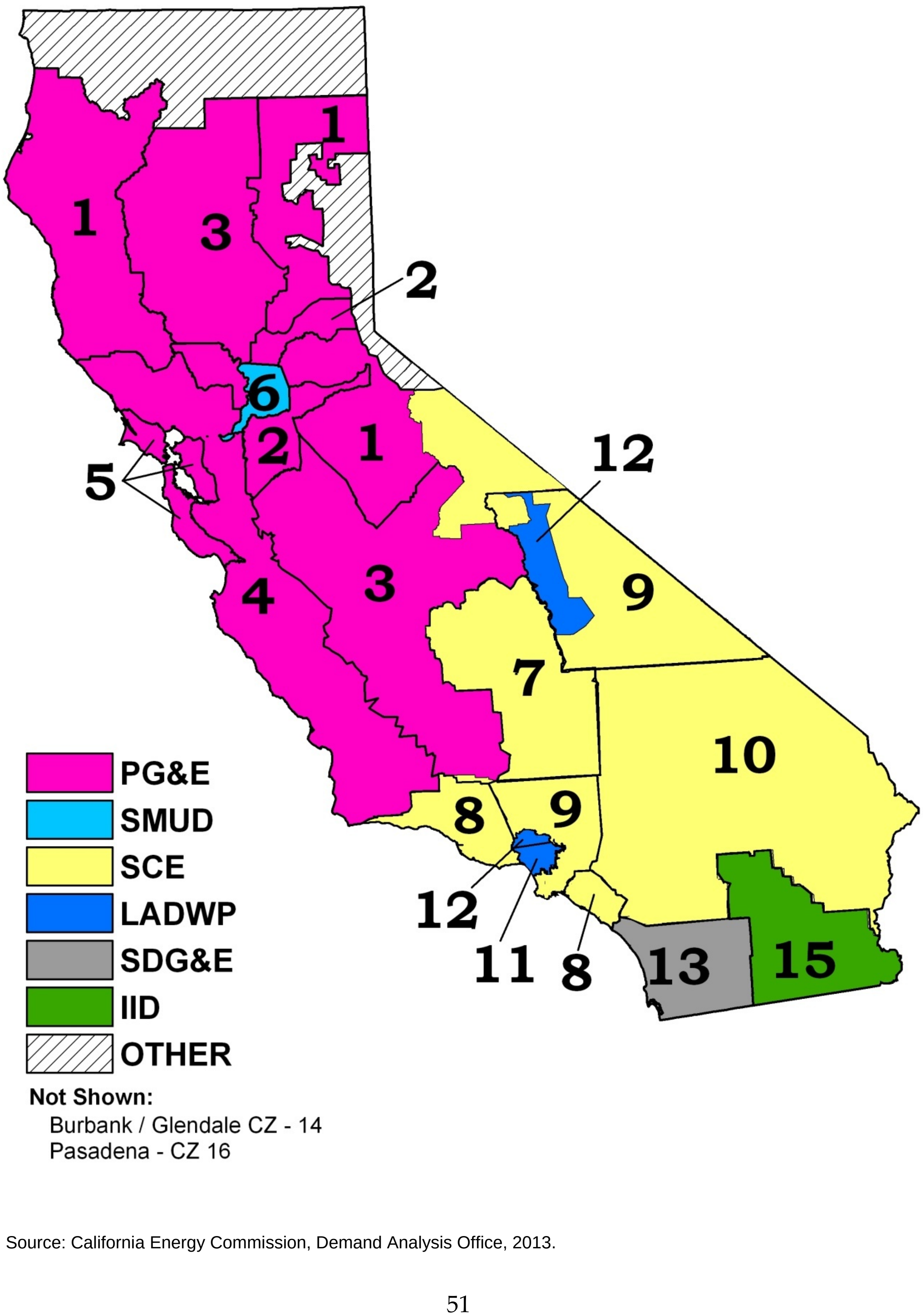
51 See http://www.energy.ca.gov/2013_energypolicy/documents/#reportsnomeeting.

Table 14: Utilities Within Forecasting Areas

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

Source: California Energy Commission, Demand Analysis Office, 2013.

Figure 15: Energy Commission Forecasting Climate Zones



Source: California Energy Commission, Demand Analysis Office, 2013.

CHAPTER 2: End-User Natural Gas Demand Forecast

This chapter presents final baseline forecasts of end-user natural gas demand for the PG&E, SoCal Gas, and SDG&E natural gas planning areas. In addition, statewide results include sales from smaller utilities, including Southwest Gas Corporation, aggregated into the category "other." Detailed forecasts for the three major planning areas and "other" are provided in the electronic natural gas forms accompanying this forecast report.[52] AAEE results are also provided in this chapter for the PG&E, SoCalGas, and SDG&E gas service territories.

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

CED 2013 Final incorporates historical natural gas consumption data up through 2012. Three demand scenarios were forecast (high, mid, and low), with the same economic/demographic assumptions as used for electricity. Also similar to electricity, the high, mid, and low scenarios incorporated low, mid, and high assumptions, respectively, for natural gas prices and committed efficiency program impacts. See Chapter 1 for a discussion of prices and economic and demographic inputs and Chapter 3 for a description of committed efficiency assumptions. Finally, statewide and major planning area results are shown with and without estimates of incremental achievable efficiency, referred to as baseline and adjusted forecasts, respectively. Incremental achievable efficiency is described further in Chapter 3.

Statewide Baseline Forecast Results

Table 15 compares the three *CED 2013 Final* baseline demand scenarios at the statewide level with the *CED 2011* mid demand case for selected years. The new forecasts begin at a lower point in 2012, as natural gas consumption in California was substantially lower this year than was predicted in the *CED 2011* mid case, and grow at a slower rate in all three scenarios from 2012 – 2022. Key factors are slower projected population growth in the *CED 2013 Final* mid and low cases, the introduction of climate change impacts in the mid and high cases,[53] and new efficiency initiatives and higher projected natural gas rates for all three scenarios. Climate change affects the mid and high scenarios through projected decreases in heating degree days

52 See http://www.energy.ca.gov/2013_energypolicy/documents/#reportsnomeeting.

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

(see Appendix A). By 2024, climate change is projected to reduce end-user natural gas demand statewide by around 250 million therms in the mid case and by roughly 640 million therms in the high case. Sector results are discussed in the planning area sections that follow.

Table 15: Statewide Baseline End-User Natural Gas Forecast Comparison

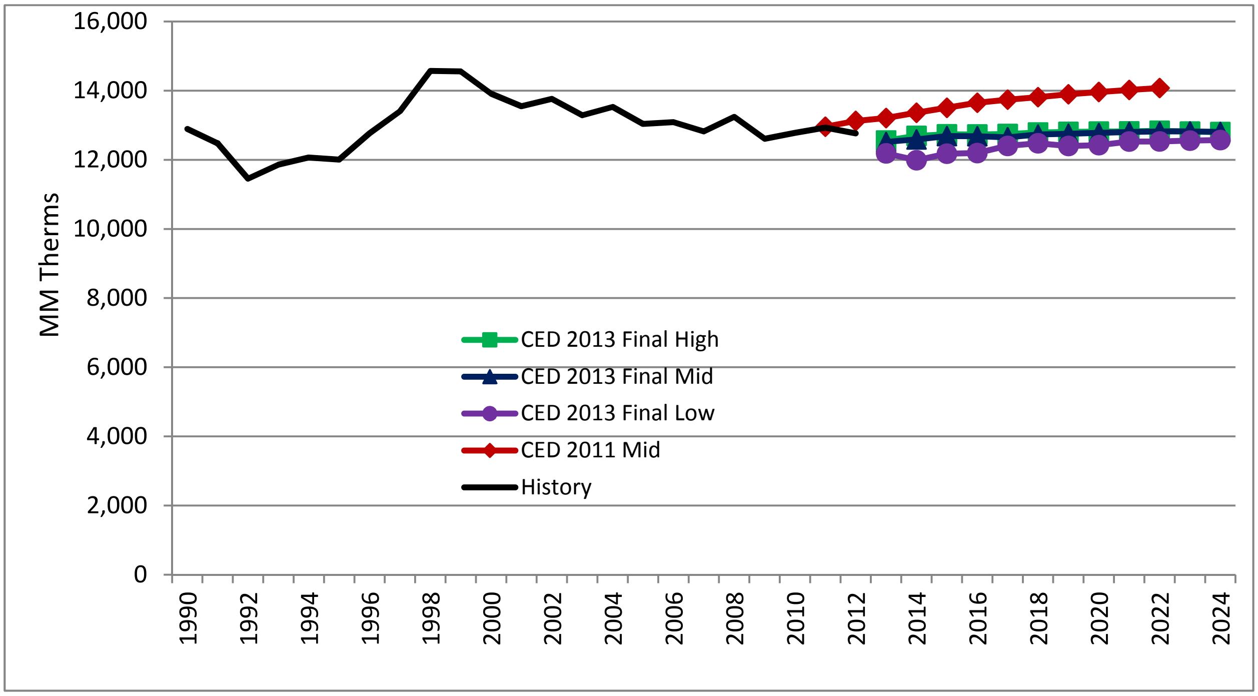
Consumption (MM Therms)				
	CED 2011 Mid Case	***CED 2013 Final High Energy Demand***	***CED 2013 Final Mid Energy Demand***	***CED 2013 Final Low Energy Demand***
1990	12,893	12,893	12,893	12,893
2000	13,913	13,913	13,913	13,913
2012	13,123	12,767	12,767	12,767
2015	13,503	12,736	12,687	12,176
2020	13,961	12,816	12,774	12,423
2024	--	12,801	12,806	12,569
	Average Annual Growth Rates			
1990-2000	0.76%	0.76%	0.76%	0.76%
2000-2012	-0.49%	-0.71%	-0.71%	-0.71%
2012-2015	0.96%	-0.08%	-0.21%	-1.57%
2012-2022	0.70%	0.06%	0.04%	-0.19%
2012-2024	--	0.02%	0.03%	-0.13%
Historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2013.

Figure 16 shows the forecasts. By 2022, demand in the *CED 2013 Final* mid case is projected to be around 9 percent lower compared to the *CED 2011* mid case. The three scenarios are fairly close together as climate change impacts reduce consumption in the mid and high cases and resource extraction output[54] is lower in the high demand case. Lower resource extraction gas consumption and higher climate change impacts are enough to push the high demand case below the mid case by 2024. In general, growth rates for total consumption are lower compared to electricity, reflecting a historical trend for gas demand that is flat or declining for most of the previous decade, an indication of the effectiveness of building codes and standards. The volatility of projected natural gas prices (from the Energy Commission's NamGas model) in the early years of the forecasts leads to variation in the natural gas forecast trajectories, particularly in the low case.

54 Unlike industrial electricity demand, resource extraction—specifically enhanced oil recovery—contributes significantly to natural gas demand in the industrial sector.

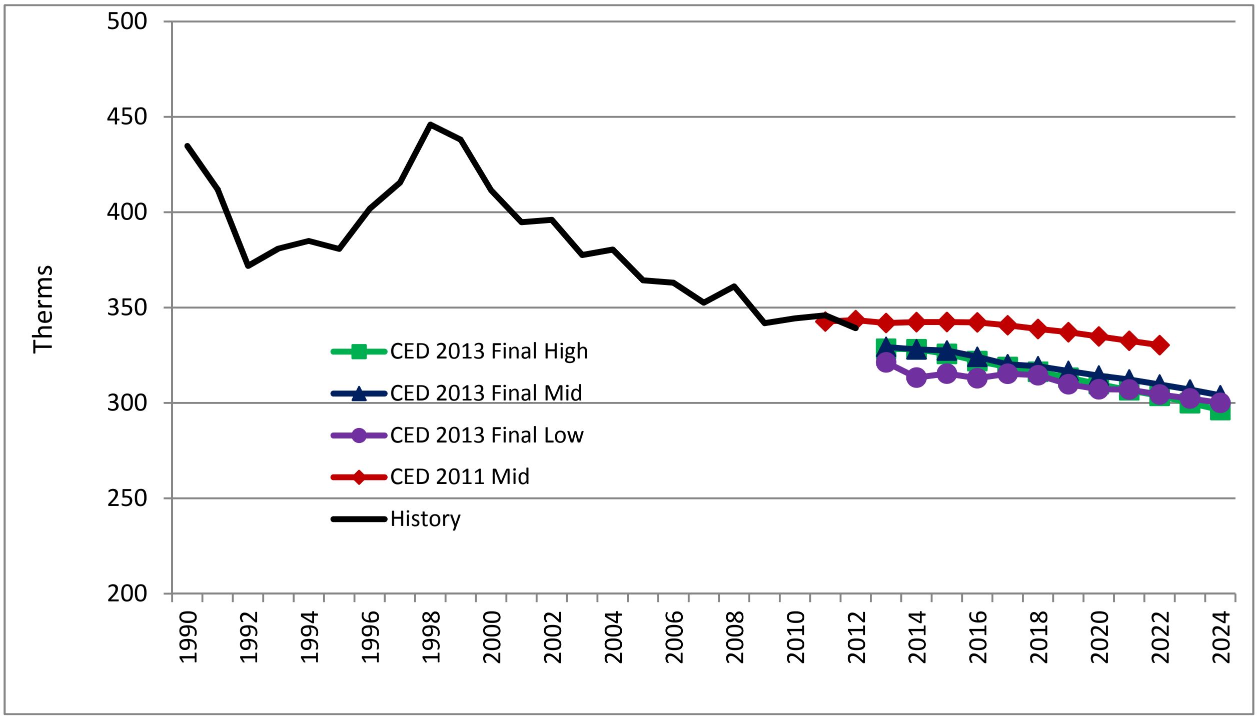
Figure 16: Statewide Baseline End-User Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013

Figure 17 compares *CED 2013 Final* baseline per capita natural gas consumption with the *CED 2011* mid case. Annual per capita demand varies in response to annual temperatures and business conditions but has been generally declining since the late 1990s. This trend is projected to continue as projected population grows faster than total natural gas demand. Per capita consumption in all three scenarios is lower in 2012 than projected in the *CED 2011* mid case due in part to a historically low number of heating degree days. Because of higher population growth in the high demand case, per capita consumption is lowest in this scenario.

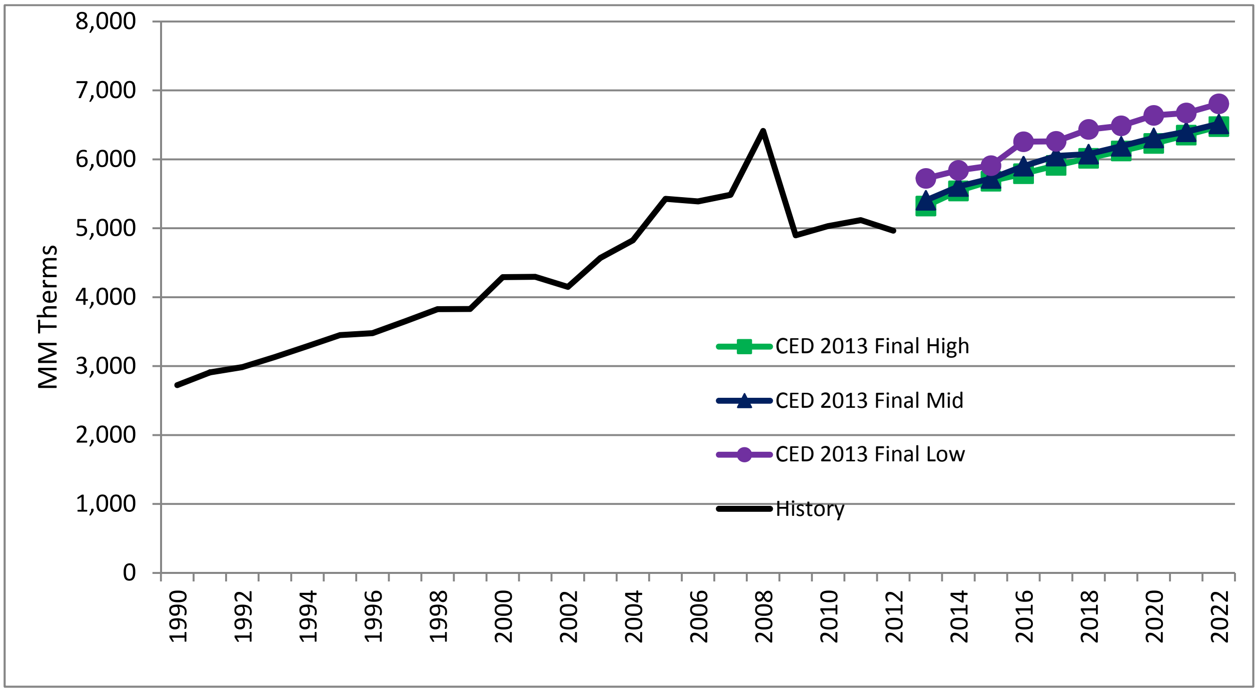
Figure 17: Statewide End-User Baseline per Capita Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013.

Figure 18 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 35 historical years of impacts from rate changes and standards. Savings from standards are directly related to the demand outcome (higher demand associated with more new construction), while program and price effects are inversely related. The result is that savings in the mid and low scenarios are roughly equal, while price effects from higher rates push the low scenario above the other two cases. The large increase in impacts seen in 2008 comes from a sharp rise in natural gas prices. In 2024, accumulated efficiency impacts are expected to correspond to around a 35 percent decrease in consumption in the mid demand case relative to use assuming no efficiency impacts since 1975.

Figure 18: Statewide Natural Gas Committed Efficiency Impacts



Source: California Energy Commission, Demand Analysis Office, 2013.

Chapter 4 provides AAEE natural gas savings at the statewide (combined IOU) level. AAEE savings by service territory along with adjusted service territory forecasts are given in the planning area sections below.

Planning Area Baseline Results

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

Pacific Gas and Electric Planning Area

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

Table 16 compares the *CED 2013 Final* PG&E planning area baseline forecasts with the *CED 2011* mid case. The new forecasts begin at almost the same level as projected in *CED 2011* mid but grow at a slower rate in all three scenarios as projected natural gas prices increase. By 2020, demand is about 6.5 percent lower in the mid case compared to *CED 2011*. Climate change impacts and slower growth in resource extraction output in the *CED 2013 Final* high demand case reduce demand almost to the level of the *CED 2013 Final* mid case by 2024.

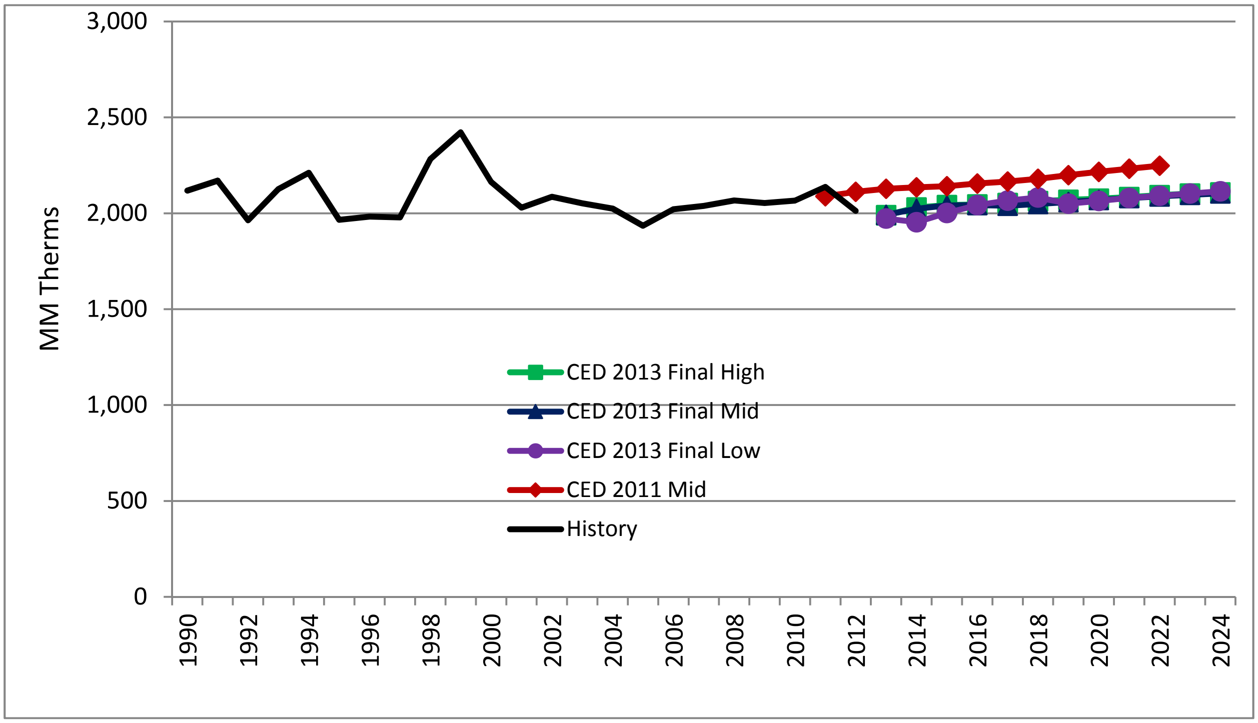
Table 16: PG&E Baseline Natural Gas Forecast Comparison

Consumption (MM Therms)				
	CED 2011 Mid Case	***CED 2013 Final High Energy Demand***	***CED 2013 Final Mid Energy Demand***	***CED 2013 Final Low Energy Demand***
1990	5,275	5,275	5,275	5,275
2000	5,291	5,291	5,291	5,291
2012	4,746	4,761	4,761	4,761
2015	4,862	4,699	4,679	4,477
2020	5,035	4,777	4,720	4,544
2024	--	4,786	4,739	4,611
	Average Annual Growth Rates			
1990-2000	0.03%	0.03%	0.03%	0.03%
2000-2012	-0.90%	-0.88%	-0.88%	-0.88%
2012-2015	0.80%	-0.44%	-0.58%	-2.03%
2012-2022	0.68%	0.07%	-0.04%	-0.36%
2012-2024	--	0.04%	-0.04%	-0.27%
Historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2013.

Figure 19 compares *CED 2013 Final* and *CED 2011* mid case PG&E baseline residential forecasts. The new forecasts are lower throughout the forecast period as actual consumption recorded in 2012 was lower than predicted in the *CED 2011* mid case. Average annual growth from 2012 – 2022 in all three scenarios (0.40, 0.37, and 0.38 percent, respectively, for the high, mid, and low cases) is slower versus the *CED 2011* mid case (0.63 percent), reflecting the effect of lower population growth in the mid and low cases, climate change impacts in the mid and high cases, and higher projected rates and more efficiency savings in all three scenarios.

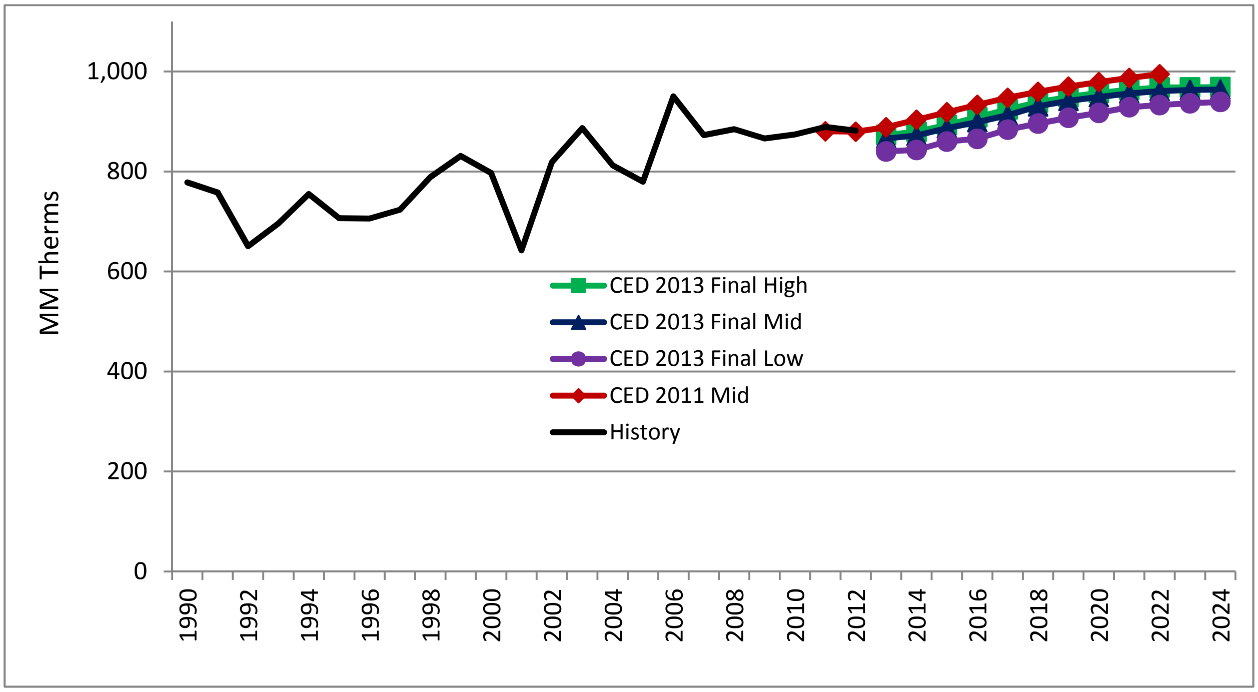
Figure 19: PG&E Planning Area Baseline Residential Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013.

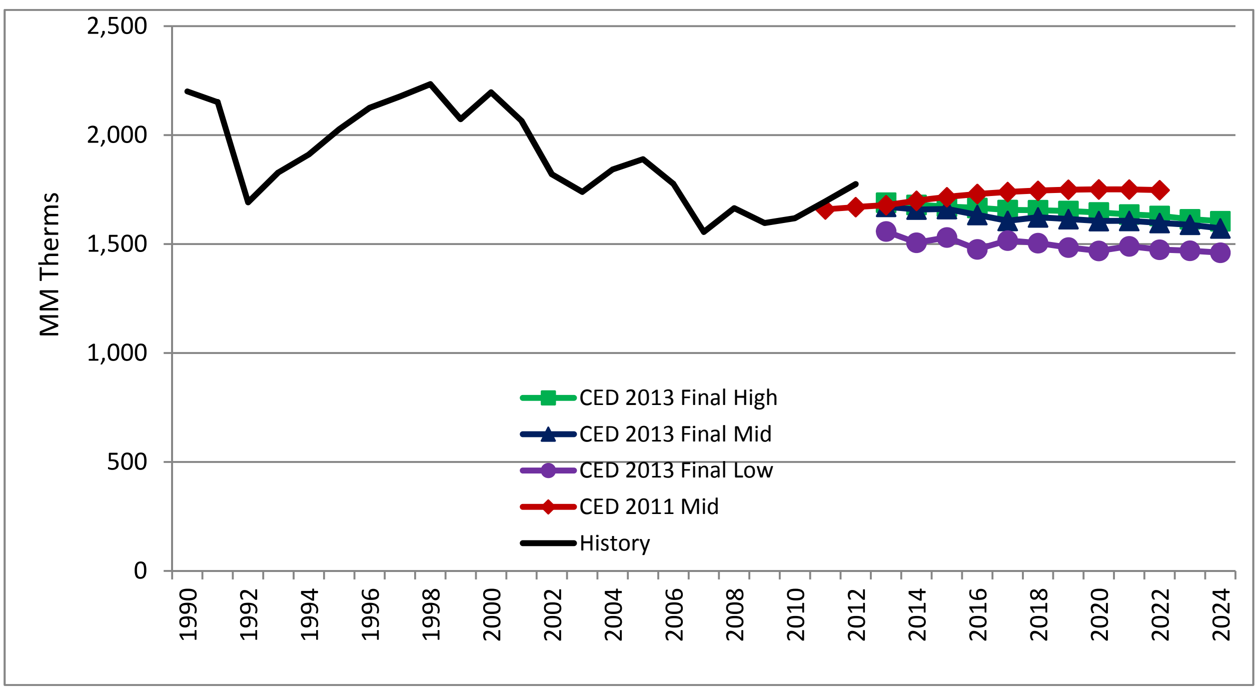
Figure 20 and **Figure 21** show the baseline forecasts for the PG&E commercial and industrial sectors. Additional efficiency, climate change, and rate impacts result in lower growth in the commercial sector in all three scenarios versus the *CED 2011* mid case. By 2022, projected *CED 2011* mid demand was around 3.5 percent higher than in the new forecast. Projected industrial sector demand in the *CED 2013 Final* mid case is lower compared to the *CED 2011* mid case, as slightly higher manufacturing growth in the new forecast is more than offset by the introduction of climate change impacts. As in the commercial sector, *CED 2013 Final* high demand climate change impacts, along with slower growth in resource extraction activity, push this scenario almost as low as in the mid case.

Figure 20: PG&E Planning Area Baseline Commercial Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013.

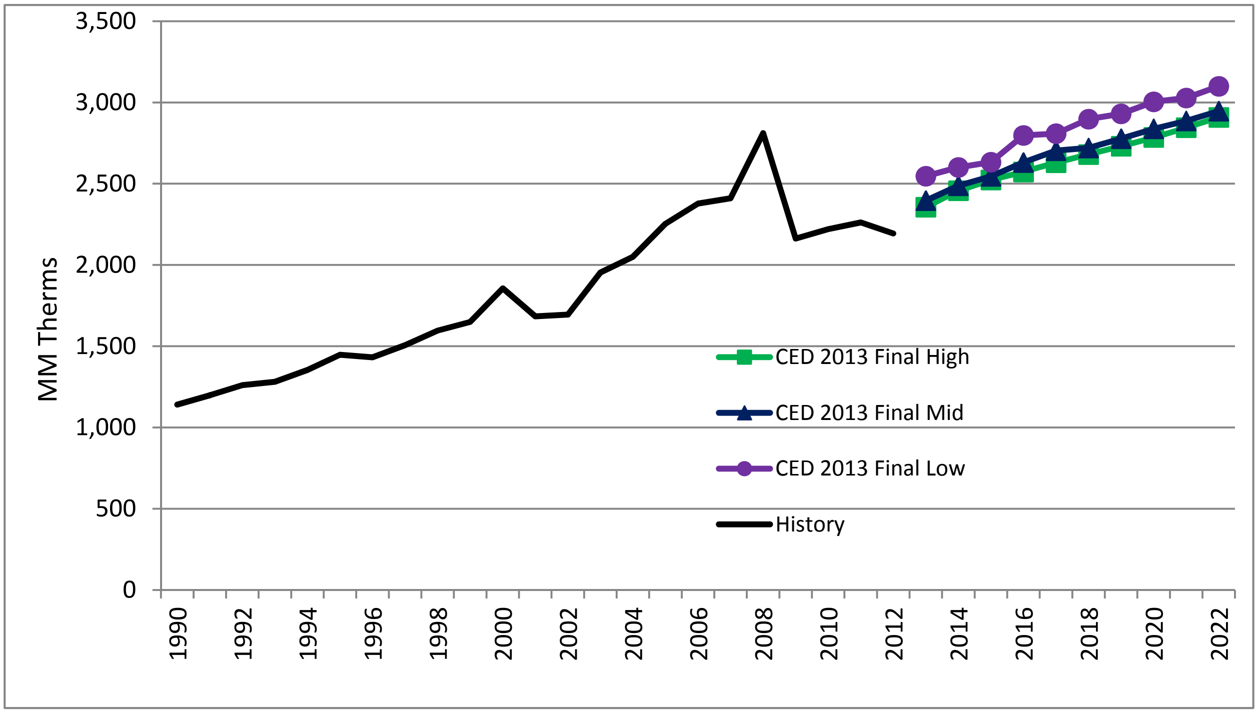
Figure 21: PG&E Planning Area Baseline Industrial Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013.

Figure 22 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. In 2024, accumulated efficiency impacts are expected to correspond to about a 39 percent decrease in consumption in the mid demand scenario relative to use, assuming no efficiency impacts since 1975.

Figure 22: PG&E Planning Area Natural Gas Committed Efficiency Impacts



Source: California Energy Commission, Demand Analysis Office, 2013.

AAEE savings were estimated for the PG&E natural gas service territory (slightly smaller than the planning area; see **Table 14**) for the five scenarios described in Chapter 4. **Table 17** provides total natural gas savings by scenario and year; further breakout of savings by source and sectors are available in the demand forms accompanying this report.[55] **Figure 23** shows the mid baseline forecast for the PG&E service territory[56] and forecasts adjusted for the three mid AAEE scenarios. Average annual rates of growth for 2012 - 2024 for the forecasts adjusted for low mid, mid, and high mid AAEE savings are projected at -0.28 percent, -0.37 percent, and -0.46 percent, respectively, compared to -0.04 percent in the baseline.

55 See http://www.energy.ca.gov/2013_energypolicy/documents/#reportsnomeeting.

56 The service territory forecast was developed by applying the projected growth rate for the planning area to 2012 consumption.

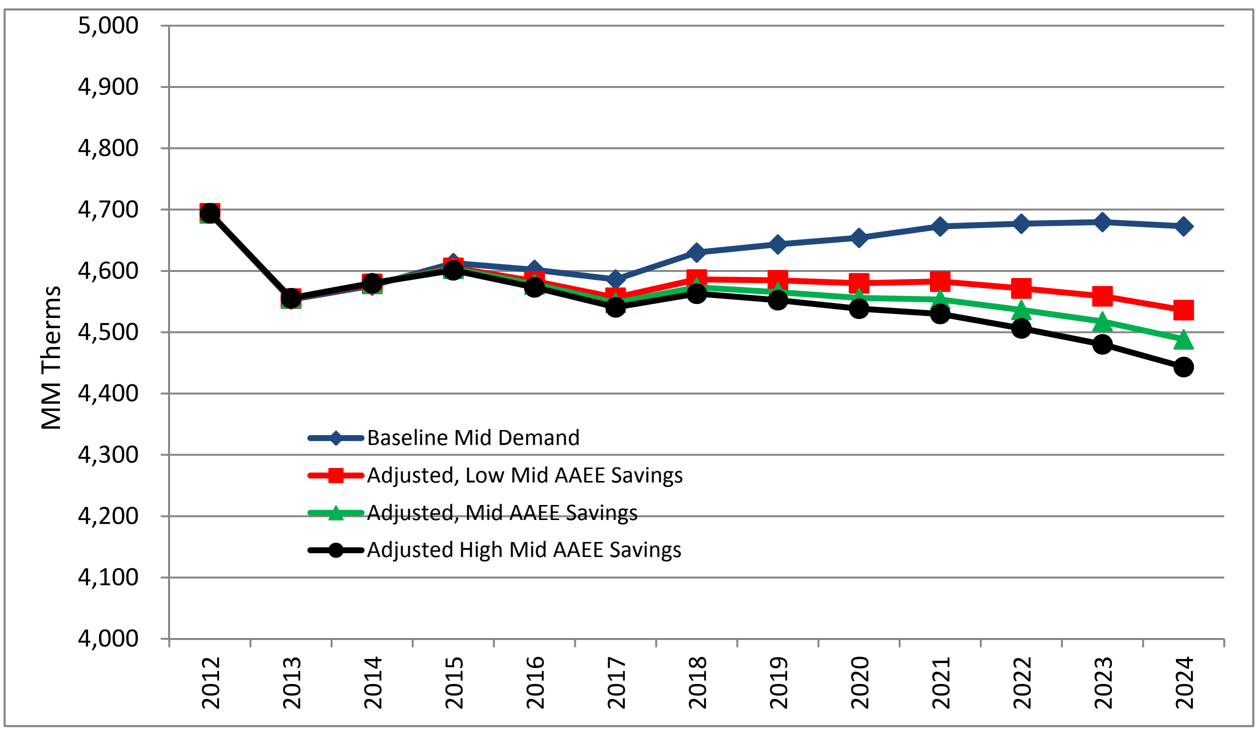
Table 17: AAEE Savings by Scenario and Year, PG&E Service Territory (MM Therms)

Year	Scenario 1 (low)	Scenario 2 (low mid)	Scenario 3 (mid)	Scenario 4 (high mid)	Scenario 5 (high)
2013	(2)	(2)	(2)	(2)	(2)
2014	(3)	(3)	(4)	(4)	(4)
2015	8	8	9	12	12
2016	18	19	24	29	28
2017	29	30	38	45	45
2018	43	44	57	67	67
2019	57	59	78	91	91
2020	72	74	98	115	116
2021	87	90	119	143	143
2022	102	105	141	171	171
2023	117	121	162	199	199
2024	131	137	184	229	229

NOTE: Negative entries reflect interactive effects relative to electricity savings.

Source: California Energy Commission, Demand Analysis Office, 2013

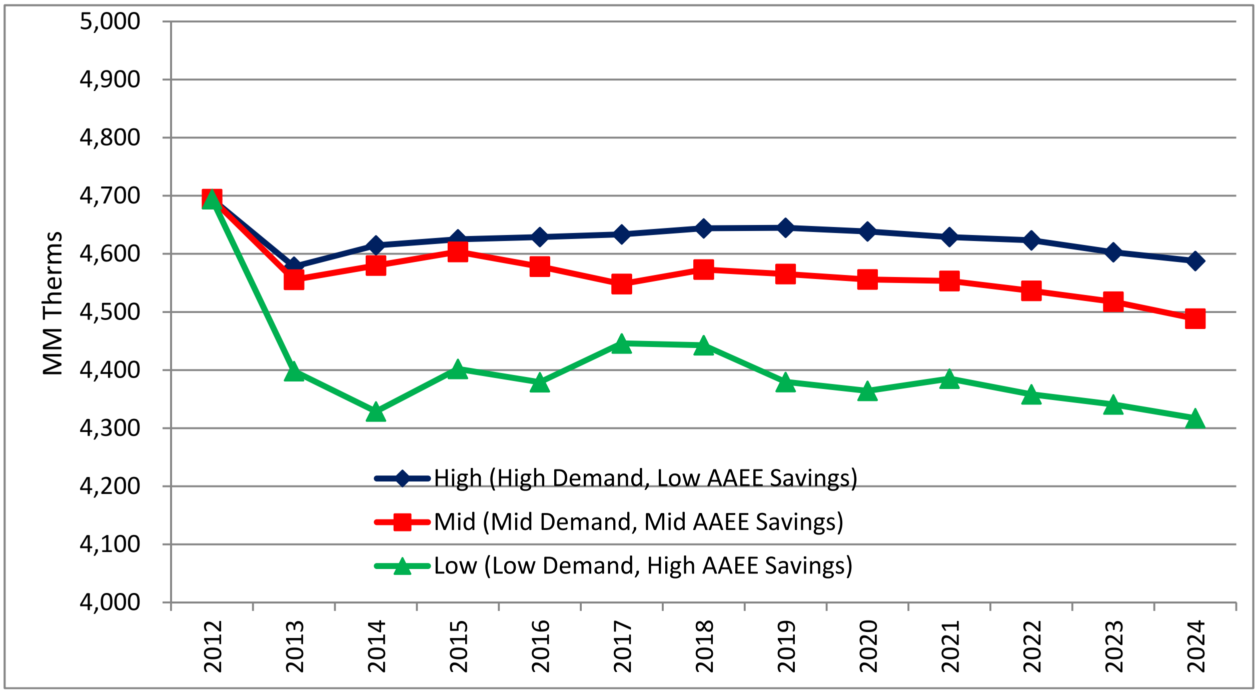
Figure 23: PG&E Service Territory Baseline and Adjusted Mid Forecasts



Source: California Energy Commission, Demand Analysis Office, 2013

Figure 24 shows the high demand, mid demand, and low demand baseline forecasts for the PG&E service territory when adjusted by low AAEE savings, mid savings, and high savings, respectively. Annual growth for 2012-2024 averages -0.19 percent in the adjusted high scenario, -0.37 percent in the mid, and -0.70 percent in the low case.

Figure 24: Adjusted Demand Scenarios for Natural Gas, PG&E Service Territory



Source: California Energy Commission, Demand Analysis Office, 2013

Southern California Gas Company Planning Area

The SoCalGas planning area is composed of the SCE, Burbank and Glendale, Pasadena, and LADWP electric planning areas. It includes customers of those utilities, city of Long Beach customers, customers of private marketers using the SoCal Gas natural gas distribution system, as well as customers served directly by natural gas pipeline companies.

Table 18 compares the *CED 2013 Final* SoCalGas planning area baseline forecasts with the *CED 2011* mid case. In all three scenarios, average annual gas demand growth from 2012 – 2022 is below that of *CED 2011* mid case. By 2022, demand in the new mid case is over 9 percent lower than in the previous forecast. Slower growth in the *CED 2013 Final* high demand scenario versus the *CED 2013 Final* mid case comes from less growth in resource extraction activities and more pronounced climate change impacts.

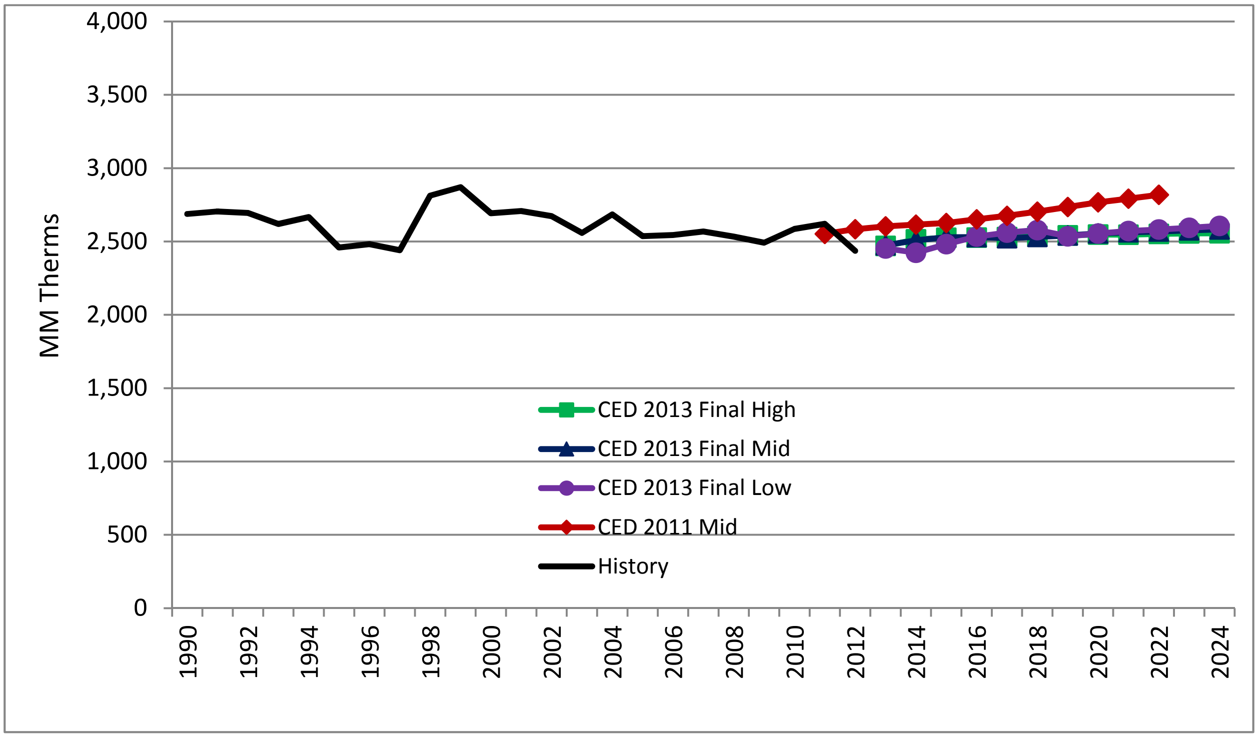
Table 18: SoCalGas Baseline Natural Gas Forecast Comparison

Consumption (MM Therms)				
	CED 2011 Mid Case	***CED 2013 Final High Energy Demand***	***CED 2013 Final Mid Energy Demand***	***CED 2013 Final Low Energy Demand***
1990	6,806	6,806	6,806	6,806
2000	7,938	7,938	7,938	7,938
2012	7,656	7,357	7,357	7,357
2015	7,889	7,391	7,365	7,072
2020	8,109	7,370	7,388	7,220
2024	--	7,335	7,386	7,275
	Average Annual Growth Rates			
1990-2000	1.55%	1.55%	1.55%	1.55%
2000-2012	-0.30%	-0.63%	-0.63%	-0.63%
2012-2015	1.00%	0.16%	0.04%	-1.31%
2012-2022	0.63%	0.02%	0.06%	-0.13%
2012-2024	--	-0.02%	0.03%	-0.09%
Historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2013.

Figure 25 compares the *CED 2011* mid case and *CED 2013 Final* SoCalGas baseline residential forecasts. Average annual growth from 2012 – 2022 in all three scenarios (0.46, 0.53, and 0.58 percent, respectively, for the high, mid, and low cases) is slower versus the *CED 2011* mid case (0.87 percent), reflecting the effect of lower population growth in the mid and low cases, climate change impacts in the mid and high cases, and higher projected rates and more efficiency savings in all three scenarios.

Figure 25: SoCalGas Planning Area Baseline Residential Natural Gas Consumption

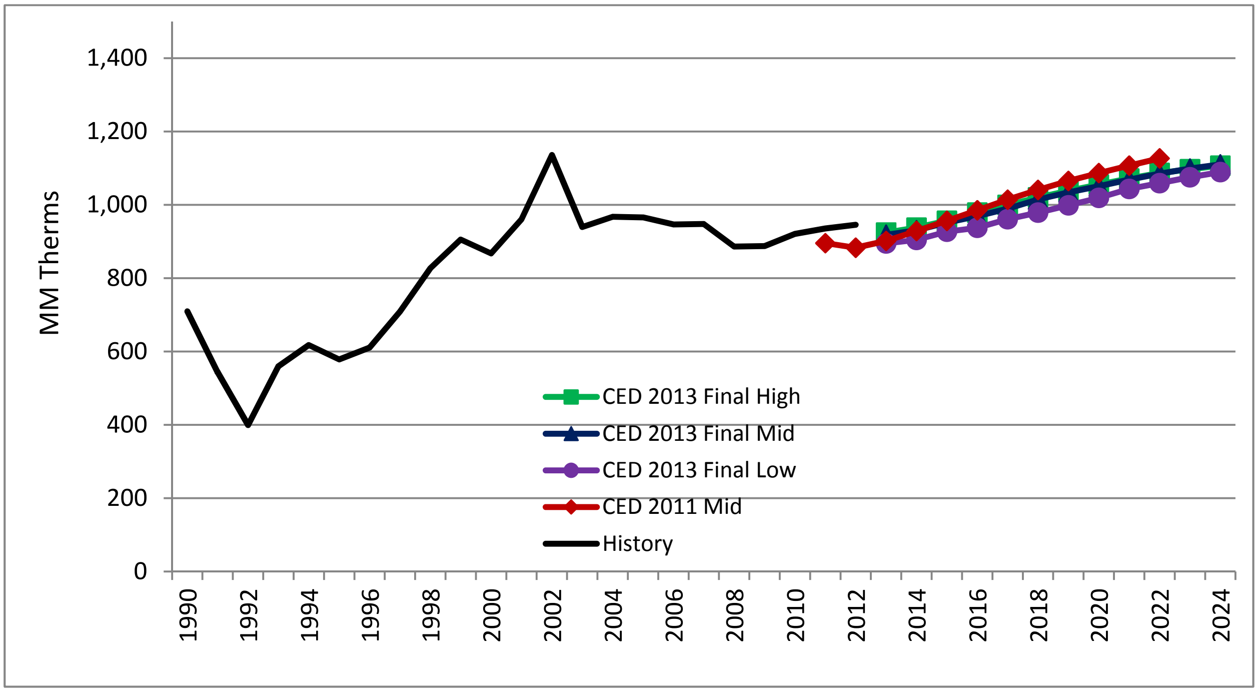


Source: California Energy Commission, Demand Analysis Office, 2013.

Figure 26 and **Figure 27** show the baseline forecasts for the SoCalGas commercial and industrial sectors, respectively. In the commercial sector, the three scenarios are similar to the *CED 2011* mid case through 2014. Afterward the scenarios show consumption growing at a slower rate for the rest of the forecast period due to additional efficiency savings, climate change, and rate impacts. By 2022, demand is projected to be about 3.5 percent lower in the new mid case relative to the old. The *CED 2013 Final* high demand case falls below the mid case by 2024 because of more pronounced climate change impacts.

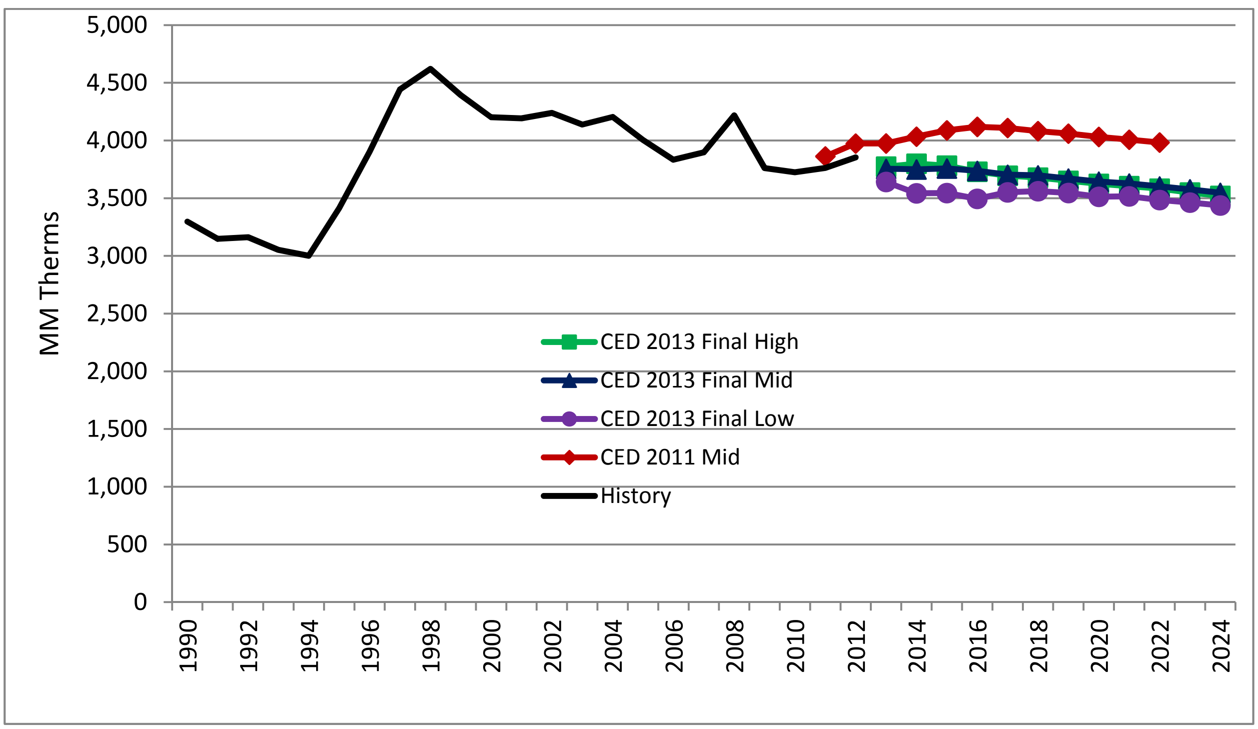
The projections for industrial natural gas consumption reflect an expected long-term decline in this sector's output in the Los Angeles region in all three *CED 2013 Final* scenarios. Unlike *CED 2011*, gas demand is not projected to increase in the short term because of higher rates and the impacts of the 2013 – 2014 IOU efficiency programs. By 2022, projected consumption is around 10 percent below that forecast in the *CED 2011* mid case in all three scenarios.

Figure 26: SoCalGas Planning Area Baseline Commercial Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013.

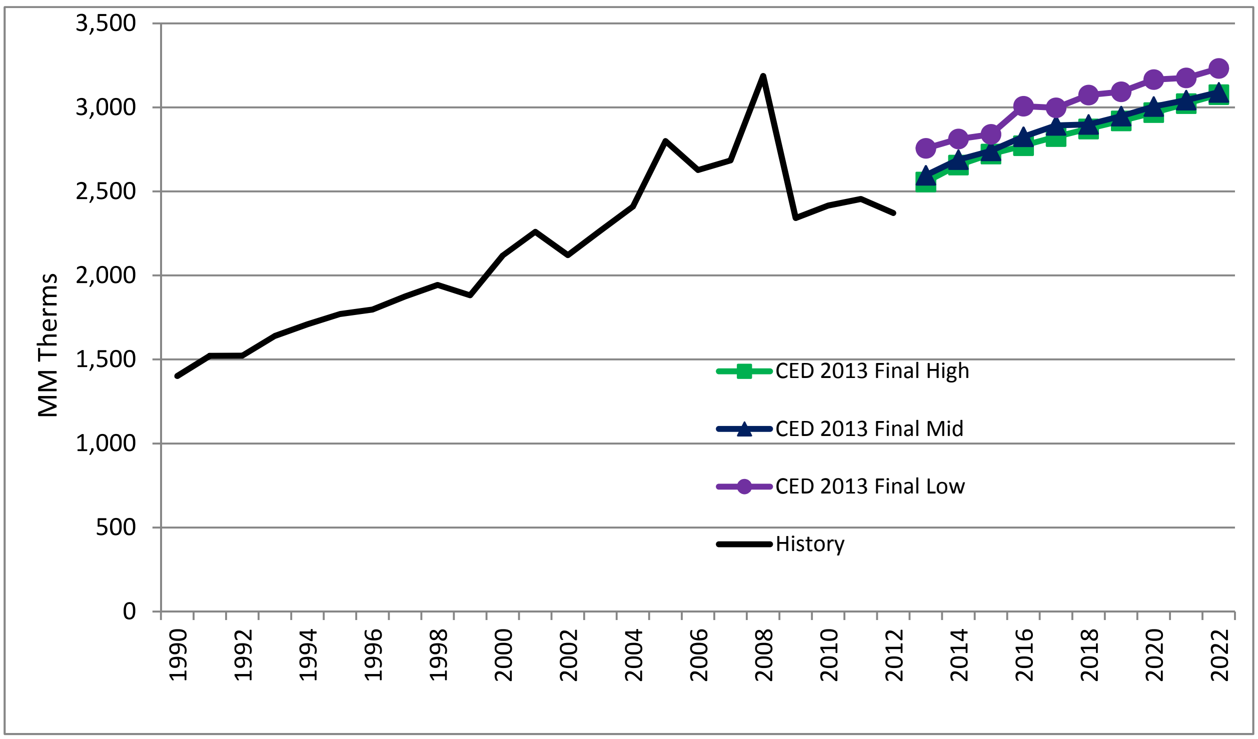
Figure 27: SoCalGas Planning Area Baseline Industrial Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013.

Figure 28 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. Savings from standards are directly related to the demand outcome, while program and price effects are inversely related. The result is that savings in the mid and low scenarios are roughly equal, while price effects from higher rates push the low scenario above the other two cases. The large increase in impacts seen in 2008 comes from a sharp rise in natural gas prices. In 2024, accumulated efficiency impacts are expected to correspond to roughly a 30 percent decrease in consumption in the mid demand scenario relative to use, assuming no efficiency impacts since 1975.

Figure 28: SoCalGas Planning Area Natural Gas Committed Efficiency Impacts



Source: California Energy Commission, Demand Analysis Office, 2013

AAEE savings were estimated for the SoCalGas natural gas service territory, which is a subset of the planning area (see **Table 14**), for the five scenarios described in Chapter 4. **Table 19** provides total natural gas savings by scenario and year; further breakout of savings by source and sectors are available in the demand forms accompanying this report.[57] **Figure 29** shows the mid baseline forecast for the SoCalGas service territory[58] and forecasts adjusted for the three

57 See http://www.energy.ca.gov/2013_energypolicy/documents/#reportsnomeeting.

58 The service territory forecast was developed by applying the projected growth rate for the planning area to 2012 consumption.

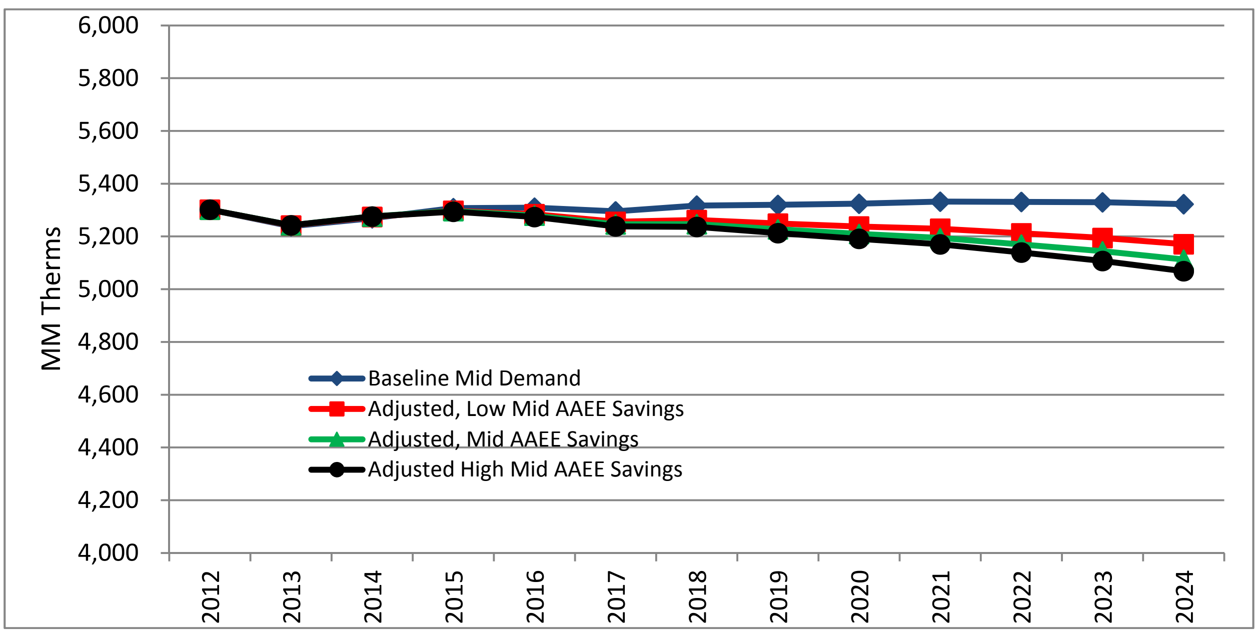
mid AAEE scenarios. Average annual rates of growth for 2012-2024 for the forecasts adjusted for low mid, mid, and high mid AAEE savings are projected at -0.21 percent, -0.30 percent, and -0.37 percent, respectively, compared to 0.03 percent for the baseline.

Table 19: AAEE Savings by Scenario and Year, SoCalGas Service Territory (MM Therms)

Year	Scenario 1 (low)	Scenario 2 (low mid)	Scenario 3 (mid)	Scenario 4 (high mid)	Scenario 5 (high)
2013	(3)	(3)	(4)	(4)	(4)
2014	(5)	(5)	(6)	(6)	(7)
2015	10	10	11	14	14
2016	24	25	30	36	36
2017	39	40	49	57	57
2018	54	55	70	81	82
2019	69	71	93	107	108
2020	84	86	114	133	134
2021	100	103	138	162	163
2022	116	119	162	192	193
2023	131	135	185	222	224
2024	147	152	210	254	256

NOTE: Negative entries reflect interactive effects relative to electricity savings.
Source: California Energy Commission, Demand Analysis Office, 2013

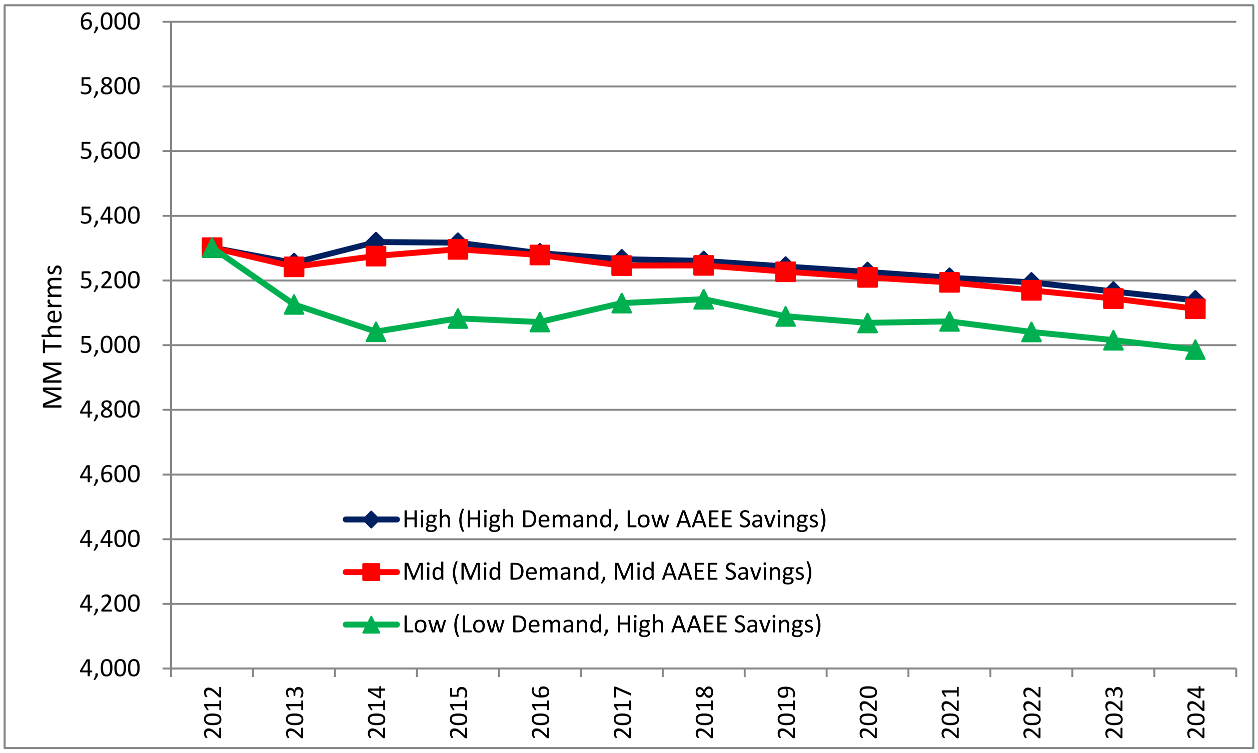
Figure 29: SoCalGas Service Territory Baseline and Adjusted Mid Forecasts



Source: California Energy Commission, Demand Analysis Office, 2013

Figure 30 shows the high demand, mid demand, and low demand baseline forecasts for the SoCalGas service territory when adjusted by low AAEE savings, mid savings, and high savings, respectively. Annual growth for 2012-2024 averages -0.26 percent in the adjusted high scenario, -0.30 percent in the mid, and -0.51 percent in the low case.

Figure 30: Adjusted Demand Scenarios for Natural Gas, SoCalGas Service Territory



Source: California Energy Commission, Demand Analysis Office, 2013

San Diego Gas & Electric Planning Area

The SDG&E planning area contains SDG&E customers plus customers of private marketers using the SDG&E natural gas distribution system. **Table 20** compares the *CED 2013 Final* SDG&E planning area baseline forecasts with the *CED 2011* mid case. The new forecasts begin at a significantly lower level and grow at a slower rate from 2012 – 2022 in all three scenarios. By 2020, projected demand is more than 20 percent lower in the new mid case compared to *CED 2011*. A key reason for the large difference between the 2013 and 2011 forecasts in the early years (along with the introduction of the 2013 – 2014 IOU efficiency programs) is that projected personal income growth in San Diego was revised downward significantly for the new forecast. Climate change impacts and slower growth in resource extraction activities in the *CED 2013 Final* high demand case help reduce demand below that in the *CED 2013 Final* mid and low cases.

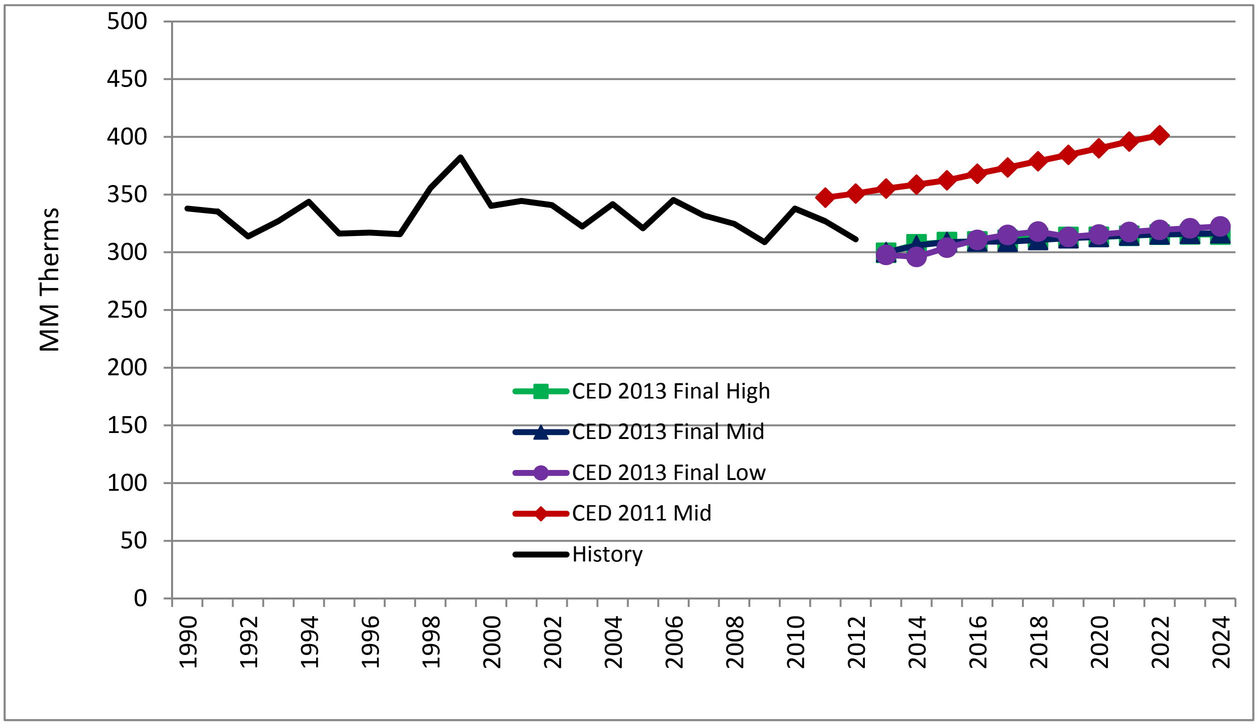
Table 20: SDG&E Baseline Natural Gas Forecast Comparison

Consumption (MM Therms)				
	CED 2011 Mid Case	***CED 2013 Final High Energy Demand***	***CED 2013 Final Mid Energy Demand***	***CED 2013 Final Low Energy Demand***
1990	717	717	717	717
2000	565	565	565	565
2012	580	515	515	515
2015	609	508	507	495
2020	665	524	524	522
2024	--	530	535	541
	Average Annual Growth Rates			
1990-2000	-2.35%	-2.35%	-2.35%	-2.35%
2000-2012	0.22%	-0.78%	-0.78%	-0.78%
2012-2015	1.62%	-0.43%	-0.51%	-1.28%
2012-2022	1.69%	0.26%	0.31%	0.34%
2012-2024	--	0.24%	0.32%	0.41%
Historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2013.

Figure 31 compares the *CED 2011* mid case and *CED 2013 Final* SDG&E baseline residential forecasts. Average annual growth from 2012 – 2022 in all three scenarios (0.13, 0.14, and 0.26 percent, respectively, for the high, mid, and low cases) is slower versus the *CED 2011* mid case (1.35 percent), reflecting the effect of lower population growth in San Diego in the mid and low cases, climate change impacts in the mid and high cases, and higher projected rates and more efficiency savings in all three scenarios. Climate change impacts reverse the order of the scenarios by 2024.

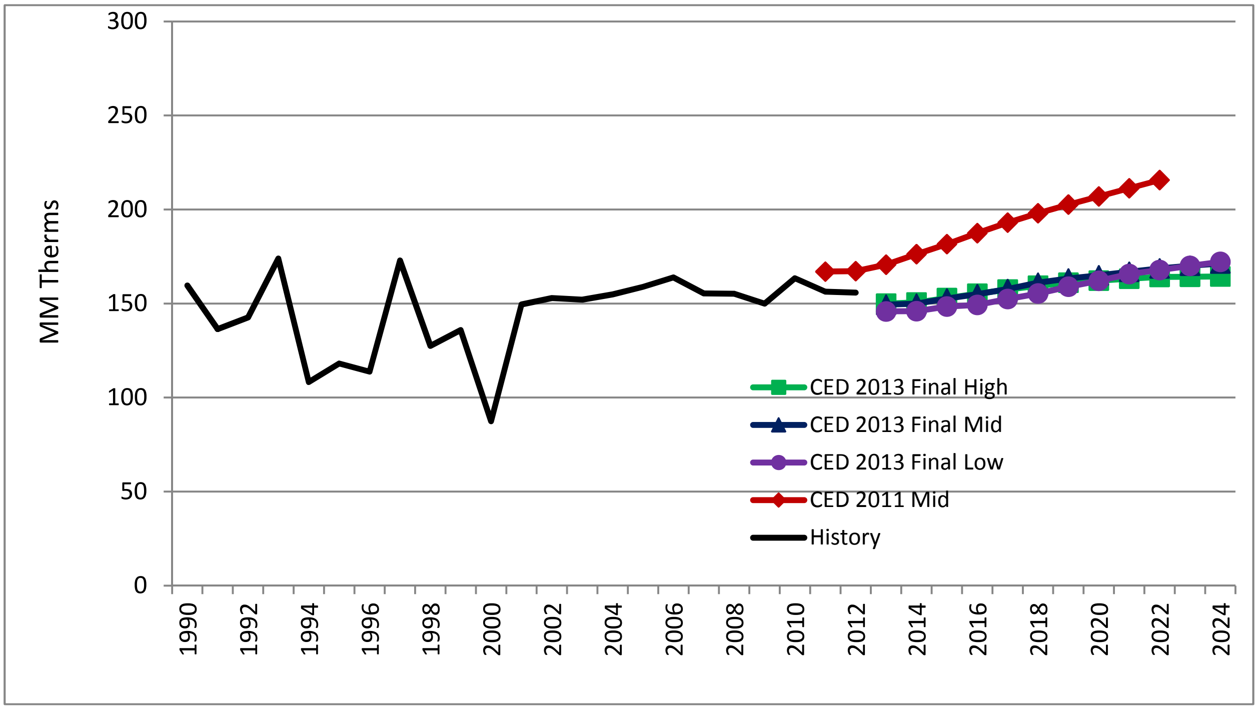
Figure 31: SDG&E Planning Area Baseline Residential Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013.

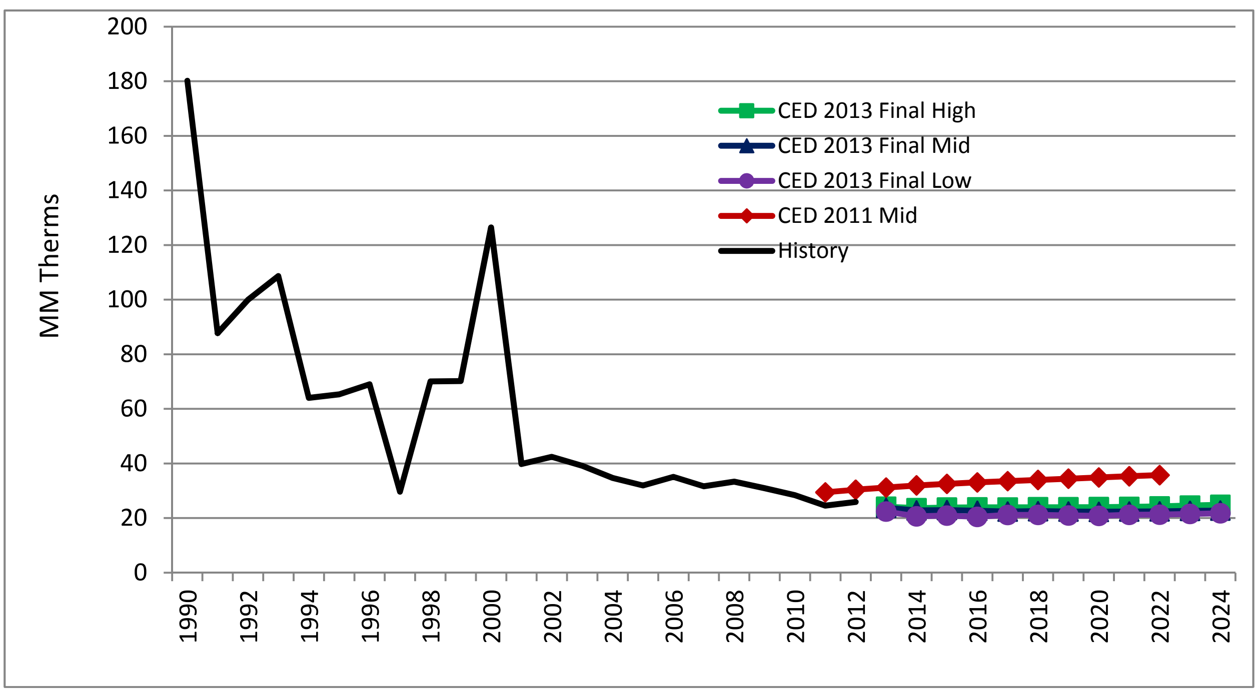
Figure 32 and **Figure 33** show the baseline forecasts for the SDG&E commercial and industrial sectors. Additional efficiency, climate change, and rate impacts result in lower growth in the commercial sector in all three scenarios versus the *CED 2011* mid case. By 2022, projected *CED 2011* mid case demand is almost 22 percent higher than in the new forecast. As in the residential sector, climate change impacts reverse the order of the scenarios by 2024. Projected industrial sector demand is flat throughout the forecast period and slightly below that predicted in the *CED 2011* mid case.

Figure 32: SDG&E Planning Area Baseline Commercial Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013.

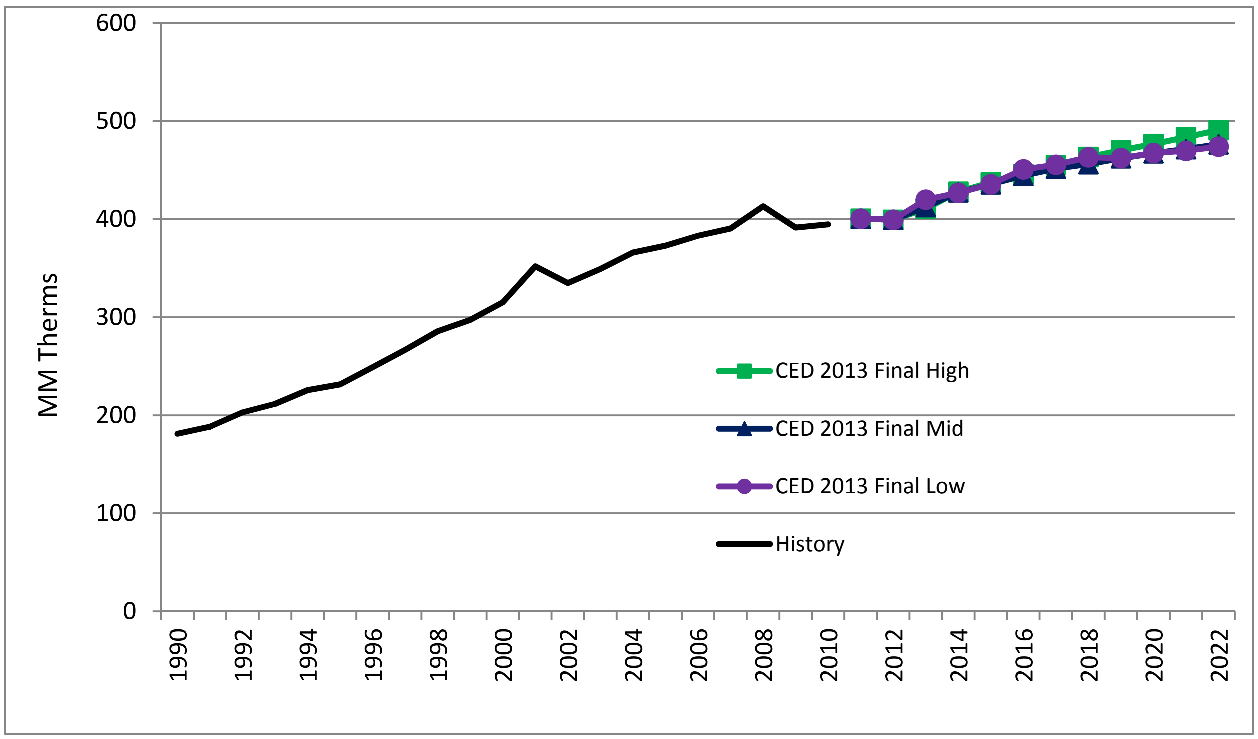
Figure 33: SDG&E Planning Area Baseline Industrial Natural Gas Consumption



Source: California Energy Commission, Demand Analysis Office, 2013.

Figure 34 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. Savings from standards are directly related to the demand outcome, while program and price effects are inversely related. The result is that savings in the mid and low scenarios are roughly equal, while price effects from higher rates push the low scenario above the other two cases. The increase in impacts seen in 2008 comes from a sharp rise in natural gas prices, although not as sharp as in the SoCalGas planning area. In 2024, accumulated efficiency impacts are expected to correspond to about a 48 percent decrease in consumption in the mid case demand scenario relative to use, assuming no efficiency impacts since 1975.

Figure 34: SDG&E Planning Area Natural Gas Committed Efficiency Impacts



Source: California Energy Commission, Demand Analysis Office, 2013

AAEE savings were estimated for the SDG&E natural gas service territory (which is identical to the planning area) for the five scenarios described in Chapter 4. **Table 21** provides total natural gas savings by scenario and year; further breakout of savings by source and sectors are available in the demand forms accompanying this report.[59] **Figure 35** shows the mid baseline forecast for the SDG&E service territory and forecasts adjusted for the three mid AAEE

59 See http://www.energy.ca.gov/2013_energypolicy/documents/#reportsnomeeting.

scenarios. Average annual rates of growth for 2012-2024 for the forecasts adjusted for low mid, mid, and high mid AAEE savings are projected at -0.03 percent, -0.12 percent, and -0.29 percent, respectively, compared to 0.32 percent for the baseline..

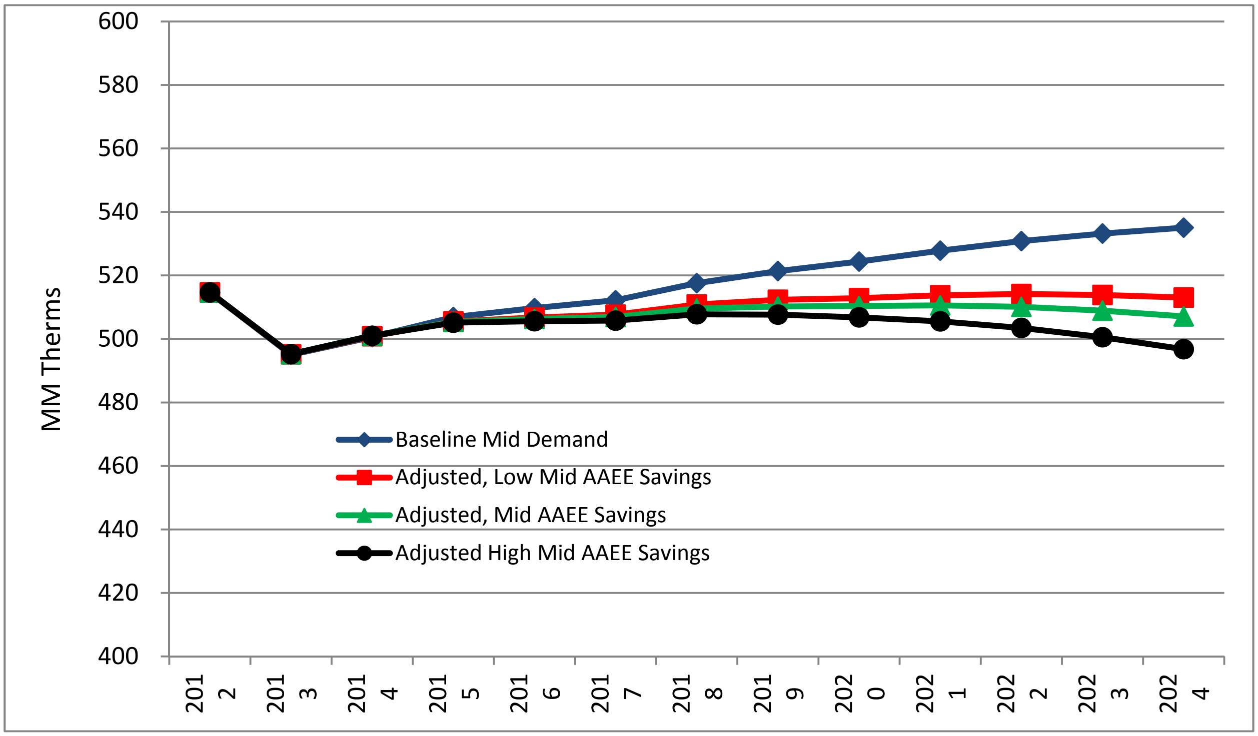
Table 21: AAEE Savings by Scenario and Year, SDG&E Service Territory (MM Therms)

Year	Scenario 1 (low)	Scenario 2 (low mid)	Scenario 3 (mid)	Scenario 4 (high mid)	Scenario 5 (high)
2013	-0.2	-0.2	-0.2	-0.2	-0.2
2014	-0.3	-0.3	-0.4	-0.4	-0.4
2015	1.2	1.4	1.5	1.8	1.8
2016	2.7	3.0	3.4	4.1	4.2
2017	4.2	4.6	5.3	6.4	6.6
2018	6.3	6.7	8.0	9.8	10.0
2019	8.5	9.0	11.2	13.7	14.2
2020	10.8	11.5	14.0	17.6	18.4
2021	13.1	14.0	17.2	22.3	23.5
2022	15.5	16.7	20.7	27.4	29.0
2023	17.9	19.3	24.3	32.7	34.7
2024	20.2	22.0	27.9	38.3	40.6

NOTE: Negative entries reflect interactive effects relative to electricity savings.

Source: California Energy Commission, Demand Analysis Office, 2013

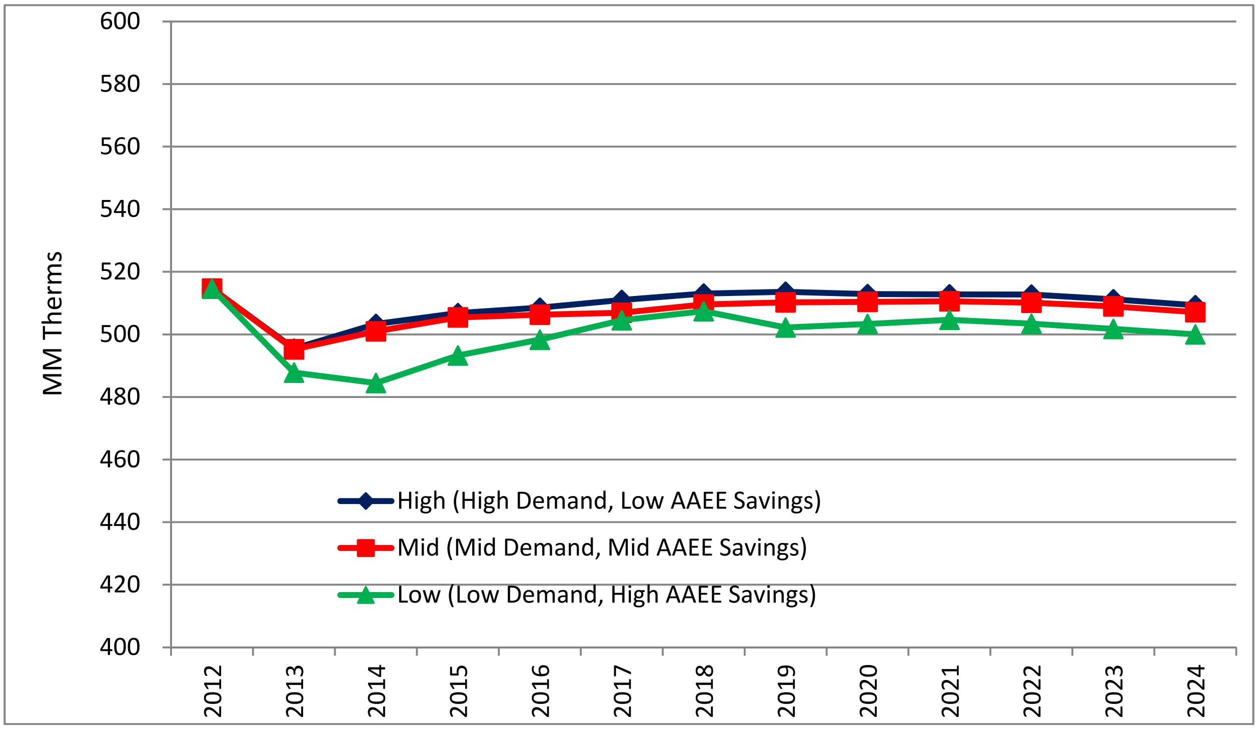
Figure 35: SDG&E Service Territory Baseline and Adjusted Mid Forecasts



Source: California Energy Commission, Demand Analysis Office, 2013

Figure 36 shows the high demand, mid demand, and low demand baseline forecasts for the SDG&E service territory when adjusted by low AAEE savings, mid savings, and high savings, respectively. Annual growth for 2012-2024 averages -0.09 percent in the adjusted high scenario, -0.12 percent in the mid, and -0.24 percent in the low case.

Figure 36: Adjusted Demand Scenarios for Natural Gas, SDG&E Service Territory



Source: California Energy Commission, Demand Analysis Office, 2013

CHAPTER 3: Committed Energy Efficiency and Conservation

Introduction

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

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

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

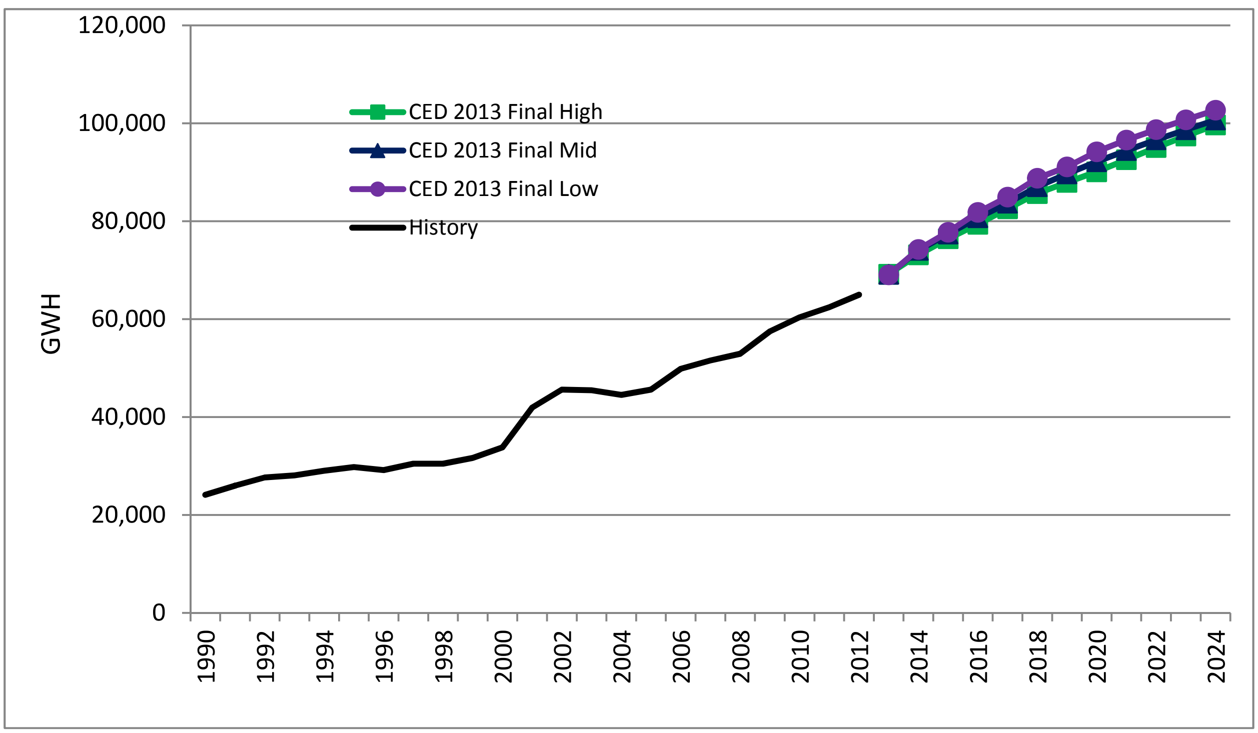
- New building and appliance standards, including impacts from the 2013 Title 24 building standards update and the 2011 battery charger standards
- IOU 2013-2014 efficiency programs
- Updated program savings for POUs, using estimated first-year savings through 2013
- Updated price elasticity estimates

Committed Energy Efficiency

The baseline forecast incorporates savings in energy demand associated with three sources: committed utility and public agency efficiency programs; finalized or implemented residential and commercial building and appliance standards; and residential, commercial, and industrial price and "other" effects, which are intended to capture the impacts from energy price changes and certain market trends not directly associated with programs or standards.[60]

Figure 37 and **Figure 38** show staff estimates of statewide historical and projected committed electricity consumption and peak savings, respectively. Savings are measured relative to a 1975 base and incorporate the simplifying assumption that "counterfactual" demand equals measured demand plus these savings. Within the demand scenarios, higher demand yields more standards savings since new construction and appliance usage increase, while lower demand is associated with more program savings and higher rates (and therefore more price effects). The net result is that savings vary inversely with demand outcome, although the totals are very similar. For electricity consumption, total efficiency savings are around 65,500 GWh in 2012. Increasing rates, the addition of new programs, and the continuing impacts of existing standards (as buildings and appliances turn over) plus savings from new standards push total savings to around 100,000 GWh in all three demand scenarios by the end of the forecast period. Peak demand savings increase to around 25,000 MW in 2024, up from around 15,500 MW in 2012.

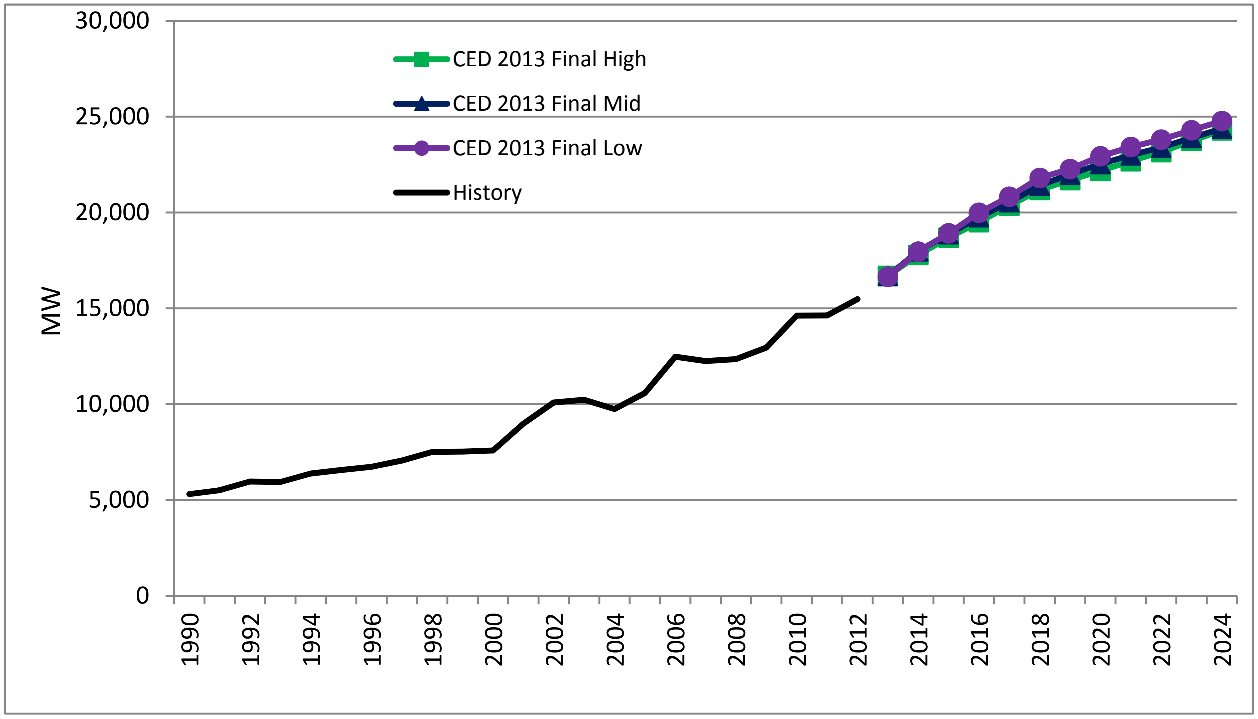
Figure 37: Historical and Projected Statewide Committed Efficiency Electricity Consumption Savings Impacts



Source: California Energy Commission, Demand Analysis Office, 2013.

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

Figure 38: Historical and Projected Statewide Committed Electricity Efficiency Peak Savings Impacts



Source: California Energy Commission, Demand Analysis Office, 2013.

Table 22 shows these savings as a percentage reduction[61] in consumption and peak for selected years. The increasing impact of standards relative to electricity use and increasing rates during the forecast period result in the percentages growing through 2024. Percentages increase across the scenarios as demand decreases since relatively similar savings totals are divided by lower consumption and peak demand totals.

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

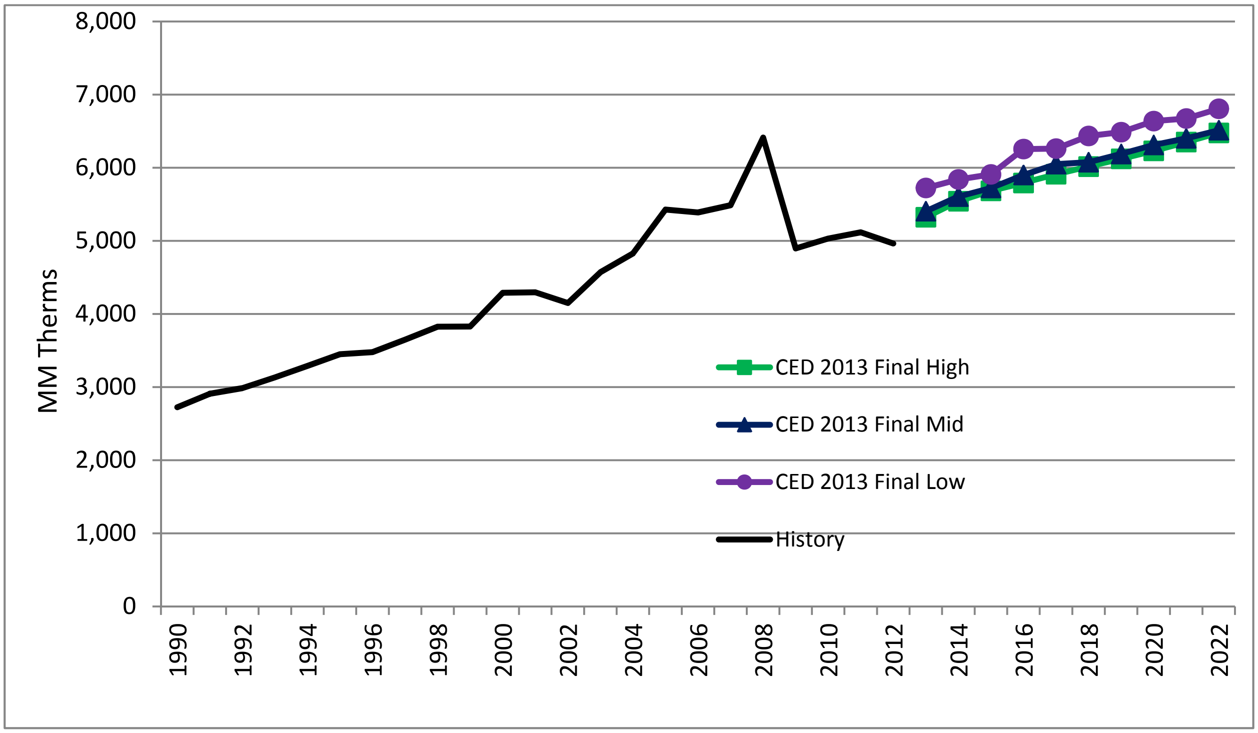
Table 22: Committed Electricity Efficiency Savings as a Percentage of Consumption and Peak Demand

	Consumption		
	CED 2013 Final High Energy Demand	***CED 2013 Final Mid Energy Demand***	***CED 2013 Final Low Energy Demand***
1990	9.6%	9.6%	9.6%
2000	11.5%	11.5%	11.5%
2012	19.0%	19.0%	19.0%
2015	21.0%	21.5%	22.1%
2020	22.5%	23.7%	24.8%
2024	23.3%	24.4%	25.7%
	Peak Demand		
	CED 2013 Final High Energy Demand	***CED 2013 Final Mid Energy Demand***	***CED 2013 Final Low Energy Demand***
1990	10.1%	10.1%	10.1%
2000	12.4%	12.4%	12.4%
2012	20.6%	20.6%	20.6%
2015	22.4%	22.8%	23.4%
2020	23.8%	24.8%	26.1%
2024	24.4%	25.5%	26.9%

Source: California Energy Commission, Demand Analysis Office, 2013.

Figure 39 shows estimated historical and forecast impacts of committed efficiency on statewide natural gas consumption. As with electricity, projected savings impacts are higher in the low demand scenario. Savings in the low and mid case demand scenarios are virtually identical by the end of the forecast period, as higher program and price effects in the former are offset by more standards savings in the latter. Gas consumption savings increase to between 6,500 and 7,000 million therms by 2024, up from around 5,000 million therms in 2012. The large increase in impacts seen in 2008 comes from a sharp rise in natural gas prices.

Figure 39: Statewide Natural Gas Committed Efficiency Impacts



Source: California Energy Commission, Demand Analysis Office, 2013.

Table 23 shows natural gas 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 23: Committed Natural Gas Efficiency Savings as a Percentage of Consumption

	CED 2013 Final High Energy Demand	*CED 2013 Final Mid Energy Demand*	*CED 2013 Final Low Energy Demand*
1990	17.4%	17.4%	17.4%
2000	23.6%	23.6%	23.6%
2012	28.0%	28.0%	28.0%
2015	30.9%	31.1%	32.7%
2020	32.7%	33.1%	34.8%
2022	34.6%	34.5%	35.8%

Source: California Energy Commission, Demand Analysis Office, 2013.

Staff believes **Figure 40**, **Figure 41**, and **Figure 42** provide reasonable estimates of total savings but acknowledges the uncertainty involved in attribution of savings among standards, programs, and price effects, especially during the historical period. Standards and programs are often designed to work together to reduce a targeted usage, and rate hikes increase the likelihood of participating in an incentive program or complying with a given standard. Therefore, no attribution among the three sources is shown, except for estimates of standards impacts and *future* committed program savings presented later in this chapter.

Committed Efficiency Programs

Historical electricity and natural gas program impacts were treated similarly to *CED 2011*,[62] with both POU and IOU savings through 2012 incorporating the most recent CPUC evaluation, measurement, and verification studies.[63] First-year utility-reported net savings are adjusted at the end-use level using realization rates[64] derived from these studies. These savings are then decayed (adjusted in each year by estimated rate of product failure) over the forecast period using expected useful measure lives from the most recent Database for Energy Efficient Resources (DEER) and applying an exponential decay function.

For the 2013 – 2014 IOU programs, staff relied on utility-projected net savings, translating measure-level detail to the appropriate end uses required for the forecast. Utilities were required to estimate measure impacts to be consistent with CPUC evaluation, measurement, and verification studies, so staff felt comfortable applying these savings without additional adjustments (such as realization rates), unlike past program cycles. In previous forecasts, decay by end use was reduced by 50 percent to reflect the CPUC's directive that one-half of measure decay be replaced through additional program activities.[65] However, CPUC staff has advised that this assumption is no longer needed or relevant, given the manner in which future efficiency goals will be developed.[66]

Figure 40 and **Figure 41** show resulting projected 2013 – 2014 IOU cumulative program consumption savings for electricity and natural gas, respectively, over the forecast period. These savings were used in the mid demand case. Electricity savings for the combined IOUs reach almost 2,400 GWh in 2014 and decay to around 1,100 GWh by 2024. Combined savings for natural gas are estimated at around 80 million therms in 2014, decreasing to about 55 million

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

63 The CPUC is working on a review of 2010– 2012 program accomplishments, so final results are not yet available for this forecast.

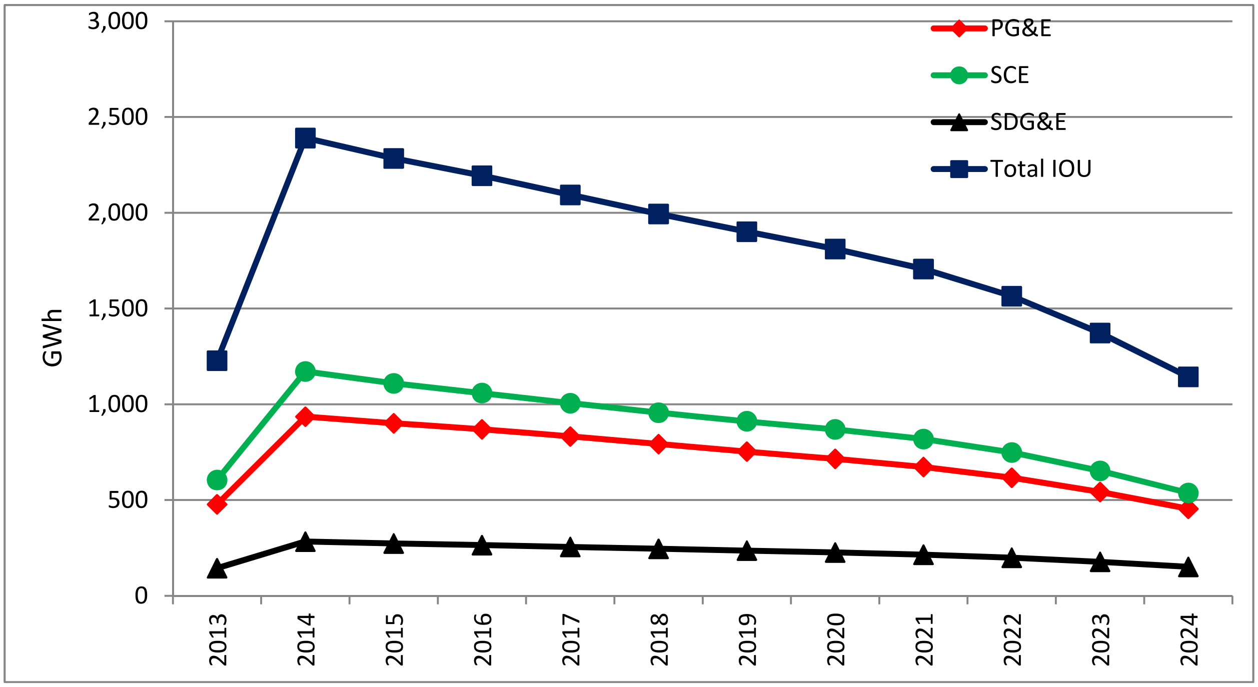
64 Realization rates are meant to be an adjustment for real-world phenomena that may reduce measure savings. For example, compact fluorescents that are purchased but never installed.

65 CPUC Decision 09-09-047, September 2009.

66 CPUC staff expects that future goals will be set based on first-year incremental rather than accumulated efficiency program savings.

therms in 2024. As alternative program scenarios for the other demand cases, staff assumed a 10 percent increase in savings for the low case and a 10 percent decrease for the high.[67]

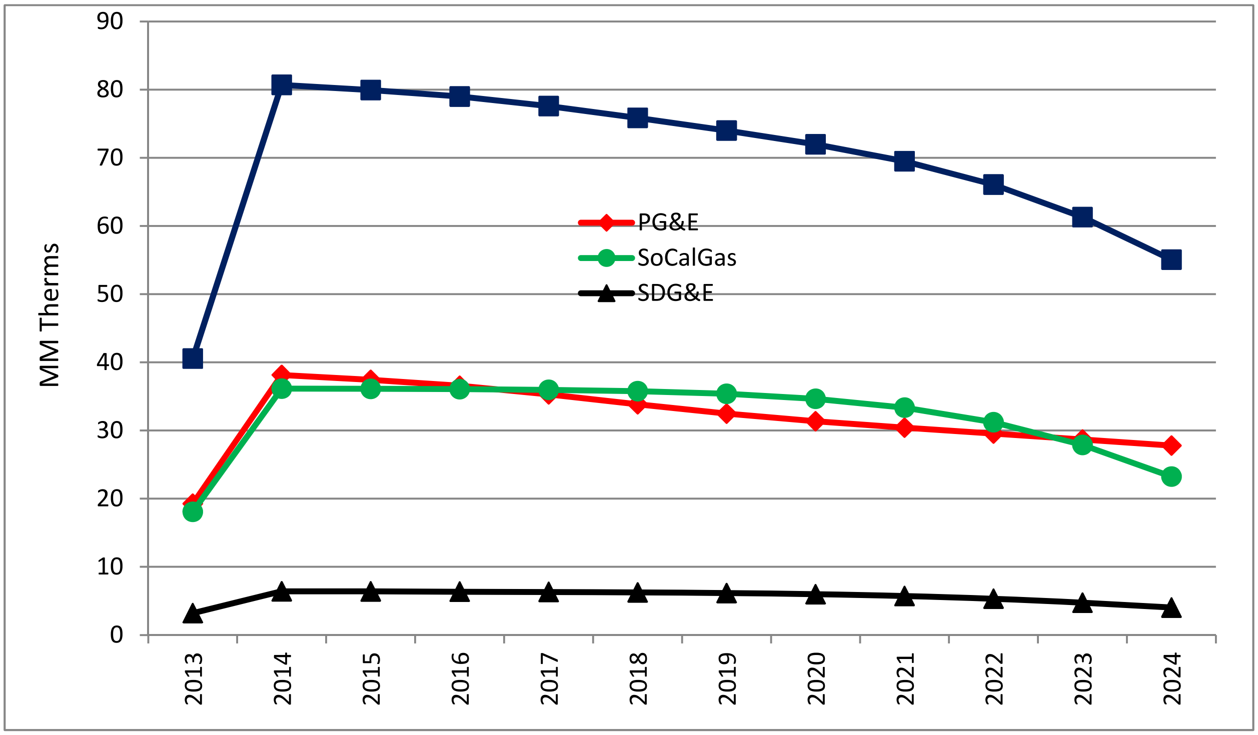
Figure 40: Projected Electricity Savings, 2013 – 2014 IOU Programs, Mid Demand Case



Source: California Energy Commission, Demand Analysis Office, 2013.

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

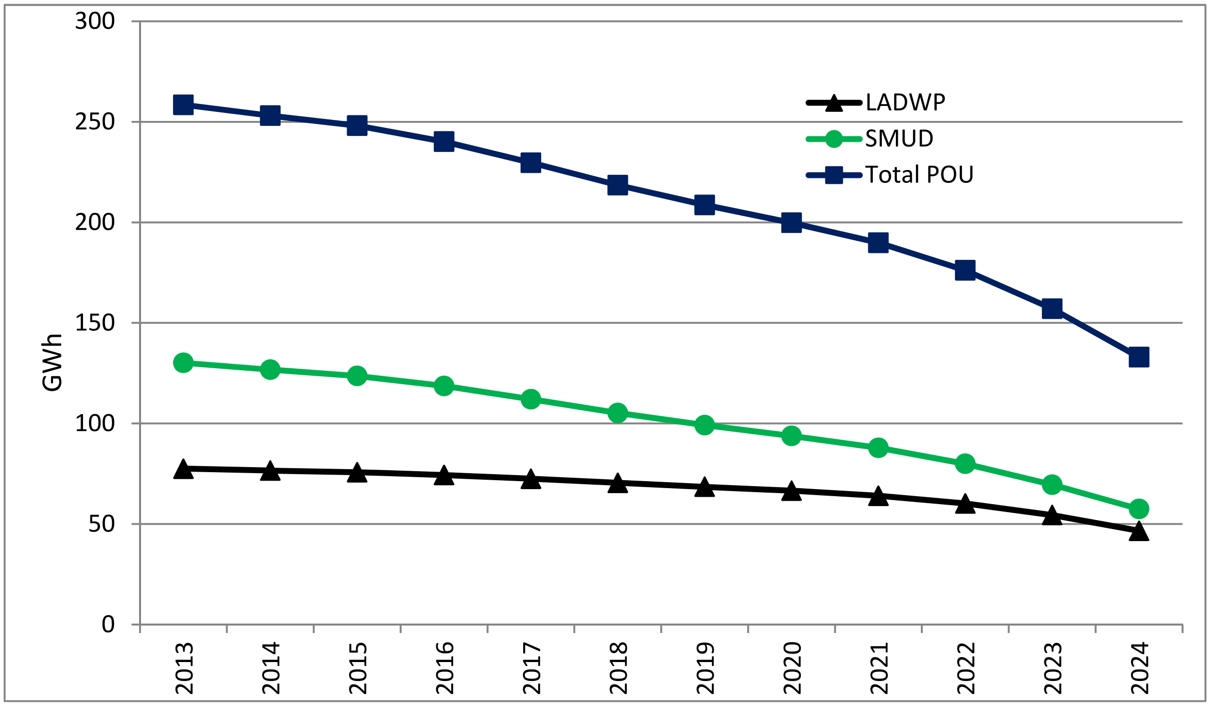
Figure 41: Projected Natural Gas Savings, 2013 – 2014 IOU Programs, Mid Demand Case



Source: California Energy Commission, Demand Analysis Office, 2013.

POU efficiency programs are funded through 2013 (and therefore committed), but estimated savings for 2013 will not be available until early 2014. Staff assumed that POUs would achieve the same level of savings as reported in 2012, with the same distribution across end uses. Realization rates for the high demand scenario were assumed to be similar at the end-use level to those estimated during the CPUC's evaluation of the 2006 – 2009 IOU programs (around 70 percent on average). Realization rates for the low demand case were set at 100 percent and for mid case at an average of rates in the high and low cases. **Figure 42** shows projected cumulative statewide electricity consumption savings for POUs from 2013 programs in the mid demand case through 2024, along with savings for the two largest POUs, LADWP and SMUD. Projected savings in the low and high demand cases are around 10 percent higher and lower, respectively, compared to the mid case.

Figure 42: Projected Electricity Savings From 2013 POU Programs, Mid Demand Case



Source: California Energy Commission, Demand Analysis Office, 2013.

Price Effects

Price effects measure the reduced consumption or demand in the face of higher electricity or natural gas rates. These effects are based on estimated price elasticities in the residential, commercial, and industrial sectors. On average, the price elasticity of electricity demand is around -0.1, which means that a doubling of rates reduces demand by about 10 percent. Individual sector price elasticities are shown in Appendix A.

Building Codes and Appliance Standards

Energy Commission forecasting models incorporate committed building codes and appliance standards through changes in end-use energy intensities that affect consumption per household in the residential sector and end-use consumption per square foot in the commercial sector. **Table 24** shows the codes and standards included in *CED 2013 Final* by sector.

Table 24: Committed Building Codes and Appliance Standards Incorporated in *CED 2013 Final*

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

Source: California Energy Commission, Demand Analysis Office, 2013.

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

Table 25 shows estimated electricity consumption, peak demand, and natural gas savings from appliance and building standards for the residential and commercial sectors in the mid demand scenario. Forecast standards impacts increase slightly in the high demand scenario due to more projected commercial floor space, home additions, and appliance usage and are slightly less in the low demand case. In 2024, projected electricity standards impacts are around 5 percent above the mid case in the high demand case and 3 percent below in the low case. For natural gas, savings from standards are 7 percent higher and 3 percent lower, respectively.

Table 25: Estimated Savings From Building Codes and Appliance Standards: Mid Demand Scenario

	Consumption (GWh)						
	Residential			Commercial			
	Building Standards	Appliance Standards	Total	Building Standards	Appliance Standards	Total	Total Standards
1990	2,811	2,751	5,562	1,333	845	2,178	**7,740**
2000	4,715	7,782	12,497	3,363	2,390	5,754	**18,251**
2012	7,039	18,530	25,569	6,778	4,393	11,172	**36,740**
2015	7,913	24,103	32,015	8,086	5,418	13,503	**45,519**
2020	9,639	29,848	39,487	11,266	7,832	19,098	**58,585**
2024	10,805	32,235	43,040	13,605	9,104	22,709	**65,749**
	Peak (MW)						
	Residential			**Commercial**			
	Building Standards	**Appliance Standards**	**Total**	**Building Standards**	**Appliance Standards**	**Total**	**Total Standards**
1990	721	690	1,412	289	186	475	**1,887**
2000	1,173	1,849	3,022	696	496	1,193	**4,215**
2012	2,007	5,103	7,109	1,418	920	2,339	**9,448**
2015	2,306	6,805	9,112	1,704	1,143	2,847	**11,958**
2020	2,792	8,409	11,201	2,372	1,651	4,023	**15,223**
2024	3,071	8,919	11,990	2,865	1,920	4,785	**16,775**
	Natural Gas (MM Therms)						
	Residential			**Commercial**			
	Building Standards	**Appliance Standards**	**Total**	**Building Standards**	**Appliance Standards**	**Total**	**Total Standards**
1990	785	664	1,449	36	32	68	**1,517**
2000	1,417	1,192	2,608	73	64	137	**2,746**
2012	1,821	1,499	3,320	117	127	244	**3,564**
2015	1,900	1,562	3,462	128	141	270	**3,731**
2020	2,074	1,645	3,719	161	170	331	**4,050**
2024	2,207	1,713	3,920	186	191	376	**4,297**

Source: California Energy Commission, Demand Analysis Office, 2013.

NOTE: Individual entries may not sum to total due to rounding.

Table 26 shows projected statewide electricity savings from the 2013 Title 24 building standards update and the 2011 battery charger standards, the most recent standards introduced into the forecast. By the end of the forecast period, these standards are projected to produce savings of almost 2,700 GWh. Savings were derived to be consistent with estimates provided by the Energy Commission's Efficiency Division, adjusted for noncompliance (assumed to be 15 percent[68]) and “naturally occurring” adoptions of relevant technologies.[69] The Title 24 update also provides an estimated 22 million therms of natural gas savings by 2024.

Table 26: Estimated Statewide Electricity Savings* (GWh) From 2013 Title 24 Building Standards Update and 2011 Battery Charger Standards

Year	Title 24 Update	Battery Charger Standards	Total
2015	162	460	622
2018	613	850	1,463
2020	932	1,083	2,015
2024	1,546	1,147	2,693

Source: California Energy Commission, Demand Analysis Office, 2013.

*Projected unadjusted (gross) savings reach more than 2,900 GWh for Title 24 and more than 1,900 GWh for battery chargers by 2024.

NOTE: Individual entries may not sum to total due to rounding.

68 Based on CPUC. *Final Evaluation Report, Codes & Standards (C&S) Programs Impact Evaluation, California Investor Owned Utilities' Codes and Standards Program Evaluation for Program Years 2006–2008*. Prepared by KEMA, Inc., The Cadmus Group, Inc., Itron, Inc., and Nexus Market Research, Inc.

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

CHAPTER 4: Additional Achievable Energy Efficiency

Background

Committed efficiency savings reflect savings from initiatives that have been approved, finalized, and funded, whether already implemented or not. There are also likely additional savings from initiatives that are neither finalized nor funded but are reasonably expected to occur, including impacts from future updates of building codes and appliance standards and utility efficiency programs expected to be implemented after 2014 (program measures). These savings are referred to as *achievable*. Resource and transmission planners now require an adjustment to the Energy Commission's baseline forecasts (which include only committed savings) to account for these likely impacts.

Achievable savings estimates begin with a comprehensive efficiency potential study, as provided in the *2013 California Energy Efficiency Potential and Goals Study (2013 Potential Study*), completed for the California Public Utilities Commission (CPUC) by Navigant Consulting, Inc., in August 2013.[70] The *2013 Potential Study* estimated energy efficiency savings that could be realized through utility programs as well as codes and standards within the investor-owned utility (IOU) service territories for 2006-2024,[71] given current or soon-to-be-available technologies. Because many of these savings are already incorporated in the Energy Commission's current *CED 2013 Final* baseline forecasts, staff needed to estimate the portion of savings from the *2013 Potential Study* not accounted for in the these forecasts. These nonoverlapping savings are referred to as *additional achievable energy efficiency* (AAEE) impacts.

Staff developed five AAEE scenarios, based on recommendations from the Joint Agency Steering Committee[72] and input from Navigant and forecast stakeholders through the Demand Analysis Working Group (DAWG). These scenarios varied by assumptions related to economic growth, changes in electricity and natural gas rates, and a host of inputs associated with efficiency measure adoption and the impact of building codes and appliance standards. These variations in input assumptions across the five scenarios are shown in **Table 34**.

70 Available at http://demandanalysisworkinggroup.org/documents/2013_08_16_ES_Pup_EE_Pot_final/CA_PGT_Model_2012_2013_Release_Aug_2013.ana.zip

71 The analysis begins in 2006 because results are calibrated using the CPUC's Standard Program Tracking Database, which tracks program activities from 2006-2011.

72 The Joint Agency Steering Committee is composed of managerial representatives from the Energy Commission, the California Independent System Operator, and the California Public Utilities Commission and is committed to improving coordination and process alignment across state planning processes that use the Energy Commission's demand forecast.

This chapter summarizes the AAEE results, describes the scenarios and method used to develop these estimates, and shows adjusted forecasts for the combined IOUs. Adjusted forecasts for individual IOU service territories are provided in the electricity planning area chapters in Volume 2 of this report and in Chapter 2 of this volume. Detailed results for AAEE savings at the utility level are included in the demand forms accompanying this report.[73] AAEE electricity savings were estimated for the PG&E, SCE, and SDG&E service territories. Natural gas savings were estimated for the PG&E, SDG&E, and SoCalGas gas service territories.

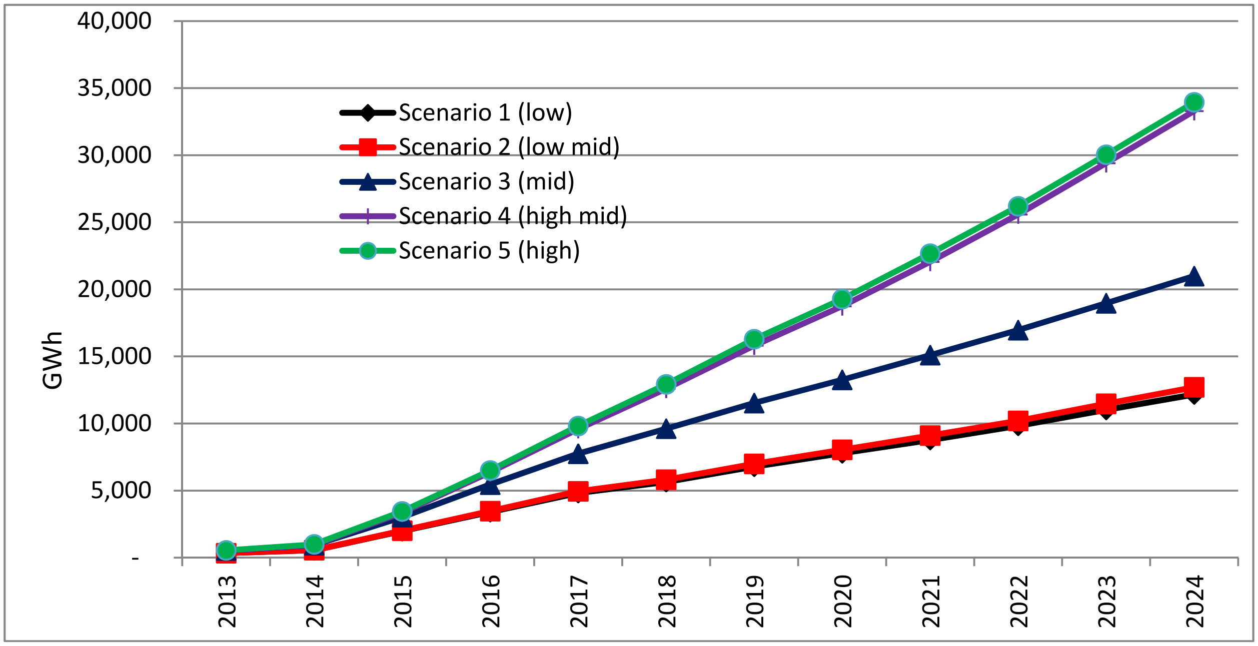
Summary of Results

Figure 43, **Figure 44**, and **Figure 45** show estimated AAEE savings by scenario for the IOUs combined in GWh, MW, and million therms, respectively. AAEE savings begin in 2013 because 2012 was the last recorded historical year for consumption in *CED 2013 Final*. As discussed in more detail in the next section, Scenario 3 represents a "most likely" (in terms of scenario definition), or mid case, while Scenario 1 (low savings) and Scenario 5 (high savings) are meant to provide a range of outcomes through pessimistic and optimistic assumptions, respectively, regarding efficiency measure adoption and standards implementation. Scenarios 2 (low mid savings) and 4 (high mid savings) are similar to Scenarios 1 and 5, respectively, but assume the same economic growth and energy prices as Scenario 3, and are constructed to provide alternatives to Scenario 3.

By 2024, AAEE savings reach nearly 21,000 GWh, almost 5,000 MW, and more than 400 million therms in the mid case. The high case reaches around 34,000 GWh, 8,000 MW, and 500 million therms in this year, while projected totals in the low scenario are about 12,000 GWh, 3,000 MW, and 300 million therms in 2024. As indicated, totals for the low mid and high mid scenarios are very similar to the high and low cases, respectively. Natural gas savings are slightly negative in 2013 and 2014 in all scenarios, a reflection of *interactive* effects modeled in the *2013 Potential Study* that result from slightly higher gas heating requirements as lighting efficiencies improve.

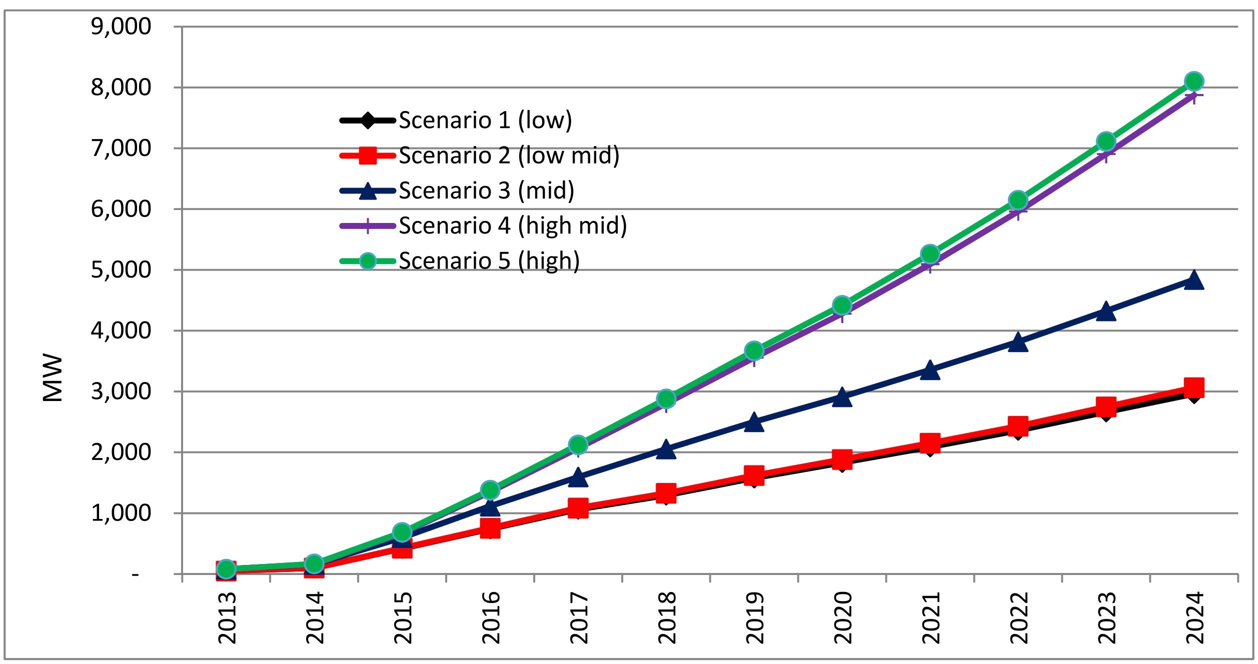
73 See http://www.energy.ca.gov/2013_energypolicy/documents/#reportsnomeeting.

Figure 43: AAEE Savings for Electricity (GWh) by Scenario, Combined IOUs



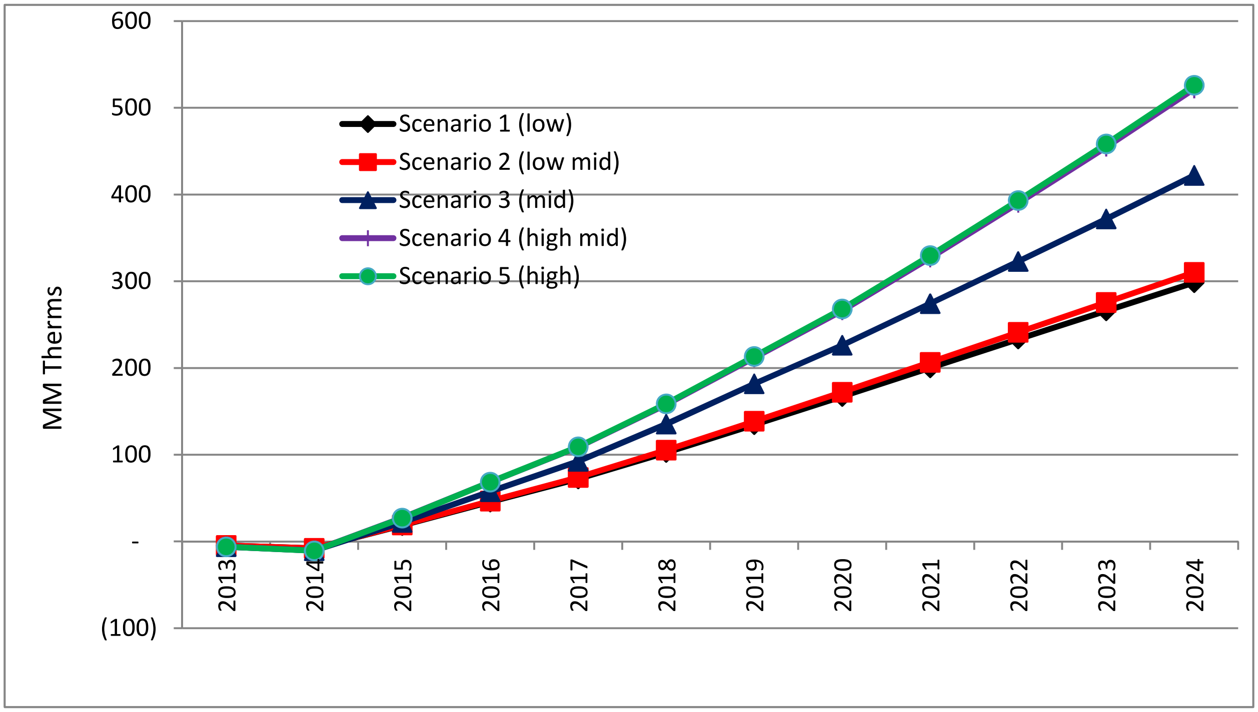
Source: California Energy Commission, Demand Analysis Office, 2013

Figure 44: AAEE Savings for Electricity Peak Demand (MW) by Scenario, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2013

Figure 45: AAEE Savings for Natural Gas (MM therms) by Scenario, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2013

Table 27 shows combined IOU AAEE savings by type (program measures and standards) in the mid scenario. The proportion of savings attributed to standards is reduced relative to the *2013 Potential Study* since most of the overlapping lighting savings from *CED 2013 Final* were deducted from standards. (See next section.) **Table 28** provides the totals by type in 2024 for all five scenarios. The standards proportion of savings increases in the higher scenarios (3-5) with the introduction of future Title 24 and Title 20 standards. In the low and low mid scenarios, the only AAEE standards savings come from federal standards, and the associated lighting efficiency improvements result in negative natural gas savings throughout the forecast period. In 2013 and 2014, the only program measure savings come from behavioral programs, and Navigant does not provide peak savings for this category.

Table 27: AAEE Savings by Type, Combined IOUs, Mid Savings Scenario

Year	GWh			MW			MM Therms		
	Program Measures	Standards	Total	Program Measures	Standards	Total	Program Measures	Standards	Total
2013	24	506	531	-	77	77	1	(7)	(6)
2014	48	883	931	-	157	157	2	(13)	(11)
2015	1,523	1,504	3,027	247	350	597	37	(15)	22
2016	3,058	2,393	5,451	500	614	1,115	72	(15)	57
2017	4,512	3,237	7,749	750	846	1,596	107	(14)	92
2018	5,461	4,154	9,614	942	1,114	2,056	145	(10)	135
2019	6,662	4,865	11,528	1,162	1,341	2,503	186	(4)	182
2020	7,700	5,558	13,258	1,339	1,575	2,914	224	3	226
2021	8,882	6,213	15,095	1,551	1,807	3,357	265	10	274
2022	10,141	6,822	16,963	1,783	2,035	3,818	307	16	323
2023	11,591	7,375	18,965	2,074	2,252	4,326	350	22	372
2024	13,094	7,896	20,990	2,379	2,462	4,841	394	28	422

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

Table 28: Combined IOU AAEE Savings by Type, 2024

		Scenario 1 (low)	Scenario 2 (low mid)	Scenario 3 (mid)	Scenario 4 (high mid)	Scenario 5 (high)
GWh	Program Measures	8,160	8,538	13,094	21,255	21,269
	Standards	4,006	4,161	7,896	12,039	12,678
	Total	12,166	12,699	20,990	33,293	33,947
MW	Program Measures	1,495	1,570	2,379	4,136	4,175
	Standards	1,468	1,493	2,462	3,738	3,926
	Total	2,963	3,063	4,841	7,874	8,101
Million Therms	Program Measures	300	312	394	504	506
	Standards	(2)	(2)	28	18	20
	Total	298	310	422	522	526

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

Table 29 shows the combined IOU AAEE savings for the mid scenario by sector in selected years. The distribution reflects Navigant's conclusion that the largest share of remaining energy efficiency potential resides in the commercial sector. For peak demand, residential savings are closer to commercial because the residential sector tends to have higher peak demand relative to average load. **Table 30** provides savings by sector for all scenarios in 2024.

Table 29: Combined IOU AAEE Savings by Sector, Mid Savings Scenario

	Sector	2013	2016	2019	2022	2024
GWh	Residential	91	1,138	2,849	4,790	5,749
	Commercial	425	3,629	7,055	9,655	12,140
	Industrial	15	412	936	1,415	1,720
	Agricultural	-	208	529	854	1,071
	Street-Lighting	-	65	159	250	310
	All Sectors	531	5,451	11,528	16,963	20,990
MW	Residential	15	450	1,105	1,754	2,156
	Commercial	61	607	1,266	1,862	2,436
	Industrial	2	41	90	135	164
	Agricultural	-	17	42	68	85
	Street-Lighting	-	-	-	-	-
	All Sectors	77	1,115	2,503	3,818	4,841
Million Therms	Residential	(3)	11	55	110	150
	Commercial	(3)	8	33	66	90
	Industrial	-	35	85	134	165
	Agricultural	-	3	8	13	17
	Street-Lighting	-	-	-	-	-
	All Sectors	(6)	57	182	323	422

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

Table 30: Combined IOU AAEE Savings by Sector, 2024

	Sector	Scenario 1 (low)	Scenario 2 (low mid)	Scenario 3 (mid)	Scenario 4 (high mid)	Scenario 5 (high)
GWh	Residential	2,727	2,786	5,749	7,288	7,550
	Commercial	7,117	7,584	12,140	21,498	21,853
	Industrial	1,345	1,348	1,720	2,516	2,547
	Agricultural	794	794	1,071	1,336	1,339
	Street-Lighting	184	187	310	655	657
	All Sectors	12,166	12,699	20,990	33,293	33,947
MW	Residential	1,421	1,424	2,156	2,465	2,598
	Commercial	1,347	1,443	2,436	5,097	5,188
	Industrial	131	132	164	207	209
	Agricultural	64	64	85	106	106
	Street-Lighting	-	-	-	-	-
	All Sectors	2,963	3,063	4,841	7,874	8,101
Million Therms	Residential	76	85	150	216	219
	Commercial	82	84	90	88	88
	Industrial	128	129	165	197	197
	Agricultural	12	12	17	21	21
	Street-Lighting	-	-	-	-	-
	All Sectors	298	310	422	522	526

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

Table 31 shows the savings impact of emerging technologies across all scenarios for the combined IOUs in selected years. This category encompasses technologies that are not yet available in today's market or at very low penetration levels but expected to become commercially viable during the forecast period. For electricity, most of the savings from emerging technologies comes from light-emitting diode (LED) lighting and new air-conditioning technologies. Natural gas savings come mainly from new furnace and dishwasher technologies.

As indicated in the next section, assumptions for emerging technologies varied significantly among the scenarios, both in terms of cost-benefit adoption criteria and adjustments to the Navigant model results. For GWh, the percentage of total AAEE savings provided by emerging technologies ranges from 2 percent in Scenario 1 to 29 percent in Scenario 4.

Table 31: Combined IOU Emerging Technology Savings by Scenario

	Year	Scenario 1 (low)	Scenario 2 (low mid)	Scenario 3 (mid)	Scenario 4 (high mid)	Scenario 5 (high)
GWh	2015	10	20	99	291	290
	2018	53	107	613	1,704	1,754
	2020	102	206	1,201	3,583	3,677
	2022	176	356	2,127	6,320	6,322
	2024	281	599	3,369	9,735	9,660
MW	2015	1	1	9	31	30
	2018	6	12	77	258	259
	2020	14	28	174	597	597
	2022	27	55	341	1,123	1,127
	2024	47	96	575	1,841	1,827
Million	2015	0	0	0	0	0
Therms	2018	1	2	5	10	9
	2020	2	4	13	28	27
	2022	4	8	26	56	55
	2024	6	13	44	96	92

Source: California Energy Commission, Demand Analysis Office, 2013

Table 32 provides AAEE savings by individual IOU in the mid savings scenario for selected years. Total savings are generally a function of total sales or peak demand in each IOU, although electricity savings percentages (relative to sales or peak) are slightly lower for SDG&E because of less potential in the agricultural and industrial sectors. **Table 33** provides savings by IOU by scenario for 2024.

Table 32: AAEE Savings by IOU, Mid Savings Scenario

	Utility	2013	2016	2019	2022	2024
GWh	PG&E	225	2,335	4,998	7,431	9,208
	SCE	264	2,579	5,378	7,806	9,628
	SDG&E	42	538	1,152	1,727	2,154
	Total IOU	531	5,451	11,528	16,963	20,990
MW	PG&E	33	476	1,088	1,684	2,141
	SCE	38	523	1,152	1,728	2,183
	SDG&E	6	116	264	406	518
	Total IOU	77	1,115	2,503	3,818	4,841
Million Therms	PG&E	(2)	24	78	141	184
	SoCalGas	(4)	30	93	162	210
	SDG&E	(0)	3	11	21	28
	Total IOU	(6)	57	182	323	422

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

Table 33: AAEE Savings by IOU and Scenario, 2024

	Utility	Scenario 1 (low)	Scenario 2 (low mid)	Scenario 3 (mid)	Scenario 4 (high mid)	Scenario 5 (high)
GWh	PG&E	5,332	5,562	9,208	14,646	14,924
	SCE	5,554	5,748	9,628	15,205	15,492
	SDG&E	1,280	1,389	2,154	3,442	3,530
	Total IOU	12,166	12,699	20,990	33,293	33,947
MW	PG&E	1,274	1,319	2,141	3,514	3,613
	SCE	1,367	1,401	2,183	3,544	3,632
	SDG&E	322	342	518	816	856
	Total IOU	2,963	3,063	4,841	7,874	8,101
Million Therms	PG&E	131	137	184	229	229
	SoCalGas	147	152	210	254	256
	SDG&E	20	22	28	38	41
	Total IOU	298	310	422	522	526

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

Method and Scenarios

Navigant Consulting provided invaluable assistance in developing the AAEE savings estimates, including training Energy Commission staff in the use of the model employed in the CPUC's *2013 Potential Study*, referred to as the Potential, Goals, and Targets (PGT) model. The PGT model includes methodologies to estimate program measure savings, savings from codes and standards, and savings from behavioral programs. Navigant developed a modified version of the PGT model specifically for this effort.

For a user-defined scenario, the PGT model estimates gross and net[74] first-year and cumulative technical, economic, and market potential efficiency impacts from the three sources of savings beginning in 2006 for electricity consumption, peak demand, and natural gas consumption.[75] In general, the effort to characterize AAEE savings consists of determining the portion of estimated net market potential in a given scenario not incorporated in the *CED 2013 Final* baseline forecast. For program measures, AAEE includes net accumulated market savings beginning in 2015,[76] since *CED 2013 Final* incorporates utility programs through 2014. For standards, AAEE consists of net savings from expected (or recently finalized) regulations not

74 Net savings equals gross savings minus naturally occurring market savings, or "free ridership" savings that would be expected to occur without any efficiency initiative.

75 Natural gas consumption savings estimates incorporate *interactive* effects and thus can be negative for certain categories in the detailed results.

76 There are a small amount of behavior-related savings included starting in 2013.

included in *CED 2013 Final*, and the PGT model is set up to calculate estimated savings for the following:

- 2016 Title 20 standards
- Adopted and future federal appliance standards
- 2016, 2019, and 2022 Title 24 standards.

Specific elements assumed for each set of standards are provided in the *2013 Potential Study* report. As shown below, the specific standards included varied with the scenario.

The *CED 2013 Final* forecasts include a substantial amount of lighting savings in anticipation of the effects of Assembly Bill 1109 (AB 1109, Huffman, Chapter 534, Statutes of 2007) through future programs and Title 20 standards. These savings can be expected to overlap with lighting savings estimated in any given PGT-modeled scenario. To account for this overlap, Energy Commission staff subtracted *CED 2013 Final* lighting savings accumulating during the forecast period from future standards and program lighting savings estimated by the PGT model for each scenario.

The PGT model requires a variety of inputs and input assumptions from which savings scenarios can be developed. The following summarizes the parameters used in constructing the five scenarios. More information can be found in the *2013 Potential Study* report.

1. *Incremental Costs*: Incremental costs are the difference in costs between code- or standard-level equipment and the higher-efficiency equipment under consideration. The incremental costs for efficient technologies come from the Database for Energy Efficiency Resources (DEER) – the CPUC-approved database for various energy savings parameters.
2. *Implied Discount Rate*: The implied discount rate is the effective discount rate that consumers apply when making a purchase decision; it determines the value of savings in a future period relative to the present. The implied discount rate is higher than standard discount rates used in other analyses because it is meant to account for market barriers that may impact customer decisions.
3. *Marketing and Word of Mouth Effects*: The base factors for market adoption are a customer's willingness to adopt and awareness of efficient technologies, which were derived from a regression analysis of technology adoptions from several studies on technology diffusion. Each end use in each sector was assigned marketing and word-of-mouth effectiveness factors corresponding to diffusion rates in the studies.
4. *TRC Threshold*: The Total Resource Cost (TRC) is the primary cost-effectiveness indicator that the CPUC uses to determine funding levels and adoption thresholds for energy efficiency. The TRC test measures the net resource benefits from the perspective of all ratepayers by combining the net benefits of the program to participants and nonparticipants. A TRC threshold of 1.0 means that the benefits of a program or measure must at least equal the costs. The CPUC uses a TRC of 0.85 as a "rule of thumb," allowing

programs to include marginal yet promising measures. For emerging technologies, an even lower threshold is typically used.

5. *Efficient Measure Density*: *Measure density* is defined as the number of units of a technology per unit area. Higher densities for efficient technologies mean more familiarity and a greater likelihood of adoption, all else equal. Specifically, measure density is categorized as follows:

   - *Baseline measure density:* the number of units of a baseline technology per home for the residential sector, or per unit of floor space for the commercial sector.
   - *Energy-efficient measure density*: the number of energy-efficient units existing per home for the residential sector, or per unit of floor space for the commercial sector.
   - *Total measure density:* typically the sum of the baseline and efficient measure density. When two or more efficient measures compete to replace the same baseline measure, then the total density is equal to the sum of the baseline density and all applicable energy-efficient technology densities.

6. *Unit Energy Savings*: Unit energy savings (UES) is the estimated difference in annual energy consumption between a measure, group of technologies, or processes and the baseline, expressed as kWh for electric technologies and therms for gas technologies.

7. *Incentive Level*: The incentive level is the amount or percentage of incremental cost that is offset for a targeted efficient measure. While the IOUs may vary the incentive level from measure to measure, they must work within their authorized budget to maximize savings, and their incentives typically average out to be about 50 percent of the incremental cost.

In addition, assumptions regarding future standards and associated compliance rates, economic growth (in the form of increases in building stock), energy prices, and avoided costs varied among the scenarios.

Table 34 shows the input assumptions for the five scenarios. For the low, mid, and high savings cases, building stock, prices, and avoided costs were designed to be consistent with the three baseline *CED 2013 Final* scenarios, which combine high economic growth, lower efficiency program savings, and lower rates in the high demand case and lower growth, higher program savings, and higher rates in the low demand case. For the adjusted forecasts, therefore, the low AAEE savings case is paired with the high demand baseline and the high savings case with the low demand baseline. The low mid and high mid cases (Scenarios 2 and 4) use the same building stock and price assumptions as the mid savings case to provide consistent alternatives to the mid savings case with respect to these assumptions for planning purposes.

The low and low mid savings cases assume a 20 percent decrease in compliance rates compared to base compliance rates developed by Navigant.[77] The high savings case assumes compliance

77 Base compliance rates are derived from CPUC. *Final Evaluation Report, Codes & Standards (C&S) Programs Impact Evaluation, California Investor Owned Utilities' Codes and Standards Program Evaluation for*

rates that increase above the base levels, to a maximum of 100 percent by the end of the forecast period.[78] In the high mid and high cases, additional likely (but not adopted) federal appliance standards are introduced.

Future lighting savings in *CED 2013 Final* varied by baseline demand scenario, so the amount of overlapping lighting savings to be subtracted from future lighting savings output by the PGT model depended on the savings scenario. In the low savings case, future lighting savings associated with the high demand baseline forecast were deducted, while savings from the low demand baseline forecast were deducted in the high savings case (and mid demand savings in the three mid savings scenarios).[79]

Program Years 2006-2008. Prepared by KEMA, Inc., The Cadmus Group, Inc., Itron, Inc., and Nexus Market Research, Inc.

78 Whether 100 percent compliance is reached depends on the date of introduction of the standards.

79 The amount of overlapping lighting savings increased over the forecast period, reaching 3,100 GWh in the *CED 2013 Revised* low demand forecast, 3,200 GWh in the mid demand case, and 3,350 GWh in the high case in 2024. Associated peak demand overlap reached 430 MW, 450 MW, and 470 MW, respectively.

Table 34: AAEE Savings Scenarios

Scenario Number	1	2	3	4	5
Scenario Name	Low Savings	Low Mid Savings	Mid Savings	High Mid Savings	High Savings
ET's	25% of model Results	50% of model Results	100% of model results	150% of Model Results	150% of Model Results
Building Stock	High Demand Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Low Demand Case from 2011 IEPR
Retail Prices	High Demand Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Low Demand Case from 2011 IEPR
Avoided Costs	High Demand Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Mid Case from 2011 IEPR	Low Demand Case from 2011 IEPR
UES	Estimate minus 25%	Estimate minus 25%	Best Estimate UES	Estimate plus 25%	Estimate plus 25%
Incremental Costs	Estimate plus 20%	Estimate plus 20%	Best Estimate Costs	Estimate minus 20%	Estimate minus 20%
Incentive Level	50% of incremental cost	50% of incremental cost	50% of incremental cost	50% of incremental cost	50% of incremental cost
TRC Threshold	1	1	0.85	0.75	0.75
ET TRC Threshold	0.85	0.85	0.5	0.4	0.4
Measure Densities	Estimate minus 20%	Estimate minus 20%	Best Estimate Costs	Estimate plus 20%	Estimate plus 20%
Word of Mouth Effect*	39%	39%	43%	47%	47%
Marketing Effect*	1%	1%	2%	3%	3%
Implied Discount Rate	20%	20%	18%	14%	14%
Standards Compliance	No Compliance Enhancements, Compliance Rates Reduced by 20 percent	No Compliance Enhancements, Compliance Rates Reduced by 20 percent	No Compliance Enhancements	No Compliance Enhancements	Compliance Enhancements
Title 24 Updates	None	None	2016, 2019, 2022	2016, 2019, 2022	2016, 2019, 2022
Title 20 Updates	None	None	2016-2018	2016-2018	2016-2018
Federal Standards	Already adopted	Already adopted	Already adopted	Future Federal Standards	Future Federal Standards

Sources: Navigant Consulting and California Energy Commission, Demand Analysis Office, 2013

To arrive at a final set of scenarios, staff first solicited stakeholder input through the DAWG. Stakeholders were provided a preliminary set of savings scenarios based on three cases presented in the *2013 Potential Study* report as well as additional scenarios developed by Energy Commission staff as variations around the *2013 Potential Study* mid case results. In this manner, stakeholders expressed their preferences for a specific scenario and commented on individual input assumptions. Eight stakeholder groups submitted written comments: the Efficiency Council, the Natural Resources Defense Council, the California Independent System Operator, the Independent Energy Producers, PG&E, SCE, SDG&E, and SoCalGas. Stakeholder comments are posted on the DAWG website.[80] The Joint Agency Steering Committee reviewed these comments and, through discussions with CPUC and Energy Commission staff, developed proposed recommendations for the scenarios.

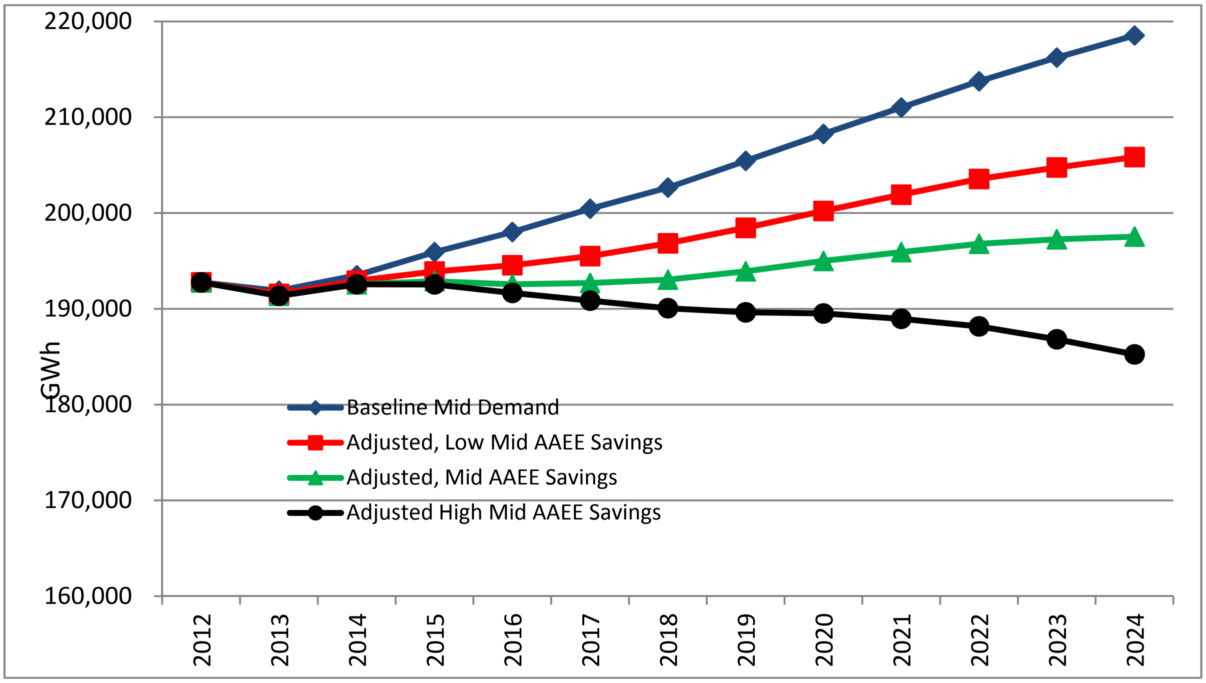
Adjusted Forecasts

Staff develops the baseline forecasts for consumption, sales, and peak demand at the planning area level. However, the AAEE savings presented in this chapter are meant to be applied to service territories, which are a subset of the associated planning areas in the case of PG&E, SCE, and SoCalGas. To develop baseline forecasts for these service territories, staff applies a similar rate of growth as the planning areas to service territory sales and peak in the last historical year (2012 and 2013). Adjusted forecasts presented in this section are for the four IOU service territories (or the sum of service territories).

Figure 46, **Figure 47**, and **Figure 48** show the effects of the estimated low mid, mid, and high mid AAEE savings on *CED 2013 Final* mid baseline demand for the combined IOU service territories for electricity sales, peak demand, and end-user natural gas sales. Adjusted electricity sales and peak demand increase slightly using the low mid AAEE scenario, are relatively flat using the mid savings case, and decline with the low mid savings case. Natural gas sales, already relatively flat in the mid baseline forecast, decline after adjustments with all AAEE three savings scenarios.

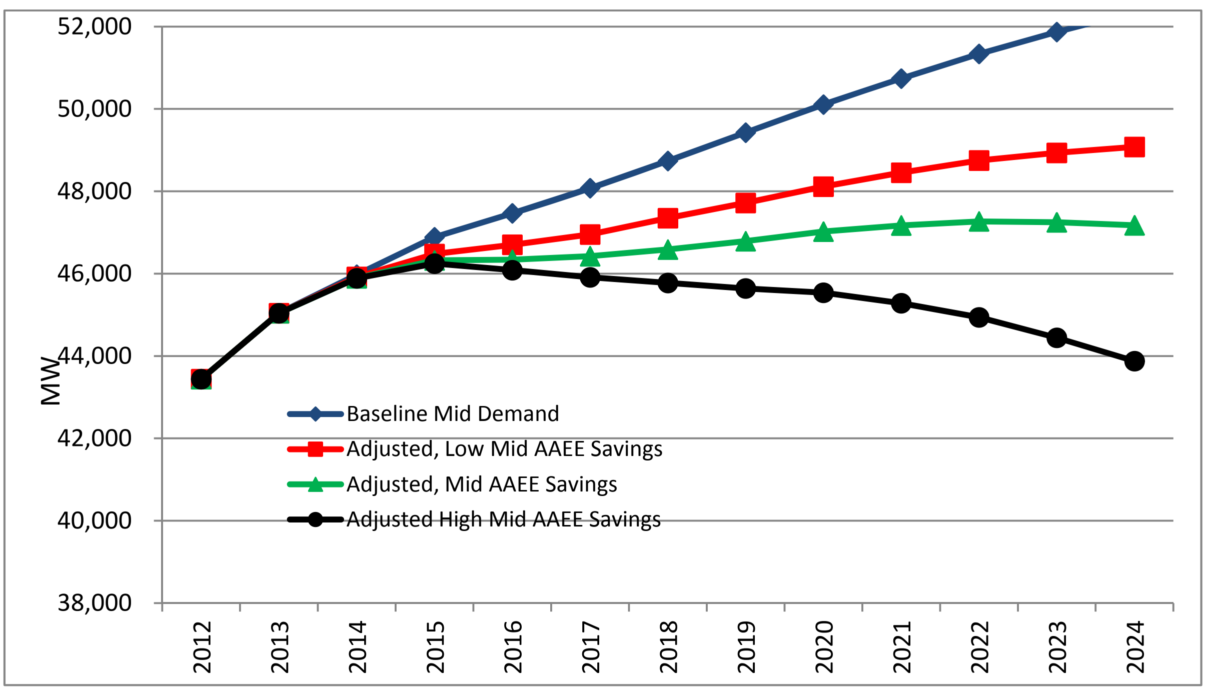
80 http://demandanalysisworkinggroup.org/?p=844

Figure 46: Baseline Mid Demand Electricity and Adjusted Sales, Combined IOUs



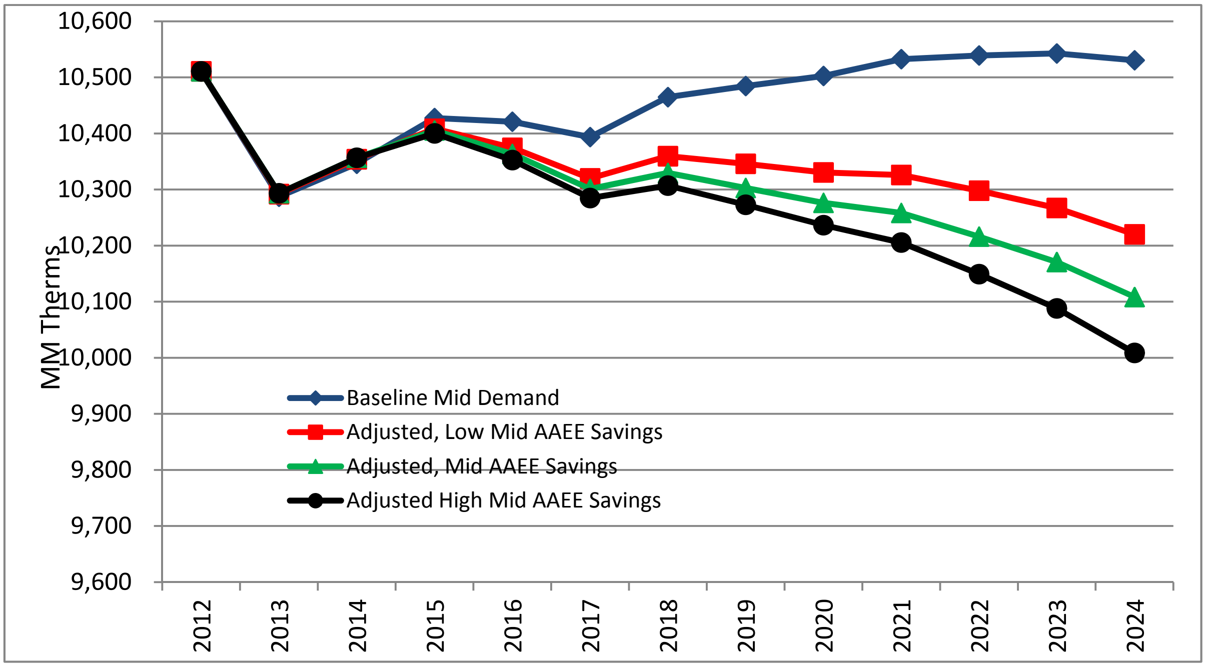
Source: California Energy Commission, Demand Analysis Office, 2013

Figure 47: Baseline Mid Demand and Adjusted Peaks, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2013

Figure 48: Baseline Mid Demand and Adjusted End-User Natural Gas Sales, Combined IOUs



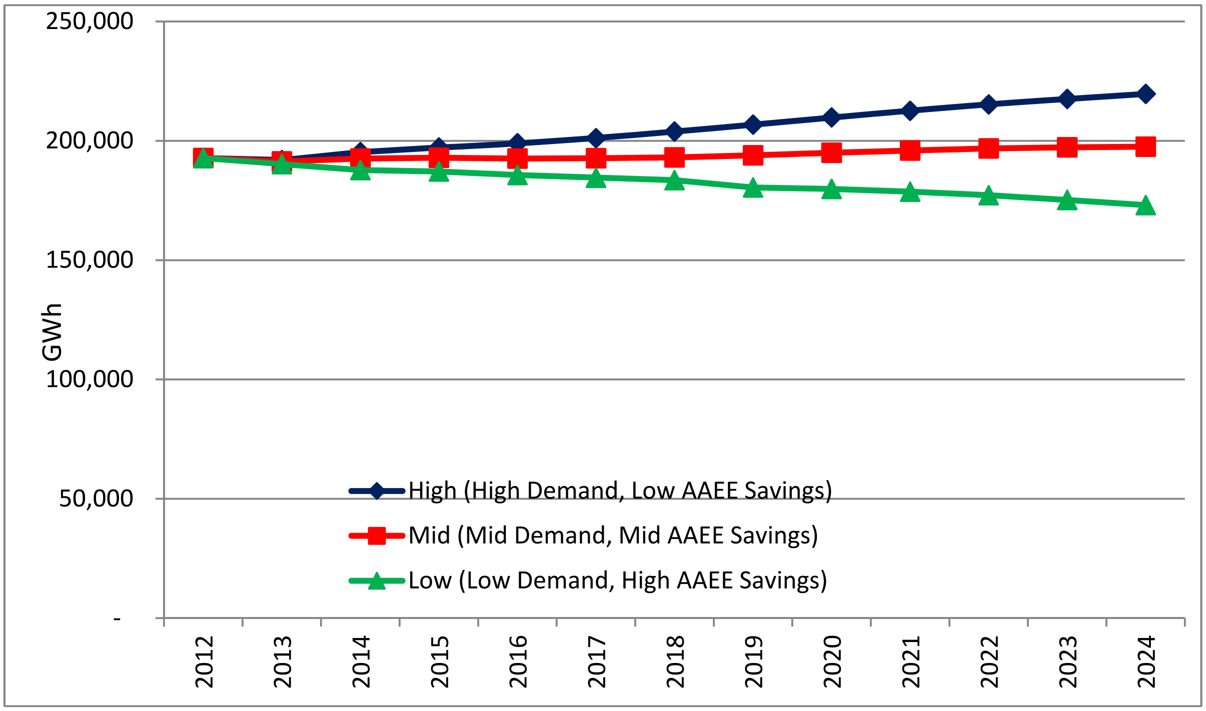
Source: California Energy Commission, Demand Analysis Office, 2013

Figure 49, **Figure 50**, and **Figure 51** show the *CED 2013 Final* high demand, mid demand, and low demand baseline forecasts when adjusted by low AAEE savings, mid savings, and high savings, respectively, for the combined IOUs. Relative to the baseline forecasts, electricity sales in 2024 are reduced by 5.3 percent, 9.6 percent, and 16.4 percent for the high, low, and mid demand cases, respectively. Peak demand is reduced by 5.7 percent, 9.9 percent, and 17.7 percent, respectively, in 2024. Natural gas sales decline in all three adjusted scenarios, and are reduced by 2.8 percent, 4.0 percent, and 5.1 percent, respectively, from baseline levels in 2024. Numbers corresponding to these graphs are provided in the demand forms accompanying this report.[81]

The adjusted service territory forecasts provided in this report constitute options to form the basis for a "managed" forecast to be used for planning purposes in Energy Commission, CPUC, and California ISO proceedings. The choice of scenarios (baseline and AAEE) to use for this purpose will be documented in the *2013 IEPR* to be adopted in January 2014.

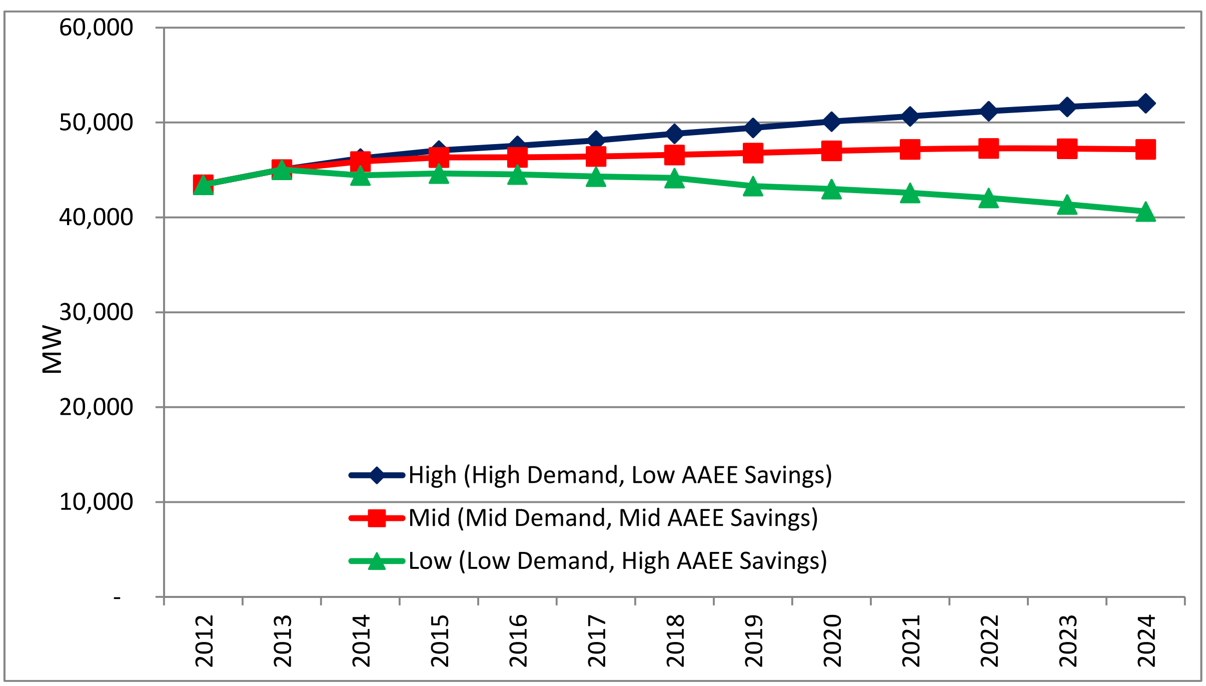
81 See http://www.energy.ca.gov/2013_energypolicy/documents/#reportsnomeeting.

Figure 49: Adjusted Demand Scenarios for Electricity Sales, Combined IOUs



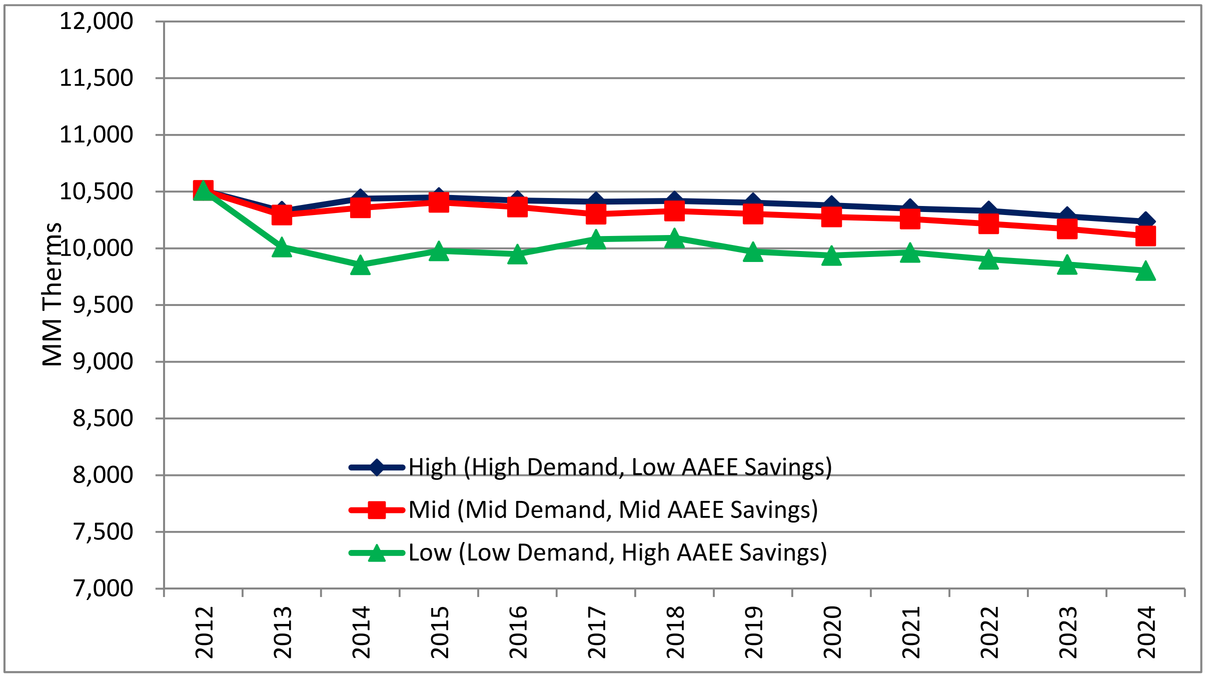
Source: California Energy Commission, Demand Analysis Office, 2013

Figure 50: Adjusted Demand Scenarios for Peak, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2013

Figure 51: Adjusted Demand Scenarios for End-User Natural Gas Sales, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2013

List of Acronyms

Acronym	Definition
AAEE	Additional achievable energy efficiency
AB 2021	Assembly Bill 2021
BEV	Battery electric vehicle
California ISO	California Independent System Operator
CED	*California Energy Demand*
CEUS	Commercial End-Use Survey
CED 2011	*California Energy Demand 2012 – 2022 Final Forecast*
CED 2013 Preliminary	*California Energy Demand 2014 – 2024 Preliminary Forecast*
CED 2013 Final	*California Energy Demand 2014 – 2024 Final Forecast*
CHP	Combined heat and power
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
DEER	Database for Energy Efficient Resources
DG	Distributed generation
DOF	Department of Finance
E^3	Energy and Environmental Economics, Inc.
EIR	Environmental impact report
Energy Commission	California Energy Commission
ERP	Emerging Renewables Program
ESP	Electric service provider
EV	Electric vehicle
GW	Gigawatt
GWh	Gigawatt hour
HSR	High-speed rail
HELM	Hourly Electricity Load Model
IEPR	*Integrated Energy Policy Report*
IID	Imperial Irrigation District
INFORM	Industrial End Use Forecasting Model
IOU	Investor-owned utility
IRR	Internal rate of return
ISO	California Independent System Operator
KW	Kilowatt
KWh	Kilowatt hour
LADWP	Los Angeles Department of Water and Power
LSE	Load-serving entity

Acronym	Definition
LTPP	Long Term Procurement Plan
Moody’s	Moody’s Analytics
MW	Megawatt
MWh	Megawatt hour
NAMGas	North American Gas-Trade Model
NEMS	National Energy Modeling System
NREL	National Renewable Energy Laboratory
NSHP	New Solar Homes Partnership
PG&E	Pacific Gas and Electric Company
PGT	Potential, Goals, and Targets Model
PHEV	Plug-in hybrid vehicle
POU	Publicly owned utility
PV	Photovoltaic
QFER	Quarterly Fuel Energy Report
RASS	Residential Appliance Saturation Survey
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SGIP	Self-Generation Incentive Program
SHW	CSI Thermal Program for Solar Hot Water
SMUD	Sacramento Municipal Utility District
SoCal Gas	Southern California Gas Company
TAC	Transmission Access Charge
TCU	Transportation, communications and utilities
TRC	Total Resource Cost
UEC	Unit energy consumption
U.S. EIA	United States Energy Information Administration
ZEV	Zero-emission vehicle

APPENDIX A: Additional Methodology Documentation and Econometric Results

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

Industrial Model

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

As in the INFORM model, industrial (manufacturing, resource extraction, and construction) energy demand is forecast based on projected growth in dollar output or employment for 28 categories (for example, chemicals and paper), projected average industrial rates, and changes in end-use characteristics, including energy intensities.[82] In this context, energy intensity measures energy use per dollar of output. The marginal impact of economic growth on energy use in each of the 28 categories was estimated using regression analysis. Applying the estimated coefficients to the appropriate economic indicator provides a "business as usual" forecast for each industrial category. This forecast is adjusted for rate increases, using price elasticities estimated in the sector econometric models.[83] Finally, the forecast is adjusted to account for changes in end-use energy intensity.

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

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

83 See **Table A-6**.

continue for every subsector and end use through 2024. For the mid and high cases, the trend was reduced to 0.5 percent and 0.25 percent per year, respectively. Construction and resource extraction historical data showed no clear trend, and intensities were assumed constant over the forecast period.

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

Comparison of *CED 2013 Final* and Full Econometric Forecasts

Table A-1 compares *CED 2013 Final* electricity results for 2024 by major planning area and statewide with those from a full econometric forecast. More complete results are provided along with the demand forms posted with this report.[84] For consumption, differences range from around zero to almost 4.5 percent above for the econometric forecasts. Peak demand differs from around 1.2 percent higher to around 5 percent higher. Likely reasons for these differences are discussed in Chapter 1 of this volume. Differences are largest for LADWP peak demand and smallest for SMUD consumption.

Table A-2 compares *CED 2013 Final* end-user natural gas results for 2024 by major planning area and statewide with those from a full econometric forecast. Differences range from around 5 percent higher for the econometric forecast to over 11 percent higher. Most of the differences come from the residential sector, reflecting increases in efficiency impacts not fully reflected in the econometric results.

84 See http://www.energy.ca.gov/2013_energypolicy/documents/#reportsnomeeting.

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

Planning Area	Demand Scenario	Consumption (GWh)			Peak (MW)		
		CED 2013 Final	Econo-metric	% Difference	*CED 2013 Final*	Econo-metric	% Difference
LADWP	High	29,576	30,220	2.18%	6,912	7,226	4.55%
	Mid	28,162	29,084	3.27%	6,546	6,830	4.34%
	Low	26,945	28,152	4.48%	6,119	6,428	5.06%
PG&E	High	132,510	133,902	1.05%	28,298	28,638	1.20%
	Mid	126,699	128,234	1.21%	27,010	27,511	1.85%
	Low	121,804	124,556	2.26%	25,578	26,374	3.11%
SCE	High	120,745	121,279	0.44%	27,513	28,182	2.43%
	Mid	114,503	115,858	1.18%	26,028	26,678	2.50%
	Low	109,206	111,955	2.52%	24,482	25,176	2.84%
SDG&E	High	25,983	25,967	-0.06%	5,724	5,878	2.69%
	Mid	24,564	24,967	1.64%	5,357	5,494	2.57%
	Low	23,337	23,977	2.74%	5,009	5,130	2.41%
SMUD	High	13,119	13,103	-0.13%	3,780	3,899	3.16%
	Mid	12,430	12,585	1.25%	3,555	3,655	2.83%
	Low	11,883	12,115	1.95%	3,338	3,433	2.87%
State	High	337,713	340,339	0.78%	75,153	76,817	2.21%
	Mid	321,734	326,369	1.44%	71,312	73,081	2.48%
	Low	308,277	316,204	2.57%	67,203	69,384	3.25%

Source: California Energy Commission, Demand Analysis Office, 2013.

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

Planning Area	Demand Scenario	Consumption (MM therms)		
		CED 2013 Final	Econometric	% Difference
PG&E	High	4,786	5,320	11.17%
	Mid	4,739	5,105	7.72%
	Low	4,611	5,048	9.47%
SoCal Gas	High	7,335	7,823	6.65%
	Mid	7,386	7,696	4.19%
	Low	7,275	7,638	4.99%
SDG&E	High	530	581	9.68%
	Mid	535	585	9.41%
	Low	541	589	9.02%
State	High	12,801	13,878	8.42%
	Mid	12,806	13,541	5.74%
	Low	12,569	13,429	6.84%

Source: California Energy Commission, Demand Analysis Office, 2013

Impacts From Climate Change

CED 2013 Final estimates the impacts of potential climate change for both energy (electricity and natural gas) and electricity peak demand. Energy impacts are estimated through changes in the number of annual heating and cooling degree days,[85] while peak demand impacts are simulated though increases in annual maximum daily average temperatures.

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

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

Average631 =
Daily Average Temperature[86] × 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.[87]

To gauge the potential impact of climate change on annual degree days and *average631* temperatures through 2024, staff used a 2012 update of a climate change impact assessment by the California Climate Change Center, sponsored by the Energy Commission.[88] The update uses 24 climate change simulations for California consisting of two scenarios for each of 12 models, providing simulation results for daily maximum and minimum temperatures, average daily humidity, and sea level rises through 2099.

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

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

87 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.

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

Climate change model simulations were performed for grids of 50 square miles within the state; staff used simulated daily maximum and minimum temperatures for grids corresponding to the 10 weather stations used for the 16 forecasting climate zones. Staff chose climate change scenarios that resulted in an average temperature impact over all scenarios for the mid demand case and a relatively high temperature impact for the high demand case.[89] For the low demand scenario, staff assumed no climate change impacts. Staff converted simulated daily averages for each weather station to degree days and *average631* indices for each planning area by weighting each climate zone either by estimated number of air conditioners (*average631* and cooling degree days) or population (heating degree days). Changes in annual degree days and maximum *average631* temperatures starting in 2013 were derived using long-term trends (2010-2040) from the two climate scenarios.[90]

Table A-3 shows the projected impacts of climate change in the mid and high demand scenarios on electricity consumption for the five major planning areas and for the state as a whole. By 2024, statewide consumption impacts reach almost 1,200 GWh in the mid demand case and almost 1,700 GWh in the high demand case. Also shown are the simulated annual heating and cooling degree days (weighted by climate zone) for the two climate change scenarios used. Degree days in 2012 represent a historical 30-year average for the planning area.

The consumption increases shown in **Table A-3** are *net* impacts, representing increasing electricity consumption from cooling minus reduced usage from less heating need. Heating impacts are typically 10 – 40 percent of cooling increases, depending on the planning area and year. For the state as a whole in 2024, projected electricity consumption increases by more than 1,400 GWh from more cooling need in the mid demand case, all else equal, and decreases by around 250 GWh from less heating. In the high demand case, the totals are about 2,300 GWh and 600 GWh, respectively. For the state as a whole, the largest portions of the consumption increase come from the commercial sector (50 percent and 60 percent in the mid and high cases, respectively), since the effect from warmer temperatures is not mitigated by decreasing heating degree days, as in the residential sector (see Appendix C).

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

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

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

		Mid Demand Scenario		High Demand Scenario			
		Annual Cooling Degree Days (65^o Reference)	Annual Heating Degree Days (65^o Reference)	Annual Cooling Degree Days (65^o Reference)	Annual Heating Degree Days (65^o Reference)	Consump. Impact, Mid Scenario (GWh)	Consump. Impact, High Scenario (GWh)
LADWP	2012	1,275	1,410	1,275	1,410	--	--
	2015	1,310	1,382	1,343	1,339	25	43
	2020	1,369	1,334	1,458	1,219	68	116
	2024	1,417	1,296	1,550	1,123	104	171
PG&E	2012	1,387	2,464	1,387	2,464	--	--
	2015	1,424	2,432	1,442	2,389	108	138
	2020	1,484	2,379	1,533	2,264	298	379
	2024	1,533	2,336	1,606	2,164	457	574
SCE	2012	1,536	1,381	1,536	1,381	--	--
	2015	1,577	1,350	1,608	1,307	87	129
	2020	1,645	1,299	1,729	1,182	240	339
	2024	1,700	1,257	1,826	1,082	365	497
SDG&E	2012	800	1,177	800	1,177	--	--
	2015	840	1,137	876	1,101	48	83
	2020	906	1,070	1,002	974	128	211
	2024	960	1,016	1,103	872	190	300
SMUD	2012	1,267	2,586	1,267	2,586	--	--
	2015	1,307	2,565	1,332	2,523	16	23
	2020	1,374	2,529	1,441	2,417	43	63
	2024	1,428	2,501	1,528	2,332	66	95
State	2015	--	--	--	--	288	426
	2020	--	--	--	--	790	1,133
	2024	--	--	--	--	1,198	1,676

Source: California Energy Commission, Demand Analysis Office, 2013.

Table A-4 shows projections of natural gas consumption reductions in the two climate change scenarios because of decreasing heating degree days, reductions that reach around 240 million therms in the mid demand case and about 620 million therms in the high case by 2024 for the state as a whole. At the statewide level, roughly 50 percent of the decrease occurs in the residential sector, with another 25 percent coming from commercial.

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

		Annual Heating Degree Days (65°	Annual Heating Degree Days (65°	Consumption Impact, Mid Scenario (MM therms)	Consumption Impact, High Scenario (MM therms)
PG&E	2012	2,476	2,476	--	--
	2015	2,445	2,402	17	41
	2020	2,393	2,278	47	120
	2024	2,352	2,179	72	188
SoCal Gas	2012	1,384	1,384	--	--
	2015	1,354	1,311	32	80
	2020	1,303	1,190	91	237
	2024	1,263	1,093	141	379
SDG&E	2012	1,177	1,177	--	--
	2015	1,137	1,101	5	10
	2020	1,070	974	15	31
	2024	1,016	872	24	51
State	2015	--	--	54	131
	2020	--	--	153	387
	2024	--	--	237	619

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

Table A-5 shows the projected impacts of climate change in the mid and high demand scenarios on peak demand for the five major planning areas and for the state as a whole. By 2024, statewide peak impacts reach around 950 MW in the mid demand case and around 1,550 MW in the high demand case. Also shown are the simulated annual maximum *average631* temperatures in degrees Fahrenheit for the two climate change scenarios used. Temperatures in 2012 represent a historical 30-year average for the planning area.

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

		Annual Maximum *Average631* (°F), Mid	Annual Maximum *Average631* (°F), High	Peak Impact, Mid Scenario (MW)	Peak Impact, High Scenario (MW)
LADWP	2012	83.5	83.5	--	--
	2015	83.8	84.0	21	37
	2020	84.3	84.8	61	107
	2024	84.6	85.4	95	169
PGE	2012	85.7	85.7	--	--
	2015	86.0	86.1	83	123
	2020	86.4	86.7	239	360
	2024	86.8	87.3	377	569
SCE	2012	85.8	85.8	--	--
	2015	86.0	86.2	78	121
	2020	86.5	86.8	225	358
	2024	86.8	87.4	355	570
SDGE	2012	78.0	78.0	--	--
	2015	78.2	78.4	16	28
	2020	78.6	79.0	45	82
	2024	78.9	79.6	72	131
SMUD	2012	85.2	85.2	--	--
	2015	85.4	85.6	7	17
	2020	85.7	86.3	21	50
	2024	85.9	86.8	33	80
State	2015	--	--	209	334
	2020	--	--	604	982
	2024	--	--	950	1,559

Source: California Energy Commission, Demand Analysis Office, 2013.

For future versions of this forecast, staff plans to complete an analysis of how climate change might affect the distribution of temperatures and therefore the relationship between "1 in 10" (extreme weather) and "1 in 2" (normal weather) peak demand. Staff had hoped to include such an analysis in *CED 2013 Final*, but Scripps climate scientists are not yet comfortable with modeling results related to extreme temperatures. Work is ongoing.

Price Elasticities

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

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

Sector	Electricity	Natural Gas
Residential	-0.08	-0.035
Commercial	-0.15	-0.15
Industrial: Manufacturing	-0.17	-0.11
Industrial: Resource Extraction and Construction	-0.10	-0.02

Source: California Energy Commission, Demand Analysis Office, 2013.

APPENDIX B: Self-Generation Forecasts

Compiling Historical Distributed Generation Data

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

- The California Solar Initiative (CSI).[91]
- New Solar Homes Partnership (NSHP).[92]
- Self-Generation Incentive Program (SGIP).[93]
- CSI Thermal Program for Solar Hot Water (SHW).[94]
- Emerging Renewables Program (ERP).[95]
- POU programs.[96]

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 QFER Form 1304.[97] QFER data include fuel use, generation, onsite use, and exports to the grid. These various sources of data were used to quantify DG activity in California and to build a comprehensive database to track DG activity. One concern in using incentive program data along with QFER data is the possibility of double-counting generation if the project has a capacity of at least 1 MW. This can occur since the publicly available incentive program data do not list the name of the entity receiving the DG incentive for confidentially reasons while QFER data collects information from the plant owner. Therefore, it is not possible to determine if a

91 Downloaded on 6/19/13 from http://www.californiasolarstatistics.org/current_data_files/.

92 Program data received on 6/26/13 from staff in the Energy Commission's Renewable Energy Office.

93 Downloaded on 06/24/13 from https://energycenter.org/index.php/incentive-programs/self-generation-incentive-program/sgip-documents/sgip-documents. Data cover up to first quarter of 2013.

94 Downloaded on 6/24/13 from http://www.gosolarcalifornia.org/solarwater/index.php.

95 Program data received on 1/18/13 from staff in the Commission's Renewable Energy Office.

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

97 Data received from Energy Commission's Electricity Analysis Office on 6/26/13.

project from a DG incentive program is already reporting data to the Energy Commission under QFER. For example, the SGIP has 118 completed projects that are at least 1 MW and about 50 pending projects that are also 1 MW or larger. Given the small number of DG projects meeting the reporting size threshold of QFER, double-counting may not be significant but could become an issue as an increasing amount of large SGIP projects come on-line.

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

Projects from incentive programs were classified as either completed or uncompleted. This was accomplished by examining the current status of a project. Each program varies in how it categorizes a project. CSI projects having the following statuses are counted as completed projects: "Completed," "PBI – In Payment," "Pending Payment," "Incentive Claim Request Review," and "Suspended – Incentive Claim Request Review." For the SGIP program, a project with the status "Completed" is counted as completed. For the ERP program, there was no field indicating the status of a project. However, there was a column labeled "Date Completed," and this column was used to determine whether a project was completed or uncompleted. For the NSHP, a project that has been approved for payment is counted as a completed project. For SHW, any project having the status "Paid" was counted as a completed project. POU PV data provided installations by sector. Staff then projected when uncompleted projects will be completed based on how long it has taken completed projects to move between the various application stages or, if available, made use of supplemental program data.[98]

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

98 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.

kilowatts (kW) were mapped to the residential sector while both non-PV and PV projects greater than 10 kW were mapped to the commercial sector. Finally, capacity and peak factors from DG evaluation reports were used to estimate energy and peak impacts.[99] [100]

Staff then needed to make assumptions about technology degradation. PV output is assumed to degrade by 1 percent annually; this rate is consistent with other reports examining this issue.[101] Staff decided to not degrade output for non-PV technologies, given the uncertainty in selecting an appropriate factor and the implication of using these factors in a forecast with a 10-year horizon. This decision was based on information from a report focused on combined heat and power projects funded under the SGIP program.[102] The report found significant decline in energy production on an annual basis by technology; however, the reasons for the decline varied and ranged from improper planning during the project design phase, a lack of significant coincident thermal load (for combined heat and power applications), improper maintenance, and fuel price volatility. Also, some technologies, such as fuel cells and microturbines, were just beginning to be commercially sold in the market, and project developers did not have a full awareness of how these technologies would perform in a real-world setting across different industries. This does not mean that staff will not use degradation factors in future reports, and once better data have been collected, staff will revisit this issue.

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

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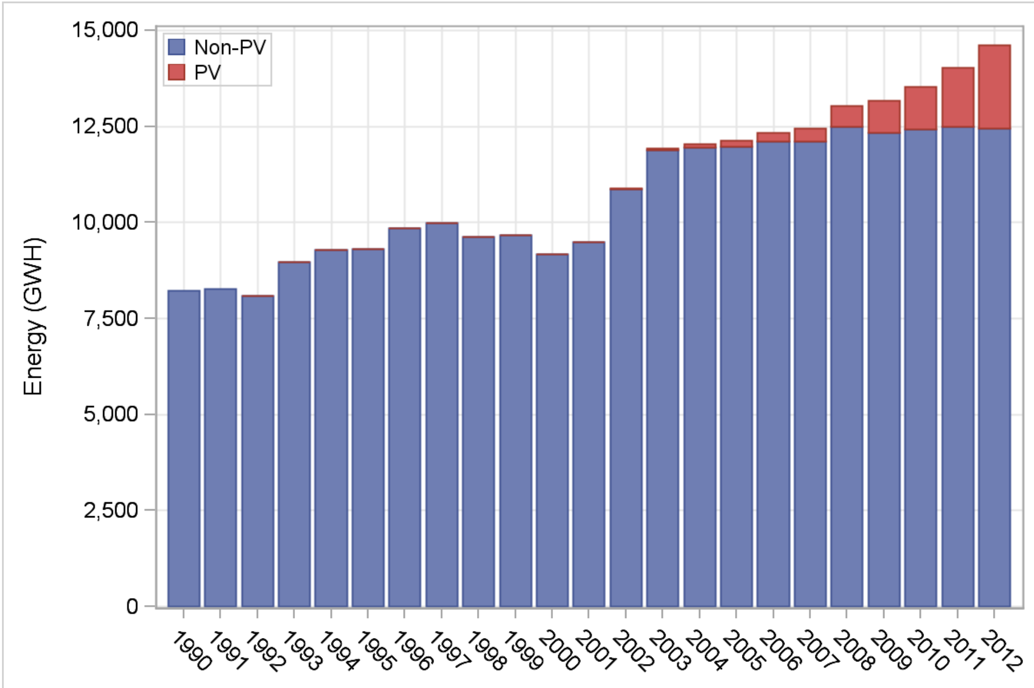
99 For SGIP program: Itron. June 2012. *CPUC Self-Generation Incentive Program Eleventh-Year Impact Evaluation*. Report available at http://www.cpuc.ca.gov/NR/rdonlyres/EC6C16C5-9285-4424-87CF-4A55B0E9903E/0/SGIP_2011_Impact_Eval_Report.pdf.

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

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

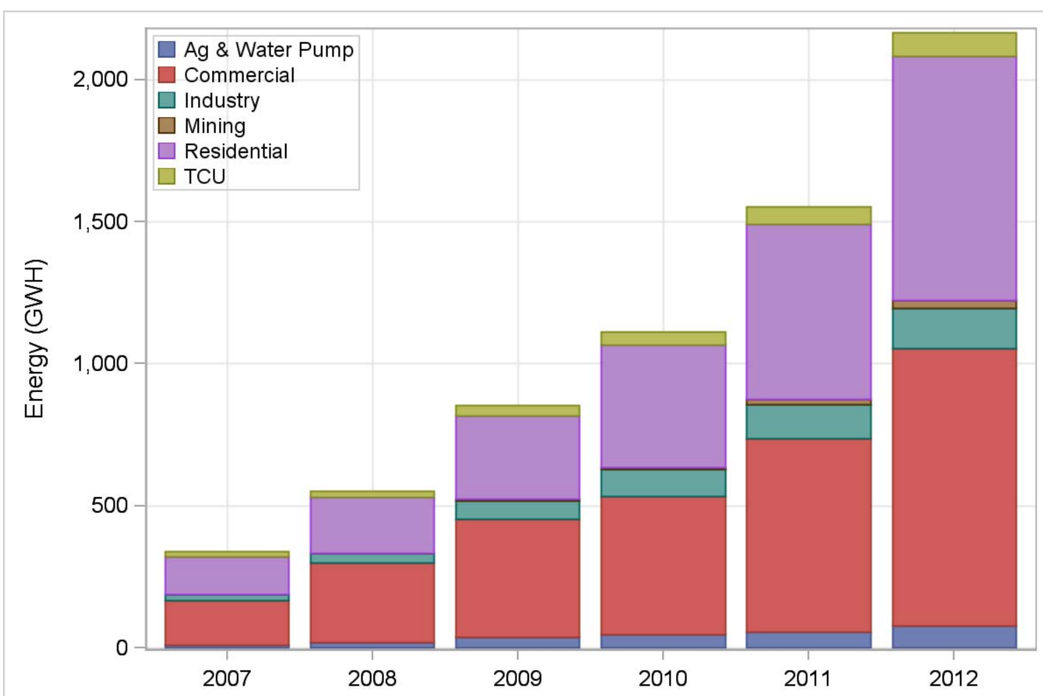
102 Navigant Consulting. April 2010. *Self-Generation Incentive Program Combined Heat and Power Performance Investigation.* Report available at http://www.cpuc.ca.gov/NR/rdonlyres/594FEE2F-B37A-4F9D-B04A-B38A4DFBF689/0/SGIP_CHP_Performance_Investigation_FINAL_2010_04_01.pdf.

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



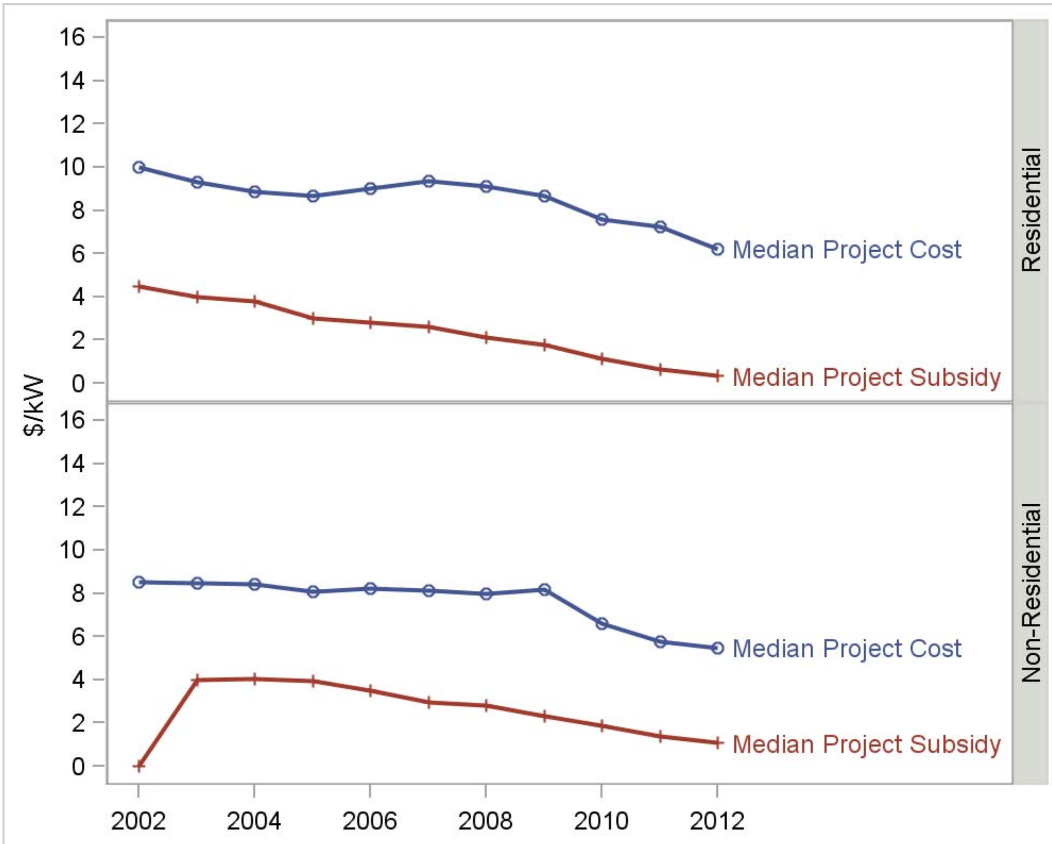
Source: California Energy Commission, Demand Analysis Office, 2013.

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



Source: California Energy Commission, Demand Analysis Office, 2013.

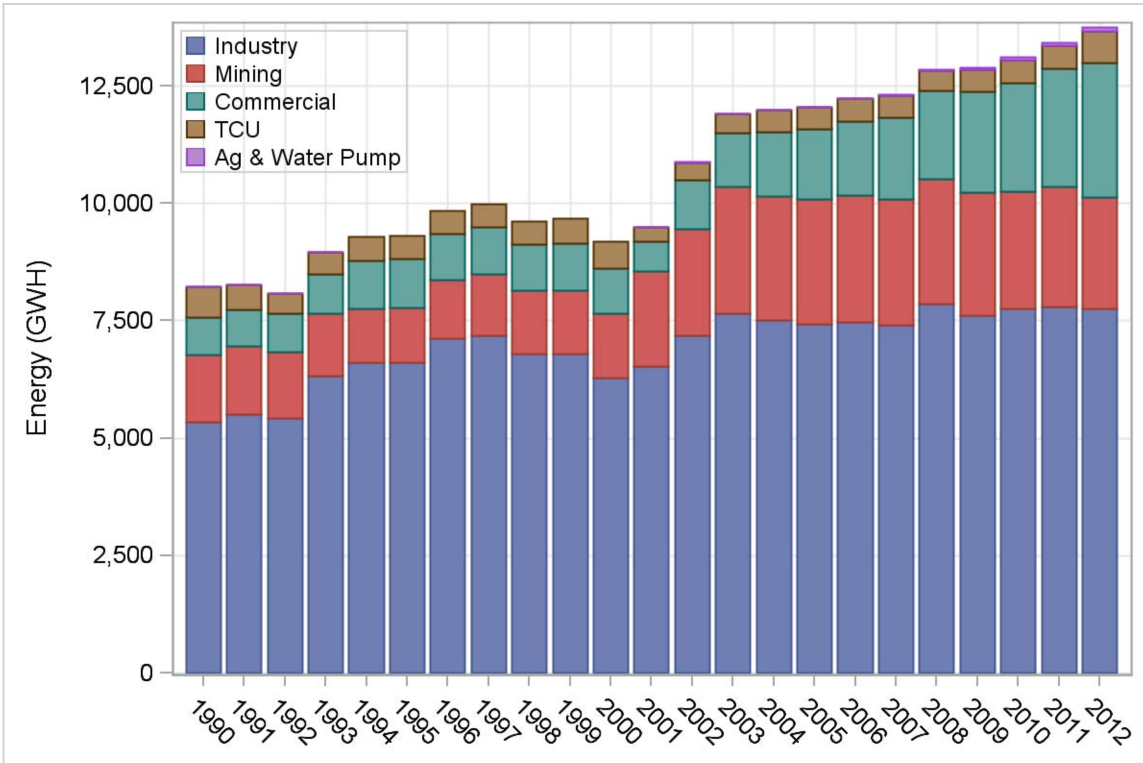
Figure B-3: Median PV Installation Costs and Subsidies, Statewide



Source: California Energy Commission, Demand Analysis Office, 2013.

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

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



Source: California Energy Commission, Demand Analysis Office, 2013.

Residential Sector Predictive Model

The residential sector self-generation model was designed to forecast PV and SHW adoption using estimated times for full payback, which depends on rate, cost, and performance assumptions. The model is similar in structure to the cash flow-based DG model in the NEMS as used by the U.S. EIA[103] and the *SolarDS* model developed by the NREL.[104]

PV cost and performance data were based on analysis performed by the U.S. EIA for the *2013 Annual Energy Outlook* forecast report. Historical PV prices were developed from incentive program data. To forecast the installed cost of PV, staff adjusted the base year mean PV installed cost compiled from DG program data to be consistent with the PV price forecast developed by the U.S. EIA. While this captures the overall trend in installed cost,

103 Office of Integrated Analysis and Forecasting, U.S. EIA. May 2010. *Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M067 (2010).

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

staff feels that more attention needs to be devoted in future *IEPR* proceedings to untangle the changes in the major cost components of PV systems.

SHW cost and performance data were based on analysis conducted by ITRON in support of a CPUC proceeding examining the costs and benefits of SHW systems.[105] Adjustments were made for incentives offered by the appropriate utility to obtain the net cost.

Residential electricity and gas rates consistent with those used in *CED 2013 Final* were used to calculate the value of bill savings. The useful life for both PV and SHW was assumed to be 30 years, which is longer than the forecast period. Rates for years beyond 2024 were held constant. PV surplus generation was valued at a uniform rate of $0.06/kilowatt hour (kWh).[106]

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

$$MaximumMarketFraction = e^{-PaybackSensitivity*Payback}$$

Payback sensitivity was set to 0.3.[107] To estimate actual penetration, maximum market share was multiplied by an estimated adoption rate, calculated using a Bass Diffusion curve, to

105 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.

106 Annual residential energy use by housing type and water heater type from the Energy Commission’s Residential Model is used with the estimated PV generation to determine if any surplus generation occurs. The recent CPUC proposed decision on surplus compensation estimated that the surplus rate for 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.

107 Based on an average fit of two empirically estimated market share curves by R.W. 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.

estimate annual PV and SHW adoption. The Bass Diffusion curve is often used to model adoption of new technologies and is part of a family of technology diffusion functions 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:

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

The terms p and q represent the impact of early and late adopters of the technology, respectively. Staff used mean values for p (0.03) and q (0.38), derived from a survey of empirical studies.[108]

Projected housing counts were allocated to two water heating types – electric and gas. The allocation is based on saturation levels used in the Energy Commission's residential model. For multifamily units, data from the most recent Residential Appliance Saturation Survey (RASS) are used to allocate multifamily units to two size categories: two to four units and five or more units. PV systems were sized to each housing type based on RASS floor space data, assumptions regarding roof slope, and factors to account for shading and orientation.[109] PV system size was constrained to be no more than 4 kW for single-family homes, 7 kW for two- to four-unit multifamily units, and 15 kW for five or more multifamily units. For PV systems, hourly generation over the life of the system was estimated based on data provided to staff by the Energy Commission's Efficiency and Renewable Energy Division.[110] For SHW systems, energy saved on an annual basis was used directly to estimate bill savings. PV and SHW energy output were degraded at the same rate based on the PV degradation factor estimated by ICF for U.S. EIA. From year to year, available housing stock was reduced by penetration from existing programs in previous years and increased by the projected amount of new residential construction.

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

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108 Meade, Nigel and Towidul Islam. 2006. "Modeling and Forecasting the Diffusion of Innovation – A 25-Year Review," *International Journal of Forecasting*, Vol. 22, Issue 3.

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

110 Data come from the NSHP Incentive calculator.

Self-Generation Forecast, Nonresidential Sectors

Commercial CHP and PV Forecast

CED 2013 Preliminary incorporated a newly developed predictive model for commercial CHP. *CED 2013 Final* incorporates within the same model a predictive framework for commercial PV adoption. The model uses the same basic payback framework as in the residential predictive model. Staff began by allocating energy use to different building types using the *2006 Commercial End-Use Survey* (CEUS).[111] The survey contains information on each site that participated in the survey, including:

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

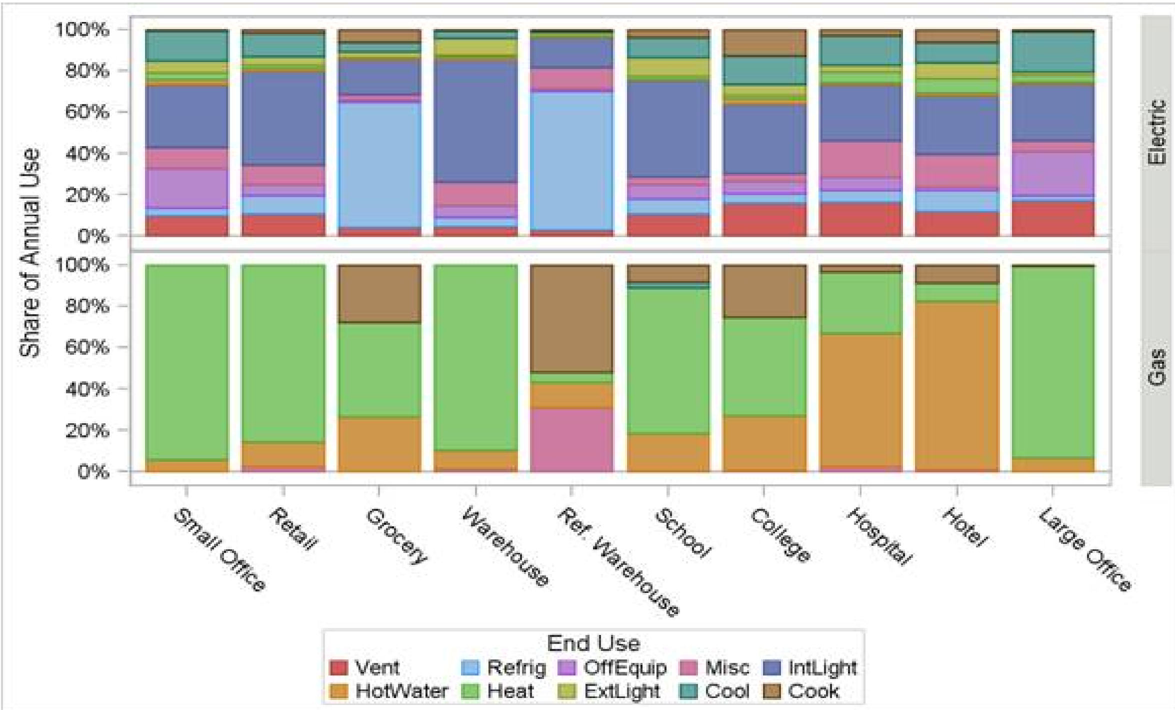
Building sizes were grouped into four size categories based on annual electricity use. Fuel intensities (use per square foot) were then calculated for each building type and size for electricity and natural gas.

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

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

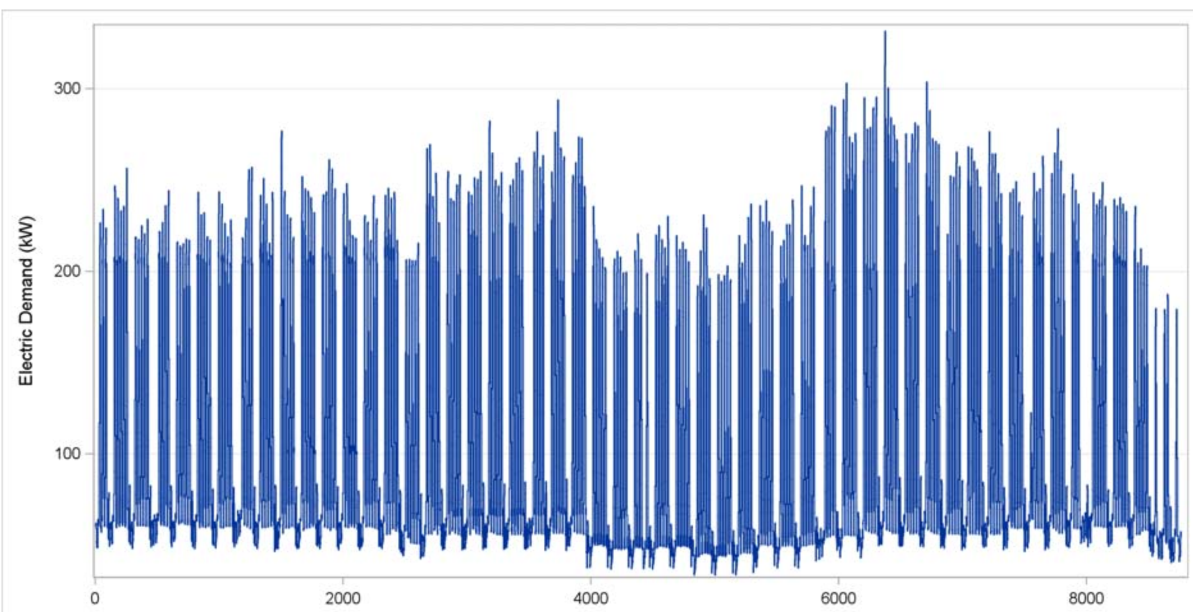
111 Itron. March 2006. Report available at http://www.energy.ca.gov/2006publications/CEC-400-2006-005/CEC-400-2006-005.PDF.

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



Source: California Energy Commission, Demand Analysis Office, 2013.

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



Source: California Energy Commission, Demand Analysis Office, 2013.

*In chronological order.

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

For CHP, staff assumed that waste heat will be recovered to meet the site demand for hot water and space heating and that this will displace gas used for these two purposes.[112] Based on this assumption, the power-to-heat ratio was then calculated for each building type and size category by forecast climate zone and demand scenario.

CHP system sizing was determined by the product of the thermal factor, which is the ratio of the power-to-heat ratio of the CHP system to the power-to-heat ratio of the application, and the average electrical demand of the building type. A thermal factor less than one would indicate that the site is thermally limited relative to its electric load, while a thermal factor greater than one would indicate that the site is electrically limited relative to its thermal load. Thermal factors greater than one mean that the site can export power to the grid if the CHP system is sized to meet the base load thermal demand. Thermal factors were less than one for most building types. For PV, system sizing was based on assessing the displacement of summer afternoon load to reduce consumption in the higher priced time-of-use periods. Based on the applicable tariff, a properly sized PV system could reduce energy charges from the higher priced time-of-use period; however, displacing demand charges, if applicable, can be difficult. The difficulty in avoiding the demand charge occurs when the peak monthly site demand does not correlate with the peak output from the PV system. As in the residential sector predictive model, constraints were applied when calculating PV system size to account for net energy metering (NEM) eligibility, roof area, and annual electric consumption. Currently, to qualify for NEM, a site's PV system size cannot be greater than 1 MW. **Figure B-7** compares the distribution of modeled PV system sizes relative to the historical distribution of nonresidential PV system sizes from the CSI incentive program data.

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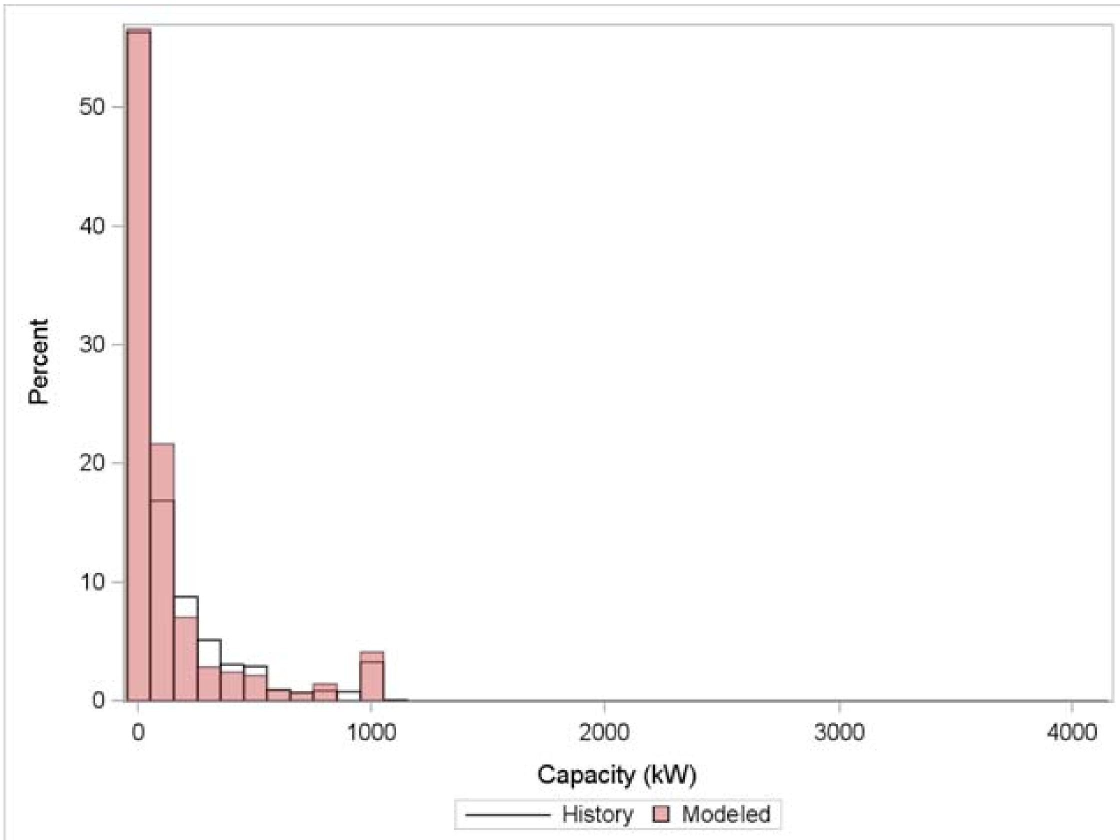
112 ICF International. February 2012. *Combined Heat and Power: Policy Analysis and 2011-2030 Market Assessment.* Report available at http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002.pdf.

Figure B-7: Distribution of Nonresidential Historical and Modeled PV System Sizes



Source: California Energy Commission, Demand Analysis Office, 2013.

Finally, cost and benefits were developed to derive payback. Staff applied the same set of assumptions used in a prior Energy Commission-sponsored report to characterize CHP technology operating characteristics such as heat rate, useful heat recovery, installed capital cost, and operating costs.[113] PV technology details such as installed cost, module electrical efficiency, and overall system losses were based from the same EIA dataset used to project system costs and system details for the residential sector predictive model. Avoided retail electric and gas rates were derived from utility tariff sheets and based on estimated premise-level maximum demand. Current retail electric and gas rates were escalated based on the rates of growth developed for the *CED 2013 Final* scenarios. In addition, CHP technologies may face additional costs, such as standby and departing load charges. Details for these charges were also collected and used in the economic assessment. Staff examined details surrounding the applicability of these charges and applied them as appropriate. The fuel cost for using gas by the different CHP technologies also had to be estimated. Staff began with border prices and then added a transportation charge. Staff from the Energy

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113 See footnote immediately previous.

Commission's Electricity Analysis Office supplied the historical border prices. The Malin border price was used for PG&E, and the Southern California border price was used for both SoCal Gas and SDG&E. For the forecast period, staff escalated average 2012 border prices at a rate consistent with the Electricity Analysis Office's gas rate scenarios.[114] Staff also identified federal tax credits for installing CHP and PV and assessed the eligibility for utility rebate programs, such as the SGIP and CSI.

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

Other Sector Self-Generation

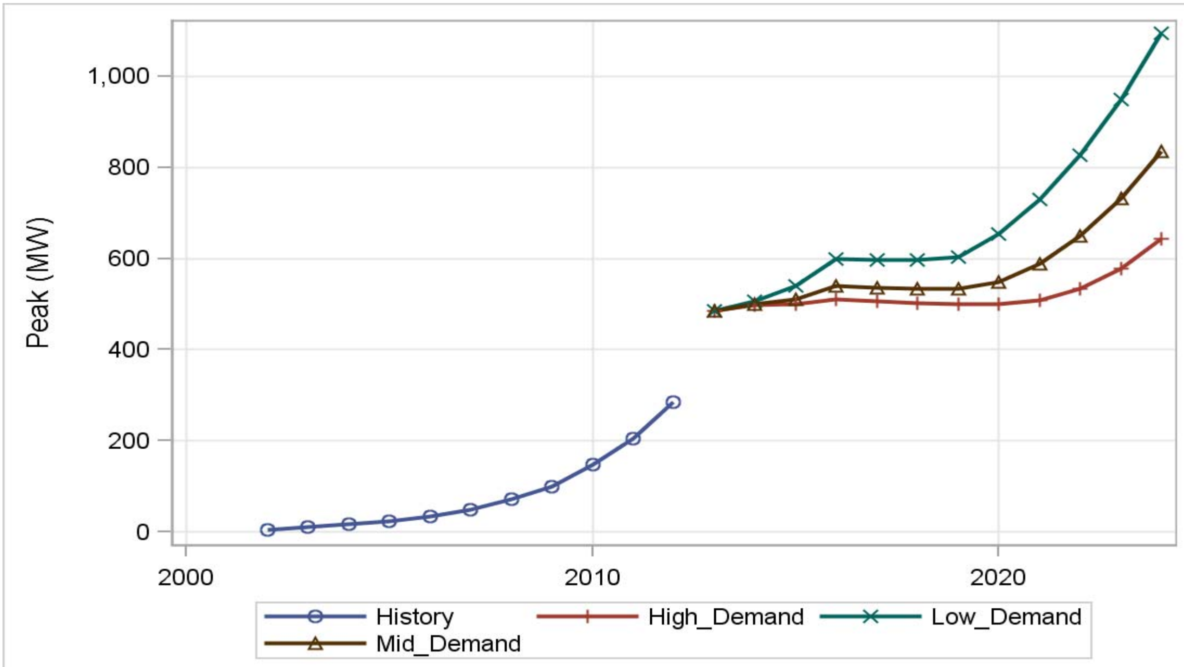
Staff used a trend analysis for forecasting adoption of PV in the noncommercial/nonresidential sectors. Using CSI incentive program data, staff calculated the average annual growth rate for each sector and forecast climate zone for 2008 – 2012. Given strong growth for PV adoption in this period, the maximum annual growth rate was capped at 12 percent. Installed capacity was allowed to grow at this rate until 2016, when the growth rate was reduced by half to account for expiration of federal tax credits. For SHW, staff assumed that nonresidential sector adoption would follow a ratio similar to residential versus nonresidential PV adoption.

Statewide Modeling Results

The following figures show results from the three predictive models at the statewide level by demand scenario. **Figure B-8** shows the PV peak demand impact in the residential sector, which reaches more than 800 MW in the mid demand case and around 1,100 MW in the low case by 2024. Potential adoptions were limited to owner-occupied households, meaning that model results were reduced by percentage of home rentals in each planning area derived from RASS data. For future forecasting cycles, staff will attempt to analyze potential adoption in rental properties separately. Additions decrease substantially with the expiration of the federal tax credit, which occurs in the middle of the forecast period, but then begin to increase as rates increase and PV installed costs decrease.

114 Brathwaite, Leon, Paul Deaver, Robert Kennedy, et al. *2011 Natural Gas Market Assessment: Outlook.* May 2012. Report available at (http://www.energy.ca.gov/2011publications/CEC-200-2011-012/CEC-200-2011-012-SF.pdf). The 2012 daily rates come from Natural Gas Intelligence and were supplied by staff from Electricity Analysis Office.

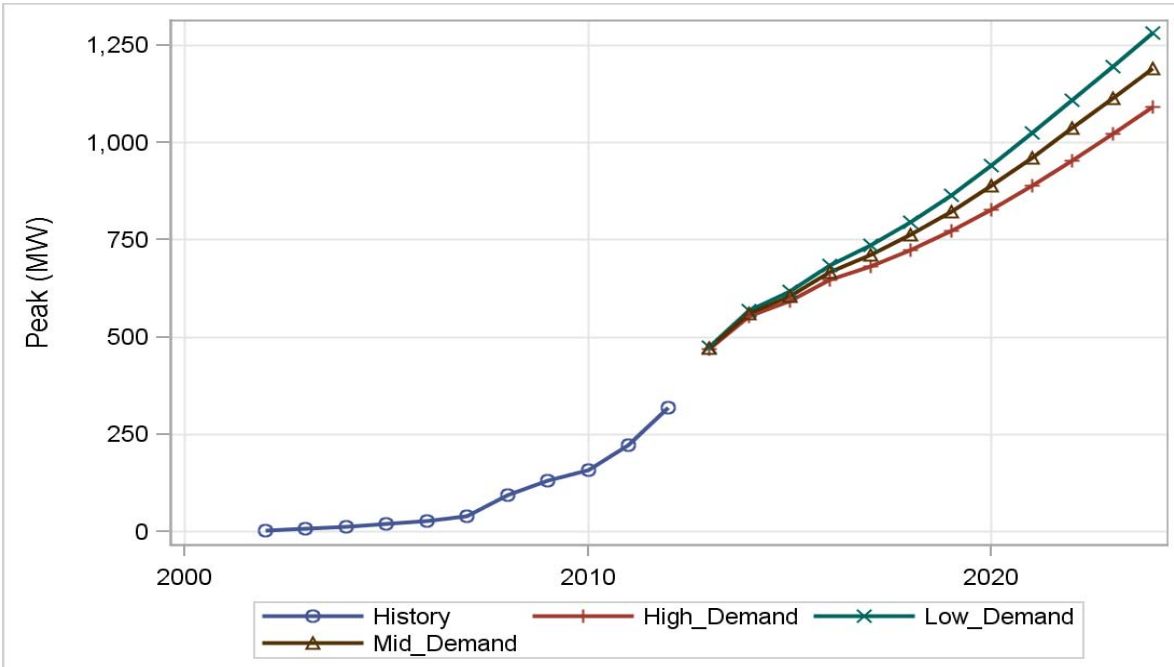
Figure B-8: Residential Sector PV Peak Impact, Statewide



Source: California Energy Commission, Demand Analysis Office, 2013.

Figure B-9 shows the PV peak demand impact in the commercial sector, which reaches around 1,200 MW in the mid and low demand cases by 2024. Unlike the residential sector, the expiration of the federal tax credit has minimal effect on additions. The primary reason for the differential impact comes from using actual retail marginal rates in the commercial sector predictive model versus using sector-average rates (average revenue) in the residential sector. Applying higher marginal rates for adoption decisions makes the tax credit a less significant portion of benefits and therefore less vital to the decision. Staff attempted to revise the residential PV model to use actual residential marginal rates but determined that there was not enough time to complete this revision because of additional data needs. Staff plans to update the residential model to reflect actual rates for the next forecast cycle.

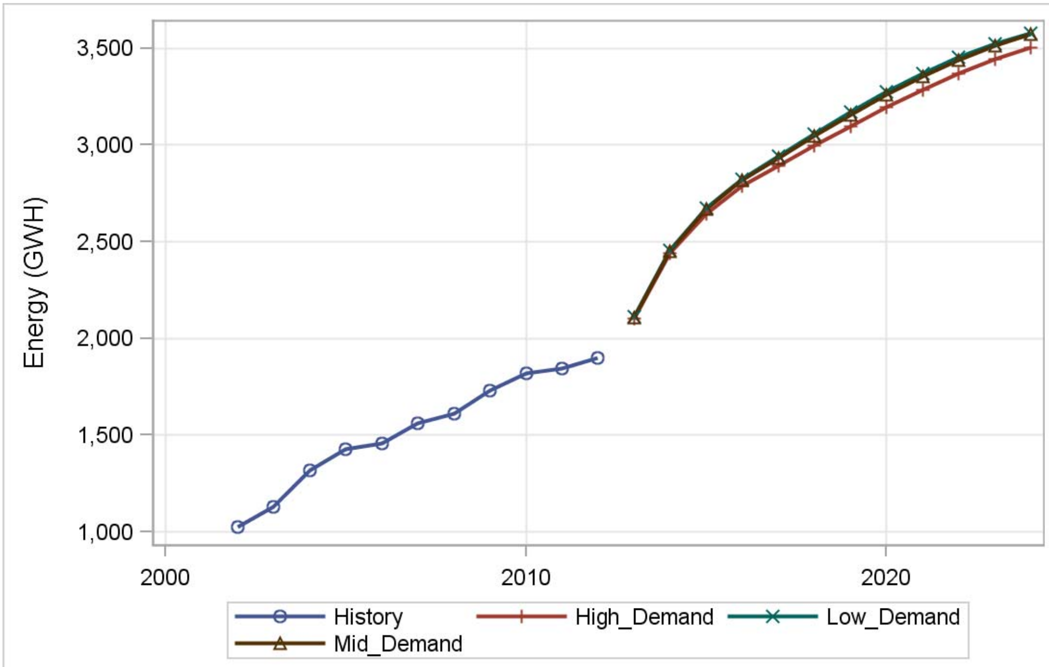
Figure B-9: Commercial Sector PV Peak Impact, Statewide



Source: California Energy Commission, Demand Analysis Office, 2013.

Figure B-10 shows the CHP energy impact in the commercial sector, which reaches around 3,500 GWh by 2024 in all three scenarios. The rapid jump between 2012 and 2014 occurs because of the need to account for pending projects currently moving through the SGIP program. CHP additions in the SGIP slowed because of changes in program design, which limited participation mainly to fuel cells; however, SGIP now provides incentives for conventional CHP technologies, and this has led to many pending projects moving through the various application stages. Higher commercial floor space projections in the high demand case increase adoption relative to the other cases, while higher rates in the low case have the same effect. The net result is that all three scenarios are very similar throughout the forecast period, with the low demand scenario yielding slightly more impact than the mid and low cases.

Figure B-10: Commercial Sector CHP Energy Impact, Statewide



Source: California Energy Commission, Demand Analysis Office, 2013.

APPENDIX C:
Regression Results

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

Table C-1: Residential Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Persons per Household	0.3698	0.1113	3.32
Per capita income (2012$)	0.1460	0.0405	3.60
Unemployment Rate	-0.0039	0.0009	-4.42
Residential Electricity Rate (2012¢/kWh)	-0.0836	0.0099	-8.43
Number of Cooling Degree Days (70^o)	0.0336	0.0030	11.35
Number of Heating Degree Days (60^o)	0.0134	0.0045	2.96
Dummy: 2001	-0.0455	0.0075	-6.05
Dummy: 2002	-0.0399	0.0075	-5.31
Constant: Burbank/Glendale	-0.5638	0.0154	-36.49
Constant: IID	0.1588	0.0250	6.35
Constant: LADWP	-0.5898	0.0142	-41.51
Constant: Pasadena	-0.6672	0.0246	-27.15
Constant: PG&E	-0.3571	0.0126	-28.42
Constant: SCE	-0.4902	0.0152	-32.27
Constant: SDG&E	-0.4709	0.0187	-25.21
Overall Constant	7.1801	0.4078	17.61
Trend Variables			
Time: Burbank/Glendale	0.0095	0.0014	6.59
Time Squared: Burbank/Glendale	-0.0001	0.0000	-3.10
Time: IID	0.0065	0.0007	9.51
Time: LADWP	0.0062	0.0007	8.96
Time: Pasadena	0.0193	0.0028	6.90
Time Squared: Pasadena	-0.0003	0.0001	-3.62
Time: PG&E	0.0017	0.0008	2.23
Time: SCE	0.0050	0.0008	6.54
Time: SDG&E	0.0032	0.0009	3.77
Time: SMUD	-0.0047	0.0015	-3.07
Time Squared: SMUD	0.0001	0.0000	2.07
Adjusted for autocorrelation and cross-sectional correlation. Wald chi squared = 31,808 Dependent variable = natural log of electricity consumption per household by planning area, 1980- All variables in logged form except time and unemployment rate.			

Source: California Energy Commission, Demand Analysis Office, 2013.

Table C-2: Commercial Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Commercial Floor Space (mm. sq. ft.)	0.8682	0.0658	13.19
% of Floor Space Refrigerated	0.2931	0.0364	8.06
Commercial Employment/Floor Space	0.4662	0.0788	5.92
Personal Income (billion 2012$)	0.1437	0.0588	2.44
Commercial Electricity Rate (2012¢/kWh)	-0.0173	0.0147	-1.18
Natural Gas Rate: except SMUD (2012$/mm.	0.0109	0.0072	1.52
Number of Cooling Degree Days (65^o)	0.0470	0.0083	5.64
Dummy: 2001 (LADWP)	-0.0445	0.0196	-2.27
Dummy: 2001 (PG&E)	-0.0340	0.0148	-2.30
Dummy: 2001 (SDG&E	-0.0709	0.0177	-4.00
Constant: IID	0.1110	0.0442	2.51
Constant: LADWP	-0.1214	0.0339	-3.58
Constant: Pasadena	0.3863	0.0787	4.91
Constant: PG&E	-0.2973	0.0624	-4.76
Constant: SCE	-0.3012	0.0616	-4.89
Overall Constant	2.0984	0.2001	10.49
Trend Variables			
Time	0.0086	0.0017	4.97
Time Squared	-0.0002	0.0000	-5.49
Additional Time Impact: Burbank/Glendale	0.0295	0.0036	8.13
Additional Time Squared Impact:	-0.0006	0.0001	-6.39
Additional Time Impact: IID	0.0151	0.0030	5.10
Additional Time Squared Impact: IID	-0.0003	0.0001	-3.55
Additional Time Impact: Pasadena	0.0068	0.0038	1.78
Additional Time Impact: SCE	0.0036	0.0006	5.81
Adjusted for autocorrelation and cross-sectional correlation.			
Wald chi squared = 378,145			
Dependent variable = natural log of commercial consumption by planning area, 1980-2012.			
All variables in logged form except time and % of floor space refrigerated.			

Source: California Energy Commission, Demand Analysis Office, 2013.

Table C-3: Manufacturing Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Manufacturing Output (million 2012$)	0.5425	0.0541	10.03
Manufacturing Output/Manufacturing Employment	-0.3985	0.0469	-8.51
Output Textiles, Fiber, Printing/Manufacturing	0.6060	0.2881	2.10
Output Chemicals, Energy, Plastic/Manufacturing	-0.2168	0.1207	-1.80
Industrial Electricity Rate (2012¢/kWh)	-0.1097	0.0212	-5.18
Constant: Burbank/Glendale	0.6147	0.1588	3.87
Constant: LADWP	1.2666	0.2188	5.79
Constant: PASD	-0.3433	0.1287	-2.67
Constant: PG&E	2.5035	0.2627	9.53
Constant: SCE	2.3157	0.2711	8.54
Constant: SDG&E	0.5191	0.1657	3.13
Overall Constant	3.6359	0.2071	17.56
Trend Variables			
Time: Burbank/Glendale	-0.0419	0.0065	-6.47
Time: IID	-0.0759	0.0127	-5.99
Time Squared: IID	0.0027	0.0004	6.60
Time: Pasadena	-0.0717	0.0162	-4.44
Time Squared: Pasadena	0.0009	0.0005	1.89
Time: PG&E	-0.0052	0.0026	-2.02
Time: SDG&E	0.0384	0.0041	9.38
Time Squared: SDG&E	-0.0011	0.0001	-10.01
Time: SMUD	0.0765	0.0158	4.84
Time Squared: SMUD	-0.0015	0.0005	-3.17
Adjusted for autocorrelation and cross-sectional correlation.			
Wald chi squared = 33,383			
Dependent variable = natural log of industrial consumption by planning area, 1980-2012.			
All variables in logged form except time, output textiles, fiber, printing/manufacturing output and			
output chemicals, energy, plastic/manufacturing output.			

Source: California Energy Commission, Demand Analysis Office, 2013.

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

Variable	Estimated Coefficient	Standard Error	t-statistic
Output, Resource Extraction (million 2005$)	0.1457	0.0419	3.47
Employment in Construction (thousands)	0.2776	0.0787	3.53
Percent Employment Resource Extraction	2.5095	0.9558	2.63
Industrial Electricity Rate (2012 cents/kWh)	-0.0995	0.0565	-1.76
Dummy: 2002	-0.0694	0.0331	-2.10
Dummy: 1997 SDG&E	-1.0476	0.0870	-12.04
Dummy: 1980 and 1981 PG&E	-1.1116	0.0737	-15.08
Constant: BUGL	-1.3089	0.1520	-8.61
Constant: IID	-1.6041	0.2564	-6.26
Constant: LADWP	0.8687	0.2499	3.48
Constant: PASD	-3.6428	0.3032	-12.01
Constant: PG&E	2.8922	0.3529	8.20
Constant: SCE	2.6223	0.3556	7.37
Overall Constant	2.6761	0.3075	8.70
Trend Variables			
Time: BUGL	0.1178	0.0112	10.49
Time squared: BUGL	-0.0026	0.0003	-8.72
Time: IID	0.1130	0.0286	3.94
Time squared: IID	-0.0016	0.0008	-1.94
Time: PASD	0.3326	0.0351	9.47
Time squared: PASD	-0.0086	0.0010	-8.66
Time: PG&E	-0.0521	0.0137	-3.82
Time squared: PG&E	0.0016	0.0004	4.39
Time: SDG&E	0.1149	0.0251	4.59
Time Squared: SDG&E	-0.0029	0.0008	-3.86
Time: SMUD	0.0474	0.0174	2.72
Time Squared: SMUD	-0.0007	0.0005	-1.40
Adjusted for autocorrelation and cross-sectional correlation.			
Wald chi squared = 32,039			
Dependent variable = natural log of construction & resource extraction consumption by planning area 1980-2012.			
All variables in logged form except time and percentage employment resource extraction.			

Source: California Energy Commission, Demand Analysis Office, 2013.

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

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

Source: California Energy Commission, Demand Analysis Office, 2013.

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

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

Source: California Energy Commission, Demand Analysis Office, 2013.

Table C-7: Street Lighting Sector Electricity Econometric Model

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

Source: California Energy Commission, Demand Analysis Office, 2013.

Table C-8: Peak Demand Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Per Capita Income (2012$)	0.2038	0.0351	5.80
Unemployment Rate	-0.0020	0.0010	-1.90
Persons per Household	-0.7507	0.1707	-4.40
Residential Electricity Rate	-0.0425	0.0177	-2.40
Annual Max *Average631*	1.1110	0.0558	19.91
Residential Consumption per Capita	0.2080	0.0316	6.57
Commercial Consumption per Capita	0.0964	0.0250	3.85
Dummy: 2001	-0.0661	0.0105	-6.32
Constant: IID	0.1839	0.0400	4.60
Constant: LADWP	-0.1849	0.0124	-14.95
Constant: Pasadena	-0.0909	0.0146	-6.20
Constant: PG&E	-0.1856	0.0133	-13.99
Constant: SCE	-0.1433	0.0176	-8.14
Constant: SDG&E	-0.4421	0.0204	-21.70
Overall Constant	-7.9576	0.4095	-19.43
Trend Variables			
Time: Burbank/Glendale	0.0036	0.0007	5.45
Time: Imperial Irrigation District	0.0023	0.0008	2.96
Time: LADWP	0.0064	0.0016	4.04
Time Squared: LADWP	-0.0002	0.0000	-3.90
Time: Pasadena	0.0205	0.0017	11.93
Time Squared: Pasadena	-0.0004	0.0000	-10.33
Time: SCE	0.0053	0.0020	2.72
Time Squared: SCE	-0.0001	0.0001	-2.44
Time: SDG&E	0.0057	0.0008	7.36
Adjusted for autocorrelation and cross-sectional correlation.			
Wald chi squared = 23,143			
Dependent variable = natural log of annual peak per capita by planning area, 1980-2012.			
All variables in logged form except time and unemployment rate.			

Source: California Energy Commission, Demand Analysis Office, 2013.

Table C-9: Residential Sector Natural Gas Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Income per Household (2012$)	0.1848	0.1102	1.68
Residential Gas Rate (2012¢/therm)	-0.0223	0.0240	-0.93
Number of Heating Degree Days (65^{o})	0.2640	0.0170	15.55
Dummy: 2001	-0.0286	0.0267	-1.07
Constant: Southern California Gas	0.2824	0.0217	13.00
Overall Constant	2.3664	1.2176	1.94
Trend Variables			
Time: PG&E	-0.0247	0.0039	-6.30
Time Squared: PG&E	0.0002	0.0001	2.58
Time: Southern California Gas	-0.0295	0.0040	-7.45
Time Squared: Southern California Gas	0.0003	0.0001	3.33
Time: SDG&E	-0.0368	0.0041	-8.87
Time Squared: SDG&E	0.0004	0.0001	4.04
Adjusted for autocorrelation and cross-sectional correlation.			
Wald chi squared = 2,509			
Dependent variable = natural log of natural gas consumption per household by planning area.			
All variables in logged form except time.			

Source: California Energy Commission, Demand Analysis Office, 2013.

Table C-10: Commercial Sector Natural Gas Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Personal Income (billion 2012$)	0.4953	0.0763	6.49
Commercial Gas Rate (2012$/mmBTU)	-0.0287	0.0347	-0.83
Number of Heating Degree Days (60^{o})	0.2194	0.0370	5.93
Dummy: 2001	-0.2141	0.0384	-5.57
Constant: PG&E	0.6774	0.1312	5.16
Constant: Southern California Gas	0.8619	0.1514	5.69
Overall Constant	1.5533	0.3507	4.43
Trend Variables			
Time	-0.0748	0.0272	-2.76
Adjusted for autocorrelation and cross-sectional correlation.			
Wald chi squared =2,759			
Dependent variable = natural log of commercial gas consumption by planning area, 1980-2012.			
All variables in logged form.			

Source: California Energy Commission, Demand Analysis Office, 2013.

Table C-11: Manufacturing Sector Natural Gas Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Manufacturing Output (2005$)	1.0299	0.3070	3.35
Manufacturing Output/Manufacturing	-0.8922	0.2708	-3.29
Industrial Gas Rate (2012$/therm)	-0.1622	0.0720	-2.25
Number of Heating Degree Days (65^{o})	0.2997	0.1208	2.48
Dummy: SDG&E (1990)	1.0425	0.2635	3.96
Dummy: PG&E (1980 and 1981)	0.4006	0.0918	4.36
Constant: PG&E	1.8945	0.6358	2.98
Constant: Southern California Gas	1.6159	0.7825	2.07
Overall Constant	-4.0061	1.8294	-2.19
Trend Variables			
Time: Southern California Gas	-0.0530	0.0226	-2.35
Time Squared: Southern California Gas	0.0019	0.0007	2.86
Time: SDG&E	0.0507	0.0400	1.27
Time Squared: SDG&E	-0.0023	0.0011	-2.01
Adjusted for autocorrelation and cross-sectional correlation.			
Wald chi squared = 1,554			
Dependent variable = natural log of natural gas consumption by planning area, 1980-2012.			
All variables in logged form except time.			

Source: California Energy Commission, Demand Analysis Office, 2013.

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

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

Source: California Energy Commission, Demand Analysis Office, 2013.

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

Variable	Estimated Coefficient	Standard Error	t-statistic
Sector Employment	0.8910	0.0510	17.48
Per Capita Income (2012$)	1.1383	0.5302	2.15
Commercial Gas Rate (2012$ per mmBTU)	-0.0732	0.0937	-0.78
Dummy: 2001	-0.1346	0.0903	-1.49
Overall Constant	-12.0340	5.2987	-2.27
Trend Variables			
Time: PG&E	-0.0290	0.0095	-3.06
Time: Southern California Gas	0.0249	0.0083	2.99
Time: SDG&E	-0.0321	0.0120	-2.68
Adjusted for autocorrelation and cross-sectional correlation.			
Wald chi squared = 1,569			
Dependent variable = natural log of natural gas consumption by planning area, 1980-2012.			
All variables in logged form except time.			

Source: California Energy Commission, Demand Analysis Office, 2013.