California Energy Commission

DRAFT STAFF REPORT

PRELIMINARY CALIFORNIA ENERGY DEMAND FORECAST 2012-2022

CALIFORNIA
ENERGY COMMISSION

Edmund G. Brown Jr., Governor

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The staff demand forecast is the combined product of the hard work and expertise of numerous staff members in the Demand Analysis Office. In addition to the contributing authors listed previously, Mohsen Abrishami prepared the commercial sector forecast. Bryan Alcorn and Mehrzad Soltani Nia prepared the industrial forecast. Miguel Garcia-Cerrutti and Ted Dang ran the revised Summary Model. Andrea Gough supervised data preparation. Steven Mac, Irene Salazar, Gary Occhiuzzo, and Keith O'Brien prepared the historical energy consumption data. Nahid Movassagh forecasted consumption for the agriculture and water pumping sectors. Kate Sullivan prepared the demographic projections and developed the alternative economic scenarios. Don Schultz, Che McFarlin, and Doug Kemmer developed the energy efficiency program estimates. Margaret Sheridan provided the residential forecast. Mitch Tian prepared the peak demand forecast. Ravinderpal Vaid provided the projections of commercial floor space, with contribution from Gary Occhiuzzo. Malachi Weng-Gutierrez provided the forecast for electric vehicles.

ABSTRACT

The *Preliminary California Energy Demand Forecast 2012-2022* describes the California Energy Commission staff's preliminary forecasts for 2012–2022 electricity consumption, peak, and natural gas demand for each of five major planning areas and for the state as a whole and supports the analysis and recommendations of the *Integrated Energy Policy Report 2011*. The forecast includes three full scenarios: a *high energy demand* case, a *low energy demand* case, and a *mid energy demand* case. The *high energy demand* case incorporates relatively high economic/demographic growth, relatively low electricity and natural gas rates, and relatively low efficiency program and self-generation impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed rates, and higher efficiency program and self-generation impacts. The *mid* case uses input assumptions at levels between the *high* and *low* cases.

Keywords

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

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EXECUTIVE SUMMARY

Introduction

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

CED 2011 Preliminary includes three full scenarios: a *high energy demand* case, a *low energy demand* case, and a *mid energy demand* case. The *high energy demand* case incorporates relatively high economic/demographic growth, relatively low electricity and natural gas rates, and relatively low efficiency program and self-generation impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed rates, and higher efficiency program and self-generation impacts. The *mid* case uses input assumptions at levels between the *high* and *low* cases.

Electricity Forecast Results

Table 1-1 compares *CED 2011 Preliminary* for selected years with *California Energy Demand 2010-2020 Adopted Forecast (CED 2009)*, the forecast used in the *2009 IEPR*. The new forecast begins approximately 3 percent below *CED 2009* in 2010, reflecting a significant drop in actual electricity consumption in 2009 and 2010 as the recent recession worsened relative to the outlook in 2009, combined with a relatively mild weather year in 2010. However, consumption in the mid and high scenarios grows at a faster rate over the forecast period compared to *CED 2009*. By 2020, consumption is only 1.8 percent lower in the mid demand case and 1.6 percent higher in the high case. This pattern repeats for state (non-coincident) peak demand. Peak demand in 2010 (weather-normalized) is 3.2 percent lower than predicted in *CED 2009*, but only 1.9 percent lower by 2020 in the mid scenario. Peak demand in the high case is 1.2 percent higher than *CED 2009* by 2020.

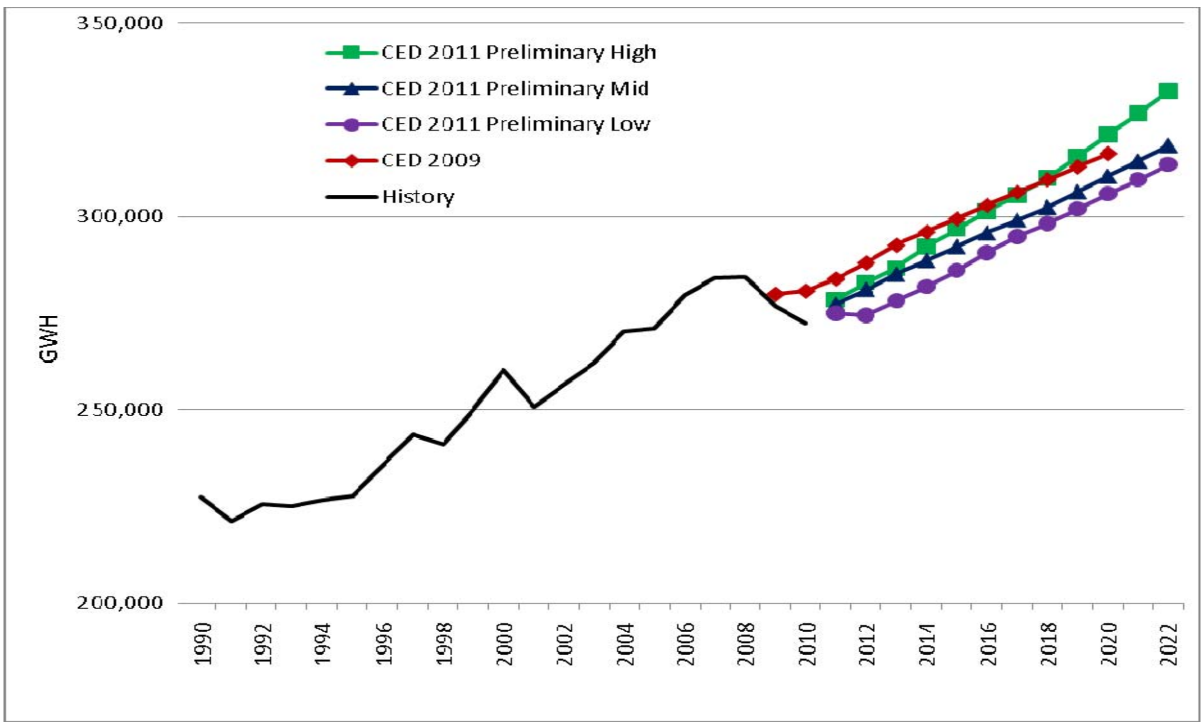
Table ES-1: Comparison of *California Energy Demand 2010-2020 Adopted Forecast* and *Preliminary California Energy Demand Forecast 2012-2022* Statewide Electricity Demand

Consumption (GWh)				
	CED 2009 (Dec. 2009)	*CED 2011 Preliminary High Demand Case* (August 2011)	*CED 2011 Preliminary Mid Demand Case* (August 2011)	*CED 2011 Preliminary Low Demand Case* (August 2011)
1990	228,473	227,586	227,586	227,586
2000	264,230	260,408	260,408	260,408
2010	280,843	272,342	272,342	272,342
2015	299,471	296,821	292,286	286,100
2020	316,280	321,268	310,462	305,932
2022	--	332,514	318,396	313,493
	Average Annual Growth Rates			
1990-2000	1.46%	1.36%	1.36%	1.36%
2000-2010	0.61%	0.45%	0.45%	0.45%
2010-2015	1.29%	1.74%	1.42%	0.99%
2010-2020	1.20%	1.67%	1.32%	1.17%
2010-2022	--	1.68%	1.31%	1.18%
Non-Coincident Peak (MW)				
	CED 2009 (Dec. 2009)	*CED 2011 Preliminary High Demand Case* (August 2011)	*CED 2011 Preliminary Mid Demand Case* (August 2011)	*CED 2011 Preliminary Low Demand Case* (August 2011)
1990	47,521	47,520	47,520	47,520
2000	53,703	53,703	53,703	53,703
2010*	62,459	60,455	60,455	60,455
2015	66,868	66,569	65,701	64,246
2020	71,152	72,006	69,818	68,498
2022	--	74,220	71,280	69,738
	Average Annual Growth Rates			
1990-2000	1.23%	1.23%	1.23%	1.23%
2000-2010	1.52%	1.23%	1.23%	1.23%
2010-2015	1.37%	1.19%	1.19%	1.19%
2010-2020	1.31%	1.95%	1.68%	1.22%
2010-2022	--	1.76%	1.45%	1.26%
Historical values are shaded				
*2011 forecasts use 2010 weather-normalized peak rather than actual to estimate growth rates				

Source: California Energy Commission, 2011

Figure 1-1 shows statewide historic electricity consumption, projected consumption for the three scenarios, and the *CED 2009* consumption forecast. Consumption grows at a faster average annual rate from 2010 to 2020 in the mid and high energy demand cases (1.32 and 1.67 percent, respectively) relative to *CED 2009* (1.20 percent). In the low demand scenario, annual growth is higher than in *CED 2009* after 2012. Higher projected growth rates in *CED 2011 Preliminary* reflect a deeper recession than assumed in 2009, as well as a very mild weather year, and therefore faster growth in reverting to expected long-term weather and economic trends. Forecast consumption reaches *CED 2009* projected levels by 2018 in the high demand scenario and surpasses the 2020 *CED 2009* projection in the mid case by 2022.

Figure ES-1: Statewide Annual Electricity Consumption

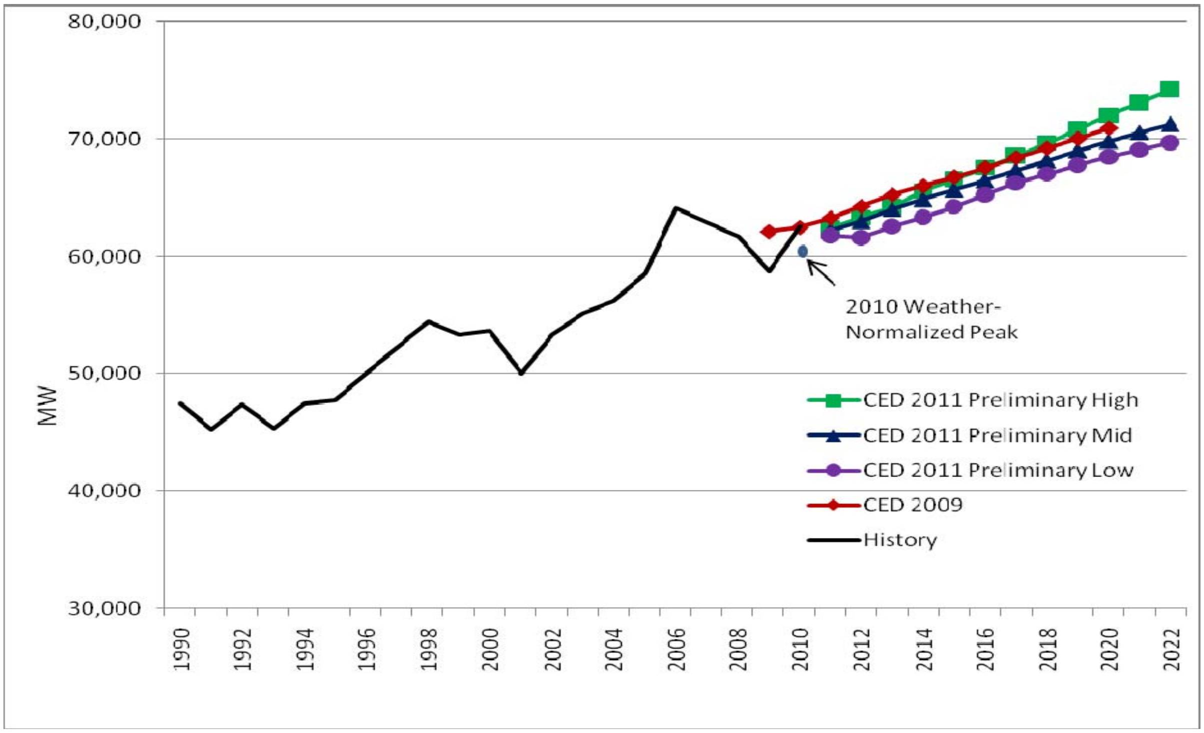


Source: California Energy Commission, 2011

Figure 1- compares *CED 2011 Preliminary* statewide non-coincident peak demand with *CED 2009*. Unlike consumption, peak over all sectors in 2010 was very close to the *CED 2009* statewide projection; although 2010 was a mild weather year overall, a heat storm event in September 2010 yielded a relatively high peak. The figure also indicates weather-normalized peak demand in 2010. As is the case with consumption, growth in peak demand from 2010-2020, relative to a weather-normalized 2010, is faster in the high and mid cases (1.76 percent and 1.45 percent, respectively) than in *CED 2009* (1.31 percent). Statewide peak demand is projected to reach the *CED 2009* level by 2017 in the high demand scenario and to surpass the 2020 *CED 2009* projection in the mid case by 2022. Average annual growth rates from

2010-2020 relative to actual peak in 2010 are projected to be 1.41 percent, 1.10 percent, and 0.91 percent, respectively, in the high, mid, and low demand scenarios.

Figure ES-2: Statewide Annual Non-Coincident Peak Demand



Source: California Energy Commission, 2011

Natural Gas Forecast Results

Table ES-2 compares three *CED 2011 Preliminary* end-user natural gas demand forecasts at the statewide level with *CED 2009* for selected years. The new forecasts begin at a higher point in 2010, as natural gas consumption in California was substantially higher this year than predicted in *CED 2009*, and grows at a faster rate from 2010-2020.

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

Consumption (MM Therms)				
	CED 2009 (Dec. 2009)	*CED 2011 Preliminary* High (August 2011)	*CED 2011 Preliminary* Mid (August 2011)	*CED 2011 Preliminary* Low (August 2011)
1990	12,893	12,893	12,893	12,893
2000	13,913	13,914	13,914	13,914
2010	12,162	12,665	12,665	12,665
2015	12,751	13,372	13,338	12,891
2020	12,997	13,832	13,789	13,552
2022	--	14,175	13,992	13,773
	Average Annual Growth Rates			
1990-2000	0.76%	0.76%	0.76%	0.76%
2000-2010	-1.34%	-0.94%	-0.94%	-0.94%
2010-2015	0.95%	1.09%	1.04%	0.36%
2010-2020	0.67%	0.89%	0.85%	0.68%
2010-2022	--	0.94%	0.83%	0.70%
Historical values are shaded				

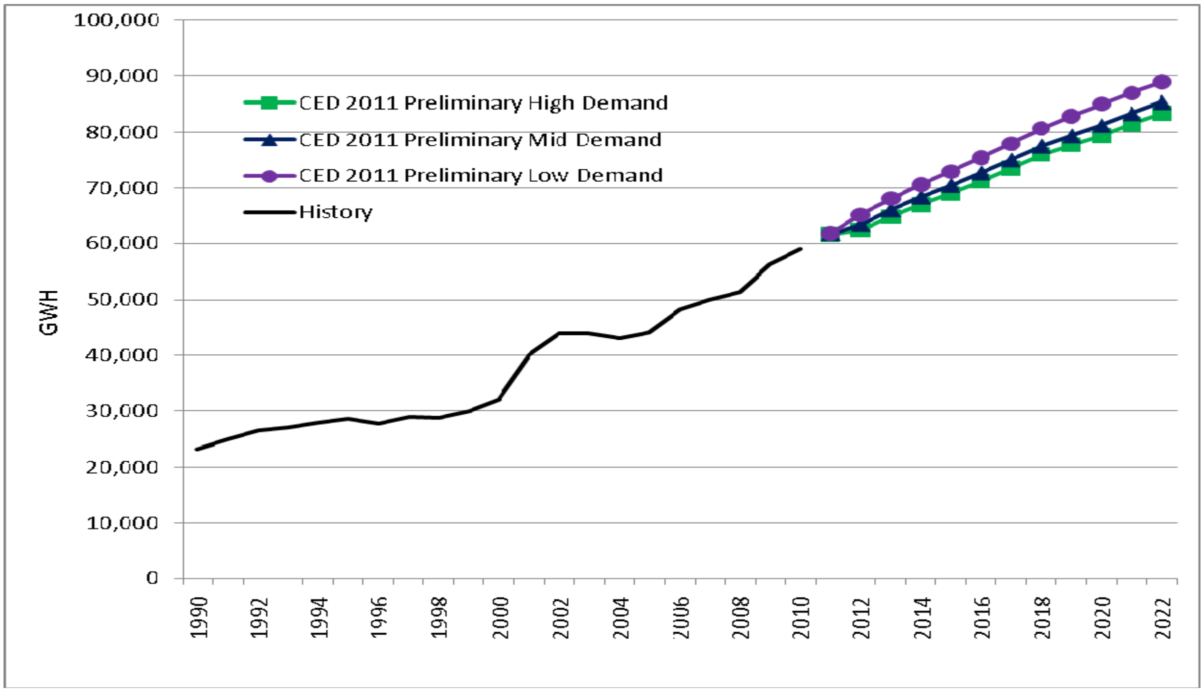
Source: California Energy Commission, 2011

Conservation/Efficiency

Energy Commission demand forecasts seek to account for efficiency and conservation expected to occur. Since the *1985 Electricity Report*, initiatives have been split into two types: committed and uncommitted. *CED 2011 Preliminary* continues that distinction. Committed initiatives include utility and public agency programs, codes and standards, legislation and ordinances that have final authorization, firm funding, and a design that can be readily translated into characteristics which can be 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 effects not directly related to a specific initiative. Chapter 8 gives details regarding the committed energy efficiency impacts projected for this forecast. The chapter also presents incremental savings estimates for a set of uncommitted efficiency initiatives and shows the effect on the forecast of incorporating these impacts.

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

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



Source: California Energy Commission, 2011

Summary of Changes to Forecast

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

For the residential, commercial, and industrial sectors, forecasts were developed in two ways: through the Energy Commission's existing models and through new econometric models developed by staff in 2011. In addition, peak projections were developed with both staff's Hourly Electricity Load Model and with a new econometric model. Adjustments were made to existing models based on the econometric estimations and results from existing models were compared to econometric results.

As part of the continuing effort to comprehensively capture the impacts of energy efficiency initiatives, this forecast incorporates recent revisions to building and appliance standards, including effects from Assembly Bill 1109 (AB 1109, Huffman, Chapter 534, Statutes of 2007) as well as an update to natural gas efficiency program impacts. Chapter 8 provides details on staff work related to efficiency impact measurement for this forecast. In addition, Chapter 8 provides adjustments to the forecast to incorporate *incremental uncommitted* efficiency impacts, based on the work by the Energy Commission and Itron for the *2009 IEPR*.

Residential adoption of PV systems and solar water heaters was forecast using a new predictive model rather than a trend analysis as in previous forecasts. Finally, potential climate change was incorporated in the forecast, using temperature scenarios developed by the Scripps Institute. These scenarios, and a discussion of how they were incorporated in the forecast, are discussed in the Appendix.

CHAPTER 1: Statewide Forecast Results and Methods

Introduction

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

The IEPR Committee will conduct a workshop on August 30, 2011, to receive public comments on this forecast. Following the workshop, subject to the direction of the Committee, staff may prepare a revised forecast or range of forecasts for adoption by the Energy Commission.

The final forecasts will be used in a number of applications, including the California Public Utilities Commission (CPUC) 2012 long-term procurement process. The CPUC has identified the IEPR process as "the appropriate venue for considering issues of load forecasting, resource assessment, and scenario analyses, to determine the appropriate level and ranges of resource needs for load serving entities in California."[1] The final forecasts will also be an input to California Independent System Operator (California ISO) controlled grid studies and other transmission planning studies and in the *California Gas Report*[2] and electricity supply-demand assessments.

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1 Peevey, Assigned Commissioner's Ruling On Interaction Between The CPUC Long-Term Planning Process And The California Energy Commission Integrated Energy Policy Report Process, September 9, 2004 Rulemaking 04-04-003.

2 The California Gas Report is prepared by California electric and gas utilities in compliance with California Public Utilities Commission Decision D.95-01-039.

Summary of Changes to Forecast

The previous long run forecast, *California Energy Demand 2010-2020*[3] (*CED 2009*) was based on 2008 peak demand and energy. For the current forecast, staff added 2009 and 2010 energy consumption data to the historic series used for forecasting. The peak demand forecast incorporates recent analysis of 2010 temperatures and peak demand at the planning area level.

CED 2011 Preliminary includes three full scenarios: a *high energy demand* case, a *low energy demand* case, and a *mid energy demand* case. The *high energy demand* case incorporates relatively high economic/demographic growth, relatively low electricity and natural gas rates, and relatively low efficiency program and self-generation impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed rates, and higher efficiency program and self-generation impacts. The *mid* case uses input assumptions at levels between the *high* and *low* cases. Details on input assumptions for these scenarios are provided later in this chapter.

For the residential, commercial, industrial (a combination of manufacturing and resource extraction and construction) sectors, forecasts were developed in two ways: through the Energy Commission's existing models and through new econometric models developed by staff in 2011. In addition, peak projections were developed with both staff's Hourly Electricity Load Model (HELM) and with a new econometric model. Adjustments were made to existing models based on the econometric estimations and results from existing models were compared to econometric results.

As part of the continuing effort to comprehensively capture the impacts of energy efficiency initiatives, *CED 2011 Preliminary* incorporates recent revisions to building and appliance standards, including effects from Assembly Bill 1109 (AB 1109, Huffman, Chapter 534, Statutes of 2007), as well as an update to natural gas efficiency program impacts. Staff focused on electricity programs in *CED 2009*, and time and resources did not permit any revision to natural gas program impacts. Chapter 8 provides details on staff work related to efficiency impact measurement for this forecast. In addition, Chapter 8 provides adjustments to the forecast to incorporate *incremental uncommitted* efficiency impacts, based on the work by the Energy Commission and Itron for the *2009 IEPR*.[4]

Residential adoption of PV systems and solar water heaters was forecast using a predictive model rather than a trend analysis as in previous forecasts. This model is based on

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3 California Energy Commission. *California Energy Demand 2010–2020 Adopted Forecast,* December 2009. Publication no. CEC-200-2009-012-CMF.

4 Electricity and Natural Gas Committee. *Incremental Impacts of Energy Policy Initiatives Relative to the* 2009 Integrated Energy Policy Report *Adopted Demand Forecast*. CEC-200-2009-001-CTF.

methodologies used by the Energy Information Administration, as part of their National Energy Modeling System, and the National Renewable Energy Laboratory. Details of the model are provided in the Appendix.

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

Statewide Forecast Results

Table 1-1 provides a comparison of the *CED 2011 Preliminary* forecast for selected years with *CED 2009*, the forecast used in the *2009 IEPR*. The new forecast begins approximately 3.0 percent below *CED 2009* in 2010, reflecting a significant drop in actual electricity consumption in 2009 and 2010 as the recent recession worsened relative to the outlook in 2009, combined with a relatively mild weather year in 2010. However, consumption in the mid and high scenarios grows at a faster rate over the forecast period compared to *CED 2009*. By 2020, consumption is only 1.8 percent lower in the mid demand case and 1.6 percent higher in the high case. This pattern repeats for state (non-coincident) peak demand. By 2010, weather normalized[5] peak demand was 3.2 percent lower than predicted in *CED 2009*, but 1.9 percent lower by 2020 in the mid scenario. Peak demand in the high case is 1.2 percent higher than *CED 2009* by 2020.

The historic data used for this forecast differs slightly from *CED 2009* because of revised data submitted by utilities, and because a detailed review of self-generation consumption data found some data had been misclassified.

5 Peak demand is weather-normalized in 2010 to provide the proper benchmark for comparison to future peak demand, which assumes average, or normalized, weather.

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

Consumption (GWh)				
	CED 2009 (Dec. 2009)	*CED 2011 Preliminary High Energy Demand* (August 2011)	*CED 2011 Preliminary Mid Energy Demand* (August 2011)	*CED 2011 Preliminary Low Energy Demand* (August 2011)
1990	228,473	227,586	227,586	227,586
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2022	--	332,514	318,396	313,493
	Average Annual Growth Rates			
1990-2000	1.46%	1.36%	1.36%	1.36%
2000-2010	0.61%	0.45%	0.45%	0.45%
2010-2015	1.29%	1.74%	1.42%	0.99%
2010-2020	1.20%	1.67%	1.32%	1.17%
2010-2022	--	1.68%	1.31%	1.18%
Non-Coincident Peak (MW)				
	CED 2009 (Dec. 2009)	*CED 2011 Preliminary High Energy Demand* (August 2011)	*CED 2011 Preliminary* Mid Energy Demand (August 2011)	*CED 2011 Preliminary Low Energy Demand* (August 2011)
1990	47,521	47,520	47,520	47,520
2000	53,703	53,703	53,703	53,703
2010*	62,459	60,455	60,455	60,455
2015	66,868	66,569	65,701	64,246
2020	71,152	72,006	69,818	68,498
2022	--	74,220	71,280	69,738
	Average Annual Growth Rates			
1990-2000	1.23%	1.23%	1.23%	1.23%
2000-2010	1.52%	1.23%	1.23%	1.23%

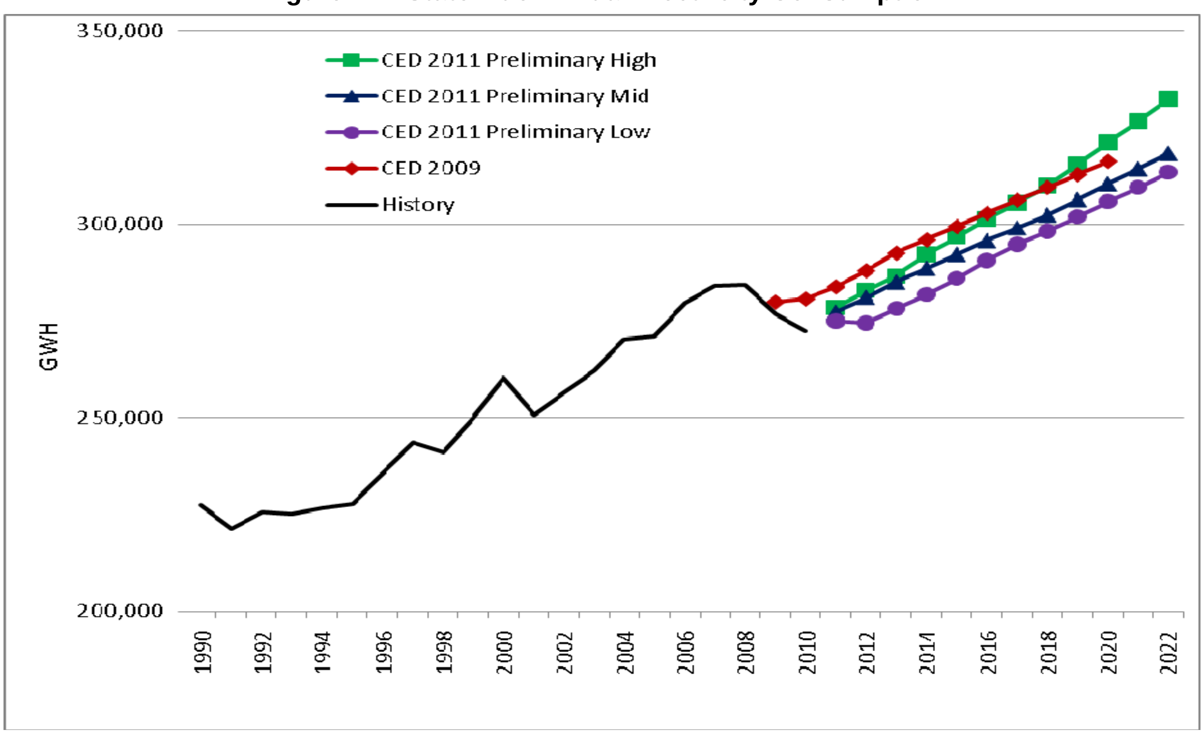
2010-2015	1.37%	1.19%	1.19%	1.19%
2010-2020	1.31%	1.95%	1.68%	1.22%
2010-2022	--	1.76%	1.45%	1.26%
Historical values are shaded				
*2011 forecasts use 2010 weather-normalized peak rather than actual to estimate growth rates				

Source: California Energy Commission, 2011

Annual Electricity Consumption

Figure 1-1 shows statewide historic electricity consumption, projected consumption for the three scenarios, and the *CED 2009* consumption forecast. Consumption grows at a faster average annual rate from 2010 to 2020 in the mid and high energy demand cases (1.32 and 1.67 percent, respectively) relative to *CED 2009* (1.20 percent). In the low demand scenario, annual growth is higher than in *CED 2009* after 2012. Higher projected growth rates in the 2011 forecast reflect a deeper recession than assumed in 2009 as well as a very mild weather year, and therefore faster growth in reverting to expected long-term weather and economic trends. Forecast consumption reaches *CED 2009* projected levels by 2018 in the high demand scenario and surpasses the 2020 *CED 2009* projection in the mid case by 2022.

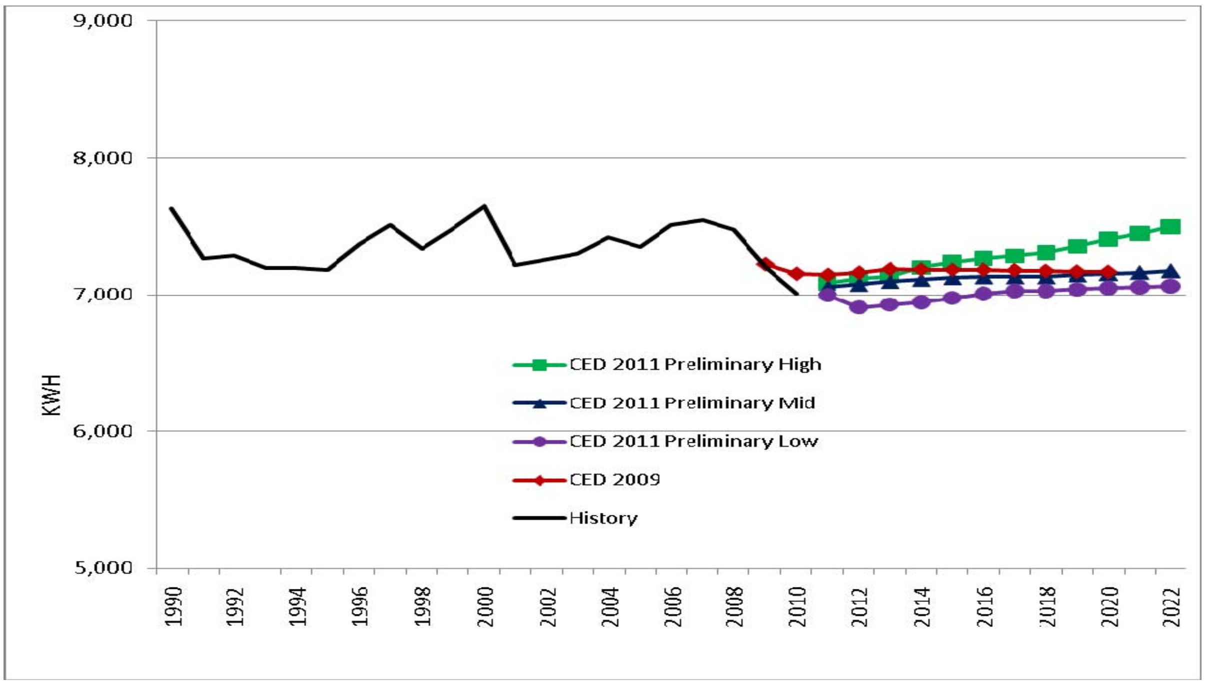
Figure 1-1: Statewide Annual Electricity Consumption



Source: California Energy Commission, 2011

As shown in **Figure 1-2**, per capita electricity is flat throughout the forecast period in the mid case and from 2017 on in the low case, which assumes a longer delay for full economic recovery. Higher economic/demographic growth in the high demand case increases per capita consumption throughout the forecast period. By 2020, projected per capita consumption is around 250 kWh higher than in the previous forecast.

Figure 1-2: Statewide Electricity Annual Consumption per Capita



Source: California Energy Commission, 2011

Table 1-2 compares projected annual consumption in each scenario for the three major economic sectors, residential, commercial, and industrial, with *CED 2009*. Projected growth in the residential and commercial sectors is higher in all three scenarios compared to *CED 2009*, partly because of a reversion to average weather in the forecast period from a historically mild 2010. To compare across weather-normalized years, growth rates for 2011-2020 are also shown for the residential and commercial sectors (consumption is much less weather-sensitive in the industrial sector). Residential growth over this period is lower in the mid and low cases versus *CED 2009*, reflecting the impacts of reduced lighting from AB 1109. Growth in the high case remains above *CED 2009* for 2011-2020, as faster income growth more than offsets reduced lighting use. In the commercial sector, growth from 2011-2020 remains at or above *CED 2009* in all three scenarios, as a result of faster growth in commercial floor space (as shown later in this chapter). Industrial consumption growth from 2010-2020 is lower in the mid and low cases compared to *CED 2009*; although manufacturing output is projected to grow faster compared to *CED 2009* projections, this is offset by an adjustment made by staff for labor productivity (discussed later in this chapter). In the high demand case, much higher growth in manufacturing than in the mid and low cases results in a 2010-2020 growth rate significantly above that in *CED 2009*.

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

Residential				
	CED 2009	*CED 2011 Preliminary High Energy Demand*	*CED 2011 Preliminary Mid Energy Demand*	*CED 2011 Preliminary Low Energy Demand*
2010	90,712	87,390	87,390	87,390
2015	97,353	95,931	94,679	98,074
2020	108,529	108,687	105,988	105,029
2022	--	114,021	111,046	109,554
Average Annual Growth, Residential Sector				
2010-2020	1.81%	2.20%	1.95%	1.86%
2011-2020	1.91%	2.09%	1.79%	1.75%
2010-2022	--	2.24%	2.02%	1.90%
Commercial				
	CED 2009	*CED 2011 Preliminary High Energy Demand*	*CED 2011 Preliminary Mid Energy Demand*	*CED 2011 Preliminary Low Energy Demand*
2010	103,143	100,185	100,185	100,185
2015	110,313	109,387	108,805	106,085
2020	116,278	117,620	116,792	113,705
2022	--	120,886	119,656	116,803
Average Annual Growth, Commercial Sector				
2010-2020	1.21%	1.62%	1.55%	1.27%
2011-2020	1.20%	1.54%	1.48%	1.20%
2010-2022	--	1.58%	1.49%	1.29%
Industrial				
	CED 2009	*CED 2011 Preliminary High Energy Demand*	*CED 2011 Preliminary Mid Energy Demand*	*CED 2011 Preliminary Low Energy Demand*
2010	49,315	47,011	47,011	47,011
2015	52,546	51,492	49,046	46,901

2020	52,162	55,433	48,266	47,886
2022	--	57,747	47,948	47,498
Average Annual Growth, Industrial Sector				
2010-2020	0.56%	1.66%	0.26%	0.18%
2010-2022	--	1.73%	0.16%	0.09%
Historical values are shaded				

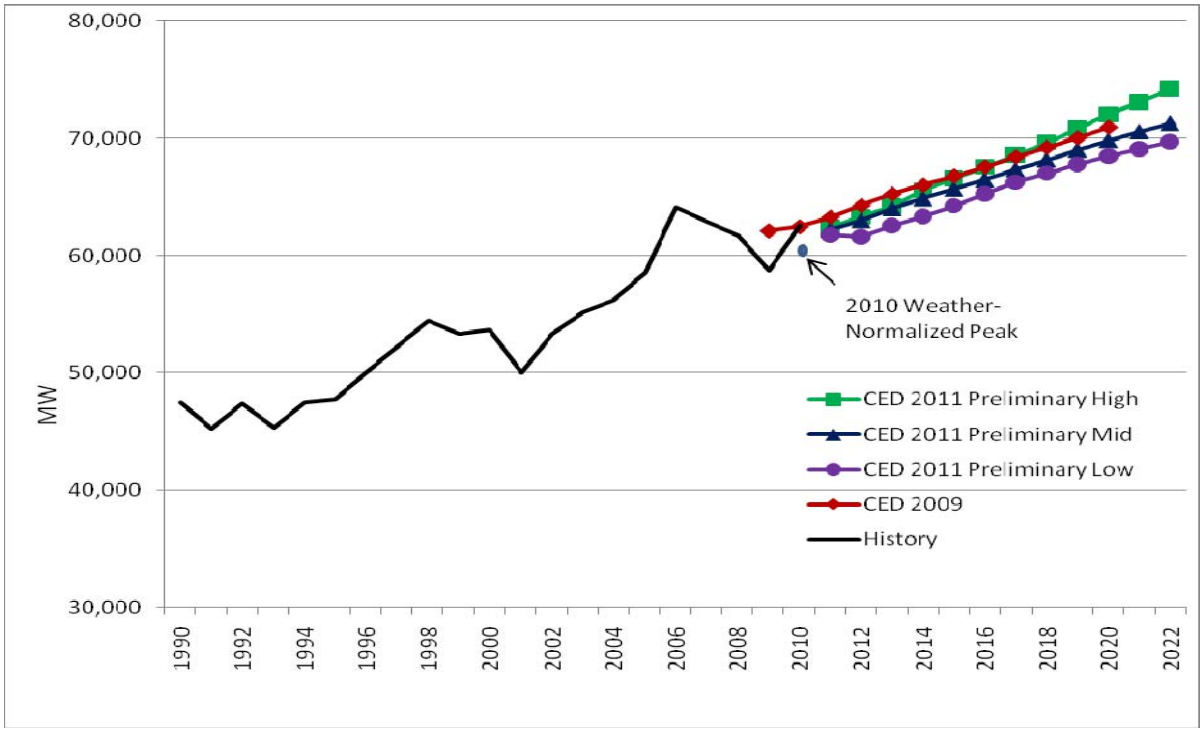
Source: California Energy Commission, 2011

To support sub-regional electricity system analysis, staff disaggregates the planning area forecasts to correspond to control areas and congestion zones. These forecasts, for both consumption and peak demand, are provided in spreadsheet files in the forms accompanying this forecast report.

Statewide Peak Demand

Figure 1-3 compares *CED 2011 Preliminary* statewide non-coincident peak demand with *CED 2009*. Unlike consumption, peak over all sectors in 2010 was very close to the *CED 2009* statewide projection; although 2010 was a mild weather year overall, a heat storm event in September 2010 yielded a relatively high peak. The figure also indicates weather-normalized peak demand in 2010. As is the case with consumption, growth in peak demand from 2010-2020, relative to a weather-normalized 2010, is higher in the high and mid cases (1.76 percent and 1.45 percent, respectively) than in *CED 2009* (1.31 percent). Statewide peak demand is projected to reach the *CED 2009* level by 2017 in the high demand scenario and to surpass the 2020 *CED 2009* projection in the mid case by 2022. Average annual growth rates from 2010-2020 relative to actual peak in 2010 are projected at 1.41 percent, 1.10 percent, and 0.91 percent, respectively, in the high, mid, and low demand scenarios.

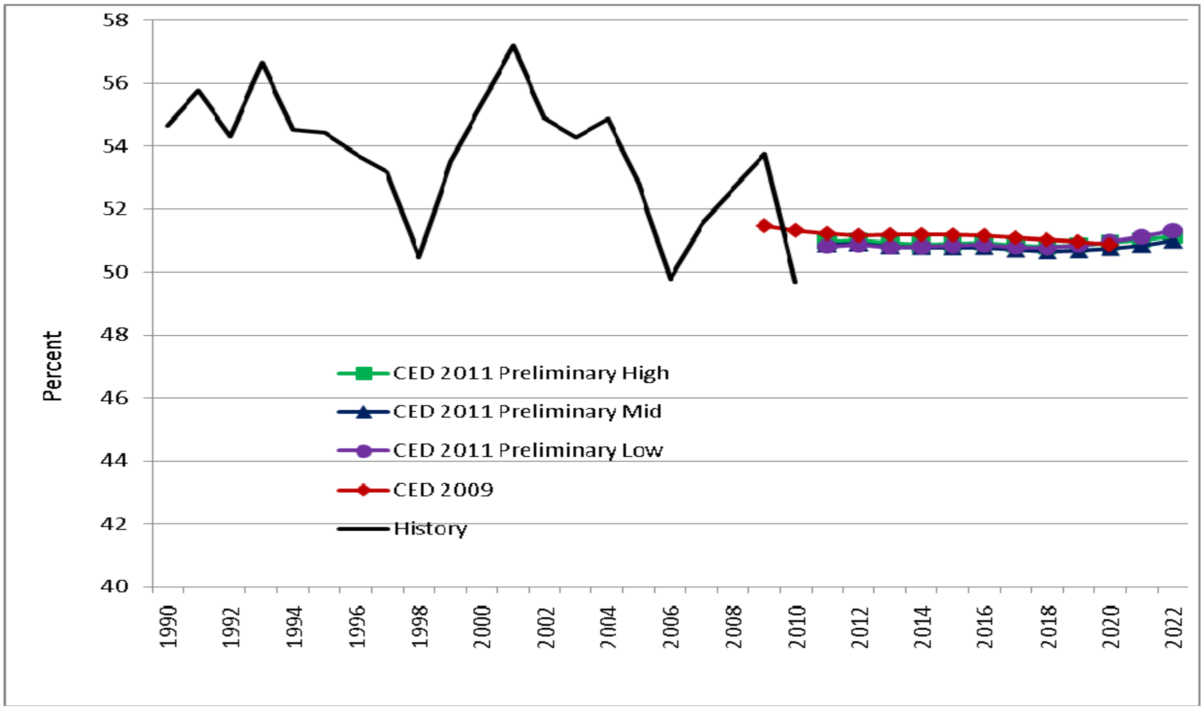
Figure 1-3: Statewide Annual Non-Coincident Peak Demand



Source: California Energy Commission, 2011

Figure 1-4 shows load factors for the state as a whole. The load factor represents the relationship between average energy demand and peak. The smaller the load factor, the greater is the difference between peak and average hourly demand. The load factor varies with temperature; in years with extreme heat (1998, 2006, 2010), 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 the forecast period for all three demand scenarios (as in *CED 2009*) until 2020. Energy efficiency measures, such as more efficient lighting, contribute to the declining load factor by reducing energy use while having an insignificant effect on peak. After 2020, projected increasing numbers of electric vehicles, which are assumed to affect consumption much more than peak demand, begin to push load factors upward.

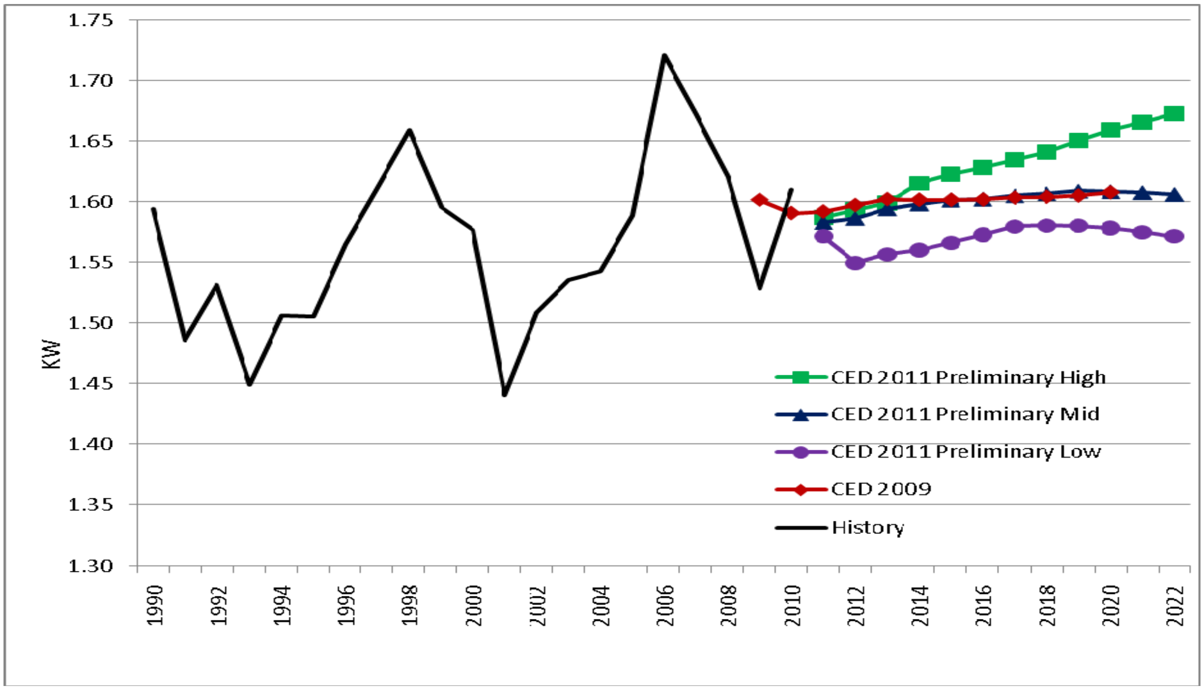
Figure 1-4: Statewide Non-Coincident Peak Load Factors



Source: California Energy Commission, 2011

Figure 1-5 shows historical and projected non-coincident peak demand per capita. Per capita demand increases at the beginning of the forecast period in all three scenarios as the California economy recovers. Afterward, demand flattens out and begins to decline toward the end of the forecast period in the mid and low demand scenarios, reflecting efficiency improvements and PV system adoption. Stronger economic growth in the high demand case, along with less efficiency improvement and PV adoption relative to the other scenarios, is enough to keep per capita demand increasing.

Figure 1-5: Statewide Non-Coincident Peak Demand per Capita



Source: California Energy Commission, 2011

Table 1-3 shows projected annual non-coincident peak demand by the major economic sectors. Although the peak over all sectors is close to that projected in *CED 2009*, as shown in **Figure 1-3,** estimated[6] residential peak in 2010 is significantly lower than the *CED 2009* projection. Residential peak may indeed have been this low, but it is more likely that this is a reflection of the difficulty in calibrating the Energy Commission's HELM peak model to a relatively high peak when consumption is low because of a mild weather year. That is, the current residential end-use load shapes may lead to this sector being insufficiently responsive to isolated heat events in the HELM model. This also means that peaks in the other sectors may be overstated in 2010.[7] Therefore, it is more useful to compare growth rates for the weather-normalized years 2011-2020.

As in the case of statewide consumption, residential sector peak growth in the mid and low demand cases for 2011-2020 is below that of *CED 2009* for the same reason (AB 1109). Similarly, higher income growth in the high demand case offsets the lighting reductions from AB 1109, so that growth is higher than *CED 2009*. Commercial and industrial peak growth also mirror the consumption results relative to *CED 2009*: commercial growth from

6 The Energy Commission's HELM peak model calibrates to actual system peaks; sector peaks are estimates based on sector consumption and load shapes.

7 Staff will attempt to address this issue between the preliminary and revised forecasts.

2011-2020 is higher in all three scenarios while industrial growth is slower in the mid and low cases and significantly faster in the high case.

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

Residential				
	CED 2009	*CED 2011 Preliminary High Energy Demand*	*CED 2011 Preliminary Mid Energy Demand*	*CED 2011 Preliminary Low Energy Demand*
2010	25,268	23,250	23,250	23,250
2015	27,689	26,878	26,657	26,353
2020	30,567	29,738	29,186	28,972
2022	--	30,992	30,334	29,974
Average Annual Growth, Residential Sector				
2010-2020	1.92%	2.49%	2.30%	2.22%
2011-2020	1.95%	2.02%	1.77%	1.74%
2010-2022	--	2.42%	2.24%	2.14%
Commercial				
	CED 2009	*CED 2011 Preliminary High Energy Demand*	*CED 2011 Preliminary Mid Energy Demand*	*CED 2011 Preliminary Low Energy Demand*
2010	21,327	22,320	22,320	22,320
2015	22,621	22,868	22,737	22,168
2020	23,676	24,553	24,324	23,610
2022	--	25,219	24,897	24,199
Average Annual Growth, Commercial Sector				
2010-2020	1.05%	0.96%	0.86%	0.56%
2011-2020	1.03%	1.50%	1.41%	1.09%
2010-2022	--	1.02%	0.91%	0.68%
Industrial				
	CED 2009	*CED 2011 Preliminary High Energy Demand*	*CED 2011 Preliminary Mid Energy Demand*	*CED 2011 Preliminary Low Energy Demand*
2010	7,698	7,815	7,815	7,815
2015	8,214	8,071	7,661	7,276
2020	8,154	8,666	7,531	7,448
2022	--	9,049	7,473	7,373
Average Annual Growth, Industrial Sector				
2010-2020	0.58%	1.04%	-0.37%	-0.48%
2011-2020	0.44%	1.64%	0.37%	0.66%
2010-2022	--	1.23%	-0.37%	-0.48%
Estimates of historical values are shaded				

Source: California Energy Commission, 2011

Natural Gas Demand Forecast

Table 1-4 compares the three *CED 2011 Preliminary* natural gas demand forecasts at the statewide level with *CED 2009* for selected years. The forecast does not include natural gas used for generation of electricity. The new forecasts begin at a higher point in 2010, as natural gas consumption in California was substantially higher in this year than predicted in *CED 2009*, and grew at a faster rate from 2010-2020. This results from faster projected demand growth for all three scenarios in the industrial sector and for the mid and high cases in the residential sector. Sector results are discussed further in Chapter 7.

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

Consumption (MM Therms)				
	CED 2009 (Dec. 2009)	*CED 2011 Preliminary* High Energy Demand (August 2011)	*CED 2011 Preliminary* Mid Energy Demand (August 2011)	*CED 2011 Preliminary* Low Energy Demand (August 2011)
1990	12,893	12,893	12,893	12,893
2000	13,913	13,914	13,914	13,914
2010	12,162	12,665	12,665	12,665
2015	12,751	13,372	13,338	12,891
2020	12,997	13,832	13,789	13,552
2022	--	14,175	13,992	13,773
	Average Annual Growth Rates			
1990-2000	0.76%	0.76%	0.76%	0.76%
2000-2010	-1.34%	-0.94%	-0.94%	-0.94%
2010-2015	0.95%	1.09%	1.04%	0.36%
2010-2020	0.67%	0.89%	0.85%	0.68%
2010-2022	--	0.94%	0.83%	0.70%
Historical values are shaded				

Source: California Energy Commission, 2011

Overview of Methods and Assumptions

Although the methods to estimate energy efficiency impacts and self-generation have undergone refinement, *CED 2009* uses essentially the same methods as earlier long-term staff demand forecasts. Models for the major economic sectors produce forecasts of annual energy consumption in each utility planning area. After adjusting for historic 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 to account for the forecasted impacts of mandatory energy efficiency standards and other energy efficiency programs that seek to force or encourage adoption of more efficient technologies by end-users. The forecasts of agricultural and water pumping energy consumption are made using econometric methods, and projections for the Transportation, Communications, and Utilities (TCU) and street lighting sectors rely on trend analyses because of a lack of detailed information in these sectors. A detailed discussion of forecast methods and data sources is available in the 2005 *Methods Report*.[8]

In addition to existing models, staff incorporated econometric model estimation and forecast results from models estimated for total peak demand and for electricity consumption in the three major sectors: residential, commercial, and industrial. The latter sector includes separate models for manufacturing and for resource extraction and construction. Details of the econometric models including estimation results are provided in a recent staff report.[9]

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

- Electricity price elasticities for the residential end use and industrial (INFORM) models were changed to be consistent with elasticities estimated for the residential and industrial econometric models.
- The weather adjustment made to commercial end use model electricity consumption results was changed to be consistent with the coefficient for cooling degree days in the commercial econometric model.
- The INFORM electricity forecast for the manufacturing sector was adjusted downward to reflect a negative impact from increasing labor productivity estimated for the manufacturing econometric model.
- Peak results from the HELM were adjusted to incorporate climate change scenarios using results from the peak econometric model.

These adjustments, as well as the climate change scenarios, are discussed further in the Appendix. In addition, the resource extraction and construction econometric model forecast was used instead of the results from the INFORM model. Staff judged the INFORM results to be suspect: projected electricity consumption growth decreased for some planning areas in a manner inconsistent with the economic drivers behind the forecast. Staff will look into this issue further in preparation for the revised forecast.

8 California Energy Commission, *Energy Demand Forecast Methods Report,* CEC-400-2005-036, June 2005.

9 Kavalec, Chris. 2011. *Draft Staff Report - Updated California Energy Demand Forecast 2011-2022*. California Energy Commission, Electricity Analysis Division. Publication Number: CEC-200-2011-006-SD.

Estimation of new econometric models is part of the Energy Commission's effort to incorporate a *multi-resolution* modeling process, generating more aggregate "tops down" results to compare with the detailed "bottoms up" results from existing end use models. Although staff used existing models for this forecast (with the exception of resource extraction and consumption), a comparison with econometric results generates some differences that will be investigated for the revised forecast. The residential end use consumption forecasts tended to be higher than econometric residential results, around 6 percent higher at the statewide level in the mid demand case by 2022. Forecasts for the commercial and manufacturing sectors were much closer, with econometric results 0.5 percent lower and 1.4 percent higher, respectively, at the statewide level in 2022. The econometric peak forecast was almost 3 percent higher than the end-user version, with most of the difference occurring in the LADWP and PG&E planning areas.[10]

Economic and Demographic Assumptions

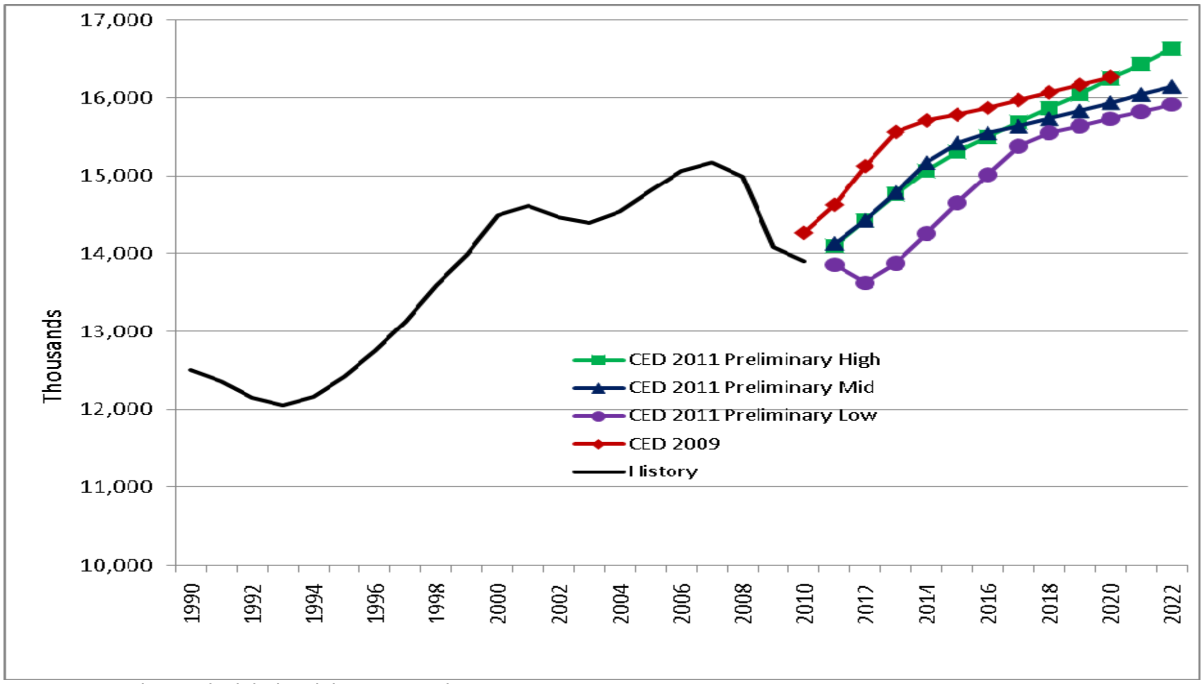
Economic projections were provided by Moody's Analytics and IHS Global Insight (April 2011). Moody's base case economic forecast was used for the mid energy scenario. For the low and high scenarios, staff selected Moody's *protracted slump* case and the Global Insight *optimistic* economic scenario. These two cases, in general, project the lowest and highest rates of economic growth, respectively, of the various scenarios provided by the two companies.[11]

Figure 1-6 and **Figure 1-7** compare projections for two key indicators used in the three scenarios, total statewide employment and statewide household personal income, respectively, with those used in *CED 2009*. Employment projections for the mid and low scenarios remain below corresponding *CED 2009* projections, with high case projections slightly above *CED 2009* by 2020. The economic forecasts reflect employment impacts from the recent recession more severe than projected for *CED 2009*. Employment in each of the three scenarios in 2010 is significantly below the 2010 projection for *CED 2009*, and remains lower through 2020 except in the high scenario. However, dollar output, reflected by projected statewide personal income in **Figure 1-7**, is more in line with 2009 short-term projections, with growth from 2010-2020 in all three scenarios higher than in *CED 2009*. Projected average annual growth in personal income between 2010 and 2020 is 3.76 percent, 3.45 percent, and 2.82 percent in the low, mid, and high scenarios, respectively, compared to 2.75 percent in *CED 2009*.

10 In terms of addressing these differences, for example, the income elasticity in the residential end use model could be reduced downward if staff determines this is warranted. For peak demand, it may be that weather-sensitive load shapes need to be revised for LADWP and PG&E, or that the econometric model needs to be re-estimated with more coefficients that are specific to these two planning areas.

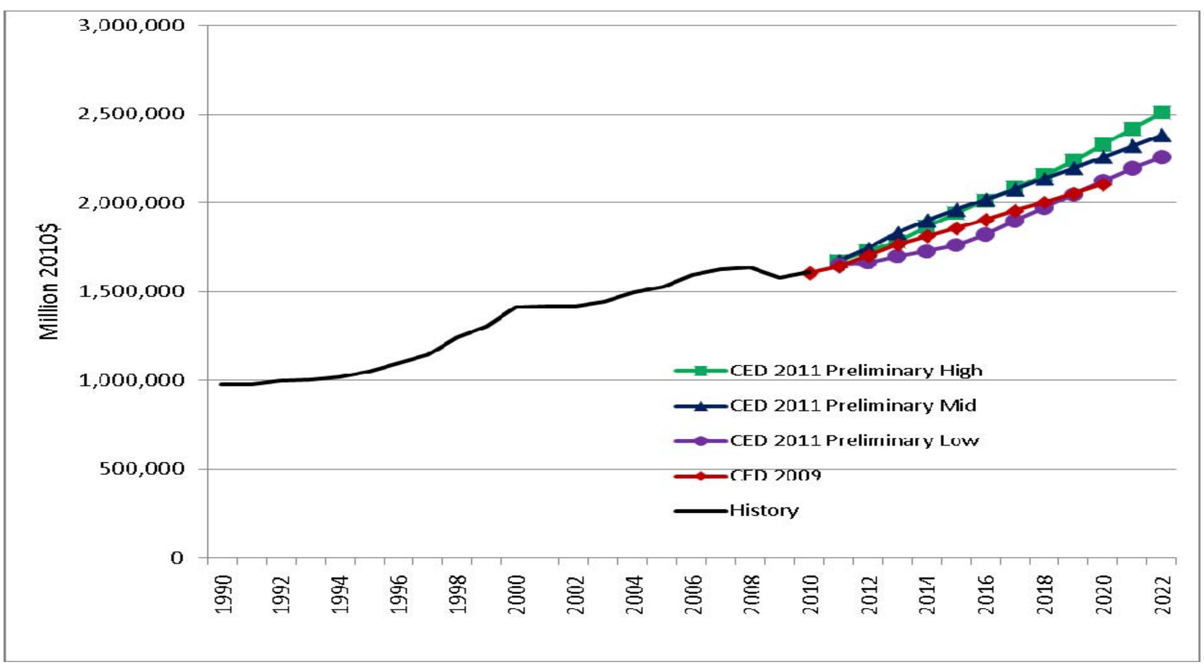
11 Moody's Analytics provides five scenarios and Global Insight three.

Figure 1-6: Statewide Employment Projections



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

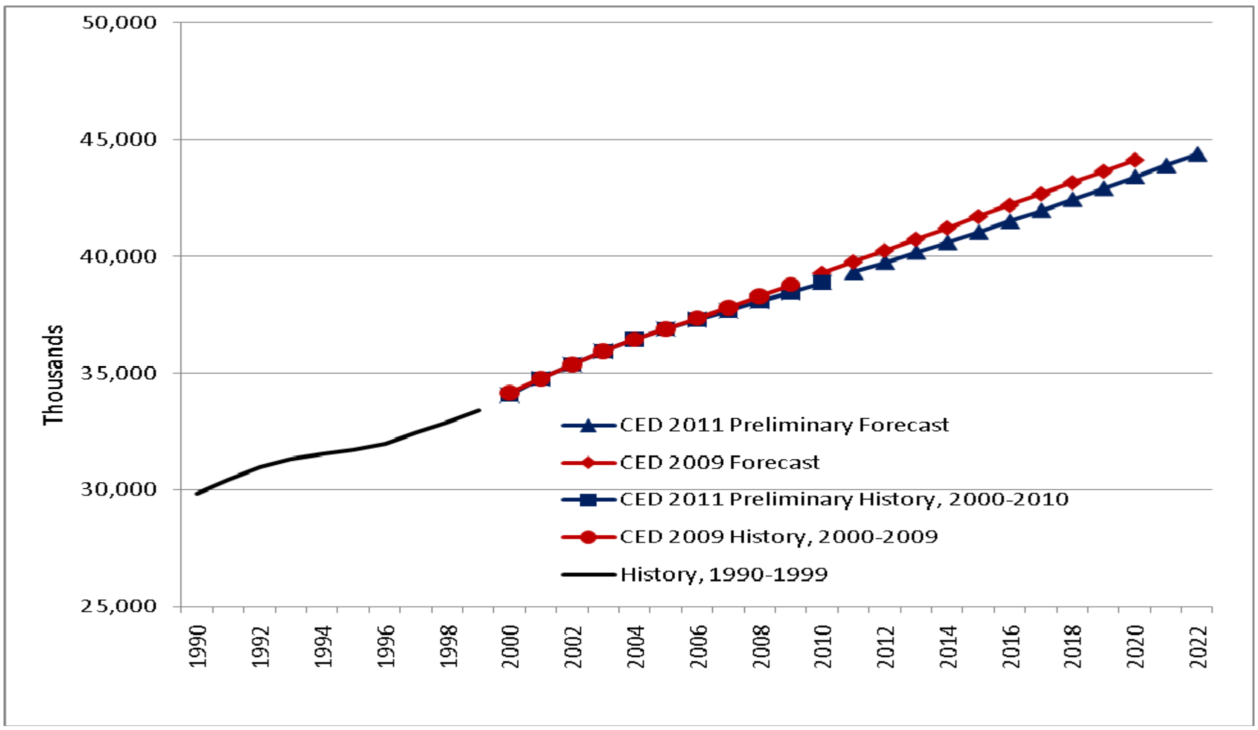
Figure 1-7: Statewide Household Personal Income Projections



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

Population growth is a key driver for residential energy consumption, as well as for commercial growth and consumption for water pumping and other services. Energy Commission demand forecasts typically use California Department of Finance (DOF) population projections. However, the DOF had not yet updated its population forecast to incorporate the 2010 census in time for this forecast. Therefore, staff used growth rates from the Moody's population forecast, which has been updated, applied to DOF historic estimates. As shown in **Figure 1-8**, this leads to a lower statewide population forecast compared to *CED 2009* (both DOF and Moody's provide only one population scenario).

Figure 1-8: Historic and Projected Total Statewide Population

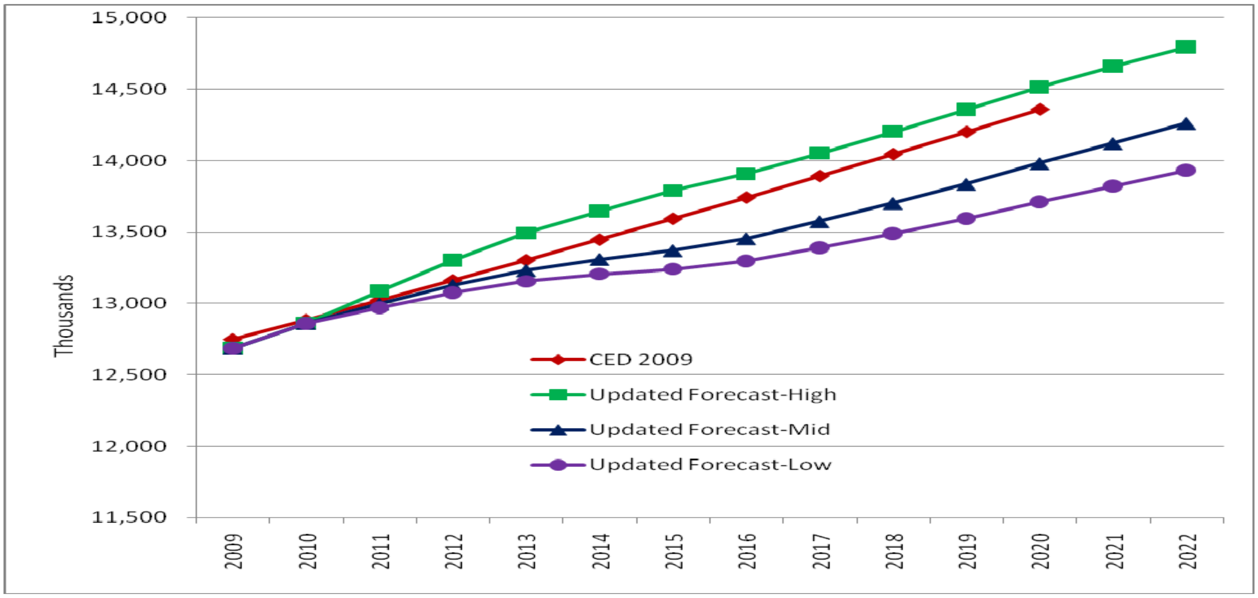


Sources: Moody's and California Department of Finance, 2009 and 2011

Scenario projections for number of households, shown in **Figure 1-9**, were developed by varying expected average persons per household. For the low demand case (higher persons per household), staff fit an exponential growth curve to historical persons per household for 2000-2010. The high case used Moody's projections.[12] The mid case assumed changes in persons per household halfway between the high and low. The decrease in persons per household for the high demand scenario is enough to result in a higher number of households compared to *CED 2009* throughout the forecast period, even with a lower population.

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

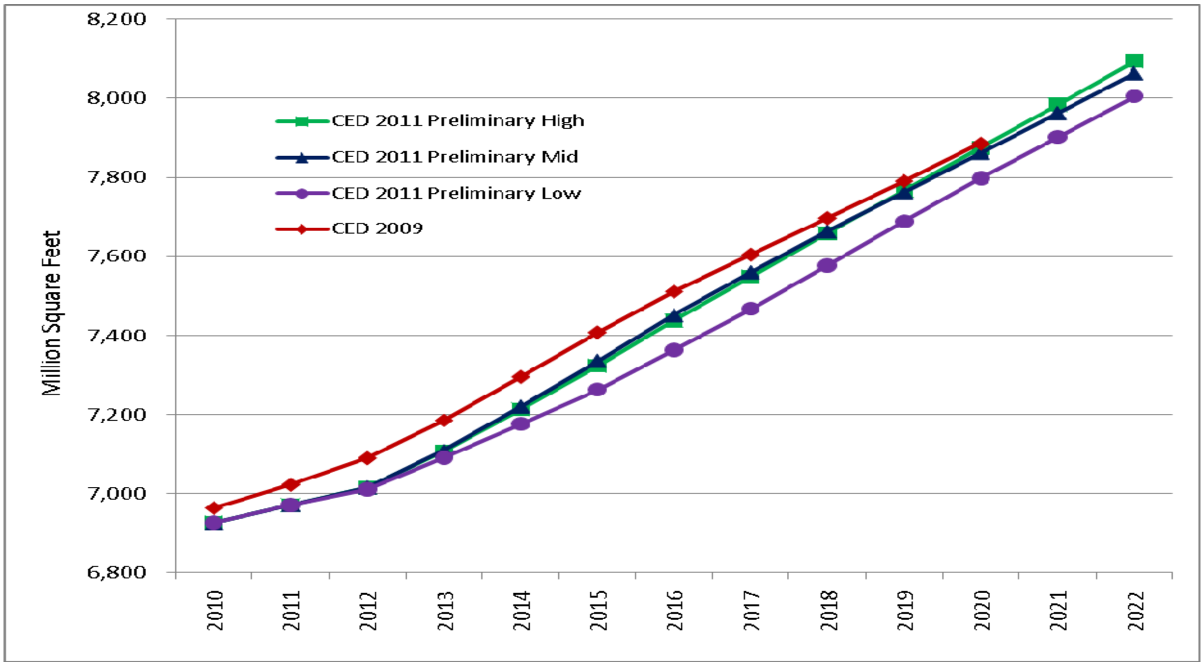
Figure 1-9: Forecasts for Number of Households, Statewide



Source: California Energy Commission, 2011

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

Figure 1-10: Projected Commercial Floor Space, Statewide



Source: California Energy Commission, 2011

Electricity and Natural Gas Rate Projections

Natural gas rates were projected using recent Henry Hub price forecasts from the Energy Information Administration (EIA) and Bentek, as well as Henry Hub futures prices. For the mid demand case, staff used the 2011 EIA *reference case* forecast, with the first three years (2011-2014) replaced by average current futures prices for these years. The low demand scenario used the EIA 2010[13] *no shale* natural gas price scenario, which assumes no further development of shale reserves beyond what is approved (and therefore higher prices). For the high demand scenario, staff used a first quarter 2011 forecast from Bentek[14] for 2011-2015, with 2016-2022 projections held constant at the 2015 level.

The electricity price forecasts were generated using the Energy and Environmental Economics (E3) calculator.[15] The E3 calculator allows users to create electricity price scenarios by inputting assumptions for efficiency savings, natural gas rates, amount of renewables, amount of combined heat and power, penetration of PV systems, level of demand response, and price regime (cap and trade). **Table 1-15** provides the assumptions used to generate rate growth for each of the three demand scenarios.

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13 The 2011 scenarios were not available in time for this forecast.

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

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

Table 1-15: Electricity Price Assumptions by Scenario

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

Source: California Energy Commission 2011

Resulting percentage growth by year for each scenario from the natural gas and electricity price forecasts was applied to current planning area rates, and are shown in **Table 1-16.** In the case of electricity, E3 provided projections for 2012-2020, so staff assumed 2010 rates for 2011 and extrapolated rates for 2021 and 2022 using average growth rates for 2015-2020. Staff used the E3-projected state average for percentage growth for each planning area, except in the case of 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 that resulting LADWP rates remained at least 10 percent lower those of SCE.[16] Resulting rate projections for each of the five major planning areas are provided in the forms accompanying this report.

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

Table 1-16: Growth in Energy Rates, *CED 2011 Preliminary* Forecast

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

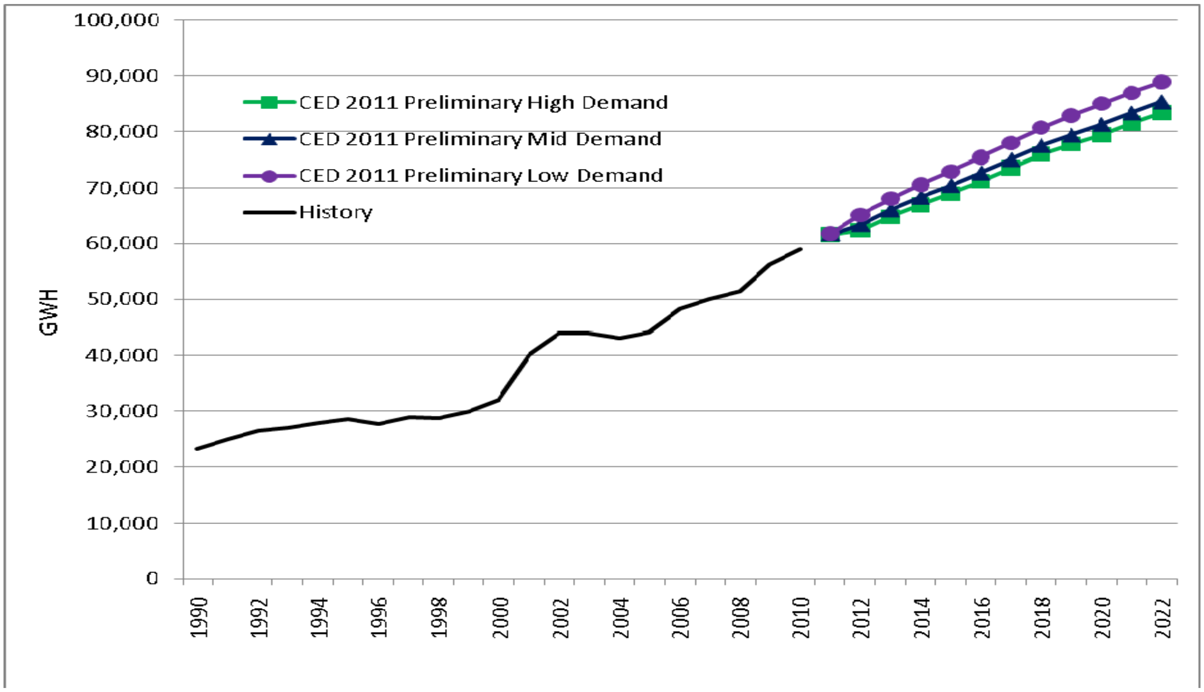
Source: California Energy Commission 2011

Conservation/Efficiency Impacts

Energy Commission demand forecasts seek to account for efficiency and conservation *reasonably expected to occur*. Since the 1985 *Electricity Report*, reasonably expected to occur initiatives are split into two types: committed and uncommitted. *CED 2011 Preliminary* continues that distinction. Committed initiatives include utility and public agency programs, codes and standards, and legislation and ordinances that have final authorization, firm funding, and a design that can be readily translated into characteristics that can be evaluated and used to estimate future impacts (for example, a package of IOU incentive programs that has been funded by CPUC order). In addition, committed impacts include price and other effects not directly related to a specific initiative. Chapter 8 gives details regarding the committed energy efficiency impacts projected for this forecast. This chapter also presents incremental savings estimates for a set of uncommitted efficiency initiatives and shows the effect on the forecast of including these impacts.

Figure 1-11 shows staff estimates of historic and projected committed savings impacts, which include programs, codes and standards (including AB 1109 lighting savings), 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.

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



Source: California Energy Commission, 2011

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. Dispatchable programs, such as direct control, interruptible tariffs, or demand bidding programs, have triggering conditions that are not under the control of and cannot be anticipated by the customer. Energy or peak load saved from dispatchable programs is treated as a resource, and therefore not accounted for in the demand forecast. Nondispatchable 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 nondispatchable programs should be included in the demand forecast.

At this time, all of the existing demand response programs have some form of triggering condition. Although the utility or California ISO may not have direct control, the customer only has the opportunity to participate in the program when the program operator has called an event, either because of high market prices or resource scarcity. Therefore, in this forecast, no demand response impacts are counted on the demand side.

Self-Generation

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

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

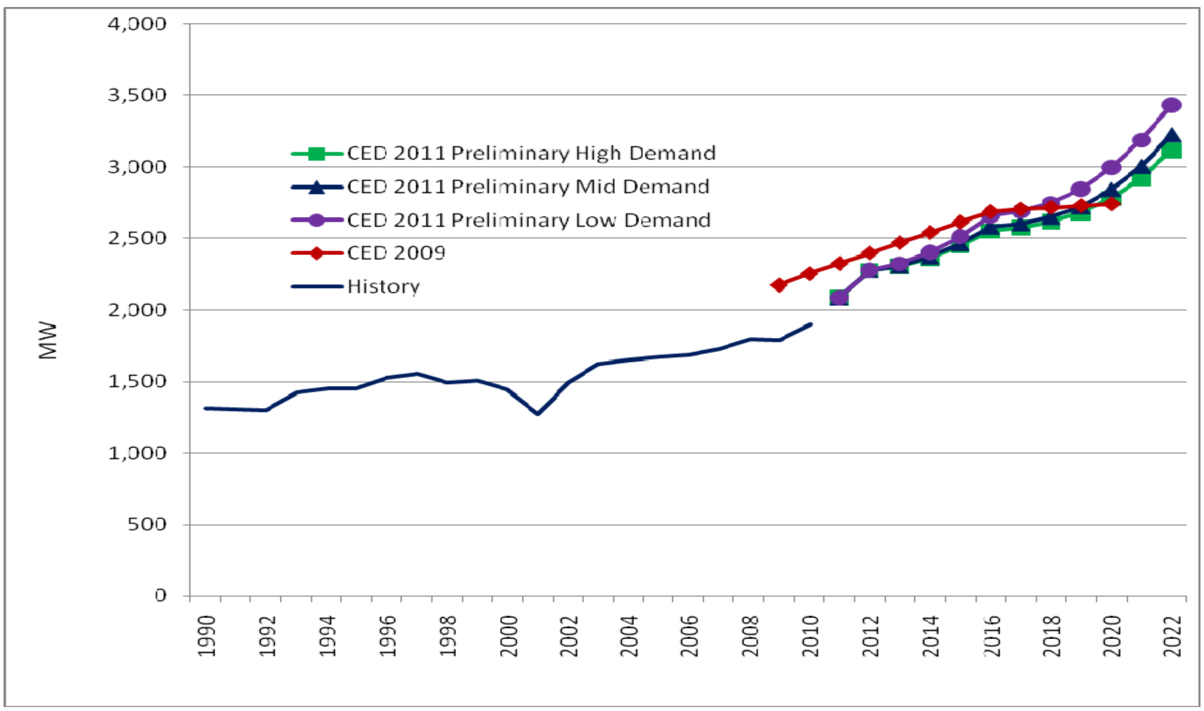
The forecast also accounts for power plants reporting information to the Energy Commission. The principal source is Form CEC 1304 and staff only included power plants that explicitly listed themselves as operating under cogeneration or self-generation mode.

The general strategy of the ERP, CSI, SGIP, and NSHP programs is to encourage demand for self-generation technologies, such as PV (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 and solar water heating adoption are forecast using a predictive model recently developed by staff, which is based on estimated payback periods and cost-effectiveness, determined by up-front 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 that of lower growth in households. Self-generation for other technologies and sectors is projected using a trend analysis and does not vary by demand scenarios. The Appendix provides details on these methods.

Figure 1-12 shows historic and projected peak impacts of self-generation, which are projected to reduce peak load by over 3,000 MW by 2022 in all three demand scenarios. Historic impacts were revised downward because some self-generation data was misclassified, so *CED 2009* projections began well above current estimates of historic impacts. Higher projections for PV peak impacts (shown in **Figure 1-13)** in both the residential and commercial sectors drive total self-generation peak above *CED 2009* levels by 2020 in all three scenarios, as.[17] The temporary flattening of the curve after 2016 corresponds to expiration of the CSI program and the federal tax credit. Most of the difference in PV peak comes from a significant increase in residential adoption, a result from application of the predictive model. **Figure 1-14** shows projected PV peak impacts in the residential sector. Staff is currently working on a commercial PV predictive model, so future *IEPR* forecasts could show a similar increase in commercial adoption if this model projects adoptions above current trends, as in the residential case. The predictive model also projects residential electricity consumption statewide from solar water heating to reach 250 GWh and 285 GWh in the high and low demand cases, respectively, by 2022.[18]

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

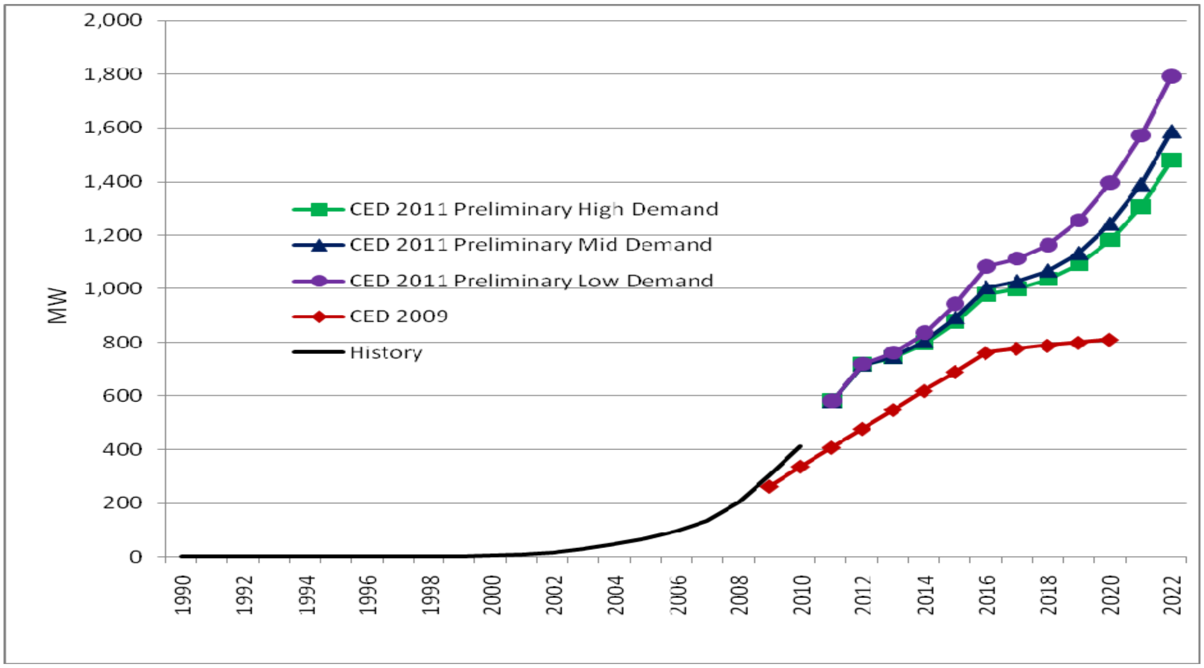


Source: California Energy Commission, 2011

17 In 2015, projected PV peak impacts correspond to capacities of 1,671 MW, 1,699 MW, and 1,789 MW in the high, mid, and low demand cases, respectively. By 2022, capacities reach 2,904 MW, 3,095 MW, and 3,471 MW.

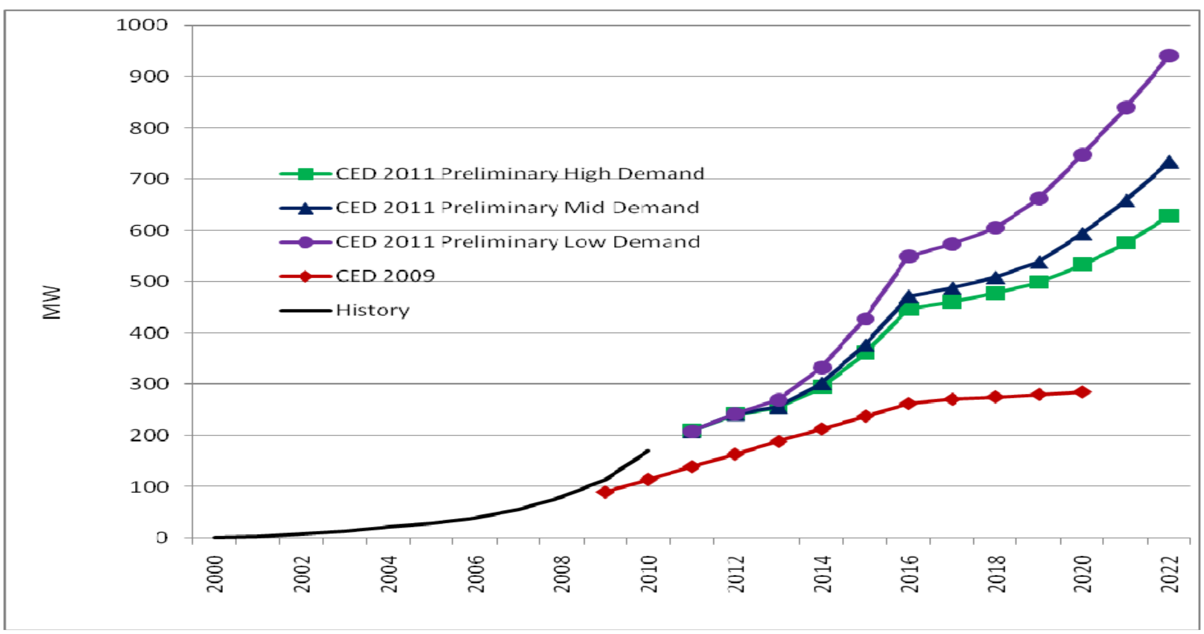
18 Note that "peak impacts" cannot be defined for this technology.

Figure 1-13: Statewide Peak Impacts of PV Systems



Source: California Energy Commission, 2011

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



Source: California Energy Commission, 2011

Table 1-7 shows historic and projected statewide electricity consumption from self-generation, broken out into PV and non-PV applications. For traditional combined heat and power (CHP) technologies, self-generation is assumed constant, so that retired CHP plants are replaced with new ones with no net change in generation. Given the recent attention to CHP, staff will develop scenarios for this technology for the revised forecast. Growth in non-PV self-generation comes mainly from historical growth in engines and recent increases in the application of fuel cells projected forward.

Table 1-7: Electricity Consumption from Self-Generation, GWh

	1990	2000	2010	2015	2020	2022
Non-PV Self-Generation, Low Demand	8,242	9,179	9,651	10,366	10,852	11,065
Non-PV Self-Generation, Mid Demand	8,258	9,205	9,652	10,615	10,829	11,040
Non-PV Self-Generation, High Demand	8,258	9,205	9,652	10,613	10,823	11,029
PV, Low Demand	3	10	1,110	3,063	4,691	6,060
PV, Mid Demand	3	10	1,110	2,874	4,118	5,290
PV, High Demand	3	10	1,110	2,817	3,894	4,896
Total Self-Generation, Low Demand	8,245	9,189	10,761	13,429	15,543	17,125
Total Self-Generation, Mid Demand	8,245	9,189	10,761	13,488	14,945	16,329
Total Self-Generation, High Demand	8,245	9,189	10,761	13,429	14,716	15,924

Source: California Energy Commission, 2011

Electric Vehicles

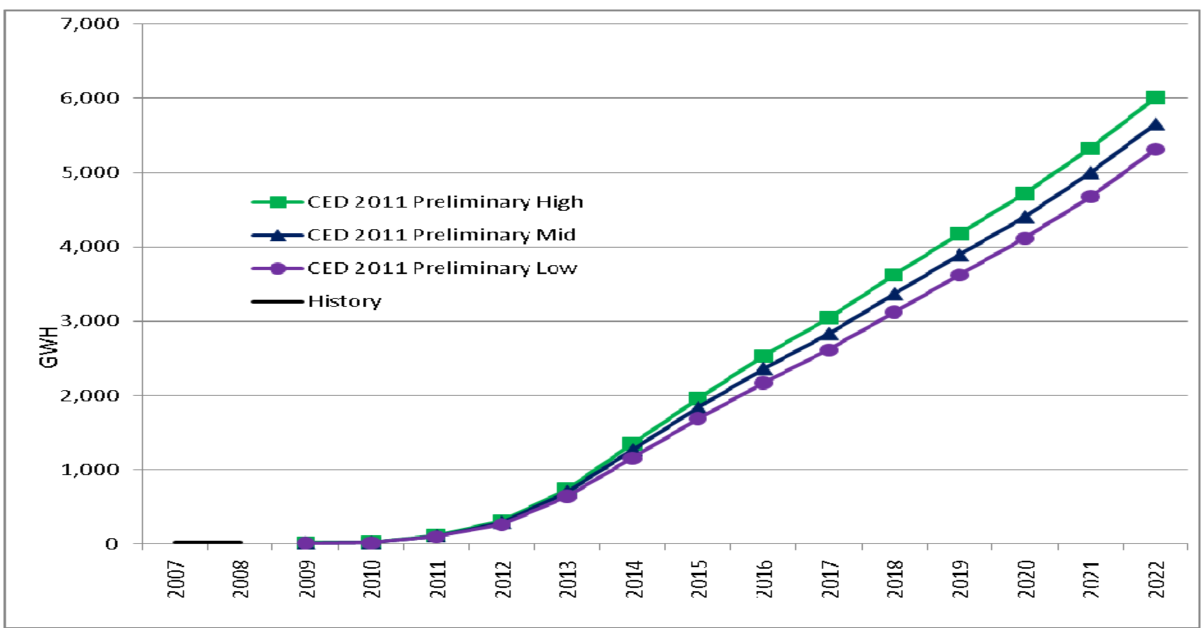
CED 2011 Preliminary incorporates a forecast for electricity consumption from light-duty electric vehicles (EVs), including both dedicated EVs and plug-in hybrids, provided by the

Energy Commission's Fuels Office.[19] As this report was being prepared, the Fuel's Office had not yet completed a forecast for the *2011 IEPR*. Therefore, *CED 2011 Preliminary* uses the EV forecast generated for the *2009 IEPR*. The revised version of this forecast will incorporate a more recent EV forecast.

In order to develop a plausible range for alternative fuel vehicle demand, the Fuels Office ran two scenarios in 2009: a "high gasoline price, low alternative fuel price" case and a "low gasoline price, high alternative fuel price" case. *CED 2009* used the average of these two scenarios for electric vehicles; *CED 2011 Preliminary* uses the first scenario in the high demand case and the second in the low case. The mid case uses the same average used in 2009.

Figure 1-15 shows projected statewide electricity consumption for EVs for all three scenarios, which reaches around 5,300 GWh by 2020 in the low case and 6,000 GWh in the high scenario. Forecasts for the five major planning areas are provided in Chapters 2-6 of this report. A critical assumption made in the EV forecast is that plug-in hybrids operate half of the time (during city driving) using the electric motor, with the gasoline motor engaged for higher speed travel.

Figure 1-15: Statewide Electric Vehicle Consumption

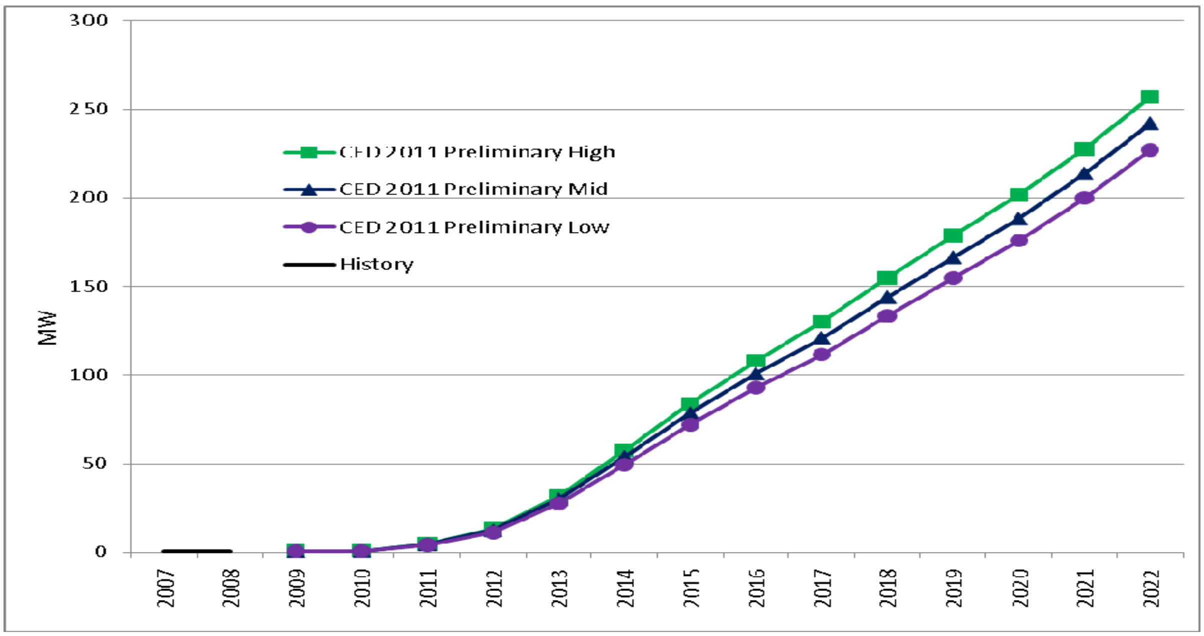


Source: California Energy Commission, 2011

19 Details of the electric vehicle forecast are provided in *Transportation Energy Forecasts and Analyses for the 2009 Integrated Energy Policy Report, Final Staff Report*, available at http://www.energy.ca.gov/2009publications/CEC-600-2009-012/

To translate consumption to peak demand, as in *CED 2009*, staff assumed that 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.[20] This recharging profile assumes some form of favored off-peak pricing for electric vehicle owners by utilities. **Figure 1-16** shows the projected EV contribution to statewide non-coincident peak. Peak impacts are relatively small compared to consumption because of recharging assumptions, and EVs provide a slight increase to the statewide load factor.

Figure 1-16: Statewide Electric Vehicle Peak Demand



Source: California Energy Commission, 2011

Historic Electricity Consumption Estimates

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

The quality of the QFER data continues to be undermined by LSE data coding errors, lack of adherence to regulations by some LSE's, and failure to provide economic classification for

20This is consistent with "reference case" assumptions made in a recent Electric Power Research Institute study, *Environmental Assessment of Plug-in Hybrid Electric Vehicles, Volume 1: Nationwide Greenhouse Gas Emissions*, Electric Power Research Institute, July 2007.

some of the data. However, unclassified consumption has declined significantly in recent year. From a high of almost 20,000 GWh in 2003, unclassified energy use dropped to less than 6,000 GWh in 2010 as economic classification is provided for direct access customers, per current reporting requirements. Staff allocated unclassified consumption to economic sectors using professional judgment, relying on factors such as unrealistic changes in historic consumption.

Structure of Report

Chapters 2-6 provide *CED 2011 Preliminary* electricity forecasts for the following planning areas: Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), SMUD, and LADWP, in that order. The planning areas included in this forecast are described in **Table 1-8**. Chapter 7 provides statewide results for the end-user natural gas forecast, along with results for the PG&E, Southern California Gas Company, and SDG&E distribution areas. Chapter 8 presents energy efficiency and conservation savings estimated for the forecast. This chapter also presents *incremental* savings estimates for a set of uncommitted efficiency initiatives and shows the effect on the forecast of including these impacts. The Appendix provides additional information about adjustments to existing models, incorporation of climate change, and self-generation.

Table 1-8: Utilities within Forecasting Areas

Planning Area	Utilities Included	
Electric Areas		
Pacific Gas and Electric (PG&E)	PG&E Alameda Biggs Calaveras Gridley Healdsburg Lassen MUD Lodi Lompoc Merced Modesto Palo Alto	Plumas – Sierra Port of Stockton PWRPA Redding Roseville San Francisco Shasta Silicon Valley Tuolumne Turlock Irrigation District Ukiah USBR-CVP
Sacramento Municipal Utility District (SMUD)	SMUD	
Southern California Edison (SCE)	Anaheim Anza Azusa Banning Bear Valley Colton MWD	Ranch Cucamonga Riverside Southern California Edison USBR-Parker Davis Valley Electric Vernon Victorville
Los Angeles Department of Water and Power (LADWP)	LADWP	
San Diego Gas & Electric (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 Electric Planning Area, SMUD	
SDG&E	SDG&E	
Southern California Gas Company (SCG)	SCG, Long Beach	
OTHER	Avista Energy, Southwest Gas Corporation	

Source: California Energy Commission, 2011

CHAPTER 2: Pacific Gas and Electric Planning Area

The Pacific Gas and Electric (PG&E) planning area includes:

- PG&E bundled retail customers.
- Customers served by energy service providers (ESPs) using the PG&E distribution system to deliver electricity to end users.
- Customers of publicly owned utilities and irrigation districts in PG&E's transmission system, with the exception of SMUD. SMUD is treated as its own planning area as discussed in a later chapter.

For purposes of this chapter, the PG&E planning area forecast includes other members of the SMUD control area, which are not in the SMUD service area. These entities include Roseville, Redding, and the Western Area Power Administration (WAPA).

To support electricity and transmission system analysis, staff uses historic consumption and load data to develop individual forecasts for all medium and large utilities in the planning area. Those results are presented in Forms 1.5a through 1.5c in the statewide forms accompanying this forecast report. The results in this chapter are for the entire PG&E transmission planning area.

This chapter is organized as follows. First, forecasted consumption and peak loads for the PG&E planning area are discussed; both total and per capita values are presented. The *CED 2011 Preliminary* values are compared to the adopted *CED 2009* forecast, with differences between the two forecasts explained. The forecasted load factor, jointly determined by the consumption and peak load estimates, is also discussed. Second, the chapter presents sector consumption and peak load forecasts. The residential, commercial, industrial, and "other" sector forecasts are compared to those in *CED 2009*, and differences between the two are discussed. Third, the chapter discusses the forecasts of electric vehicles, self generation, and the impacts of conservation and efficiency programs.

Planning Area Results

For this forecast, three demand scenarios were developed. The high demand scenario included high economic and demographic projections, low energy price projections and low efficiency impact assumptions. The low demand scenario included low economic and demographic projections, high energy price projections and high efficiency impact assumptions. Chapter 1 provides more detail on the construction of the demand scenarios.

Table 2-1 presents a comparison of the *CED 2011 Preliminary* high, mid and low demand scenarios with *CED 2009* for electricity consumption and peak demand for selected years.

In the PG&E planning area, the mid-term *CED 2011 Preliminary* forecasts for all three scenarios are lower than the *CED 2009* forecast. This trend also continues for both the mid and low demand forecasts throughout the remainder of the forecast period. Only the high demand case is higher than the *CED 2009* forecast at the end of the forecast period. This is caused by the recent economic downturn resulting in 2010 estimated consumption being about 2 percent lower than the *CED 2009* forecast. The 2011-2020 forecast growth rate for the *CED 2011 Preliminary* mid demand case is similar to the *CED 2009* forecast.

The difference in peak forecasts is similar to the difference in consumption forecasts, with the mid-term *CED 2011 Preliminary* peak forecast scenarios all being lower than the *CED 2009* forecast. By the end of the forecast period, only the high demand peak forecast is at the level of the *CED 2009* forecast. Both the low and mid demand scenarios remain below the *CED 2009* forecast throughout the forecast period. The smaller reduction in peak compared to consumption forecasts is caused by a greater reduction in non-weather sensitive end-uses which have little impact on peak (e.g. residential lighting).

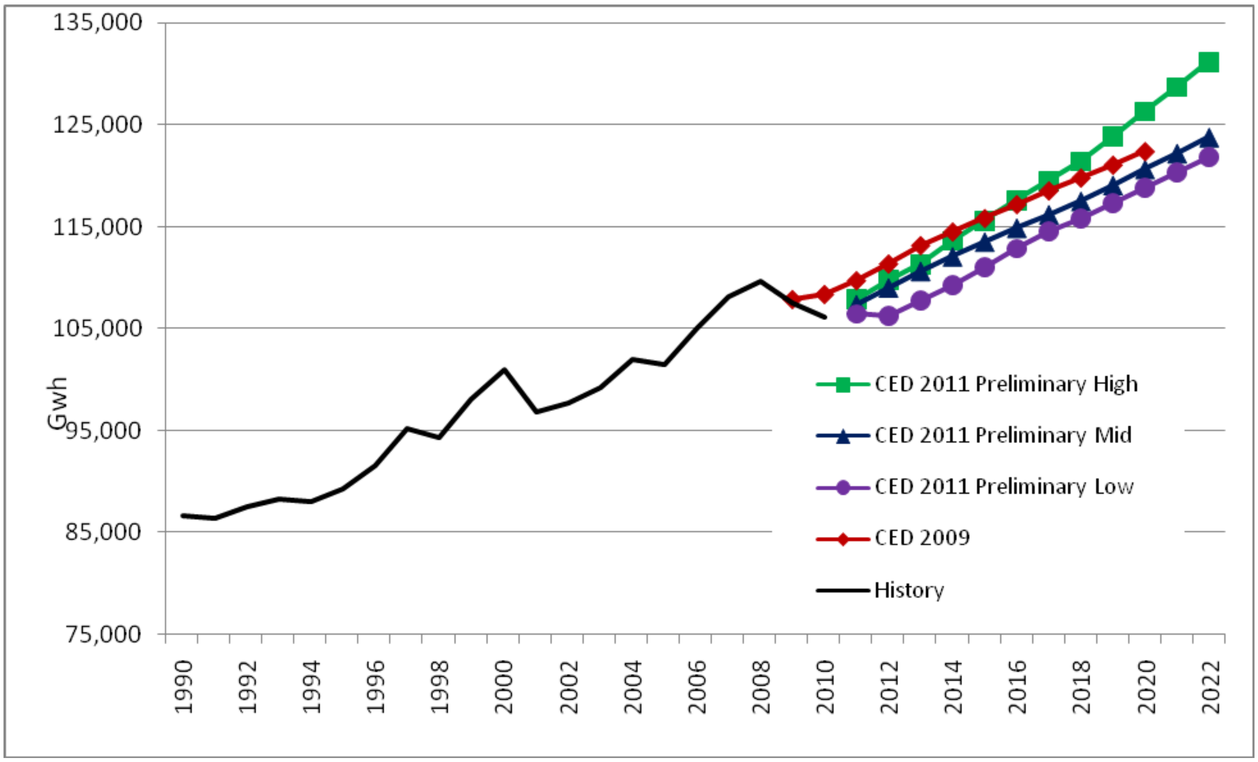
Table 2-1: PG&E Planning Area Forecast Comparison

Consumption (GWH)				
	CED 2009 (Dec. 2009)	*CED 2011* Preliminary-High	*CED 2011* Preliminary-Mid	*CED 2011* Preliminary-Low
1990	86,803	86,597	86,597	86,597
2000	101,333	100,969	100,969	100,969
2010	108,344	106,119	106,119	106,119
2011	109,703	107,914	107,369	106,489
2015	115,828	115,634	113,520	111,008
2020	122,414	126,352	120,669	118,820
2022	--	131,191	123,804	121,839
Average Annual Growth Rates				
1990-2000	1.56%	1.55%	1.55%	1.55%
2000-2010	0.67%	0.50%	0.50%	0.50%
2011-2015	1.37%	1.74%	1.40%	1.04%
2011-2020	1.23%	1.77%	1.31%	1.22%
2011-2022	--	1.79%	1.30%	1.23%
Peak (MW)				
	CED 2009 (Dec. 2009)	*CED 2011* Preliminary-High	*CED 2011* Preliminary-Mid	*CED 2011* Preliminary-Low
1990	17,250	17,250	17,250	17,250
2000	20,628	20,628	20,628	20,628
2010	23,479	22,922	22,922	22,922
2011	23,810	23,236	23,151	22,973
2015	25,193	24,779	24,402	23,832
2020	26,877	26,887	25,831	25,334
2022	--	27,729	26,313	25,734
	Average Annual Growth Rates			
1990-2000	1.80%	1.80%	1.80%	1.80%
2000-2010	1.30%	1.06%	1.06%	1.06%
2011-2015	1.42%	1.62%	1.32%	0.92%
2011-2020	1.36%	1.63%	1.22%	1.09%
2011-2022	--	1.62%	1.17%	1.04%
Historical values are shaded				

Source: California Energy Commission, 2011

As shown in **Figure 2-1**, *CED 2011 Preliminary* electricity consumption mid and low demand scenario forecasts for the PG&E planning area are lower over the entire forecast period compared to *CED 2009*. The high demand scenario is also lower through the first half of the forecast period before increasing to a level above *CED 2009*.

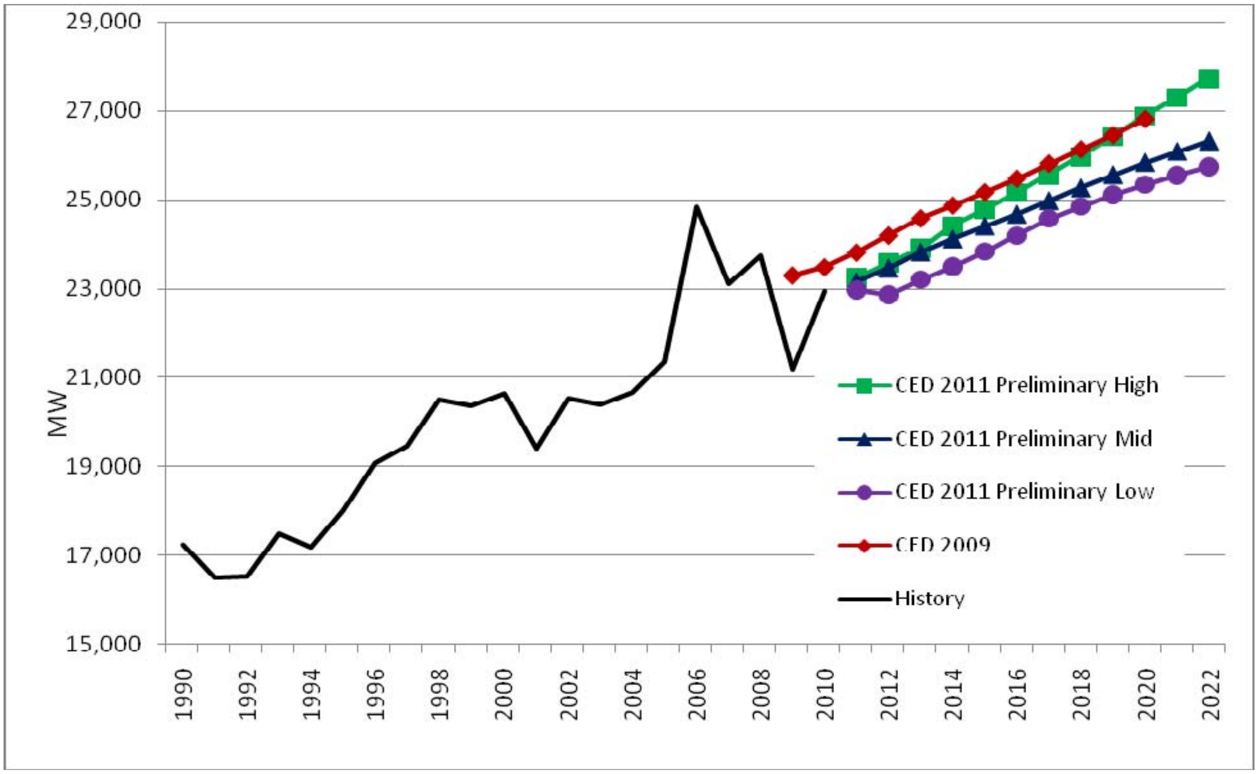
Figure 2-1: PG&E Planning Area Electricity Forecast



Source: California Energy Commission, 2011

The *CED 2011 Preliminary* PG&E planning area peak demand forecasts, shown in **Figure 2-2**, are also lower over the entire forecast period than *CED 2009* with the exception of the high demand scenario, which reaches the *CED 2009* forecast level by the end of the forecast period. The decrease in the peak forecasts are somewhat less than the corresponding energy forecast because a significant portion of the energy reductions come from end uses that do not have as great an impact on peak, such as increased lighting efficiency.

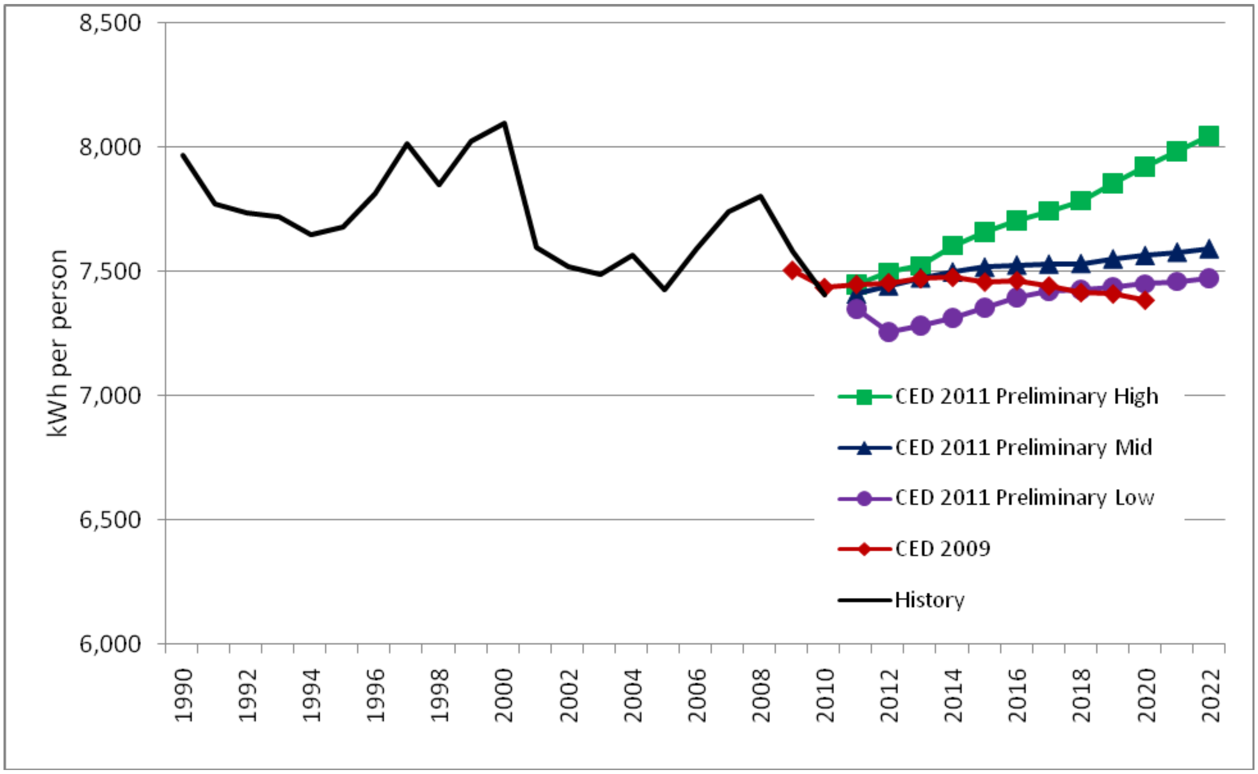
Figure 2-2: PG&E Planning Area Peak



Source: California Energy Commission, 2011

Figure 2-3 provides a comparison of *CED 2011 Preliminary* and *CED 2009* per capita electricity consumption. Forecasts for all three demand scenarios are higher than *CED 2009* by 2020. Per capita consumption increases over the forecast period in the mid and high demand scenarios as opposed to a decline in *CED 2009*. This is caused partly by a higher rate of income growth in all three scenarios versus *CED 2009*. In the low demand scenario, there is a reduction in near-term levels caused by lower economic and demographic projections as well as near term increases in efficiency program savings.

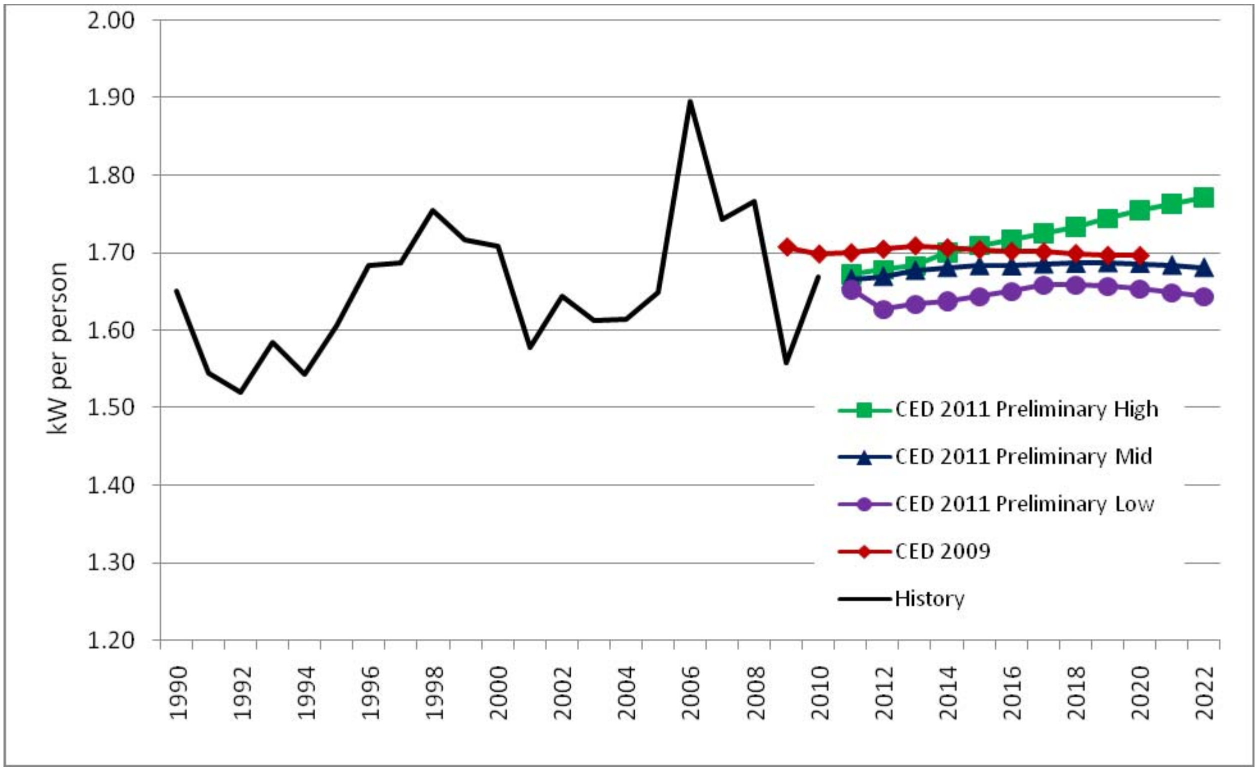
Figure 2-3: PG&E Planning Area Per Capita Electricity Consumption



Source: California Energy Commission, 2011

In contrast, per capita peak demand, shown in **Figure 2-4**, is relatively constant over the forecast period. This difference is partly caused by the assumption that electric vehicles will be charged off peak. *CED 2011 Preliminary* projected levels of per capita peak are estimated to be at a level similar to the mid-to late-1990s, prior to the energy crisis.

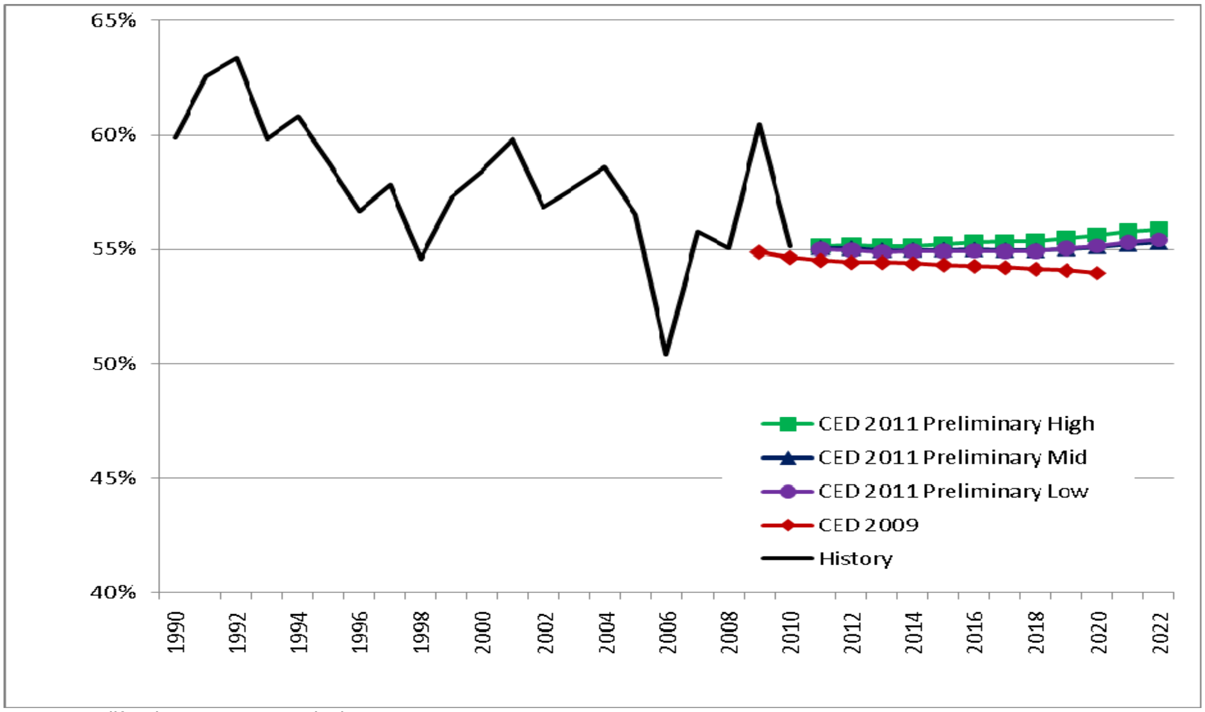
Figure 2-4: PG&E Planning Area per Capita Peak Demand



Source: California Energy Commission, 2011

Figure 2-5 provides a comparison of forecast load factors. The load factor is a measure of the increase in peak demand relative to annual electricity consumption. Lower load factors indicate "a needle peak"; higher load factors indicate a more stable load. Historical data show a long-term downward trend as consumption shifted away from the industrial sector toward residential and commercial use. Further, more population and economic growth in the PG&E planning area has been taking place in hotter inland areas, leading to greater saturation of central air conditioning. In addition, recent years have seen a greater use of air conditioning equipment in the cooler Bay Area on warm days. *CED 2011 Preliminary* projected load factors are relatively constant over the forecast period and slightly higher than the *CED 2009* forecast.

Figure 2-5: PG&E Planning Area Load Factors



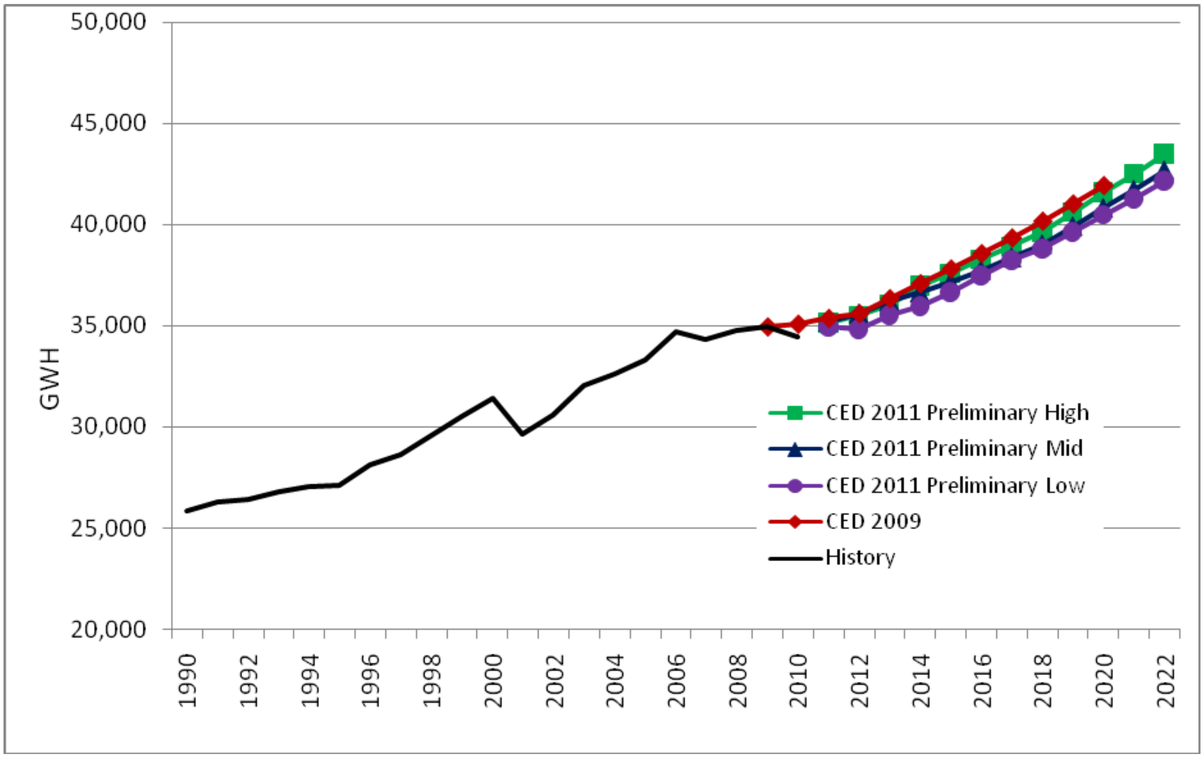
Source: California Energy Commission, 2011

Sector Level Results and Input Assumptions

Residential Sector

Figure 2-6 provides a comparison between *CED 2011 Preliminary* and *CED 2009* PG&E planning area residential forecasts. All three *CED 2011 Preliminary* forecast scenarios are lower at the end of the forecast period mainly because of lowered household projections. There is little difference between the low and high demand cases in the residential forecast because of similar income growth.

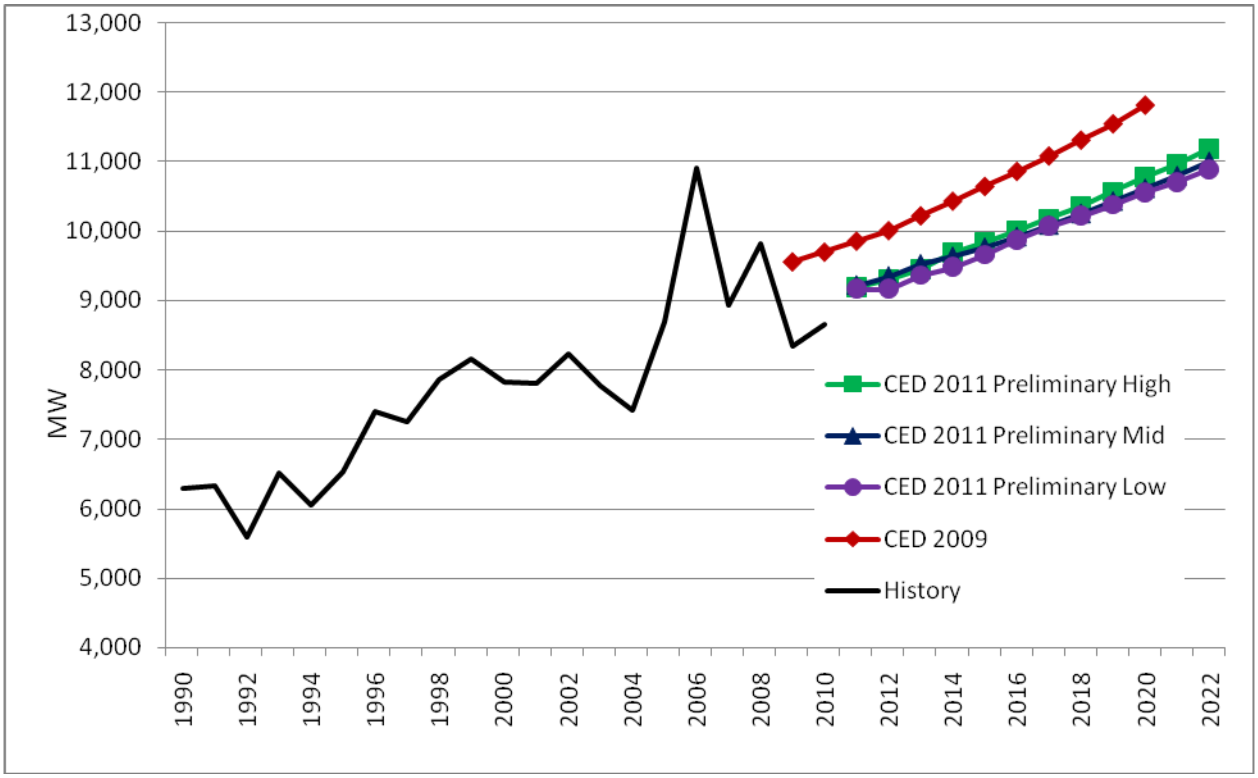
Figure 2-6: PG&E Planning Area Residential Consumption



Source: California Energy Commission, 2011

Figure 2-7 provides a comparison of *CED 2011 Preliminary* and *CED 2009* residential peak demand forecasts. The *CED 2011 Preliminary* residential peak forecasts are lower than the *CED 2009* forecast because of lower estimated residential historic peaks in 2009 and 2010. The growth rates for the *CED 2011 Preliminary* scenarios are similar to *CED 2009*.

Figure 2-7: PG&E Planning Area Residential Peak

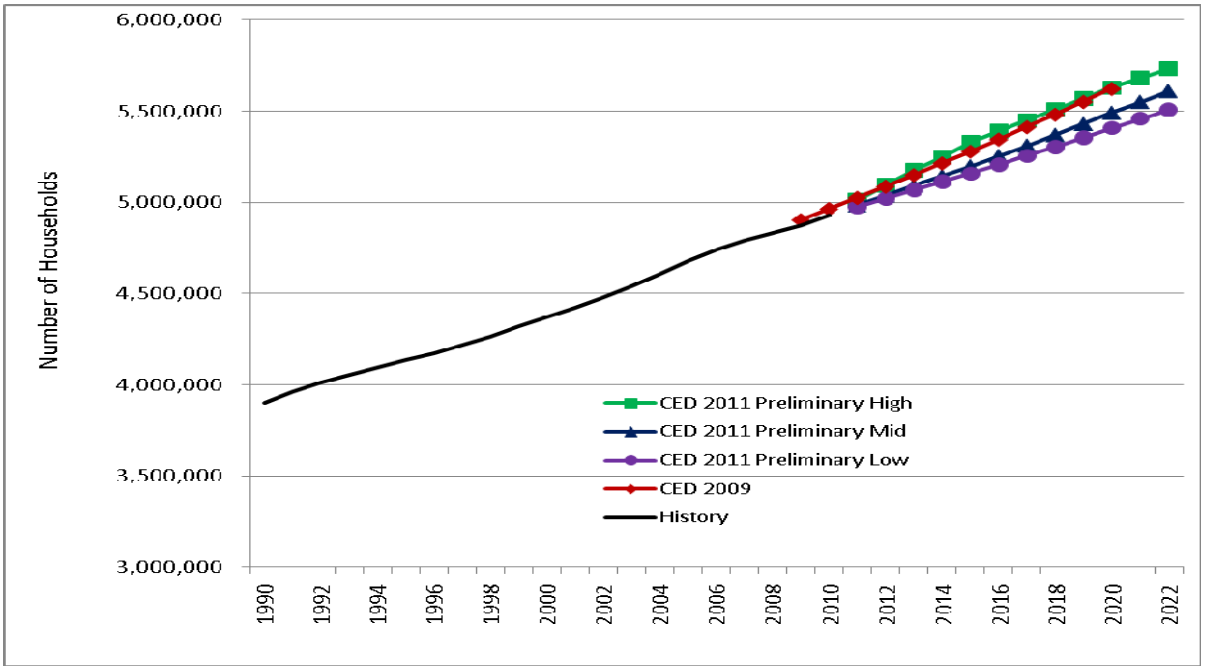


Source: California Energy Commission, 2011

Figure 2-8, **Figure 2-9**, and **Figure 2-10** provide comparisons of the residential drivers used in *CED 2011 Preliminary* forecast with those used for *CED 2009*.

Figure 2-8 provides comparisons of total households. The *CED 2011 Preliminary* forecast mid and low demand scenarios are lower than the previous forecast because of a slightly lower total population forecast resulting from updates to 2009 and 2010 population estimates at the county level. The *CED 2011 Preliminary* forecast does not include the most recent updated county population forecast from the California Department of Finance (DOF), which incorporates information from the 2010 census. The updated population forecast will be included in the revised demand forecast.

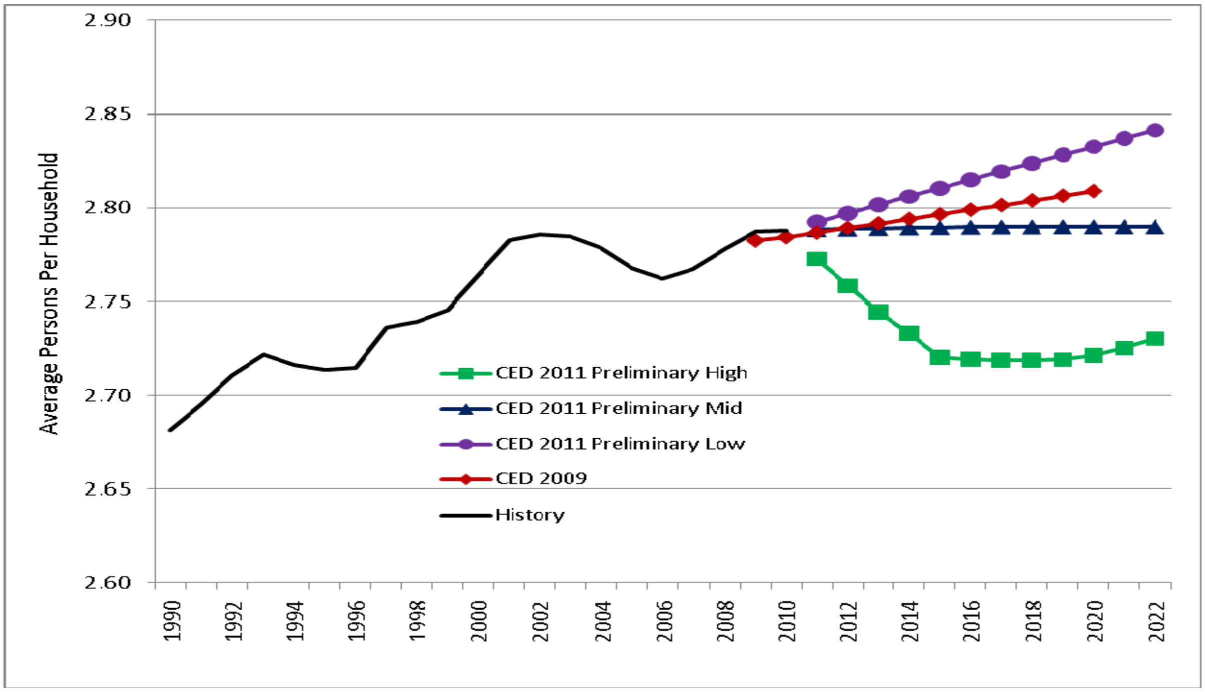
Figure 2-8: PG&E Planning Area Residential Household Projections



Source: California Energy Commission, 2011

The household scenarios are based on persons per household changes shown in **Figure 2-9**. The high demand scenario uses a lower person per household projection (more households) and the low demand scenario uses a higher persons per household projection (less households). See Chapter 1 for a discussion of assumptions driving these projections. The mid demand scenario uses a relatively constant projection for persons per household. All three scenarios use the same household population forecast.

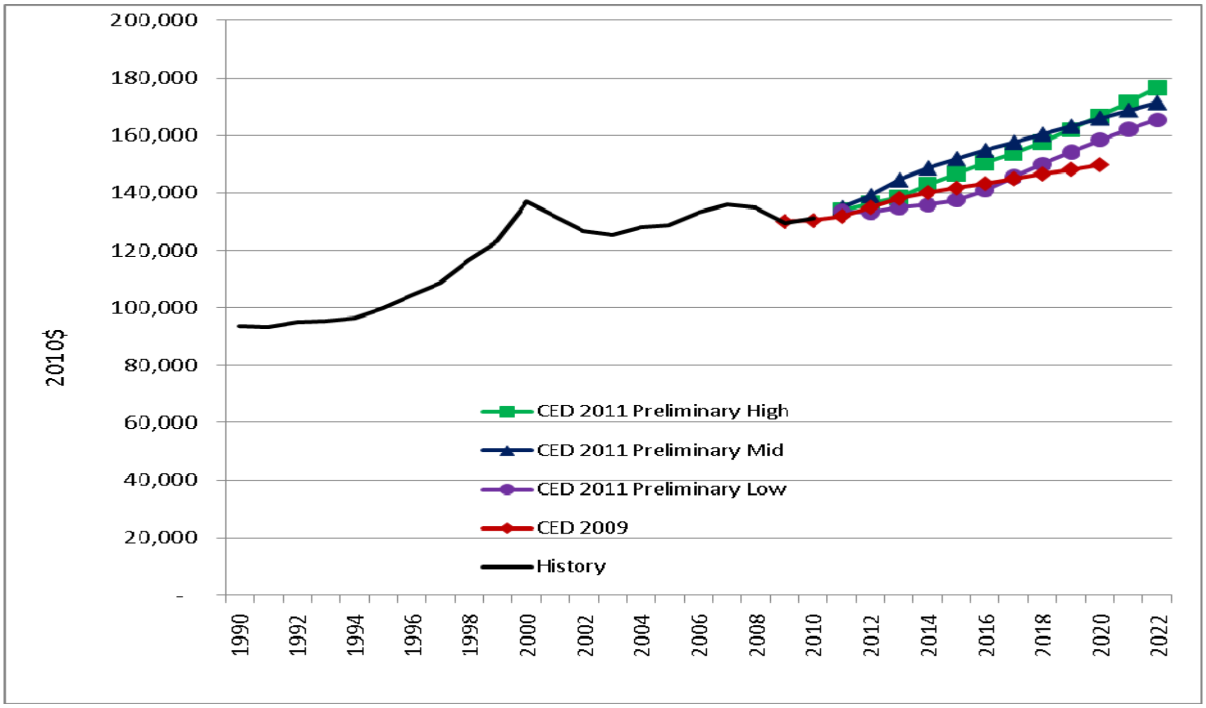
Figure 2-9: PG&E Planning Area Persons per Household Projections



Source: California Energy Commission, 2011

Figure 2-10 provides a comparison of average household income (per capita income multiplied by persons per household) between the two forecasts. *CED 2011 Preliminary* estimates of household income are higher at the end of the forecast period than *CED 2009*. This caused higher growth projections for personal income than were used in the previous forecast. The difference between scenarios is a function of the variation in per capita income and persons per household used to define the scenarios.

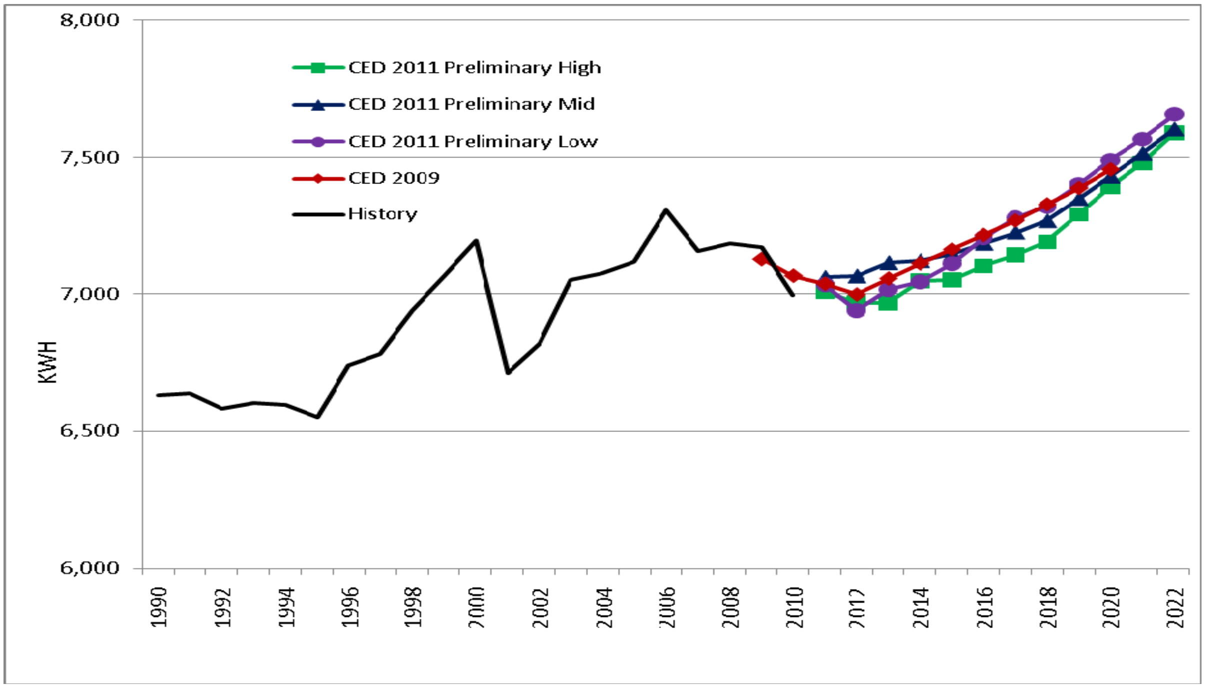
Figure 2-10: PG&E Planning Area Average Household Income Projections



Source: California Energy Commission, 2011

Figure 2-11 gives a comparison of annual electricity consumption per household. *CED 2011 Preliminary* forecasts are similar *CED 2009*. The mid demand scenario is slightly higher in the near term and slightly lower in the long-term than the *CED 2009* forecast. This caused by differences in the underlying economic and demographic assumptions. Most of the growth in use per household after 2015 caused increased numbers of electric vehicles in the residential sector. This adds about 370 kWh per household to the residential total by 2022 in the PG&E planning area. Without the inclusion of electric vehicle charging, residential use would be relatively constant over the forecast period.

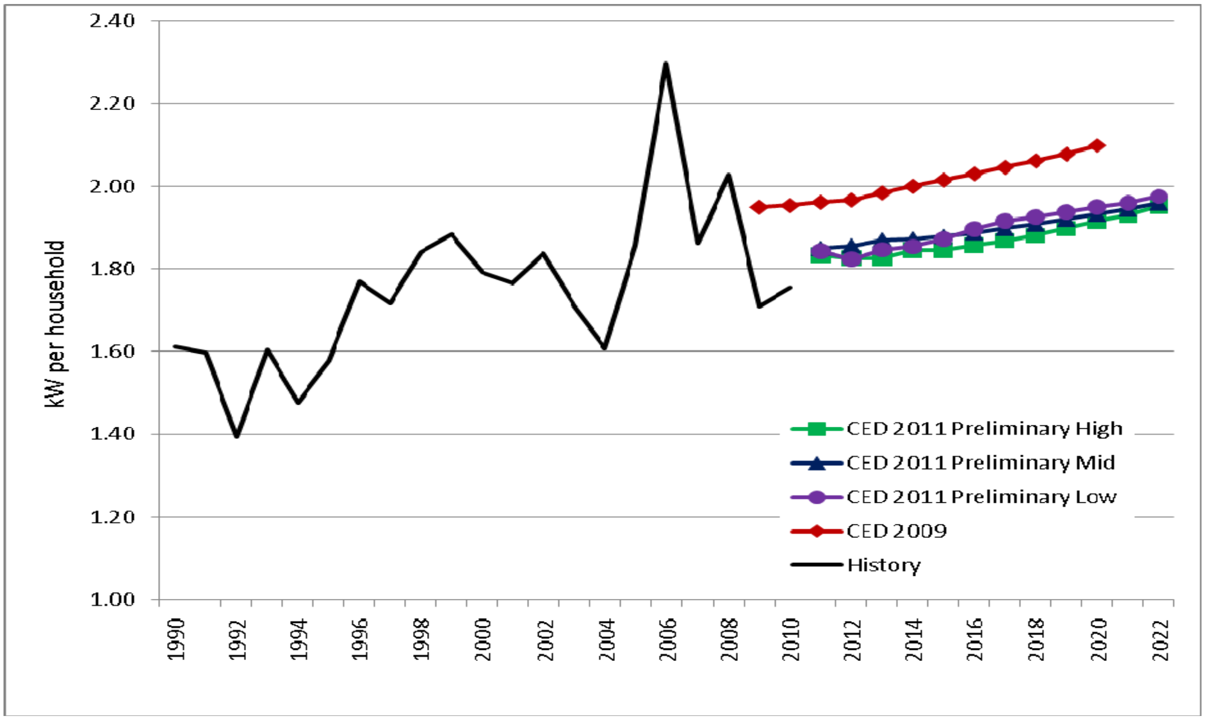
Figure 2-11: PG&E Planning Area Consumption per Household



Source: California Energy Commission, 2011

Figure 2-12 presents a comparison of peak use per household. The *CED 2011 Preliminary* forecast of peak use per household is projected to increase only slightly over the forecast period in a pattern similar to that in the *CED 2009* forecast, although at a lower level. The decrease in level is caused by lower recent historic estimates of residential peak.

Figure 2-12: PG&E Planning Area Peak Use per Household



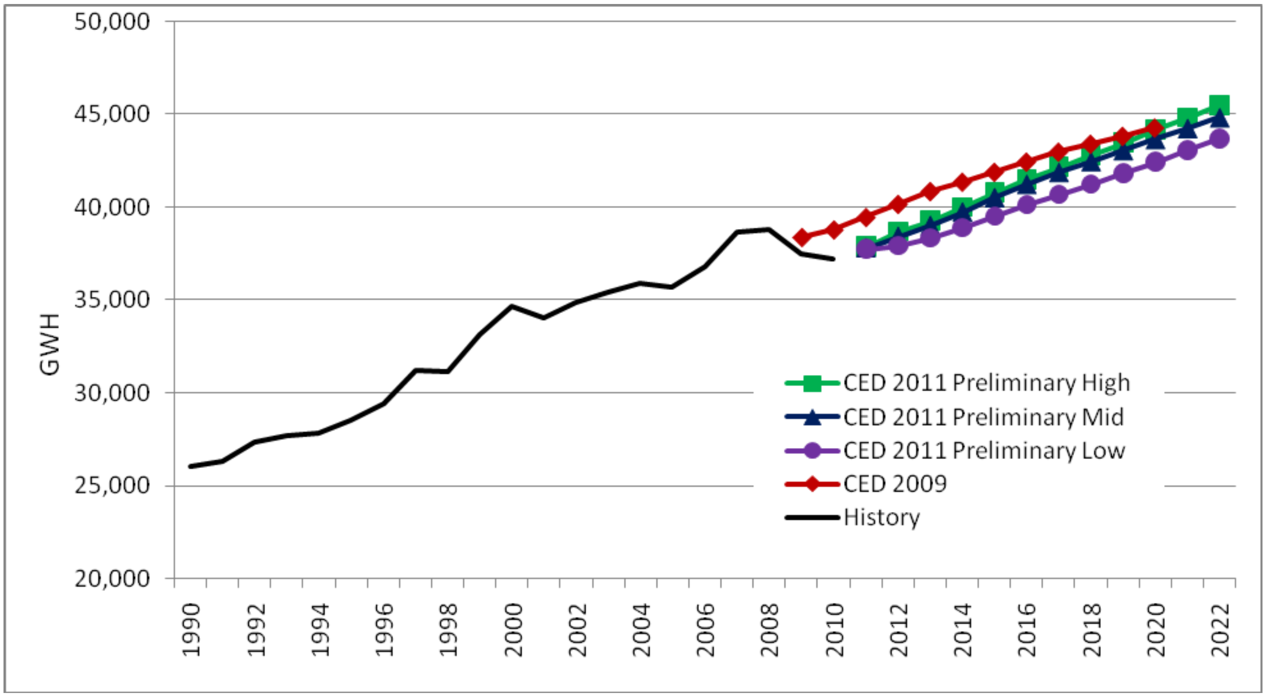
Source: California Energy Commission, 2011

Commercial Sector

Figure 2-13 provides a comparison of the commercial sector forecasts. *CED 2011 Preliminary* mid and low demand scenarios are lower throughout the entire forecast period than *CED 2009*. The high demand scenario is lower than the *CED 2009* forecast until the end of the forecast period. These differences are primarily caused by a lower starting point as a result of lower estimates of recent historic commercial floor space. The growth rate of commercial consumption is slightly higher in all three demand scenarios than in *CED 2009* because of higher projections for floor space growth.

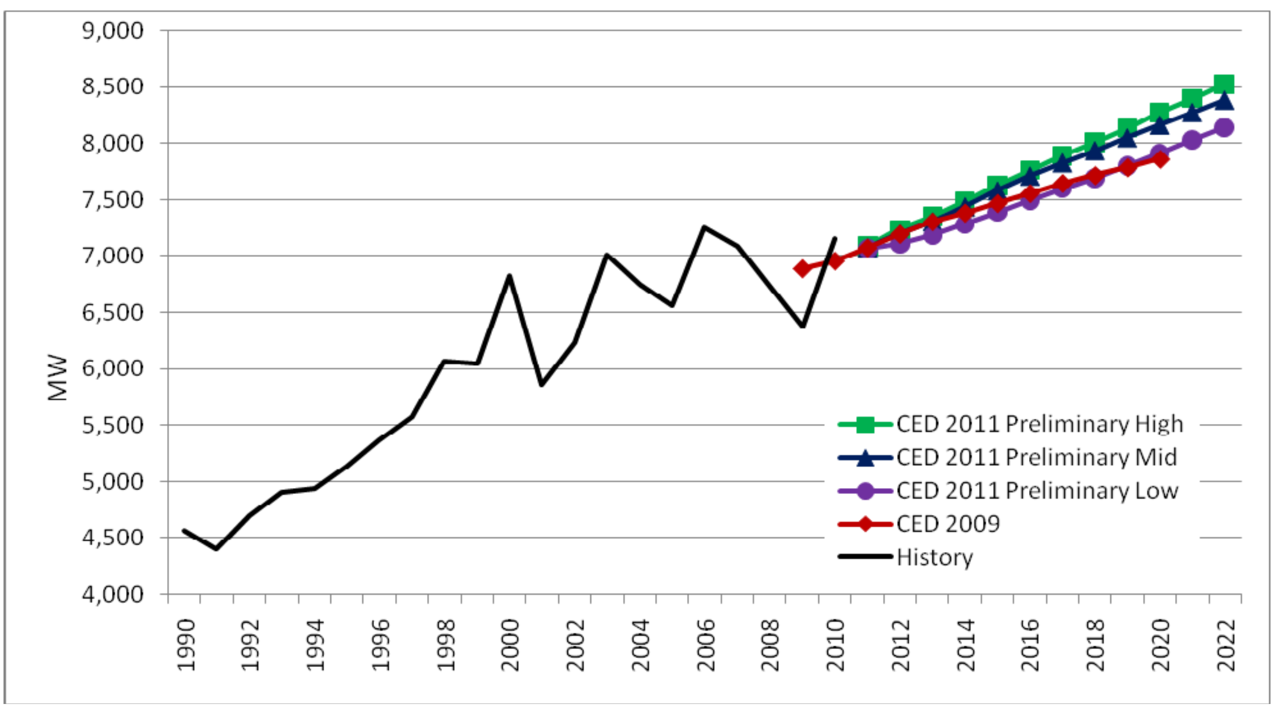
Figure 2-14 provides a comparison of the commercial peak demand forecasts. Growth in both forecasts is driven by the underlying electricity consumption forecast, which exhibits the same pattern. The *CED 2011 Preliminary* forecast mid and high demand scenarios produce a higher peak forecast because of higher growth in floor space.

Figure 2-13: PG&E Planning Area Commercial Consumption



Source: California Energy Commission, 2011

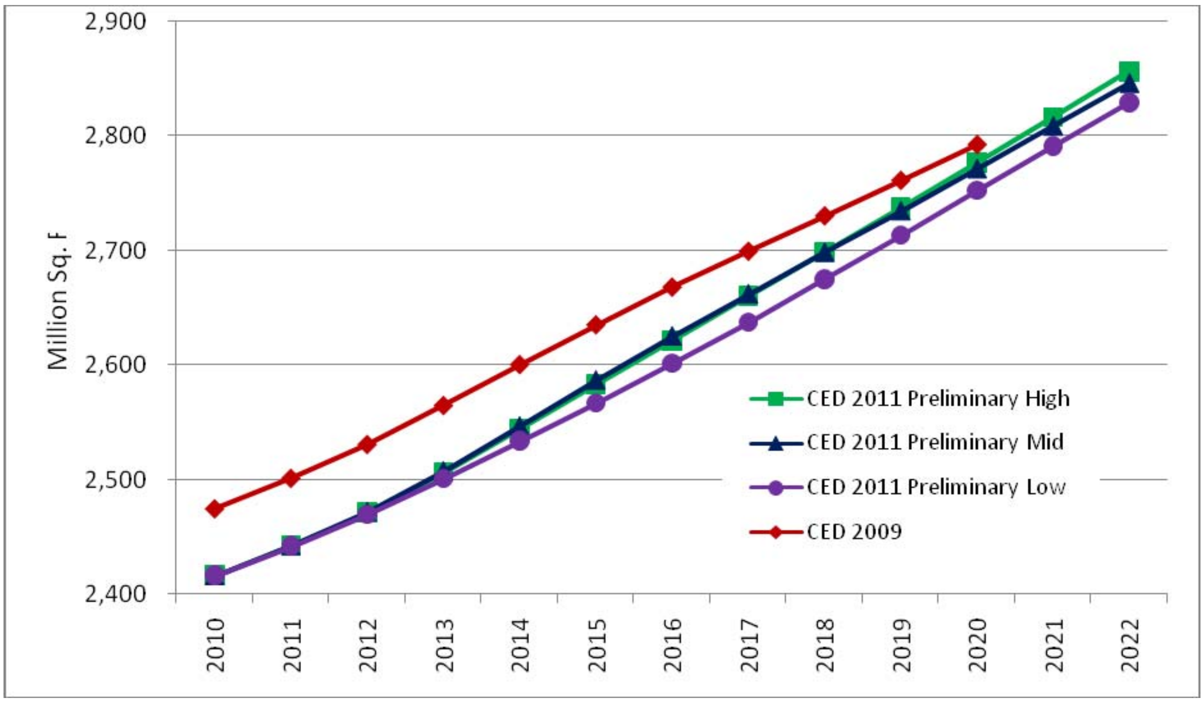
Figure 2-14: PG&E Planning Area Commercial Sector Peak



Source: California Energy Commission, 2011

In staff's commercial building sector forecasting model, floor space by building type, such as retail, offices, and schools, is the key driver. **Figure 2-15** provides a comparison of total commercial floor space projections. *CED 2011 Preliminary* floor space projections are somewhat lower over the forecast period than those used in the previous forecast because of a lower starting point. However, the growth rate of each of the three *CED 2011 Preliminary* scenarios is higher than in *CED 2009*.

Figure 2-15: PG&E Planning Area Commercial Floor Space

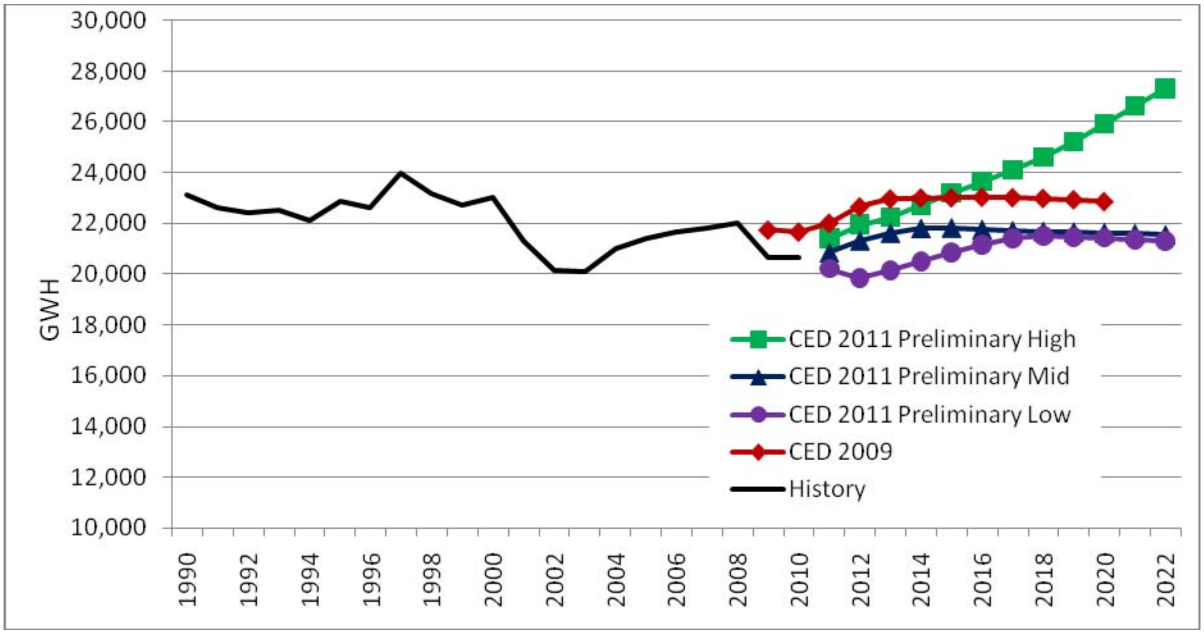


Source: California Energy Commission, 2011

Industrial Sector

Figure 2-16 provides comparisons of the PG&E planning area industrial sector electricity consumption forecasts. *CED 2011 Preliminary* industrial consumption forecasts are all lower than the *CED 2009* forecast in the short-term because of recent economic developments. However, the projected growth in the *CED 2011 Preliminary* forecast high demand case is higher in the longer term than was projected in the *CED 2009* forecast because of more optimistic economic projections. The mid demand scenario follows the same growth pattern as the *CED 2009* forecast but starts from a lower historic starting point. The differences in demand scenarios are mainly driven by differences in economic output projections.

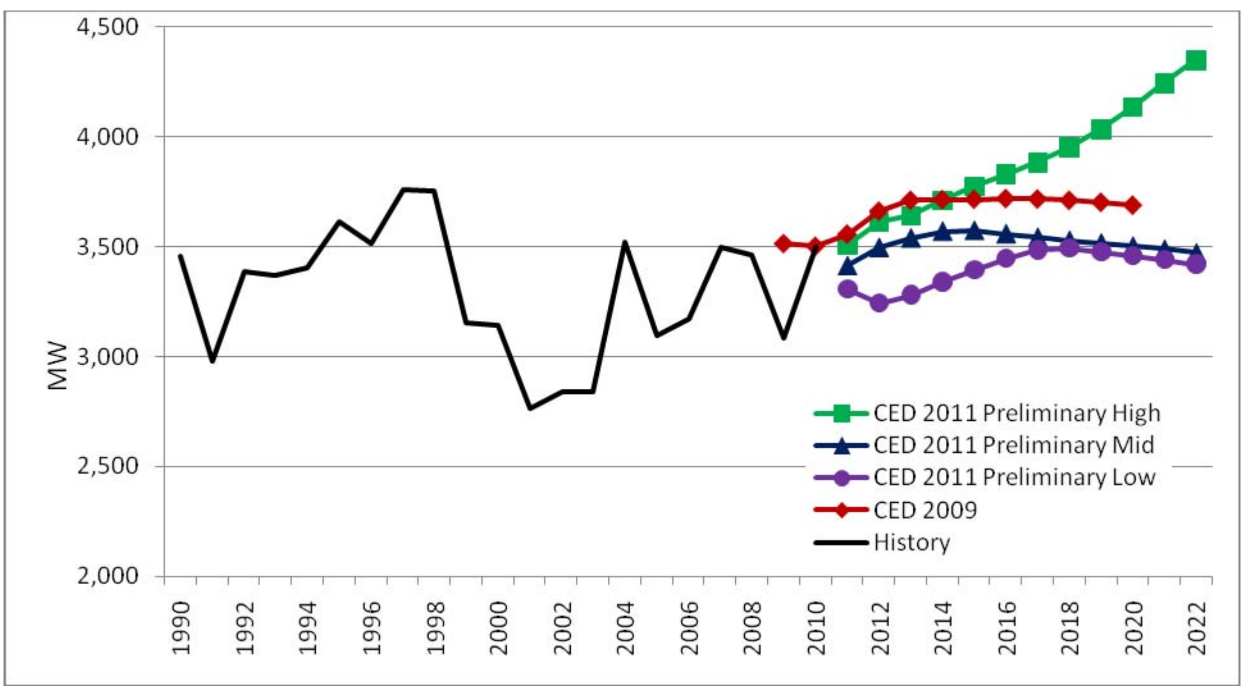
Figure 2-16: PG&E Planning Area Industrial Consumption



Source: California Energy Commission, 2011

Figure 2-17 provides a comparison of the industrial sector peak forecasts. The *CED 2011 Preliminary* industrial peak forecasts follow the same pattern as the consumption forecasts.

Figure 2-17: PG&E Planning Area Industrial Sector Peak

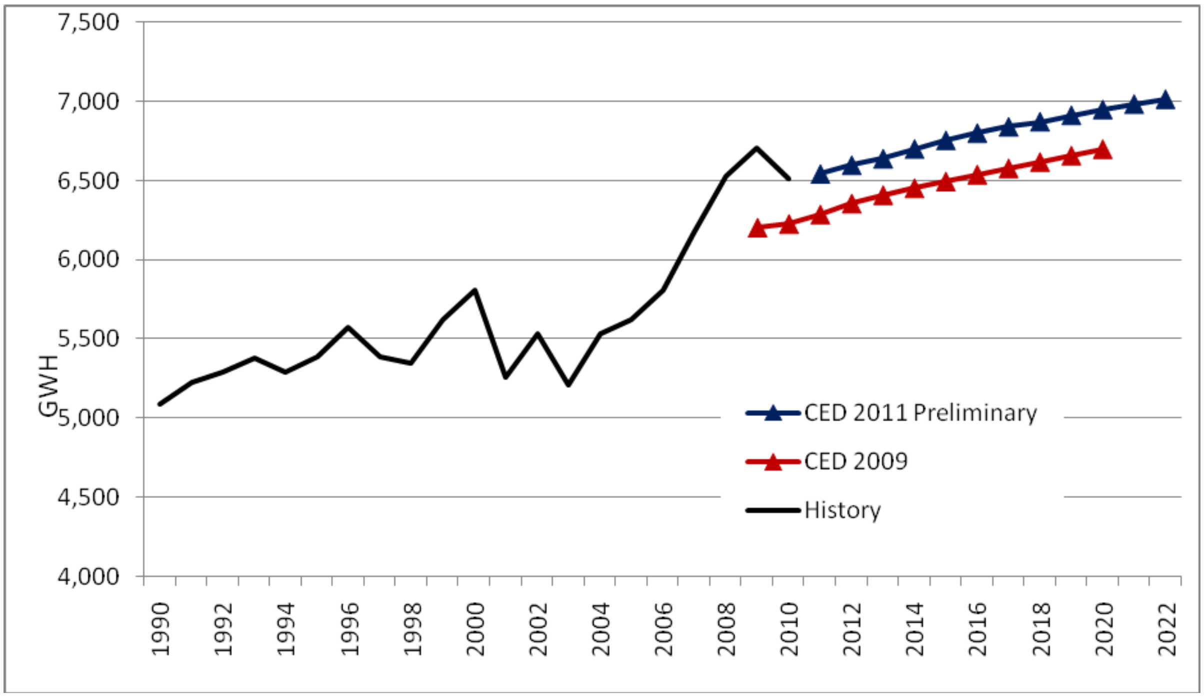


Source: California Energy Commission, 2011

Other Sectors

Figure 2-18 provides a comparison of the electricity consumption forecasts for the TCU sector, which includes street lighting. In this case, a single scenario was run.[21] *CED 2011 Preliminary* is higher than *CED 2009* given the higher starting point, a result of assigning previously unclassified consumption to this sector based on recent QFER filings.

Figure 2-18: PG&E Planning Area Transportation, Communication, Utilities and Street lighting Sector Electricity Forecasts

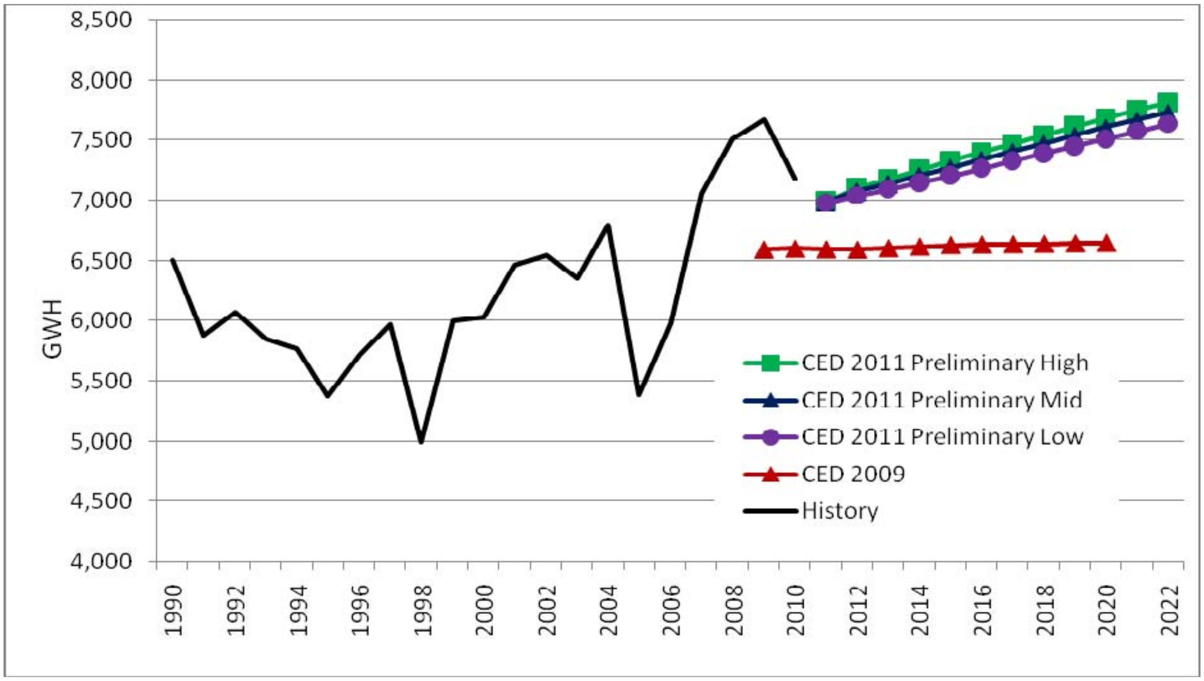


Source: California Energy Commission, 2011

Figure 2-19 provides a comparison of the electricity consumption forecasts for the agriculture and water pumping sectors. The *CED 2011 Preliminary* agriculture and water pumping forecasts are higher than *CED 2009* because of a higher starting point. All three demand scenarios are projected to grow slightly over time rather than remain flat as projected in the *CED 2009* forecast. This caused a projected increase in ground water pumping. The small difference in consumption between the *CED 2011 Preliminary* demand scenarios is a result of different household projections for urban water pumping and agricultural pumping rates in the PG&E planning area.

[21] Growth in TCU consumption depends mainly on population, for which there is only one scenario.

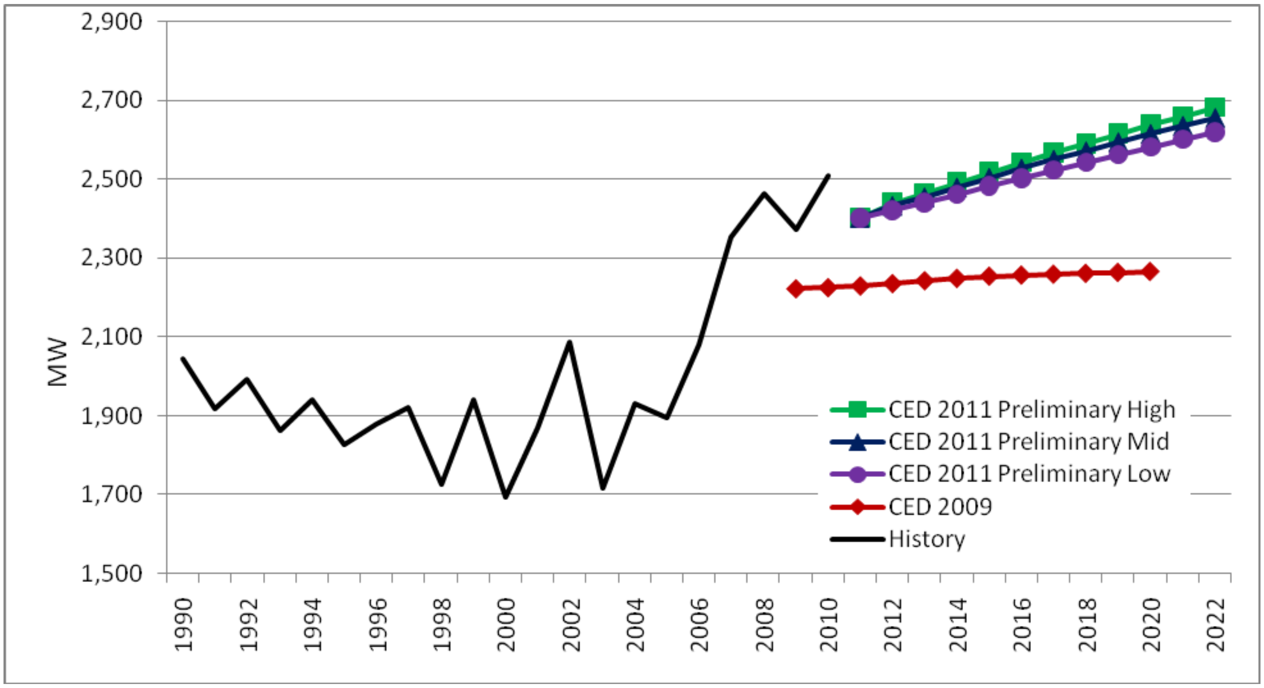
Figure 2-19: PG&E Planning Area Agriculture & Water Pumping Sector Electricity Forecasts



Source: California Energy Commission, 2011

Figure 2-20 provides a comparison of projected combined peak for these sectors. *CED 2011 Preliminary* is higher over the entire forecast period in all three scenarios compared to *CED 2009* because of a higher starting point. *CED 2011 Preliminary* growth rates are also higher than that of the *CED 2009* forecast because of increased water pumping loads.

Figure 2-20: PG&E Planning Area Other Sector Peak

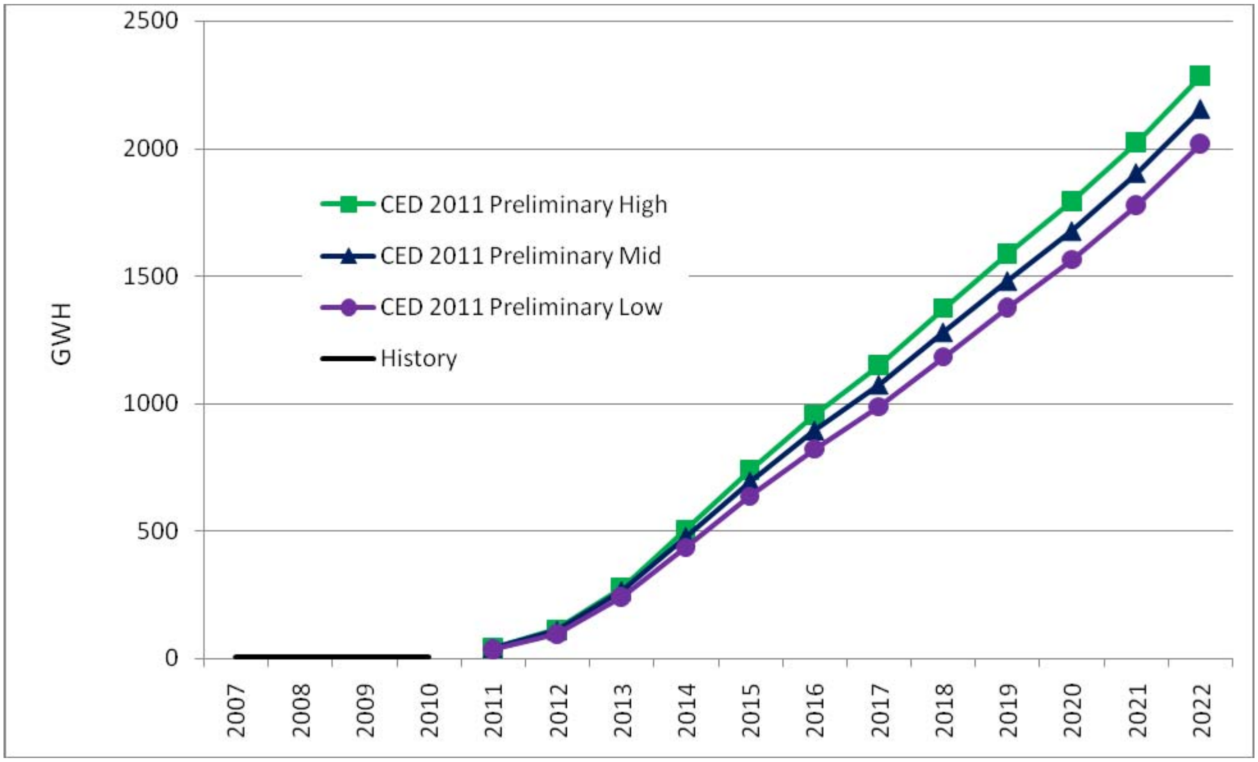


Source: California Energy Commission, 2011

Electric Vehicles

The consumption of electric vehicles in 2010 was 7 GWh for the PG&E planning area and is expected to rise to over 800 GWh by 2016. By the end of the forecast period in 2022, PG&E planning area use by electric vehicles is projected to be over 2,000 GWh in all three scenarios. Staff assumed most recharging would occur during off-peak hours so peak impacts would be relatively small, causing an increase of only 86 MW in the low use case and 97 MW in the high use case by 2022. **Figure 2-21** presents the PG&E planning area electric vehicle consumption forecast for each of the demand scenarios.

Figure 2-21: PG&E Electricity Consumption of Electric Vehicles



Source: California Energy Commission, 2011

Self-Generation

The peak demand forecast is reduced by self-generation, including the effects of SGIP, CSI, and other programs, as discussed in Chapter 1. The effects of these programs are forecast based on recent trends in installations and a residential predictive model. **Table 2-2** shows the forecast of peak impacts from PV and non-PV self-generation. Only residential PV impacts varied in the demand scenarios, based on differences in households and energy rates. Staff projects about between 740 to 880 MW of peak reduction from PV systems by 2022. Peak reductions are based on installed PV system capacities ranging from 820 MW in 2015 and 1,360 MW in 2022 in the high demand case to 875 MW in 2015 and 1,596 MW in 2022 in the low demand case.

Table 2-2: PG&E Planning Area Self Generation Peak Impacts (MW)

Year	1990	2000	2010	2015	2020	2022
Non-Photovoltaic Self-Generation	618.09	684.86	677.51	706.29	714.63	725.71
Photovoltaic, Low Demand	0.00	0.52	236.23	491.73	690.86	880.54
Photovoltaic, Mid Demand	0.00	0.52	236.23	468.44	625.04	788.65
Photovoltaic, High Demand	0.00	0.52	236.23	458.99	598.10	741.22
Total Self-Generation, Low Demand	618.09	685.38	913.74	1198.01	1405.49	1606.26
Total Self-Generation, Mid Demand	618.09	685.38	913.74	1174.72	1339.67	1514.37
Total Self-Generation, High Demand	618.09	685.38	913.74	1165.28	1312.73	1466.93

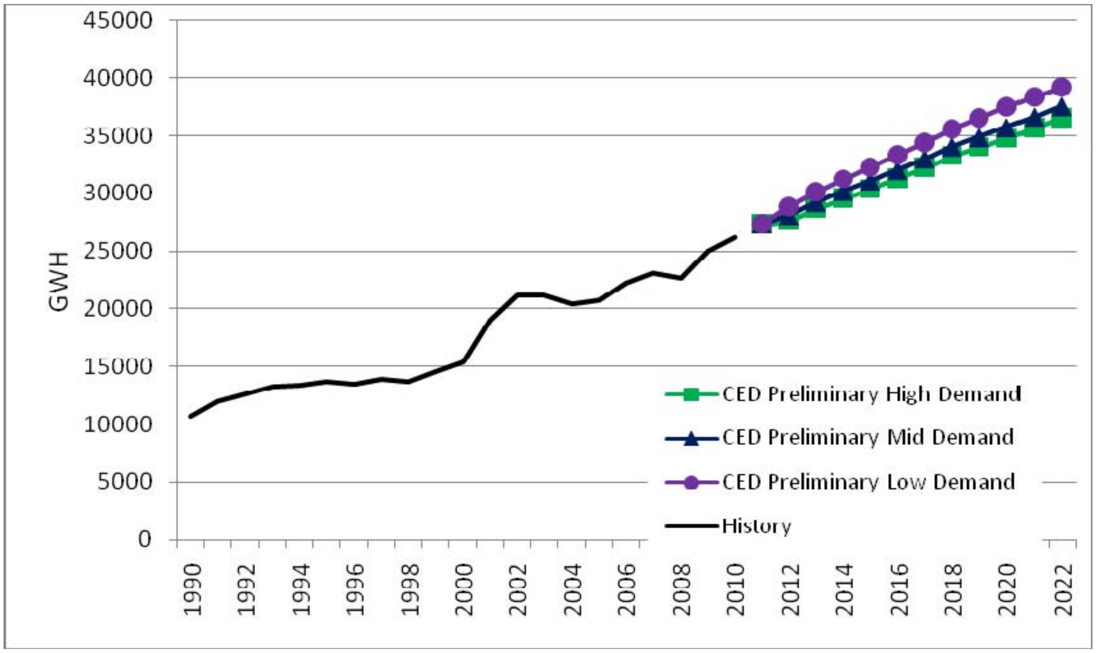
Source: California Energy Commission, 2011

Conservation/Efficiency Impacts

Staff has spent a great deal of time refining methods to account for energy efficiency and conservation impacts while preparing this forecast. **Figure 2-22** and **Figure 2-23** show electricity consumption and peak efficiency savings estimates from all sources, including standards, 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.

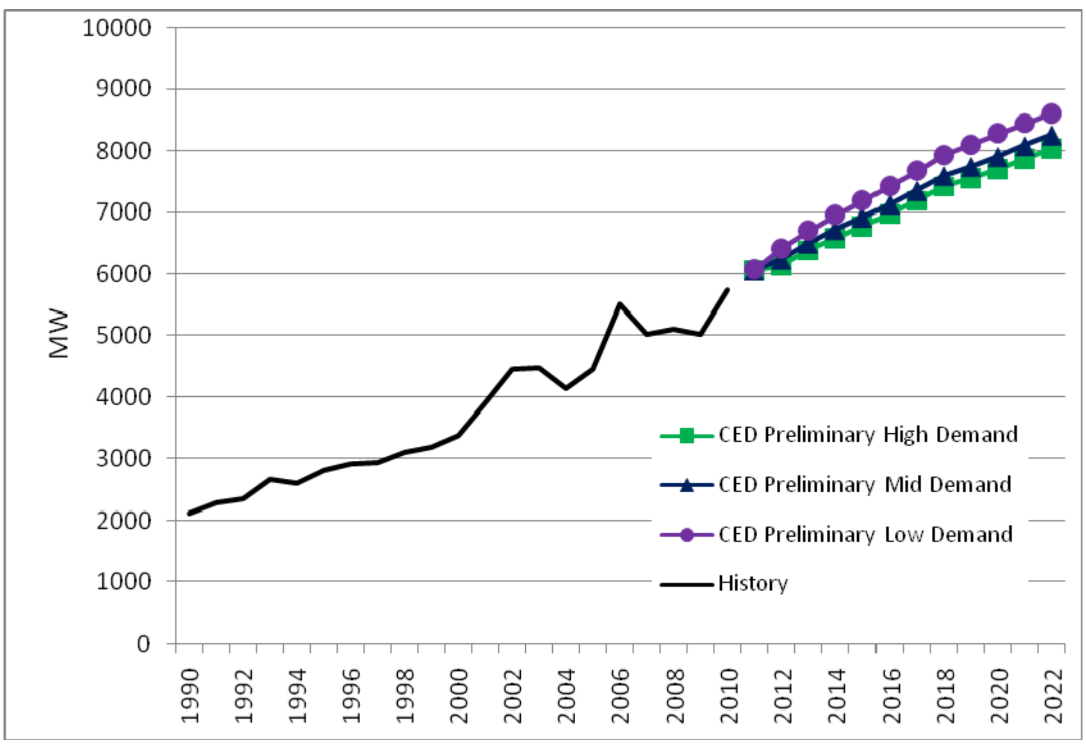
Table 2-3 presents estimated savings for building and appliance standards in the mid demand case for selected years. Total standards impacts are higher in the high demand case by 1.5-2.0 percent because of higher home and commercial floor space construction and 1.5-2.0 percent lower in the low demand case. The standards savings estimates include the 2010 revision to Title 24 building standards as well as AB 1109 lighting savings. Savings are measured against a baseline before 1975, so they incorporate more than 30 years of impacts. Chapter 8 provides more detail on staff work related to energy efficiency and conservation.

Figure 2-22: PG&E Planning Area Electricity Consumption Savings Estimates



Source: California Energy Commission, 2011

Figure 2-23: PG&E Planning Area Electricity Peak Savings Estimates



Source: California Energy Commission, 2011

Table 2-3: PG&E Planning Area Standards Savings Estimates

Electricity Consumption Savings (GWH)							
	Residential			Commercial			
	Building Standards	Appliance Standards	Total	Building Standards	Appliance Standards	Total	Total Standards
1990	781	972	1,754	421	235	655	2,409
2000	1,595	3,104	4,699	959	703	1,662	6,361
2010	2,012	6,755	8,768	1,730	1,182	2,912	11,679
2015	2,315	8,869	11,184	2,420	1,587	4,007	15,191
2020	2,662	10,400	13,062	3,210	2,211	5,422	18,484
2022	2,762	10,618	13,380	3,525	2,331	5,855	19,235
Electricity Peak Demand Savings (MW)							
	Residential			Commercial			
	Building Standards	Appliance Standards	Total	Building Standards	Appliance Standards	Total	Total Standards
1990	190	236	426	74	41	115	541
2000	397	773	1,170	189	139	327	1,497
2010	505	1,695	2,200	332	227	559	2,759
2015	608	2,331	2,940	453	297	749	3,689
2020	692	2,704	3,396	600	413	1,013	4,409
2022	712	2,737	3,449	659	435	1,094	4,543

Source: California Energy Commission, 2011

CHAPTER 3: Southern California Edison Planning Area

The SCE planning area includes

- SCE bundled retail customers.
- Customers served by energy service providers (ESPs) using the SCE distribution system to deliver electricity to end users.
- Customers of the various southern California municipal and irrigation district utilities with the exception of the cities Imperial Irrigation District and the cities of, Los Angeles, Pasadena, Glendale, and Burbank and IID. Also excluded from the SCE planning area is San Diego County and the southern portion of Orange County served by SDG&E.

This chapter is organized as follows: First, forecasted consumption and peak loads for the SCEE planning area are discussed; both total and per capita values are presented. The *CED 2011 Preliminary* values are compared to the adopted *CED 2009* forecast, with differences between the two forecasts explained. The forecasted load factor, jointly determined by the consumption and peak load estimates, is also discussed. Second, the chapter presents sector consumption and peak load forecasts. The residential, commercial, industrial, and “other” sector forecasts are compared to those in *CED 2009* and differences between the two are discussed. Third, the chapter discusses the forecasts of electric vehicles, self generation, and the impacts of conservation and efficiency programs.

Forecast Results

Table 3-1 compares the *CED 2009* and with the *CED 2011 Preliminary* forecast scenarios of electricity consumption and peak demand for selected years. *CED 2011 Preliminary* mid demand electricity consumption is 2.2 percent lower than the *CED 2009* forecast in 2020. This is primarily a result of the recent economic downturn, causing 2010 recorded consumption to be 2.5 percent lower than was projected in the *CED 2009* forecast. The long-term growth rate of the mid demand scenario is only slightly lower than was projected in the *CED 2009* forecast. *CED 2011 Preliminary* high demand is about 0.6 percent above *CED 2009* forecast in 2020 while the low demand scenario is 3.7 percent below. The difference in peak forecasts is similar to the difference in consumption forecasts. Growth rates for the respective peak forecasts mirror the differences in consumption forecast.

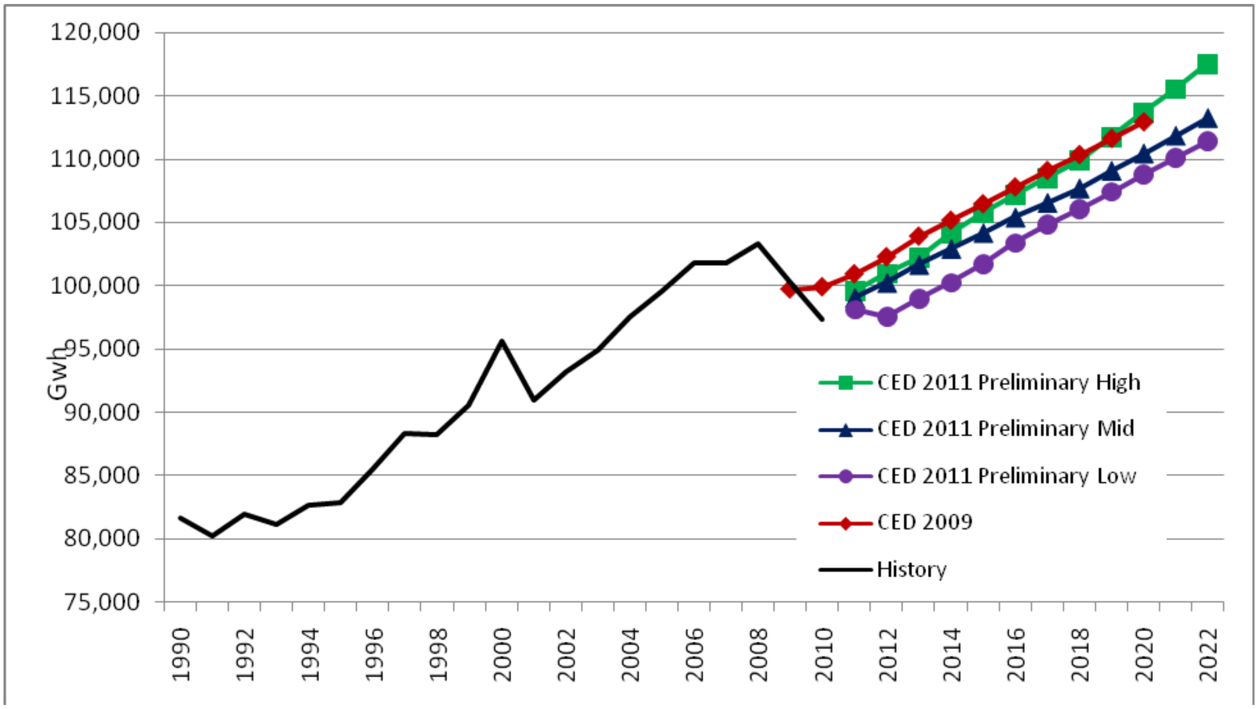
Table 3-1: SCE Planning Area Forecast Comparison

Consumption (GWH)				
	CED 2009 (Dec. 2009)	*CED 2011* Preliminary-High	*CED 2011* Preliminary-Mid	*CED 2011* Preliminary-Low
1990	82,069	81,671	81,671	81,671
2000	99,148	95,601	95,601	95,601
2010	99,875	97,366	97,366	97,366
2011	100,907	99,534	99,075	98,117
2015	106,460	105,688	104,177	101,746
2020	112,964	113,672	110,442	108,793
2022	--	117,548	113,228	111,440
	Average Annual Growth Rates			
1990-2000	1.91%	1.59%	1.59%	1.59%
2000-2010	0.07%	0.18%	0.18%	0.18%
2011-2015	1.35%	1.51%	1.26%	0.91%
2011-2020	1.26%	1.49%	1.21%	1.15%
2011-2022	--	1.52%	1.22%	1.16%
Peak (MW)				
	CED 2009 (Dec. 2009)	*CED 2011* Preliminary-High	*CED 2011* Preliminary-Mid	*CED 2011* Preliminary-Low
1990	17,647	17,647	17,647	17,647
2000	19,506	19,506	19,506	19,506
2010	22,877	22,916	22,916	22,916
2011	23,181	23,075	23,021	22,843
2015	24,572	24,586	24,308	23,748
2020	26,337	26,524	25,885	25,382
2022	--	27,330	26,446	25,853
	Average Annual Growth Rates			
1990-2000	1.01%	1.01%	1.01%	1.01%
2000-2010	1.61%	1.62%	1.62%	1.62%
2011-2015	1.47%	1.60%	1.37%	0.98%
2011-2020	1.43%	1.56%	1.31%	1.18%
2011-2022	--	1.55%	1.27%	1.13%
Historical values are shaded				

Source: California Energy Commission, 2011

As shown in **Figure 3-1**, *CED 2011 Preliminary* electricity consumption forecasts are lower at the beginning of the forecast period than the *CED 2009* forecast because of the recent economic downturn, causing a greater than anticipated drop in 2010 consumption. The mid demand case projects growth similar to that in *CED 2009* while the high demand case grows at a faster rate. The low demand case continues lower growth for another year before increasing at a similar rate to the mid demand case.

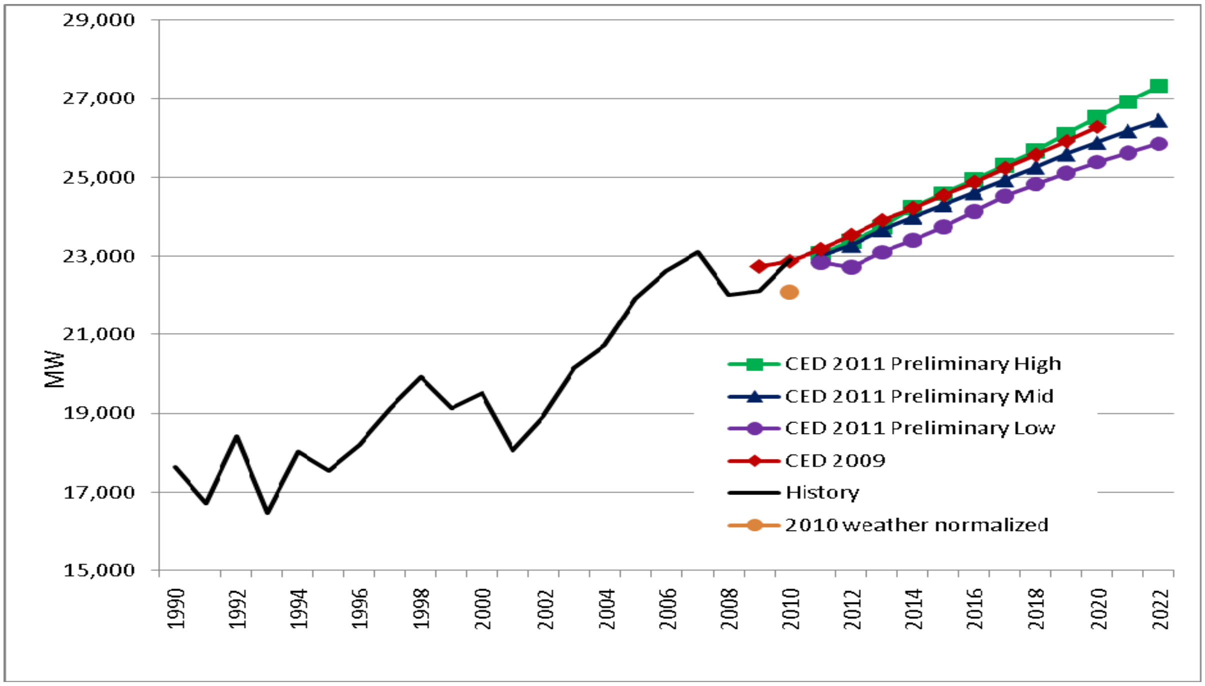
Figure 3-1: SCE Planning Area Electricity Forecast



Source: California Energy Commission, 2011

The *CED 2011 Preliminary* SCE planning area peak demand forecast, shown in **Figure 3-2**, is only slightly lower than the *CED 2009* forecast. This is consistent with the differences seen in the electricity forecasts. The *CED 2011 Preliminary* high demand scenario is higher than the previous peak forecast after 2013. The projected flatness in peak growth between 2010 actual peak and 2011 forecasted peak is the result of the 2010 SCE peak being caused by an extreme weather event. Using the weather-normalized 2010 SCE planning area peak of 22,095 MW (noted in **Figure 3-2**) produces 2010-2011 growth similar to that seen in the energy consumption forecast.

Figure 3-2: SCE Planning Area Peak

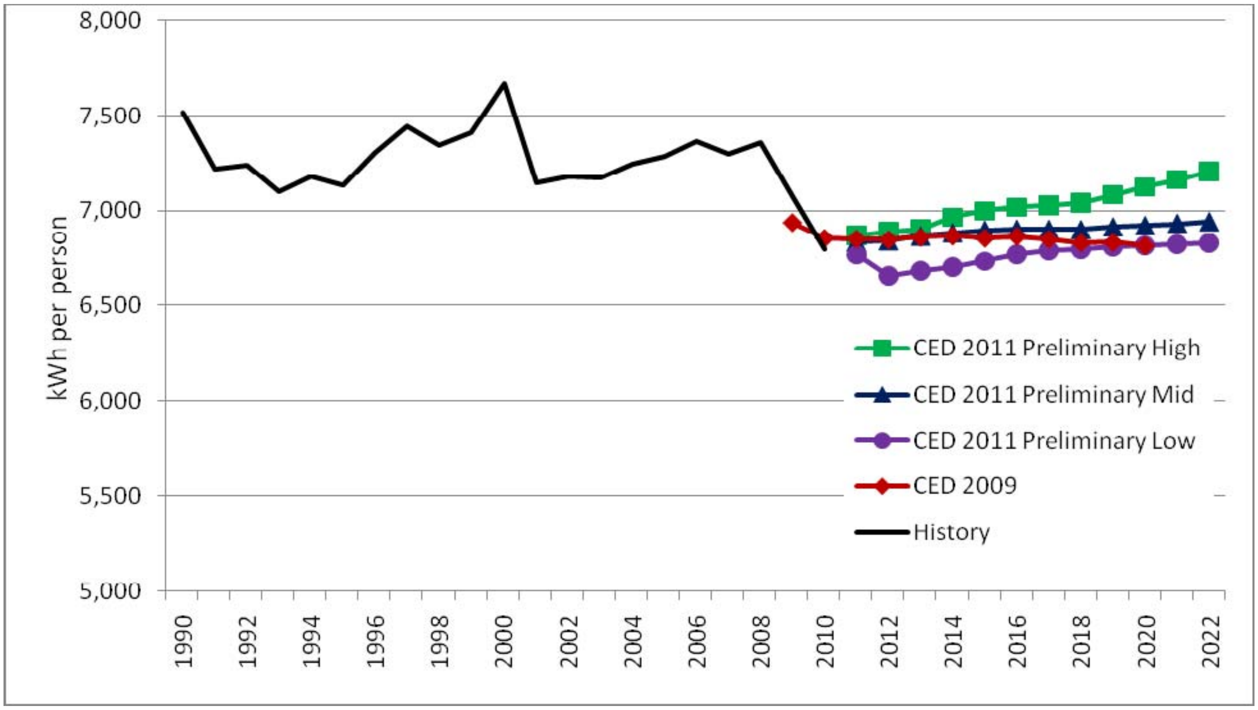


Source: California Energy Commission, 2011

As **Figure 3-3** shows, per capita electricity consumption is slightly higher in the *CED 2011 Preliminary* forecast mid and high demand scenarios throughout the entire period compared to *CED 2009*. For the low demand scenario, per capita consumption declines in the early period and then increases to the level of the previous forecast by the end of the period. *CED 2011 Preliminary* projections remain below levels of per capita electricity consumption witnessed in recent history in the mid and low demand cases.

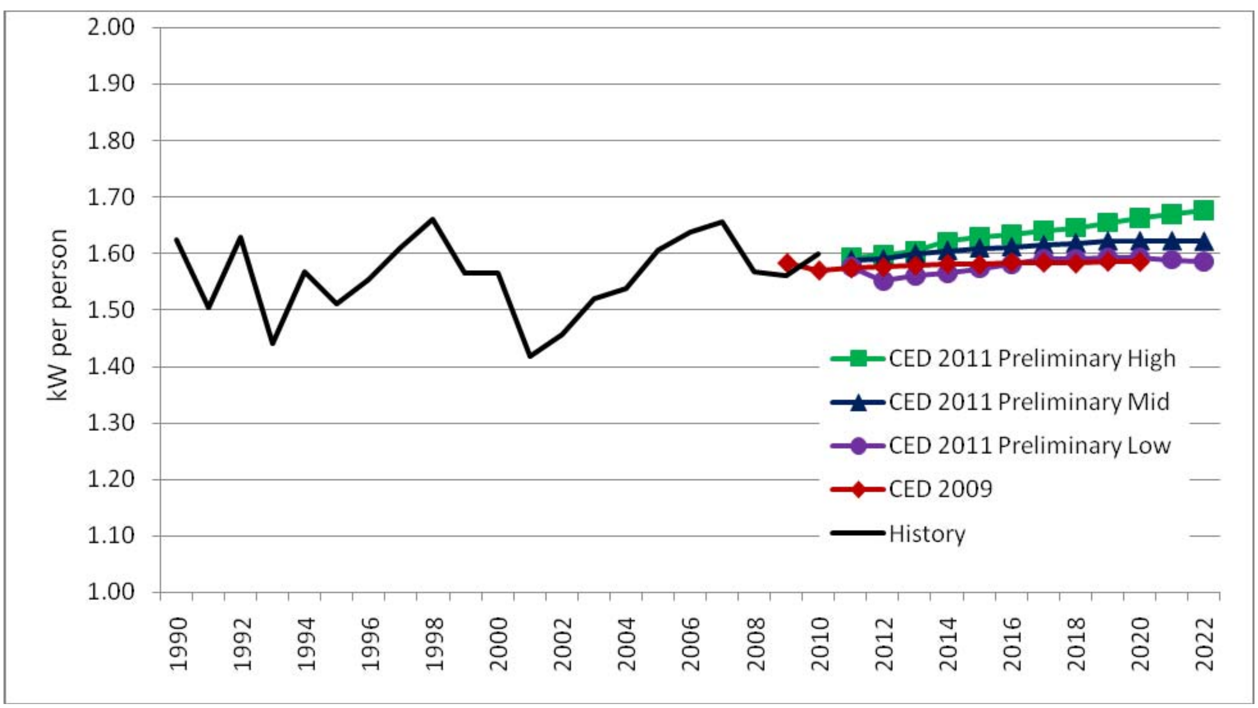
Figure 3-4 provides a comparison of per capita peak demand. *CED 2011 Preliminary* per capita peak scenarios follow the same pattern as the per capita consumption scenarios. The per capita peak values are projected to remain in the range of recent historic levels for the mid and low demand scenarios. The high demand scenario rises above the historic range by the end of the forecast period.

Figure 3-3: SCE Planning Area per Capita Electricity Consumption



Source: California Energy Commission, 2011

Figure 3-4: SCE Planning Area per Capita Peak Demand

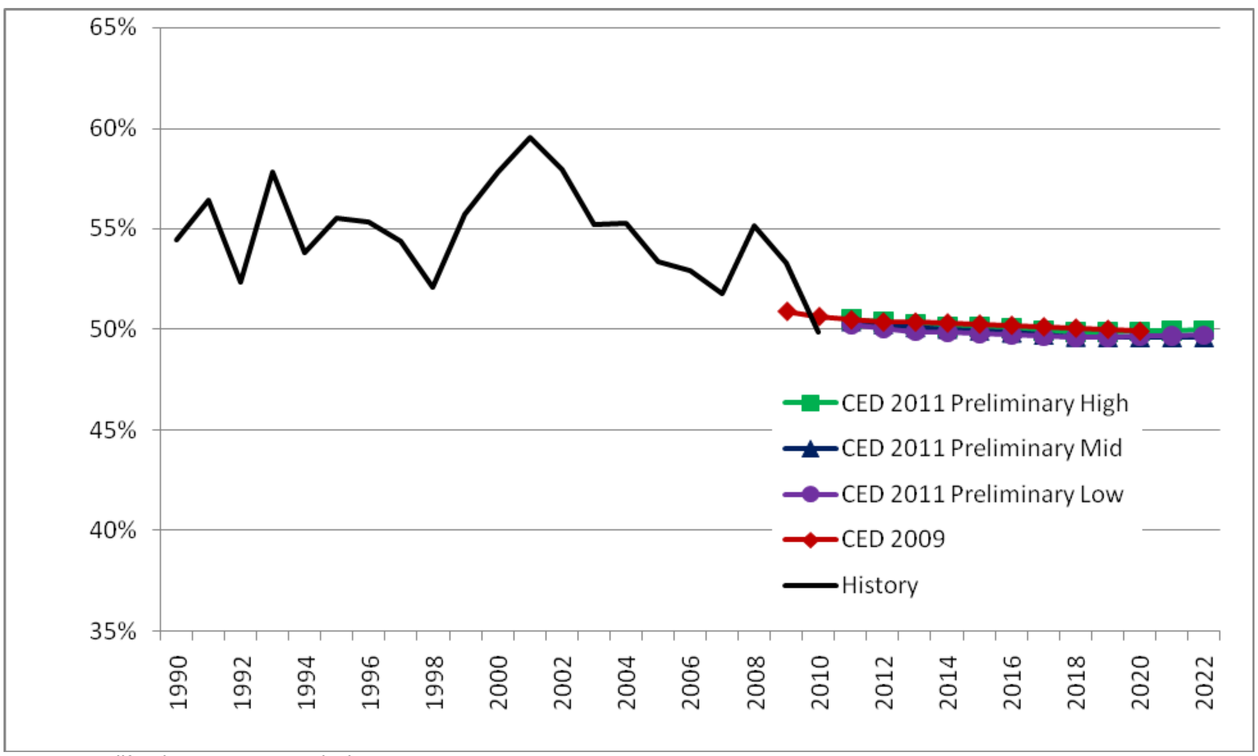


Source: California Energy Commission, 2011

Figure 3-5 compares the load factors for the *CED 2011 Preliminary* and *CED 2009* forecasts. The load factor is a measure of the relative increase in peak demand with respect to annual electricity consumption. Lower load factors indicate a sharper "needle" peak, and higher load factors indicate a more stable load. Historic variation in load factors is caused by variation in annual weather patterns. In Southern California, recent peak temperatures before 2006 were lower than the 57-year median value, resulting in higher-than-expected load factors. The 2006 and 2010 load factors are low because of the higher-than-normal peak conditions experienced in those years. *CED 2011 Preliminary* projected load factors are on the low end of the range of recent values.

Over the forecast period, the *CED 2011 Preliminary* load factor declines slightly, which is consistent with higher weather-sensitive load growth. Consumption in the SCE planning area is shifting toward residential and commercial sectors and away from the industrial sectors. Growth is also increasingly taking place in hotter inland areas leading to greater saturation of central air conditioning as well as more use of air conditioning equipment in cooler coastal areas.

Figure 3-5: SCE Planning Area Load Factors



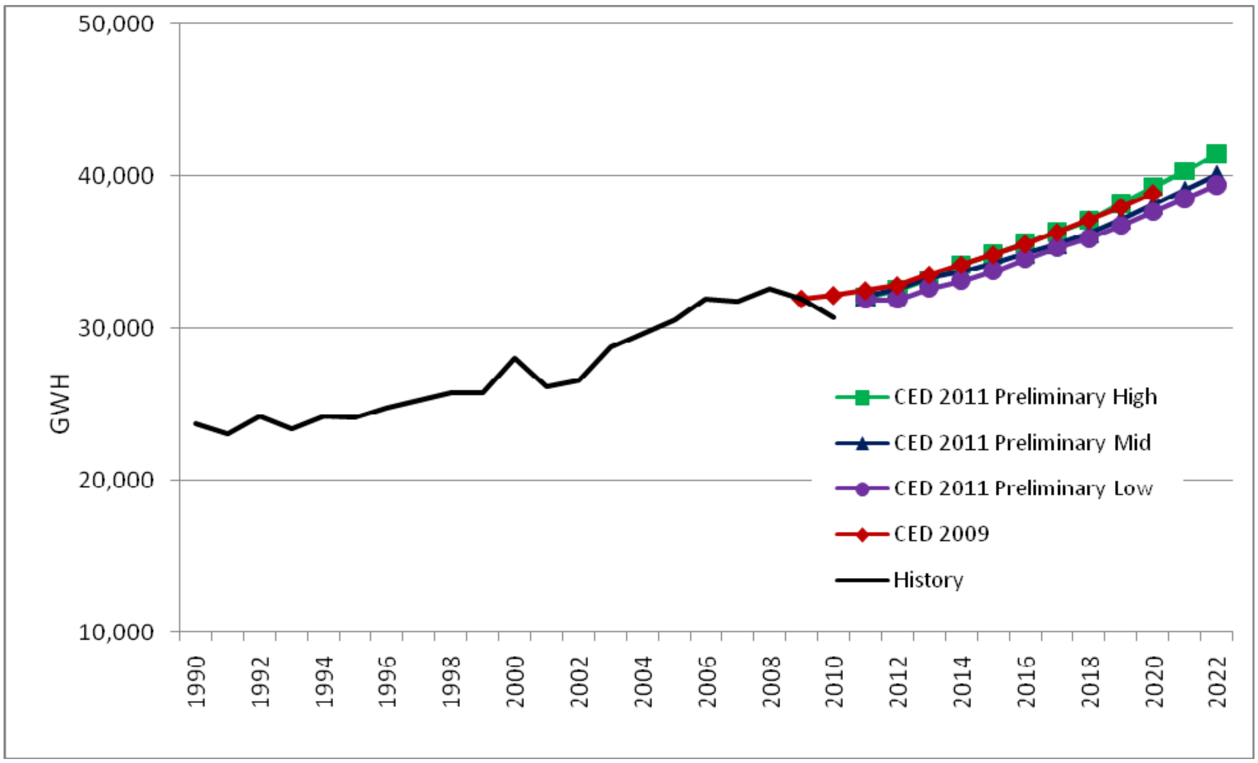
Source: California Energy Commission, 2011

Sector Level Results and Input Assumptions

Residential

Figure 3-6 provides a comparison of *CED 2011 Preliminary* and *CED 2009* SCE planning area residential forecasts. The mid and low demand scenarios are lower throughout the entire forecast period while the high demand scenario is very similar to the *CED 2009.*

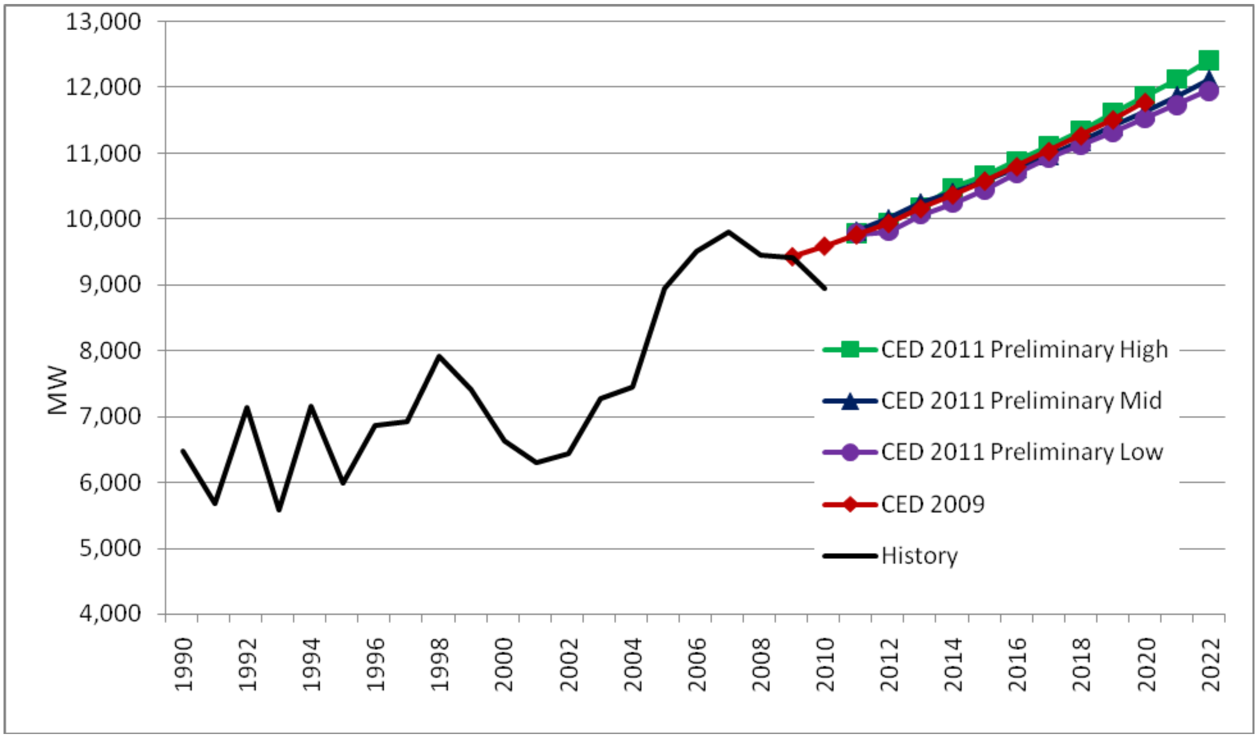
Figure 3-6: SCE Planning Area Residential Consumption



Source: California Energy Commission, 2011

Figure 3-7 provides a comparison of *CED 2011 Preliminary* and *CED 2009* residential peak demand forecasts. The differences between peak forecasts are smaller than the difference in energy forecasts, although they follow a similar pattern. The difference between the peak forecasts is driven primarily by the difference in electricity consumption.

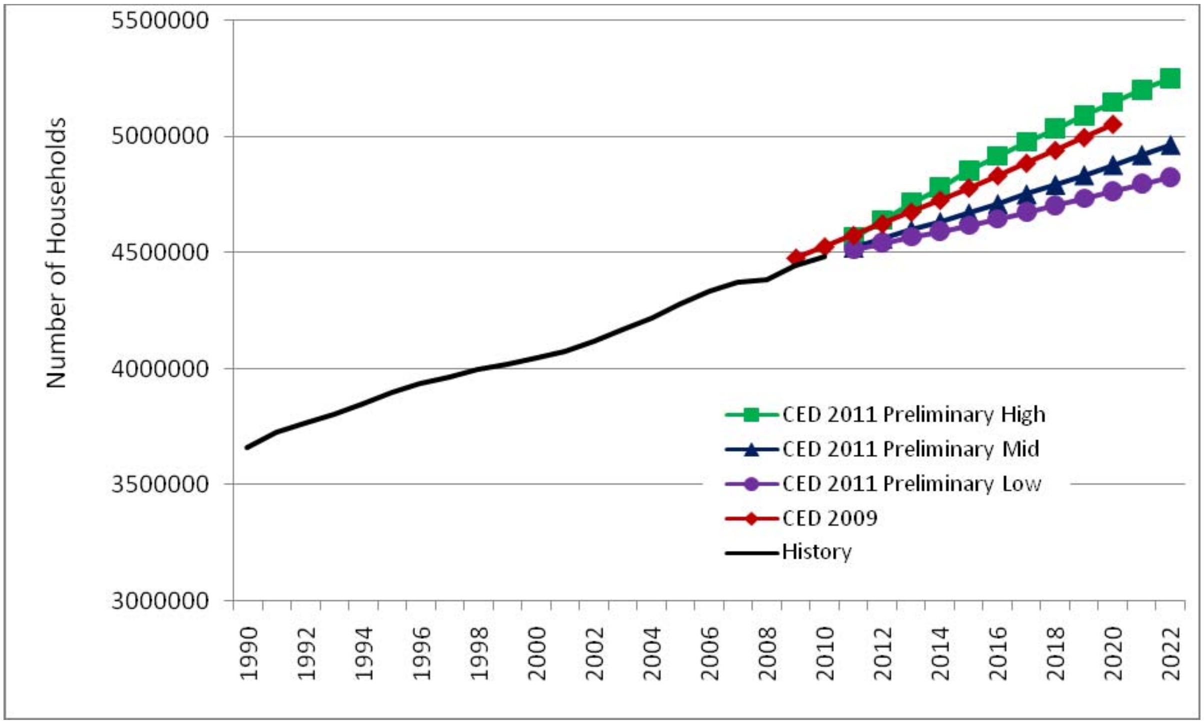
Figure 3-7: SCE Planning Area Residential Peak



Source: California Energy Commission, 2011

Figure 3-8, **Figure 3-9**, and **Figure 3-10** provide comparisons of the residential drivers used in *CED 2011 Preliminary* with those used in *CED 2009*. **Figure 3-8** provides comparisons of total household projections. The *CED 2011 Preliminary* forecast mid and low demand scenarios are lower than the previous forecast because of a slightly lower total population forecast. *CED 2011 Preliminary* forecast does not include the most recent updated county population forecast from the California Department of Finance (DOF), which incorporates information from the 2010 census. This updated population forecast will be included in the revised demand forecast.

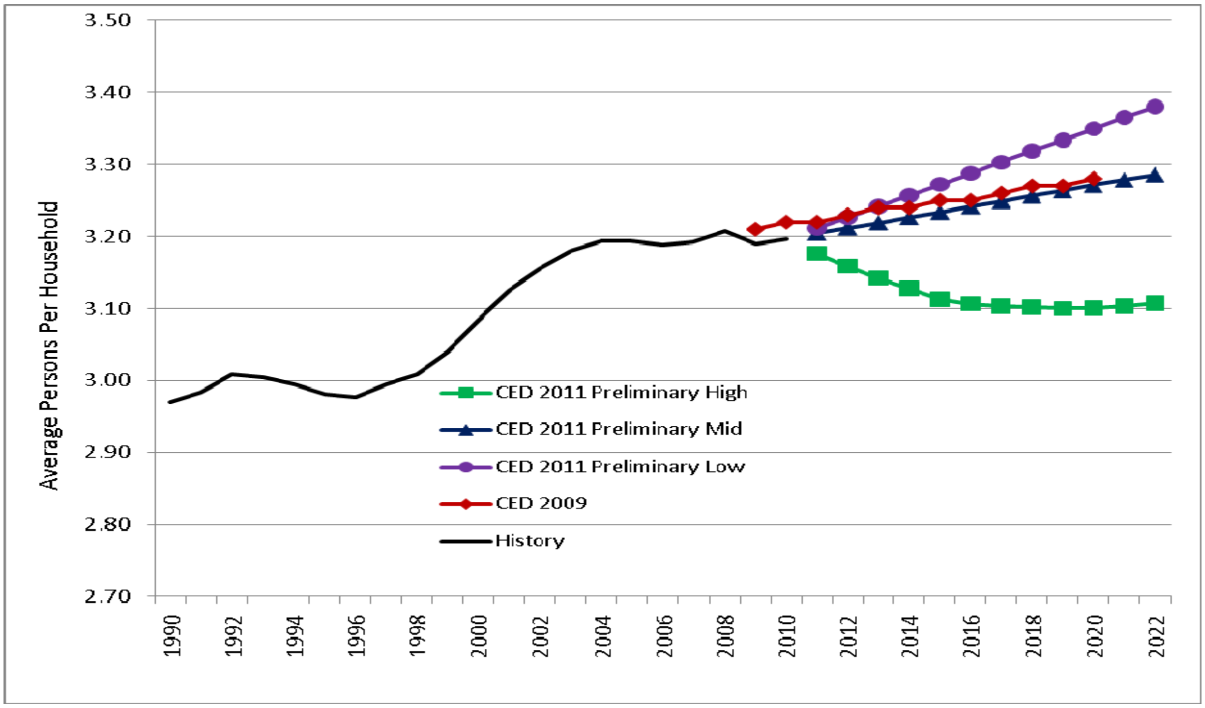
Figure 3-8: SCE Planning Area Residential Household Projections



Source: California Energy Commission, 2011

The household scenarios are based on persons per household changes shown in **Figure 2-9**. The high demand scenario uses a lower persons per household projection (more households) and the low demand scenario uses a higher persons per household projection (less households). See Chapter 1 for a discussion of assumptions driving these projections. The mid demand scenario assumes growth in persons per household similar to the projection used in the C*ED 2009* forecast. All three scenarios use the same household population forecast.

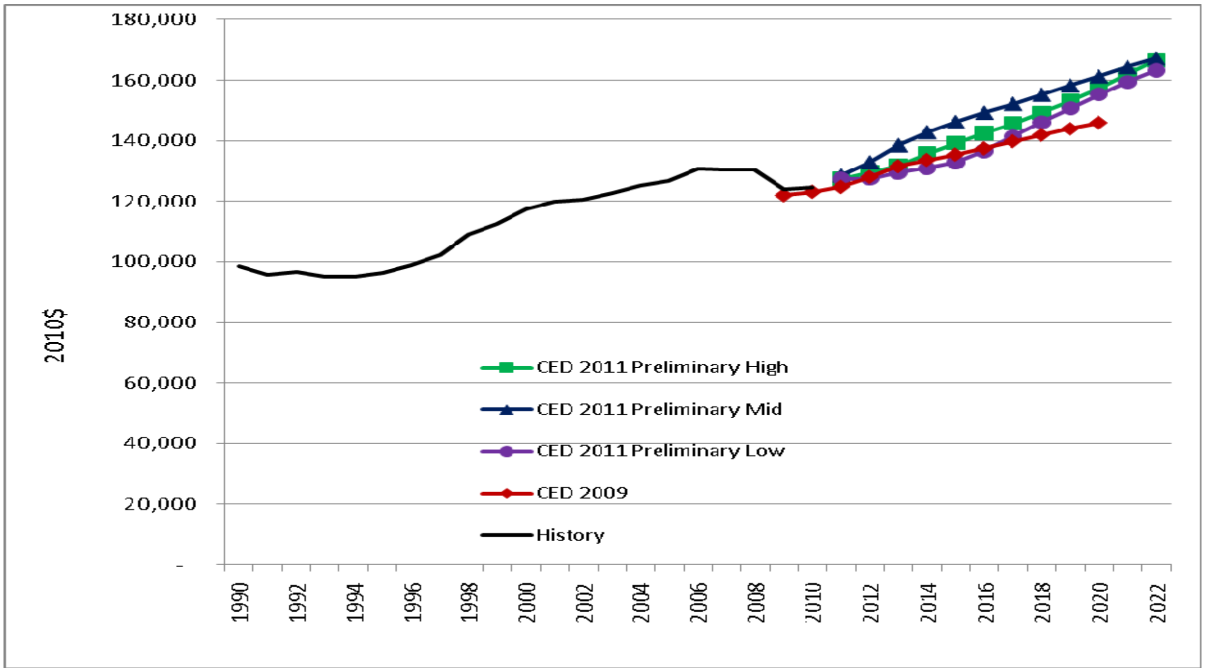
Figure 3-9: SCE Planning Area Persons per Household Projections



Source: California Energy Commission, 2011

Figure 2-10 provides a comparison of average household income (per capita income multiplied by persons per household) between the two forecasts. *CED 2011 Preliminary* estimates of household income growth are higher than the *CED 2009*. This is caused by higher growth projections of personal income than were used in the previous forecast. The difference between scenarios is a function of the variation in per capita income and persons per household used to define the scenarios.

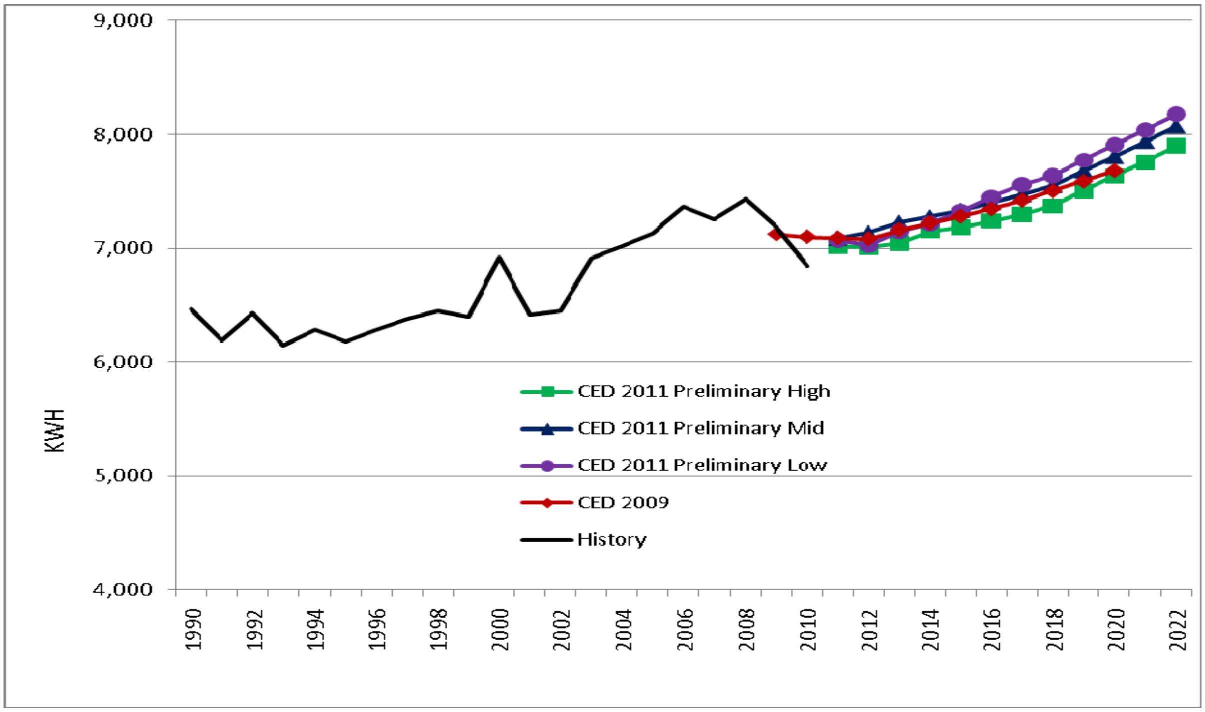
Figure 3-10: SCE Planning Area Average Household Income Projections



Source: California Energy Commission, 2011

Figure 2-11 gives a comparison of annual electricity consumption per household. The *CED 2011 Preliminary* forecasts are similar to the *CED 2009* forecast. *CED 2011 Preliminary* consumption per household in the mid demand scenario is slightly higher throughout the forecast period than *CED 2009*. This is caused by differences in the underlying economic and demographic assumptions. Most of the growth in use per household after 2015 is caused by increasing numbers of electric vehicle in the residential sector. This adds about 410 kWh per household to the residential total by 2022 in the SCE planning area. Without the inclusion of electric vehicle charging, residential use would be relatively constant over the forecast period.

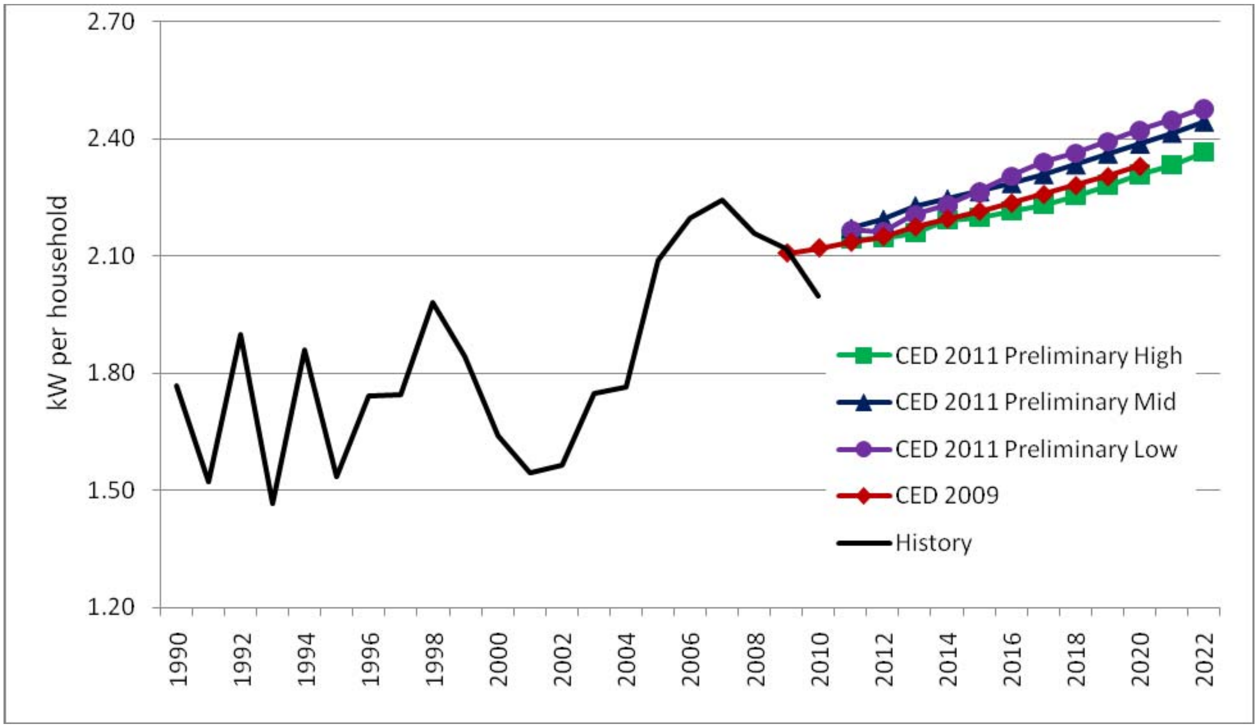
Figure 3-11: SCE Planning Area Use per Household



Source: California Energy Commission, 2011

CED 2011 Preliminary peak use per household, presented in **Figure 3-12**, is also higher than what was projected in *CED 2009*. This is in part driven by the short-term difference in energy forecasts. The mid to long-term growth in peak is similar to the *CED 2009* forecast. The difference in forecast level is caused mainly by the difference in the starting point.

Figure 3-12: SCE Planning Area Peak Use per Household

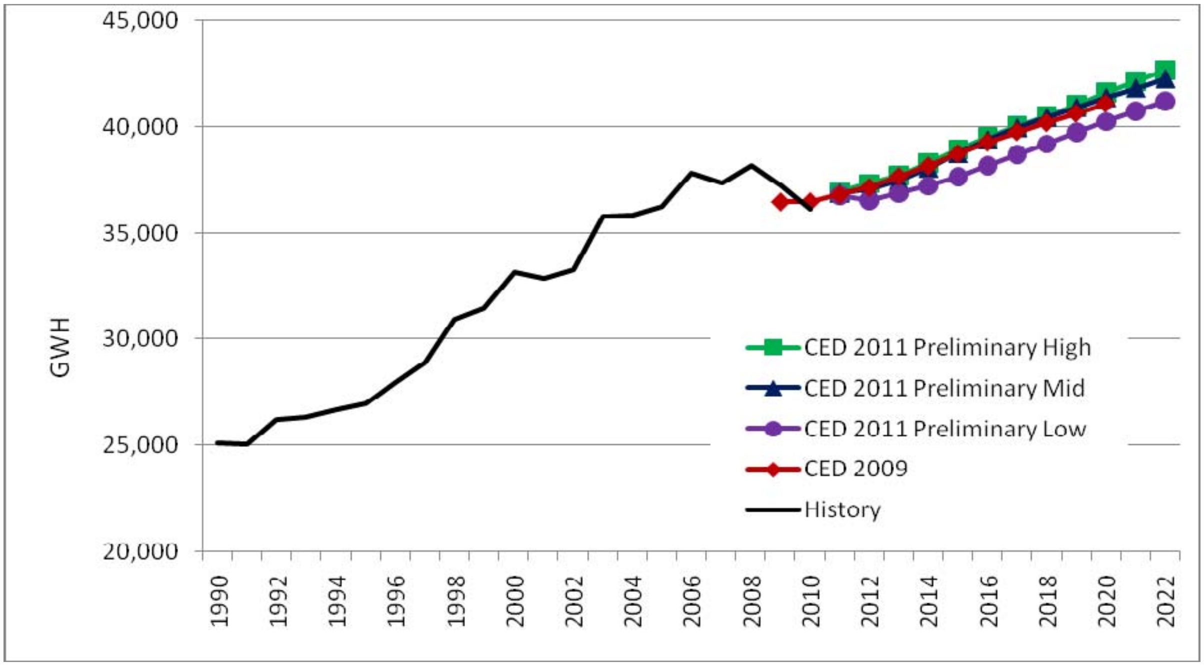


Source: California Energy Commission, 2011

Commercial Sector

Figure 3-13 provides a comparison of the commercial building sector forecasts. *CED 2011 Preliminary* forecast mid and high demand scenarios are very similar to *CED 2009*. The low demand scenario is lower throughout the entire forecast period because of lower floor space projections.

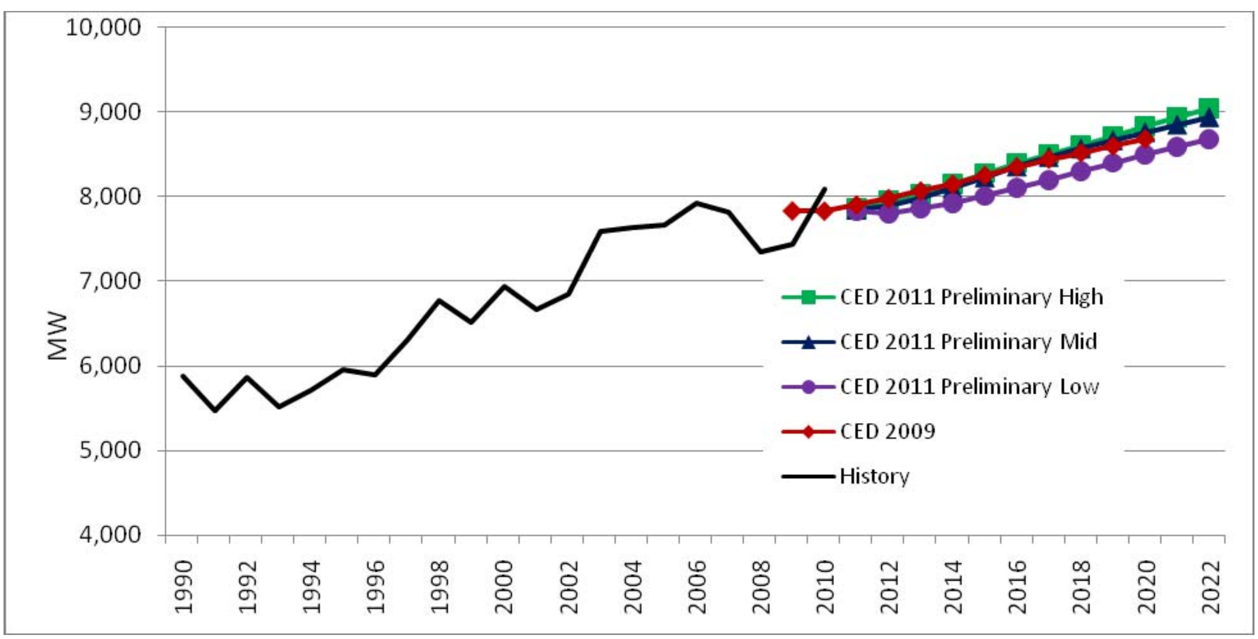
Figure 3-13: SCE Planning Area Commercial Consumption



Source: California Energy Commission, 2011

Figure 3-14 provides a comparison of the commercial peak demand forecasts. Growth in the commercial peak demand forecasts is driven primarily by the underlying electricity consumption forecasts. Therefore, the consumption and peak forecasts exhibit the same patterns.

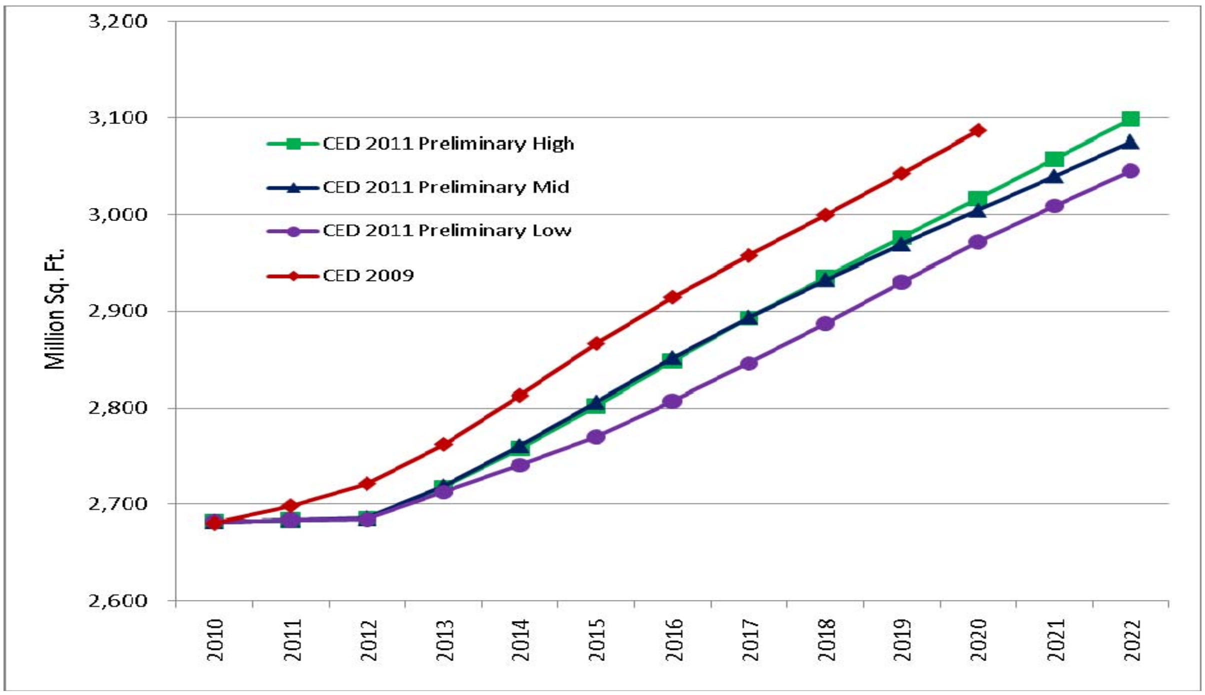
Figure 3-14: SCE Planning Area Commercial Sector Peak



Source: California Energy Commission, 2011

In staff's commercial building sector forecasting model, floor space by building type (for example, retail, schools and offices) is the key driver of energy use for each specific building type. **Figure 3-15** provides a comparison of total commercial floor space projections. The lower *CED 2011 Preliminary* floor space projections compared to *CED 2009* is caused by lower estimates of floor space stock for recent years.

Figure 3-15: SCE Planning Area Commercial Floor Space

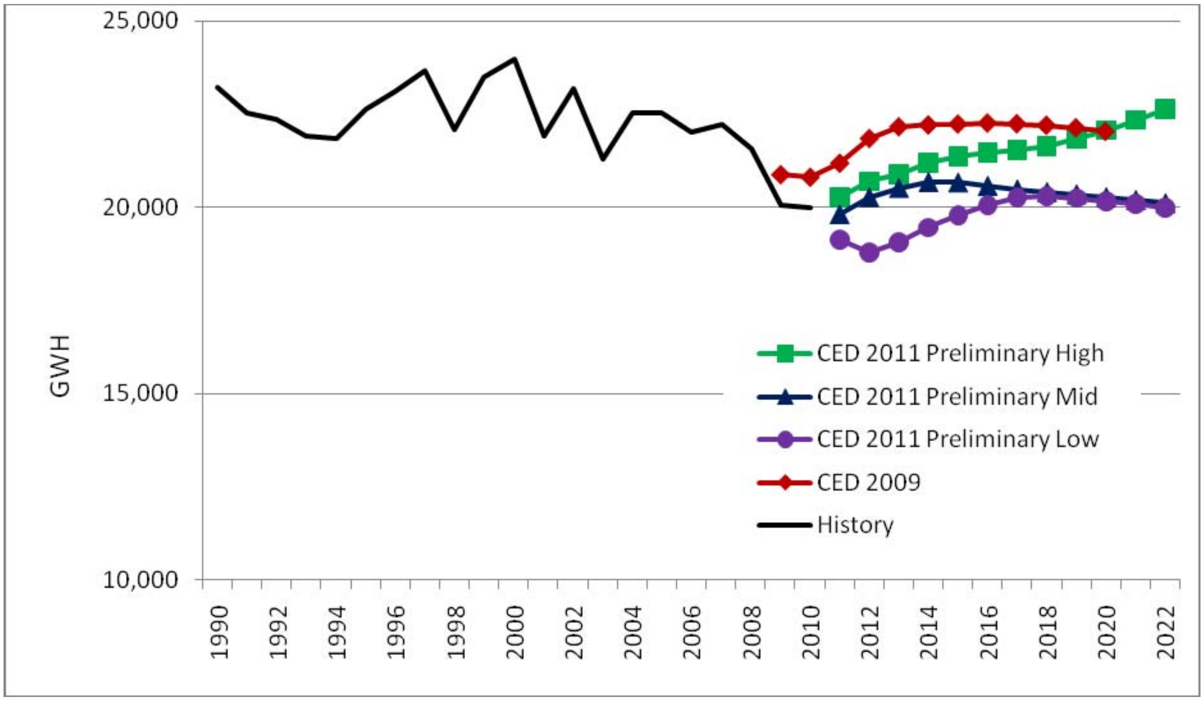


Source: California Energy Commission, 2011

Industrial Sector

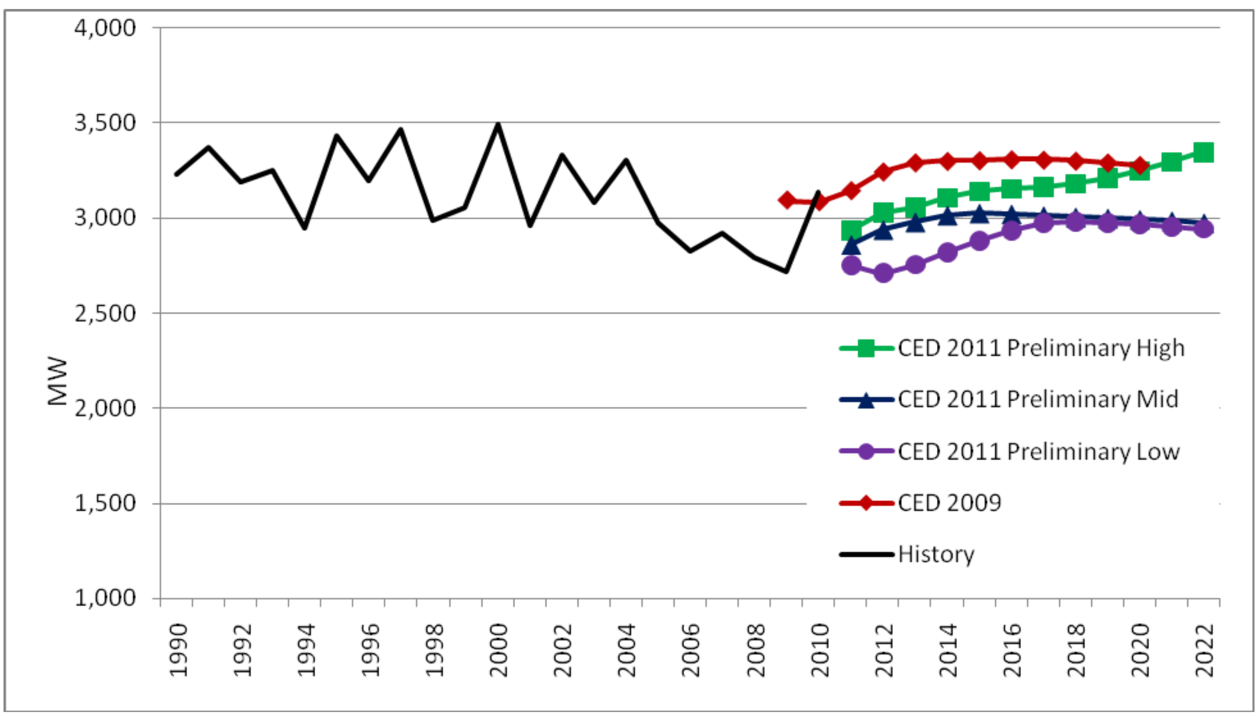
Figure 3-16 provides comparisons of industrial sector electricity consumption for the SCE planning area. *CED 2011 Preliminary* forecast scenarios start from a lower point than *CED 2009* forecast and the mid and low demand cases remain below *CED 2009* throughout the forecast period. Consumption in the high demand scenario is above *CED 2009* at the end of the forecast period. This is a result of the current economic projections used to drive the industrial forecast. **Figure 3-17** provides a comparison of the industrial sector peak forecasts. Forecasted growth patterns are similar to those seen for consumption.

Figure 3-16: SCE Planning Area Industrial Consumption



Source: California Energy Commission, 2011

Figure 3-17: SCE Planning Area Industrial Sector Peak

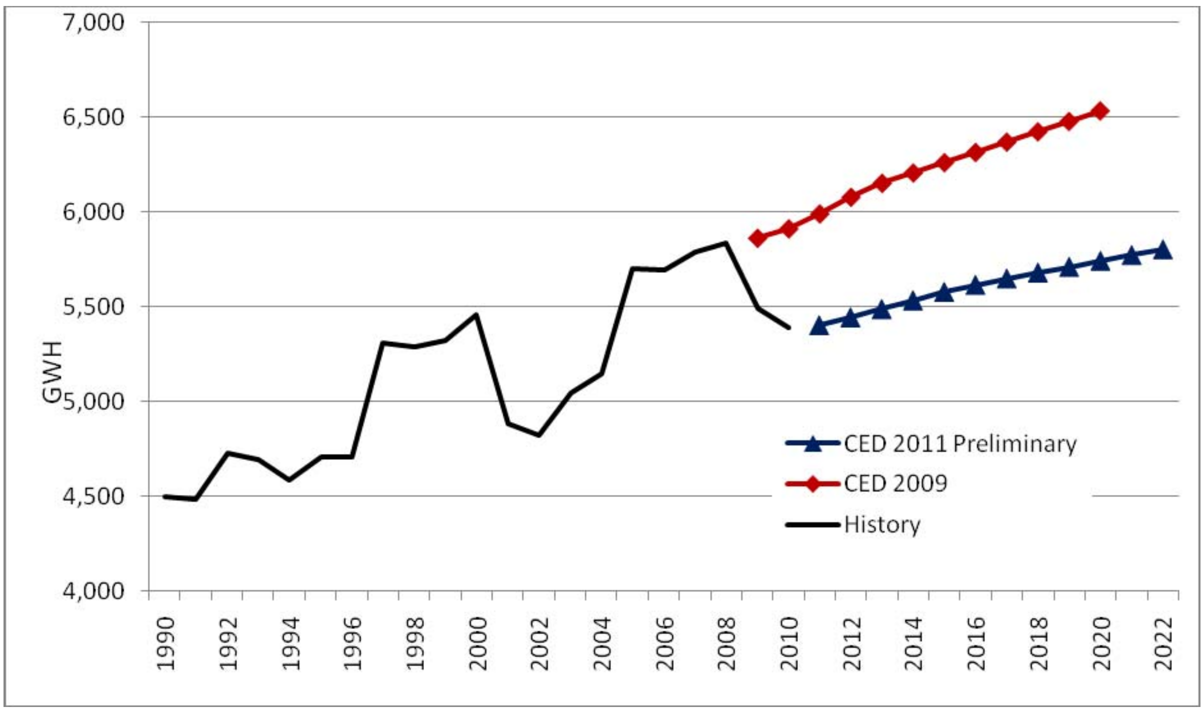


Source: California Energy Commission, 2011

Other Sectors

Figure 2-18 provides a comparison of the electricity consumption forecasts for the transportation, communication, utilities sector, which includes street lighting. In this case, a single scenario was run.[22] *CED 2011 Preliminary* is lower than *CED 2009* given a lower starting point, a result of more recent sector historic consumption estimates from QFER filings.

Figure 3-18: SCE Planning Area Transportation, Communication, Utilities and Streetlighting Sector Electricity Forecasts

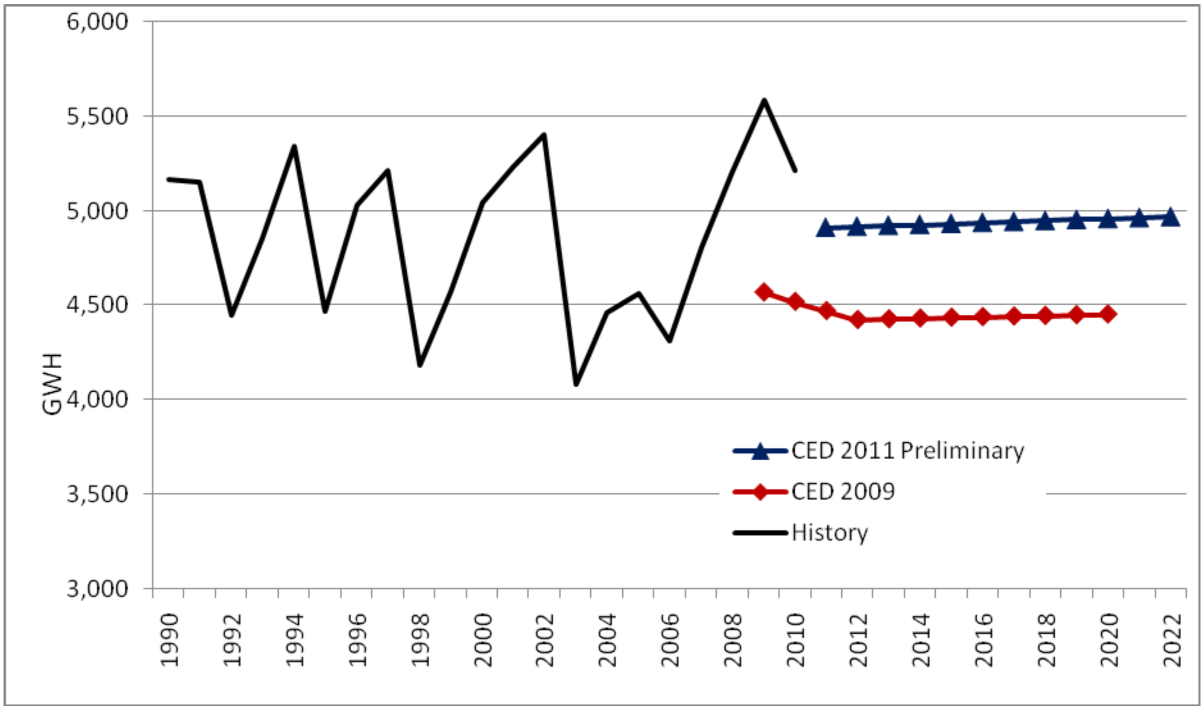


Source: California Energy Commission, 2011

[22] Growth in TCU consumption depends mainly on population, for which there is only one scenario.

Figure 3-19 provides a comparison of the electricity consumption forecasts for the agriculture and water pumping sectors. The econometric estimation for SCE uses population and found no price responsiveness; thus there is only one *CED 2011 Preliminary* scenario. The *CED 2011 Preliminary* agriculture and water pumping forecast is higher in the short-term than *CED 2009* because of a higher starting point based on historic consumption estimates. The *CED 2011 Preliminary* forecast is relatively constant over the forecast period.

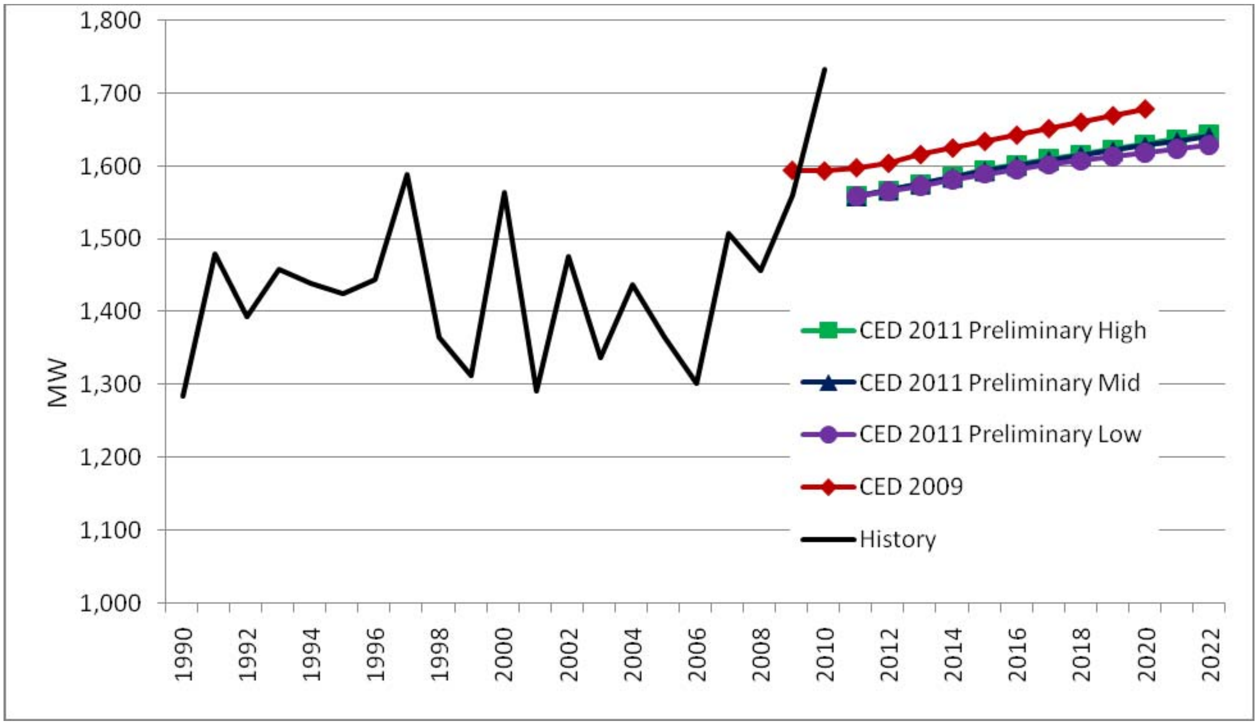
Figure 3-19: SCE Planning Area Agriculture and Water Pumping Sector Forecast



Source: California Energy Commission, 2011

Figure 3-20 provides a comparison of the combined peak for these sectors. The *CED 2011 Preliminary* peak forecast is somewhat lower than *CED 2009* because of an estimated lower starting point. The growth rates between the two forecasts are similar.

Figure 3-20: SCE Planning Area Other Sector Peak

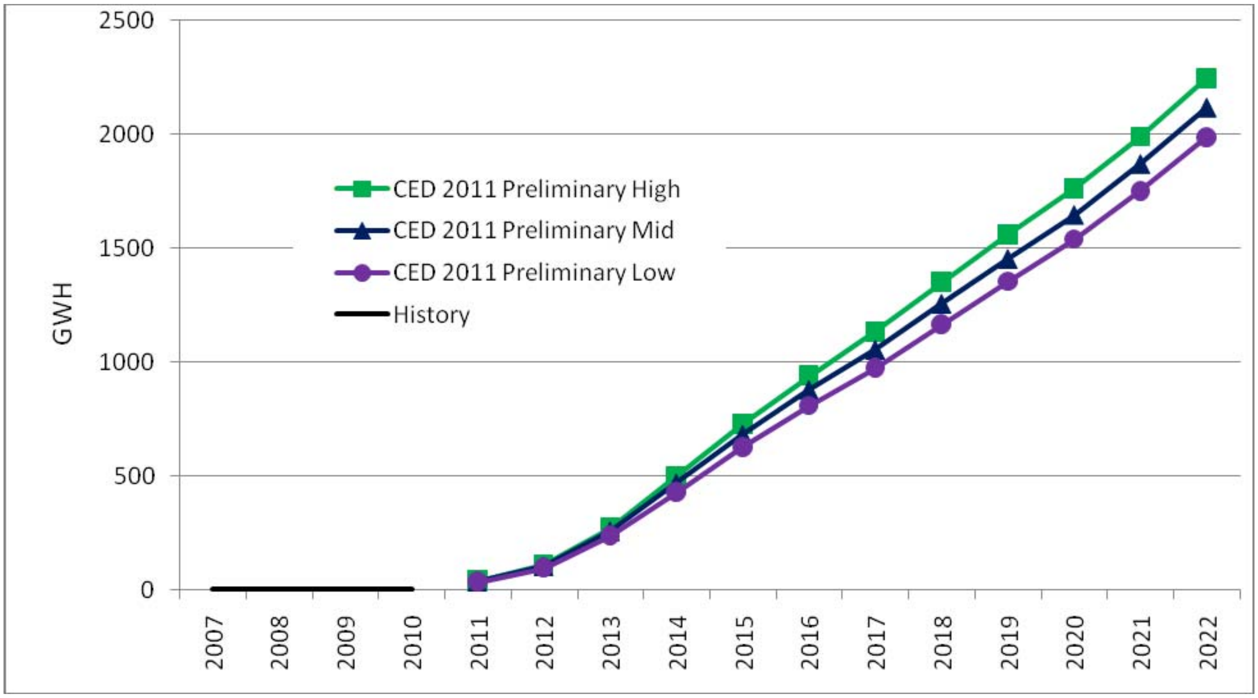


Source: California Energy Commission, 2011

Electric Vehicles

The consumption of electric vehicles in 2010 was 7 GWh, which is expected to increase to over 800 GWh by 2016 in all three demand scenarios. By the end of the forecast period, total electricity used by electric vehicles is projected to be over 2,000 GWh in the mid and high cases. Staff assumed most recharging would occur during off-peak hours so peak impacts would be relatively small causing an increase of 85 MW in the low use case and 96 MW in the high use case by 2022. **Figure 3-21** presents the SCE planning area electric vehicle forecast for each of the demand scenarios.

Figure 3-21: SCE Electricity Consumption of Electric Vehicles



Source: California Energy Commission, 2011

Self-Generation

The peak demand forecast is reduced by self-generation, including the effects of SGIP, CSI, and other programs, as discussed in Chapter 1. The effects of these programs are forecast based on recent trends in installations and a residential predictive model. **Table 3-2** shows *CED 2011 Preliminary* forecasts of peak impacts from PV and non-PV self-generation. Only residential PV impacts varied in the demand scenarios, based on differences in households and energy rates. Staff projects between 460 to 575 MW of peak reduction from PV systems in the SCE planning area by 2022. Peak reductions are based on installed PV system capacities ranging from 563 MW in 2015 and 969 MW in 2022 in the high demand case to 608 MW in 2015 and 1,201 MW in 2022 in the low demand case.

Table 3-2: SCE Planning Area Self Generation Peak Impacts

Year	1990	2000	2010	2015	2020	2022
Non-Photovoltaic Self-Generation	469.29	503.88	525.43	554.42	573.65	599.57
Photovoltaic, Low Demand	0.00	0.26	102.01	295.28	447.74	575.40
Photovoltaic, Mid Demand	0.00	0.26	102.01	276.43	388.04	496.97
Photovoltaic, High Demand	0.00	0.26	102.01	272.08	365.35	457.01
Total Self-Generation, Low Demand	469.29	504.14	627.43	849.70	1021.39	1174.97
Total Self-Generation, Mid Demand	469.29	504.14	627.43	830.85	961.70	1096.54
Total Self-Generation, High Demand	469.29	504.14	627.43	826.50	939.00	1056.58

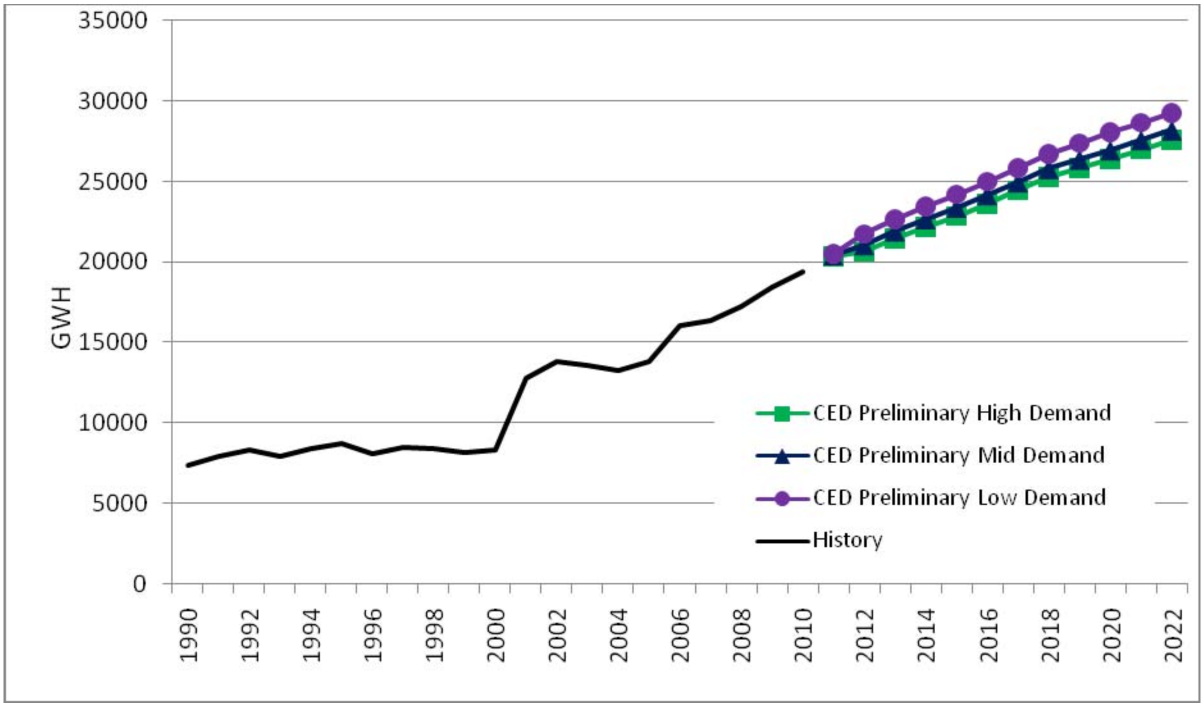
Source: California Energy Commission, 2011

Conservation/Efficiency Impacts

Staff has spent a great deal of time refining methods to account for energy efficiency and conservation impacts while preparing this forecast. **Figure 3-22** and **Figure 3-23** show electricity consumption and peak efficiency savings estimates from all sources, including standards, 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.

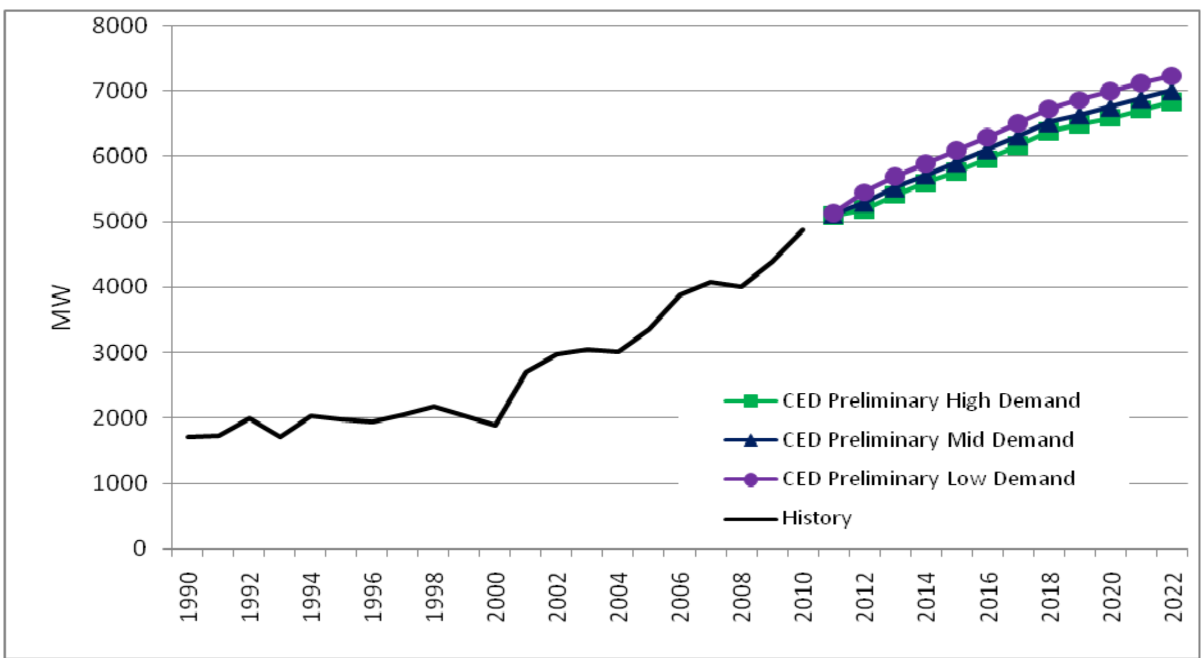
Table 3-3 presents estimated savings for building and appliance standards in the mid demand case for selected years. Total standards impacts are higher in the high demand case by 1.5-2.0 percent because of higher home and commercial floor space construction and 1.5-2.0 percent lower in the low demand case. The standards savings estimates include the 2010 revision to Title 24 building standards as well as AB 1109 lighting savings. Savings are measured against a baseline before 1975, so they incorporate more than 30 years of impacts. Chapter 8 provides more detail on staff work related to energy efficiency and conservation.

Figure 3-22: SCE Planning Area Electricity Consumption Savings Estimates



Source: California Energy Commission, 2011

Figure 3-23: SCE Planning Area Electricity Peak Savings Estimates



Source: California Energy Commission, 2011

Table 3-3: SCE Planning Area Electricity Standards Savings Estimates

Electricity Consumption Savings (GWH)							
	Residential			Commercial			
	Building Standards	Appliance Standards	Total	Building Standards	Appliance Standards	Total	Total Standards
1990	864	1,004	1,867	511	360	871	2,738
2000	1,038	2,740	3,778	1,390	1,017	2,407	6,185
2010	1,452	6,144	7,597	2,721	1,769	4,490	12,087
2015	1,673	7,937	9,610	3,405	2,193	5,598	15,208
2020	1,876	9,149	11,024	4,327	2,868	7,195	18,219
2022	1,930	9,319	11,250	4,671	3,020	7,691	18,941
Electricity Peak Demand Savings (MW)							
	Residential			Commercial			
	Building Standards	Appliance Standards	Total	Building Standards	Appliance Standards	Total	Total Standards
1990	236	274	510	120	84	204	715
2000	246	650	897	291	213	504	1,400
2010	425	1,796	2,221	610	396	1,006	3,227
2015	516	2,450	2,966	723	466	1,189	4,156
2020	573	2,797	3,370	916	607	1,523	4,893
2022	584	2,820	3,404	988	639	1,626	5,031

Source: California Energy Commission, 2011

CHAPTER 4: San Diego Gas & Electric Planning Area

The SDG&E planning area includes SDG&E bundled retail customers and customers served by various energy service providers using the SDG&E distribution system to deliver electricity to end users.

This chapter is organized similar to those for the other planning areas. Forecasts of total consumption, per capita consumption, peak loads and load factors give an overview of SDG&E's projected electricity demand in the coming decade. This precedes a more detailed discussion of key sector-level inputs and results. Results for self-generation, efficiency, conservation, and electric vehicles are found toward the end of this chapter.

This report presents three demand scenarios—high, mid and low. The high case is characterized by low electricity rates, high population growth, high levels of efficiency, and low self-generation. Inversely, the low case is characterized by high electricity rates, low population, etc. The tables and charts presented throughout this chapter show results for all three scenarios alongside the *CED 2011 Preliminary* mid case results, for reference.

Forecast Results

Table 4-1 presents a comparison of the planning area electricity consumption and peak demand forecasts for selected years. For both consumption and peak demand, growth rates starting in 2011 are shown in order to compare weather-normalized growth, since consumption in 2010 was reduced significantly because of a very mild weather year overall while a heat storm even in September 2010 yielded a relatively high peak.

Due to a lower starting point, all three scenarios project a lower level of consumption than *CED 2009* in the short-term. However, the overall annual growth rate from 2011-2020 is higher than *CED 2009* in all three scenarios. The mid demand scenario estimates 1.78 percent annual growth in consumption and 0.84 percent annual growth in peak demand. By 2022, total consumption in the high case is projected to be 5.6 percent higher than the low case. The spread between peak demand scenarios is slightly wider, with the high case projected to be 7.5 percent higher than the low case.

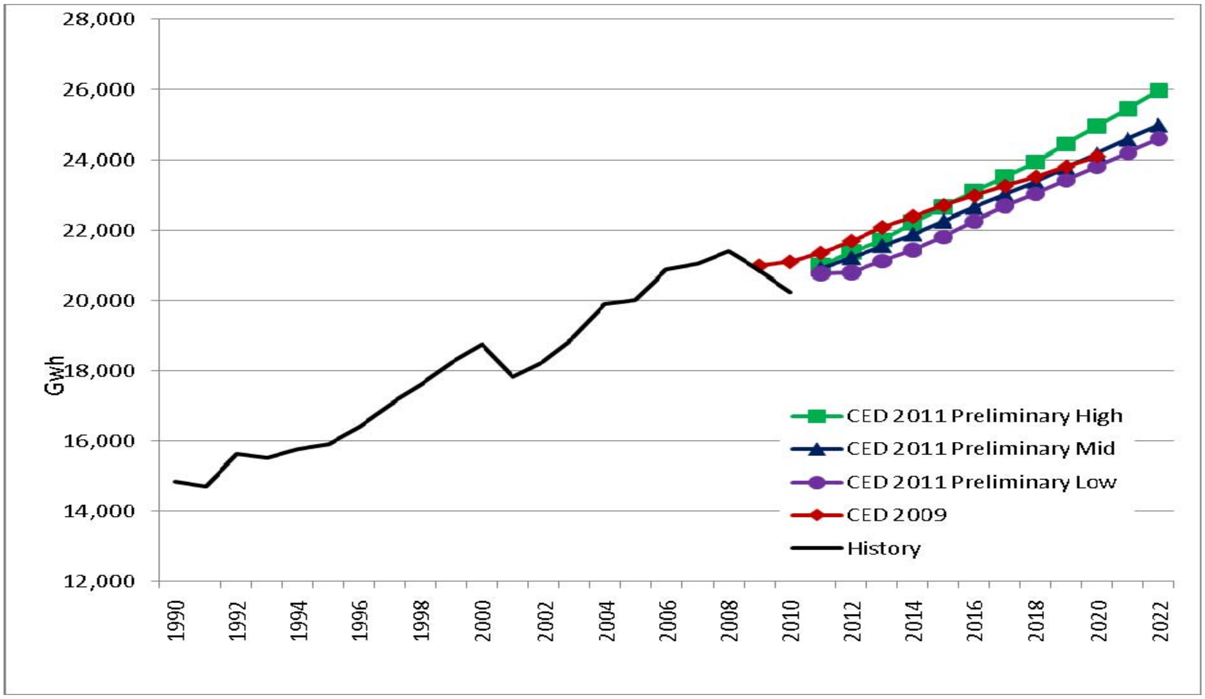
Table 4-1: SDG&E Planning Area Forecast Comparison

Consumption (GWh)				
	CED 2009 (Dec. 2009)	*CED 2011 Preliminary- High Energy Demand*	*CED 2011 Preliminary- Mid Energy Demand*	*CED 2011 Preliminary- Low Energy Demand*
1990	14,926	14,863	14,863	14,863
2000	19,294	18,784	18,784	18,784
2010	21,100	20,235	20,235	20,235
2011	21,354	20,999	20,898	20,772
2015	22,707	22,666	22,268	21,820
2020	24,119	24,971	24,187	23,817
2022	--	25,987	25,005	24,604
	Average Annual Growth Rates			
1990-2000	2.60%	2.37%	2.37%	2.37%
2000-2010	0.90%	0.75%	0.75%	0.75%
2011-2015	1.55%	1.93%	1.60%	1.24%
2011-2020	1.36%	1.94%	1.64%	1.64%
2011-2022	--	2.11%	1.78%	1.64%
Peak (MW)				
	CED 2009 (Dec. 2009)	*CED 2011 Preliminary- High Energy Demand*	*CED 2011 Preliminary- Mid Energy Demand*	*CED 2011 Preliminary- Low Energy Demand*
1990	2,978	2,978	2,978	2,978
2000	3,485	3,485	3,485	3,485
2010	4,516	4,687	4,687	4,687
2011	4,578	4,463	4,490	4,508
2015	4,863	4,835	4,746	4,636
2020	5,174	5,271	5,077	4,964
2022	--	5,432	5,183	5,054
	Average Annual Growth Rates			
1990-2000	1.58%	1.58%	1.58%	1.58%
2000-2010	2.63%	3.01%	3.01%	3.01%
2011-2015	1.52%	2.02%	1.39%	0.70%
2011-2020	1.37%	1.87%	1.38%	1.08%
2011-2022	--	1.24%	0.84%	0.63%
Historical values are shaded				

Source: California Energy Commission, 2011

At the start of the forecast period, the *CED 2011 Preliminary* mid case consumption forecast is 2.1 percent lower than the *CED 2009* projection. **Figure 4-1** illustrates how the higher growth rate in the mid case causes the two forecasts to converge to roughly the same value by 2020.

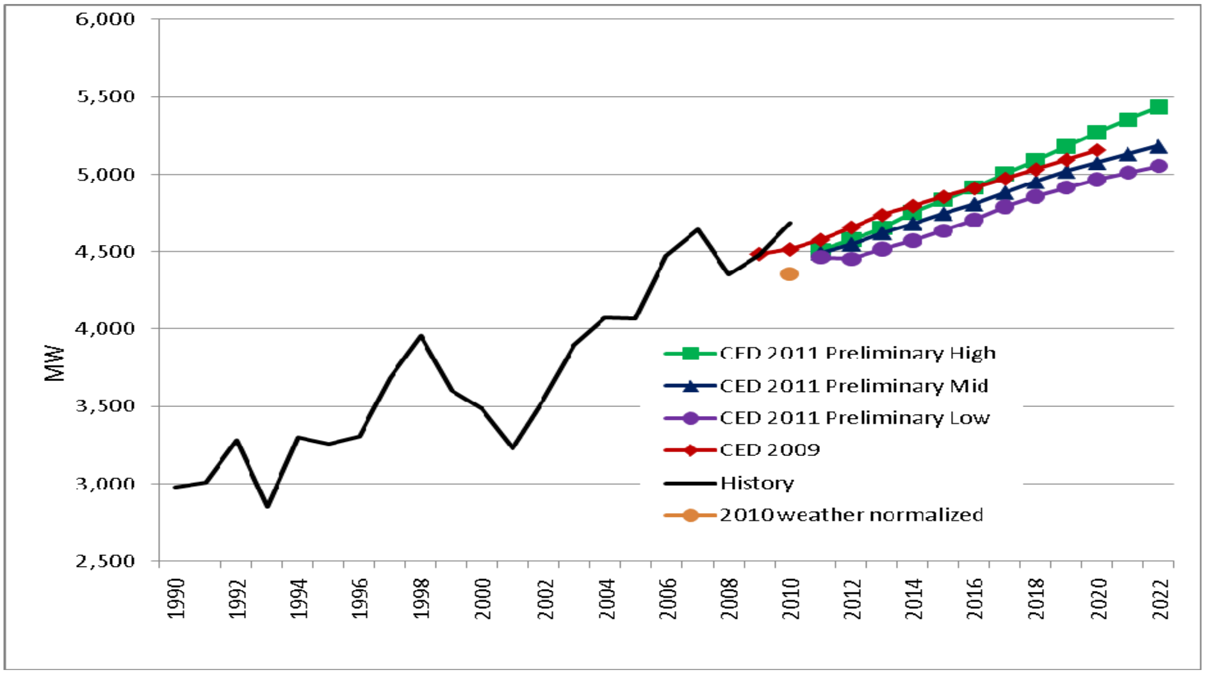
Figure 4-1: SDG&E Planning Area Electricity Forecast



Source: California Energy Commission, 2011

The *CED 2011 Preliminary* SDG&E planning area peak demand forecast is about 1.9 percent lower than the *CED 2009* forecast in the beginning of the forecast period as shown in **Figure 4-2**. By the end of the forecast period, the *CED 2011 Preliminary* mid forecast is only 1.5 percent lower. The peak forecast assumes normal weather conditions, and the 2010 weather normalized peak value is estimated to be 7.1 percent lower than the actual recorded peak load for that year.

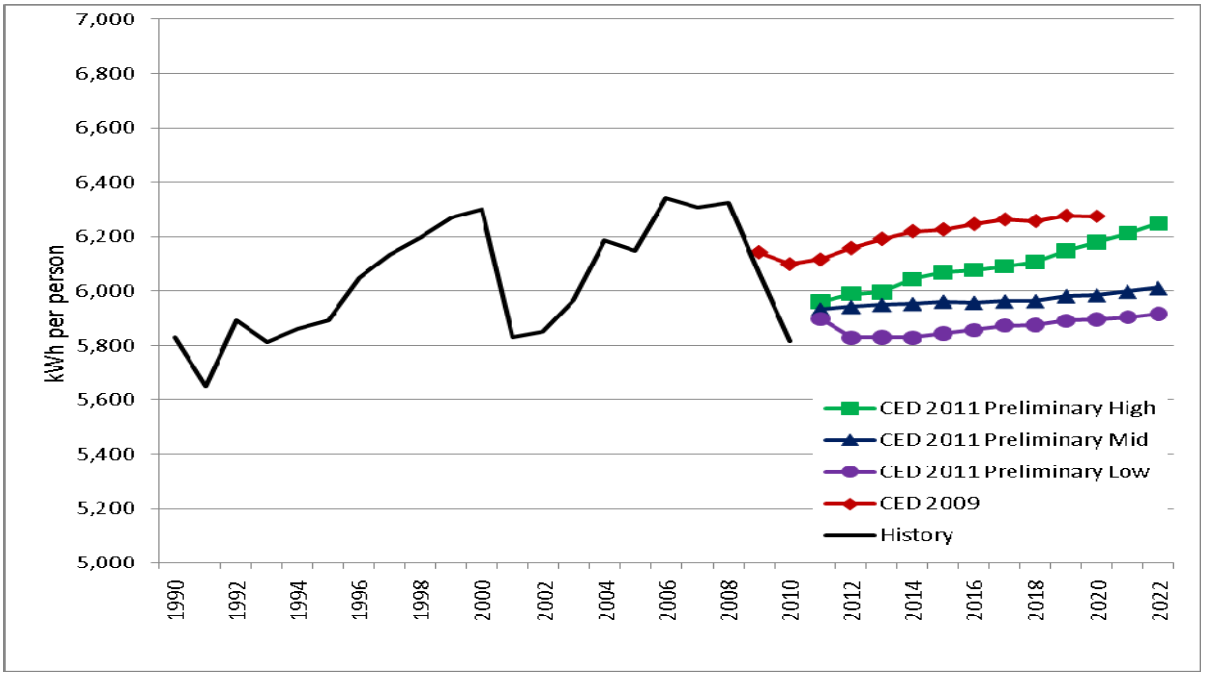
Figure 4-2: SDG&E Planning Area Peak



Source: California Energy Commission, 2011

Figure 4-3 compares forecasts of per capita residential electricity consumption. Per capita consumption in the *CED 2011 Preliminary* forecast is lower for all demand scenarios than the *CED 2009* forecast. The scenarios start lower than the *CED 2009* forecast in 2011. The preliminary mid case maintains a relatively flat trajectory over the first half of the forecast period, then a period of low growth toward the end. This slight growth indicates the effect of an increasing number of electric vehicles.

Figure 4-3: SDG&E Planning Area per Capita Electricity Consumption

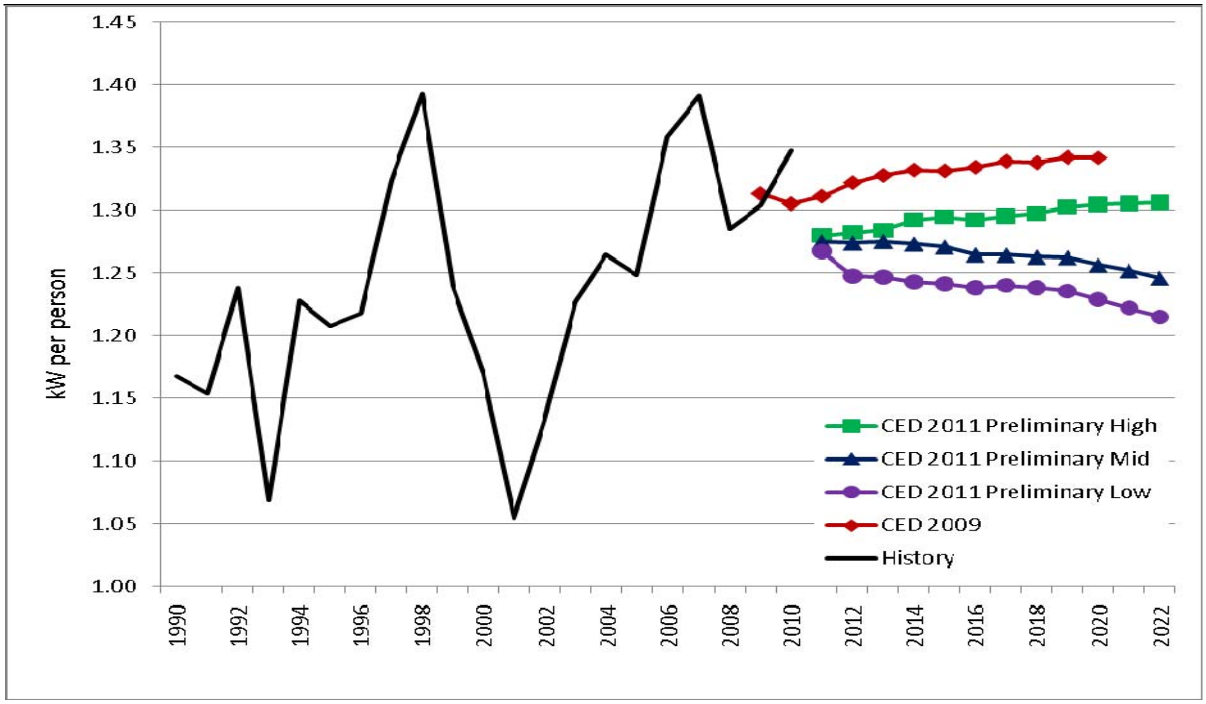


Source: California Energy Commission, 2011

Per capita peak demand, shown in

Figure 4-4, is lower over the entire forecast period because of a lower starting point. The *CED 2011 Preliminary* high demand scenario grows at a similar rate as the *CED 2009* forecast while the mid and low cases decline over the forecast period.

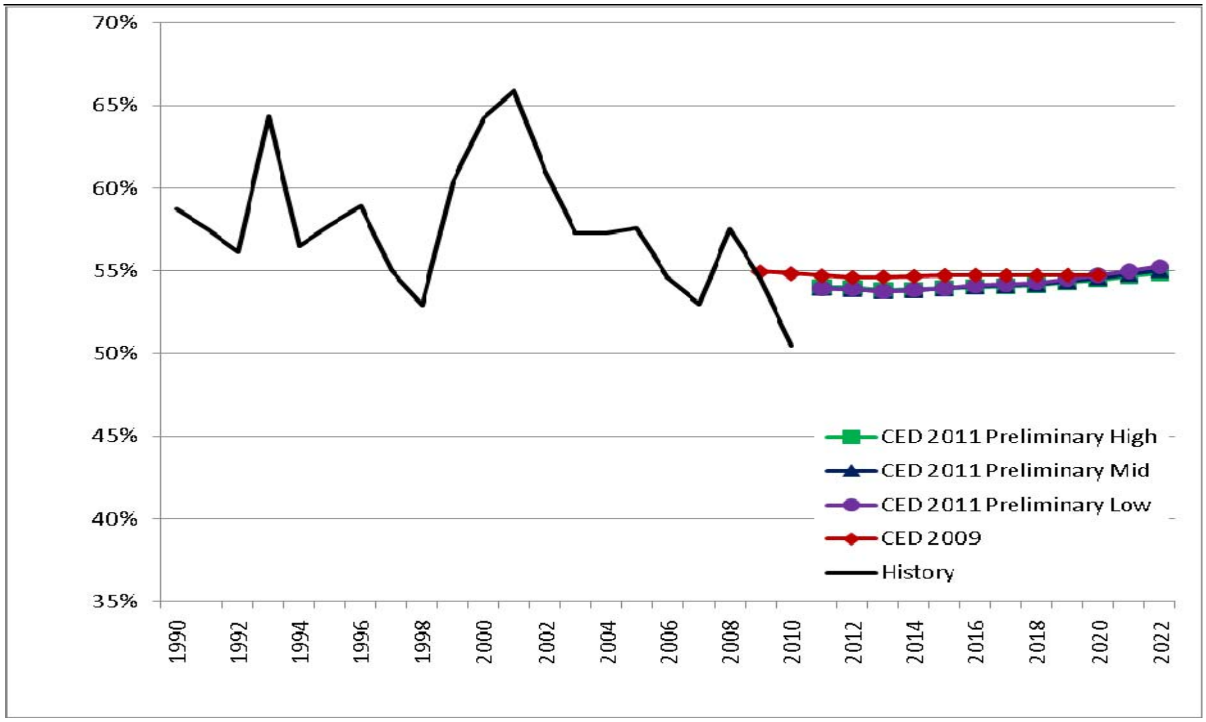
Figure 4-4: SDG&E Planning Area per Capita Peak Demand



Source: California Energy Commission, 2011

Figure 4-5 provides a comparison of the respective forecast load factors. High load factors observed from 1998-2005 are a product of lower-than-average peak temperatures and reaction to the energy crisis. The projected load factors, based on average temperatures and a return to normal air conditioning use patterns, should be lower than these recent values, with the exception of 2010, during which southern California experienced unusually cool summer temperatures.

Figure 4-5: SDG&E Planning Area Peak Load Factors



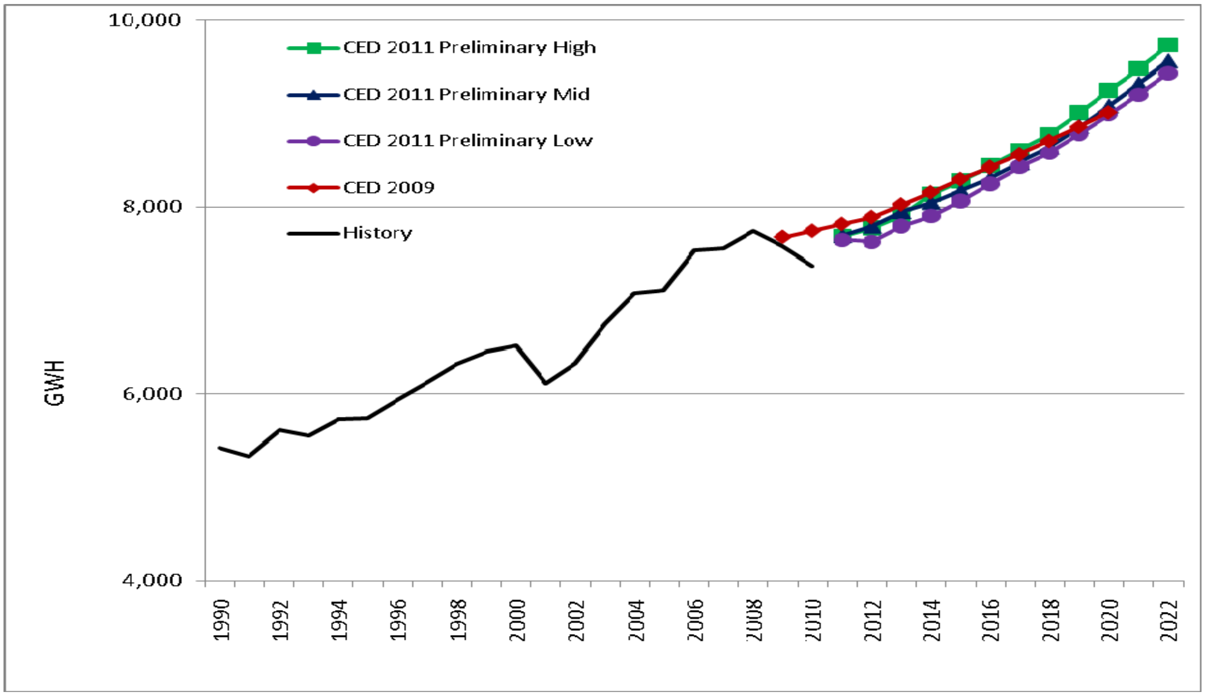
Source: California Energy Commission, 2011

Sector Level Results and Input Assumptions

Residential

Figure 4-6 provides a comparison between the *CED 2011 Preliminary* and *CED 2009* SDG&E planning area residential forecasts. Due to a lower starting point, all three scenarios project a lower level of consumption than *CED 2009* in the very near term. However, for each scenario, the overall growth rate is higher than *CED 2009* due to higher growth in occupied households and higher income growth in the mid and high demand scenarios. By 2020, all three scenarios are within 1.3 percent of the *CED 2009* forecast. This narrow range of forecasts reflects a relatively narrow spread in personal income between the scenarios. The mid case grows at an annual rate of 2.2 percent to reach 9560 GWh by 2022.

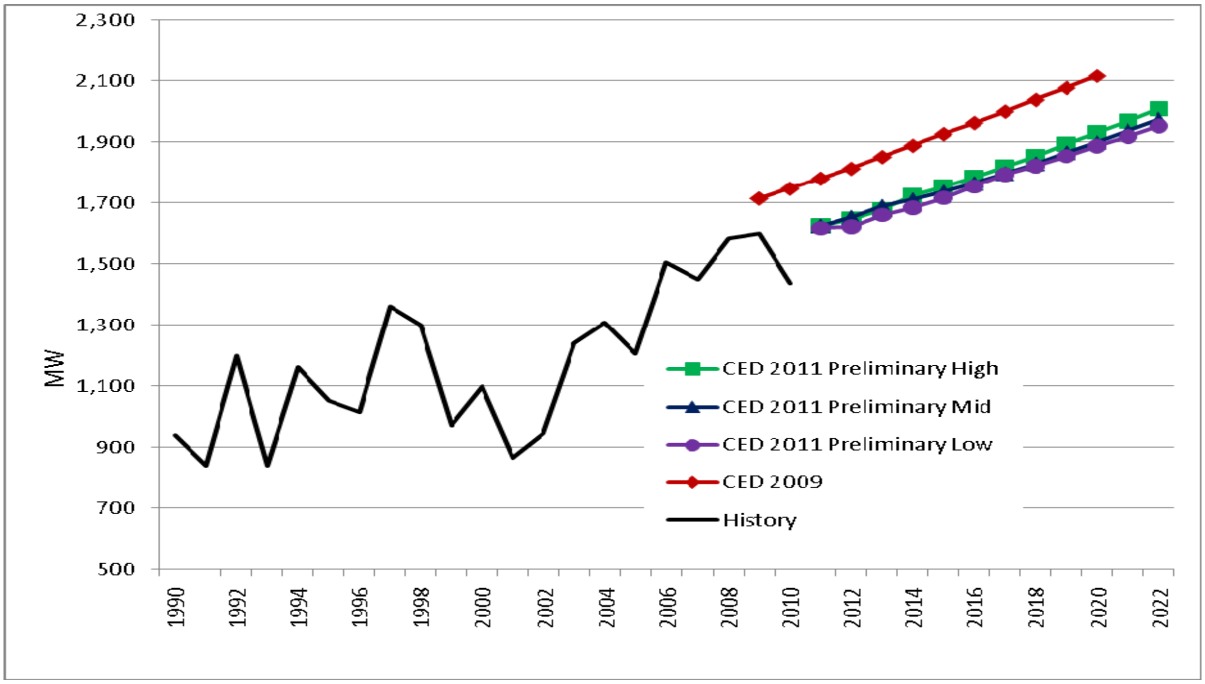
Figure 4-6: SDG&E Planning Area Residential Consumption



Source: California Energy Commission, 2011

Figure 4-7 provides a comparison of the *CED 2011 Preliminary* and *CED 2009* residential peak demand forecasts. The *CED 2011 Preliminary* forecasts are all lower than the *CED 2009* forecast but grow at about the same rate. The mid case grows at an annual rate of 2.7 percent to reach almost 2,000 MW by 2022.

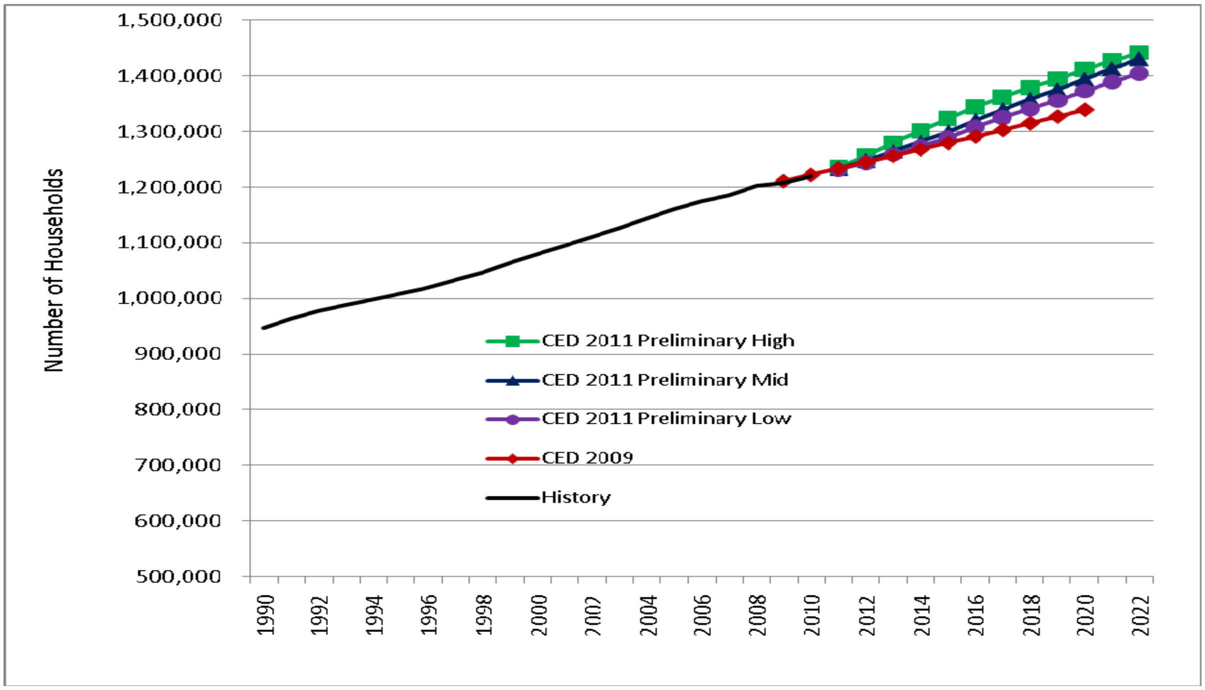
Figure 4-7: SDG&E Planning Area Residential Peak



Source: California Energy Commission, 2011

Figure 4-8, **Figure 4-9**, and **Figure 4-10** provide comparisons of the residential economic/demographic drivers used in *CED 2011 Preliminary* forecast with those used in *CED 2009*. **Figure 4-8** provides comparisons of total household projections. There is very little change in the year-to-year growth in the mid and low demand scenarios. The high scenario grows quickly in the near term and then slows. By the end of the forecast period, the trajectories of all three scenarios are lower than *CED 2009*.

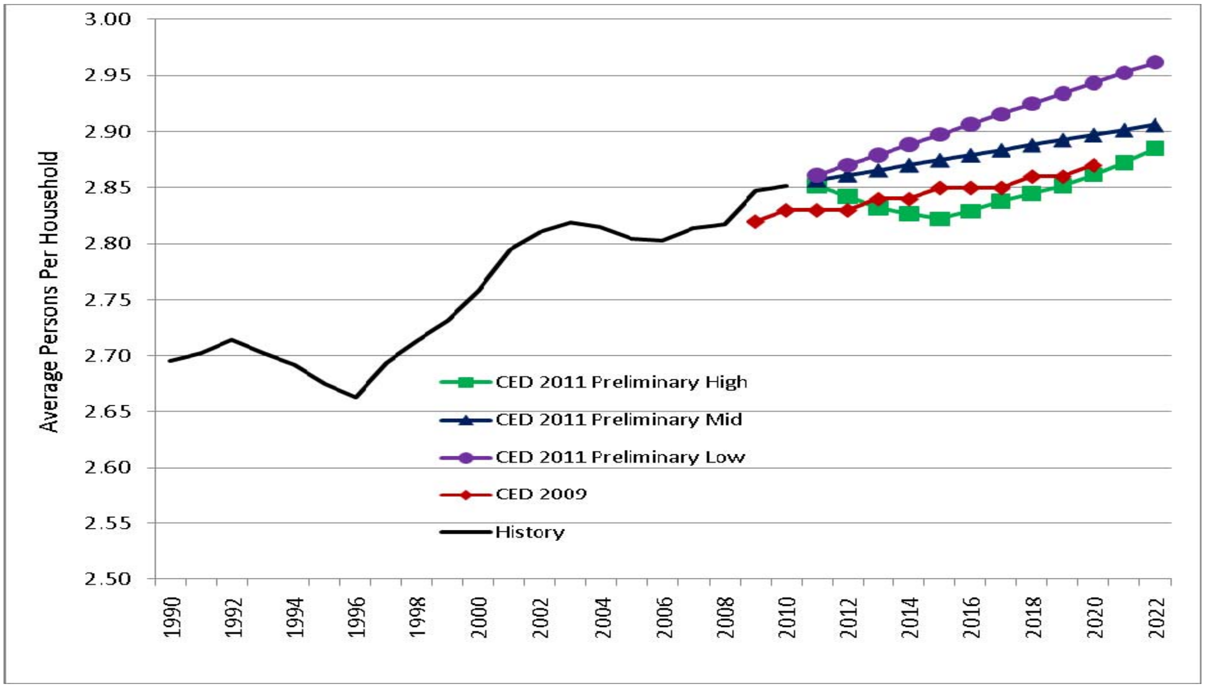
Figure 4-8: SDG&E Planning Area Household Projections



Source: California Energy Commission, 2011

Figure 4-9 provides comparisons of persons per household. Population assumptions are consistent across all three scenarios, so the projections of households and persons per household are inversely related. The low and mid cases grow steadily while the high case declines in the near term before growing rapidly in the latter half of the forecast period.

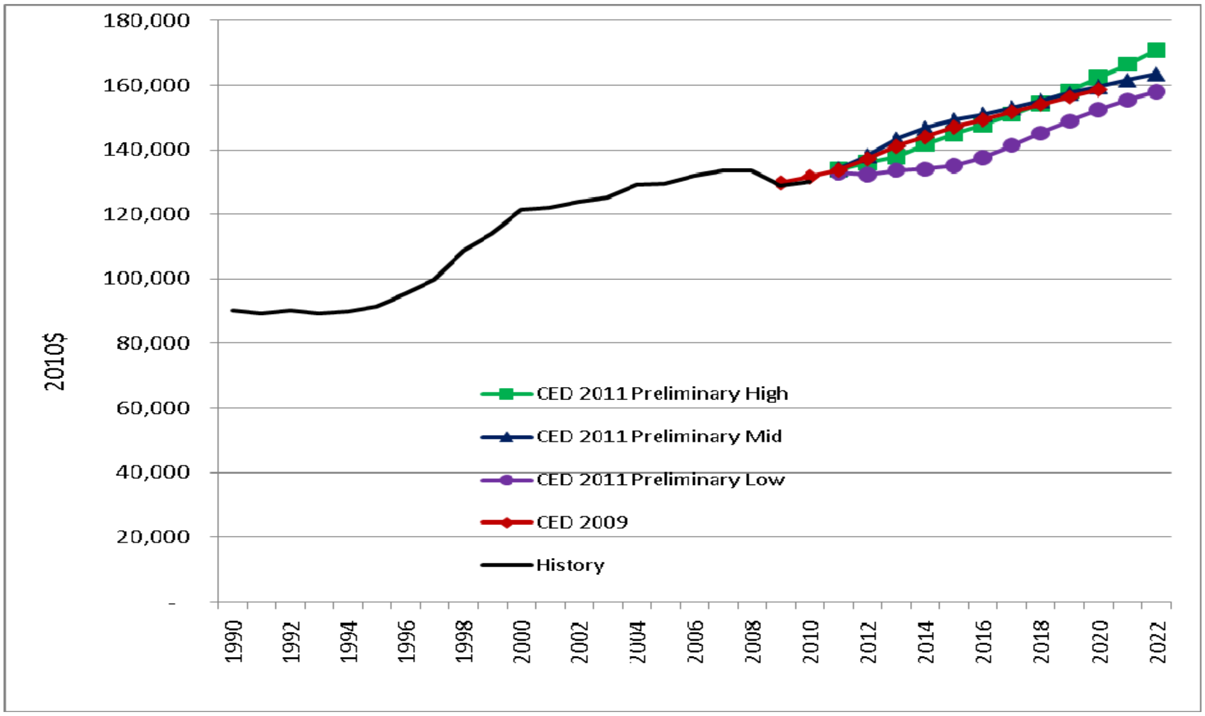
Figure 4-9: SDG&E Planning Area Persons per Household Projections



Source: California Energy Commission, 2011

Figure 4-10 provides a comparison of average household income between the forecasts and shows that the *CED Preliminary* mid demand case tracks very closely with the *CED 2009* projection. Compared to the mid scenario, the high demand case has lower total household income in the early years of the forecast. This, combined with differences in the projected growth rate of households versus total household income, yields lower income per household in the high case than in the mid case until the later years of the forecast period.

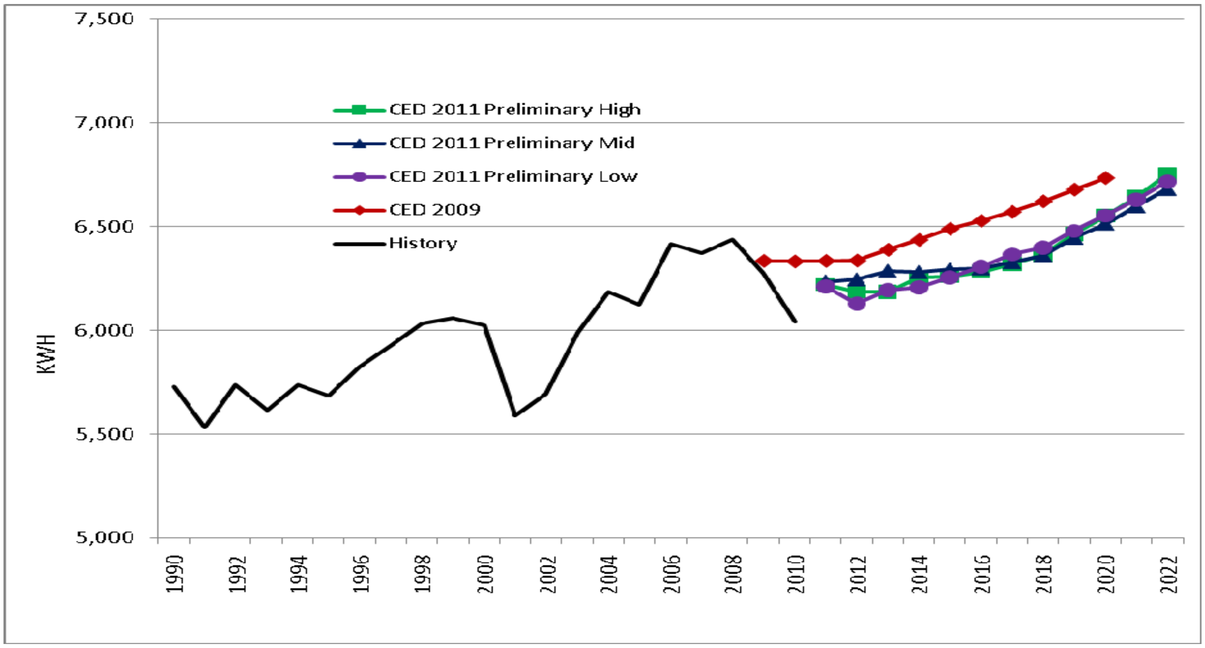
Figure 4-10: SDG&E Planning Area Average Household Income Projections



Source: California Energy Commission, 2011

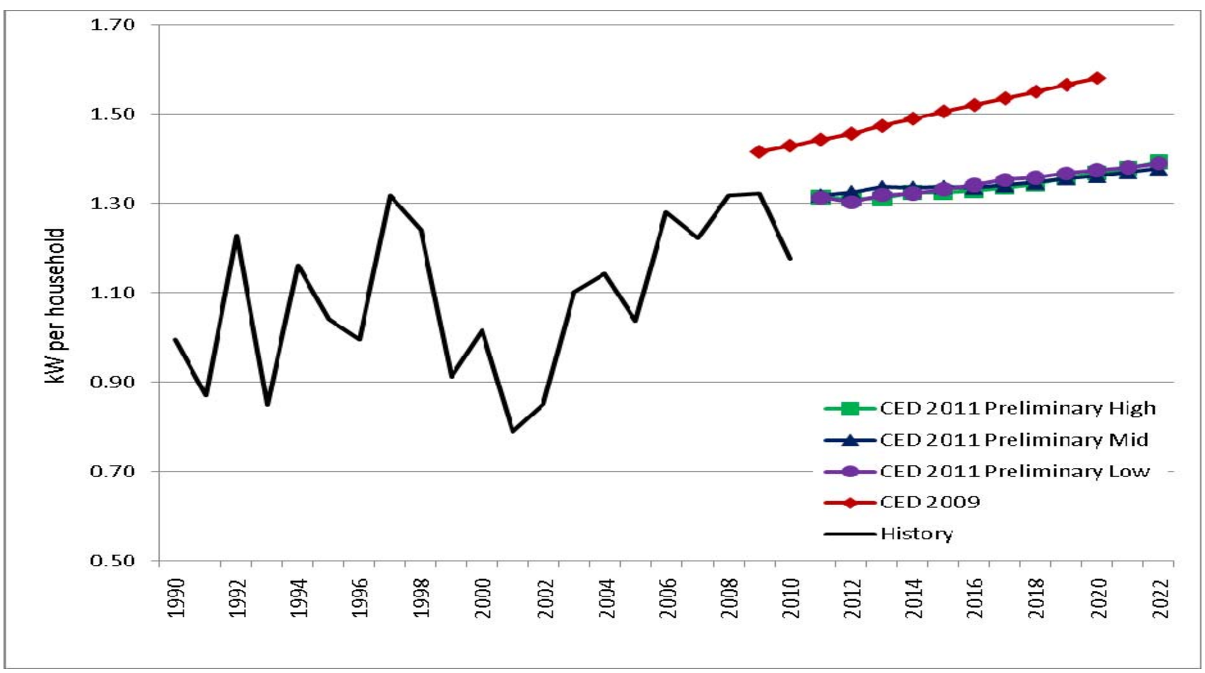
Figure 4-11 and **Figure 4-12** present comparisons of residential consumption per household and residential peak use per household, respectively. The *CED 2011 Preliminary* forecast of use per household is significantly lower than that projected in *CED 2009* due to a lower starting point. By 2022, the mid demand scenario actually projects a lower use per household than the low case. This is because the low case assumes more persons per household than the mid case. There is relatively little difference in household income between the two scenarios.

Figure 4-11: SDG&E Planning Area Consumption per Household



Source: California Energy Commission, 2011

Figure 4-12: SDG&E Planning Area Peak Use per Household

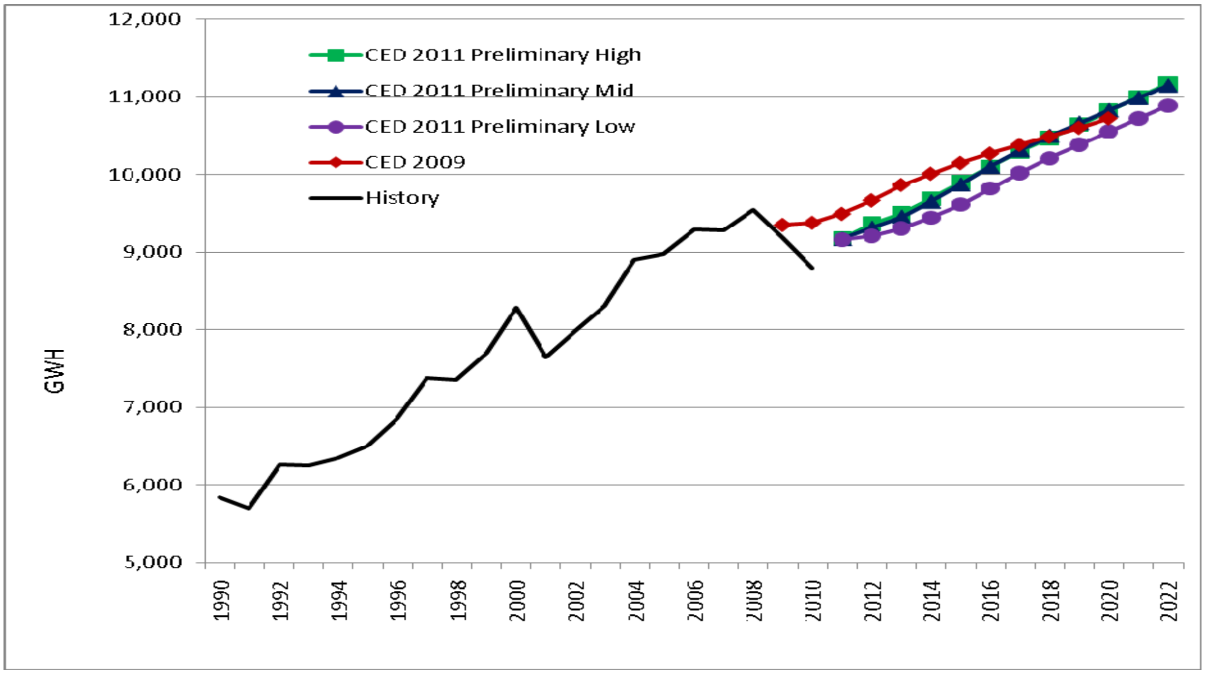


Source: California Energy Commission, 2011

Commercial Sector

Figure 4-13 provides a comparison of the commercial sector consumption forecasts. Projected growth from 2011-2020 in commercial consumption is faster in all three scenarios compared to *CED 2009* because of faster projected growth in commercial floor space. Relatively similar projections of floor space among the scenarios (see Chapter 1) lead to little difference among the scenarios. Since 2010 marked unusually cool weather in Southern California, the consumption scenarios began at a value lower than predicted by *CED 2009*. The mid case grows at an annual rate of 1.8 percent to reach 11,150 GWh by 2022.

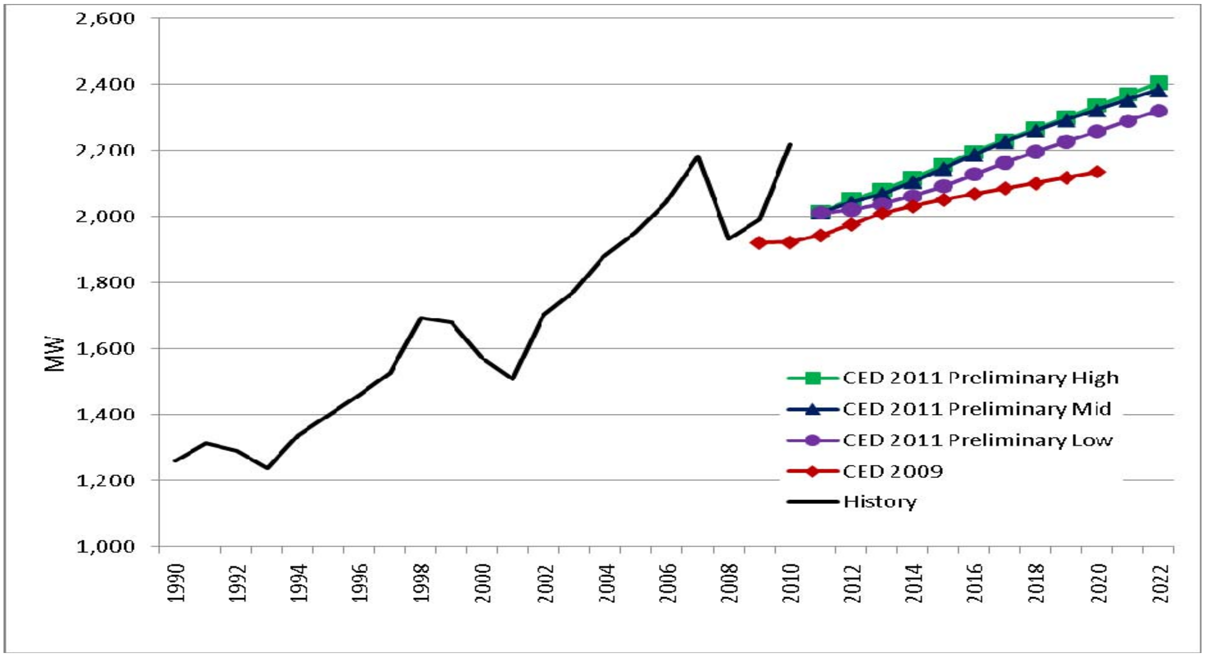
Figure 4-13: SDG&E Planning Area Commercial Consumption



Source: California Energy Commission, 2011

Figure 4-14 provides a comparison of the commercial sector peak demand forecasts. Differences in the peak forecasts are similar to those in the consumption forecasts. The mid case grows at an annual rate of 1.5 percent to reach 2,385 MW by 2022.

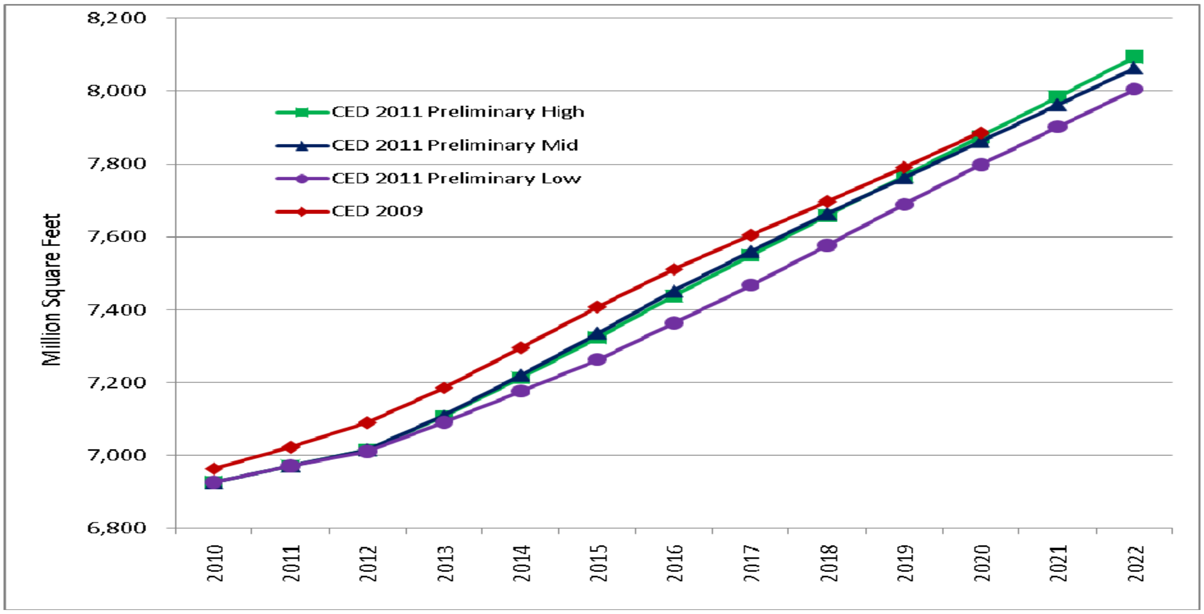
Figure 4-14: SDG&E Planning Area Commercial Sector Peak



Source: California Energy Commission, 2011

In staff's commercial building sector forecasting model, floor space by building type (for example, retail, schools, and offices) is the key driver of energy use for each specific building type. **Figure 4-15** provides a comparison of total commercial floor space projections. Floor space projections are driven by employment forecasts in individual subsectors (retail, wholesale, restaurants, and so on). These may differ among the economic forecasts so that a subsector employment forecast may be higher in the low demand scenario than in the high case, even though total employment is lower. This can lead to the result shown in **Figure 4-15**, where mid demand floor space is higher than the high case projection. However, lower projected rates in the high demand case keep commercial consumption above that in the other two scenarios, as shown in **Figure 4-13**.

Figure 4-15: SDG&E Planning Area Commercial Floor Space

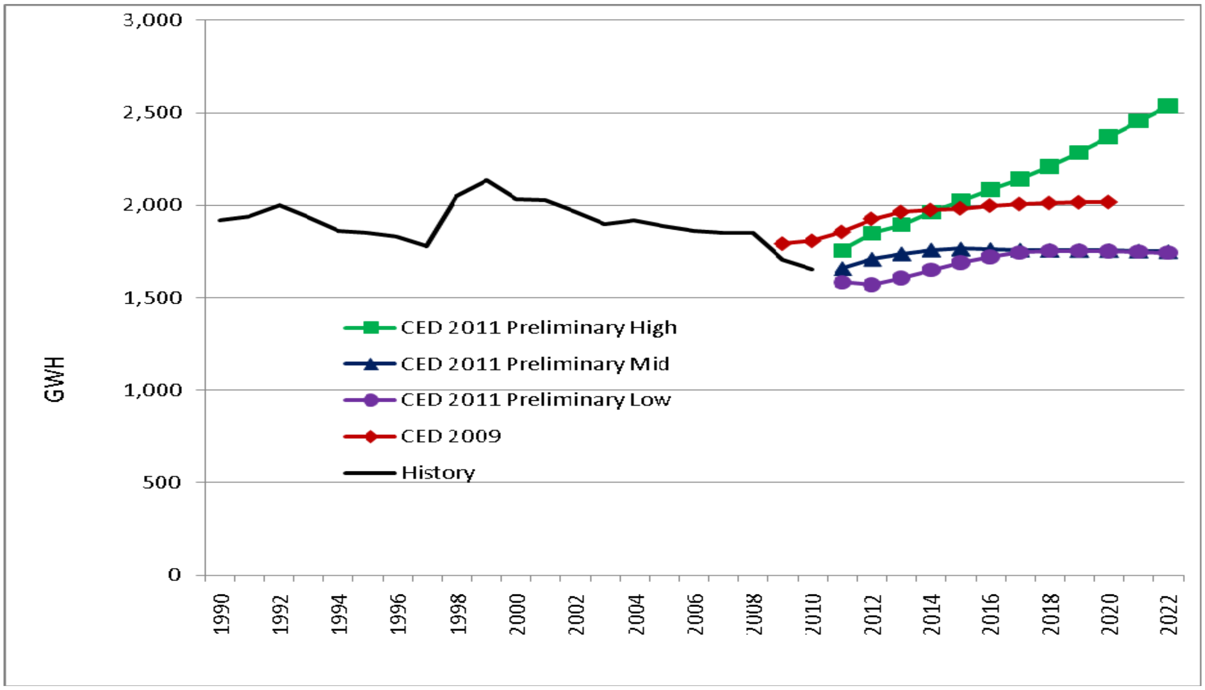


Source: California Energy Commission, 2011

Industrial Sector

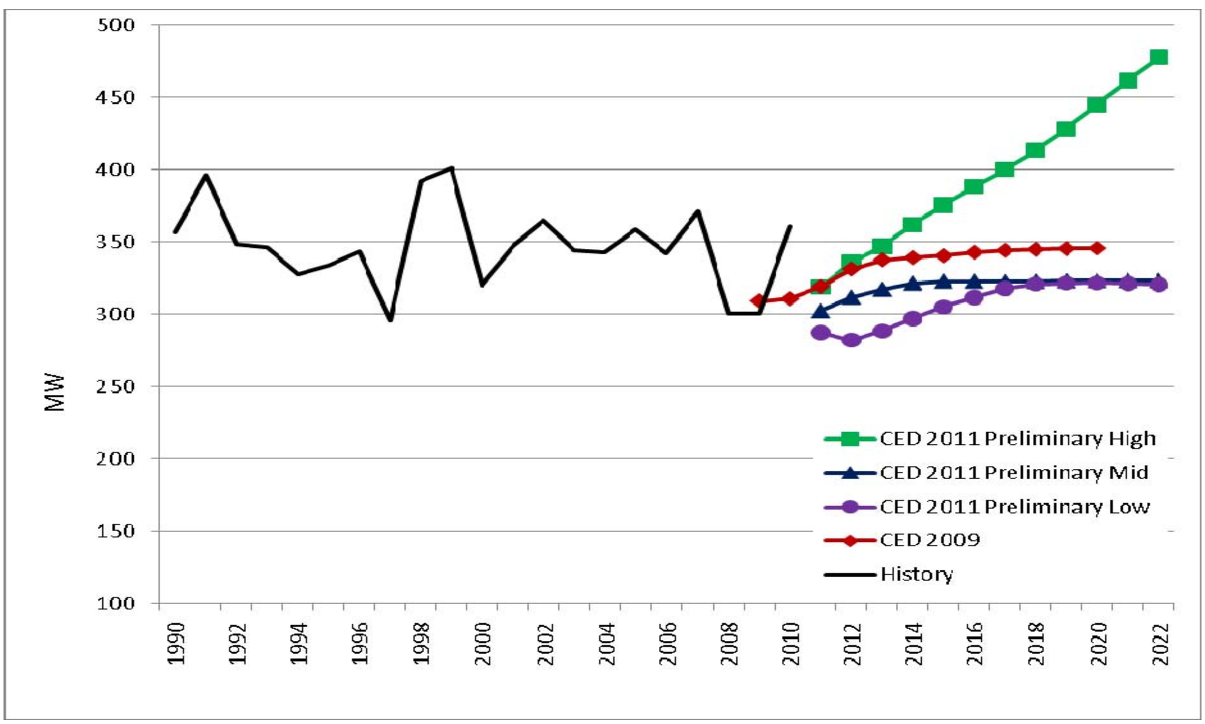
Figure 4-16 provides a comparison of the industrial sector electricity consumption forecasts for the SDG&E planning area. *CED 2011 Preliminary* mid and low cases echo a pattern described in *CED 2009*—short-term recovery followed by a return to long-term decline. The lower starting point for *CED 2011 Preliminary* follows from actual industrial consumption in 2010, which was lower than projected in *CED 2009*. The substantial spread between low and high cases (the high case is about 45 percent higher than the low case in 2022) reflects disparate input forecasts. Global Insight, which was used in the high case, projects very high growth in manufacturing and construction relative to Moody's, which was used in the mid and low cases.

Figure 4-16: SDG&E Planning Area Industrial Consumption



Source: California Energy Commission, 2011 **Figure** 4-17 provides a comparison of the industrial sector peak forecasts. Differences in the peak forecasts are similar to those of the consumption forecasts.

Figure 4-17: SDG&E Planning Area Industrial Sector Peak



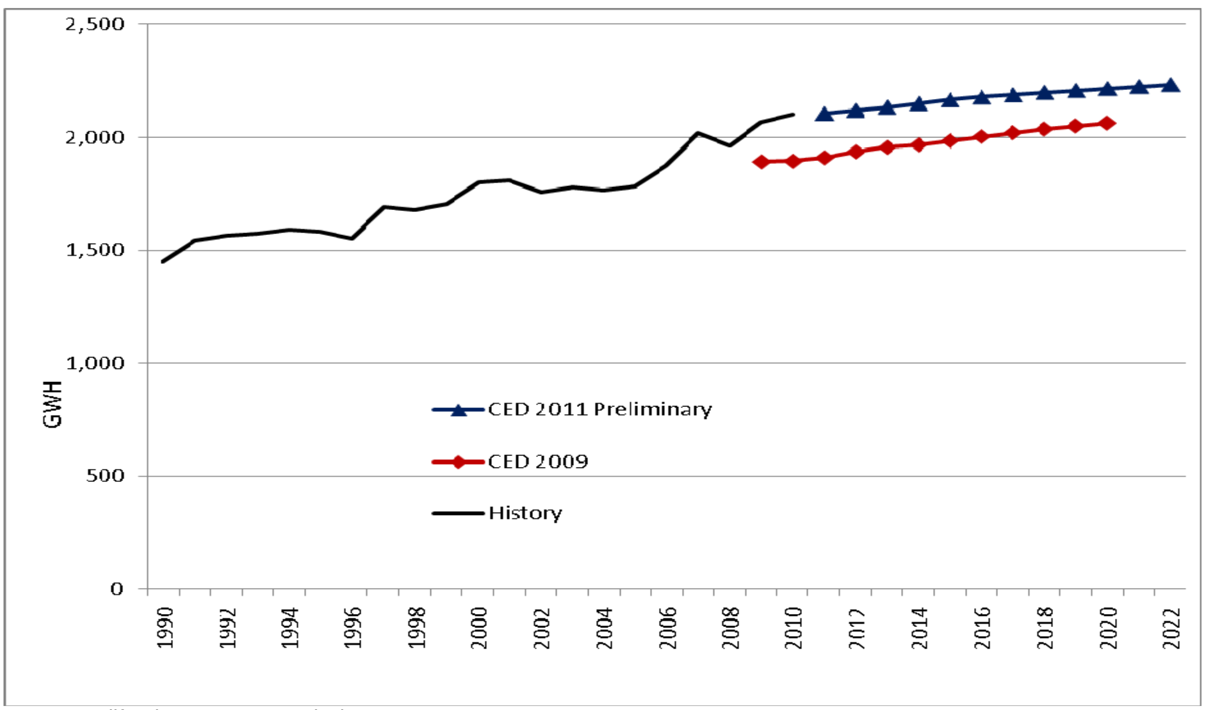
Source: California Energy Commission, 2011

Other Sectors

Figure 4-18 and **Figure 4-19** provide comparisons of the remaining sector electricity consumption forecasts. **Figure 4-18** provides a comparison of the transportation, communication and utilities sector forecast, which includes street lighting. In this case, a single scenario was run.[23] The *CED 2011 Preliminary* forecast is higher than the *CED 2009* forecast because of a higher historic starting point. The preliminary forecast has a lower annual growth rate, however, at 0.5 percent.

Figure 4-19 provides comparisons of the agriculture and water pumping sector forecasts. The *CED 2011 Preliminary* agriculture and water pumping forecast does not deviate significantly from *CED 2009*, though it does have a slightly higher annual growth rate at 0.6 percent in the mid case. The slight differences between demand scenarios reflect different forecasts of occupied households.

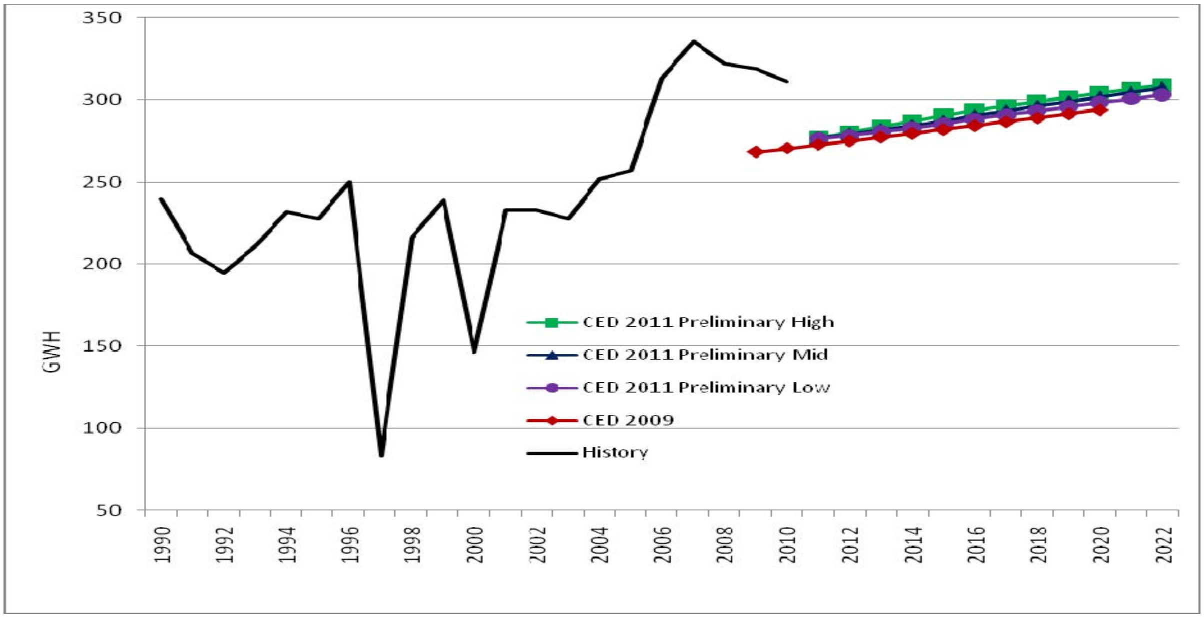
Figure 4-18: SDG&E Planning Area Transportation, Communication and Utilities Sector Electricity Consumption



Source: California Energy Commission, 2011

23 Growth in TCU consumption depends mainly on population, for which there is only one scenario.

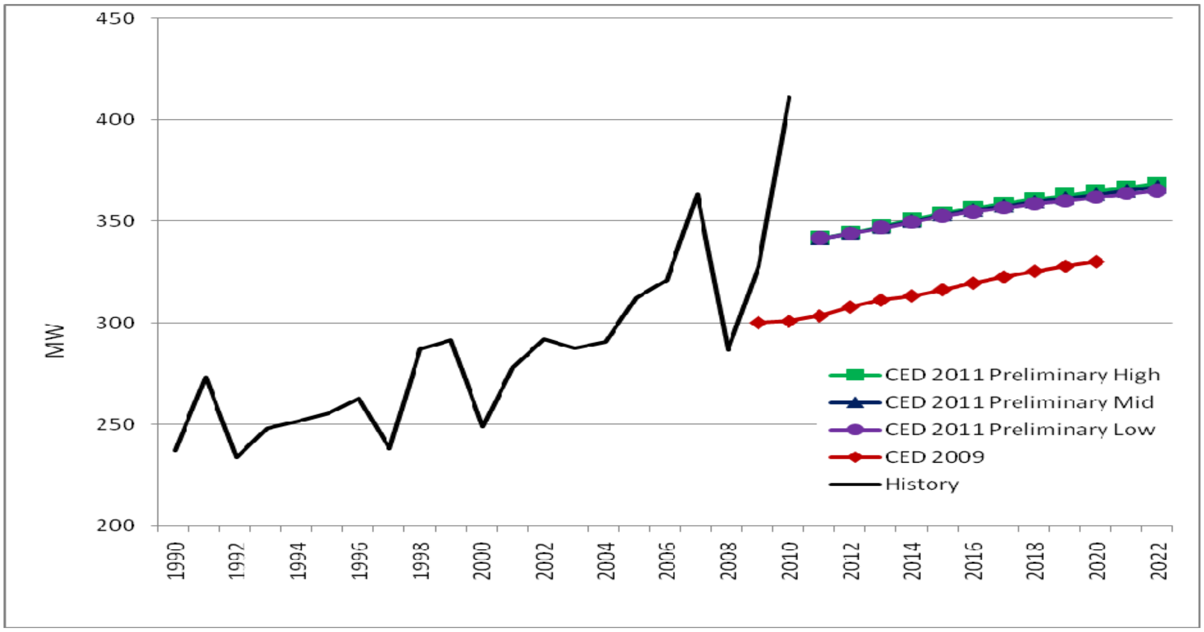
Figure 4-19: SDG&E Planning Area Agriculture & Water Pumping Forecasts



Source: California Energy Commission, 2011

Figure 4-20 provides a comparison of the combined "other" sector peak forecasts. This sector includes the combined demands of the transportation, communication, utility, street lighting, agricultural and water pumping sectors. The *CED 2011 Preliminary* forecast grows at a rate of 0.6 percent annually, roughly the same growth projected by *CED 2009*. Because of the significantly higher starting point, the forecast scenarios remain much higher throughout the forecast period.

Figure 4-20: SDG&E Planning Area Other Sector Peak

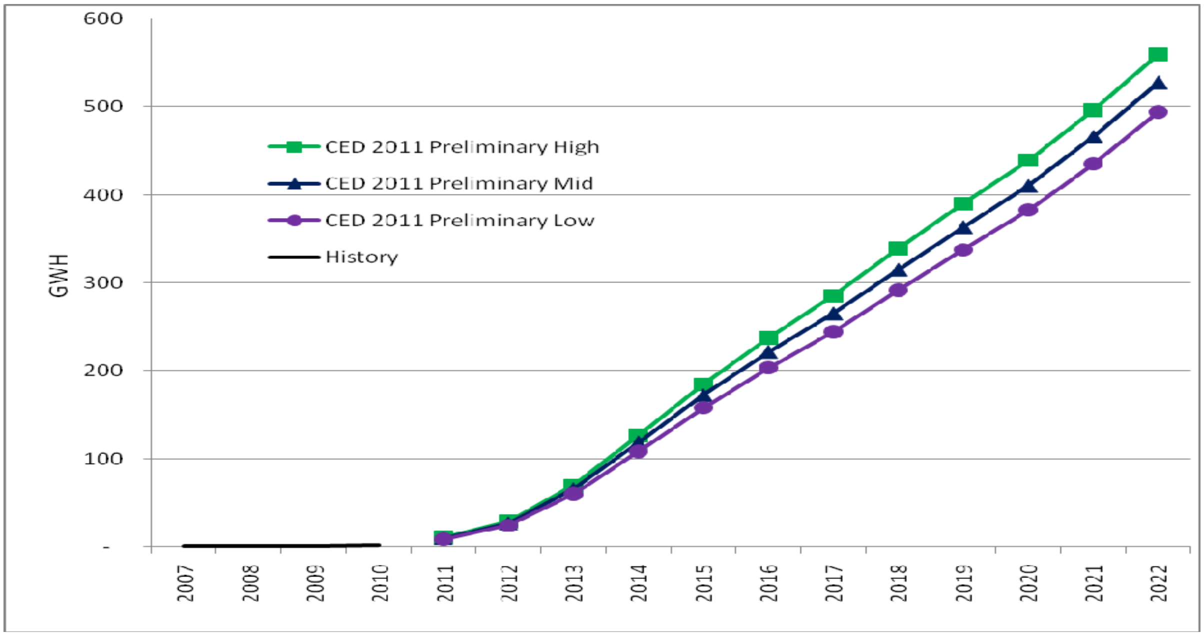


Source: California Energy Commission, 2011

Electric Vehicles

Figure 4-21 shows projected electricity consumption due to increased use of electric vehicles. Since existing electric vehicle use is included in QFER consumption data, projected consumption and peak demand incremental to 2010 usage was added to the sector model results. For the SDG&E planning area, consumption by electric vehicles was approximately 2 GWh in 2010, and is projected to rise to 527 GWh in the mid case by 2022. For many of these electric vehicles, recharging will routinely occur during off-peak hours, resulting in relatively low peak impacts. By 2022, electric vehicles are expected to contribute an additional 21 MW of peak demand in the low demand scenario and 24 MW in the high scenario.

Figure 4-21: SDG&E Planning Area Electric Vehicle Forecast



Source: California Energy Commission, 2011

Self-Generation

As shown in **Table 4-2**, the peak demand forecast is reduced by self-generation, including the effects of the SGIP, CSI, and other programs, as discussed in Chapter 1. The effects of these programs are forecast based on recent trends in installations and a predictive model for the residential sector. Staff projects about 190 MW of peak reduction from PV installation in the mid case by 2022. Peak reductions are based on installed PV system capacities ranging from 178 MW in 2015 and 322 MW in 2022 in the high demand case to 194 MW in 2015 and 396 MW in 2022 in the low demand case.

Table 4-22: SDG&E Planning Area Self-Generation Peak Forecasts

Year	1990	2000	2010	2015	2020	2022
Non-PV Self-Generation	78.68	59.47	104.39	128.17	128.17	128.17
PV, Low Demand	0.00	0.06	45.56	108.63	171.16	219.68
PV, Mid Demand	0.00	0.06	45.56	101.18	149.79	192.34
PV, High Demand	0.00	0.06	45.56	99.41	140.18	176.13
Total Self-Generation, Low Demand	78.68	59.53	149.96	236.80	299.34	347.85
Total Self-Generation, Mid Demand	78.68	59.53	149.96	229.35	277.96	320.51
Total Self-Generation, High Demand	78.68	59.53	149.96	227.58	268.36	304.30

Source: California Energy Commission, 2011

Conservation/Efficiency Impacts

Table 4-3 shows electricity consumption and peak savings estimates for building and appliance standards for the mid demand scenario. Total standards impacts are higher in the high demand case by 1.5-2.0 percent because of higher home construction and 1.5-2.0 percent lower in the low demand case. Chapter 8 provides more detail on staff work related to energy efficiency and conservation.

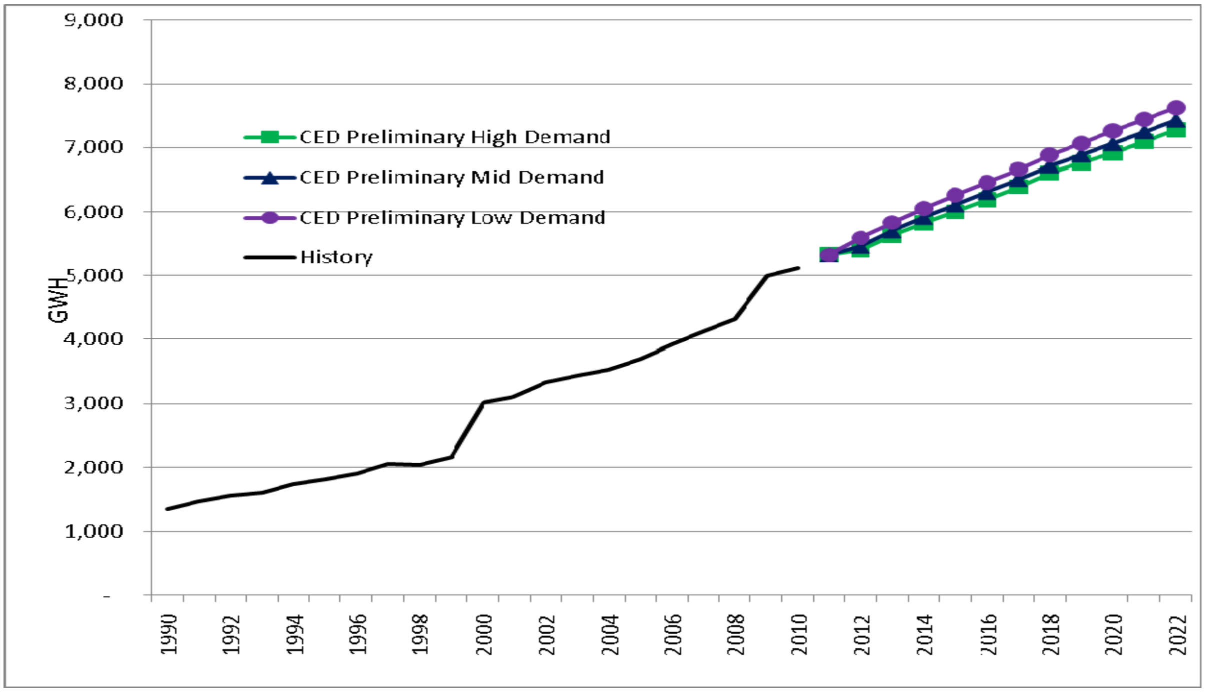
Table 4-3: SDG&E Planning Area Electricity Savings Estimates from Standards, Mid Demand Scenario

Electricity Consumption Savings (GWh)							
	Residential			Commercial			
	Building Standards	Appliance Standards	Total	Building Standards	Appliance Standards	Total	Total Standards
1990	274	264	538	151	97	247	786
2000	249	694	943	406	260	666	1,609
2010	331	1,541	1,872	789	457	1,245	3,117
2015	382	1,990	2,372	1,032	577	1,609	3,981
2020	428	2,294	2,722	1,332	751	2,083	4,805
2022	441	2,337	2,777	1,446	791	2,237	5,014
Electricity Peak Demand Savings (MW)							
	Residential			Commercial			
	Building Standards	Appliance Standards	Total	Building Standards	Appliance Standards	Total	Total Standards
1990	48	46	93	33	21	53	147
2000	42	117	159	77	49	126	285
2010	65	300	365	199	115	314	679
2015	81	423	504	224	125	350	854
2020	90	480	569	286	161	447	1,016
2022	91	482	573	309	169	478	1,052

Source: California Energy Commission, 2011

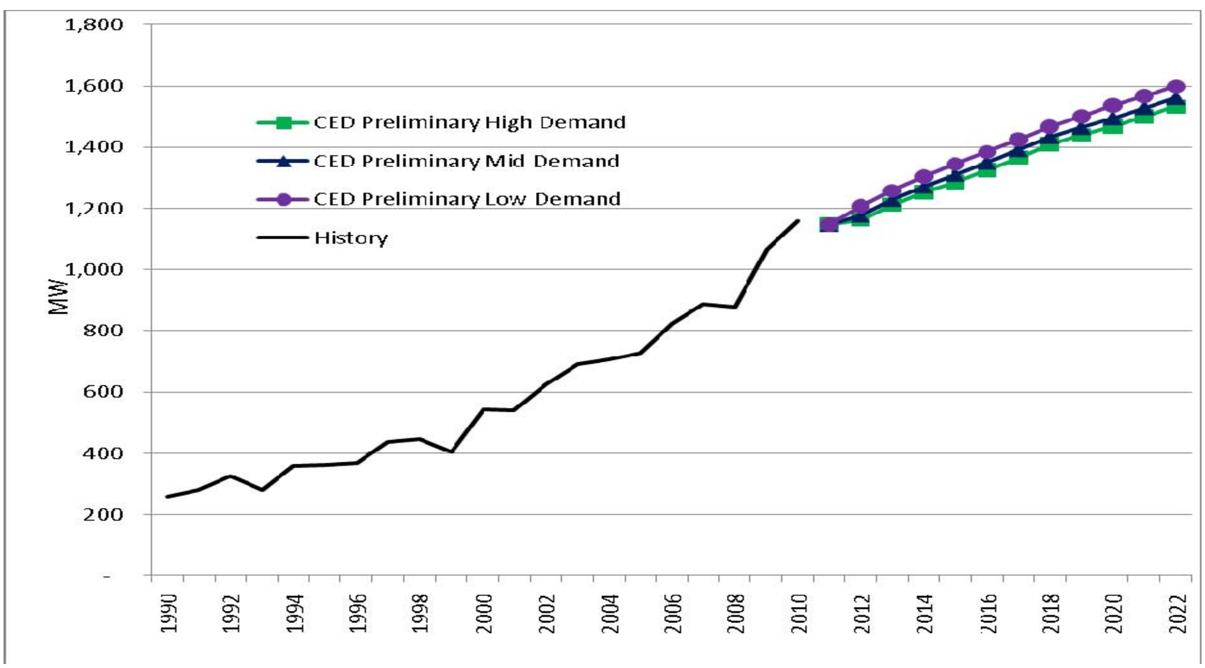
Figure 4-22 and **Figure 4-23** show forecasts of total savings impacts on electricity and peak demand respectively from building and appliance standards, utility and public agency programs, and price and other effects, or savings associated with rate changes and certain market trends not directly related to programs or standards. Savings are measured against a 1975 baseline, so they incorporate more than 30 years of impacts from rate changes and standards. Projected savings impacts are higher the lower the demand scenario, since price and program effects are inversely related to the demand outcome.

Figure 4-22: SDG&E Planning Area Electricity Consumption Savings Estimates



Source: California Energy Commission, 2011

Figure 4-23: SDG&E Planning Area Electricity Peak Savings Estimates



Source: California Energy Commission, 2011

CHAPTER 5: Sacramento Municipal Utility District Planning Area

The SMUD planning area includes SMUD retail customers, but does not include the new members of the SMUD control area, Roseville, Redding, and the WAPA. To support electricity system analysis, staff derives forecasts by control area and California ISO congestion zone from the planning area forecasts. Using historic consumption data and regional population projections, the estimated share of the PG&E forecast for WAPA, Roseville, and Redding forecasts are subtracted from the PG&E planning area and added to the SMUD control area. The results in this chapter are for the SMUD planning area only.

This chapter is organized as follows. First, forecasted consumption and peak loads for the SMUD planning area are discussed; both total and per capita values are presented. The *CED 2011 Preliminary* values are compared to the *CED 2009* forecast; differences between the two forecasts are explained. The forecasted load factor, jointly determined by the consumption and peak load estimates, is also discussed. Second, sector consumption and peak load forecasts are presented. The residential, commercial, industrial, and "other" sector staff draft forecasts are compared to those in *CED 2009*; again, differences between the two are discussed.

For the *CED 2011 Preliminary* forecast, three scenarios of electricity use were developed for analysis, which include a low, medium and high electricity demand forecast. Chapter 1 provides an explanation of the methodology and assumptions used in the scenarios.

Forecast Results

Table 5-1 presents a comparison of *CED 2011 Preliminary* projected electricity consumption and peak demand for selected years for the three demand scenarios and the *CED 2009* forecast. **Figure 5-1** and **Figure 5-2** present a graphical comparison of the forecast with the *CED 2009* forecast for the SMUD planning area for both electricity consumption and peak demand, respectively.

For both consumption and peak demand, growth rates starting in 2011 are shown in order to compare weather-normalized growth, since consumption in 2010 was reduced significantly because of a very mild weather year overall.

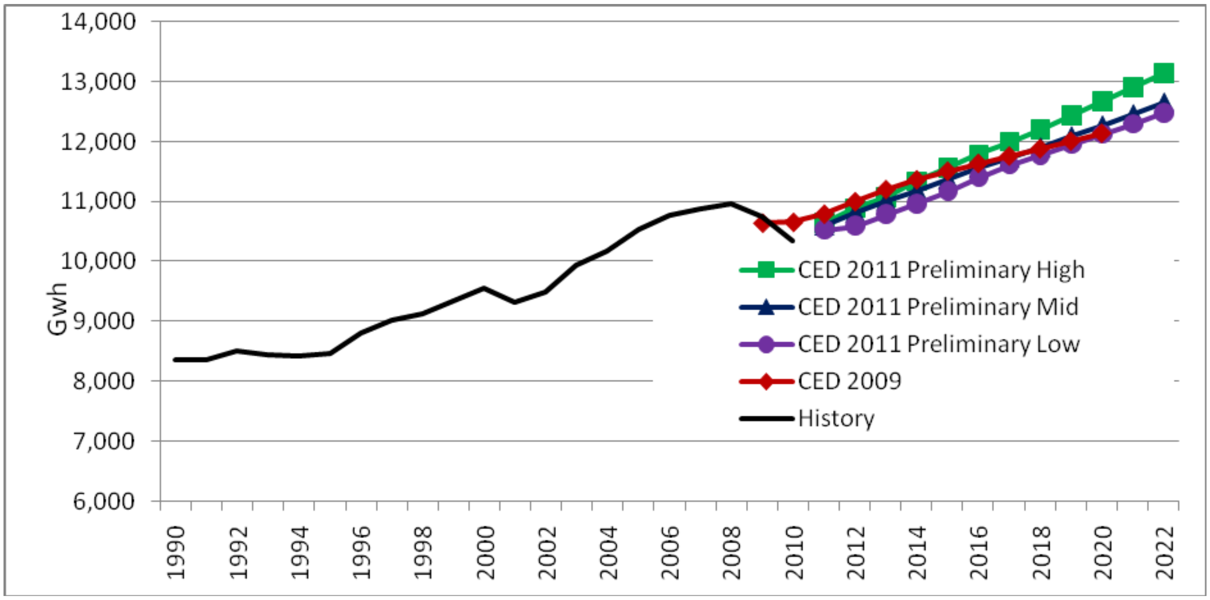
Table 5-1: SMUD Planning Area Forecast Comparison

Consumption (GWh)				
	CED 2009 (Dec. 2009)	*CED 2011 Preliminary-High Energy Demand*	*CED 2011 Preliminary-Mid Energy Demand*	*CED 2011 Preliminary-Low Energy Demand*
1990	8,358	8,361	8,361	8,361
2000	9,494	9,552	9,552	9,552
2010	10,656	10,344	10,344	10,344
2011	10,793	10,636	10,600	10,521
2015	11,504	11,565	11,370	11,172
2020	12,131	12,675	12,276	12,124
2022	--	13,151	12,657	12,486
Average Annual Growth Rates				
1990-2000	1.28%	1.34%	1.34%	1.34%
2000-2010	1.16%	0.80%	0.80%	0.80%
2011-2015	1.61%	2.11%	1.77%	1.51%
2011-2020	1.31%	1.97%	1.64%	1.60%
2011-2022	--	2.02%	1.70%	1.58%
Peak (MW)				
	CED 2009 (Dec. 2009)	*CED 2011 Preliminary-High Energy Demand*	*CED 2011 Preliminary-Mid Energy Demand*	*CED 2011 Preliminary-Low Energy Demand*
1990	2,167	2,193	2,193	2,193
2000	2,687	2,686	2,686	2,686
2010	3,050	2,975	2,975	2,975
2011	3,088	2,983	2,985	2,967
2015	3,273	3,232	3,187	3,134
2020	3,445	3,517	3,416	3,371
2022	--	3,629	3,503	3,447
Average Annual Growth Rates				
1990-2000	2.17%	2.05%	2.05%	2.05%
2000-2010	1.28%	1.03%	1.03%	1.03%
2011-2015	1.47%	2.02%	1.65%	1.38%
2011-2020	1.23%	1.84%	1.51%	1.43%
2011-2022	--	1.67%	1.37%	1.23%
Historical values are shaded				

Source: California Energy Commission, 2011

In 2010, consumption was 3.0 percent lower than predicted in *CED 2009*. The *CED 2011 Preliminary* SMUD forecast is 1.2 percent lower than the *CED 2009* forecast in 2015. By 2020, this difference shrinks to near zero for the low use scenario and becomes 4.5 percent higher in the high use scenario. From 2011 through 2020, electricity consumption grows at a rate of 1.64 percent in the mid demand case compared to 1.31 percent in *CED 2009*.

Figure 5-1: SMUD Planning Area Electricity Consumption Forecast

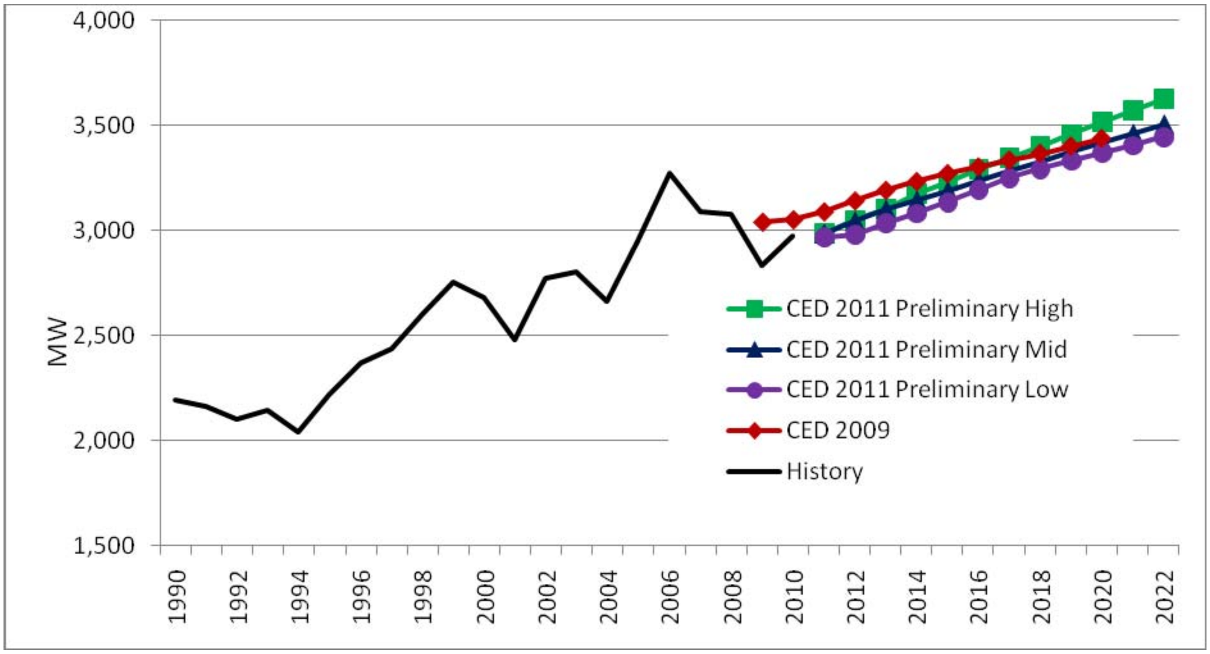


Source: California Energy Commission, 2011

The *CED 2011 Preliminary* SMUD planning area peak demand forecast, shown in **Figure 5-2**, is lower through 2020 compared to *CED 2009* forecast for both the low and mid scenarios. During the second half of the forecast, the high use scenario is higher than *CED 2009* and by 2020 reaches a difference of 2.3 percent. From 2011 through 2020, peak electricity demand grows at a rate of 1.51 percent for the new forecast compared to 1.23 percent in *CED 2009*. Growth from 2011-2020 is faster for both consumption and peak for all three scenarios versus *CED 2009* due to faster growth in the residential and commercial sectors.

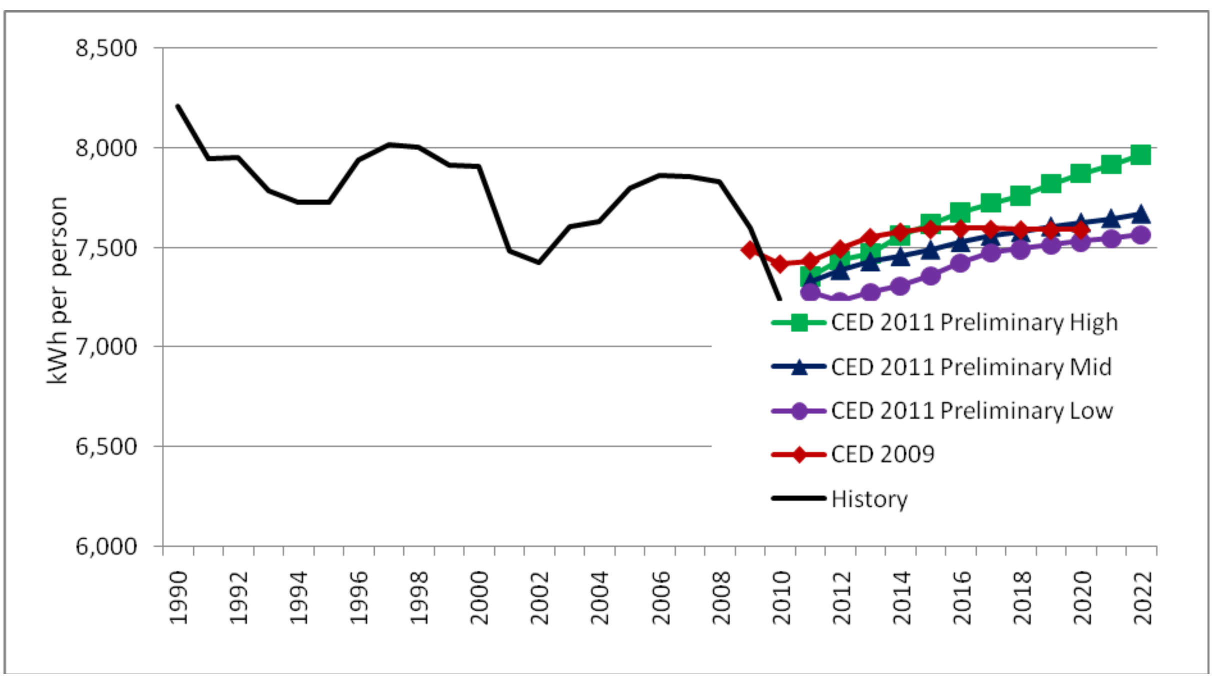
Figure 5-3 compares *CED 2011 Preliminary* and *CED 2009* per capita electricity consumption forecasts. The historical trend from 1990 through 2010 has been decreasing. It is projected to rise at the beginning of the forecast period in all three scenarios as California's economy continues to recover. Per capita consumption flattens out in the middle of the forecast period but begins to rise towards the end due to increasing numbers of electric vehicles. High income and manufacturing output growth increase per capita consumption throughout the forecast period in the high demand scenarios. In 2015, projected per capita consumption in the mid case is around 7,500 kWh compared to 7,594 kWh in *CED 2009*. However, by 2020, per capita consumption in this scenario becomes 4.5 percent higher than projected in *CED 2009*.

Figure 5-2: SMUD Planning Area Peak



Source: California Energy Commission, 2011

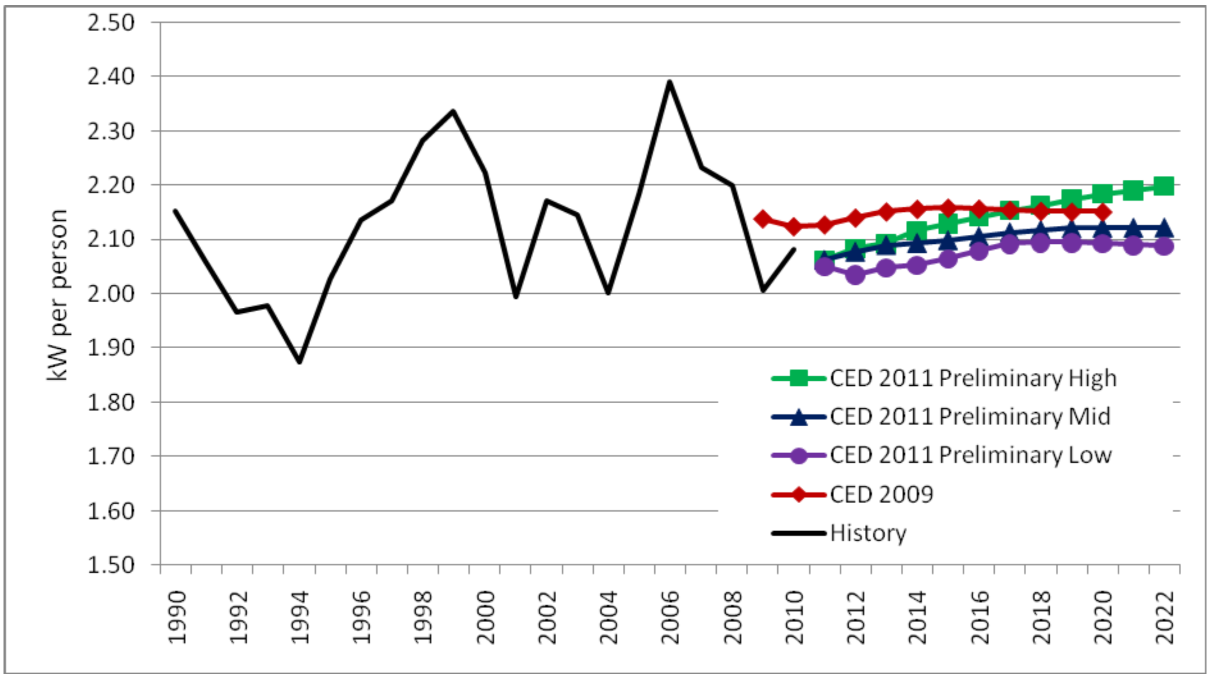
Figure 5-3: SMUD Planning Area per Capita Electricity Consumption



Source: California Energy Commission, 2011

Per capita peak demand is shown in **Figure 5-4**. The *CED 2009* forecast level was in line with the mid-range values experienced in recent history. However, since 2008, per capita peak demand has declined by 5.3 percent. *CED 2011 Preliminary* per capita peak demand is not expected to recover to CED 2009 levels for the low and mid scenarios but is expected to become 1.5 percent higher for the high scenario by 2020.

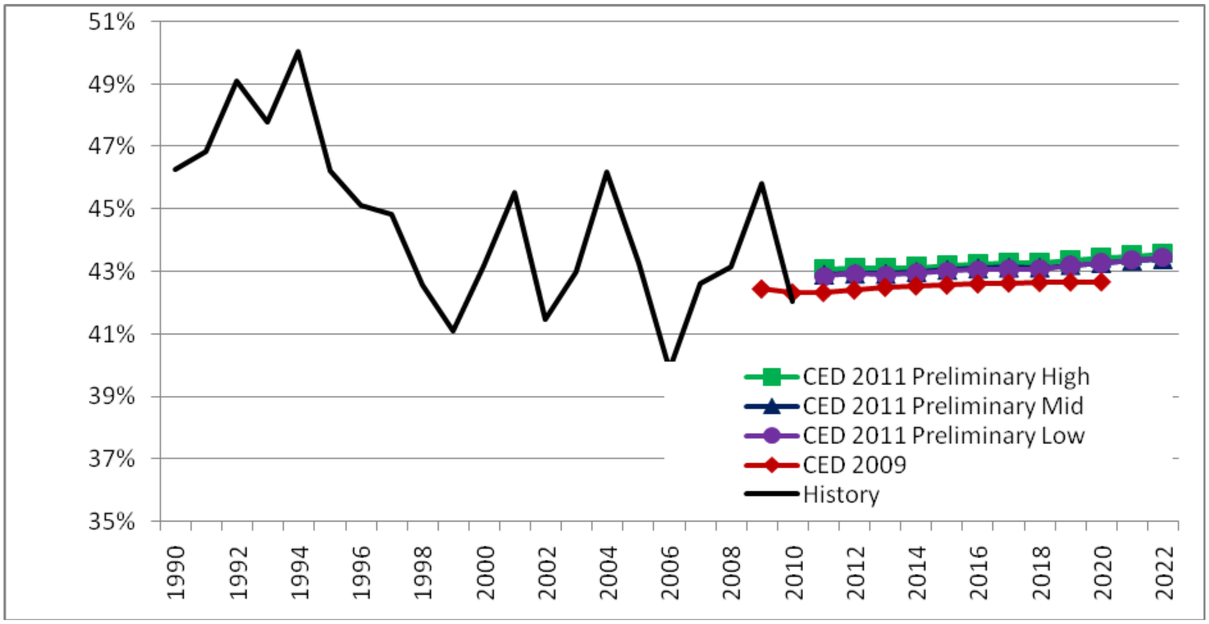
Figure 5-4: SMUD Planning Area per Capita Peak Demand



Source: California Energy Commission, 2011

Figure 5-5 compares *CED 2011 Preliminary* and *CED 2009* load factors. The load factor is a measure of the relative increase in peak demand with respect to annual electricity consumption. Lower load factors indicate a sharp rise, while higher load factors indicate a more stable load. Variation in historic load factors is caused in part by annual weather patterns. The SMUD load factor has been declining since the mid-1990's, as the residential sector—with a continually increasing presence of air conditioning—grew faster than other sectors. The forecasted load factors are fairly level as air conditioning in the SMUD planning area is close to full saturation. The slight increase in all three scenarios is due in part to increasing numbers of electric vehicles, which are assumed to affect consumption much more than peak. The annual growth rate for all three scenarios varies less than 0.03 percent and is 0.27 percent per year for the mid case.

Figure 5-5: SMUD Planning Area Load Factors



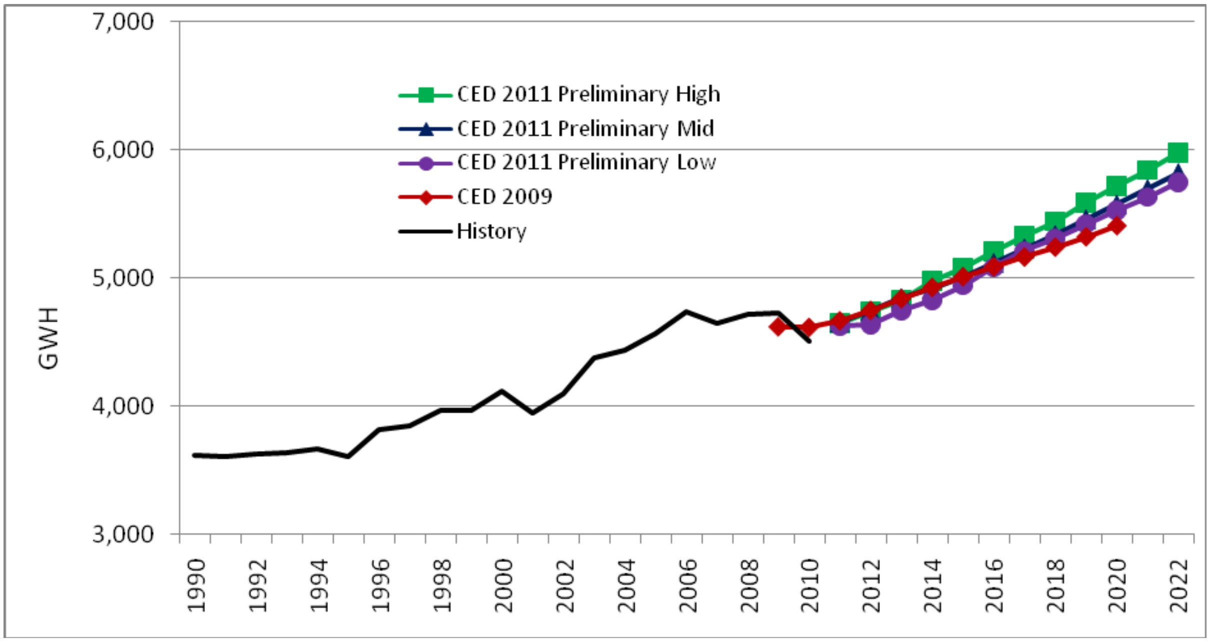
Source: California Energy Commission, 2011

Sector Level Results and Input Assumptions

Residential

Figure 5-6 provides a comparison between *CED 2011 Preliminary* and *CED 2009* SMUD residential forecasts. Because of a drop in recorded consumption of 219 GWh from 2009 to 2010, the *2011 Preliminary* forecast starts lower than the projection made in 2009. The growth rate for residential consumption over the entire forecast period is higher in all three scenarios compared to *CED 2009* because of significantly higher income growth used in the new forecast and a significant increase in the penetration of electric vehicles. For *CED 2011 Preliminary*, the low case grows at 2.07 percent per year from 2011-2020 while the high case grows at 2.39 percent, compared to 1.65 percent in *CED 2009*.

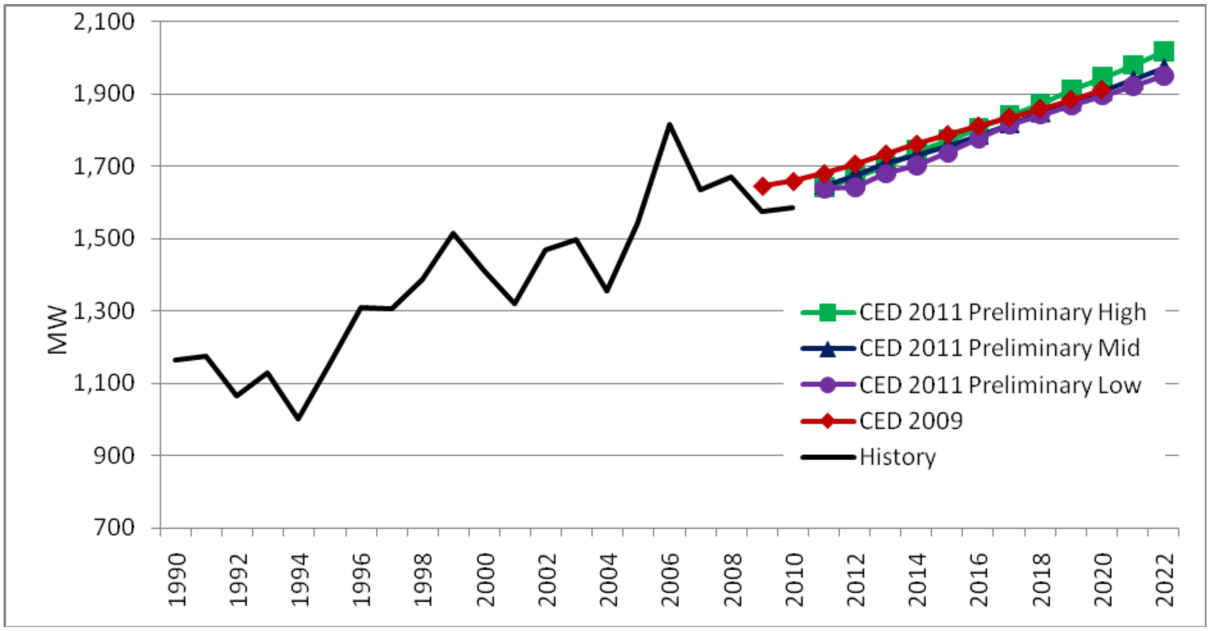
Figure 5-6: SMUD Planning Area Residential Consumption



Source: California Energy Commission, 2011

Figure 5-7 provides a comparison of the *CED 2011 Preliminary* and *CED 2009* residential peak demand forecasts. Historical residential peak demand dropped 89 MW from 2008 to 2010 and *CED 2011 Preliminary* remains lower than *CED 2009* until 2020 where the peak is nearly identical at just over 1900 MW in the mid case. Residential peak grows slightly faster in all three scenarios compared to *CED 2009*.

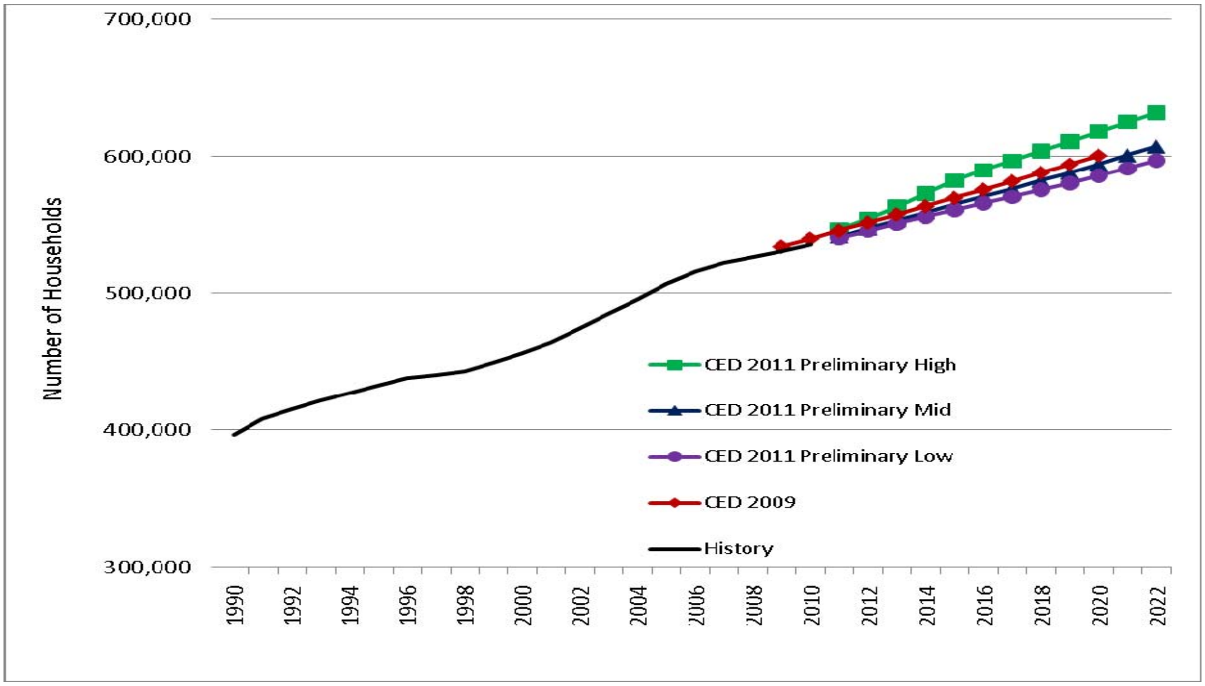
Figure 5-7: SMUD Planning Area Residential Peak



Source: California Energy Commission, 2011

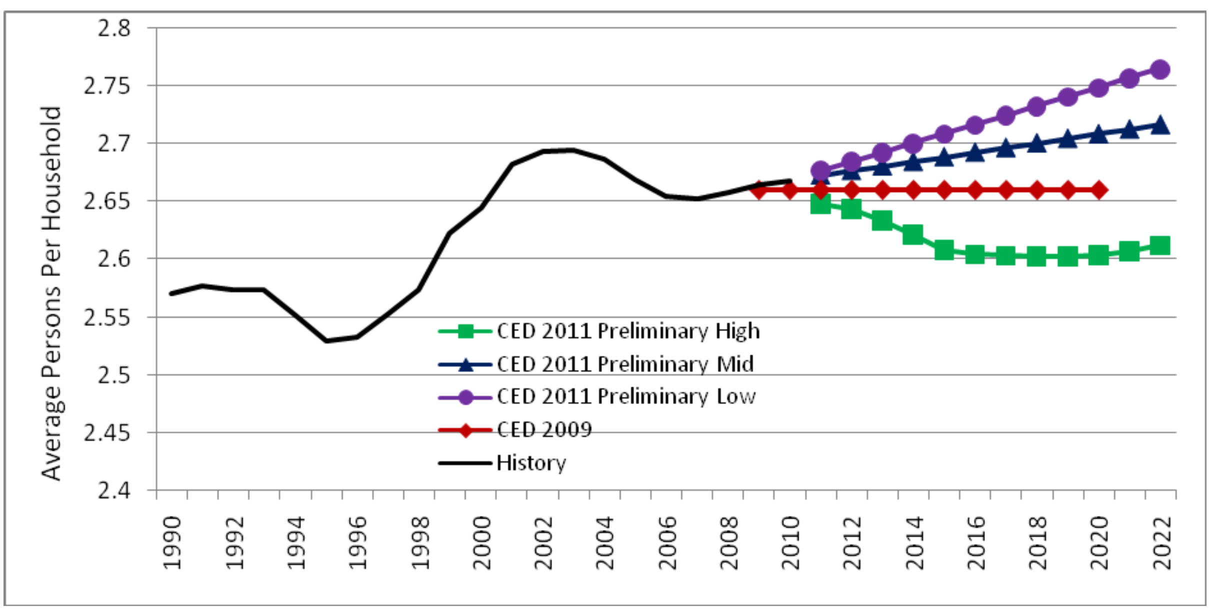
Figure 5-8 and **Figure 5-9** provide comparisons of the residential economic/demographic drivers used in the *CED 2011 Preliminary* forecast with drivers used in *CED 2009*. **Figure 5-8** provides a comparison of total households and **Figure 5-9** presents a comparison of persons per household projections. The *CED 2011 Preliminary* forecast of households is slightly lower in the mid and low demand cases than the *CED 2009* forecast because of higher projections in persons per household used in the current forecast. By 2020, *CED 2011 Preliminary* predicts around 595,000 versus 600,000 in *CED 2009*. For the *CED 2011 Preliminary* mid case, persons per household reach just over 2.7 in 2020, compared to a projection of 2.66 for *CED 2009*.

Figure 5-8: SMUD Planning Area Residential Household Projections



Source: California Energy Commission, 2011

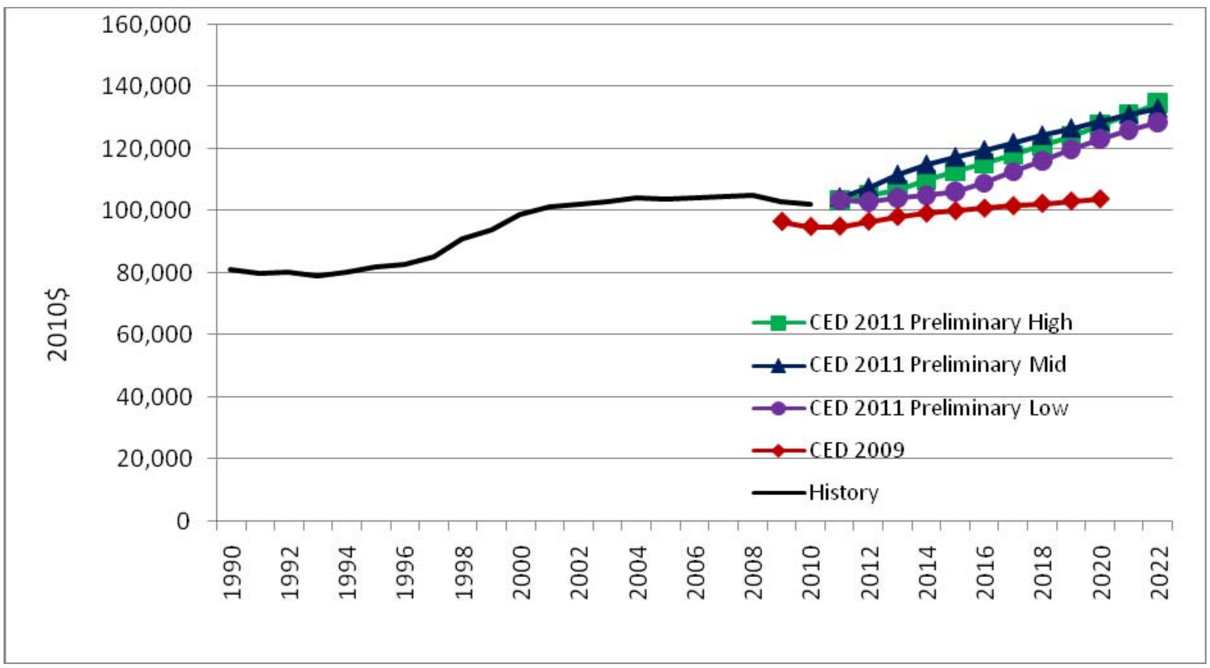
Figure 5-9: SMUD Planning Area Persons per Household Projections



Source: California Energy Commission 2011

Figure 5-10 provides a comparison of average household income between the two forecasts. The growth rate of income between 2010 and 2020 is higher in all three scenarios compared to CED 2009, as both Global Insight and Moody's project faster total personal income growth. Income per household in the high demand case is lower than in the mid case until the end of the forecast period where the two scenarios are nearly identical. This is due to lower total household income in the early years of the forecast in the high scenario compared to the mid case, as well as differences in the projected growth rate of households compared to total household income. The *CED 2009* projection declines in the short-term as a result of the economic down-turn and then grows at a much slower rate than in the *CED 2011 Preliminary* scenarios in the mid to long-term.

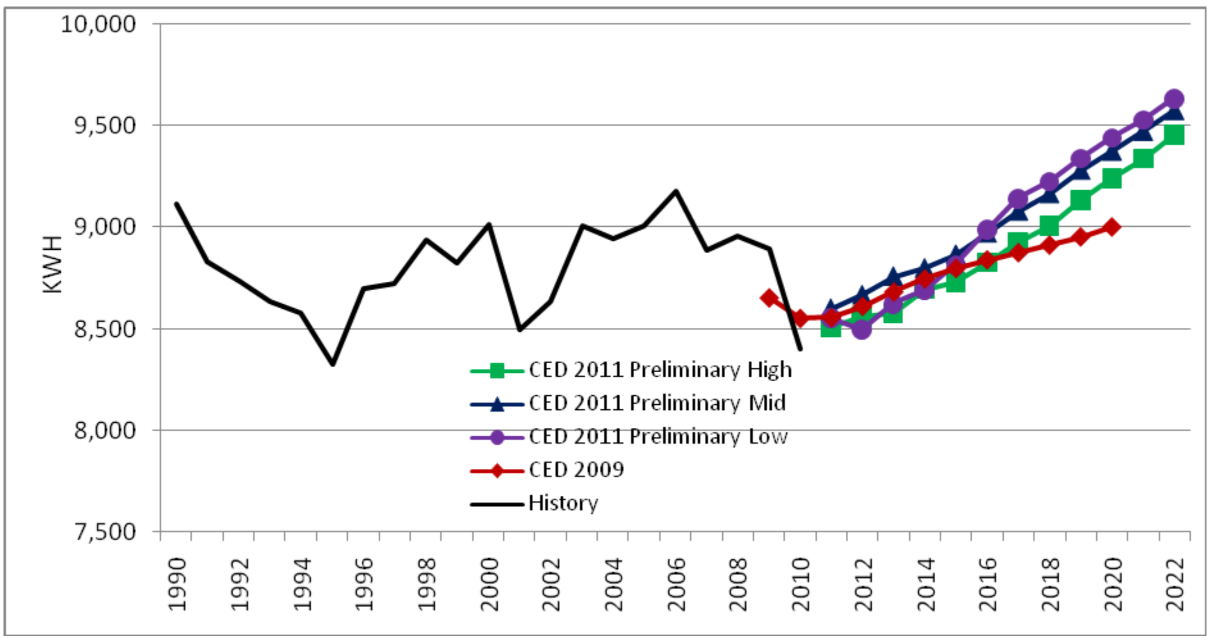
Figure 5-10: SMUD Planning Area Average Household Income Projections



Source: California Energy Commission 2011

Figure 5-11 presents a comparison of electricity use per household between the two forecasts as well as the 1990–2010 historic series. Use per household dropped in 2008 from around 9,000 kWh (near the historical high) to 8,400 kWh/HH (near the historical low). *CED 2011 Preliminary* use per household is expected to rise to almost 9,400 kWh in 2020 in the mid case growing at 1.10 percent compared to 9,000kWh/HH predicted in the *CED 2009* forecast. As in the case of per capita electricity consumption, higher growth in consumption per household results from faster income growth and increased numbers of electric vehicles. The projections for persons per household lead to use per household that is lowest for the high use scenario and highest for the low use scenario.

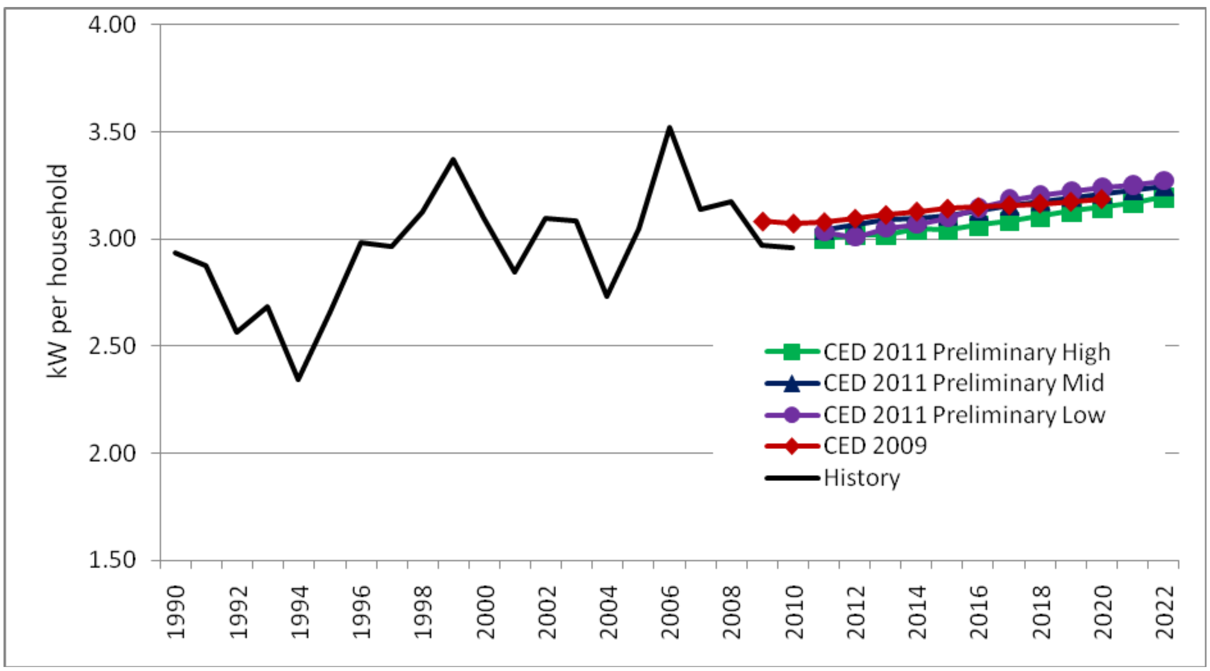
Figure 5-11: SMUD Planning Area Electricity Use per Household



Source: California Energy Commission, 2011

The relatively small increases in peak use per household for all three new scenarios shown in **Figure 5-12** are much less than those predicted for energy use per household, since charging electric vehicles has little effect on peak but a large impact on energy consumption. For the mid case, growth rate for peak use per household is 0.78 percent per year over the *CED 2011 Preliminary* forecast period. Similar to use per household, peak use per household is lowest for the high use scenario and highest for the low use scenario since projections for persons per household outweigh the effects of higher income growth. Peak use per household rises to 3.21 kW in 2020 in the mid case compared to 3.18 kW predicted in the *CED 2009* forecast.

Figure 5-12: SMUD Planning Area Peak Use per Household

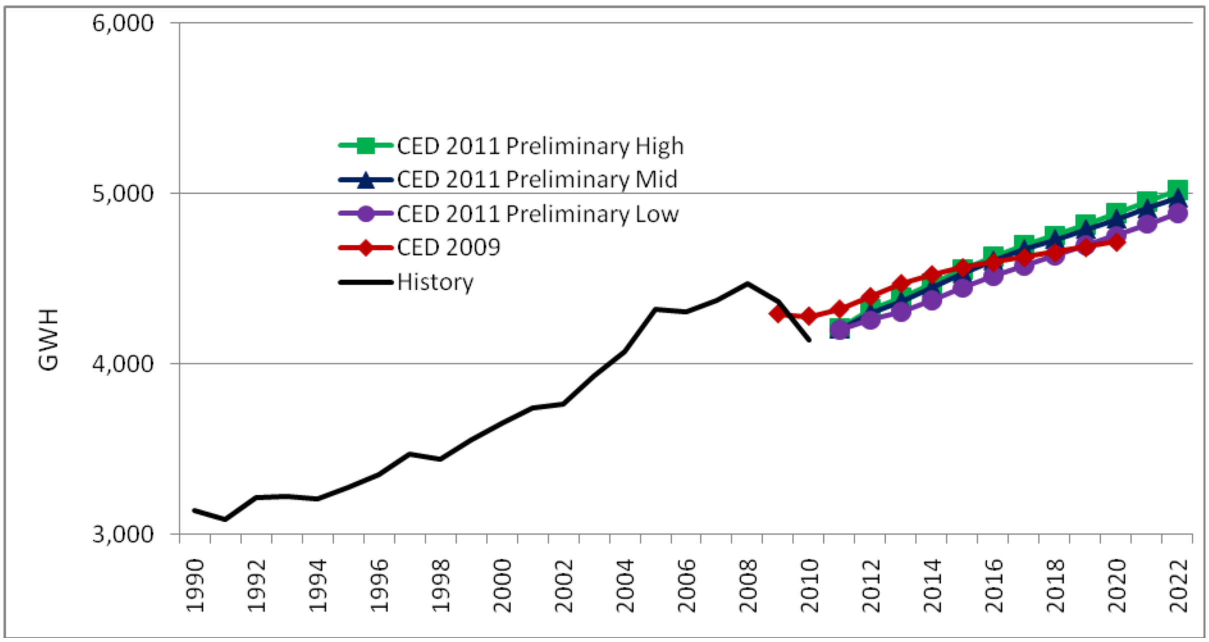


Source: California Energy Commission, 2011

Commercial Sector

Figure 5-13 provides a comparison of the commercial sector forecasts. *CED 2011 Preliminary* begins slightly below the *CED 2009* forecast. Actual consumption in 2010 was lower than the projection from *CED 2009* since the effect of the recession in Sacramento was more severe than assumed in 2009. The *CED 2011 Preliminary* forecast grows at a faster rate from 2010-2020 in all three scenarios compared to CED 2009 because of faster projected growth in floor space. The growth rate of the *CED 2011 Preliminary* commercial forecast in the mid case is 1.55 percent over the forecast period.

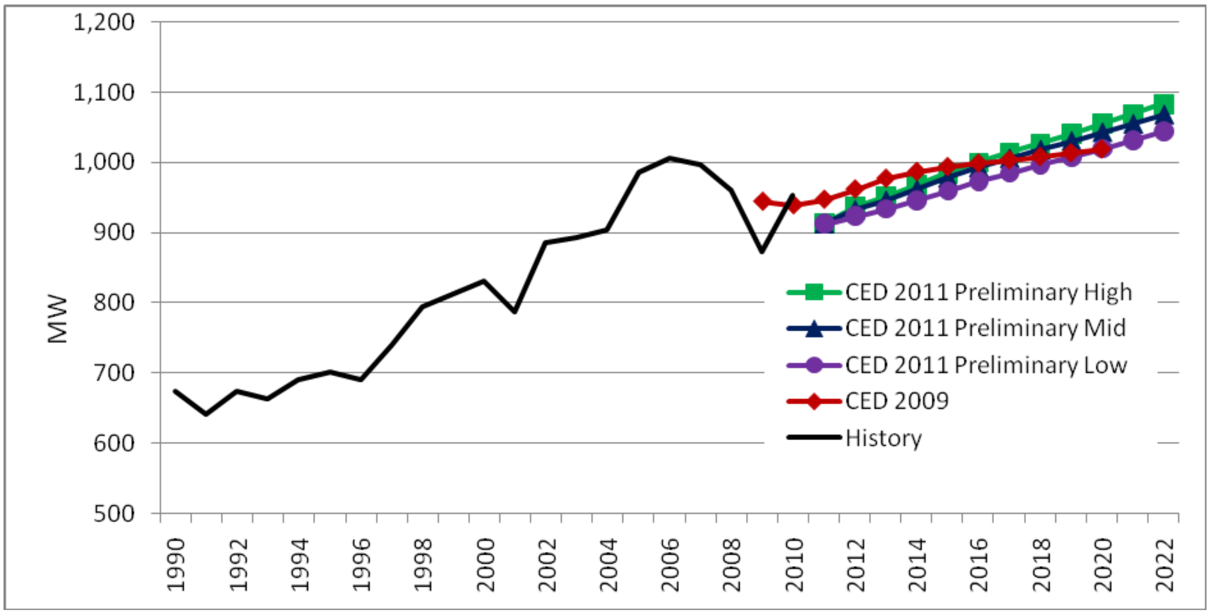
Figure 5-13: SMUD Planning Area Commercial Consumption



Source: California Energy Commission, 2011

Figure 5-14 provides a comparison of the commercial peak demand forecasts. The *CED 2011 Preliminary* mid demand forecast is slightly lower than the *CED 2009* commercial peak forecast until 2017 and then becomes higher for the remainder of the forecast period. Commercial peak grows at a rate of 1.0 percent per year in the mid case, from 952 MW in 2010 to 1069 MW in 2022. Differences in peak forecasts are driven primarily by the differences in electricity forecasts.

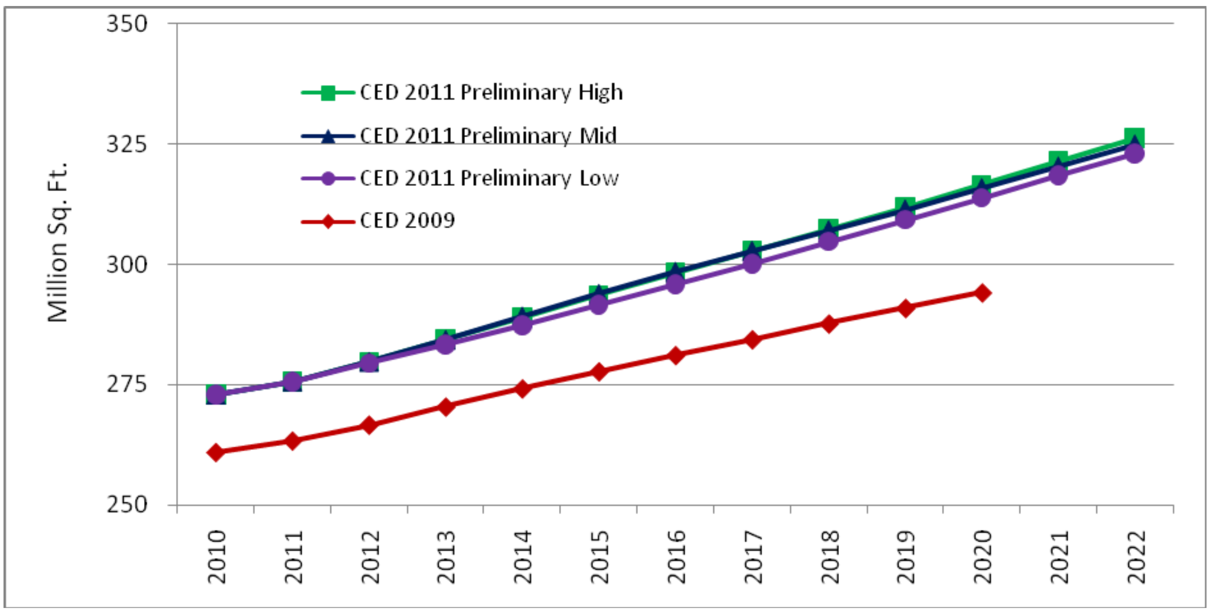
Figure 5-14: SMUD Planning Area Commercial Building Sector Peak



Source: California Energy Commission, 2011

In staff's commercial building sector forecasting model, floor space by building type (for example, retail, offices, schools, and hospitals) is the key driver of electricity growth. **Figure 5-15** provides a comparison of total commercial floor space projections. Commercial floor space grows from 273 million square feet in 2010 to 325 million square feet in 2022. The *CED 2011 Preliminary* floor space projections are higher than those used in *CED 2009* primarily because estimated 2010 floor space for Sacramento is higher than predicted in 2009.

Figure 5-15: SMUD Planning Area Commercial Floor Space

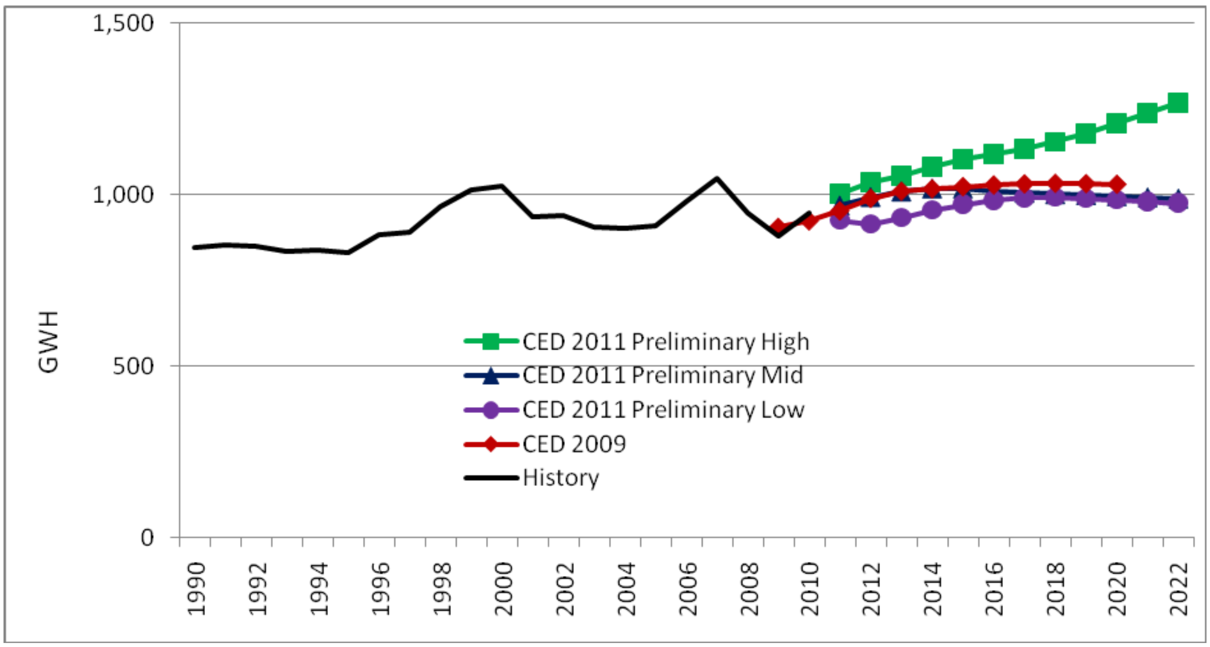


Source: California Energy Commission, 2011

Industrial Sector

Figure 5-16 provides comparisons of the SMUD planning area industrial sector electricity consumption forecasts. *CED 2011 Preliminary* industrial electricity consumption forecast in the mid case is nearly identical to the *CED 2009* forecast in the short-term, but has a slightly lower growth rate during the second half of the forecast. By the end of the forecast period, the mid and low forecasts begin to decline slightly. Overall, growth is 0.4 percent per year in the mid case from 2011-2022. Growth in manufacturing in projected to be much stronger in the (Global Insight) high demand scenario, so that consumption continues to increase throughout the forecast period.

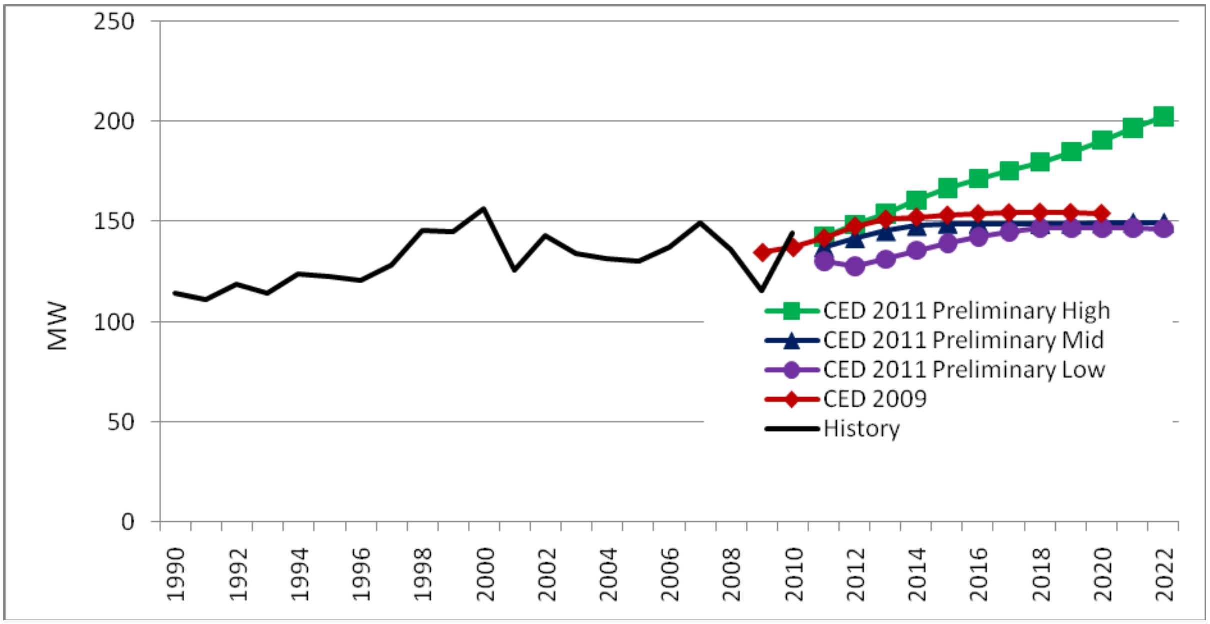
Figure 5-16: SMUD Planning Area Industrial Consumption



Source: California Energy Commission, 2011

Figure 5-17 provides a comparison of the industrial sector peak forecasts, which are very similar to the energy forecasts. The *CED 2011 Preliminary* peak forecast in the mid case increases from 138 MW in 2011 to 149 MW in 2015 at which point it is expected to remain flat until the end of the forecast period.

Figure 5-17: SMUD Planning Area Industrial Sector Peak



Source: California Energy Commission, 2011

Other Sectors

Figure 5-18 and **Figure 5-19** provide comparisons of the remaining sector electricity consumption forecasts. **Figure 5-18** provides a comparison of the transportation communications and utilities (TCU) sector forecasts, which include street lighting. In this case, a single scenario was run.[24] The *CED 2011 Preliminary* forecast is lower than the *CED 2009* forecast because of a lower historic starting point. Both forecasts have growth rates of approximately one percent over the forecast period. The historical decline of TCU electricity consumption from 1990 through 2001 is a result of military base closures. However, since 2002, the sector has experienced steady growth of approximately 1.2 percent per year.

Figure 5-19 provides comparisons of the agriculture and water pumping sector forecasts. The *CED 2011 Preliminary* agriculture and water pumping forecast grows at a slower rate from 2011-2020 compared to *CED 2009* in all three scenarios. Slower growth in the number of households versus *CED 2009* drive the results in the mid and low cases while higher rates in the high demand case keep consumption growth below that in the 2009 forecast.

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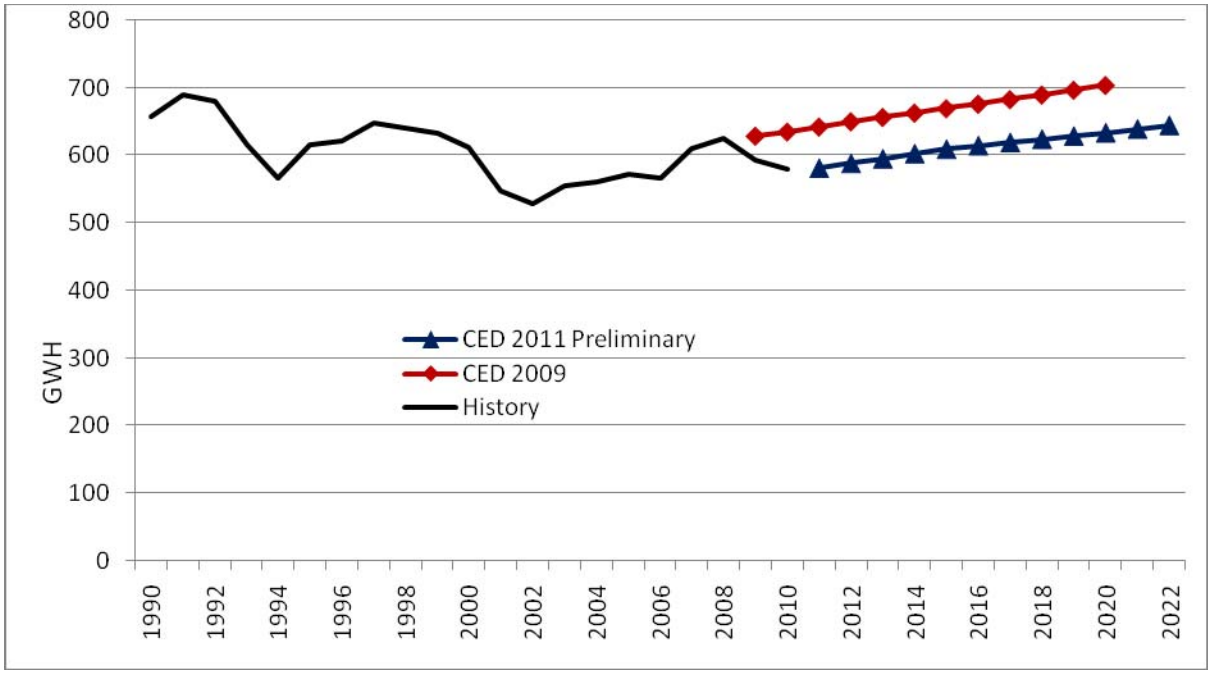
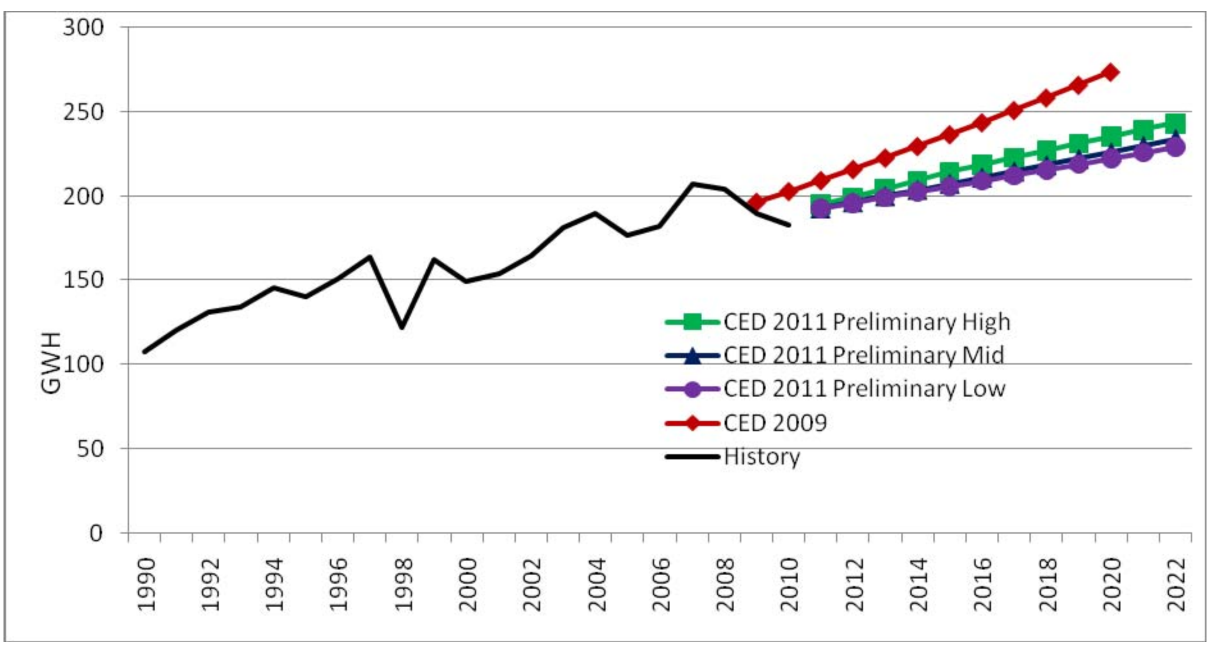
[24] Growth in TCU consumption depends mainly on population, for which there is only one scenario.

Figure 5-18: SMUD Planning Area Transportation, Communications & Utilities Sector Electricity Consumption



Source: California Energy Commission, 2011

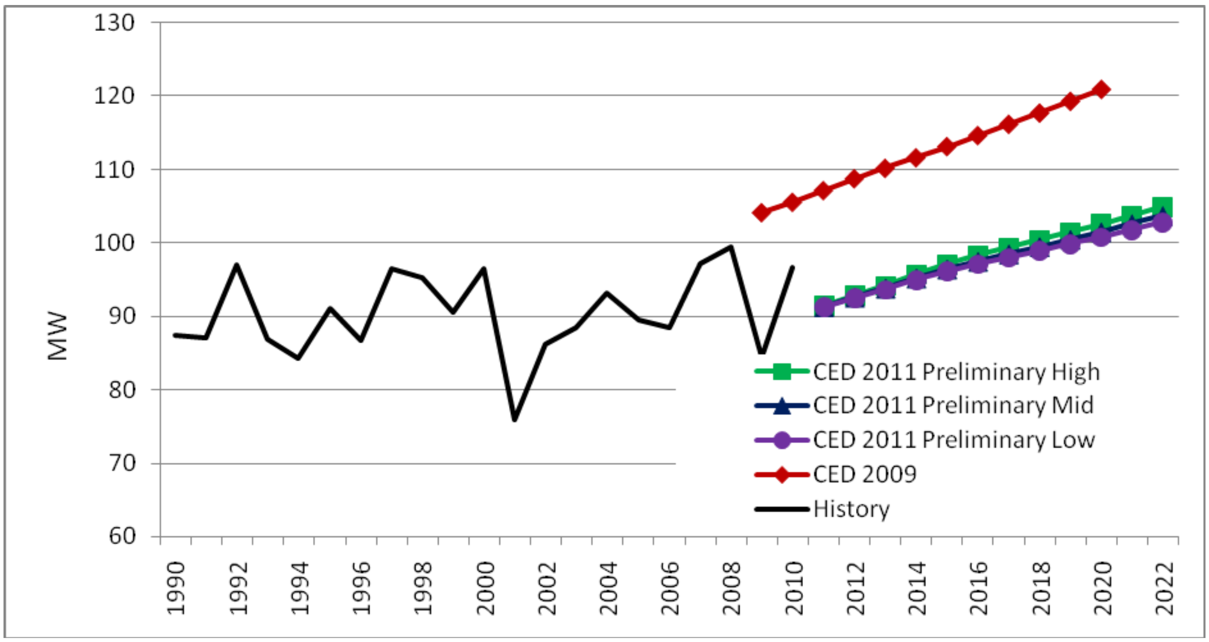
Figure 5-19: SMUD Planning Area Agriculture & Water Pumping Electricity Consumption Forecasts



Source: California Energy Commission, 2011

Figure 5-20 provides a comparison of the combined "other" sector peaks for the *CED 2011 Preliminary* and *CED 2009* forecasts, which includes the TCU sector, the street lighting sector and the agriculture and water pumping sector. The *CED 2011 Preliminary* forecasts are lower over the entire forecast period than the *CED 2009*, given a lower assumed starting point resulting from a reclassification of historical consumption. However, the growth rate of the *CED 2011 Preliminary* forecast is essentially the same as the *CED 2009* forecast.

Figure 5-20: SMUD Planning Area Other Sector Peak

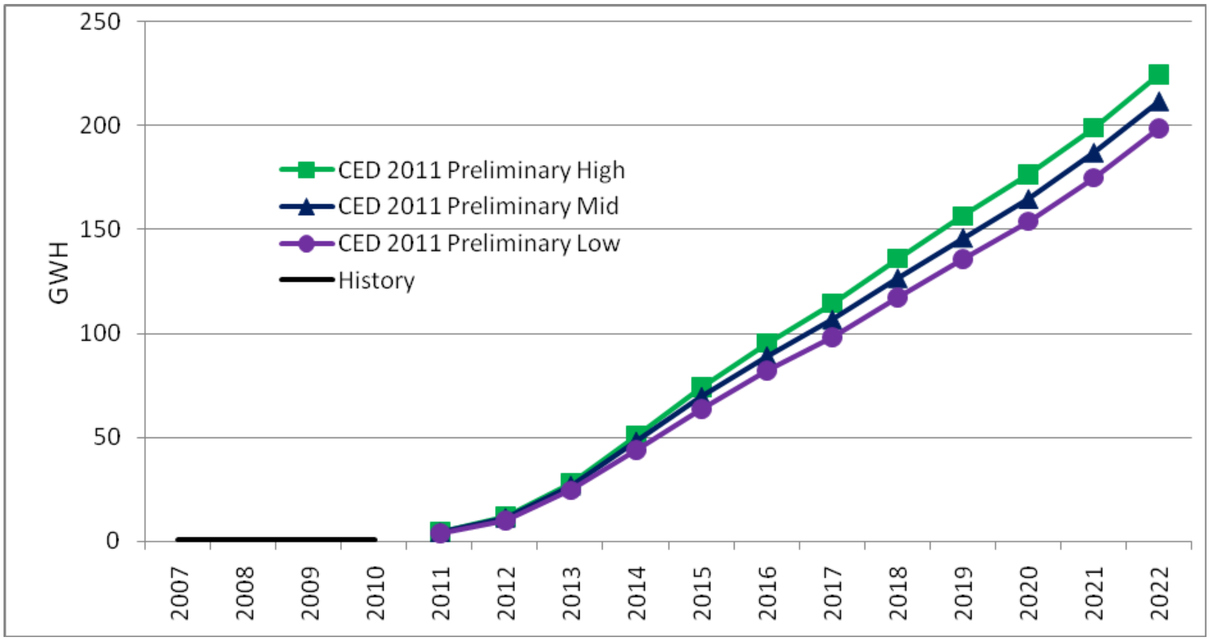


Source: California Energy Commission, 2011

Electric Vehicles

Consumption by electric vehicles in 2010 was less than 1 GWh and is expected to rise to 89 GWh by 2016 in the mid demand case, as shown in **Figure 5-21**. By the end of the forecast period, total electricity used by electric vehicles is projected to be over 200 GWh in the mid and high cases. Staff assumed that most recharging would occur during off-peak hours so that peak impacts would be relatively small, causing an increase of only 8 MW in the low demand case and 10 MW in the high case by 2022.

Figure 5-21: SMUD Electricity Consumption of Electric Vehicles



Source: California Energy Commission, 2009

Self-Generation

As shown in **Table 5-2**, the peak demand forecast is reduced by self-generation, including the effects of the SGIP, CSI, and other programs, as discussed in Chapter 1. The effects of these programs are forecast based on recent trends in installations and a predictive model for the residential sector. Staff projects about 40 MW of peak reduction from PV systems by 2022 in the mid demand case. Peak reductions are based on installed system capacities ranging from 36 MW in 2015 and 75 MW in 2022 in the high demand case to 37 MW in 2015 and 84 MW in 2022 in the low demand case.

Table 5-2: SMUD Peak Demand Reductions from Self-Generation

	1990	2000	2010	2015	2020	2022
Non-PV Self-Generation	0.00	0.00	1.70	1.70	1.70	1.70
PV, Low Demand	0.00	2.39	13.69	18.87	30.89	43.01
PV, Mid Demand	0.00	2.39	13.69	18.45	27.96	39.53
PV, High Demand	0.00	2.39	13.69	18.29	27.21	38.16
Total Self-Generation, Low Demand	0.00	2.39	15.38	20.56	32.58	44.71
Total Self-Generation, Mid Demand	0.00	2.39	15.38	20.15	29.66	41.22
Total Self-Generation, High Demand	0.00	2.39	15.38	19.99	28.91	39.86

Source: California Energy Commission, 2011

Conservation/Efficiency Impacts

Table 5-3 and **Table 5-4** show electricity consumption and peak savings estimates for building and appliance standards for the mid demand scenario. Total standards impacts are higher in the high demand case by 1.5—2.0 percent because of higher floor space and home construction values and 1.5—2.0 percent lower in the low demand case. Chapter 8 provides more detail on staff work related to energy efficiency and conservation.

Table 5-3: SMUD Planning Area Electricity Consumption Savings Estimates from Standards, Mid Demand Scenario

Electricity Consumption Savings (GWh)							
	Residential			Commercial			
	Building Standards	Appliance Standards	Total	Building Standards	Appliance Standards	Total	Total Standards
1990	385	162	547	73	97	169	716
2000	541	430	971	186	260	446	1,417
2010	650	785	1,435	357	457	814	2,249
2015	702	1,066	1,768	453	577	1,030	2,798
2020	748	1,252	2,000	556	751	1,308	3,308
2022	759	1,270	2,029	601	791	1,392	3,421

Source: California Energy Commission, 2011

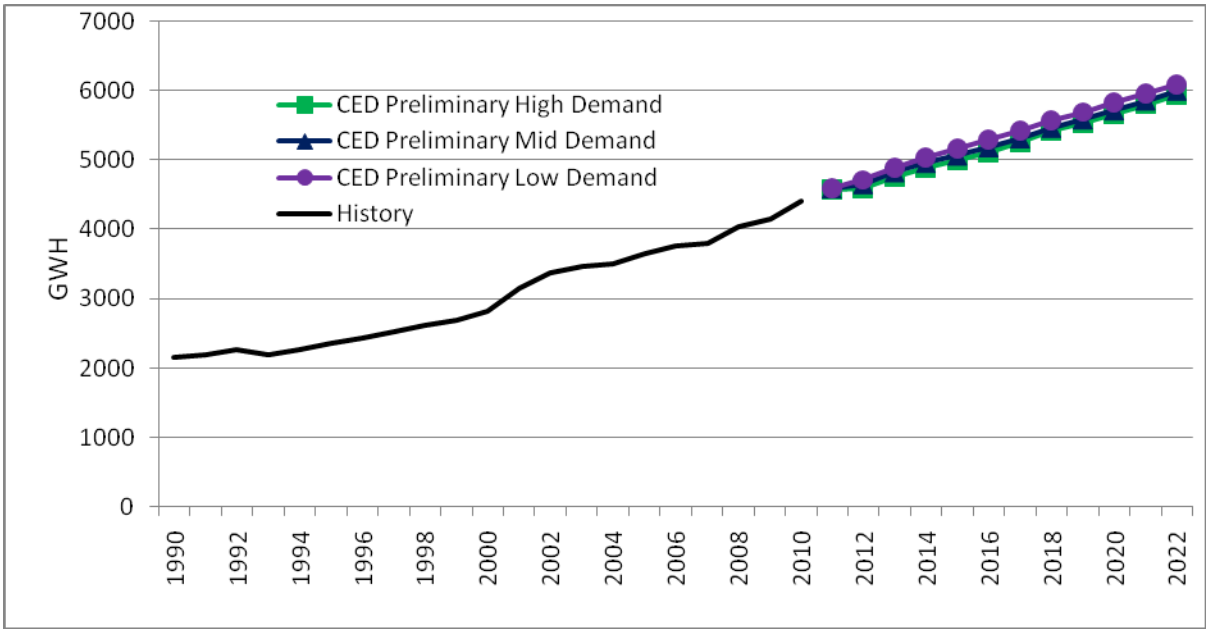
Table 5-4: SMUD Planning Area Electricity Peak Savings Estimates From Standards, Mid Demand Scenario

Electricity Peak Demand Savings (MW)							
	Residential			Commercial			
	Building standards	Appliance Standards	Total	Building Standards	Appliance Standards	Total	Total Standards
1990	124	52	176	16	21	36	212
2000	186	148	333	42	59	101	435
2010	229	277	505	82	105	187	693
2015	246	374	620	98	125	222	843
2020	256	429	685	120	162	281	966
2022	258	431	688	129	170	299	987

Source: California Energy Commission, 2011

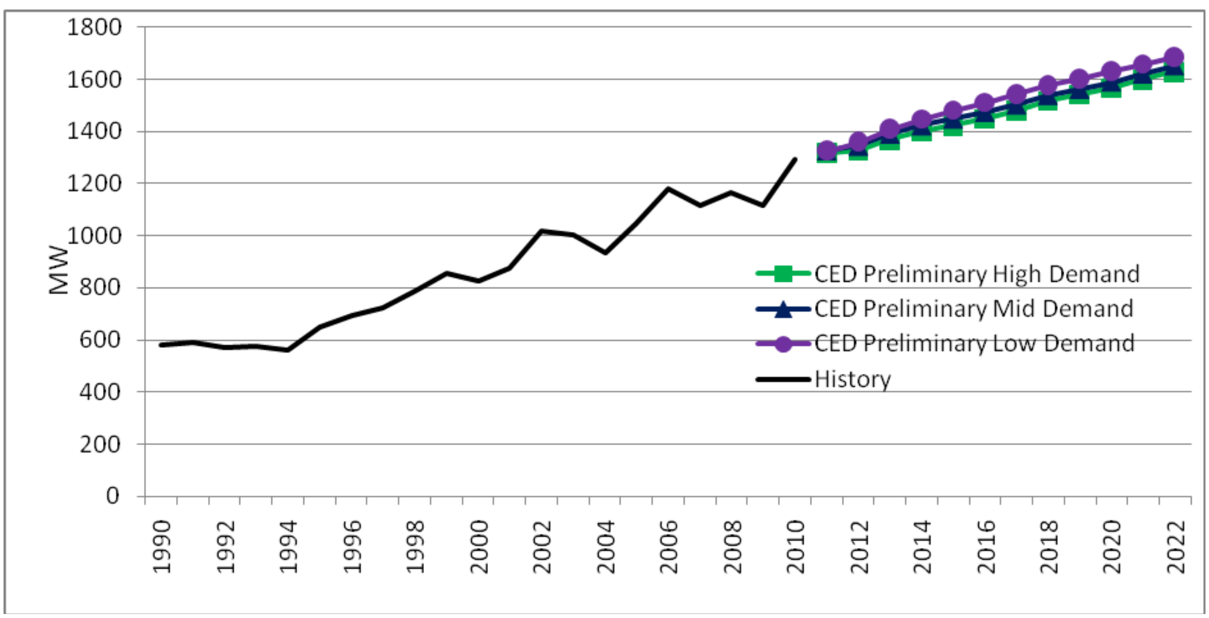
Figure 5-22 and **Figure 5-23** show forecasts of total savings impacts on electricity and peak demand respectively from building and appliance standards, utility and public agency programs, and price and other effects, or savings associated with rate changes and certain market trends not directly related to programs or standards. Savings are measured against a 1975 baseline, so they incorporate more than 30 years of impacts from rate changes and standards. Projected savings impacts are higher the lower the demand scenario, since price and program effects are inversely related to the demand outcome.

Figure 5-22: SMUD Efficiency GWh



Source: California Energy Commission, 2011

Figure 5-23: SMUD Efficiency MW



Source: California Energy Commission, 2011

CHAPTER 6: Los Angeles Department of Water and Power

The LADWP planning area includes LADWP bundled retail customers and customers served by energy service providers using the LADWP distribution system to deliver electricity to end users.

This chapter is organized similar to previous chapters. First, forecasted consumption and peak loads for the LADWP planning area are discussed; both total and per capita values are presented. The *CED 2011 Preliminary* values are compared to the *CED 2009* forecast; significant differences between the two forecasts are explained. The forecasted load factor, jointly determined by the consumption and peak load estimates, is also discussed. Second, sector consumption and peak load forecasts are presented. The residential, commercial, industrial, and "other" sector forecasts are compared to those in *CED 2009*.

Forecast Results

For both consumption and peak demand, growth rates starting in 2011 are shown in order to compare weather-normalized growth, since consumption in 2010 was reduced significantly because of a very mild weather year overall.

Table 5-1 presents a comparison of electricity consumption and peak demand for selected years. **Figure 5-1** and **Figure 5-2** present a comparison of the *CED 2011 Preliminary* forecast with the *CED 2009* forecast.

For both consumption and peak demand, growth rates starting in 2011 are shown in order to compare weather-normalized growth rates, since consumption in 2010 was reduced significantly because of a very mild weather year overall while peak demand was historically high as a result of a heat storm event in September 2010. A weather-normalized comparison (2011-2020) shows faster growth in the mid and high demand cases for consumption and in all three cases for peak demand compared to *CED 2009*. These differences result from faster income growth in the mid and high cases and faster household growth in all three scenarios versus *CED 2009*.

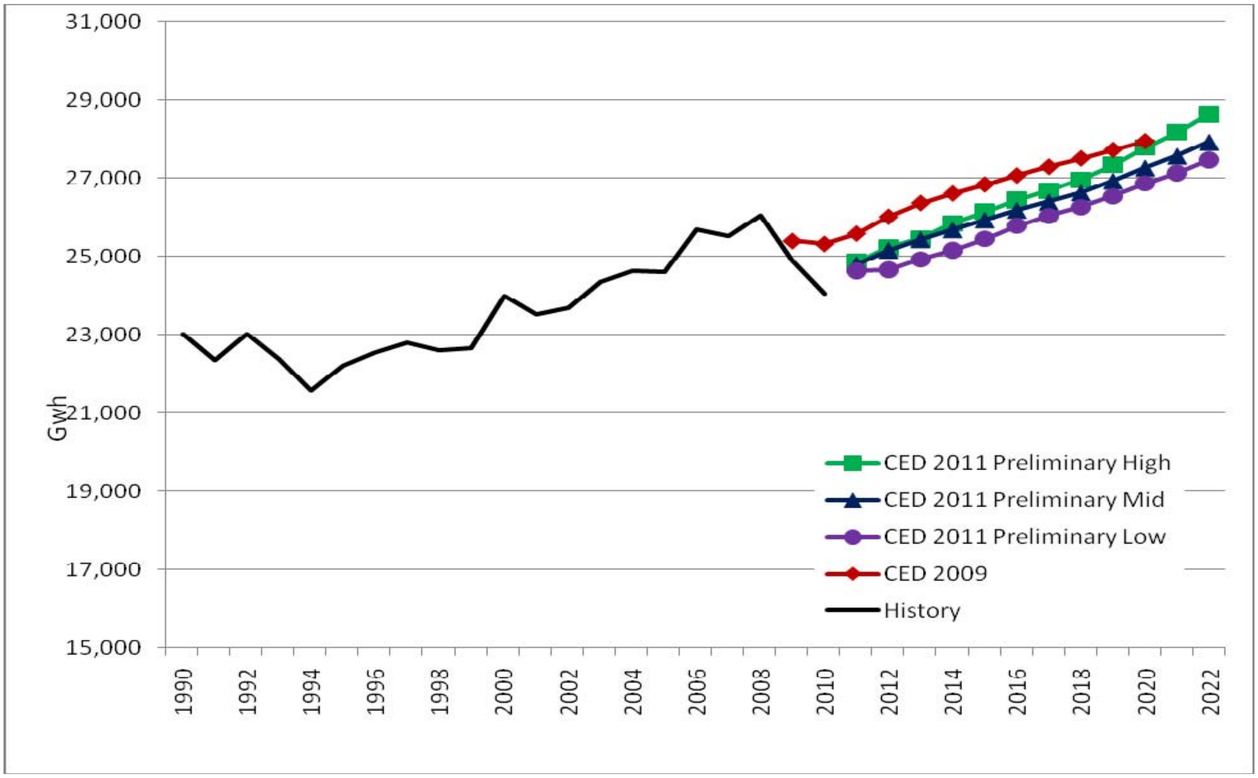
Table 6-1: LADWP Planning Area Forecast Comparison

Consumption (GWh)				
	CED 2009 (Dec. 2009)	*CED 2011 Preliminary-High Energy Demand*	*CED 2011 Preliminary-Mid Energy Demand*	*CED 2011 Preliminary-Low Energy Demand*
1990	23,263	23,038	23,038	23,038
2000	23,438	24,018	24,018	24,018
2010	25,326	24,073	24,073	24,073
2011	25,589	24,850	24,791	24,631
2015	26,841	26,143	25,929	25,453
2020	27,943	27,784	27,267	26,868
2022	--	28,633	27,930	27,475
	Average Annual Growth Rates			
1990-2000	0.07%	0.42%	0.42%	0.42%
2000-2010	0.78%	0.02%	0.02%	0.02%
2011-2015	1.20%	1.28%	1.13%	0.82%
2011-2020	0.98%	1.25%	1.06%	0.97%
2011-2022	--	1.30%	1.09%	1.00%
Peak (MW)				
	CED 2009 (Dec. 2009)	*CED 2011 Preliminary-High Energy Demand*	*CED 2011 Preliminary-Mid Energy Demand*	*CED 2011 Preliminary-Low Energy Demand*
1990	5,341	5,341	5,341	5,341
2000	5,344	5,344	5,344	5,344
2010	5,791	6,204	6,204	6,204
2011	5,846	5,764	5,755	5,720
2015	6,068	6,166	6,108	5,981
2020	6,265	6,648	6,497	6,370
2022	--	6,861	6,656	6,510
	Average Annual Growth Rates			
1990-2000	0.01%	0.01%	0.01%	0.01%
2000-2010	0.81%	1.50%	1.50%	1.50%
2011-2015	0.94%	1.70%	1.50%	1.12%
2011-2020	0.77%	1.60%	1.36%	1.20%
2011-2022	--	1.60%	1.33%	1.18%

Historical values are shaded

Source: California Energy Commission, 2011

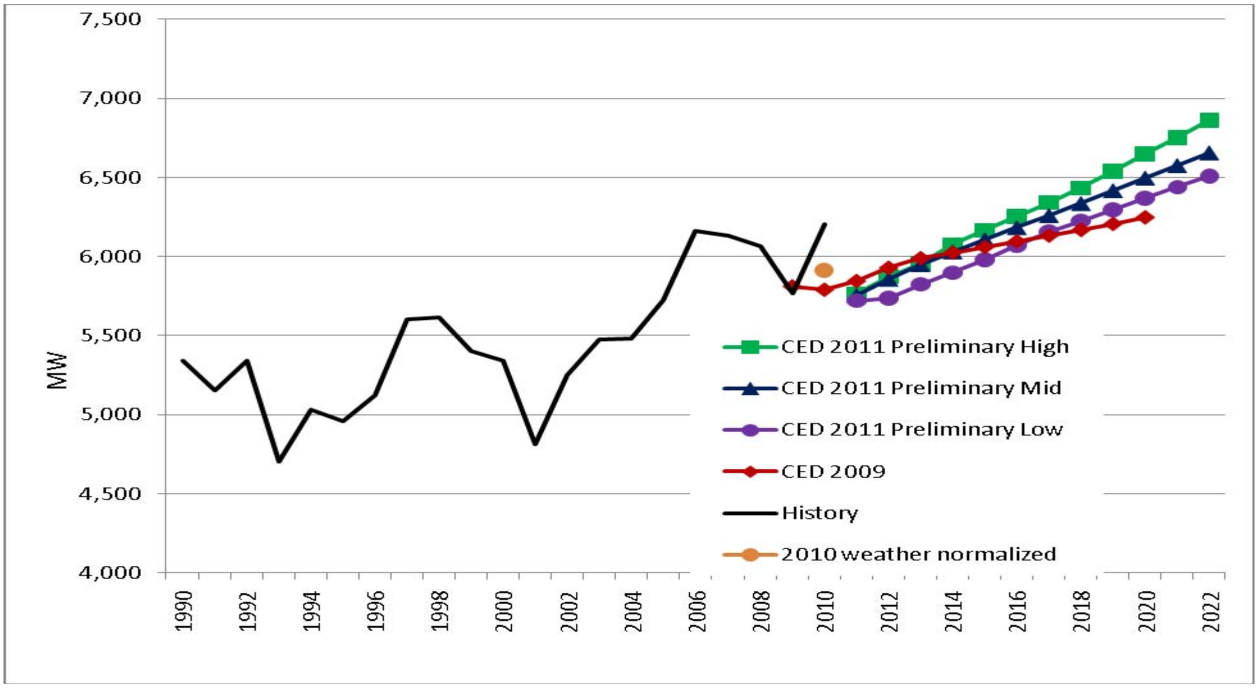
Figure 6-1: LADWP Planning Area Electricity Forecast



Source: California Energy Commission, 2011

The *CED 2011Preliminary* LADWP planning area peak demand forecast, shown in **Figure 5-2**, is lower than the *CED 2009* forecast at the beginning of the forecast period but has higher growth rates for each of the three scenarios. By 2022 the peak for each scenario is higher than the *CED 2009* forecast.

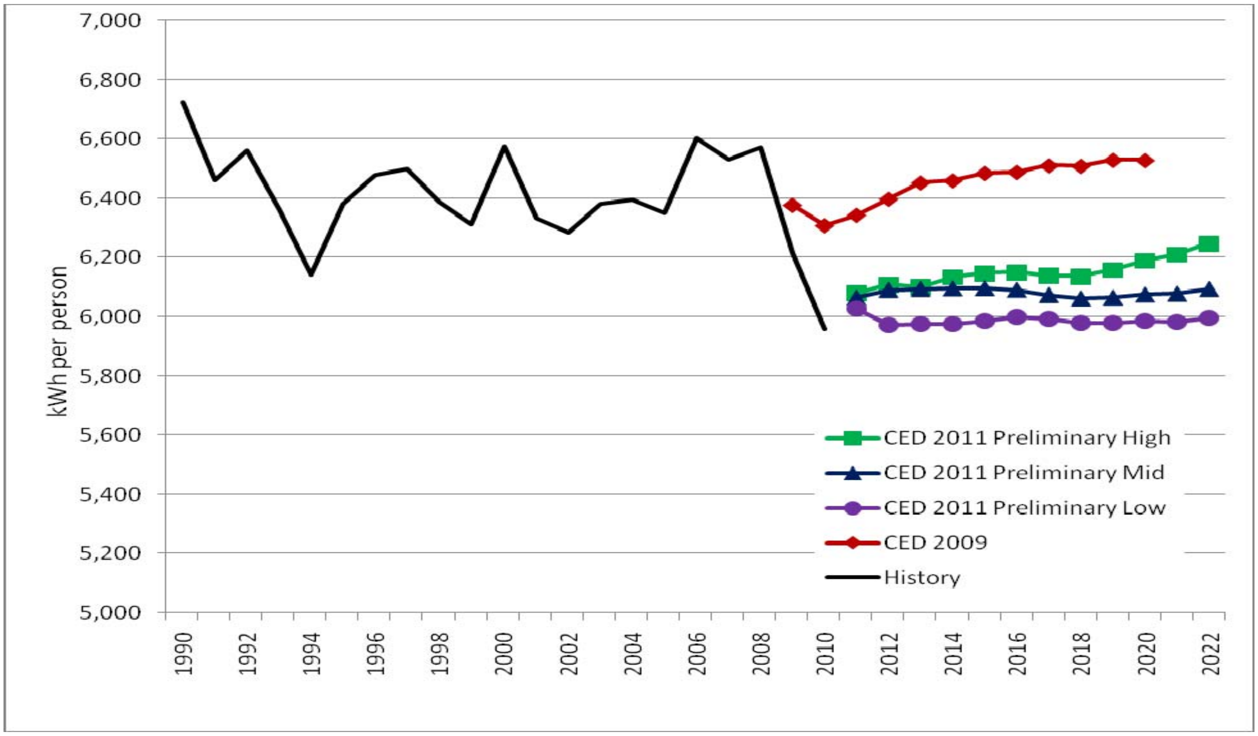
Figure 6-2: LADWP Planning Area Peak



Source: California Energy Commission, 2011

Figure 5-3 compares *CED 2011 Preliminary* and *CED 2009* per capita electricity consumption forecasts for the LADWP planning area. Projected per capita consumption in *CED 2011 Preliminary* is significantly lower than in the *CED 2009* forecast after major declines in 2009 and 2010. The *CED 2011 Preliminary* per capita electricity consumption forecast is now projected to be lower than pre-energy crisis levels. Per capita consumption rises slightly towards the end of the forecast period, reflecting increasing numbers of electric vehicles.

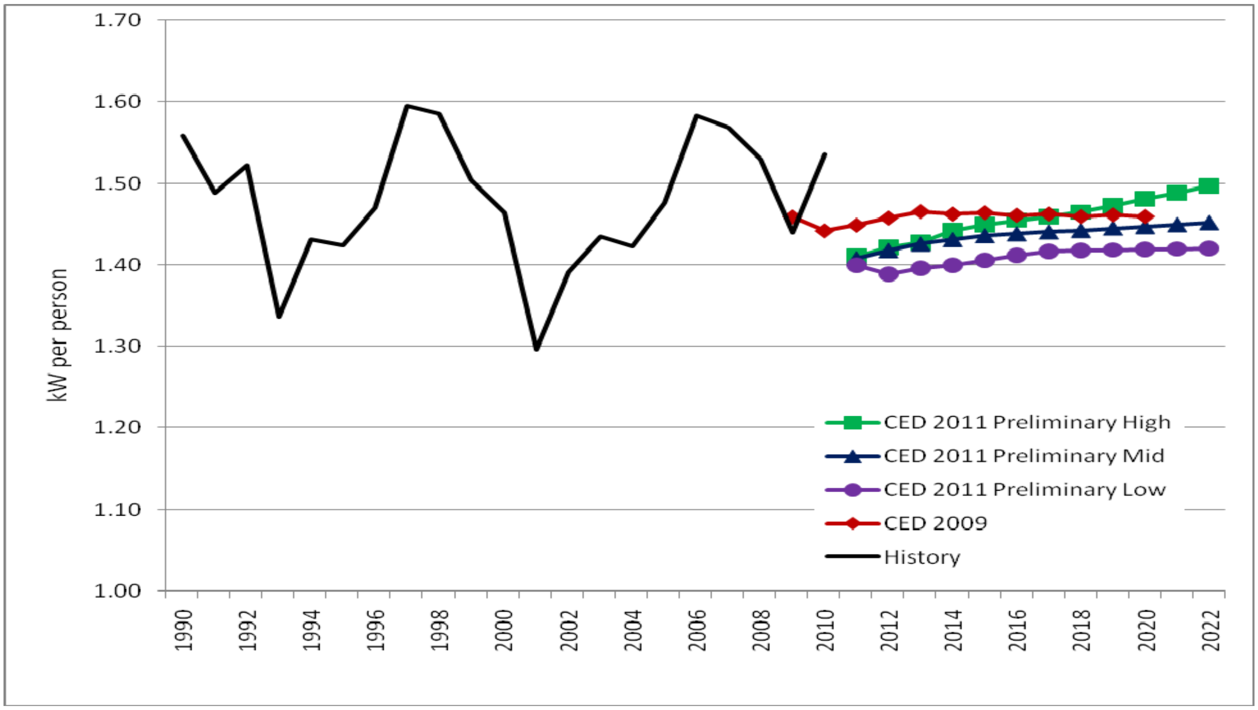
Figure 6-3: LADWP Planning Area per Capita Electricity Consumption



Source: California Energy Commission, 2011

CED 2011 Preliminary per capita peak demand, shown in **Figure 5-4**, is projected to remain relatively constant over the forecast period for the low and mid scenarios, although growing at a faster rate than the *CED 2009* forecast. The high scenario grows at an even faster rate and exceeds the *CED 2009* forecast level by 2019.

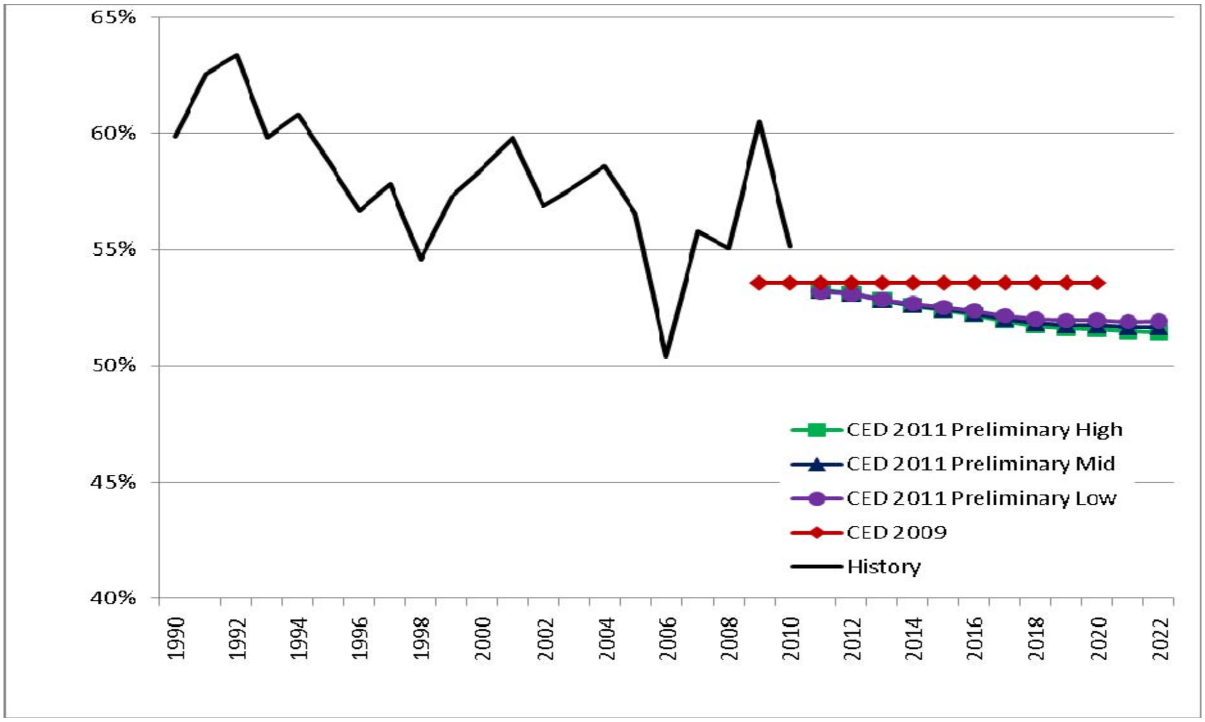
Figure 6-4: LADWP Planning Area per Capita Peak Demand



Source: California Energy Commission, 2011

Figure 5-5 compares the load factors of the two forecasts. The load factor is a measure of the relative increase in peak demand with respect to annual electricity consumption. Lower load factors indicate a sharp rise, while higher load factors indicate a more stable load. Variation in historic load factors is caused in part by annual weather patterns. The LADWP load factor has been declining since the mid-1990's, as the residential sector—with a continually increasing presence of air conditioning—grew faster than other sectors. The forecasted load factor decreases in the early years of the forecast as residential consumption – which has a lower load factor than other sectors – comprises a larger portion of consumption, thereby reducing the system load factor. The forecasted load factors increases in later years due to increasing electric vehicle usage.

Figure 6-5: LADWP Planning Area Load Factors



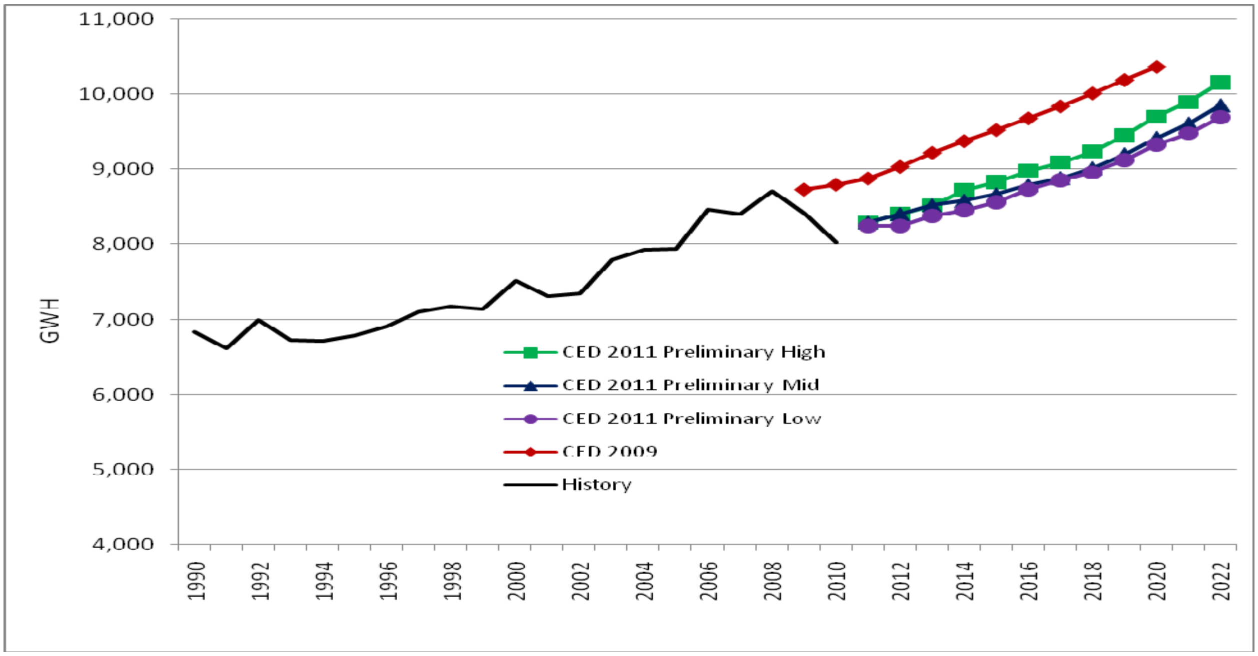
Source: California Energy Commission, 2009

Sector Level Results and Input Assumptions

Residential

Figure 5-6 provides a comparison between the *CED 2011 Preliminary* and *CED 2009* LADWP planning area residential forecasts. *CED 2011 Preliminary* is lower than *CED 2009* over the entire forecast period for all scenarios, although the growth rates for all three scenarios are higher. The higher growth rates are due to a higher projected growth rate in the number of households for each scenario compared to *CED 2009* and higher income growth in the mid and high cases. The lower preliminary forecast is primarily due to the lower starting value in 2010, which was a historically cool year and led to lower than usual consumption.

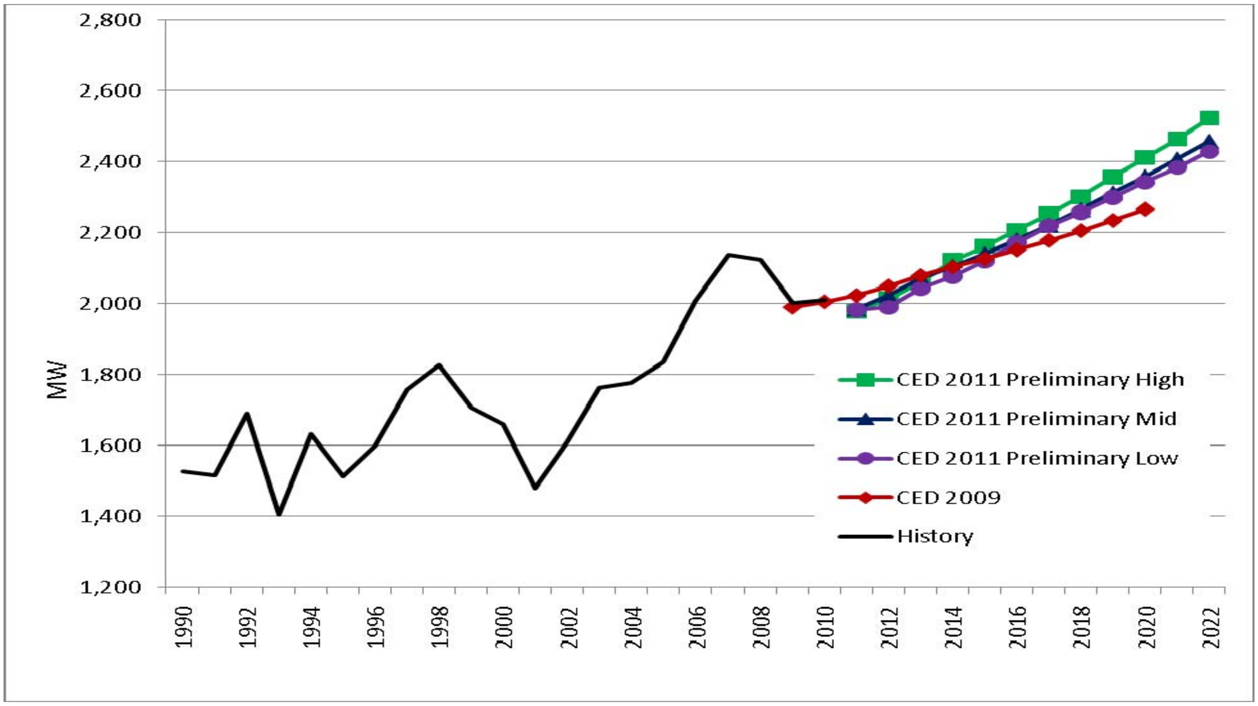
Figure 6-6: LADWP Planning Area Residential Consumption



Source: California Energy Commission, 2011

Figure 5-7 provides a comparison of *CED 2011 Preliminary* and *CED 2009* residential peak demand forecasts. As with consumption, growth in peak demand is higher in all three scenarios compared to *CED 2009* for the same reasons.

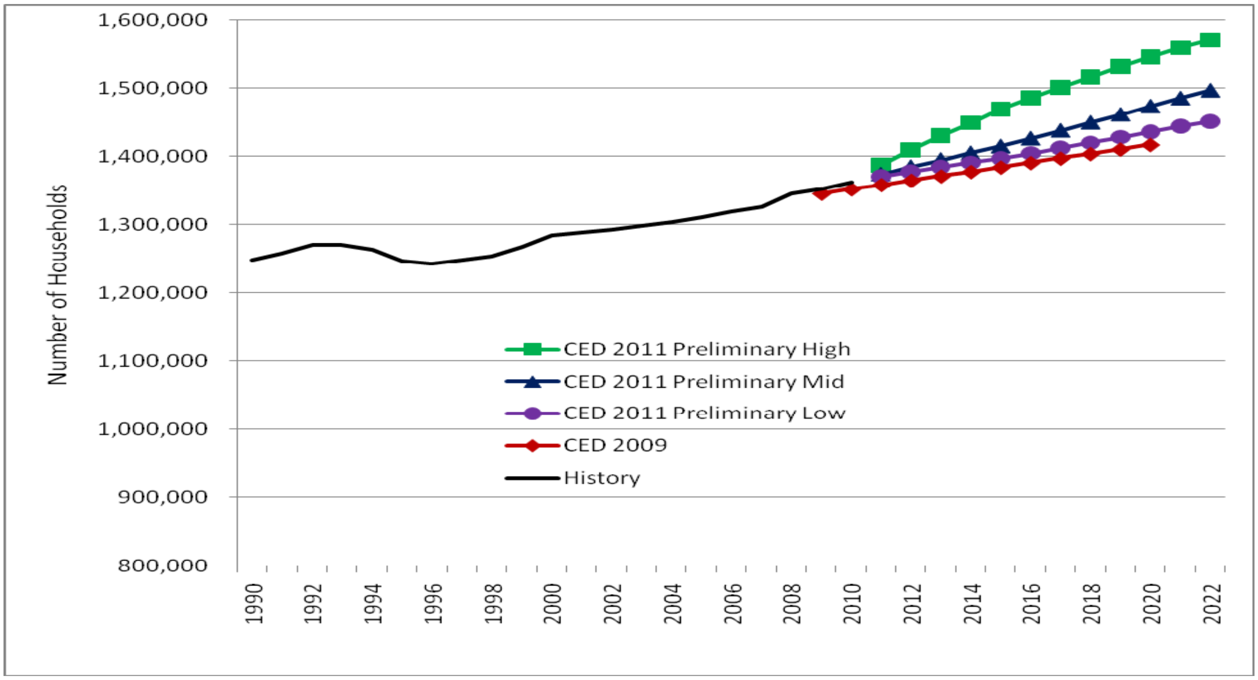
Figure 6-3: LADWP Planning Area Residential Peak



Source: California Energy Commission, 2011

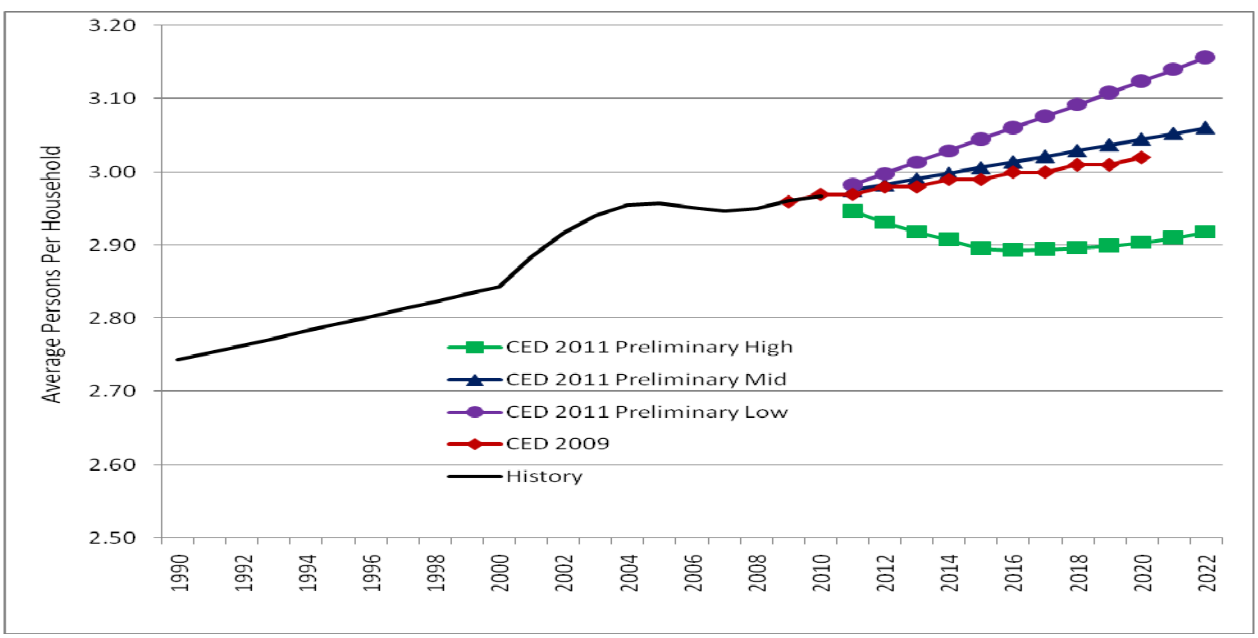
Figure 5-8 and **Figure 5-9** provide comparisons of the residential economic/demographic drivers used in *CED 2011 Preliminary* with drivers used in *CED 2009*. **Figure 5-8** provides comparisons of total households. **Figure 5-9** presents a comparison of persons per household projections. *CED 2011 Preliminary* projected number of households is higher than *CED 2009* in all three scenarios. See Chapter 1 for a description of the scenarios for persons per household.

Figure 6-4: LADWP Planning Area Residential Household Projections



Source: California Energy Commission, 2011

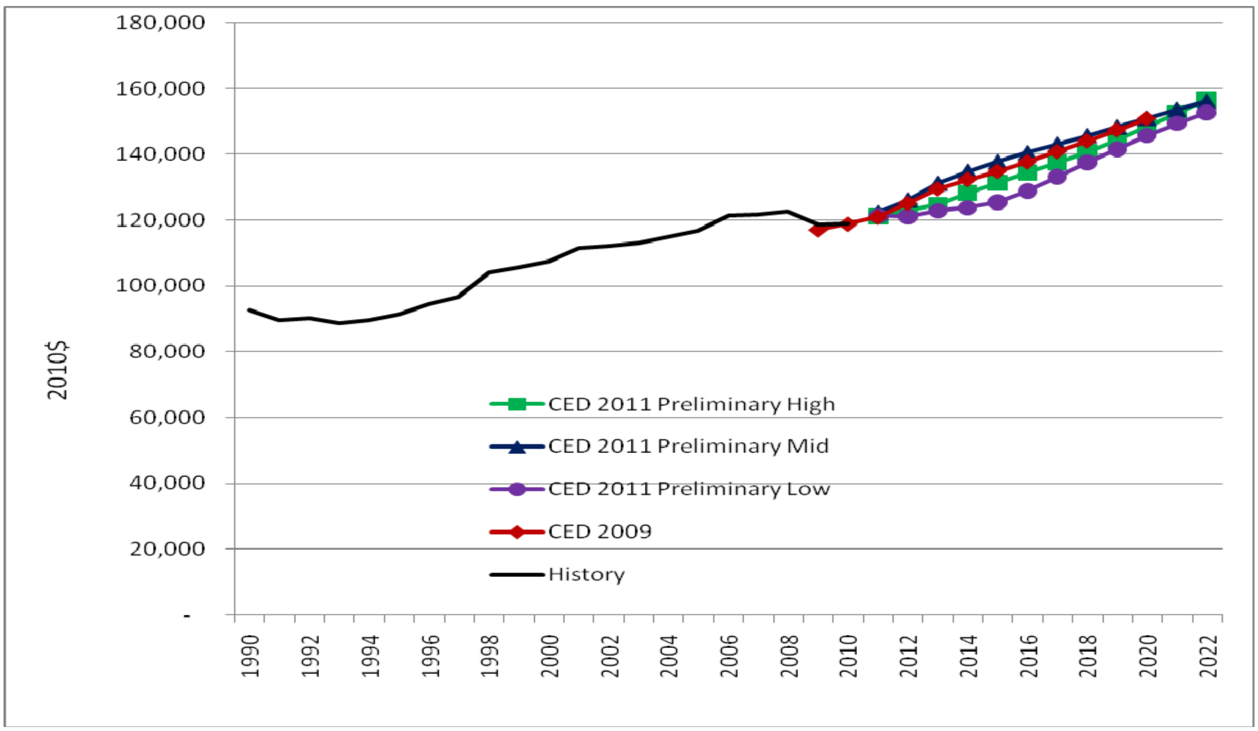
Figure 6-9: LADWP Planning Area Persons per Household Projections



Source: California Energy Commission, 2011

Figure 5-10 provides a comparison of average household income between the two forecasts. Lower total household income in the early years of the forecast in the high scenario compared to the mid case as well as differences in the projected growth rate of households versus total household income result in income per household in the high demand case lower than in the mid case until the end of the forecast period.

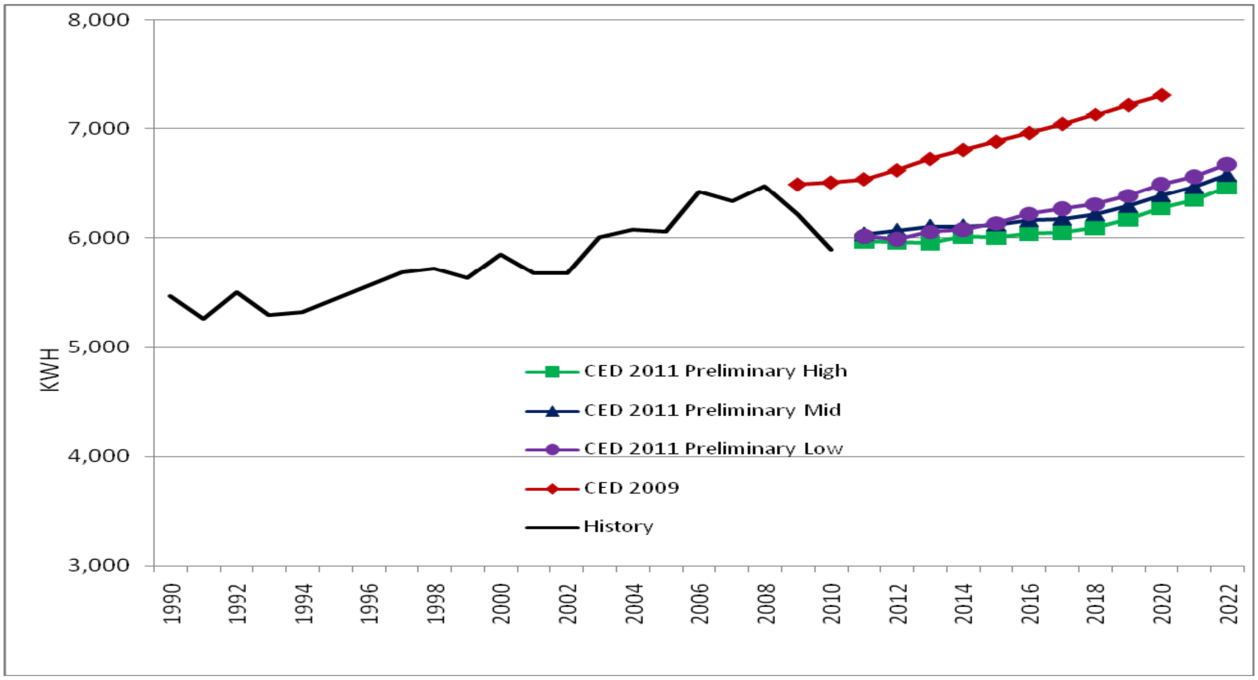
Figure 6-10: LADWP Planning Area Average Household Income Projections



Source: California Energy Commission, 2011

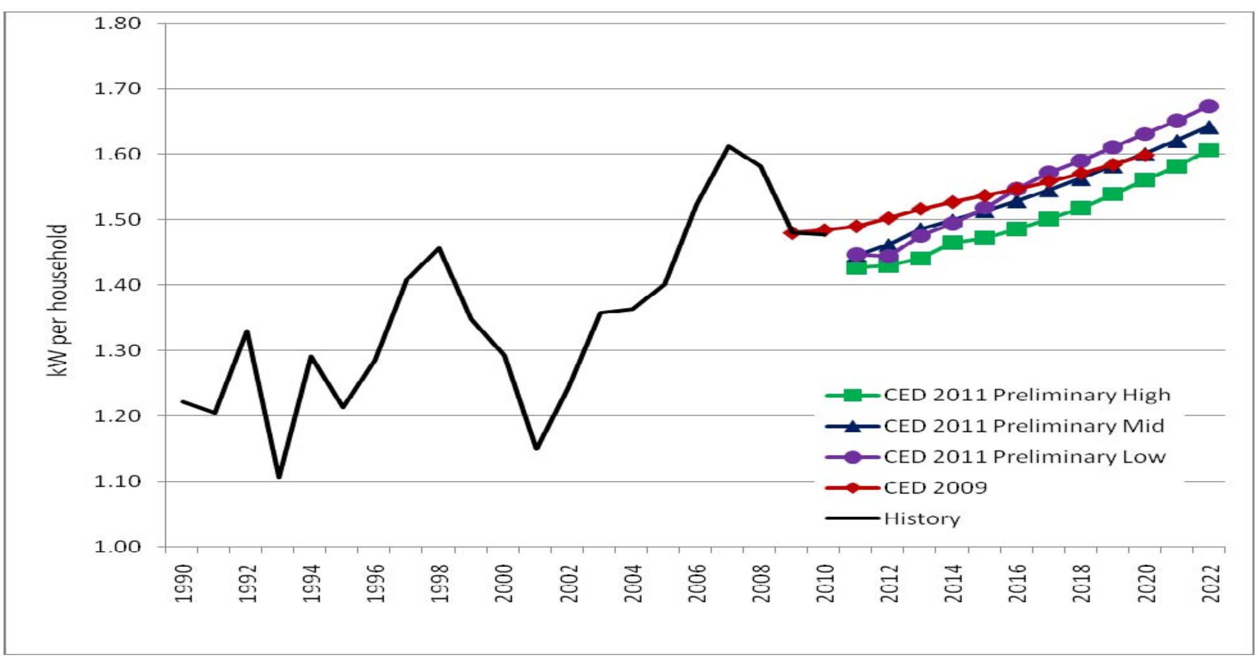
Figure 5-11 presents a comparison of electricity consumption per household between the two forecasts as well as the 1990–2010 historic series. *CED 2011 Preliminary* use per household grows similarly to the *CED 2009* forecast in the later forecast years, although it begins from a lower level due to the lower consumption forecast. The low demand scenario use per household projection is higher than the mid-level scenario, which in turn is higher than the high scenario projection. This is due to lower persons per household projections having a greater effect than does higher income. Mainly because peak use per household begins at a lower point than *CED 2009*, as seen in **Figure 5-12**, the growth rates in each scenario exceed the *CED 2009* projection, with use per household in the mid demand case matching *CED 2009* by 2020.

Figure 6-11: LADWP Planning Area Electricity Consumption per Household



Source: California Energy Commission, 2011

Figure 6-12: LADWP Planning Area Peak Use per Household

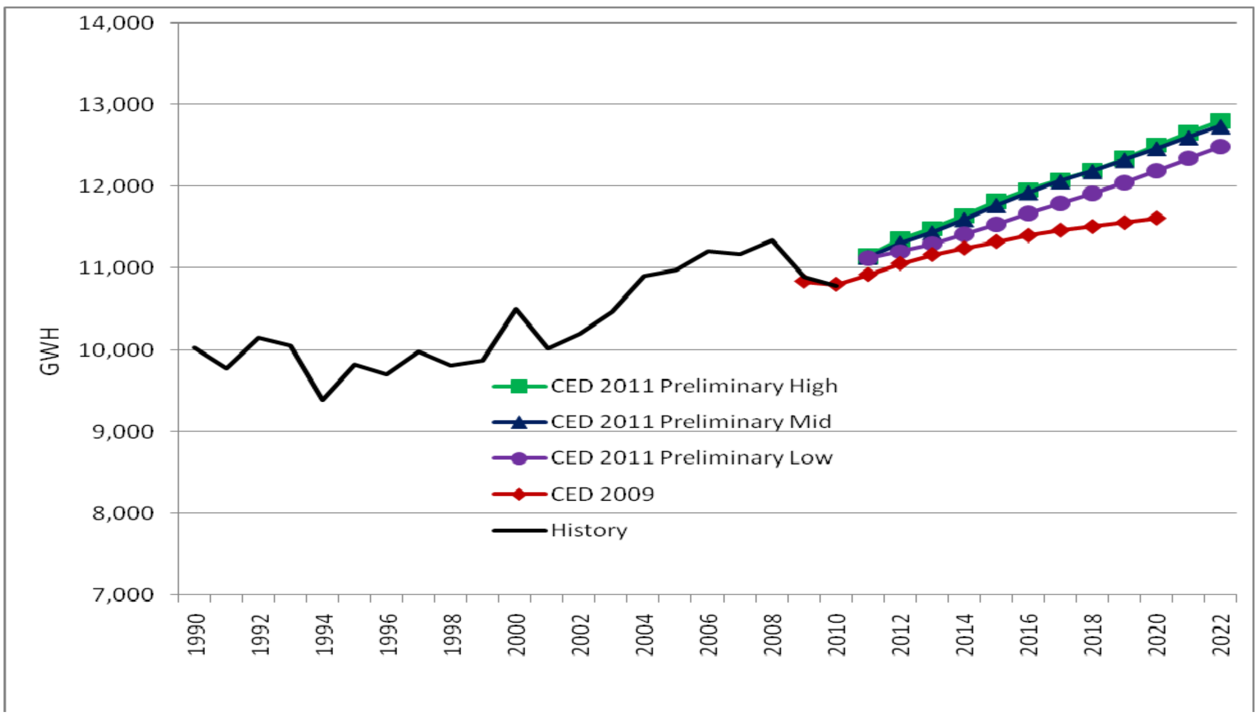


Source: California Energy Commission, 2011

Commercial Sector

Figure 5-133 provides a comparison of the commercial sector forecasts. *CED 2011 Preliminary* begins slightly above the *CED 2009* forecast and grows at a faster rate in all three scenarios. This is due to higher projected population growth, which directly affects commercial floor space. *CED 2011 Preliminary* begins in 2011 at a much higher level than actual consumption in 2010. This is the result of the historically cool weather in Southern California in 2010, which led to low consumption for the year.

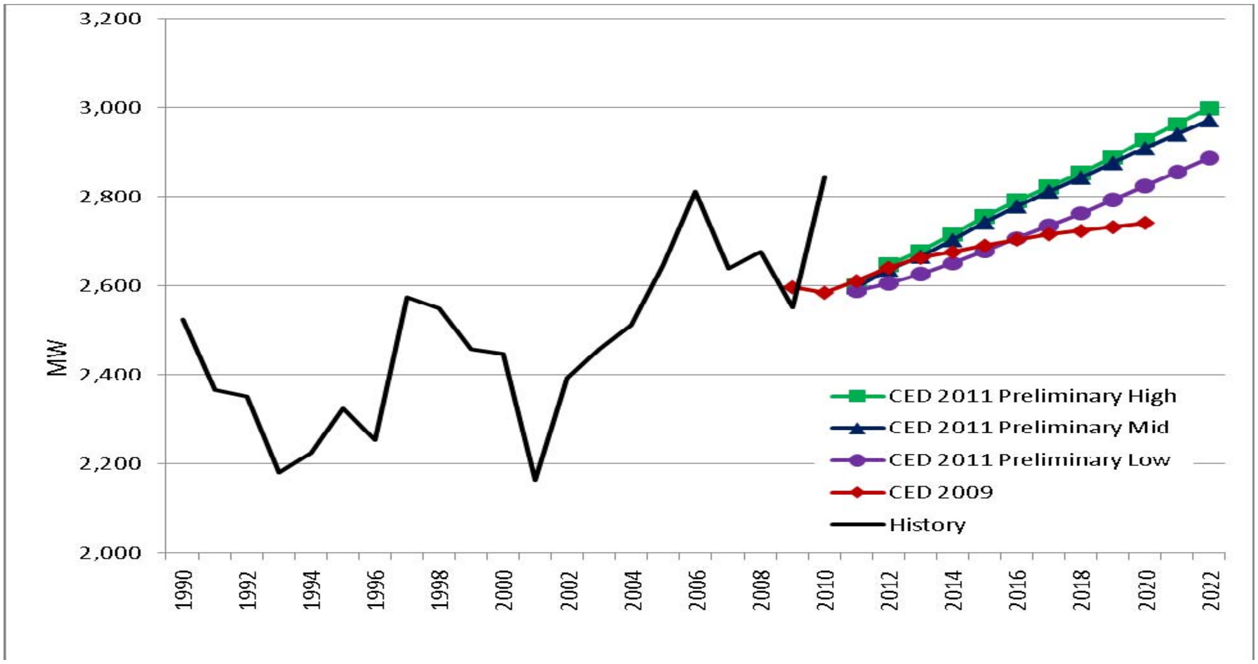
Figure 6-13: LADWP Planning Area Commercial Consumption



Source: California Energy Commission, 2011

Figure 5-144 provides a comparison of the commercial peak demand forecasts. As with consumption, *CED 2011 Preliminary* forecasted peak grows at a faster rate than *CED 2009* for all three scenarios, for the same reasons.

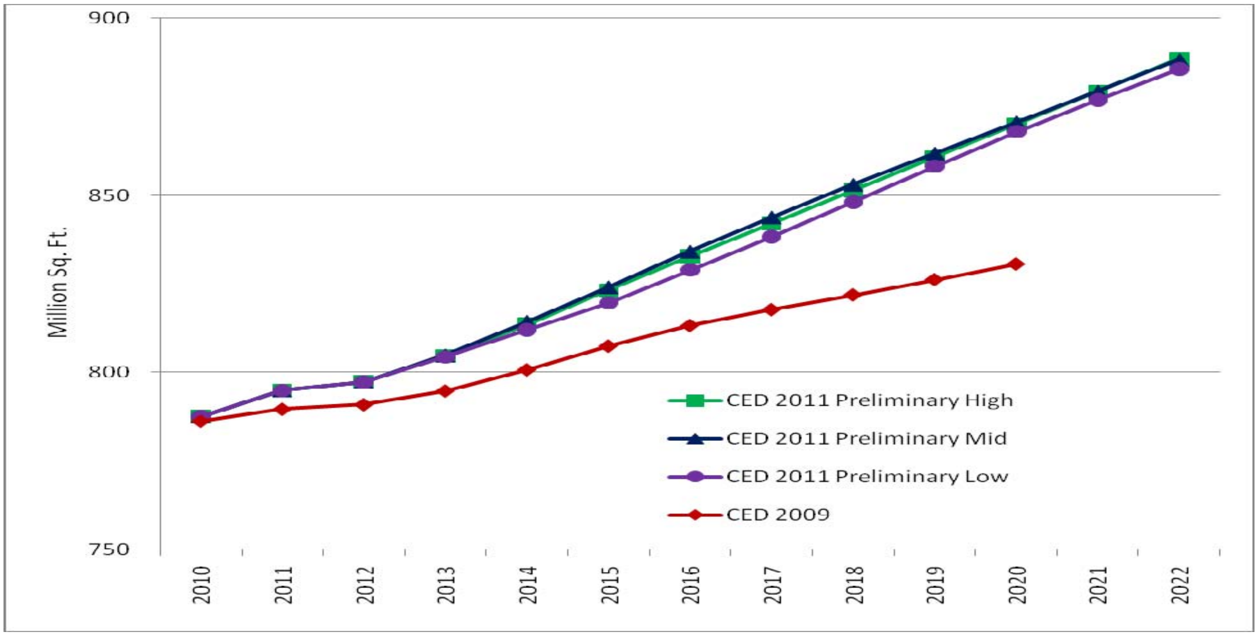
Figure 6-54: LADWP Planning Area Commercial Sector Peak



Source: California Energy Commission, 2011

In staff's commercial building sector forecasting model, floor space by building type (for example, retail, offices, schools, and hospitals) is the key driver of electricity growth. **Figure 5-155** provides a comparison of total commercial floor space projections. The *CED 2011 Preliminary* floor space projections are higher than those used in *CED 2009*. This is due to higher projected population growth. The three floor space scenarios do not vary significantly, reflecting the importance of population, which does not vary across the scenarios, in the floor space model.

Figure 6-15: LADWP Planning Area Projected Commercial Floor Space

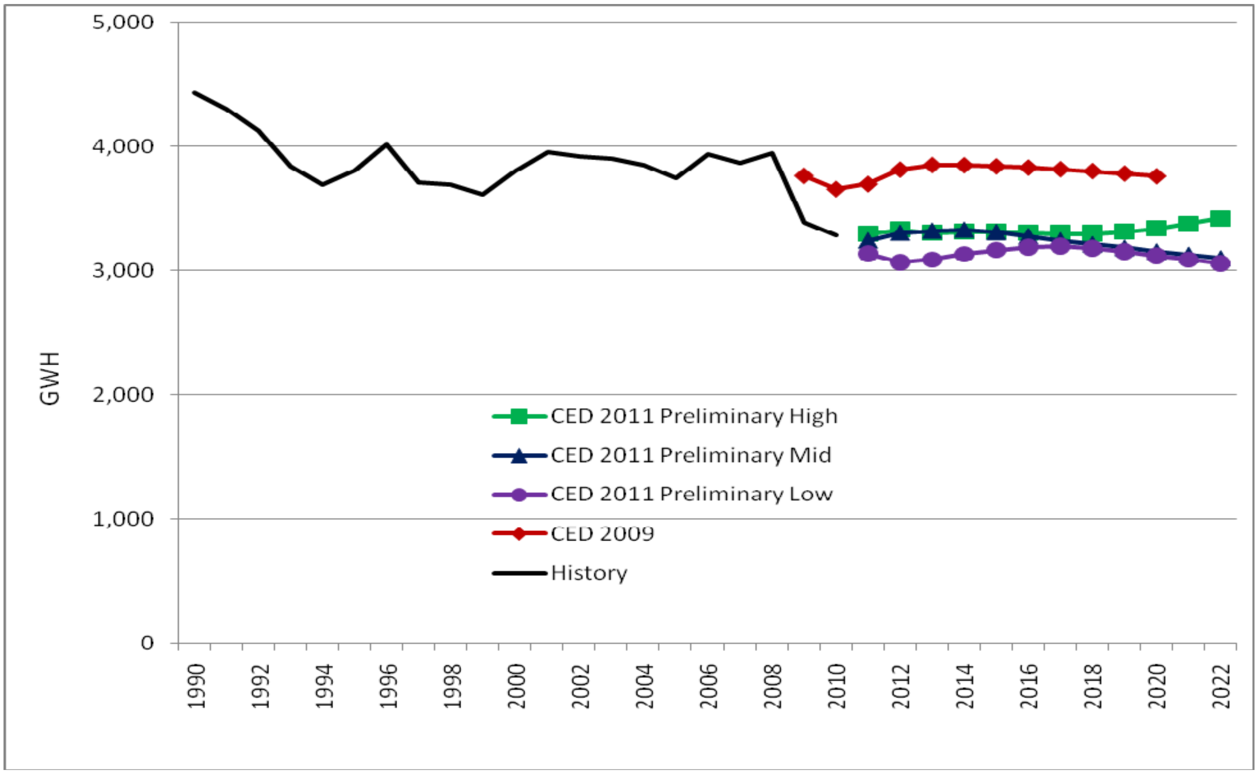


Source: California Energy Commission, 2011

Industrial Sector

Figure 5-16 provides a comparison of the LADWP planning area industrial sector electricity consumption forecasts. The *CED 2011 Preliminary* industrial electricity consumption forecast begins at a lower level than the *CED 2009* forecast, due to consumption in 2009 and 2010 being lower than was previously forecast. The low and mid scenarios reflect a long-term decline similar to that of the *CED 2009*, but growth in manufacturing output in the high scenario pushes industrial consumption up towards the end of the forecast period.

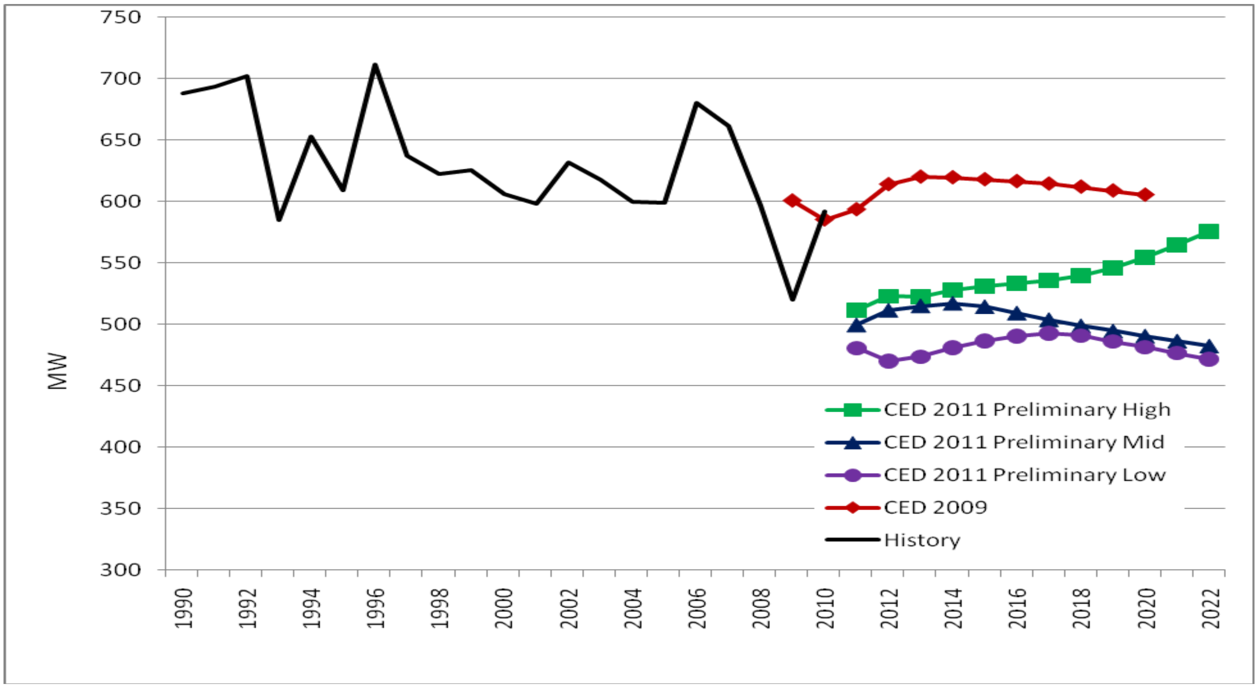
Figure 6-66: LADWP Planning Area Industrial Consumption



Source: California Energy Commission, 2011

Figure 5-17 provides a comparison of the industrial sector peak forecasts. All three peak scenarios in *CED 2011 Preliminary* are lower than the *CED 2009* forecast after large decreases in 2008 and 2009. The patterns among the scenarios mirror those for consumption.

Figure 6-7: LADWP Planning Area Industrial Sector Peak



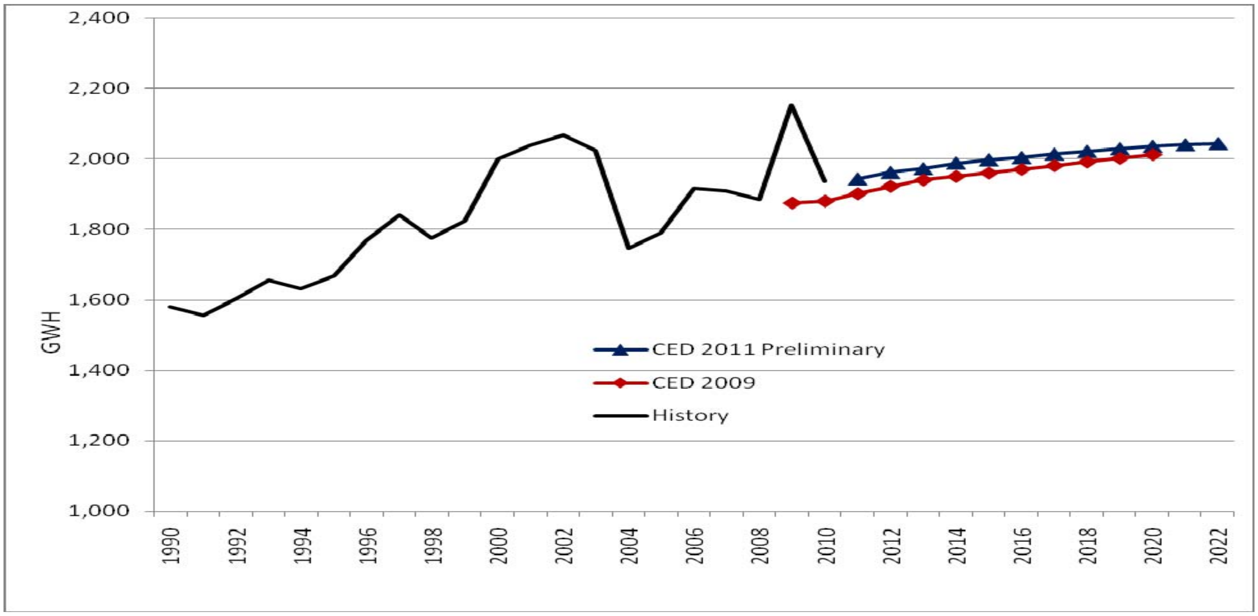
Source: California Energy Commission, 2011

Other Sectors

Figure 5-18 and **Figure 5-19** provide comparisons of the remaining sector electricity consumption forecasts. **Figure 5-18** provides a comparison of the transportation, communications, and utility (TCU) and street lighting sector forecasts. The *CED 2011 Preliminary* forecast starts from a higher point than the *CED 2009* forecast due to higher than expected consumption in 2010, but its .45 percent annual growth rate is similar to the previous forecast. The main driver of the TCU forecast is population, which does not vary by scenario, so only demand case was developed for this sector.

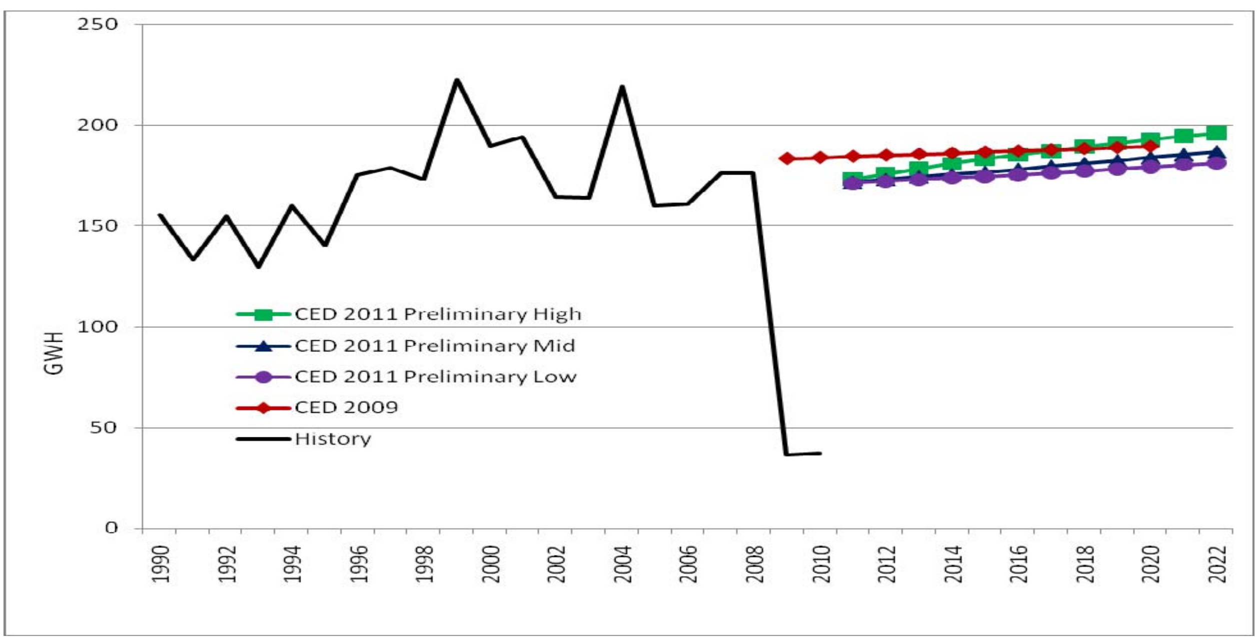
Figure 5-19 provides comparisons of the agriculture and water pumping sector forecasts. *CED 2011 Preliminary* has a faster growth rate than the *CED 2009* forecast in all three scenarios, with consumption in the high case exceeding *CED 2009* by 2018. The high scenario projection is 8 percent higher than the low scenario forecast by 2022. The large decrease in historical consumption for 2009 and 2010 is likely the result of a QFER reporting problem, which will be addressed in time for the revised forecast.

Figure 6-18: LADWP Planning Area Transportation, Communication & Utilities Sector Electricity Consumption



Source: California Energy Commission, 2011

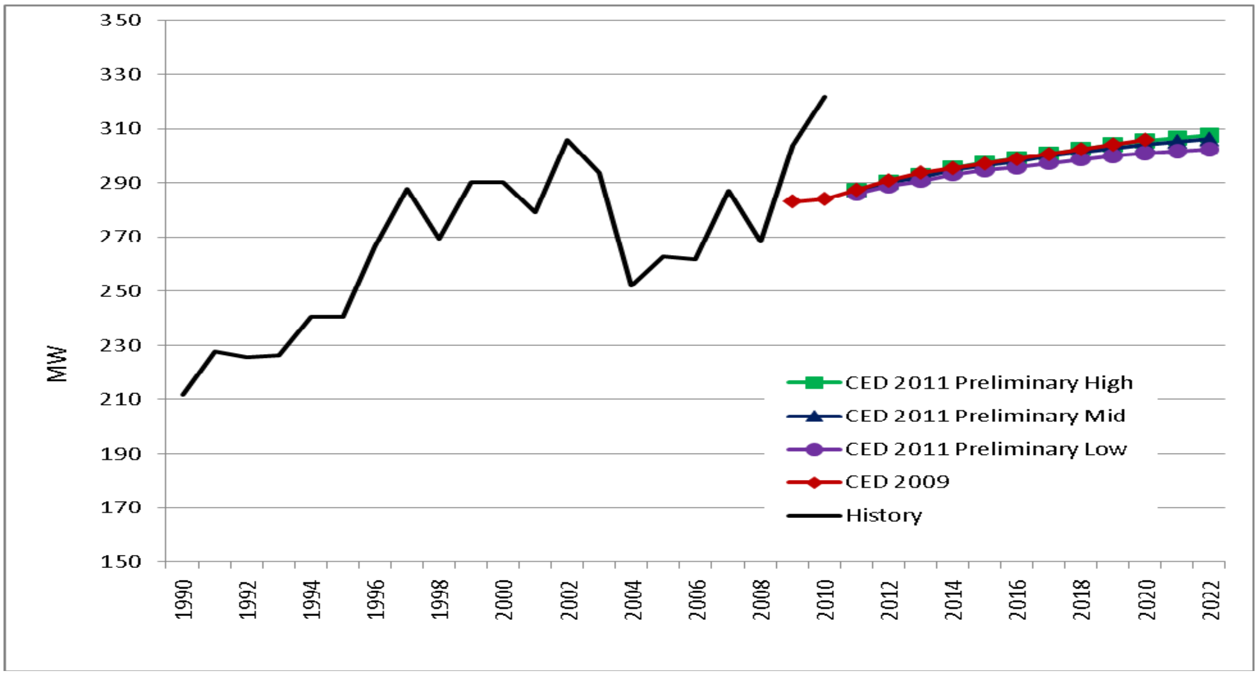
Figure 6-19: LADWP Planning Area Agriculture & Water Pumping Electricity Consumption Forecasts



Source: California Energy Commission, 2011

Figure 5-20 provides a comparison of the combined "other" sector peaks for the *CED 2011 Preliminary* and *CED 2009* forecasts. The *CED 2011 Preliminary* forecast is essentially the same as *CED 2009* in all three scenarios.

Figure 6-80: LADWP Planning Area Other Sector Peak

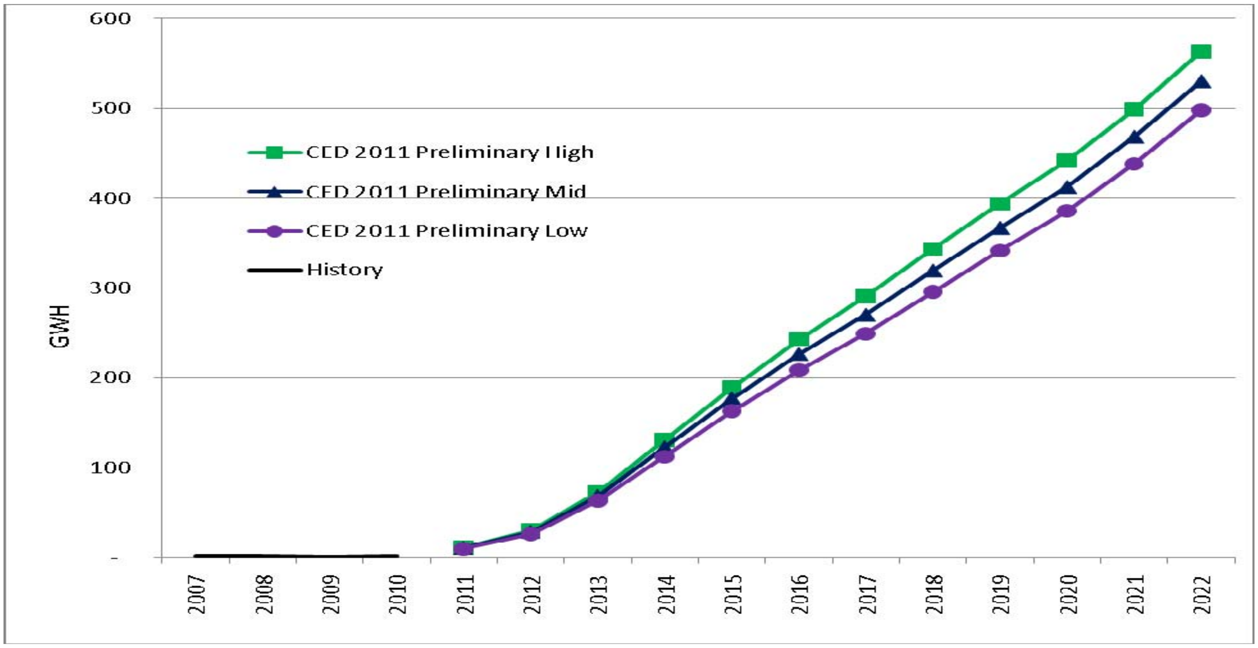


Source: California Energy Commission, 2011

Electric Vehicles

Figure 6-21 shows projected electricity consumption due to increased use of electric vehicles. Since existing electric vehicle use is included in QFER consumption data, projected consumption and peak demand incremental to 2010 usage was added to the sector model results. For the LADWP planning area, consumption by electric vehicles was approximately 2 GWh in 2010 and is projected to rise to 531 GWh in the mid case by 2022. For many of these electric vehicles, recharging will routinely occur during off-peak hours, resulting in relatively low peak impacts. By 2022, electric vehicles are expected to contribute an additional 21 MW of peak demand in the low demand scenario and 24 MW in the high scenario.

Figure 6-91: LADWP Planning Area Electric Vehicle Consumption



Source: California Energy Commission, 2011

Self-Generation

As shown in **Table 6-22**, the peak demand forecast is reduced by self generation, including the effects of the SGIP, CSI, and other programs, as discussed in Chapter 1. The effects of these programs are forecast based on recent trends in installations and a predictive model for the residential sector. Staff projects about 54 MW of peak reduction from PV installation in the mid case by 2022. Peak reductions are based on installed PV system capacities of 58 MW in 2015 and 144 MW in 2022 in the high demand case, and 58 MW in 2015 and 147 MW in 2022 in the low demand case.

Table 6-22: LADWP Planning Area Self-Generation Peak Forecasts

	1990	2000	2010	2015	2020	2022
Non-PV Self-Generation	148.50	196.70	179.78	179.83	179.90	179.96
PV, Low Demand	0.00	0.22	12.65	22.13	41.50	56.06
PV, Mid Demand	0.00	0.22	12.65	22.04	40.44	54.38
PV, High Demand	0.00	0.22	12.65	22.18	40.90	55.00
Total Self-Generation, Low Demand	148.50	196.91	192.43	201.96	221.40	236.02
Total Self-Generation, Mid Demand	148.50	196.91	192.43	201.88	220.33	234.34
Total Self-Generation, High Demand	148.50	196.91	192.43	202.02	220.80	234.96

Source: California Energy Commission, 2011

Conservation/Efficiency Impacts

Table 6-23 shows electricity consumption and peak savings estimates for building and appliance standards for the mid demand scenario. Total standards impacts are higher in the high demand case by 1.5—2.0 percent because of higher home construction and commercial floor space and 1.5—2.0 percent lower in the low demand case. Chapter 8 provides more detail on staff work related to energy efficiency and conservation.

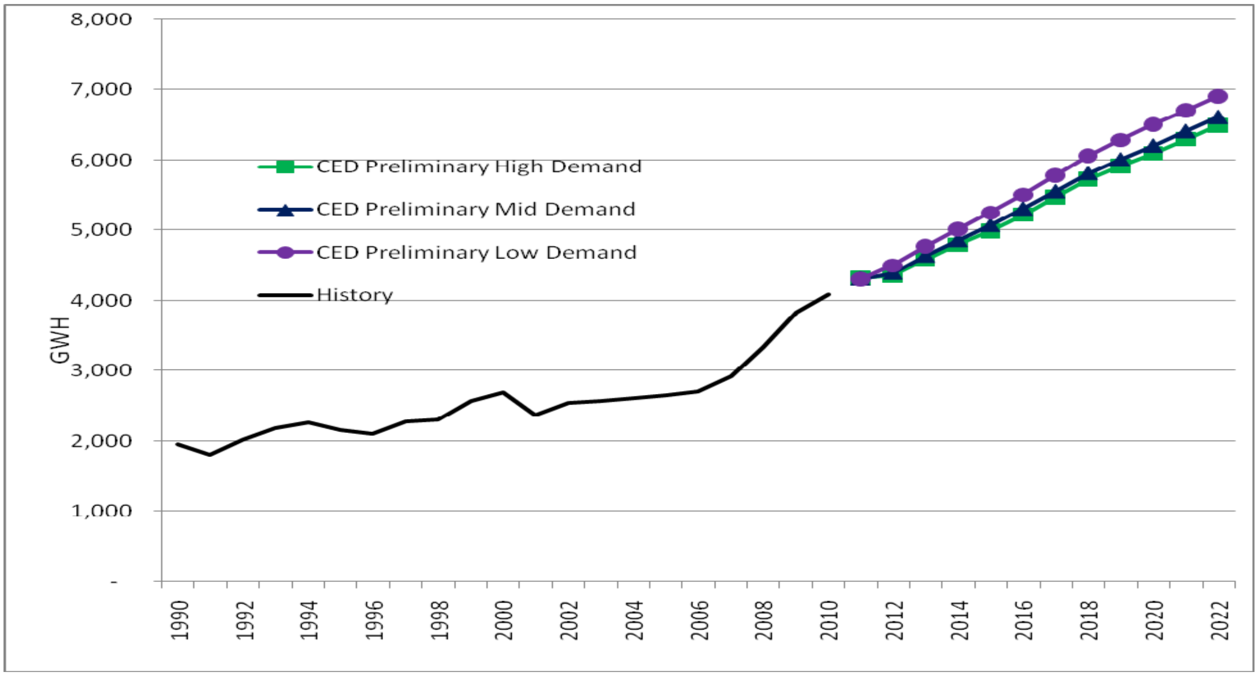
Table 6-23: LADWP Planning Area Electricity Savings Estimates from Standards, Mid Demand Scenario

Electricity Consumption Savings (GWh)							
	Residential			Commercial			
	Building Standards	Appliance Standards	Total	Building Standards	Appliance Standards	Total	Total Standards
1990	244	212	456	128	87	215	671
2000	269	615	885	267	187	454	1,339
2010	383	1,422	1,805	504	324	829	2,634
2015	442	1,837	2,278	716	449	1,165	3,443
2020	495	2,117	2,612	970	639	1,609	4,221
2022	510	2,157	2,666	1,070	679	1,749	4,415
Electricity Peak Demand Savings (MW)							
	Residential			Commercial			
	Building Standards	Appliance Standards	Total	Building Standards	Appliance Standards	Total	Total Standards
1990	55	47	102	32	22	54	156
2000	59	136	195	62	44	106	301
2010	96	356	452	133	86	219	671
2015	109	453	563	167	105	271	834
2020	124	530	654	226	149	375	1,029
2022	127	538	665	250	158	408	1,073

Source: California Energy Commission, 2011

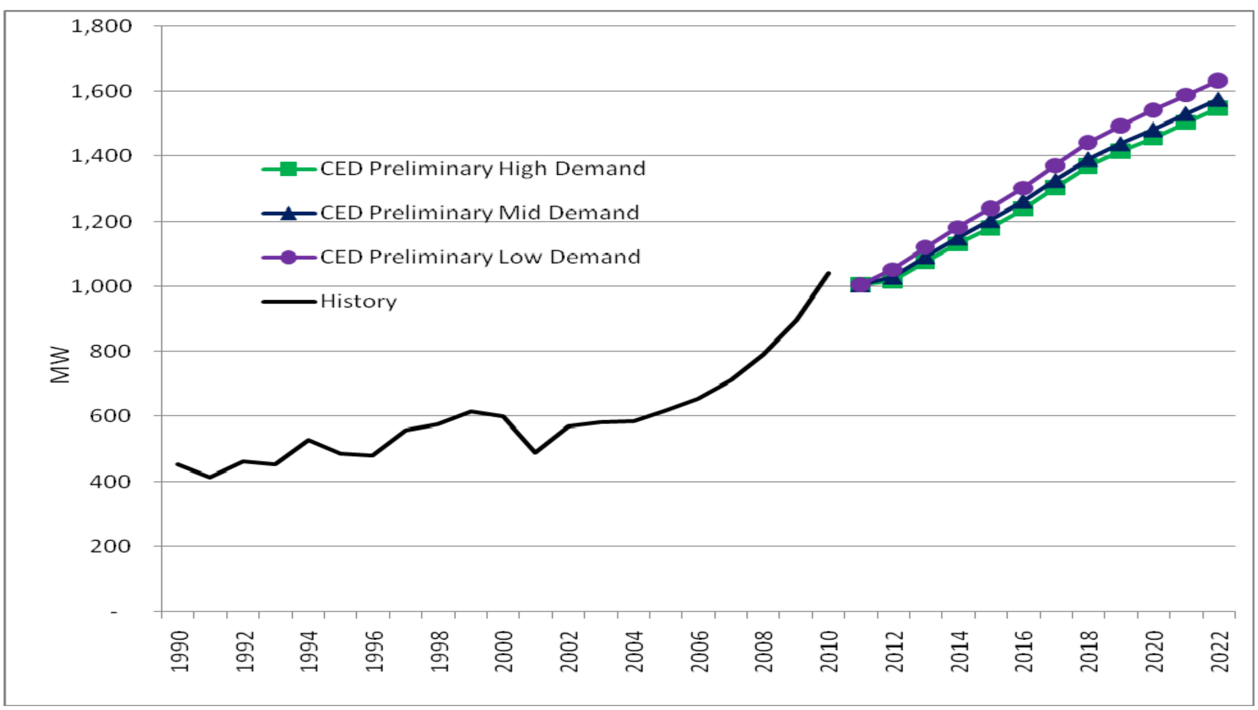
Figure 6-24 and **Figure 6-25** show forecasts of total savings impacts on electricity and peak demand respectively from building and appliance standards, utility and public agency programs, and price and other effects, or savings associated with rate changes and certain market trends not directly related to programs or standards. Savings are measured against a 1975 baseline, so they incorporate more than 30 years of impacts from rate changes and standards. Projected savings impacts are higher the lower the demand scenario, since price and program effects are inversely related to the demand outcome.

Figure 6- 24: LADWP Planning Area Electricity Consumption Savings Estimates



Source: California Energy Commission, 2011

Figure 6- 25: LADWP Planning Area Electricity Peak Savings Estimates



Source: California Energy Commission, 2011

CHAPTER 7:
End-User Natural Gas Demand Forecast

This chapter presents preliminary forecasts of end-user natural gas demand for the PG&E, Southern California Gas (SCG), and SDG&E natural gas planning areas. In addition, statewide results include sales from much smaller utilities, including Palo Alto and Avista Energy aggregated into the category "other." Detailed forecasts for the three major planning areas and the "other" are provided in the natural gas forms accompanying this forecast report.

Staff prepares these forecasts in parallel with its electricity demand forecasts, with the same models, organized along electricity planning area boundaries. The gas demand forecasts presented here are the aggregate of gas demand in the corresponding electricity planning areas. Unlike the electricity forecast, new econometric models have not been estimated for natural gas demand. These forecasts do not include natural gas used by utilities or others for electric generation.

CED 2011 Preliminary incorporates historical consumption data up through 2010. As in the case of electricity, three demand scenarios were forecast (high, mid, and low), with the same economic/demographic assumptions in each case. Also similar to electricity, the high, mid, and low scenarios incorporated low, mid, and high assumptions, respectively, for natural gas prices and efficiency program impacts. See Chapter 1 for a discussion of prices and economic and demographic inputs and Chapter 8 for a description of efficiency assumptions.

Statewide Forecast Results

Table 7-1 compares the three demand scenarios at the statewide level with *CED 2009* for selected years. The new forecasts begin at a higher point in 2010, as natural gas consumption in California was substantially higher in this year than predicted in *CED 2009*, and grow at a faster rate from 2010-2020. This results from faster projected demand growth for all three scenarios in the industrial sector and for the mid and high cases in the residential sector. Sector results are discussed further in the planning area section that follows.

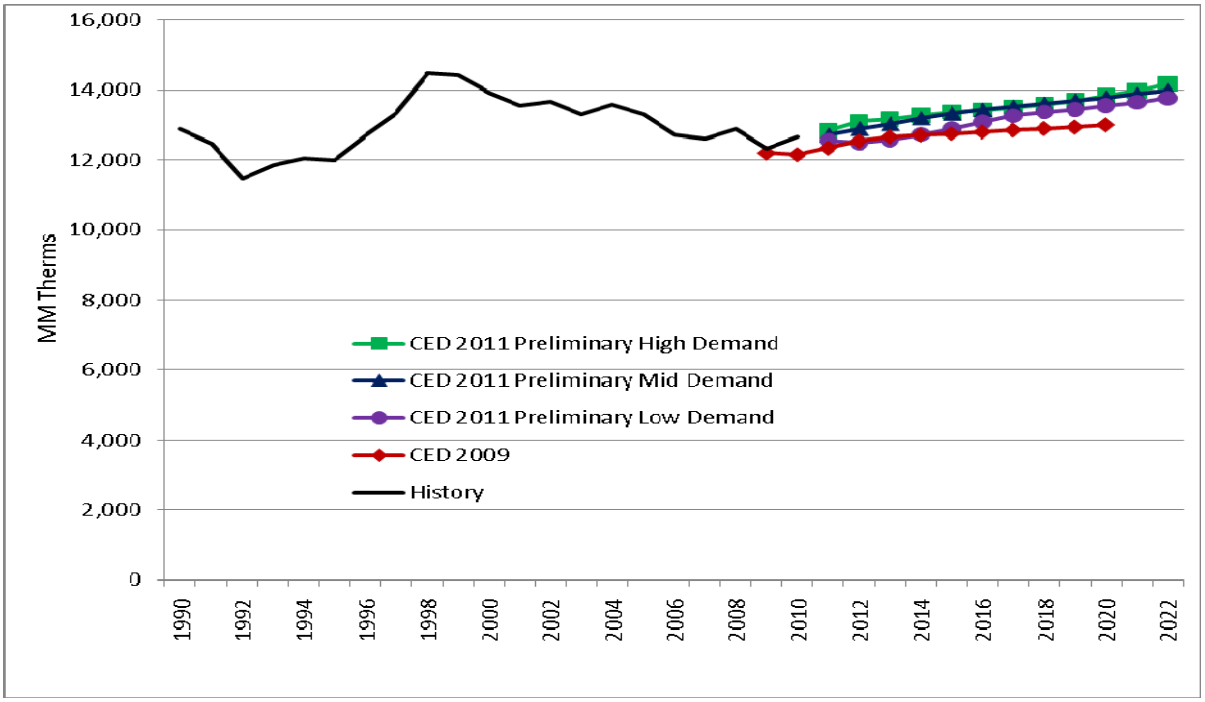
Table 7-1: Statewide End-User Natural Gas Forecast Comparison

Consumption (MM Therms)				
	CED 2009 (Dec. 2009)	*CED 2011 Preliminary High Energy Demand* (August 2011)	*CED 2011 Preliminary Mid Energy Demand* (August 2011)	*CED 2011 Preliminary Low Energy Demand* (August 2011)
1990	12,893	12,893	12,893	12,893
2000	13,913	13,914	13,914	13,914
2010	12,162	12,665	12,665	12,665
2015	12,751	13,372	13,338	12,891
2020	12,997	13,832	13,789	13,552
2022	--	14,175	13,992	13,773
	Average Annual Growth Rates			
1990-2000	0.76%	0.76%	0.76%	0.76%
2000-2010	-1.34%	-0.94%	-0.94%	-0.94%
2010-2015	0.95%	1.09%	1.04%	0.36%
2010-2020	0.67%	0.89%	0.85%	0.68%
2010-2022	--	0.94%	0.83%	0.70%
Historical values are shaded				

Source: California Energy Commission, 2011

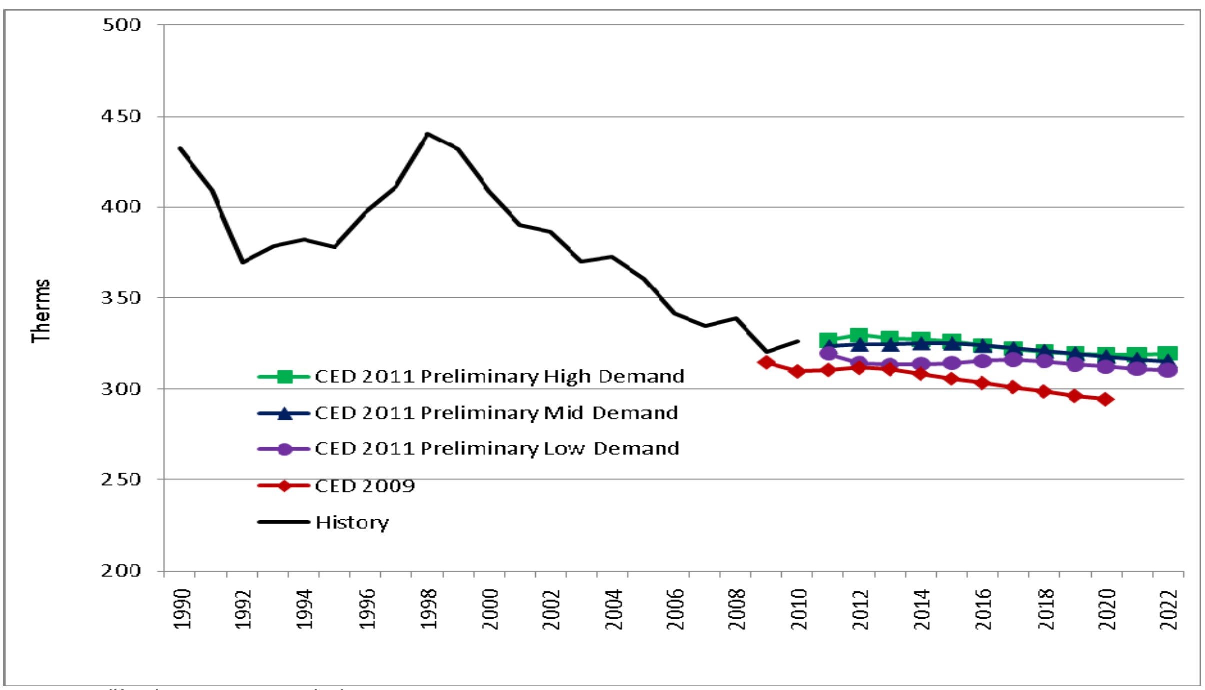
Figure 7-1 shows the forecasts graphically. By 2020, demand in the high demand case is projected to be almost 6.5 percent higher in the high demand case and around 4 percent high in the low case compared to *CED 2009*. **Figure 7-2** compares *CED 2011 Preliminary* projected per capita natural gas consumption with *CED 2009*. Annual per capita demand varies in response to annual temperatures and business conditions. This has been declining since the late 1990s. This trend is projected to continue in all four forecasts, although the decline is less severe in the new forecast for all three scenarios.

Figure 7-1: Statewide End-User Natural Gas Consumption



Source: California Energy Commission, 2011

Figure 7-2: Statewide End-User Per Capita Natural Gas Consumption



Source: California Energy Commission, 2011

Planning Area Results

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

Pacific Gas and Electric Planning Area

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

Table 7-2 compares the preliminary PG&E planning area forecasts with *CED 2009*. As in the statewide case, the new forecasts begin at a higher level and grow at a faster rate in all three scenarios. By 2020, demand is over 18 percent higher in the high case and 11 percent higher in the low case compared to *CED 2009*.

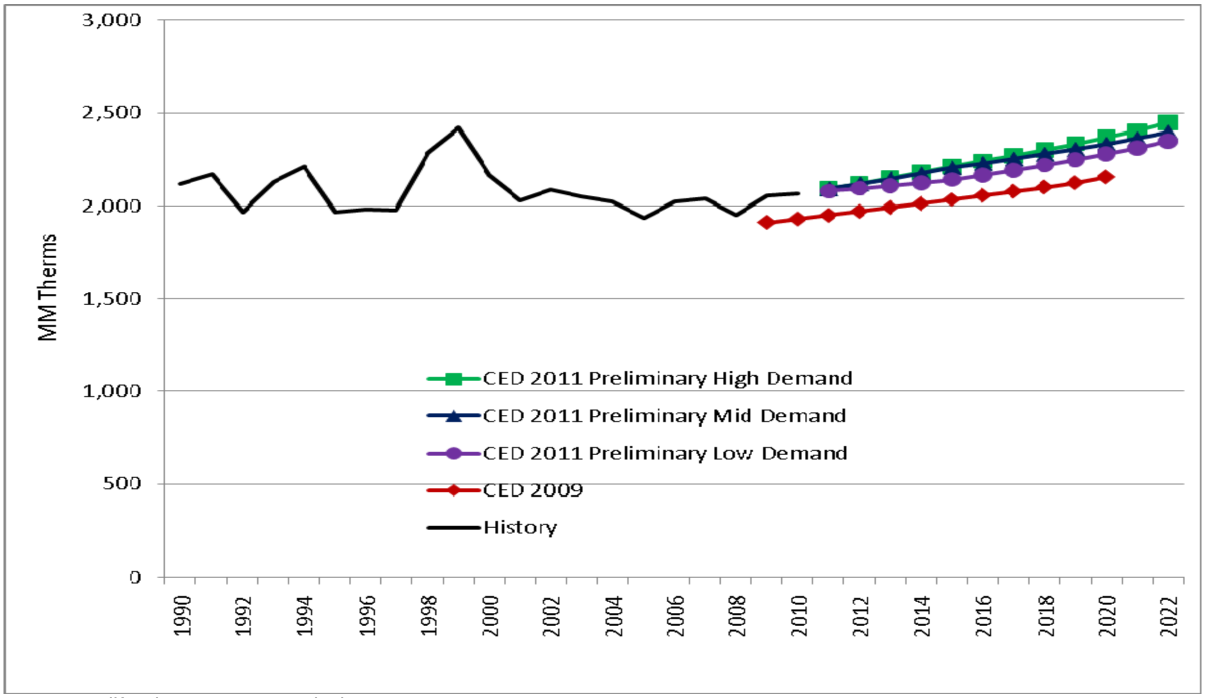
Table 7-2: PG&E Natural Gas Forecast Comparison

Consumption (MM Therms)				
	CED 2009 (Dec. 2009)	*CED 2011 Preliminary High Energy Demand* (August 2011)	*CED 2011 Preliminary Mid Energy Demand* (August 2011)	*CED 2011 Preliminary Low Energy Demand* (August 2011)
1990	5,275	5,275	5,275	5,275
2000	5,291	5,310	5,310	5,310
2010	4,186	4,530	4,530	4,530
2015	4,315	4,910	4,831	4,650
2020	4,388	5,197	5,033	4,883
2022	--	5,338	5,116	4,967
	Average Annual Growth Rates			
1990-2000	0.03%	0.07%	0.07%	0.07%
2000-2010	-2.31%	-1.58%	-1.58%	-1.58%
2010-2015	0.61%	1.63%	1.30%	0.52%
2010-2020	0.47%	1.39%	1.06%	0.76%
2010-2022	--	1.38%	1.02%	0.77%
Historical values are shaded				

Source: California Energy Commission, 2011

Figure 7-3 compares *CED 2009* and *CED 2009* PG&E residential forecasts. The new forecasts are higher throughout the entire forecast period as actual consumption recorded in 2010 was higher than predicted in *CED 2009*. Faster projected growth in income in the mid and high cases versus *CED 2009* push 2010-2020 demand growth rates in these scenarios (1.38 percent and 1.22 percent, respectively) above that projected in *CED 2009* (1.11 percent).

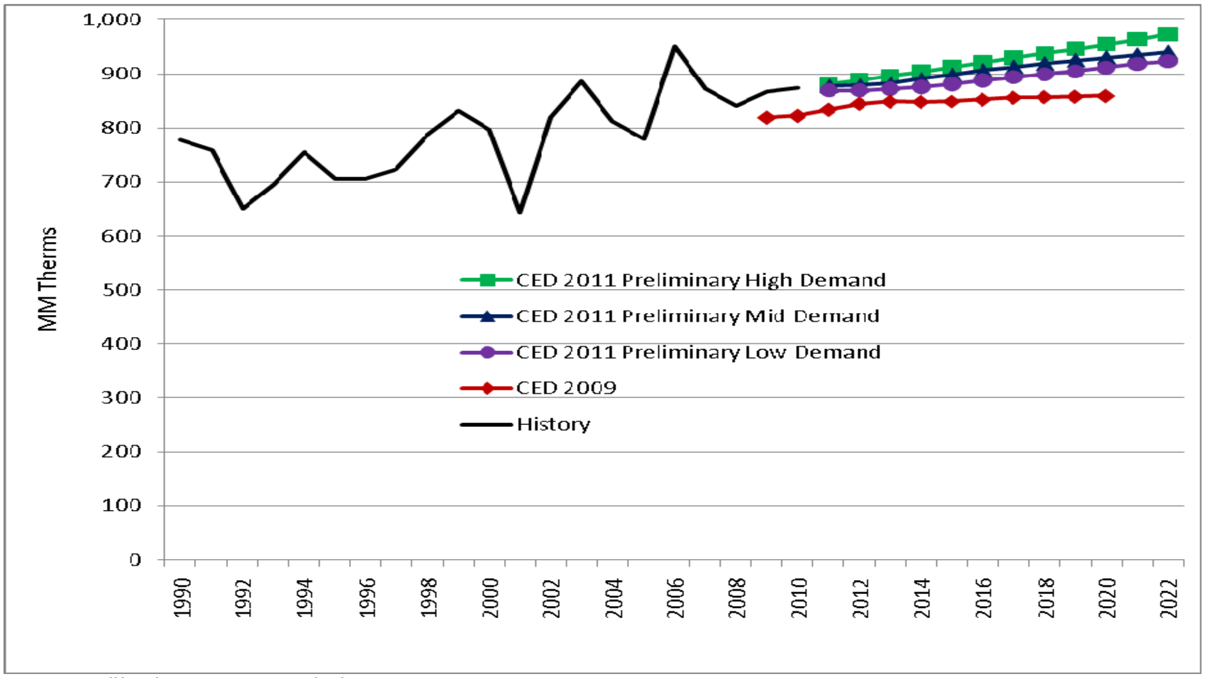
Figure 7-3: PG&E Planning Area Residential Natural Gas Consumption



Source: California Energy Commission, 2011

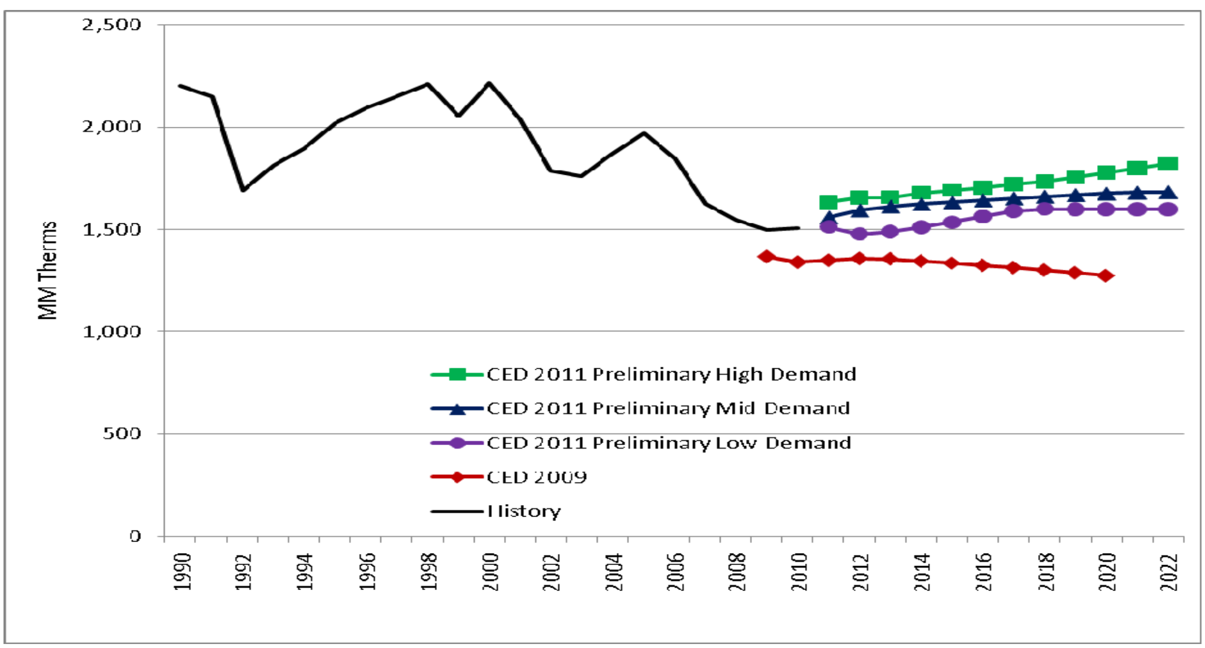
Figure 7-4 and **Figure 7-5** show the forecasts for the PG&E commercial and industrial sectors. Faster growth in all three demand scenarios for projected floor space in the commercial sector and manufacturing output in the industrial sector yield faster growth in gas demand compared to *CED 2009*. A higher 2010 starting point for *CED 2011 Preliminary* in both sectors, combined with faster demand growth, results in projected 2020 demand 11 percent higher than *CED 2009* in the commercial mid case and 32 percent higher in the industrial mid case.

Figure 7-4: PG&E Planning Area Commercial Natural Gas Consumption



Source: California Energy Commission, 2011

Figure 7-5: PG&E Planning Area Industrial Natural Gas Consumption



Source: California Energy Commission, 2011

Southern California Gas Company Planning Area

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

Table 7-3 compares the SCG preliminary planning area forecasts with *CED 2009*. Unlike the PG&E planning area and the state as a whole, gas demand growth from 2010-2020 is below that of *CED 2009* for all three demand scenarios. This results from lower projected demand growth for all three scenarios in the industrial sector and for the mid and high cases in the commercial sector. However, a higher starting point in 2010 is enough to keep total gas demand above the *CED 2009* level in 2020 in the mid and high cases. Forecasts for the industrial sector result in high case demand slightly below the mid and low cases by 2017.

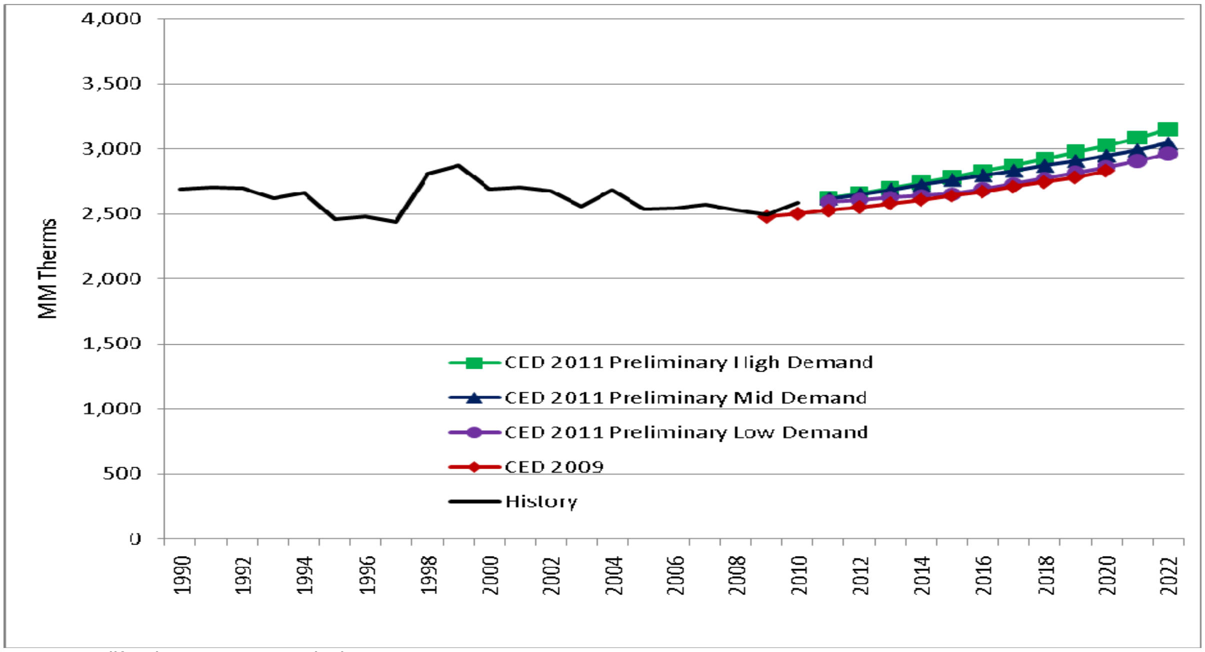
Table 7-3: SCG Natural Gas Forecast Comparison

Consumption (MM Therms)				
	CED 2009 (Dec. 2009)	*CED 2011 Preliminary High Energy Demand* (August 2011)	*CED 2011 Preliminary Mid Energy Demand* (August 2011)	*CED 2011 Preliminary Low Energy Demand* (August 2011)
1990	6,806	6,806	6,806	6,806
2000	7,938	7,920	7,920	7,920
2010	7,290	7,435	7,435	7,435
2015	7,698	7,693	7,745	7,504
2020	7,829	7,789	7,931	7,863
2022	--	7,955	8,022	7,971
	Average Annual Growth Rates			
1990-2000	1.55%	1.53%	1.53%	1.53%
2000-2010	-0.85%	-0.63%	-0.63%	-0.63%
2010-2015	1.10%	0.68%	0.82%	0.19%
2010-2020	0.72%	0.47%	0.65%	0.56%
2010-2022	--	0.57%	0.64%	0.58%
Historical values are shaded				

Source: California Energy Commission, 2011

Figure 7-6 compares *CED 2009* and *CED 2011 Preliminary* SCG residential forecasts. The new forecasts are higher throughout the forecast period as actual consumption recorded in 2010 was higher than predicted in *CED 2009*. Faster projected growth in income for the Los Angeles area in the mid and high cases versus *CED 2009* push 2010-2020 demand growth rates in these scenarios (1.59 percent and 1.33 percent) above that projected in *CED 2009* (1.25 percent).

Figure 7-6: SCG Planning Area Residential Natural Gas Consumption



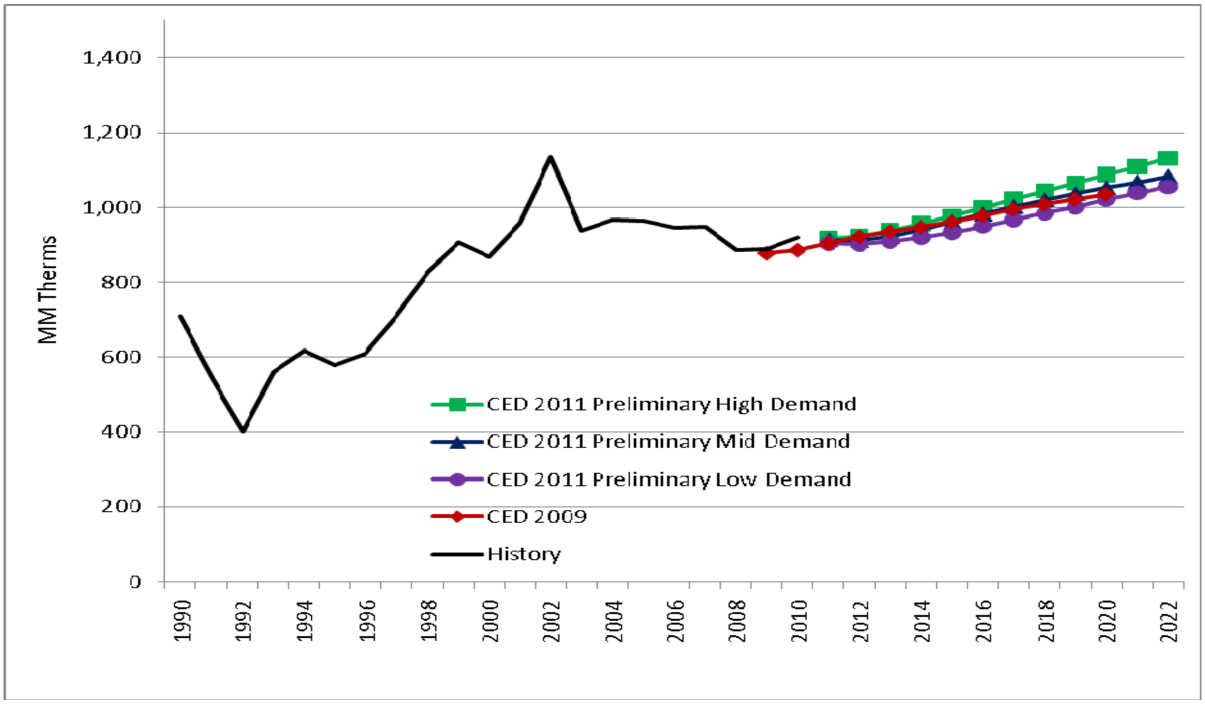
Source: California Energy Commission, 2011

Figure 7-7 and **Figure 7-8** show the forecasts for the SCG commercial and industrial sectors, respectively. Slower growth in the mid and low demand scenarios for projected floor space in the Los Angeles area yield lower average annual growth in commercial gas demand from 2010-2020 for these cases (1.34 percent and 1.04 percent, respectively) compared to *CED 2009* (1.58 percent). Although projected floor space growth in also slightly slower in the high demand case relative to CED 2009, lower natural gas rates in the high case result in faster 2010-2020 growth (1.67 percent).

Although projected industrial output growth is faster in general for *CED 2011 Preliminary* versus *CED 2009,* resource extraction, which represents a significant portion of total industrial gas demand in the SCG planning area, grows at a slower rate in all three scenarios. This yields slower growth in total industrial demand from 2010-2020 compared to *CED 2009*, although total demand in the mid and low cases is above the *CED 2009* level in 2020. In addition, resource extraction is projected to decline at a faster rate in the high demand case than in the mid and low,[25] so that projected gas demand in the high case is lower than in the other two demand scenarios by 2016.

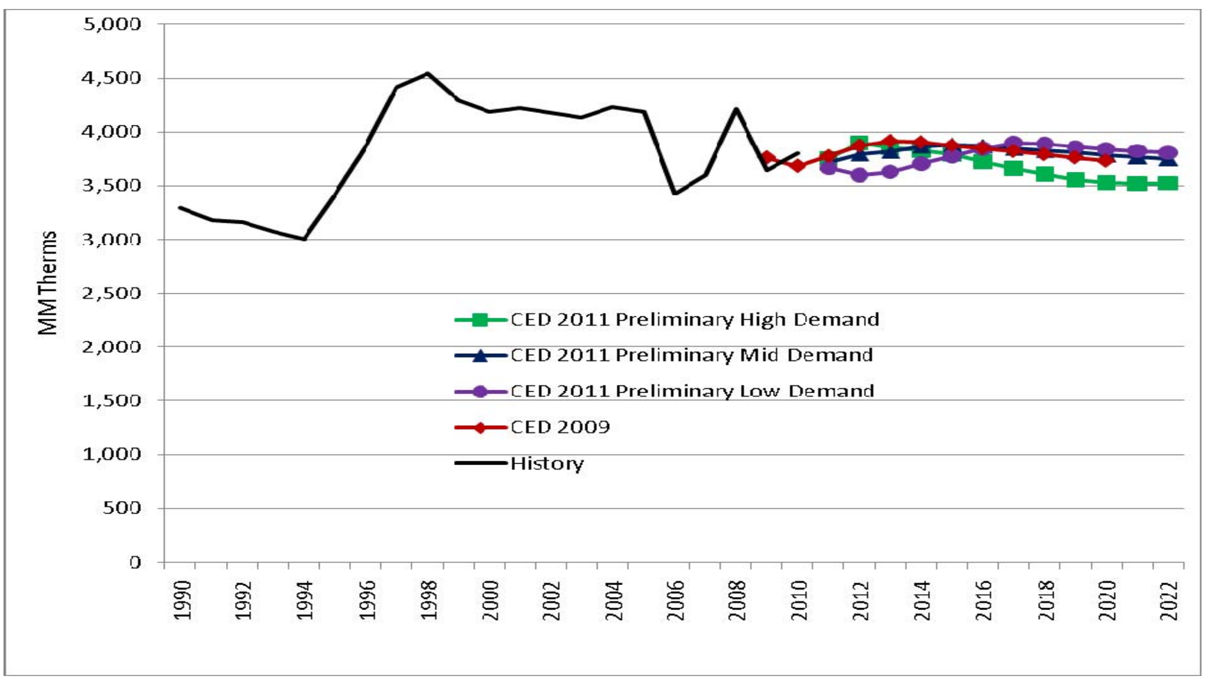
25 This result is due in part to a difference in economic forecasting techniques between Global Insight (high demand case) and Moody's (mid and low cases).

Figure 7-7: SCG Planning Area Commercial Natural Gas Consumption



Source: California Energy Commission, 2011

Figure 7-8: SCG Planning Area Industrial Natural Gas Consumption



Source: California Energy Commission, 2011

San Diego Gas and 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 7-4 compares the preliminary SDG&E planning area forecasts with *CED 2009*. As in the PG&E planning area and statewide, the new forecasts begin at a higher level and grow at a faster rate in all three scenarios. By 2020, demand is over 10 percent higher in the high case and around 5 percent higher in the low case compared to *CED 2009*.

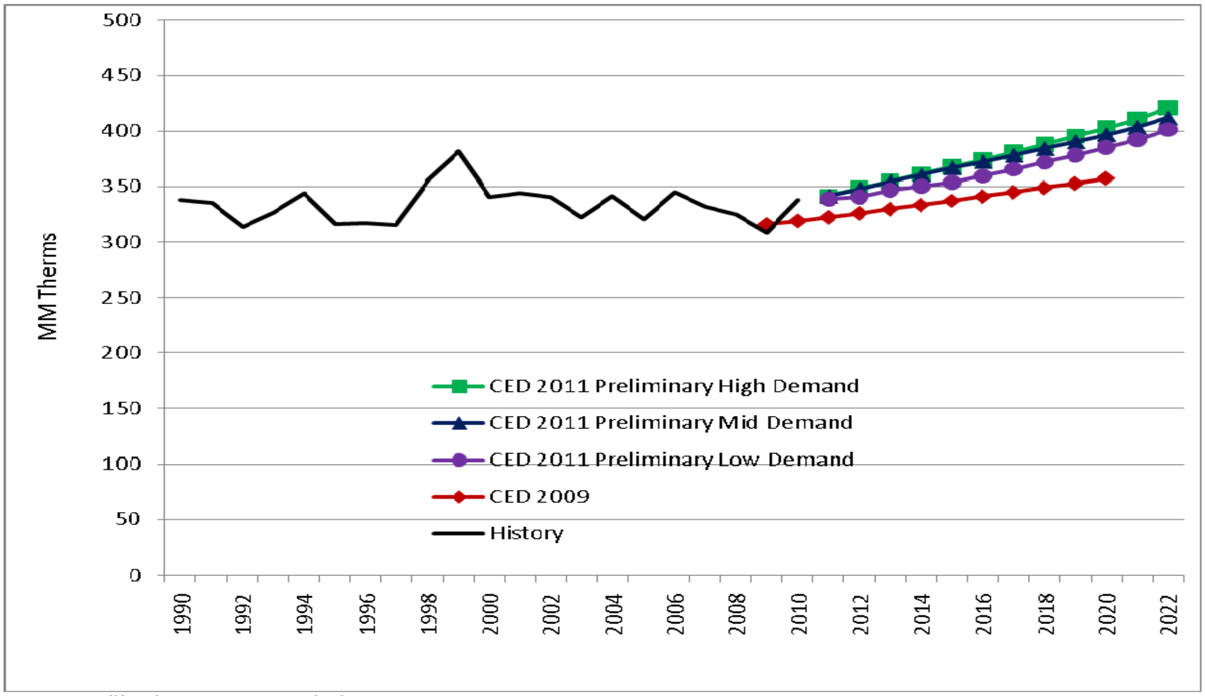
Table 7-4: SDG&E Natural Gas Forecast Comparison

Consumption (MM Therms)				
	CED 2009 (Dec. 2009)	*CED 2011 Preliminary High Energy Demand* (August 2011)	*CED 2011 Preliminary Mid Energy Demand* (August 2011)	*CED 2011 Preliminary Low Energy Demand* (August 2011)
1990	717	717	717	717
2000	565	563	563	563
2010	531	555	555	555
2015	574	612	607	586
2020	611	677	660	644
2022	--	708	683	669
	Average Annual Growth Rates			
1990-2000	-2.35%	-2.40%	-2.40%	-2.40%
2000-2010	-0.64%	-0.14%	-0.14%	-0.14%
2010-2015	1.60%	1.98%	1.79%	1.09%
2010-2020	1.43%	2.00%	1.75%	1.49%
2010-2022	--	2.04%	1.75%	1.56%
Historical values are shaded				

Source: California Energy Commission, 2011

Figure 7-9 compares *CED 2009* and *CED 2011 Preliminary* PG&E residential forecasts. The new forecasts are higher throughout the entire forecast period as actual consumption recorded in 2010 was higher than predicted in *CED 2009*. Faster projected growth in number of households in all three demand scenarios and as well as income in the mid and high cases versus *CED 2009* push 2010-2020 demand growth rates in the high, mid, and low scenarios (1.78 percent, 1.62 percent, and 1.32 percent, respectively) above that projected in *CED 2009* (1.15 percent).

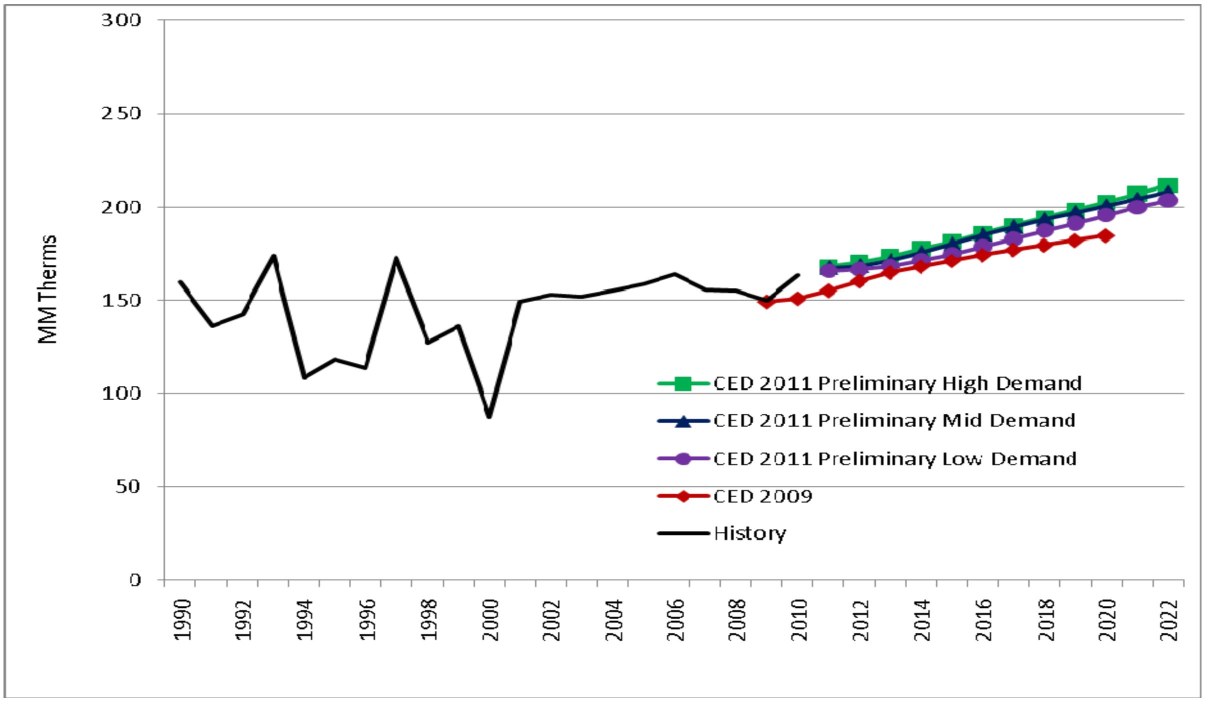
Figure 7-9: SDG&E Planning Area Residential Natural Gas Consumption



Source: California Energy Commission, 2011

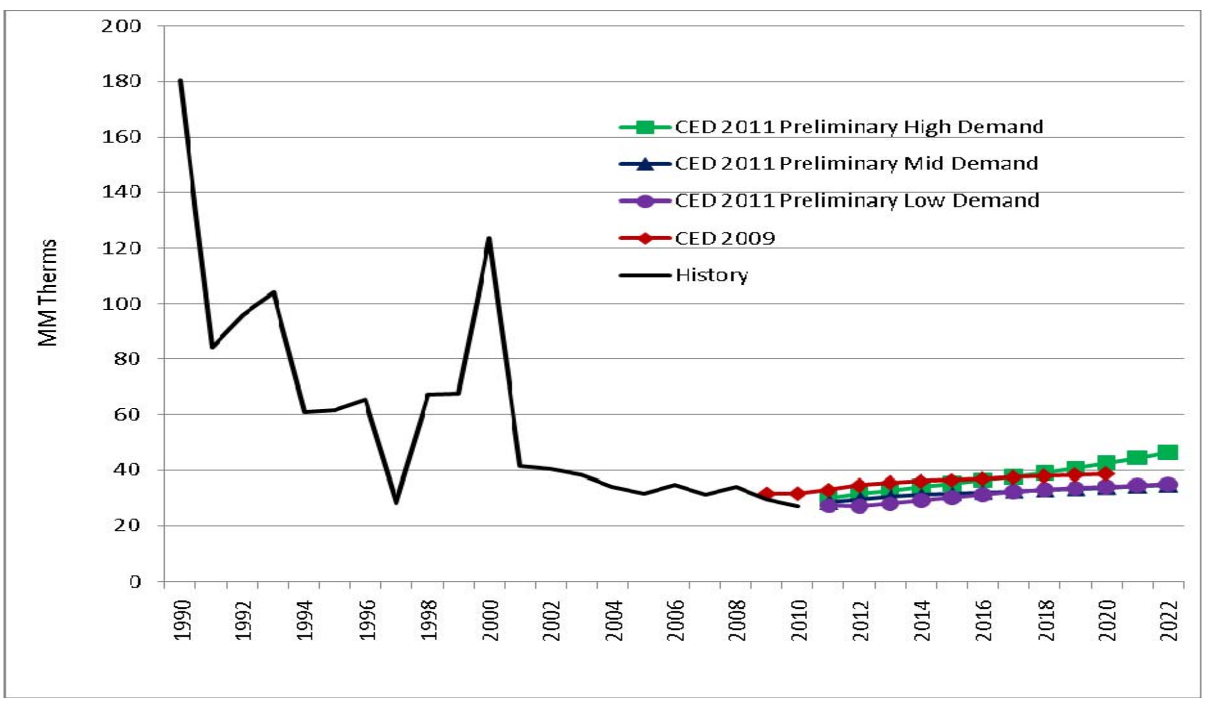
Figure 7-10 and **Figure 7-11** show the forecasts for the SDG&E commercial and industrial sectors. Faster growth in all three demand scenarios for projected floor space in the commercial sector and manufacturing output in the industrial sector yield faster growth in gas demand compared to *CED 2009* in all three cases. Projected 2020 demand is almost 9 percent higher than *CED 2009* in the commercial mid case. The new industrial demand forecasts begin at a lower point in 2010, so only the high case yields higher demand in 2020 versus *CED 2009*.

Figure 7-10: SDG&E Planning Area Commercial Natural Gas Consumption



Source: California Energy Commission, 2011

Figure 7-11: SDG&E Planning Area Industrial Natural Gas Consumption



Source: California Energy Commission, 2011

CHAPTER 8: Energy Efficiency and Conservation

Introduction

With the state's adoption of the first *Energy Action Plan (EAP)* in 2003, energy efficiency became the resource of first choice for meeting the state's future energy needs. Assembly Bill 2021(Levine, Chapter 734, Statutes of 2006) set a statewide goal of reducing total forecasted electricity consumption by 10 percent over the next 10 years. Under AB 2021, the Energy Commission, in consultation with the California Public Utilities Commission (CPUC), is responsible for setting annual statewide efficiency potential estimates and targets in a public process every three years using the most recent Investor-Owned Utilities (IOU) and publicly owned utility data. These targets, combined with California's greenhouse gas emission reduction goals, make it essential for the Energy Commission to account for energy efficiency impacts when forecasting future electricity and natural gas demand.

Since the *2007 IEPR* process, staff has undertaken a major effort to improve and refine efficiency measurement within the IEPR forecast and committed to examining methods for incorporating efficiency impacts in a public process that includes the CPUC staff, utilities, and other stakeholders. With this commitment in mind, Energy Commission staff formed the Demand Analysis Working Group (DAWG)[26] to provide a forum for interaction among key organizations on topics related to energy efficiency, demand forecasting, and energy procurement. Membership in the DAWG includes staff from the California Energy Commission, the CPUC Energy Division, the Department of Ratepayer Advocates, the California IOUs, several publicly owned utilities, and other interested parties, including the California Air Resources Board, The Utility Reform Network, and the Natural Resources Defense Council. The member list has grown to include over 100 participants.

With input from the DAWG, a substantial amount of work was dedicated to improving estimates of efficiency program impacts to be incorporated in *CED 2009.*[27] In addition, with the assistance of Itron, staff developed estimates of *incremental uncommitted* efficiency impacts during the *2009 IEPR* process,[28] designed to capture the impacts of measures that are likely to be implemented but not considered sufficiently firm to include in the main

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

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

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

forecast.[29] These incremental impacts were used as adjustments to *CED 2009* by the CPUC in its 2010 Long-term Procurement Process (LTPP).

CED 2011 Preliminary builds on the work done during the *2009 IEPR* process with the following elements:

- Incorporation of new building and appliance standards, including impacts from AB 1109 lighting regulations.
- Refinement of 2006-2009 efficiency program impacts through incorporation of the CPUC's 2006-2008 and 2009 Evaluation, Measurement, and Verification (EM&V) studies.
- Updated price elasticity estimates.
- Inclusion of industrial price effects along with residential and commercial.
- Updated committed natural gas efficiency program impacts, starting in 2006.
- Presentation of alternative scenarios for 2011-2012 projected committed efficiency program impacts consistent with the high, mid, and low demand scenarios.
- Updated incremental uncommitted efficiency scenarios that also include publicly owned utilities.

The first part of this chapter describes the committed efficiency impacts embedded in *CED 2009* and the second provides estimates of incremental uncommitted impacts and shows resulting energy and peak forecasts adjusted by these impacts.

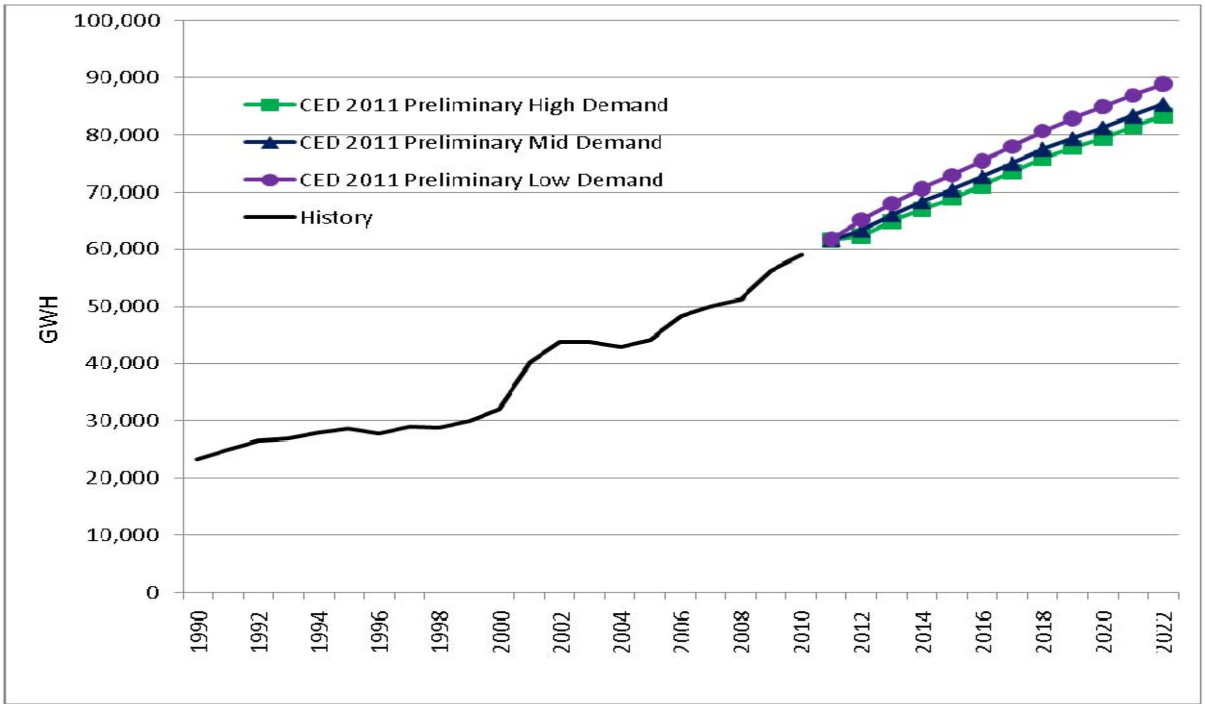
Committed Efficiency

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

29 In preparing its long-run demand forecasts, the Energy Commission follows a practice of distinguishing between demand-side impacts that it considers *committed* and others that are *uncommitted.* Committed initiatives include utility and public agency programs, codes and standards, and legislation and ordinances that have final authorization, firm funding, and a design that can be readily translated into characteristics that can be evaluated and used to estimate future impacts (for example, a package of IOU incentive programs that has been funded by CPUC order). The main forecast includes only committed impacts.

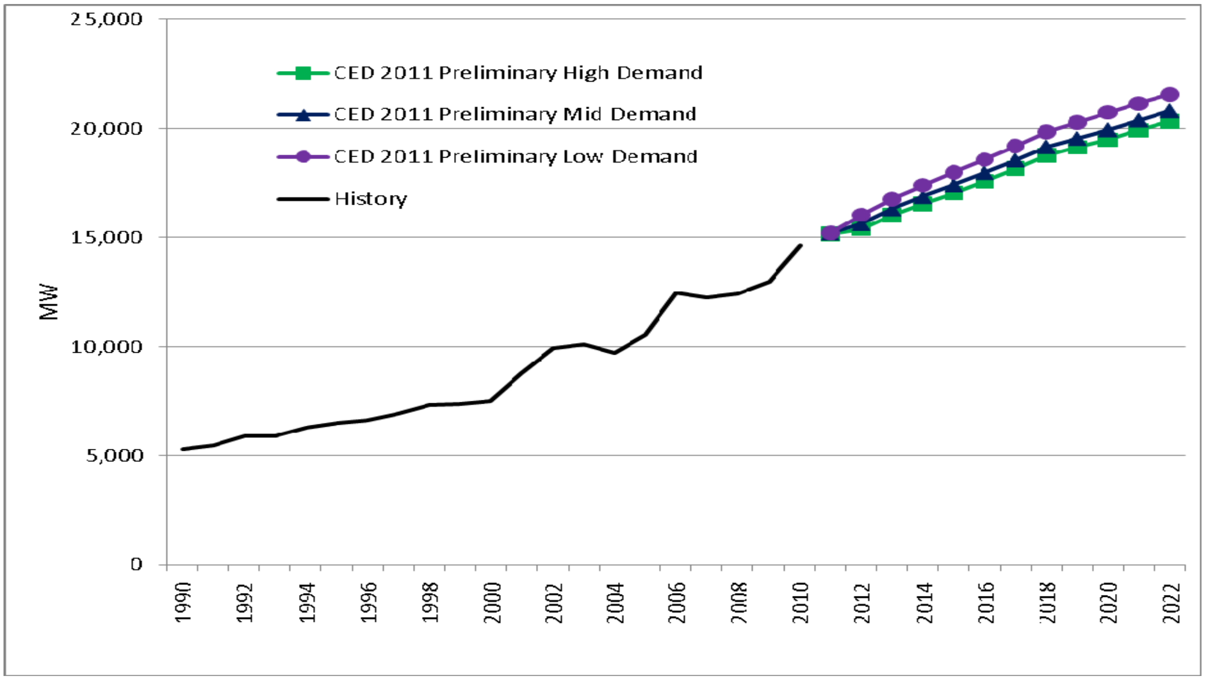
Figure 8-1 and **Figure 8-2** show staff estimates of statewide historic and projected committed electricity consumption and peak savings, respectively. Projected savings impacts are higher the lower the demand scenario, since price and program effects (for 2011 and beyond) is inversely related to the demand outcome.

Figure 8-1: Estimated Committed Efficiency Electricity Consumption Impacts



Source: California Energy Commission, 2011

Figure 8-2: Historical and Projected Statewide Committed Efficiency Peak Impacts



Source: California Energy Commission, 2011

Table 8-1 shows these savings as a percentage of total electricity 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 increasing through 2022. Since price and program effects are inversely related to the demand outcome, percentages increase as demand decreases.

Table 8-1: Electricity Efficiency Savings as a Percentage of Consumption and Peak Demand

	Consumption		
	CED 2011 Preliminary High Energy Demand	*CED 2011 Preliminary Mid Energy Demand*	*CED 2011 Preliminary Low Energy Demand*
1990	10.2%	10.2%	10.2%
2000	12.3%	12.3%	12.3%
2010	21.6%	21.6%	21.6%
2015	23.2%	24.1%	25.5%
2020	24.7%	26.2%	27.8%
2022	25.1%	26.8%	28.4%
	Peak Demand		
	CED 2011 Preliminary High Energy Demand	*CED 2011 Preliminary Mid Energy Demand*	*CED 2011 Preliminary Low Energy Demand*
1990	11.1%	11.1%	11.1%
2000	14.0%	14.0%	14.0%
2010	23.4%	23.4%	23.4%
2015	25.6%	26.5%	28.0%
2020	27.1%	28.6%	30.3%
2022	27.4%	29.2%	30.9%

Source: California Energy Commission, 2011

Because a clear, consistent record of evaluated efficiency program achievements is not readily available, at least not prior to the 2006-2008 CPUC energy efficiency program cycle, there is a great deal of uncertainty around any estimate of historical program impacts. This uncertainty, along with uncertainty around attribution of savings among standards, programs, and price effects, has been the subject of debate in recent DAWG meetings. Some parties have suggested that historical program impacts incorporated in Energy Commission demand forecasts are vastly underestimated and/or too much savings is credited to standards and price effects, especially prior to 1998.

Staff believes that **Figure 8-1** and **Figure 8-2** provide reasonable estimates of total savings, but acknowledges and shares the concerns voiced by stakeholders about savings attribution. For *CED 2011 Preliminary*, therefore, no attribution among the three sources is shown, except for estimates of standards impacts presented later in this chapter. In other words, no specific estimates of program and price effects are provided. Staff will continue to work with stakeholders on these issues, with the goal of showing attribution for at least some years in the revised forecast.

Committed Program and Price Effects

In general, historic electricity program impacts were treated the same as in *CED 2009*,[30] with a couple of differences. First, 2006-2009 IOU program savings were adjusted to incorporate the CPUC's 2006-2008 and 2009 EM&V studies.[31] Second, IOU industrial program savings were included and adjusted using the 2006-2009 study results. The adjustment to 2006-2009 program savings varied by end use, but overall resulted in a lower realization rate (around 60 percent) compared to *CED 2009* (70 percent). In addition, efficiency measure savings decay (the rate of "burn-out" for measures), was reduced by 50 percent starting with 2006 programs to reflect the CPUC's directive that one-half of measure decay be replaced through additional programmatic efforts.[32]

Natural gas efficiency program savings were updated for the preliminary forecast, starting with the 2006 program year, with realization rates derived from the same 2006-2008 and 2009 EM&V studies. Staff was not able to prepare estimates of total natural gas savings, including impacts from standards, programs, and price effects, in time for *CED 2011 Preliminary*; these will be provided for the revised forecast.

Alternative committed efficiency program scenarios for both electricity and natural gas, consistent with the high, mid, and low demand cases, were developed for 2011 and 2012 for the IOUs and for 2011 for the publicly owned utilities.[33] For the low demand case (higher efficiency program savings), staff adjusted the forecast using utility reported net savings.[34] In the high demand case, these savings were reduced to be consistent with the 2006-2008 and 2009 CPUC EM&V studies, yielding an average realization rate of around 70 percent.

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

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

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

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

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

The mid case realization rate relied on an average between the high and low cases, around 85 percent.

Residential price effects are significantly higher in *CED 2011 Preliminary* compared to *CED 2009*, based on the price elasticity estimated in the residential econometric model (see Appendix). Price effects in the industrial sector were estimated and incorporated in *CED 2011 Preliminary*, also based on econometric estimation. Although standards impacts are projected to increase slightly with demand, price effects in the lower demand cases outweigh additional savings from standards so that total savings are inversely related to the demand outcome, as shown in **Figure 8-1** and **Figure 8-2**.

Building and Appliance Standards

Energy Commission forecasting models incorporate building and appliance standards through changes in inputs estimated end-use consumption per household in the residential sector and end-use consumption per square foot in the commercial sector. **Table 8-2** shows the standards currently included in the energy demand forecast by sector.

Table 8-2: Building and Appliance Standards (Committed) Incorporated in *CED 2011 Preliminary*

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

Source: California Energy Commission, 2011

AB 1109 lighting regulations, now coded in Title 20 Appliance Standards, were introduced into the residential end use model through reductions in average household lighting use, so that electricity consumption for this end use was reduced 50 percent from 2007 levels by

2018.[35] Staff did not have the time to incorporate AB 1109 in the commercial end use model for *CED 2011 Preliminary*, and so substituted the savings estimated in the 2010 incremental uncommitted efficiency work.[36] Estimates were made only for IOUs in the 2010 study; staff estimated impacts for publicly owned utility planning areas by applying a ratio of lighting savings to consumption over the three IOUs.[37] AB 1109 impacts will be incorporated directly into the model for the revised forecast. The 2010 television standards were not incorporated in *CED 2011 Preliminary*: the Energy Commission's Efficiency and Renewables Division has not yet supplied a breakout of expected impacts by sector.

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

Table 8-3 shows estimated consumption and peak savings from appliance and building standards for the residential and commercial sectors in the mid demand scenario. Forecast standards impacts increase slightly in the high demand scenario because of more projected commercial floor space and home additions and are slightly less in the low demand case.[38]

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35 Average lighting use decreases for single-family homes from 1,800 KWh per year to 900 KWh by 2017, and remains constant thereafter. For multi-family homes, the decrease is from 1,000 KWh to 500 KWh.

36 Electricity and Natural Gas Committee, 2010, *op cit*.

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

38 By 2022, for the state as a whole, consumption savings are 2.2 percent higher and 1.6 percent lower in the high and low cases, respectively, compared to the mid case. Peak savings increase by 1.7 percent in the high case and decrease by 1.6 percent in the low.

Table 8-3: Estimated Electricity Savings from Building and Appliance Standards: Mid Demand Scenario

	Consumption (GWh)						
	Residential			Commercial			Total Standards
	Building Standards	Appliance Standards	Total	Building Standards	Appliance Standards	Total	
1990	2,581	2,673	5,254	1,232	794	2,026	7,281
2000	3,746	7,774	11,520	3,095	2,224	5,319	16,838
2010	4,908	17,089	21,997	5,910	3,846	9,755	31,753
2015	5,604	22,270	27,873	7,799	4,958	12,757	40,631
2020	6,311	25,870	32,181	10,136	6,675	16,811	48,992
2022	6,507	26,371	32,878	11,037	7,039	18,075	50,953
	Peak (MW)						
	Residential			Commercial			Total Standards
	Building Standards	Appliance Standards	Total	Building Standards	Appliance Standards	Total	
1990	660	673	1,333	281	194	475	1,808
2000	942	1,872	2,814	683	521	1,204	4,018
2010	1,338	4,545	5,883	1,417	974	2,391	8,274
2015	1,583	6,190	7,772	1,741	1,172	2,913	10,685
2020	1,759	7,123	8,882	2,244	1,564	3,808	12,690
2022	1,797	7,198	8,995	2,439	1,647	4,086	13,081

Source: California Energy Commission, 2011

Incremental Uncommitted Efficiency Savings

In 2010, Energy Commission staff and Itron estimated the incremental effect on energy and peak demand of a set of electricity energy efficiency policy initiatives that the CPUC adopted in D.08-07-047.[39] These policy initiatives are similar to the initiatives originally evaluated by Itron and adopted by the CPUC in the *2008 Energy Efficiency Goals Update Report* (*2008 Goals Study*).[40] With two exceptions, the Energy Commission does not yet consider this set of delivery mechanisms to be committed, so their estimated impacts are not included in the forecasts presented in previous chapters. Since the CPUC incorporates

39 Electricity and Natural Gas Committee, 2010, *op cit*.

40 http://www.cpuc.ca.gov/NR/rdonlyres/8944D910-ECA2-4E19-B1F3-96956FB6E643/0/Itron2008CAEnergyEfficiencyStudy.pdf.

uncommitted impacts in its LTPP, however, staff provides adjustments to *CED 2011 Preliminary* to reflect these initiatives (as in the *2009 IEPR*).

The uncommitted efficiency initiatives in the 2010 study included:

- Utility programs beyond 2012, including residential, commercial, and industrial
- Further updates to state Title 20 and 24 standards along with updated federal appliance standards, including the 2010 Title 24 revisions
- CPUC's Big Bold Energy Efficiency Initiatives (BBEES)
- Lighting efficiency measures in satisfaction of AB 1109

Since *CED 2011 Preliminary* incorporates the 2010 Title 24 update and the AB 1109 regulations as committed initiatives, these are excluded from the incremental uncommitted adjustments made in this chapter. Another difference in the results presented here is that residential peak impacts from heating, ventilation, and air conditioning (HVAC) measures (including the BBEES) are calculated using lower peak-to-energy ratios than used in the 2010 study. This change is the result of DAWG discussions that addressed peak assumptions for efficiency measures.[41]

The 2010 study examined three scenarios— high savings, mid savings, and low savings based on differing assumed levels of policy commitment. The BBEES impacts differed by progress toward the CPUC's goals. For the most recent LTPP, the CPUC adjusted the incremental uncommitted efficiency in their "most likely" LTPP case so that the low scenario savings for BBEES from the 2010 study were used rather than the mid scenario savings. Therefore, to be consistent with the CPUC change, the mid incremental uncommitted savings case developed here uses the previous BBEES low scenario savings. The high case assumes the mid level savings from 2010, while the low savings case excludes the Big Bold initiatives.

Staff had intended to develop a full revision to the incremental uncommitted savings results from 2010 to account for changing economic/demographic conditions as well as new rate forecasts. However, a new CPUC goals study is already underway, scheduled to be complete by the end of 2011. The Energy Commission has extended the schedule for the *2011 IEPR* demand forecasts into next year so that the final version can incorporate the new goals study. Therefore, staff decided it should not spend the much more significant time required for a full update given that the revised or final version of *CED 2011 Preliminary* will likely incorporate a new incremental uncommitted analysis, an analysis consistent with

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41 The 2010 study relied on peak-to-energy ratios derived by averaging peak and energy use for HVAC using the Energy Commission's residential end use model. In the DAWG discussions, staff agreed with the utilities that *marginal* impacts of an HVAC measure at peak are likely to be much lower than implied by average peak to energy, since percentage savings tend to deteriorate as maximum use is approached. Therefore, staff used the lower residential HVAC peak-to-energy ratio estimated by Itron in the 2008 Goals Study, which is also close to the DEER-recommended ratio.

economic and other assumptions made for this forecast. Instead, staff uses the incremental uncommitted estimates as developed in 2010,[42] with the exception of the changes described above, with the acknowledgment that changes since 2009 make the 2010 study estimates at least somewhat outdated.[43]

For the publicly owned utility planning areas, staff estimated the impacts from uncommitted standards and BBEES by applying the ratio of the incremental impacts relative to projected consumption (adjusted as described above) over all three IOUs to projected consumption in each of the non-IOU areas. Incremental uncommitted efficiency savings were derived from current publicly owned utility program first-year savings goals.[44] Three scenarios were developed, consistent with the committed programs savings scenarios: high savings relied on the full amount of the goals (in terms of net savings), the low savings case used a realization rate adjustment to the goals of 70 percent, and the mid case adjusted the goals assuming realization of 85 percent. These are simplifying assumptions for *CED 2011 Preliminary* only, since the new goals study plans to address publicly owned utilities as well as IOUs.

Incremental Uncommitted Efficiency Savings Estimates

Table 8-4, **Table 8-5**, **and Table 8-6** show the estimated incremental uncommitted efficiency savings for the five major utility planning areas (and statewide) by category, for the low, mid, and high savings scenarios, respectively. There is a large difference between the low and other savings scenarios because the low case includes no BBEES impacts. For the three smaller planning areas not shown in the table, the sum total of projected consumption savings ranges from 380 GWh to 650 GWh in 2022, while peak savings ranges from 145 GWh to 240 GWh.

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42 The 2010 study estimated impacts through 2020. For 2021 and 2022, staff extrapolated savings using projected growth in impacts from 2019 to 2020.

43 For example, new home construction from 2010-2020 is down around 13 percent compared to *CED 2009* in the mid demand case and up around 20 percent in the high demand case. A more complete analysis would adjust BBEES results to account for the revised lower number of new homes.

44 The 2016 goals were assumed to extend through 2022. First-year savings were decayed over the forecast period by applying measure expected useful lives at the end use level assuming savings by end use similar those reported in 2011.

Table 8-4: Projected Incremental Uncommitted Electricity Savings by Category and Planning Area, Low Savings Scenario

		Energy Savings (GWh)				Peak Savings (MW)			
		State and Federal Standards	Programs	BBEES	Total	State and Federal Standards	Programs	BBEES	Total
LADWP	2013	0.15	350.02	0.00	350.17	0.07	131.30	0.00	131.37
	2015	10.57	688.00	0.00	698.57	3.48	262.72	0.00	266.19
	2020	96.07	1434.34	0.00	1530.41	41.25	577.50	0.00	618.74
	2022	152.80	1669.02	0.00	1821.82	65.64	680.50	0.00	746.14
PG&E	2013	0.37	268.84	0.00	269.20	0.26	67.30	0.00	67.56
	2015	38.38	776.91	0.00	815.29	14.58	197.58	0.00	212.16
	2020	351.97	1867.89	0.00	2219.86	176.92	496.93	0.00	673.86
	2022	557.72	2,382.37	0.00	2940.09	281.77	640.13	0.00	921.90
SCE	2013	0.56	320.62	0.00	321.18	0.20	77.83	0.00	78.04
	2015	40.33	926.05	0.00	966.38	12.47	227.52	0.00	240.00
	2020	390.59	2222.66	0.00	2613.26	162.06	565.45	0.00	727.51
	2022	622.93	2833.40	0.00	3456.33	258.73	726.54	0.00	985.26
SDG&E	2013	0.23	52.09	0.00	52.32	0.08	15.38	0.00	15.46
	2015	9.84	150.08	0.00	159.91	2.58	44.90	0.00	47.48
	2020	81.91	357.50	0.00	439.40	27.00	111.27	0.00	138.26
	2022	130.50	454.87	0.00	585.37	42.85	142.90	0.00	185.74
SMUD	2013	0.06	236.14	0.00	236.20	0.03	72.19	0.00	72.22
	2015	5.10	473.89	0.00	478.99	1.74	147.88	0.00	149.62
	2020	47.95	1036.53	0.00	1084.48	22.11	344.36	0.00	366.47
	2022	75.69	1224.55	0.00	1300.24	35.04	412.99	0.00	448.03
State	2013	1.41	1282.02	0.00	1283.43	0.66	383.05	0.00	383.71
	2015	107.36	3132.58	0.00	3239.94	35.89	922.42	0.00	958.31
	2020	997.98	7197.69	0.00	8195.68	442.27	2199.37	0.00	2641.64
	2022	1585.77	8896.01	0.00	10481.78	704.18	2728.09	0.00	3432.28

Source: California Energy Commission, 2011

Table 8-5: Projected Incremental Uncommitted Electricity Savings by Category and Planning Area, Mid Savings Scenario

		Energy Savings (GWh)				Peak Savings (MW)			
		State and Federal Standards	Programs	BBEES	Total	State and Federal Standards	Programs	BBEES	Total
LADWP	2013	0.19	425.03	20.42	445.64	0.07	133.57	9.04	142.68
	2015	11.61	835.43	68.15	915.19	3.72	267.24	30.54	301.49
	2020	105.83	1741.70	220.01	2067.54	46.18	587.62	101.18	734.98
	2022	167.33	2026.67	305.25	2499.26	73.17	692.57	141.48	907.22
PG&E	2013	0.46	416.47	68.38	485.31	0.21	96.42	38.19	134.82
	2015	42.80	1194.23	230.10	1467.12	15.56	281.80	130.33	427.69
	2020	392.76	2804.81	754.35	3951.92	199.10	699.86	439.30	1338.26
	2022	618.04	3557.92	1,049.33	5225.29	315.66	899.06	616.21	1830.93
SCE	2013	0.70	524.64	81.96	607.30	0.25	117.98	34.10	152.33
	2015	44.37	1511.37	276.95	1832.69	13.49	344.23	116.65	474.36
	2020	433.10	3599.43	915.56	4948.08	183.36	850.96	394.93	1429.25
	2022	686.20	4580.35	1276.86	6543.42	291.20	1,092.18	554.73	1938.12
SDG&E	2013	0.28	109.27	16.13	125.68	0.10	27.76	5.24	33.10
	2015	10.91	311.85	54.17	376.93	2.85	80.64	17.92	101.41
	2020	89.71	721.79	177.03	988.52	30.38	196.83	60.56	287.77
	2022	141.87	912.01	246.02	1299.90	47.91	251.91	85.03	384.85
SMUD	2013	0.07	286.74	9.34	296.15	0.03	75.78	4.59	80.40
	2015	5.68	575.44	31.64	612.77	1.88	155.20	15.79	172.87
	2020	53.68	1258.65	104.65	1,416.98	25.07	361.59	53.73	440.39
	2022	84.17	1486.96	145.56	1,716.68	39.53	433.82	75.20	548.55
State	2013	1.76	1827.98	202.21	2031.95	0.69	471.16	93.84	565.68
	2015	118.84	4570.92	681.17	5370.92	38.62	1172.25	320.44	1531.31
	2020	1107.64	10464.31	2238.07	13810.02	498.59	2804.19	1081.24	4384.01
	2022	1748.18	12966.14	3114.26	17828.57	789.93	3498.81	1515.92	5804.66

Source: California Energy Commission, 2011

Table 8-6: Projected Incremental Uncommitted Electricity Savings by Category and Planning Area, High Savings Scenario

		Energy Savings (GWh)				Peak Savings (MW)			
		State and Federal Standards	Programs	BBEES	Total	State and Federal Standards	Programs	BBEES	Total
LADWP	2013	3.20	500.03	23.50	526.74	0.10	158.73	11.45	170.28
	2015	19.21	982.86	78.64	1080.71	5.04	317.54	38.77	361.34
	2020	159.22	2049.05	254.60	2462.87	62.93	697.86	128.56	889.35
	2022	241.48	2384.32	353.16	2978.95	99.86	822.39	179.60	1101.85
PG&E	2013	0.55	416.47	83.27	500.29	0.31	96.42	49.67	146.40
	2015	56.34	1194.23	280.58	1531.15	20.89	281.80	169.66	472.35
	2020	526.68	2804.81	922.33	4253.83	269.38	699.86	572.77	1542.01
	2022	833.35	3557.92	1284.05	5675.32	428.33	899.06	803.81	2131.20
SCE	2013	23.04	524.64	92.38	640.06	0.30	117.98	43.07	161.35
	2015	86.53	1511.37	313.20	1911.09	18.14	344.23	147.62	509.99
	2020	702.77	3599.43	1042.04	5344.24	249.33	850.96	501.52	1601.80
	2022	1032.84	4580.35	1456.07	7069.27	397.26	1092.18	705.15	2194.59
SDG&E	2013	0.34	109.27	18.31	127.92	0.12	27.76	6.34	34.22
	2015	14.55	311.85	61.63	388.03	3.80	80.64	21.74	106.17
	2020	122.83	721.79	202.22	1046.84	41.34	196.83	73.92	312.09
	2022	195.49	912.01	281.40	1388.90	65.52	251.91	103.97	421.40
SMUD	2013	1.22	337.34	11.08	349.64	0.04	89.30	5.93	95.27
	2015	8.91	676.98	37.74	723.63	2.52	182.87	20.46	205.85
	2020	78.21	1480.76	125.57	1684.54	33.97	426.02	69.89	529.88
	2022	119.01	1749.36	174.80	2043.17	53.75	511.10	97.89	662.74
State	2013	29.27	1965.48	235.45	2230.20	0.90	513.30	119.88	634.09
	2015	191.22	4845.65	795.18	5832.05	51.89	1257.84	409.99	1719.72
	2020	1638.23	11054.72	2624.45	15317.41	676.64	2997.80	1386.98	5061.42
	2022	2494.85	13658.71	3655.86	19809.42	1075.33	3728.73	1945.62	6749.67

Source: California Energy Commission, 2011

Table 8-7 compares the revised projected incremental uncommitted savings with estimates from the 2010 incremental uncommitted study for each IOU in 2020. The last row in the table shows revised savings as a percentage of those calculated in the 2010 study for the three IOUs combined. The low savings scenario is affected the most since it no longer includes BBEES. The peak percentages are lower compared to energy (consumption) because of the adjustment to the residential HVAC peak-to-energy ratios.

Table 8-7: Comparison of Incremental Uncommitted Electricity Savings for 2020 by Savings Scenario, *CED 2011 Preliminary* and 2010 Incremental Uncommitted Study

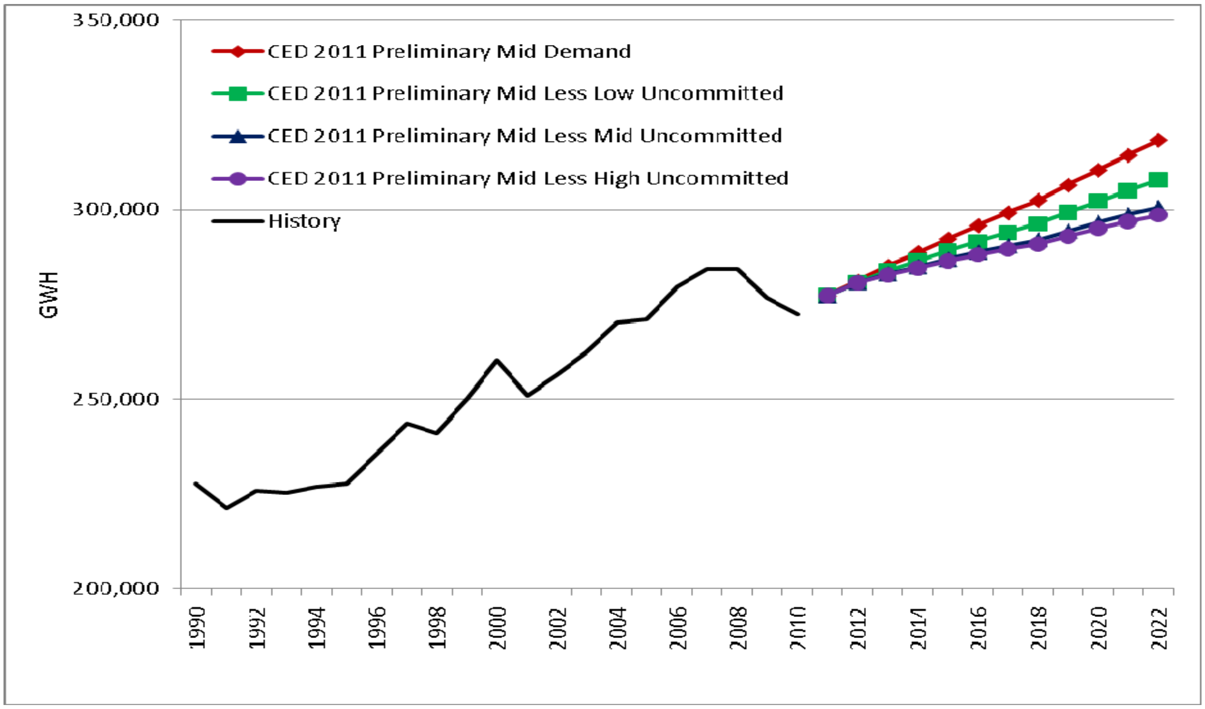
		Energy (GWh)			Peak (MW)		
		Low Savings	Mid Savings	High Savings	Low Savings	Mid Savings	High Savings
PG&E	*CED 2011 Preliminary*	2,220	3,952	4,254	674	1,338	1,542
	2010 Incremental Uncommitted	4,634	5,130	6,087	1,731	2,245	2,722
SCE	CED 2011 Preliminary	2,613	4,948	5,344	728	1,429	1,602
	2010 Incremental Uncommitted	4,971	5,874	6,848	1,941	2,245	2,722
SDG&E	CED 2011 Preliminary	439	989	1,047	138	288	312
	2010 Incremental Uncommitted	1,091	1,222	1,440	363	514	602
Total IOUs	CED 2011 Preliminary	5,273	9,889	10,645	1,540	3,055	3,456
	2010 Incremental Uncommitted	10,696	12,225	14,374	4,034	5,352	6,484
	Percent of 2010 Study Estimates	49%	81%	74%	38%	57%	53%

Source: California Energy Commission, 2011

Impact on Consumption and Peak Forecasts

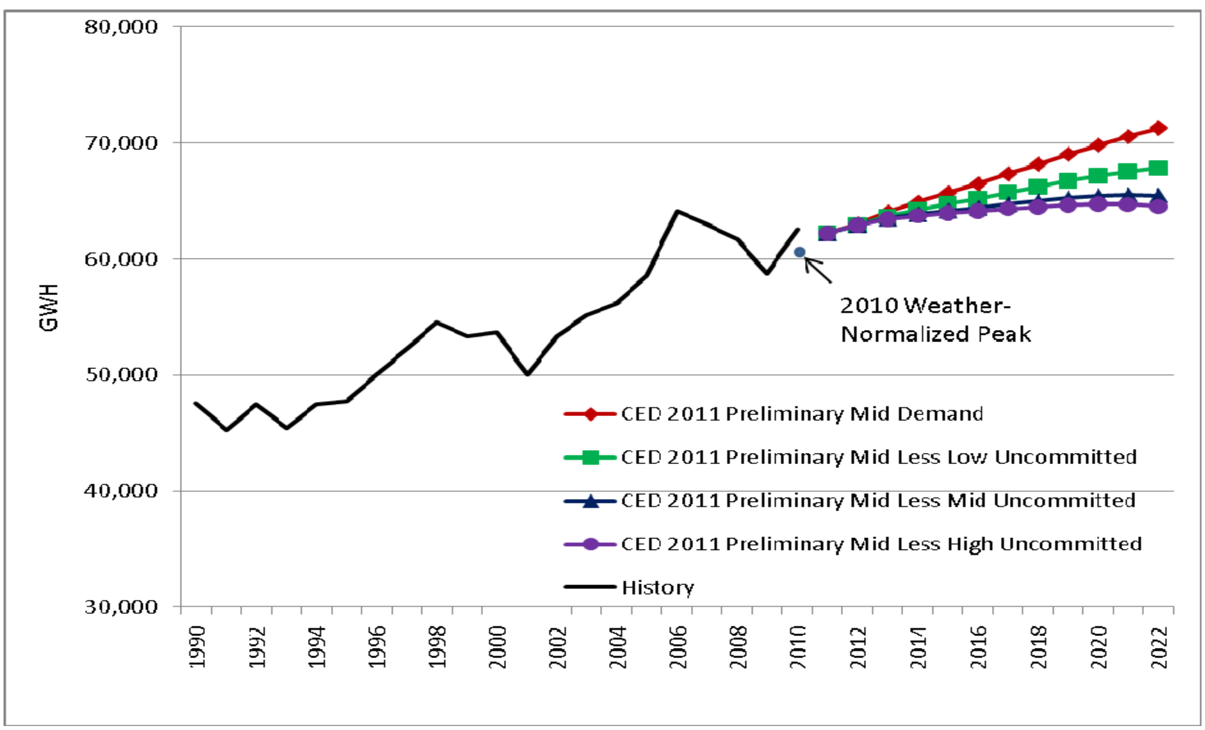
Figure 8-3 and **Figure 8-4** show the impact on total consumption and peak, respectively, in the mid demand case when subtracting the incremental uncommitted savings from each scenario. By 2022, consumption would be reduced 3.3 percent if adjusted by the low savings scenario and 6.2 percent using high incremental uncommitted savings. For peak, the reductions range from 4.8 percent to 9.5 percent, higher than consumption because the weighted-average peak-to-energy ratio for end users targeted by these initiatives is higher than the overall average ratio.

Figure 8-3: *CED 2011 Preliminary* Statewide Consumption (Mid Demand Case) Less Uncommitted Savings by Scenario



Source: California Energy Commission, 2011

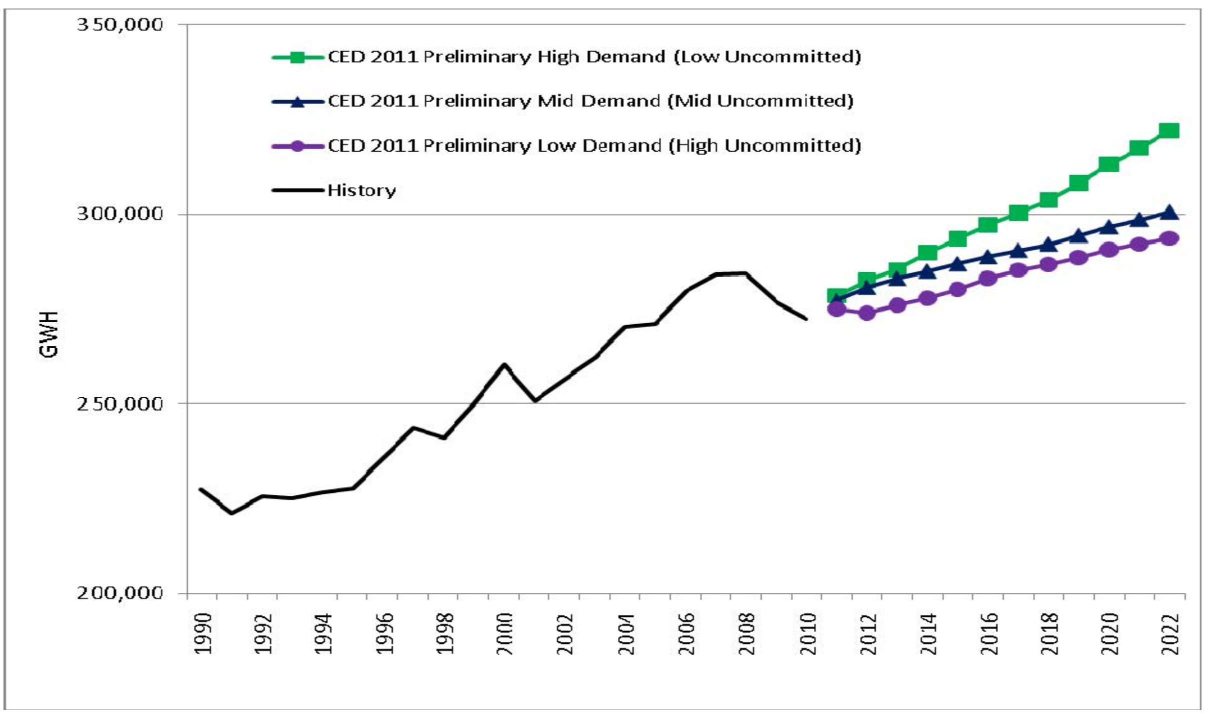
Figure 8-4: *CED 2011 Preliminary* Peak (Mid Demand Case) Less Uncommitted Savings by Scenario



Source: California Energy Commission, 2011

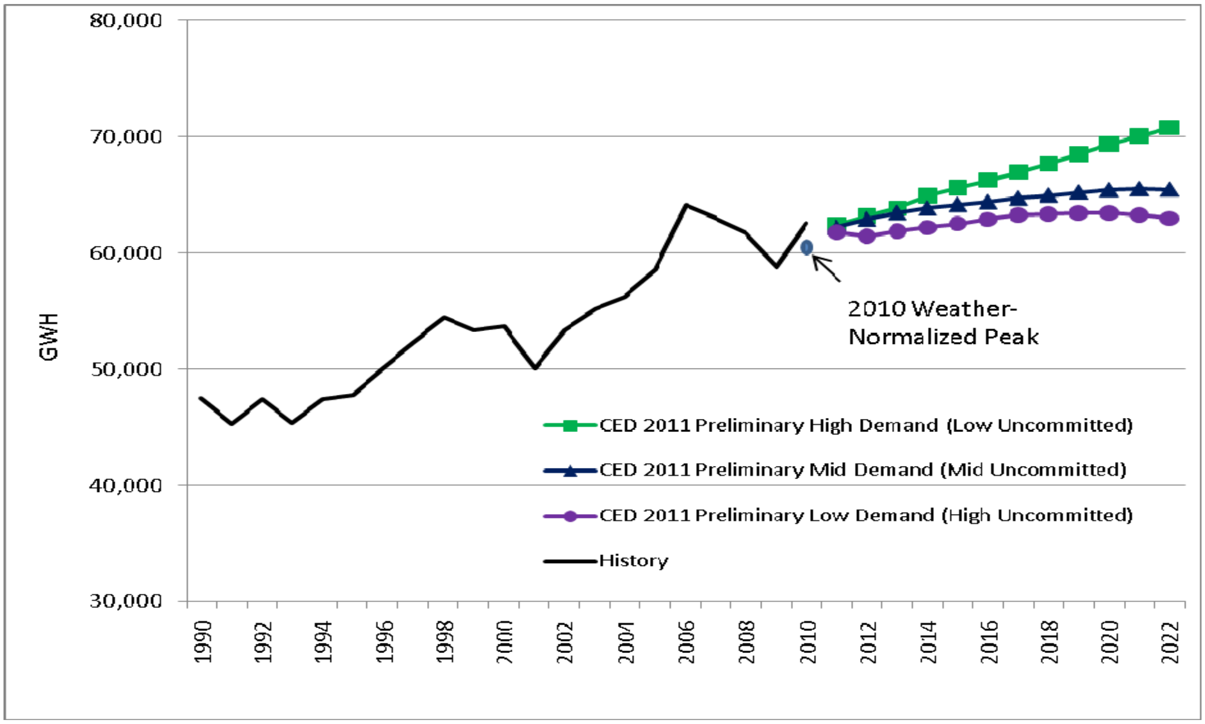
Figure 8-5 and **Figure 8-6** show new demand scenarios that incorporate incremental uncommitted savings as follows: the high demand case is combined with low incremental savings, the low demand scenario is combined with high savings, and the mid demand case incorporates the mid savings scenario. Constructing new scenarios is this fashion is not necessarily consistent since the demand scenarios are driven mainly by economic growth while the savings scenarios are driven by policy. Instead, the figures show a maximum potential range when combining the sets of scenarios. Adjusted consumption ranges from around 294,000 GWh to 322,000 GWh, compared to a range of 313,000 GWh to 332,000 GWh for unadjusted consumption. For peak demand, the new range is 63,000 MW to 71,000 MW, compared to the unadjusted range of 70,000 MW to 74,000 MW. In the adjusted mid and low demand cases, peak demand begins to drop slightly by the end of the forecast period. Peak demand in the low case drops slightly below the actual 2010 statewide (non-coincident) level.

Figure 8-5: Statewide Consumption Scenarios Incorporating Uncommitted Savings



Source: California Energy Commission, 2011

Figure 8-6: Statewide Peak Scenarios Incorporating Uncommitted Savings



Source: California Energy Commission, 2011

Finally, **Table 8-7** and **Table 8-8** show the results given in **Figure 8-5** and **Figure 8-6** for the five major planning areas for consumption and peak demand, respectively. The tables also provide the effect on 2010-2022 growth rates of including incremental uncommitted savings. The relative impact of incremental savings is higher for the publicly owned utility planning areas with growth in the adjusted, mid and low demand cases turning negative in some cases. This is mainly the result of a relatively high amount of programs savings compared to the IOUs. It must be stressed that the 2010 study incorporated overlap among the savings sources for the IOUs, which reduced the net impact of programs. Publicly owned utility program savings have not been adjusted in this manner, and therefore may be overstated.

Table 8-7: Consumption Scenarios Incorporating Uncommitted Savings by Planning Area (GWh)

		High Demand		Mid Demand		Low Demand	
		CED 2011 Preliminary	*CED 2011 Preliminary* Adjusted	*CED 2011 Preliminary*	*CED 2011 Preliminary* Adjusted	*CED 2011 Preliminary*	*CED 2011 Preliminary* Adjusted
LADWP	2013	25,457	25,106	25,430	24,985	24,927	24,401
	2015	26,143	25,444	25,929	25,014	25,453	24,372
	2020	27,784	26,254	27,267	25,200	26,868	24,405
	2022	28,633	26,812	27,930	25,431	27,475	24,496
	Growth 2010-2022	1.46%	0.90%	1.25%	0.46%	1.11%	0.15%
PG&E	2013	111,356	111,087	110,641	110,155	107,784	107,283
	2015	115,634	114,819	113,520	112,053	111,008	109,477
	2020	126,352	124,132	120,669	116,717	118,820	114,567
	2022	131,191	128,251	123,804	118,579	121,839	116,163
	Growth 2010-2022	1.78%	1.59%	1.29%	0.93%	1.16%	0.76%
SCE	2013	102,213	101,892	101,660	101,052	98,968	98,328
	2015	105,688	104,721	104,177	102,344	101,746	99,835
	2020	113,672	111,059	110,442	105,494	108,793	103,448
	2022	117,548	114,092	113,228	106,684	111,440	104,371
	Growth 2010-2022	1.58%	1.33%	1.27%	0.76%	1.13%	0.58%
SDG&E	2013	21,728	21,676	21,561	21,435	21,123	20,995
	2015	22,666	22,506	22,268	21,891	21,820	21,432
	2020	24,971	24,532	24,187	23,199	23,817	22,770
	2022	25,987	25,402	25,005	23,705	24,604	23,215
	Growth 2010-2022	2.11%	1.91%	1.78%	1.33%	1.64%	1.15%
SMUD	2013	11,074	10,838	11,014	10,718	10,783	10,433
	2015	11,565	11,086	11,370	10,757	11,172	10,448
	2020	12,675	11,591	12,276	10,859	12,124	10,439
	2022	13,151	11,850	12,657	10,940	12,486	10,442
	Growth 2010-2022	2.02%	1.14%	1.70%	0.47%	1.58%	0.08%
State	2013	286,668	285,384	285,109	283,077	278,263	276,033
	2015	296,821	293,581	292,286	286,915	286,100	280,268
	2020	321,268	313,073	310,462	296,652	305,932	290,615
	2022	332,514	322,033	318,396	300,567	313,493	293,683
	Growth 2010-2022	1.68%	1.41%	1.31%	0.83%	1.18%	0.63%
High demand case adjusted with low uncommitted savings, mid demand case with mid uncommitted savings, and low demand with high uncommitted savings.							

Source: California Energy Commission, 2011

Table 8-8: Peak Scenarios Incorporating Uncommitted Savings by Planning Area (MW)

		High Demand		Mid Demand		Low Demand	
		CED 2011 Preliminary	*CED 2011 Preliminary* Adjusted	*CED 2011 Preliminary*	*CED 2011 Preliminary* Adjusted	*CED 2011 Preliminary*	*CED 2011 Preliminary* Adjusted
LADWP	2013	5,956	5,832	5,950	5,823	5,824	5,673
	2015	6,166	5,928	6,108	5,841	5,981	5,659
	2020	6,648	6,098	6,497	5,844	6,370	5,580
	2022	6,861	6,197	6,656	5,851	6,510	5,531
	Growth 2010-2022*	1.25%	0.39%	0.99%	0.09%	0.81%	-0.55%
PG&E	2013	23,907	23,846	23,817	23,695	23,203	23,070
	2015	24,779	24,588	24,402	24,015	23,832	23,406
	2020	26,887	26,278	25,831	24,622	25,334	23,842
	2022	27,729	26,896	26,313	24,660	25,734	23,810
	Growth 2010-2022*	1.81%	1.55%	1.37%	0.82%	1.18%	0.53%
SCE	2013	23,735	23,663	23,677	23,537	23,102	22,953
	2015	24,586	24,364	24,308	23,870	23,748	23,277
	2020	26,524	25,851	25,885	24,565	25,382	23,902
	2022	27,330	26,420	26,446	24,655	25,853	23,826
	Growth 2010-2022*	1.79%	1.50%	1.51%	0.92%	1.32%	0.63%
SDG&E	2013	4,652	4,638	4,621	4,591	4,517	4,486
	2015	4,835	4,793	4,746	4,654	4,636	4,540
	2020	5,271	5,146	5,077	4,818	4,964	4,682
	2022	5,432	5,265	5,183	4,835	5,054	4,673
	Growth 2010-2022*	1.86%	1.59%	1.46%	0.88%	1.25%	0.59%
SMUD	2013	3,102	3,036	3,099	3,024	3,037	2,948
	2015	3,232	3,094	3,187	3,027	3,134	2,945
	2020	3,517	3,178	3,416	3,010	3,371	2,882
	2022	3,629	3,215	3,503	2,996	3,447	2,835
	Growth 2010-2022*	1.68%	0.66%	1.38%	0.07%	1.25%	-0.39%
State	2013	64,244	63,894	64,050	63,535	62,537	61,959
	2015	66,569	65,695	65,701	64,304	64,246	62,678
	2020	72,006	69,594	69,818	65,816	68,498	63,878
	2022	74,220	71,087	71,280	65,982	69,738	63,576

	Growth 2010-2022*	1.72%	1.48%	1.38%	0.86%	1.20%	0.54%
* Growth relative to weather-normalized 2010 peaks							
High demand case adjusted with low uncommitted savings, mid demand case with mid uncommitted savings, and low demand with high uncommitted savings.							

Source: California Energy Commission, 2011

GLOSSARY

Acronym	Definition
AB 2021	Assembly Bill 2021
CED	California Energy Demand
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
DOF	Department of Finance
EAP	Energy Action Plan
Energy Commission	California Energy Commission
ERP	Emerging Renewables Program
ESP	Electric Service Provider
GW/GWh	Gigawatt/gigawatt hours
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
IOU	Investor-owned utility
ISO	Independent System Operator
KW/KWh	Kilowatt/Kilowatt hours
LADWP	Los Angeles Department of Water and Power
LSE	Load serving entity
MW/MWH	Megawatt/megawatt hours
NSHP	New Solar Homes Partnership
PG&E	Pacific Gas and Electric Company
PV	Photovoltaic
QFER	Quarterly Fuel Energy Reporting
SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
SGIP	Self-Generation Incentive Program
SMUD	Sacramento Municipal Utility District
SCG	Southern California Gas Company
TCU	Transportation, communications and utility sector

APPENDIX A: Adjustments to Existing Models from Econometric Estimations

Results from the econometric estimations were used to adjust the following model assumptions:

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

Residential and Industrial Price Elasticities

Electricity price elasticities of demand that have been used in the residential end use model and in the industrial INFORM models are very low, on the order of 1-3 percent.[45] For *CED 2011 Preliminary*, staff replaced these elasticities with those estimated in early 2011 for the residential, manufacturing, and resource extraction/construction econometric models. This meant increasing the residential end use model elasticity to around 8 percent and the INFORM elasticity to 10 percent. The elasticity estimated for the commercial econometric model (3 percent) was significantly lower than currently used in the commercial end use model (around 15 percent), but was barely significant statistically. Therefore, the commercial end use model price elasticity was not changed.

Commercial Weather Adjustment

In the Summary Model, which aggregates and calibrates the sector model results, adjustments are made to account for actual weather, by using the ratio of degree days in a given year to a 30-year average. For the commercial results (from the end use model), the adjustment for cooling degree days resulted in a much higher effect (about twice as much) as would be applied using the estimated coefficient for cooling degree days in the commercial econometric model. Therefore, staff reduced the cooling adjustment in the

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

Summary Model by 50 percent. The residential adjustment for cooling degree days in the Summary Model is consistent with the econometric results.

Industrial Labor Productivity Adjustment

In the INFORM model, manufacturing energy demand is forecast based primarily on projected growth in output for 28 different categories (for example, chemicals and paper). In estimating the manufacturing econometric model, staff found that, in addition to output, the ratio of output to employment has had a very significant[46] effect on electricity demand. That is, as output per labor unit has increased, total energy use has declined, all else equal. The coefficient can be construed as an indicator of the effect of more efficient manufacturing processes and may also be capturing changes in the makeup of manufacturing industries. Staff used the estimated coefficient for output/labor to adjust the INFORM results, yielding a lower (and in staff's view, a more realistic) forecast for manufacturing consumption.

Peak Impacts of Climate Change

The Energy Commission demand forecasting process incorporates the potential impacts of global climate change by adjusting upward the number of cooling and heating degree days in the forecast period, based on the historical ratio of degree days in the last 12 years to that of the last 30 years. The result of this adjustment is an increase in the projected amount of cooling and a reduction in projected heating relative to the historical period. This correction attempts to account for the likelihood of a general warming trend. However, temperatures assumed in the peak forecast, an average of daily temperatures over a 30-year period, are not affected by the adjustment. Therefore, the forecast may not fully capture the impact on peak demand of possibly more frequent heat storm weather events in the form of higher maximum temperatures in a given year.

Staff used the econometric peak model to estimate the potential impacts of climate change on annual peaks, and then added these estimated impacts to the Energy Commission's HELM end use peak model results. The econometric model includes a coefficient for the annual maximum of *max631*, defined as follows:

Max631 =
Daily Maximum Temperature × 0.6
+ *Previous Day's Maximum Temperature* × 0.3
+ *Two Day's Previous Maximum Temperature* × 0.1.

46 At-statistic of -7.8.

The adjustment from a simple daily maximum temperature to *max631* is meant to provide a better indicator of sustained temperature warming than a simple daily maximum.[47]

To gauge the potential impact of climate change on *max631* temperatures through 2022, staff used a 2011 update of a climate change impact assessment by the California Climate Change Center, sponsored by the Energy Commission.[48] The update is based on eight climate change model simulations for California using four different models, providing scenario results for daily maximum and minimum temperatures, average daily humidity, and sea level rises through 2099.

Climate change model simulations were performed for grids of 50 square miles within the state; staff used simulated daily maximum and minimum temperatures for grids corresponding to the 10 weather stations used for 16 forecasting climate zones. Staff chose climate change scenarios that resulted in an average temperature impact over all scenarios for the mid demand case and in a relatively high temperature impact for the high demand case.[49] For the low demand scenario, staff assumed no climate change impacts. Staff converted simulated daily maximums for each weather station to *max631* indices for each planning area by weighting each climate zone by population. Growth in annual maximum *max631* temperatures starting in 2011 was derived using long-term trends (1990-2020) from the two climate scenarios.[50]

Table A-1 shows the projected impacts of climate change in the mid and high demand scenarios on peak demand for the five major planning areas and for the state as a whole. By 2022, statewide peak impacts reach over 400 MW in the mid demand case and around 650 MW in the high demand case. Also shown are the simulated annual maximum *max631* temperatures in degrees Fahrenheit for the two climate change scenarios used. Temperatures in 2011 represent a historical 30-year average for the planning area.

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47 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.

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

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

50 A long-term trend was used rather than the actual temperatures in each scenario because year-to year fluctuations simulated in the climate change models sometimes resulted in 2022 maximum temperatures as low as or lower than 2011 maximums.

Table A-1: Projected Peak Impacts of Climate Change by Scenario and Planning Area

		Annual Maximum *Max631* (°F), Mid Demand Scenario	Annual Maximum *Max631* (°F), High Demand Scenario	Peak Impact, Mid Scenario (MW)	Peak Impact, High Scenario (MW)
LADWP	2011	101.5	101.5	--	--
	2015	101.9	102.0	19	24
	2020	102.5	102.8	45	59
	2022	102.8	103.1	56	74
PGE	2011	99.6	99.6	--	--
	2015	99.8	100.0	43	74
	2020	100.2	100.6	105	184
	2022	100.3	100.8	131	231
SCE	2011	102.6	102.6	--	--
	2015	103.0	103.1	61	79
	2020	103.5	103.7	147	197
	2022	103.7	104.0	185	249
SDGE	2011	90.7	90.7	--	--
	2015	90.9	91.1	8	15
	2020	91.2	91.7	19	37
	2022	91.3	91.9	24	47
SMUD	2011	105.1	105.1	--	--
	2015	105.5	105.7	7	12
	2020	105.9	106.5	16	31
	2022	106.1	106.8	20	39
State	2015	--	--	141	209
	2020	--	--	341	520
	2022	--	--	427	657

Source: California Energy Commission, 2011

APPENDIX B: Self-Generation Forecasts

Self-Generation Forecasts

Compiling Historical Distributed Generation Data

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

- The California Solar Initiative (CSI)[51]
- New Solar Homes Partnership (NSHP)[52]
- Self Generation Incentive Program (SGIP)[53]
- CSI Thermal Program for Solar Water Heating (SWH)[54]
- Emerging Renewables Program (ERP)[55]
- Publically owned utility program (POU)[56]

In addition, power plants with a generating capacity of at least 1 MW are required to submit fuel use and generation data to the Commission under the Quarterly Fuel and Energy Report (QFER) Form 1304.[57] QFER data includes fuel use, total generation, onsite use, and exports to the grid. QFER accounts for the majority of onsite generation in California given the large representation of industrial cogeneration facilities. With each forecast cycle, staff continues to refine QFER data to correct for mistakes in data collection and data entry. In this cycle, staff spent time separating third-party sales ("wheeling" or "over the fence sales") from onsite generation. Also, an attempt was made to allocate third-party sales to the North American Industrial Classification System (NAICS) code reported by the form preparer. In situations where a NAICS code was not reported for a third-party sale, staff assigned the

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51 Downloaded on 05/09/11 from (http://www.californiasolarstatistics.org/current_data_files/)

52 Program data received on 05/09/11 from staff in the Energy Commission's Renewable Energy Office.

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

54 Downloaded on 05/09/11 from (http://www.gosolarcalifornia.org/solarwater/index.php)

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

56 Using 2009 as proxy since 2010 data was not submitted in time. All fund PV. http://www.energy.ca.gov/sb1/pou_reports/index.html

57 Data received from Commissions Electricity Analysis Office on 5/12/11.

third-party sales transaction to the same NAICS category as generation. This is not an unreasonable assumption given that it is most likely that firms engaged in similar industries tend to be clustered together and that these "over the fence" sales generally occur with the buyer and seller located in close proximity to one another. Staff also spent time examining the classification of plants to NAICS groups and assignment of plants to planning area. Given the self-reporting nature of QFER data, refinements to historical data will likely continue to occur in future forecast cycles.

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

Projects from incentive programs are classified as either completed or uncompleted. This is accomplished by examining the current status of a project. Each program varied in how it categorized a project as being completed. CSI projects having the following statuses are counted as completed projects: "Completed", "PBI – In Payment", "Pending Payment", "Incentive Claim Request Review", and "Suspended – Incentive Claim Request Review". For the SGIP program, a project with the status "Completed" is counted as completed. For the ERP program, there was no field indicating the status of a project. However, there was a column labeled "Date_Completed" and this column was used to determine if a project was completed or uncompleted. For the NSHP, a project that has been approved for payment is counted as a completed project. For SHW, any project having the Status "Paid" was counted as a completed project. POU PV data provided installations by sector.[58] Staff then projects when uncompleted projects will be completed based on how long it took completed projects to move between the various application stages or make use of supplemental program data.[59]

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58 Note that due to timing issues with the compilation of QFER data for sector modelers and POU data submission under SB 1, staff assumed that 2010 PV additions for POUs would remain the same as in 2009.

59Report 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 which can be helpful in determining when uncompleted projects can be expected to be completed.

The next step is to assign each project to a county and sector. For the minority of records that cannot be mapped to a county due to missing or invalid county or zip code, staff distributes these records to a county based on the distribution of records that have been mapped to a county. Sector mapping for non-residential projects can be a challenge.[60] When valid NAICS codes are provided in the program data, the corresponding NAICS sector description is used; otherwise, a default "Commercial" sector label is used. The next step for each program is to aggregate capacity additions by county to one of 16 demand forecasting climate zones. These steps are used to process data from all incentive programs in varying degrees in order to account for program specific information. For example, certain projects in the SGIP program have an investor owned utility (IOU) as the program administrator but are interconnected to a POU; these projects are mapped directly to forecasting zones. For the ERP program, PV projects less than 10 kW are mapped to the residential sector while both non-PV and PV projects greater than 10 kW are mapped to the commercial sector. Finally, capacity and peak factors from DG evaluation reports are used to estimate energy and peak impacts.[61] [62]

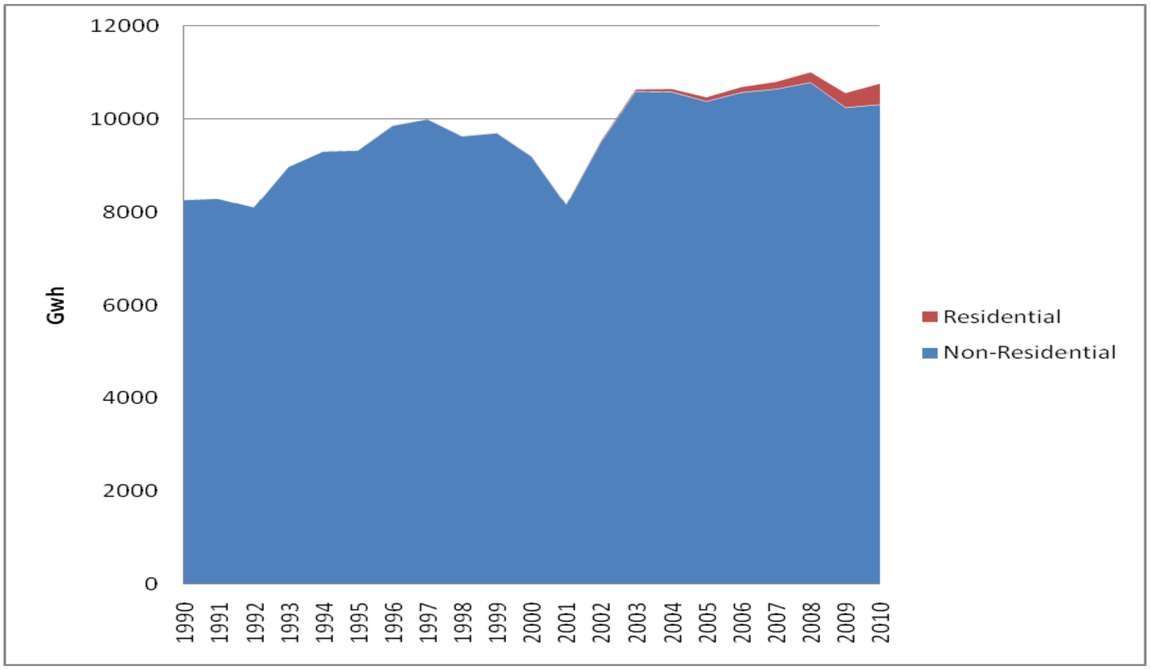
Figure B-1 shows the statewide historical distribution of self-generation between the residential and non-residential sectors, reflecting relatively recent (and small, although growing) residential contributions to the total. **Figure B-2** gives a breakout by non-residential category for the state,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

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

61 For SGIP program: Itron. CPUC *Self-Generation Incentive Program Ninth-Year Impact Evaluation*, June 2010. Report available at (http://www.cpuc.ca.gov/NR/rdonlyres/B9E262AA-4869-461A-8D5C-EE3827E9AA9D/0/SGIP_Impact_Report_2009_FINAL.pdf)

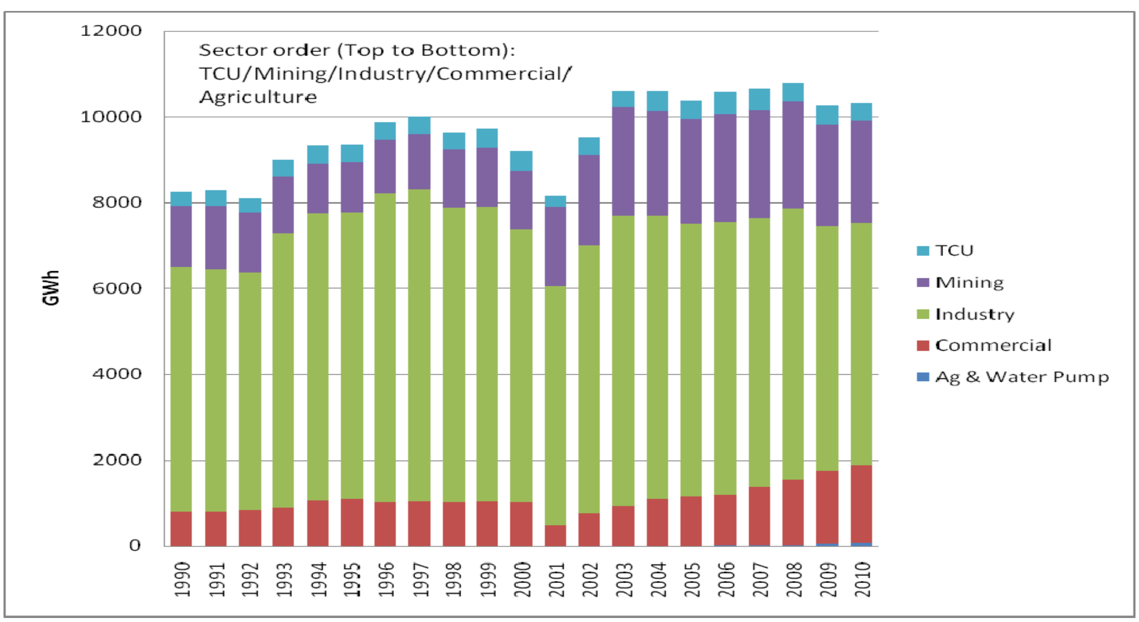
62 For CSI program: Itron. *CPUC California Solar Initiative 2010 Impact Evaluation*, June 2010. Report available at (http://www.cpuc.ca.gov/NR/rdonlyres/E2E189A8-5494-45A1-ACF2-5F48D36A9CA7/0/CSI_2010_Impact_Eval_RevisedFinal.pdf)

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



Source: California Energy Commission, 2011

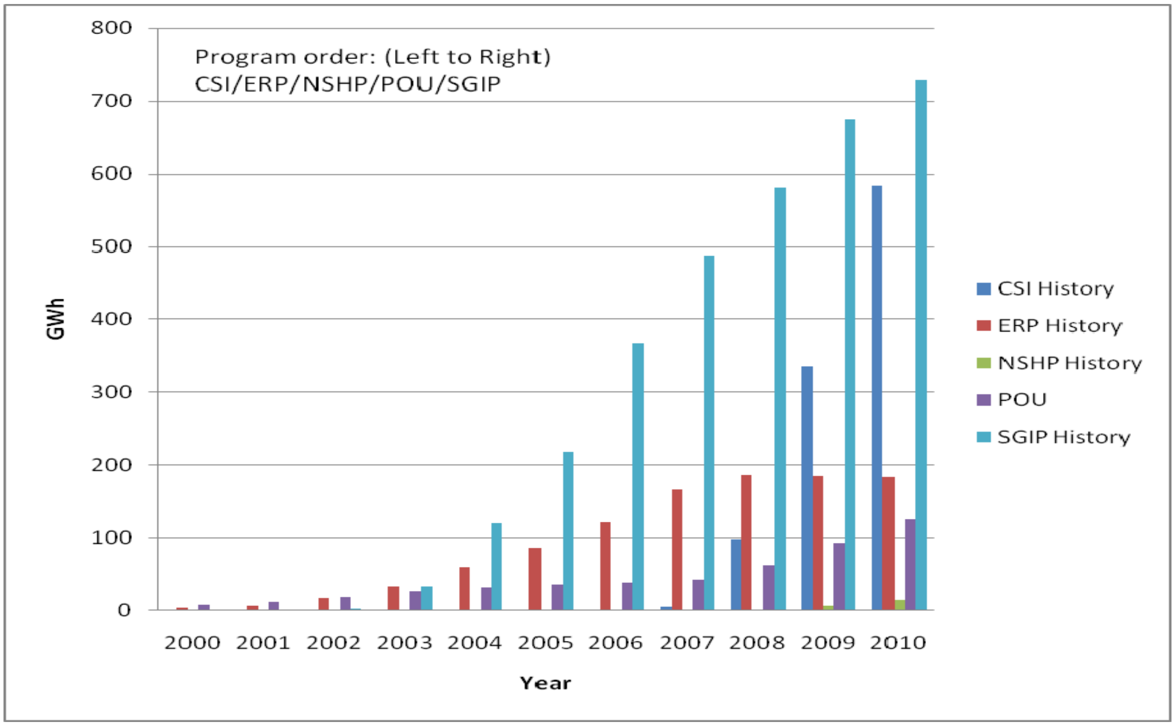
Figure B-2: Statewide Historical Distribution of Self-Generation, Non-Residential



Source: California Energy Commission 2011

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

Figure B-3: Statewide Self-Generation by Program



Source: California Energy Commission, 2011

Self-Generation Forecast, Non-Residential Sectors

Staff has begun to develop a predictive model for the commercial sector, but it has not yet been completed. For this forecast, staff used a method similar to the one used in *CED 2009*. Using DG incentive program data, staff calculated the mean growth rate in DG technology stock by sector and forecast zone for 2007 to 2010. Given strong growth for some technologies, namely fuel cells and PV, the maximum annual growth rate was capped at 7 percent. This mean growth rate was applied to the installed capacity in 2010. The installed capacity was allowed to grow at the mean rate until 2016 when the growth rate was reduced by half. It was not feasible to forecast SWH in this manner for the non-residential sector since the SWH program is relatively new. Therefore, staff assumed that the residential and non-residential sector SWH adoption would follow a ratio similar to residential and non-residential PV adoption. Staff used data from the CSI program to estimate this ratio which was then applied to SWH penetration estimated for the residential sector with the predictive model. Due to the lack of an in-house model, staff is unable to consider the impact of technology cost, incentives, electricity and gas rates, and general improvements in DG technology on non-residential DG technology adoption. As a result, there is only one scenario for the non-residential sector. Capacity and peak factors from DG program evaluation reports were used to estimate energy and peak impacts.[63]

The budget for non-residential CSI incentives for PGE and SDGE has been exhausted, and the method used to forecast PV adoption in the non-residential sector is unable to account for the effect of removing the availability of CSI incentives on PV adoption. However, based on growth in additions in the non-residential sector while incentives were declining between 2007 to 2010, the growth in third party financing, the availability of the federal investment tax credit, and the decline in the cost of PV systems, it is reasonable to expect that PV adoption in the non-residential sector for PGE and SDGE can be expected to continue to grow over the forecast horizon.

In the fall of 2010, an agreement was reached between the CPUC, utilities, and other stakeholders regarding the establishment of a statewide combined heat and power (CHP) program.[64] A major emphasis of this settlement is to re-sign contracts for existing qualifying facilities (QF). The settlement has a goal to have 3,000 MW of CHP under contract by 2020. Currently, based on QFER data and DG program data, staff can identify approximately 7,850 MW of installed CHP capacity as of 2010. This includes 2,400 MW of QFER CHP counted in the demand forecast,[65] 170 MW of DG from program data,[66] and 5,300 MW of QFER CHP not counted in the demand forecast since these plants sell generation back to the grid. At this early stage after the settlement, it is difficult to know how many existing plants will be re-signed to a contract and how many new plants will have to come online for the MW (and greenhouse gas emission reduction) goals to be met. In *CED 2011 Preliminary*, onsite use from historic non-PV technologies is held constant over the forecast horizon and is set to the level observed or estimated in the last historical year. Non-PV technologies make up approximately 3,050 MW of the total installed capacity in all three scenarios.

Residential Sector Predictive Model

The residential sector self-generation model was designed to forecast PV and SWH adoption using estimated times for full payback that depend on rate, cost, and performance assumptions. The model is similar in structure to the cash flow based DG model in the

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63 See notes 13 and 14.

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

65 Note that some of these plants use a portion of their generation onsite and also sell any excess back to the utility.

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

National Energy Modeling System as used by the Energy Information Administration[67] and the *SolarDS* model developed by the National Renewable Energy Laboratory.[68]

The payback calculation is based on the internal rate of return (IRR) methodology used in the SolarDS model. The IRR approach takes an investment perspective and takes into account the full cash flow resulting from investing in the project. The IRR is defined as the rate that makes the net present value (the discounted stream of costs and benefits) of an investment equal to zero. In general, the higher the IRR of an investment, the more desirable it is to undertake. Staff compares the IRR to a required hurdle rate (5 percent) to determine if the technology should be adopted. If the calculated IRR is greater than the hurdle rate, then payback is calculated; otherwise, the payback is set to 30 years. The formula for converting the calculated IRR (if above 5 percent) to payback is:

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

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

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

Payback sensitivity is set to 0.3.[69] To estimate actual penetration, maximum market share is multiplied by an estimated adoption rate, calculated using a Bass Diffusion curve, to estimate annual PV and SWH adoption. The Bass Diffusion curve is often used to model adoption of new technologies and is part of a family of technology diffusion functions characterized as having an "S" shaped curve to reflect the different stages of the adoption process.

The adoption rate is given by the following equation:

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

67 Office of Integrated Analysis and Forecasting, U.S. Energy Information Administration. *Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System*, May 2010. Publication no. DOE/EIA-M067(2010)

68 Denholm, Paul, Easan Drury, and Robert Margolis. *The Solar Deployment System (SolarDS) Model: Documentation and Sample Results*, September 2009. Publication no. NREL-TP-6A2-45832.

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

The terms *p* and *q* are used to represent the impact of early and late adopters of the technology, respectively. Staff uses mean values for *p* (0.03) and *q* (0.38), derived from a survey of empirical studies.[70]

PV cost and performance data are based on analysis performed by ICF International in support of EIA's 2011 *Annual Energy Outlook* forecast report.[71] SWH cost and performance data are based on analysis conducted by ITRON in support of a CPUC proceeding examining the costs and benefits of SWH systems.[72]

Projected housing counts are allocated to two water heating types – electric and gas. The allocation is based on saturation levels used in the Energy Commission's residential model. For multifamily units, data from the most recent Residential Appliance Saturation Survey (RASS) are used to allocate multifamily units to two size categories: two to four units and five or more units. PV systems are sized to each housing type based on RASS floor space data, assumptions regarding roof slope, and factors to account for shading, and orientation.[73] PV system size is constrained to be no more than 4 kW for single family homes, 7 kW for two to four unit multifamily units, and 15 kW for five or more multifamily units. For PV systems, hourly generation over the life of the system is estimated based on data provided to staff by the Energy Commission's Efficiency and Renewable Energy Division.[74] For SWH systems, energy saved on an annual basis is used directly to estimate bill savings. PV and SWH energy output are degraded at the same rate based on the PV degradation factor estimated by ICF for EIA. From year to year, available housing stock is reduced by penetration from existing programs in previous years and increased by the projected amount of new residential construction.

Staff uses the residential electricity and natural gas rates developed for *CED 2011 Preliminary* to estimate bill savings, with rates held constant over the life of PV and SWH systems. Useful life is assumed to be 30 years for both technologies. For PV, surplus generation is valued at a uniform rate of $0.06/kWh.[75] Once the revenue stream for the two

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

71 Tidball, Rick, Joel Bluestein, Nick Rodriguez, and Stu Knoke. *Cost and Performance Assumptions for Modeling Electricity Generation Technologies*, November, 2010. Publication no. NREL/SR-6A20-48595.

72 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)

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

74 Data comes from the NSHP Incentive calculator.

75 Annual residential energy use by housing type and water heater type is an output from the residential model. This data is used with the estimated PV generation to estimate if any surplus

types of technology has been estimated, the initial cost of each technology is calculated with adjustments made for incentives offered by a utility to obtain the net cost. As in the *SolarDS* simulations, staff assumes PV systems will cost 10 percent less in new residential construction. Staff also assumes that the system owner will be able to claim the federal investment tax credit and that PV and SWH systems are financed rather than purchased outright.[76] Tax savings on the loan interest is also taken into account by assuming a uniform marginal tax rate of 35 percent. Owners of multifamily units are assumed to claim the five-year Modified Accelerated Cost Recovery System (MACRS) depreciation benefit.

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

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generation occurs. Note that the recent CPUC proposed decision on surplus compensation estimated that the surplus rate for PGE in 2009 would be roughly $0.04/kWh plus an environmental adder of $0.0183/kWh. See (http://docs.cpuc.ca.gov/word_pdf/AGENDA_DECISION/136635.pdf)

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