DOCKETED

Docket Number:	15-IEPR-03
Project Title:	Electricity and Natural Gas Demand Forecast
TN #:	205141
Document Title:	CALIFORNIA ENERGY DEMAND 2016-2026, PRELIMINARY ELECTRICITY FORECAST
Description:	Staff Report
Filer:	Raquel Kravitz
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	6/23/2015 3:32:07 PM
Docketed Date:	6/23/2015

California Energy Commission

STAFF REPORT

CALIFORNIA ENERGY DEMAND 2016-2026, PRELIMINARY ELECTRICITY FORECAST

CALIFORNIA
ENERGY COMMISSION

Edmund G. Brown Jr., Governor

JUNE 2015

CEC-200-2015-003

CALIFORNIA ENERGY COMMISSION

Chris Kavalec
Asish Gautam
Primary Authors

Chris Kavalec
Project Manager

Elise Brown
Office Manager
Demand Analysis Office

Sylvia Bender
Deputy Director
Energy Assessments Division

Robert P. Oglesby
Executive Director

ACKNOWLEDGEMENTS

The demand forecast is the combined product of the hard work and expertise of numerous staff members in the Demand Analysis Office and Energy Assessments Division. In addition to the contributing authors listed previously, Mark Ciminelli provided the transportation, communications, and utilities and street lighting forecasts. Mohsen Abrishami prepared the commercial sector forecast, Mehrzad Soltani Nia prepared the industrial forecast, and Ted Dang, Tom Gorin, and Glen Sharp contributed to the residential forecast. Ravinderpal Vaid provided the projections of commercial floor space, Cary Garcia prepared the weather data, and Steven Mac and Andrea Gough prepared the historical energy consumption data. Elena Giyenko, Nick Fugate, and Doug Kemmer developed the energy efficiency program estimates, and Doug Kemmer prepared the estimates for demand response impacts. The electricity rate scenarios were developed by Lynn Marshall and the natural gas price scenarios by Leon Brathwaite and Chris Marxen. Ted Dang ran the summary model and Mitch Tian prepared the peak demand forecast.

ABSTRACT

The *California Energy Demand 2016-2026, Preliminary Electricity Forecast* describes the California Energy Commission's preliminary 10-year forecasts for electricity consumption, retail sales, and peak demand for each of five major electricity planning areas and for the state as a whole. This forecast supports the analysis and recommendations of the *2014 Integrated Energy Policy Report Update.* The forecast includes three full scenarios: a *high energy demand* case, a *low energy demand* case, and a *mid energy demand* case. The *high energy demand* case incorporates relatively high economic/demographic growth and climate change impacts and relatively low electricity rates and self-generation impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed rates, and higher self-generation impacts. The *mid* case uses input assumptions at levels between the *high* and *low* cases. Forecasts are provided at both the planning area and climate zone level.

Keywords:

Electricity, demand, consumption, forecast, weather normalization, peak, self-generation, conservation, energy efficiency, climate zone, electrification, light-duty electric vehicles, distributed generation.

Please use the following citation for this report:

Kavalec, Chris and Asish Gautam, 2015. *California Energy Demand 2016-2026, Preliminary Electricity Forecast*. California Energy Commission, Energy Assessments Division. Publication Number: CEC-200-2015-003.

.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

Page

EXECUTIVE SUMMARY

Introduction

This California Energy Commission staff report describes 10-year forecasts of electricity consumption and peak electricity demand for California and for each major utility planning area within the state for 2016-2026. The end-user natural gas forecast developed in conjunction with electricity will be detailed in the Energy Commission's forthcoming *Natural Gas Outlook*. The *California Energy Demand 2016-2026, Preliminary Electricity Forecast* (*CED 2015 Preliminary*) supports the analysis and recommendations of the *2014 Integrated Energy Policy Report Update*, including electricity system assessments and analysis of progress toward increased energy efficiency and distributed generation.

CED 2015 Preliminary includes three cases designed to capture a reasonable range of demand outcomes over the next 10 years. The *high energy demand* case incorporates relatively high economic/demographic growth and climate change impacts, and relatively low electricity rates and self-generation impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed rates, and higher self-generation impacts. The *mid* case uses input assumptions at levels between the *high* and *low* cases. These scenarios are referred to as *baseline* cases, meaning they do not include additional achievable energy efficiency savings.

Results

A comparison of the *CED 2015 Preliminary* baseline electricity forecast for selected years (five-year increments starting in 2015 plus the final year of the forecast) with the mid case from the last adopted forecast, *California Energy Demand Updated Forecast, 2015-2025* (*CEDU 2014*), is shown in **Table ES-1**. Consumption in the *CED 2015 Preliminary* mid demand case grows at a lower rate through 2025 compared to the *CEDU 2014* mid case mainly as faster growth in the number of households, tempered by a slightly lower commercial forecast due to a reassessment of commercial appliance and building standards and a slightly lower light-duty electric vehicle forecast. The new high demand case is actually lower than the new mid in the early years of the forecast because projected manufacturing output, the key driver for industrial electricity consumption, is lower during this period. *CED 2015 Preliminary* statewide peak demand (the sum of the individual planning area coincident peaks) grows at a lower rate from 2014-2025 in the mid case compared to *CEDU 2014* because of a higher self-generation forecast for the investor-owned utilities.

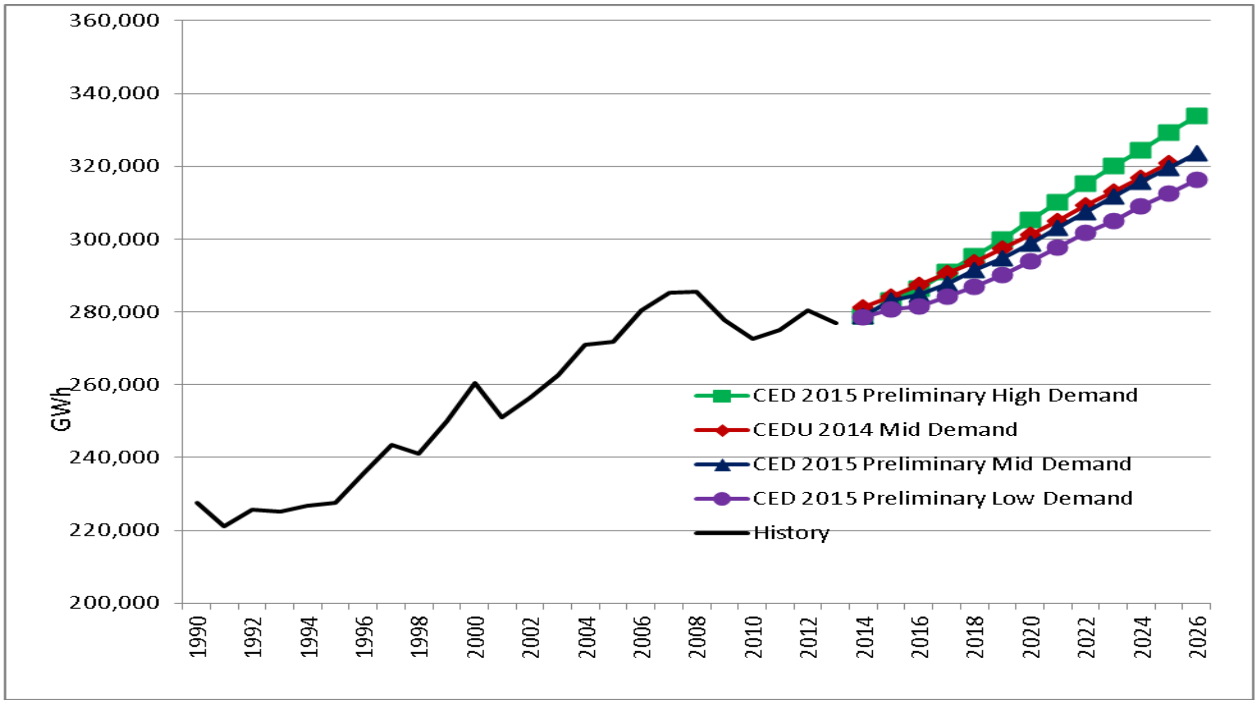
Table ES-1: Comparison of *CED 2015 Preliminary* and *CEDU 2014* Mid Case Demand Baseline Forecasts of Statewide Electricity Demand

Consumption (GWh)				
	***CEDU 2014* Mid Energy Demand**	***CED 2015 Preliminary* High Energy Demand**	***CED 2015 Preliminary* Mid Energy Demand**	***CED 2015 Preliminary* Low Energy Demand**
1990	227,576	227,576	227,576	227,576
2000	260,399	260,400	260,400	260,400
2013	277,140	277,023	277,023	277,023
2015	284,305	283,008	283,098	280,794
2020	301,290	305,119	298,838	293,815
2025	320,862	329,174	319,623	312,611
2026	--	333,930	323,628	316,362
	Average Annual Growth Rates			
1990-2000	1.36%	1.36%	1.36%	1.36%
2000-2013	0.48%	0.48%	0.48%	0.48%
2013-2015	1.28%	1.07%	1.09%	0.68%
2013-2025	1.23%	1.45%	1.20%	1.01%
2013-2026	--	1.45%	1.20%	1.03%
Noncoincident Peak (MW)				
	***CEDU 2014* Mid Energy Demand**	***CED 2015 Preliminary* High Energy Demand**	***CED 2015 Preliminary* Mid Energy Demand**	***CED 2015 Preliminary* Low Energy Demand**
1990	47,543	47,348	47,348	47,348
2000	53,702	53,755	53,755	53,755
2014*	62,454	62,518	62,517	62,517
2015	63,459	63,914	63,521	63,204
2020	67,253	67,706	66,321	64,556
2025	70,644	71,271	68,924	66,178
2026	--	71,882	69,314	66,371
	Average Annual Growth Rates			
1990-2000	1.23%	1.28%	1.28%	1.28%
2000-2014	1.08%	1.08%	1.08%	1.08%
2014-2015	1.61%	2.23%	1.61%	1.10%
2014-2025	1.13%	1.20%	0.89%	0.52%
2014-2026	--	1.17%	0.86%	0.50%
Actual historical values are shaded.				
*Weather normalized: *CEDU 2014* uses a weather-normalized peak value derived from the actual 2014 peak for calculating growth rates during the forecast period.				

Source: California Energy Commission, Demand Analysis Office, 2015.

Projected statewide electricity consumption for the three *CED 2015 Preliminary* baseline cases and the *CEDU 2014* mid demand forecast is shown in **Figure ES-1**. By 2025, consumption in the new mid scenario is projected to be only 0.4 percent lower than the *CEDU 2014* mid case, around 1,000 gigawatt-hours (GWh). Annual growth from 2013-2025 for the *CED 2015 Preliminary* forecast averages 1.45 percent, 1.20 percent, and 1.01 percent in the high, mid and low cases, respectively, compared to 1.23 percent in the *CEDU 2014* mid case.

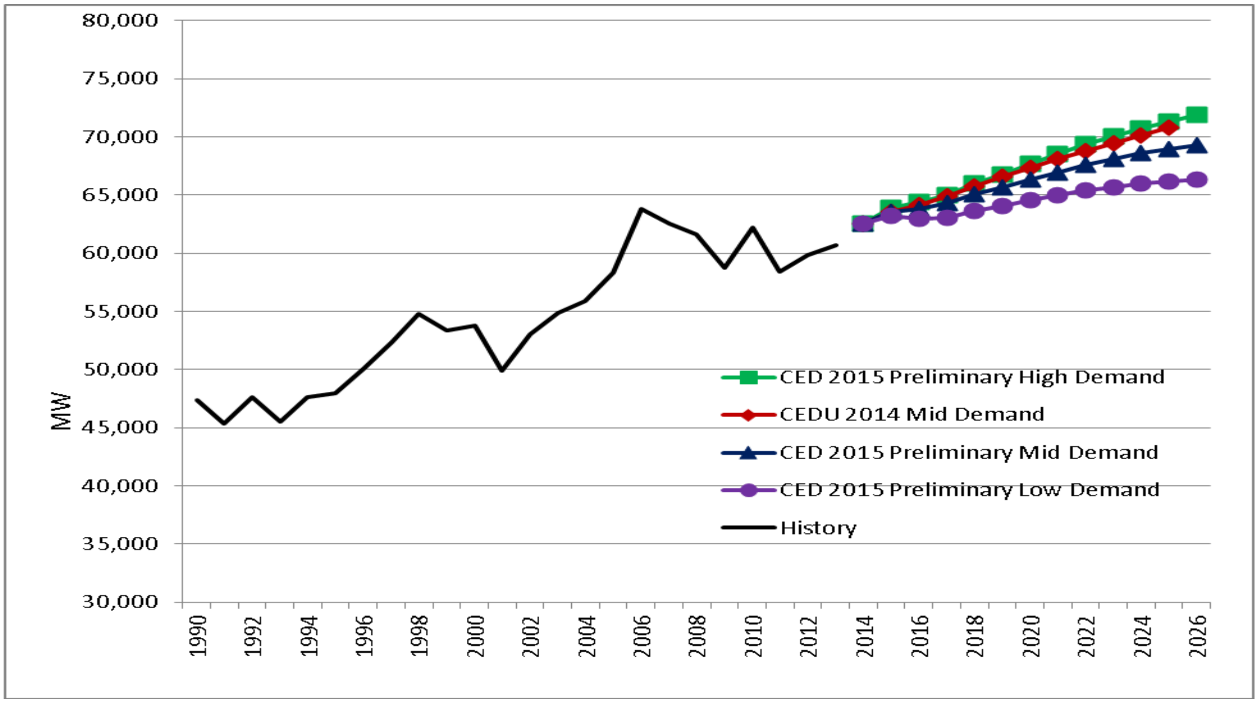
Figure ES-1: Statewide Baseline Annual Electricity Consumption



Source: California Energy Commission, Demand Analysis Office, 2015.

Projected *CED 2015 Preliminary* peak demand for the three baseline scenarios and the *CEDU 2014* mid demand peak forecast is shown in **Figure ES-2**. By 2025, statewide peak demand in the new mid scenario is projected to be 2.4 percent lower than the *CEDU 2014* mid case. Annual growth rates from 2014-2025 for the *CED 2015 Preliminary* scenarios average 1.20 percent, 0.89 percent, and 0.52 percent in the high, mid, and low scenarios, respectively, compared to 1.13 percent in the *CEDU 2014* mid case. Higher projected self-generation reduces the growth rate in the new mid case compared to *CEDU 2014*.

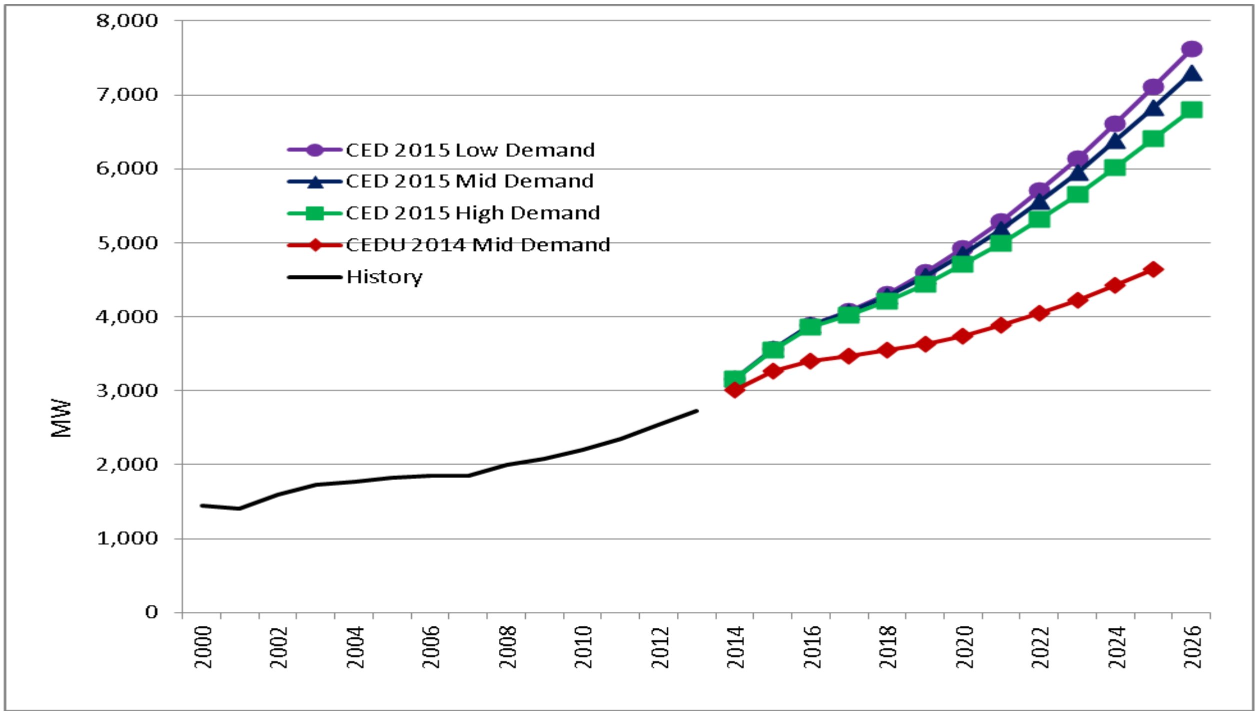
Figure ES-2: Statewide Baseline Annual Noncoincident Peak Demand



Source: California Energy Commission, Demand Analysis Office, 2015.

Historical and projected peak reduction impacts of self-generation for the three *CED 2015 Preliminary* demand cases and the *CEDU 2014* mid case are shown in **Figure ES-3**. Self-generation is projected to reduce peak load by more than 6,800 megawatts (MW) in the new mid case by 2025, an increase of more than 2,000 MW compared to *CEDU 2014*. This increase is caused by a much higher forecast of residential photovoltaic system adoption.

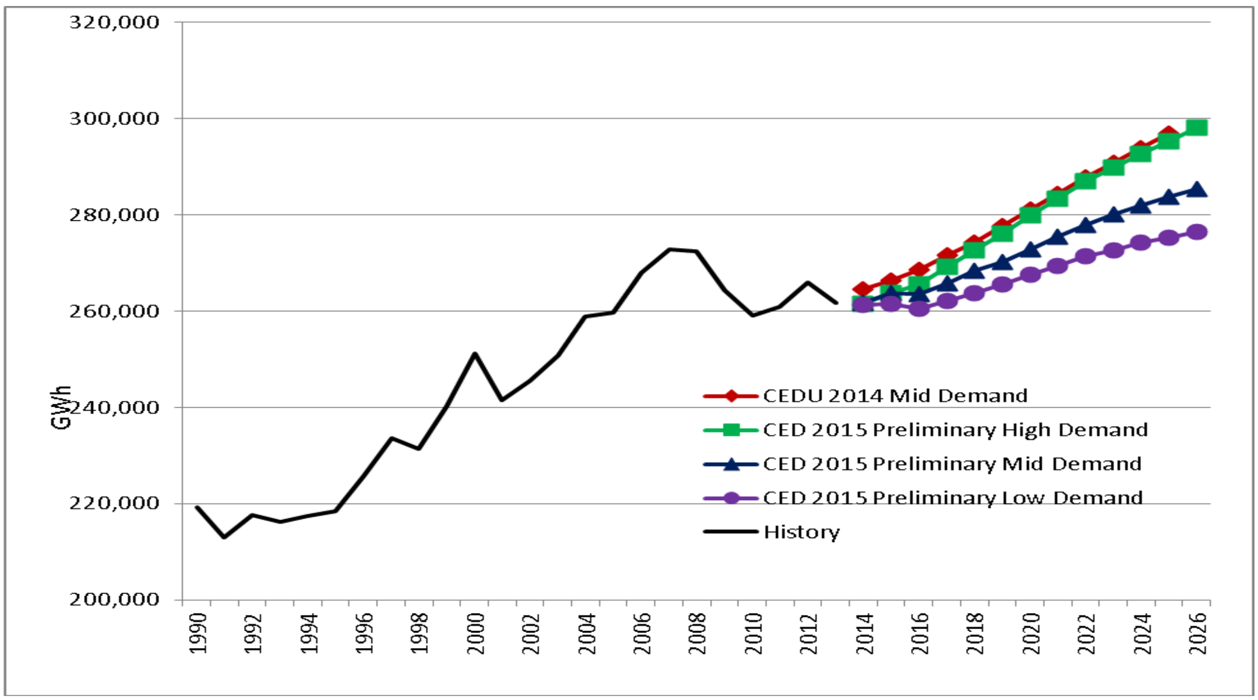
Figure ES-3: Statewide Self-Generation Peak Reduction Impact



Source: California Energy Commission, Demand Analysis Office, 2015.

The higher forecast for self-generation adoption also has a significant impact on projected statewide retail electricity sales, as shown in **Figure ES-4**. The *CED 2015 Preliminary* low and mid cases are markedly lower than the *CEDU 2014* mid case throughout the forecast period. By 2025, sales in the *CED 2015 Preliminary* mid case are projected to be more than 13,000 GWh (4.5 percent) lower than in the *CEDU 2014* mid case. Annual growth from 2013-2025 for the *CED 2015 Preliminary* scenarios averages 1.01 percent, 0.68 percent, and 0.42 percent in the high, mid and low demand cases, respectively, compared to 1.06 percent in the *CEDU 2014* mid case.

Figure ES-4: Statewide Baseline Retail Electricity Sales



Source: California Energy Commission, Demand Analysis Office, 2015.

Summary of Changes to Forecast

In an effort to make the demand forecast more useful to resource planners, *CED 2015 Preliminary* uses a revised geographic scheme for planning areas and climate zones, more closely based on California's balancing authority areas. *CED 2015 Preliminary* includes 20 climate zones, compared to 16 in previous forecasts. Future forecasts will likely incorporate further refinements to geographic granularity.

As part of the continuing effort to capture comprehensively the impacts of energy efficiency initiatives, staff spent a considerable amount of time in the last year reassessing and updating building and appliance standards savings impacts calculated within the forecast models. *CED 2015 Preliminary* also includes estimated efficiency impacts not included in *CEDU 2014*, from 2015 investor-owned utility programs and from 2014 programs administered by publicly owned utilities. The revised version of this forecast will include a new set of appliance standards, approved in May 2015, and projected additional achievable energy efficiency impacts for the investor-owned utilities, based on the California Public Utilities Commission's *2015 California Energy Efficiency Potential and Goals Study*. In addition, the revised forecast will incorporate staff estimates of publicly owned utility additional achievable energy efficiency savings.

CED 2015 Preliminary incorporates scenarios for electric vehicles fuel consumption based on scenarios developed by the Energy Commission's Transportation Energy Forecasting Unit in early 2012. These scenarios have been updated and incorporated into the *California Energy Demand 2014-2024 Final Forecast* and the *CEDU 2014*. Light-duty plug-in electric vehicle[1] purchases are comparable to *CEDU 2014,* having only been adjusted by near-term sales.

Unlike previous forecasts, this report does not provide results for projected end-user natural gas demand. Instead, to avoid duplicating staff effort, end-user natural gas results will be combined with gas generation forecasts as part of the Energy Commission's *Natural Gas Outlook*, to be published in summer 2015.

1 "Electric vehicles" refer to both full battery-electric and plug-in hybrid electric vehicles.

CHAPTER 1: Statewide Baseline Forecast Results and Forecast Method

Introduction

This California Energy Commission staff report presents forecasts of electricity consumption and peak electricity demand for California and for each major utility planning area within the state for 2016-2026. The end-user natural gas forecast developed in conjunction with electricity will be detailed in the Energy Commission's forthcoming *Natural Gas Outlook*. The *California Energy Demand 2016-2026, Preliminary Electricity Forecast* (*CED 2015 Preliminary*) supports the analysis and recommendations of the *2014 Integrated Energy Policy Report Update*, including electricity system assessments and analysis of progress toward increased energy efficiency and distributed generation.

The Integrated Energy Policy Report (IEPR) Lead Commissioner will conduct a workshop on July 7, 2015, to receive public comments on this forecast. Following the workshop, subject to the direction of the Lead Commissioner, staff will prepare a revised forecast for possible adoption by the Energy Commission. The revised forecast will include an assessment of additional achievable energy efficiency impacts not included in *CED 2015 Preliminary*.

The final forecasts will be used in several applications, including the California Public Utilities Commission (CPUC) 2016 Long Term Procurement Plan. The CPUC has identified the IEPR process as "the appropriate venue for considering issues of load forecasting, resource assessment, and scenario analyses, to determine the appropriate level and ranges of resource needs for load serving entities in California."[2] 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 electricity supply-demand (resource adequacy) assessments.

CED 2015 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 and climate change impacts, and relatively low electricity rates and self-generation impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed rates, and higher self-generation impacts. The *mid* case uses input assumptions at levels between the *high* and *low* cases. These forecasts are referred to as *baseline* cases, meaning they do not include additional achievable energy efficiency savings.

---

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

Details on input assumptions for these cases are provided later in this chapter. The forecast comparisons presented in this report show the three *CED 2015 Preliminary* cases versus the mid case from the last adopted forecast, *California Energy Demand Updated Forecast, 2015-2025 (CEDU 2014)*, except where otherwise noted.

Summary of Changes to Forecast

As in *CEDU 2014*, *CED 2015 Preliminary* is based on historical electricity consumption and sales data through 2013 and peak demand data through 2014. The revised version of this forecast will incorporate historical consumption and sales data from 2014 and peak data from 2015.

In an effort to make the demand forecast more useful to resource planners, *CED 2015 Preliminary* uses a revised geographic scheme for planning areas and climate zones, more closely based on California's balancing authority areas.[3] *CED 2015 Preliminary* includes 20 climate zones, compared to 16 in previous forecasts. The new scheme is described in more detail later in this chapter; future forecasts will likely incorporate further refinements to geographic granularity.

As part of the continuing effort to capture comprehensively the impacts of energy efficiency initiatives, staff spent a considerable amount of time in the last year reassessing and updating building and appliance standards savings impacts calculated within the forecast models. *CED 2015 Preliminary* also includes estimated efficiency impacts not included in *CEDU 2014*, from 2015 investor-owned utility (IOU) programs and from 2014 programs administered by publicly owned utilities (POUs). The revised version of this forecast will include a new set of appliance standards, approved in May 2015, and projected additional achievable energy efficiency impacts for the IOUs, based on the CPUC's *2015 California Energy Efficiency Potential and Goals Study*.[4] In addition, the revised forecast will incorporate staff estimates of POU additional achievable energy efficiency savings.

CED 2015 Preliminary incorporates scenarios for electric vehicles fuel consumption based on scenarios developed by the Energy Commission's Transportation Energy Forecasting Unit in early 2012. These scenarios have been updated and incorporated into the *California Energy Demand 2014-2024 Final Forecast* (*CED 2013*) and the *CEDU 2014*. Light-duty plug-in electric vehicle (EV) purchases are comparable to *CEDU 2014* having only been adjusted by near-term sales. Staff's self-generation model was modified to incorporate residential load patterns and a

---

3 A *balancing authority* is an entity responsible for integrating resource plans and maintaining the proper balance for load, transmission, and generation within an area defined by metered boundaries. California includes eight balancing authorities, of which the California ISO is by far the largest.

4 Information available at http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Energy+Efficiency+Goals+and+Potential+Studies.htm.

tiered rate structure, which resulted in a significantly higher forecast for photovoltaic (PV) system adoption.

Unlike in previous forecasts, this report does not provide results for projected end-user natural gas demand. Instead, to avoid duplicating staff effort, end-user natural gas results will be combined with gas generation forecasts as part of the Energy Commission's *Natural Gas Outlook*, to be published in summer 2015.

Statewide Results

The *CED 2015 Preliminary* baseline electricity forecast for selected years (five-year increments starting in 2015 plus the final year of the forecast) is compared with the *CEDU 2014* mid demand case[5] in **Table 1**. For both *CED 2015 Preliminary* and *CEDU 2014*, 2013 is the last historical year consumption was available; actual 2013 consumption was revised downward slightly in the new forecast. Consumption in the *CED 2015 Preliminary* mid demand case grows at a lower rate through 2025 compared to the *CEDU 2014* mid case mainly as a result of faster growth in number of households, tempered by a slightly lower commercial forecast due to a reassessment of commercial building and appliance standards impacts in the commercial sector (reducing commercial consumption) and a slightly lower electric vehicle forecast. The new high demand case is actually lower than the new mid in the early years of the forecast because projected manufacturing output, the key driver for industrial electricity consumption, is lower during this period. *CED 2015 Preliminary* statewide noncoincident[6] weather-normalized[7] peak demand grows at a lower rate from 2014-2025 in the mid case compared to *CEDU 2014* because of a higher self-generation forecast for the IOUs. The *CEDU 2014* mid case for peak demand roughly matches the new high case.

---

5 All numerical forecast results presented in this report and associated spreadsheets represent expected values derived from model output that have associated uncertainty. The results should therefore be considered in this context rather than precise to the last digit.

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

7 Peak demand is weather-normalized in 2014 to provide the proper benchmark for comparison to future peak demand, which assumes either average (normalized) weather or hotter conditions measured relative to 2012 due to climate change.

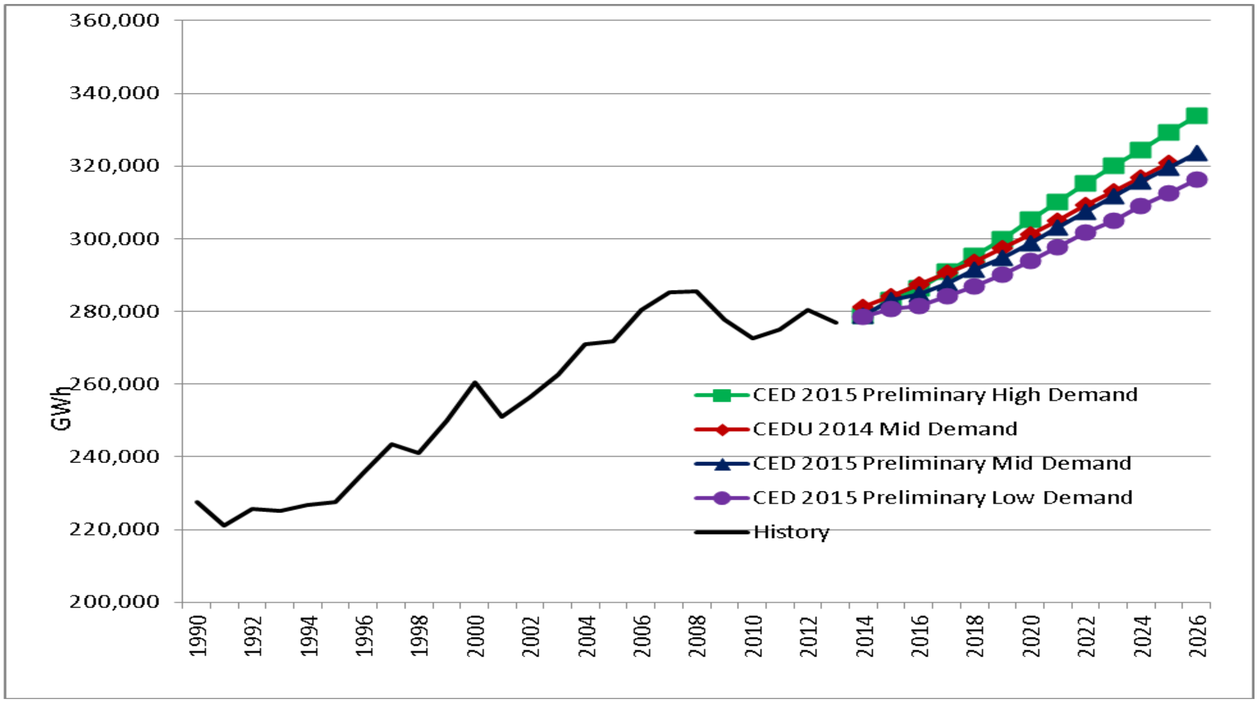
Table 1: Comparison of *CED 2015 Preliminary* and *CEDU 2014* Mid Case Demand Baseline Forecasts of Statewide Electricity Demand

Consumption (GWh)				
	***CEDU 2014* Mid Energy Demand**	***CED 2015 Preliminary* High Energy Demand**	***CED 2015 Preliminary* Mid Energy Demand**	***CED 2015 Preliminary* Low Energy Demand**
1990	227,576	227,576	227,576	227,576
2000	260,399	260,400	260,400	260,400
2013	277,140	277,023	277,023	277,023
2015	284,305	283,008	283,098	280,794
2020	301,290	305,119	298,838	293,815
2025	320,862	329,174	319,623	312,611
2026	--	333,930	323,628	316,362
	Average Annual Growth Rates			
1990-2000	1.36%	1.36%	1.36%	1.36%
2000-2013	0.48%	0.48%	0.48%	0.48%
2013-2015	1.28%	1.07%	1.09%	0.68%
2013-2025	1.23%	1.45%	1.20%	1.01%
2013-2026	--	1.45%	1.20%	1.03%
Noncoincident Peak (MW)				
	***CEDU 2014* Mid Energy Demand**	***CED 2015 Preliminary* High Energy Demand**	***CED 2015 Preliminary* Mid Energy Demand**	***CED 2015 Preliminary* Low Energy Demand**
1990	47,543	47,348	47,348	47,348
2000	53,702	53,755	53,755	53,755
2014*	62,454	62,518	62,517	62,517
2015	63,459	63,914	63,521	63,204
2020	67,253	67,706	66,321	64,556
2025	70,644	71,271	68,924	66,178
2026	--	71,882	69,314	66,371
	Average Annual Growth Rates			
1990-2000	1.23%	1.28%	1.28%	1.28%
2000-2014	1.08%	1.08%	1.08%	1.08%
2014-2015	1.61%	2.23%	1.61%	1.10%
2014-2025	1.13%	1.20%	0.89%	0.52%
2014-2026	--	1.17%	0.86%	0.50%
Actual historical values are shaded.				
*Weather normalized: *CEDU 2014* uses a weather-normalized peak value derived from the actual 2014 peak for calculating growth rates during the forecast period.				

Source: California Energy Commission, Demand Analysis Office, 2015.

Projected electricity consumption for the three *CED 2015 Preliminary* baseline cases and the *CEDU 2014* mid demand forecast is shown in **Figure 1**. By 2025, consumption in the new mid scenario is projected to be only 0.4 percent lower than the *CEDU 2014* mid case, around 1,000 GWh. Annual growth rates from 2013-2025 for the *CED 2015 Preliminary* forecast averages 1.45 percent, 1.20 percent, and 1.01 percent in the high, mid and low cases, respectively, compared to 1.23 percent in the *CEDU 2014* mid case.

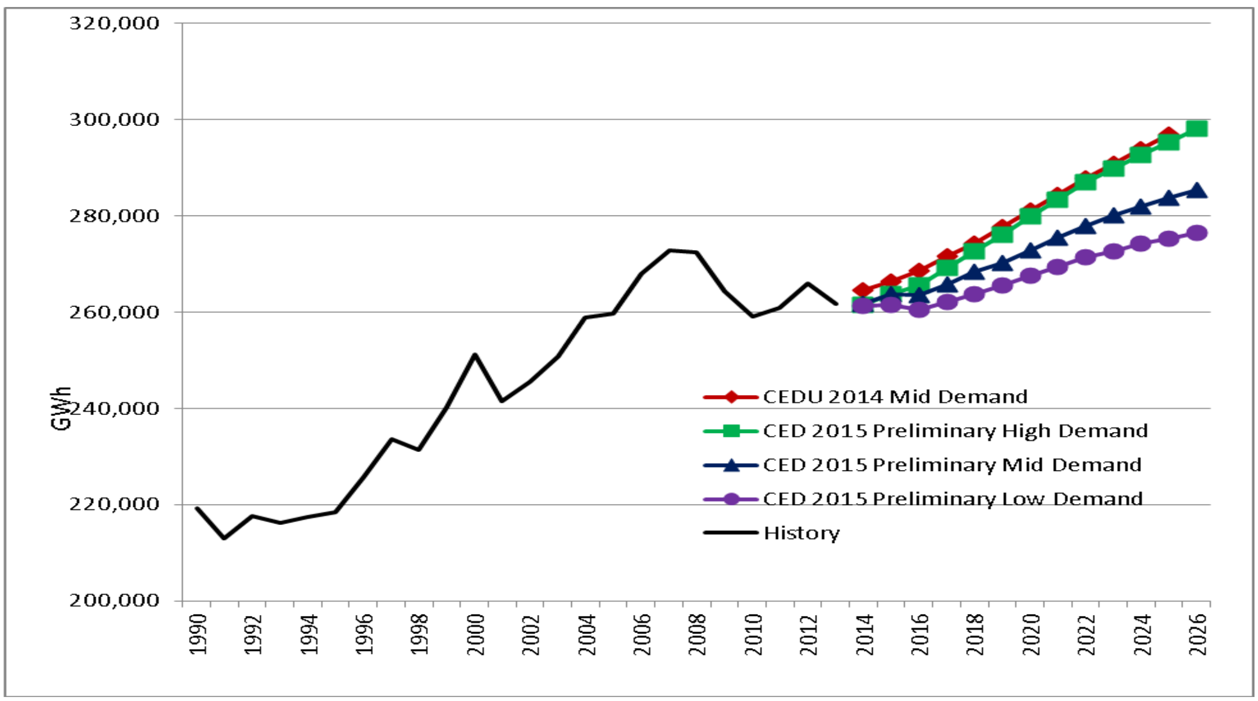
Figure 1: Statewide Baseline Annual Electricity Consumption



Source: California Energy Commission, Demand Analysis Office, 2015.

The significant increase in projected consumption met with self-generation in *CED 2015 Preliminary* as a result of more residential PV adoption reduces statewide electricity retail sales by a greater amount compared to *CEDU 2014* than consumption. Projected statewide sales for the three *CED 2015 Preliminary* cases and the *CEDU 2014* mid demand case are shown in **Figure 2**. All three new forecast cases are lower than the *CEDU 2014* mid case throughout the forecast period. By 2025, sales in the *CED 2015 Preliminary* mid scenario are projected to be around 13,300 GWh (4.4 percent) lower than in the *CEDU 2014* mid case. Annual growth from 2013-2025 for the *CED 2015 Preliminary* scenarios averages 1.01 percent, 0.68 percent, and 0.42 percent in the high, mid and low scenarios, respectively, compared to 1.06 percent in the *CEDU 2014* mid case.

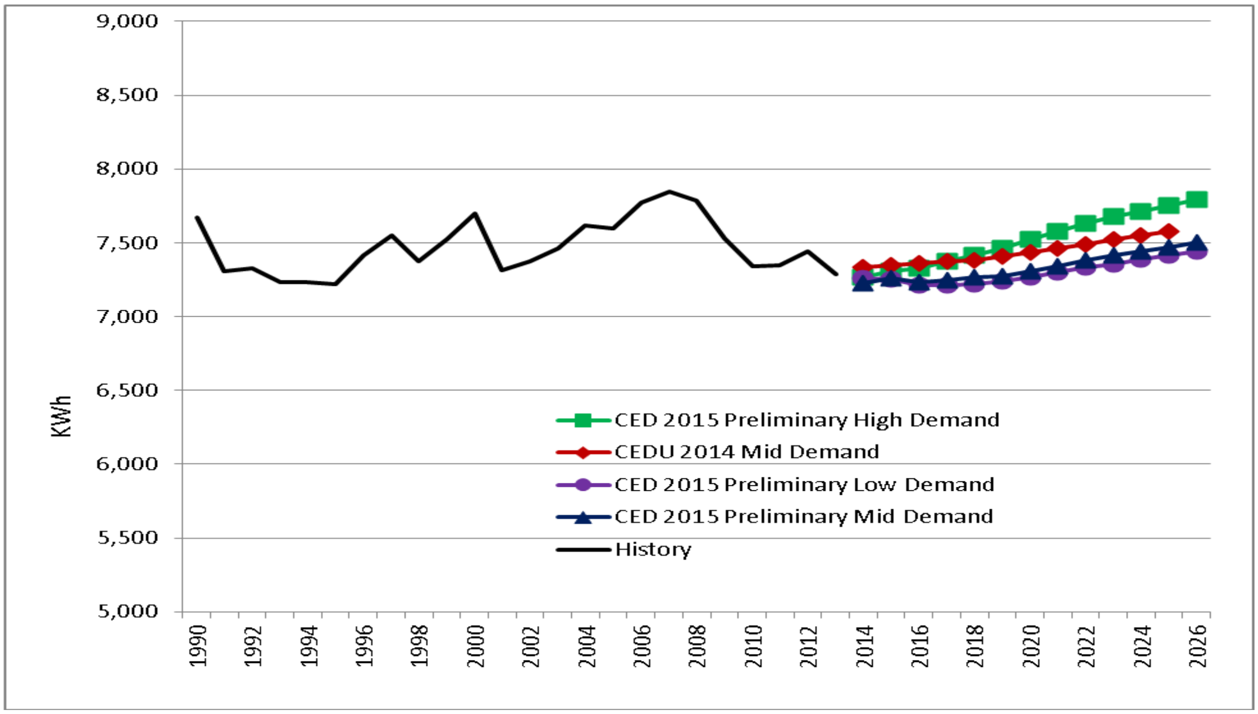
Figure 2: Statewide Baseline Retail Electricity Sales



Source: California Energy Commission, Demand Analysis Office, 2015.

As shown in **Figure 3**, *CED 2015 Preliminary* baseline per capita electricity consumption is projected to be relatively flat through 2018 in the low and mid cases because consumption is projected to grow at about the same rate as population. Thereafter, per capita consumption rises slightly due to increasing EV use. Higher economic/demographic growth in the high demand case combined with EVs increases per capita consumption throughout the forecast period. Higher population assumed in the *CED 2015 Preliminary* mid case compared to the low case offsets the difference in consumption so that the two projections are very similar. Less total electricity consumption in the new mid case combined with a slightly higher population reduces per capita consumption relative to the *CEDU 2014* mid case.

Figure 3: Statewide Baseline Electricity Annual Consumption per Capita



Source: California Energy Commission, Demand Analysis Office, 2015.

Projected baseline annual electricity consumption in each *CED 2015 Preliminary* case for the three major economic sectors—residential, commercial, and industrial (manufacturing, construction, and resource extraction)—is compared with the *CEDU 2014* mid demand case in **Table 2**. Residential consumption in the new mid case grows at a slower rate from 2013-2025 compared to *CEDU 2014* because of slightly lower projected growth in personal EVs resulting from adjustments for recent vehicle sales. Although the total light-duty EV forecast is lower than in *CEDU 2014*, a greater share of EVs are projected to be purchased in the commercial sector, which increases EV electricity consumption in this sector compared to *CEDU 2014*. This increase offsets reduced consumption from the update of standards, so that commercial consumption growth in the *CED 2015 Preliminary* mid case is almost identical to that in the *CEDU 2014* mid case. As in past forecasts, industrial electricity consumption is projected to be relatively flat, with similar growth projected in the new and older mid cases. The new high demand case is lower than the new mid for industrial electricity consumption in the early years of the forecast because projected manufacturing output, the key driver for industrial consumption, is lower during this period.

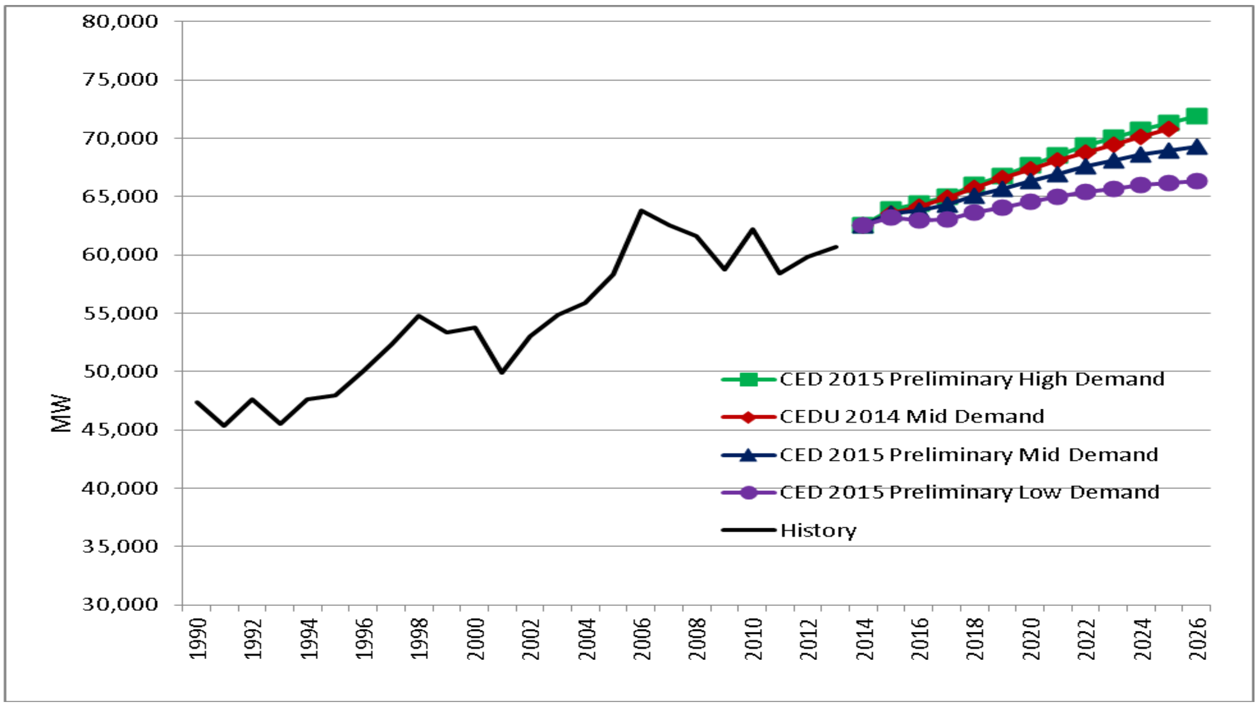
Table 2: Baseline Electricity Consumption by Sector

Residential Consumption (GWh)				
	CEDU 2014 Mid Energy Demand	***CED 2015 High Energy Demand***	***CED 2015 Mid Energy Demand***	***CED 2015 Low Energy Demand***
2013	87,527	87,527	87,527	87,527
2015	90,217	89,245	89,068	88,752
2020	97,608	98,139	96,514	95,474
2026	--	113,411	110,279	108,414
Average Annual Growth, Residential Sector				
2013-2020	1.57%	1.65%	1.41%	1.25%
2013-2025	1.83%	1.97%	1.75%	1.61%
2013-2026	--	2.01%	1.79%	1.66%
Commercial Consumption (GWh)				
	CEDU 2014 Mid Energy Demand	***CED 2015 High Energy Demand***	***CED 2015 Mid Energy Demand***	***CED 2015 Low Energy Demand***
2013	103,862	103,619	103,619	103,619
2015	105,966	106,742	106,200	105,019
2020	113,463	116,975	113,819	111,092
2026	--	126,852	122,405	118,772
Average Annual Growth, Commercial Sector				
2013-2020	1.27%	1.75%	1.35%	1.00%
2013-2025	1.23%	1.60%	1.31%	1.06%
2013-2026	--	1.57%	1.29%	1.06%
Industrial Consumption (GWh)				
	CED 2013 Mid Energy Demand	***CEDU 2014 High Energy Demand***	***CEDU 2014 Mid Energy Demand***	***CEDU 2014 Low Energy Demand***
2013	47,978	47,978	47,978	47,978
2015	48,391	48,165	48,898	48,611
2020	48,980	49,630	48,535	48,053
2026	--	51,172	49,105	48,712
Average Annual Growth, Industrial Sector				
2013-2020	0.30%	0.42%	0.30%	-0.37%
2013-2025	0.15%	0.42%	0.17%	-0.41%
2013-2026	--	0.44%	0.15%	-0.42%
Actual historical values are shaded.				

Source: California Energy Commission, Demand Analysis Office, 2015.

Projected *CED 2015 Preliminary* noncoincident peak demand for the three baseline cases and the *CEDU 2014* mid demand peak forecast is shown in **Figure 4**. By 2025, statewide peak demand in the new mid scenario is projected to be 2.4 percent lower than the *CEDU 2014* mid case. Annual growth rates from 2014-2025 for the *CED 2015 Preliminary* scenarios average 1.20 percent, 0.89 percent, and 0.52 percent in the high, mid, and low scenarios, respectively, compared to 1.13 percent in the *CEDU 2014* mid case. As with sales, higher projected self-generation reduces the growth rate in the new mid case compared to *CEDU 2014*. Relative to other demand loads, EVs have less impact on peak demand than consumption and sales, as staff assumes that most recharging occurs in off-peak hours.[8]

Figure 4: Statewide Baseline Annual Noncoincident Peak Demand

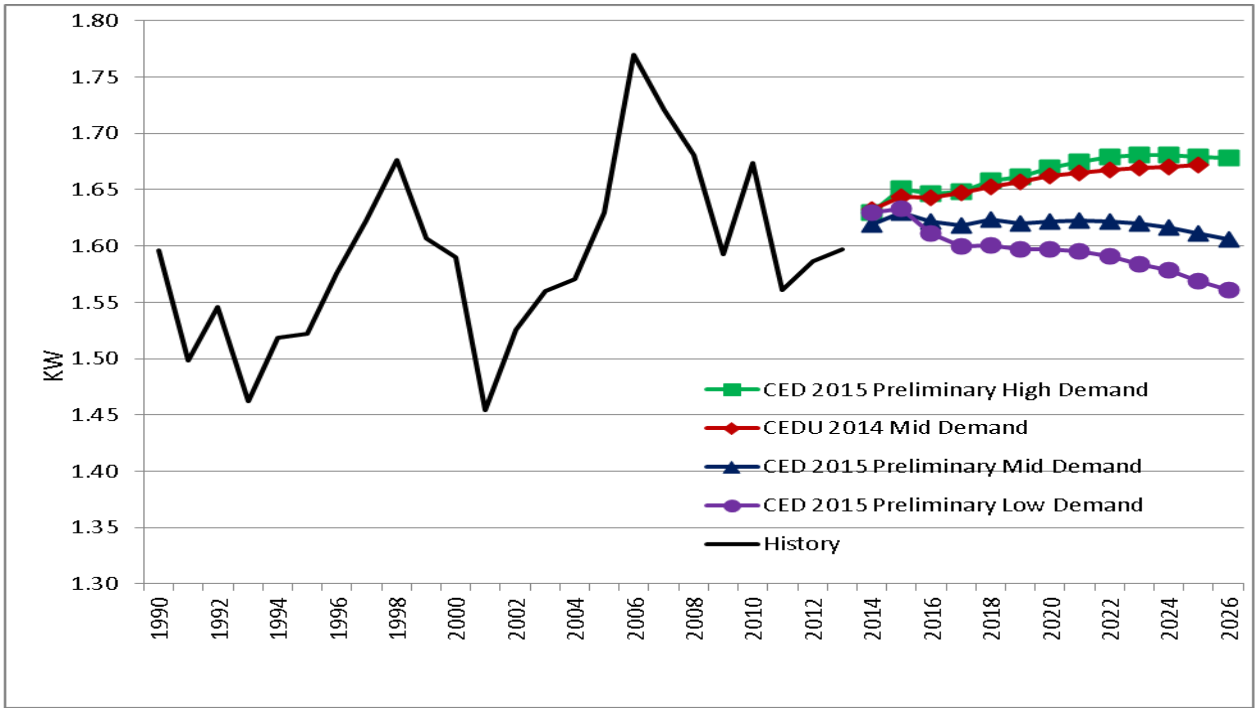


Source: California Energy Commission, Demand Analysis Office, 2015.

8 Staff assumed 75 percent of recharging would take place during off-peak hours (10 p.m. – 6 a.m.), with the rest evenly distributed over the remaining hours.

Statewide noncoincident peak demand per capita for the three *CED 2015 Preliminary* cases and the *CEDU 2014* mid case is shown in **Figure 5**. The significant increase in peak demand met by self-generation leads to declining demand per capita in the mid and low cases throughout the forecast period, unlike previous forecasts. In the high demand case, faster economic growth combined with less self-generation results in increasing peak demand per capita, similar to the *CEDU 2014* mid case.

Figure 5: Statewide Baseline Annual Noncoincident Peak Demand per Capita



Source: California Energy Commission, Demand Analysis Office, 2015

Method

Although the methods to estimate energy efficiency impacts and self-generation have undergone refinement, *CED 2015 Preliminary* uses the same technical methods as previous long-term staff demand forecasts: detailed sector models supplemented with single equation econometric models. A full description of the sector models is available in a staff report.[9]

9 http://www.energy.ca.gov/2005publications/CEC-400-2005-036/CEC-400-2005-036.PDF .

Geographic Scheme

Staff energy demand forecasts have traditionally been developed for 8 specific planning areas based on utility boundaries and, in *CED 2013* and *CEDU 2014*, 16 climate zones. However, to better serve users of this forecast, staff has modified the planning area scheme for *CED 2015 Preliminary*. The new scheme is more closely based on California's electricity balancing authorities, the geographic levels where fundamental resource planning is made.

The key differences come in the Southern California Edison (SCE) and Pacific Gas and Electric (PG&E) planning areas. These areas now coincide with the SCE and PG&E transmission access charge (TAC) areas.[10] For the SCE planning area, this change is straightforward: the Pasadena planning area and California Department of Water Resources (DWR) operations in Southern California are simply added to the previous version of the planning area.[11] Modification to the PG&E planning area required extracting Northern California load-serving entities, such as the Merced and Modesto Irrigation Districts, not affiliated with the California ISO.[12] The extracted utilities, together with the Sacramento Municipal Utility District (SMUD), form a new planning area, referred to as Northern California Non-California ISO (NCNC). NCNC includes two balancing authorities: the Turlock Irrigation District and the Balancing Authority of Northern California (BANC). The Los Angeles Department of Water and Power (LADWP), Burbank-Glendale (BUGL), Imperial Irrigation District (IID), and San Diego Gas & Electric (SDG&E) planning areas remain as before. Valley Electric Association, as a separate California ISO TAC area, becomes the eighth planning area. The load-serving entities included in each planning area are shown in **Table 3**.

---

10 A *transmission access charge* (TAC) area is a portion of the California ISO controlled grid where transmission revenue requirements are recovered through an access charge. The California ISO is composed of 4 TAC areas: SCE, PG&E, San Diego Gas & Electric, and Valley Electric Association.

11 Staff already provides separate forecasts for these two entities.

12 In addition, DWR operations in Southern California are part of the modified PG&E planning area.

Table 3: Load-Serving Entities Within Forecasting Planning Areas

Planning Area	Utilities Included
PG&E	PG&E Alameda Biggs Calaveras Department of Water Resources (North) Gridley Healdsburg Hercules Island Energy Lassen Lodi Lompoc Palo Alto Plumas – Sierra Port of Oakland Port of Stockton Power and Water Resources Pooling Authority San Francisco Silicon Valley Tuolumne Ukiah Central Valley Project (California ISO operations)
SCE	Anaheim Anza Azusa Banning Bear Valley Colton Corona Department of Water Resources (South) Metropolitan Water District Moreno Valley Pasadena Rancho Cucamonga Riverside SCE U.S. Bureau of Reclamation-Parker Davis Vernon Victorville
SDG&E	SDG&E
NCNC	Merced Modesto Redding Roseville Shasta SMUD Turlock Irrigation District Central Valley Project (BANC operations)
LADWP	LADWP
BUGL	Burbank, Glendale
IID	IID
VEA	VEA

Source: California Energy Commission, Demand Analysis Office, 2015.

As part of a continuing effort to increase geographic granularity in the forecast results, staff increased the number of forecasting climate zones from 16 to 20, changing many of the definitions. Climate zones within the California ISO balancing authority were constructed to approximate California ISO transmission "zones."[13] Staff can only approximate these zones since they are based on physical infrastructure, while the demand forecast is constrained by

13 For a description of these zones, see, for example, http://www.caiso.com/Documents/Board-Approved2013-2014TransmissionPlan_July162014.pdf.

political boundaries (for example, counties) in the input data. For NCNC, SMUD was assigned a separate climate zone. The new forecasting climate zones are described in **Table 4** by listing the counties (or parts thereof) included in each forecasting zone.[14]

Table 4: New Energy Commission Planning Area/Forecast Zone Scheme by County

Planning Area	Forecast Zone	Counties Included
1. PG&E	1. Greater Bay Area	Alameda, Contra Costa, San Francisco, San Mateo, Santa Clara
	2. North Coast	Lake, Humboldt, Marin, Mendocino, Napa, Sonoma
	3. North Valley	Butte, Glenn, Lassen, Plumas, Shasta, Sierra, Siskiyou, Tehama, Trinity
	4. Central Valley	Alpine, Amador, Calaveras, Colusa, El Dorado, Nevada, Placer, Sacramento, San Joaquin, Solano, Stanislaus, Sutter, Tuolumne, Tulare, Yolo, Yuba
	5. Southern Valley	Fresno, Kern, Kings, Madera, Mariposa, Merced
	6. Central Coast	Monterey, San Benito, San Luis Obispo Santa Barbara, Santa Cruz
2. SCE	7. LA Metro	Orange, Los Angeles
	8. Big Creek West	Santa Barbara, Ventura
	9. Big Creek East	Fresno, Kern, Kings, Tuolumne, Tulare
	10. Northeast	Inyo, Mono, San Bernardino
	11. Eastern	Imperial, Riverside
3. SDG&E	12. SDG&E	Orange, San Diego
4. NCNC	13. SMUD Service Territory	Sacramento
	14. Turlock Irrigation District	Merced, Stanislaus, Tuolumne
	15. Rest Of BANC Control Area	Merced, Placer, San Joaquin, Shasta, Stanislaus,
5. LADWP	16. Coastal	Los Angeles
	17. Inland	Los Angeles, Inyo
6. Burbank/Glendale	18. Burbank/Glendale	Los Angeles
7. Imperial Irrigation District	19. Imperial Irrigation District	Imperial
8. Valley Electric	20. Valley Electric	Inyo, Mono

Source: California Energy Commission, Demand Analysis Office, 2015.

The sector forecasting models have not yet been fully transitioned to the new planning area scheme, but this presents an issue only for PG&E and NCNC. Staff used econometric models to develop a forecast for the new NCNC planning area by sector, and these projections (minus SMUD) were subtracted from the PG&E planning area results produced by the sector models.

14 Staff is developing a geographic-information-system-based map to better illustrate the forecasting zones.

As in previous forecasts, climate zone projections were developed with econometric models, benchmarked to the new planning area results. The econometric models are presented in Appendix A of this report.

Economic and Demographic Inputs

Projections for statewide economic and demographic growth are summarized here. More detail, at the statewide level as well as for each planning area, is provided in the demand forms accompanying this report.[15] As in previous forecasts, staff relied on Moody's Analytics and IHS Global Insight to develop the economic growth scenarios to drive the three *CED 2015 Preliminary* demand cases. Demographic inputs relied on these two sources as well as the California Department of Finance (DOF).

Staff used the IHS Global Insight *Optimistic* economic scenario for the high demand case and Moody's Analytics *Below-Trend Long-Term Growth* case for the low demand case. Moody's Analytics *Baseline* economic forecast was used for the mid energy demand case. For population and households, the low case comes from the DOF's 2015 long-term projections, the mid case from Moody's Analytics, and the high from IHS Global Insight. The key assumptions used by Moody's Analytics and IHS Global Insight to develop the three economic scenarios are provided in **Table 5**.

15 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03.

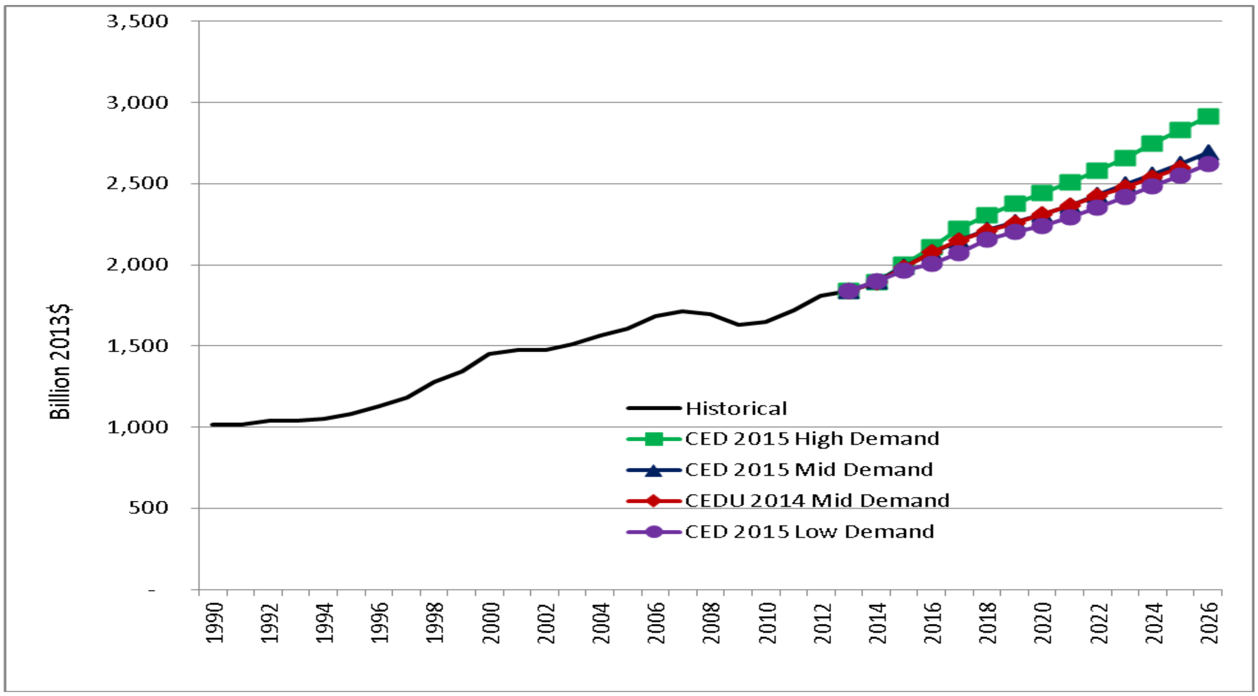
Table 5: Key Assumptions Embodied in *CED 2015 Preliminary* Economic Cases

High Demand Case (IHS Global Insight *Optimistic* Scenario), February 2015	**Mid Demand Case (Moody's Analytics *Baseline* Scenario), February 2015**	**Low Demand Case (Moody's Analytics *Below-Trend Long-Term Growth* Scenarios), February 2015**
National unemployment rate falls to 4.1 percent by 2018.	National unemployment rate stays below 5 percent through 2018.	The unemployment rate stays higher than in the baseline, at nearly 6%, until early 2018.
European Central Bank's (ECB) quantitative easing successfully steers the Eurozone away from its current economic malaise. Eurozone growth strengthens more than in the baseline as fiscal conditions improve, credit conditions ease, and pent-up demand is released. The euro appreciates in response to the ECB's policy changes, as well as to changes in interest rates and economic performance.	The Federal Reserve will normalize U.S. monetary policy by late 2017, but the European Central Bank will not be able to normalize policy until near decade's end. While the long-run fair value euro/dollar exchange rate is an estimated $1.25, the euro is expected to fall as low as parity with the dollar.	The Eurozone recovery is slower than expected. Therefore, gains in U.S. exports are slow.
National light-duty vehicles sales reach more than 18.2 million in 2016.	National light-duty vehicle sales are above 16.5 million in 2016.	National light-duty vehicle sales decline to 16.2 million in 2016.
Same as the mid scenario.	National housing starts break 1.4 million units by 2016.	National housing starts decline to 1.3 million units by 2016.
The current drivers of the oil-price decline continue: OPEC producers protecting market share, U.S. production gains continue, and non-U.S. economic growth improves. Oil prices start to pick up gradually, starting in late 2015.	Oil prices are expected to bottom out near current levels and slowly make their way back. In the long run, oil and gasoline prices are expected to trend higher, increasing at a pace that is just above the overall rate of inflation. Prices are expected to top $100 per barrel again sometime early in the next decade.	Same as the mid scenario.
The Federal Reserve raises short-term interest rates in the second half of 2015.	The Federal Reserve raises short-term interest rates in mid 2015.	The Federal Reserve raises short-term interest rates in the fourth quarter of 2015.

Source: Moody's Analytics and IHS Global Insight, 2015

Historical and projected personal income at the statewide level for the three *CED 2015 Preliminary* cases and the *CEDU 2014* mid demand case is shown in **Figure 6**.[16] The new mid and low cases are similar to the *CEDU 2014* mid case throughout the forecast period, with the new mid case around 1 percent higher than *CEDU 2014* mid in 2025. Annual growth rates from 2013-2025 average 3.66 percent, 3.01 percent, and 2.77 percent in the *CED 2015 Preliminary* high, mid, and low cases, respectively, compared to 2.92 percent in the *CEDU 2014* mid case.

Figure 6: Statewide Personal Income

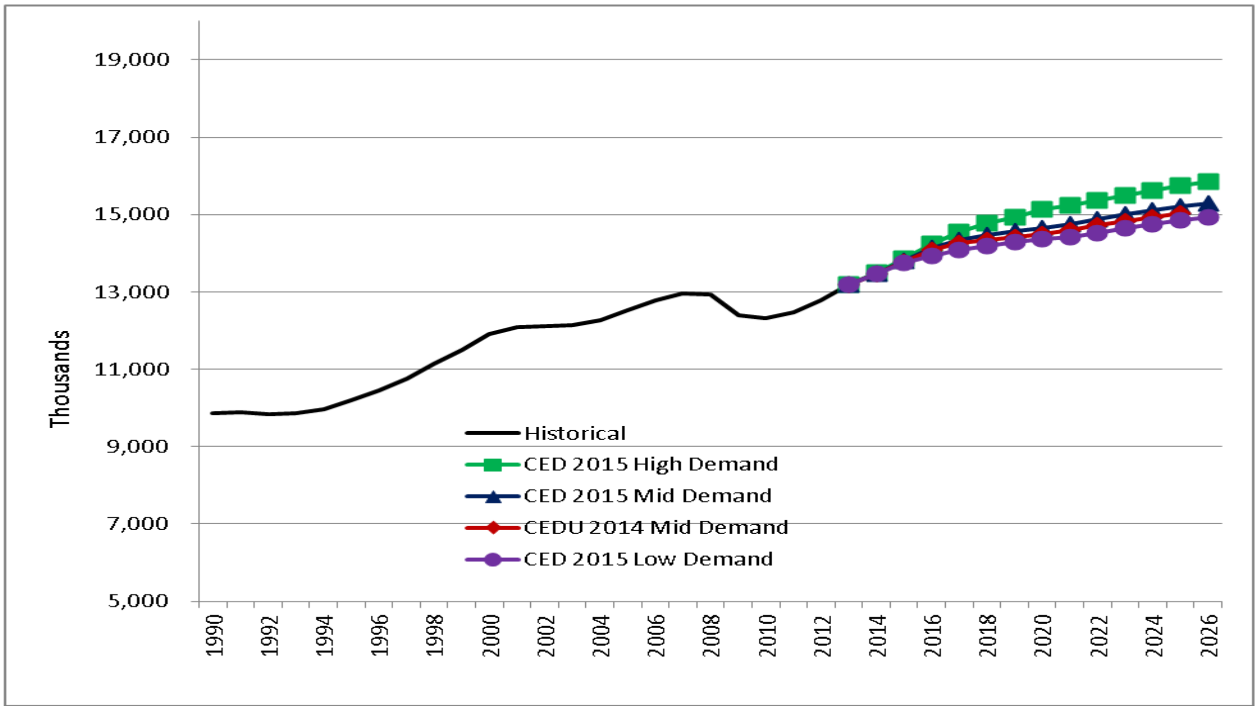


Sources: Moody's Analytics and IHS Global Insight, 2014-2015.

16 To account for periodic revisions to the historical data by Moody's Analytics and IHS Global Insight, the *CEDU 2014* mid economic case in this section is scaled so that levels match those used in *CED 2015 Preliminary* in 2013.

As shown in **Figure 7**, projections for statewide commercial employment[17] in the *CED 2015 Preliminary* mid and low cases are also similar to the *CEDU 2014* mid case, with the difference between the new and old mid cases again around 1 percent in 2025. Annual growth rates from 2013-2025 average 1.49 percent, 1.20 percent, and 1.00 percent in the *CED 2015 Preliminary* high, mid, and low cases, respectively, compared to 1.09 percent in the *CED 2013* mid case.

Figure 7: Statewide Commercial Employment

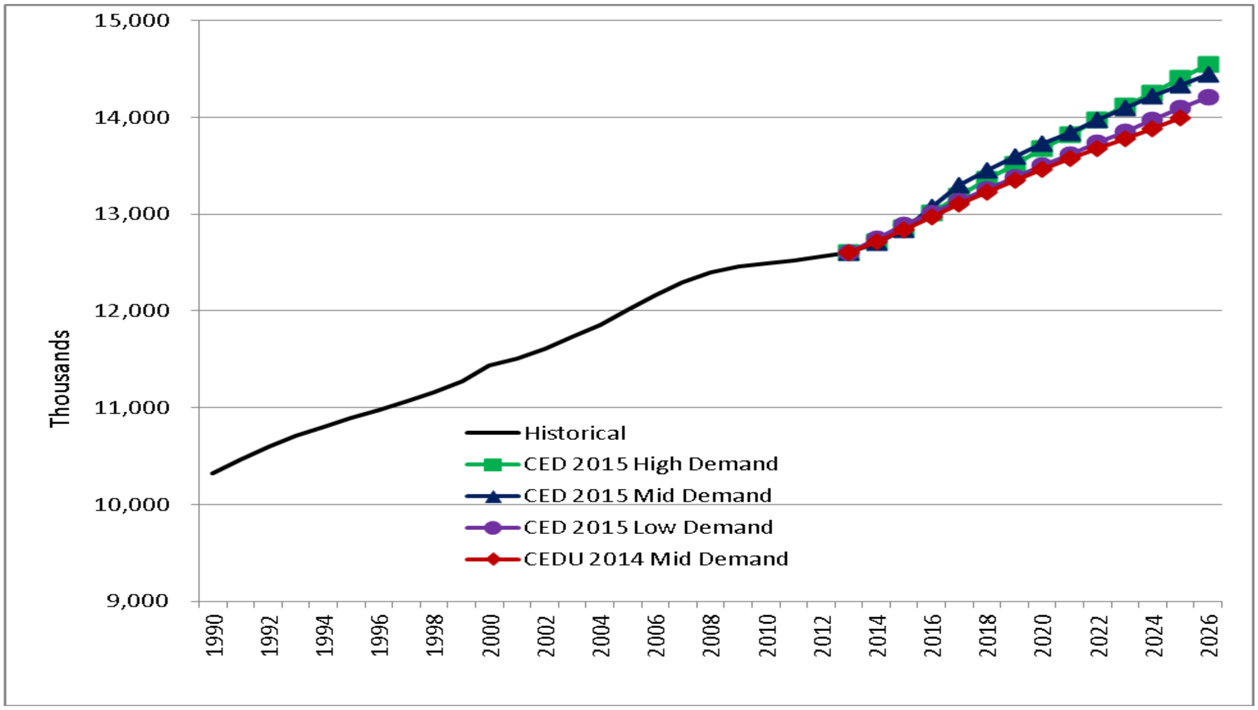


Sources: Moody's Analytics and IHS Global Insight, 2014-2015.

17 Total employment minus employment in the industrial and agricultural sectors. Commercial employment is a key driver for floor space projections used in the commercial forecasting model.

Projections for the number of California households, the key driver for the residential forecast, are shown in **Figure 8**. All three *CED 2015 Preliminary* cases project a higher number of households compared to the *CEDU 2014* mid case throughout the forecast period. This result derives from anticipated reductions in persons per household in California, consistent with assumptions from Moody's Analytics, IHS Global Insight, and DOF. In 2025, the number of households in the new mid case is around 2.5 percent higher than in *CEDU 2014* mid.

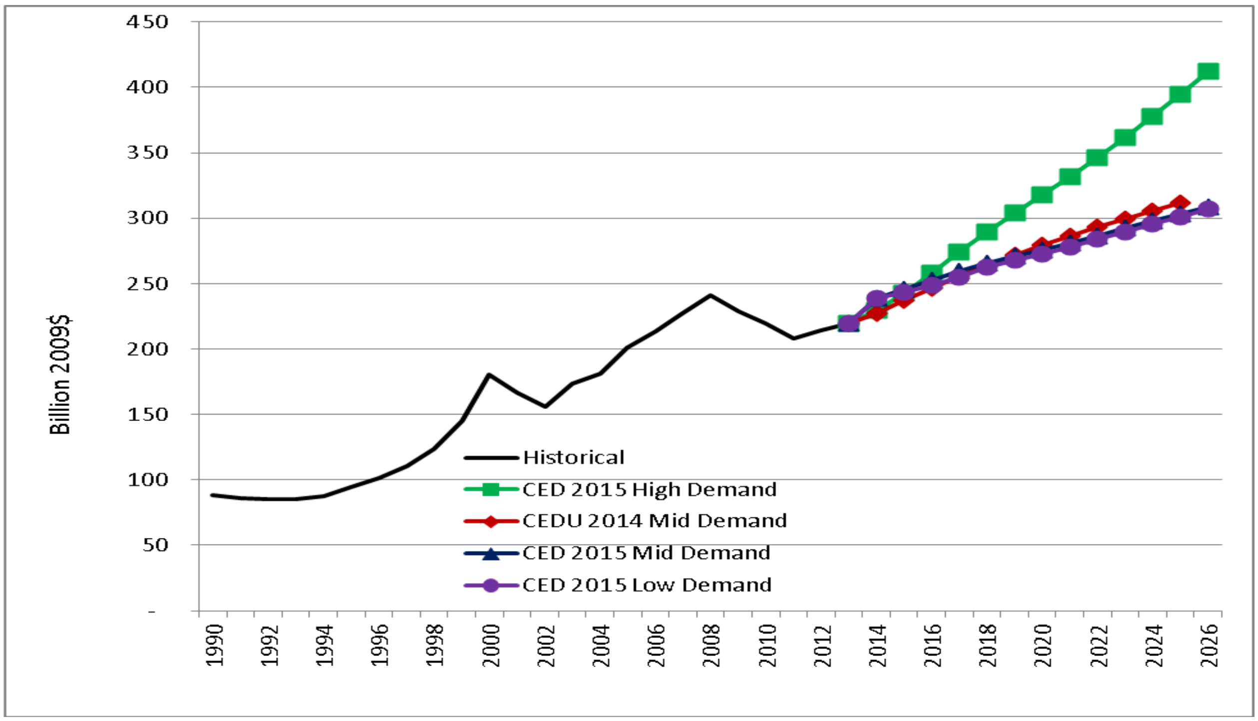
Figure 8: Statewide Number of Households



Sources: California Department of Finance, Moody's Analytics and IHS Global Insight, 2014-2015.

Historical and projected statewide manufacturing dollar output, a key driver for the industrial forecast, is shown in **Figure 9**. As in the cases of personal income and commercial employment, the *CED 2015 Preliminary* low and mid cases are similar to the *CEDU 2014* mid case. The high demand case from IHS Global Insight assumes a much more optimistic future for manufacturing in California compared to Moody's Analytics, as in previous forecasts. Annual growth rates from 2013-2025 average 5.01 percent, 2.72 percent, and 2.66 percent in the *CED 2015 Preliminary* high, mid, and low cases, respectively, compared to 2.96 percent in the *CED 2013* mid case.

Figure 9: Statewide Manufacturing Output



Sources: Moody's Analytics and IHS Global Insight, 2014-2015.

Electricity Rates

Electricity rate scenario cases used in *CED 2015 Preliminary* were developed using a new staff electricity rate model estimated by the Energy Commission's Supply Analysis Office. The model uses a set of simultaneous equations to estimate future revenue requirements, allocate them to rate classes, and calculate annual average class rates. For *CED 2015 Preliminary*, the model was run for each of the three IOU service areas and results used to represent the IOU planning areas. Rates for non-IOU planning areas were calculated from the growth rates from the IOU area corresponding to the same natural gas hub, after calibrating to actual 2013 average rates. For the revised version of this forecast, staff plans to develop rates independently for the non-IOU areas.

The largest component of electric revenue requirements is the cost of procuring electricity supply. This includes purchased power, capital expenditures, and fuel and operating costs for utility-owned resources. To estimate procurement costs, staff first estimated energy production and costs for existing resources, either owned or under long-term contract. In the next step, the costs of additional energy and capacity needed to meet the Renewables Portfolio Standard targets, serve load, and ensure reliability are estimated. After Renewables Portfolio Standard targets are met, the residual need is assumed to be purchased at the prevailing wholesale electricity price. This price is estimated using natural gas price projections developed by Supply Analysis Office staff using the North American Gas-Trade Model. The wholesale market price must also incorporate the cost of carbon emission allowances; Supply Analysis Office staff has developed carbon allowance price projections for the *2015 Integrated Energy Policy Report* (*2015 IEPR*) based on recent auction results and analysis by the California Air Resources Board Emissions Market Assessment Committee and the Market Simulation Group.[18]

Distribution revenue requirements are driven primarily by the capital investment needed to maintain and expand the distribution system and supporting infrastructure. Current data on adopted distribution revenue requirements, collected from utility advice filings, financial statements, and CPUC decisions are incorporated into the model. After the current term of adopted revenue requirements, distribution capital (the rate base upon which IOUs earn a rate of return) is assumed to grow at a nominal rate of 8 percent annually, consistent with recent trends. Total distribution revenue requirements, including depreciation, operation and maintenance, and other costs, are projected to increase by around 3 to 4 percent annually, in real dollars.

Transmission revenue requirements are based on projections from the California ISO 2013-2014 Transmission Planning Process.[19] These includes renewables integration projects and ongoing reliability upgrades. This component of rates is projected to increase at an average of 2.2 percent annually in real terms.

The model was used to generate mid, high and low electricity rate cases based on varying electricity demand and natural gas prices. For electricity demand, *CEDU 2014* demand forecasts (high, mid, and low cases) were used. The low rate case (used for the high demand case in *CED 2015 Preliminary*) assumes essentially flat natural gas prices. In the mid rate case, natural gas prices are projected to increase on average 3.7 percent per year, while the high rate case (*CED 2015 Preliminary* low demand case) assumes natural gas prices increase by 5 percent per year.

---

18 See http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN203794_20150309T125148_Preliminary_2015_IEPR_Carbon_Price_Projections_Assumptions.xlsx for 2015 Preliminary IEPR GHG Price Scenarios. “Forecasting Supply and Demand Balances in California's Greenhouse Gas Cap-and-Trade Market,” March 12, 2013, at http://www.arb.ca.gov/cc/capandtrade/simulationgroup/msg_final_v25.pdf.

19 California ISO 2014 Transmission Access Charge Forecast Model, April 2014. http://www.caiso.com/Documents/2013-2014TransmissionAccessChargeModel.xlsx.

All three cases reflect a decline in natural gas prices in 2015, based on current data, with prices rebounding in 2016. Growth in the natural gas prices in the mid and high rate cases is being driven by tempered production across North America through the forecast period along with demand growth in the industrial and generation sectors, particularly in Southern California.

Projected electricity rates for each IOU planning area for selected years for the three major sectors by demand case are shown in **Table 6**. A full listing of historical and projected rates by planning area is available in the demand forms accompanying this report.[20] The impact of increasing rates on the forecast is determined by model price elasticities of demand,[21] which average about 10 percent across the sectors.

Table 6: Rates by Demand Case for IOU Planning Areas (2013 cents per kWh)

	Residential			Commercial			Industrial		
Year	High Demand	Mid Demand	Low Demand	High Demand	Mid Demand	Low Demand	High Demand	Mid Demand	Low Demand
PG&E									
2013	16.79	16.79	16.79	14.99	14.99	14.99	11.21	11.21	11.21
2015	16.87	17.10	17.99	15.06	15.26	16.06	11.27	11.42	12.01
2020	18.53	19.94	21.26	16.54	17.80	18.98	12.37	13.32	14.19
2026	18.83	20.64	22.38	16.81	18.42	19.98	12.57	13.78	14.95
SCE									
2013	16.58	16.58	16.58	13.86	13.86	13.86	10.82	10.82	10.82
2015	16.40	17.49	18.66	13.71	14.62	15.60	10.71	11.42	12.18
2020	17.23	19.92	21.75	14.40	16.65	18.18	11.25	13.01	14.20
2026	17.76	20.99	23.46	14.84	17.55	19.61	11.59	13.71	15.32
SDG&E									
2013	17.35	17.35	17.35	15.47	15.47	15.47	10.69	10.69	10.69
2015	17.70	18.04	19.28	15.77	16.08	17.18	10.90	11.11	11.87
2020	18.11	20.07	22.01	16.14	17.89	19.62	11.15	12.36	13.56
2026	18.28	20.80	23.66	16.30	18.54	21.09	11.26	12.81	14.57

Source: California Energy Commission, Supply Analysis Office, 2015.

20 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03.

21 A price elasticity of demand measures the percentage change in demand induced by a given percentage change in price. An elasticity of 10 percent means, for example, that a doubling of prices would be expected to reduce demand by 10 percent, all else equal.

Self-Generation

As in previous forecasts, *CED 2015 Preliminary* attempts to account for all major programs designed to promote self-generation, building up from sales of individual systems. Incentive programs include:

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

The ERP and NSHP are managed by the Energy Commission, and the CSI and SGIP by the CPUC. The forecast also accounts for power plants reporting information to the Energy Commission. The principal source is Form CEC 1304.[22] Staff included only power plants that explicitly listed themselves as operating under cogeneration or self-generation mode.

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

Residential PV and solar water heating adoption are forecast using a predictive model developed in 2011, based on estimated payback periods and cost-effectiveness, determined by upfront costs, energy rates, and incentive levels. For *CED 2015 Preliminary*, staff modeled residential rates for the IOUs using the existing tier structure and estimated hourly load patterns rather than assuming average rates/usage as in past forecasts. This change resulted in a significant increase in projected adoption of PV systems, as shown below. Staff has not yet made these modifications for the POU planning areas.

Commercial PV adoption is modeled similarly to residential, with adoptions developed by building type (hospitals, schools, and so on). The same predictive model is used to forecast commercial combined heat and power (CHP) technologies, employing estimated load shapes by building type. Results for adoption in both the commercial and residential sectors differ by demand scenario since projected electricity and natural gas rates and number of homes varies across the scenarios. Lower electricity demand corresponds to higher adoptions; the effect from higher rates outweighs lower growth in households. Self-generation for other technologies and sectors is projected using a trend analysis and does not vary by demand scenario. Appendix B provides much more detail on the self-generation modeling method.

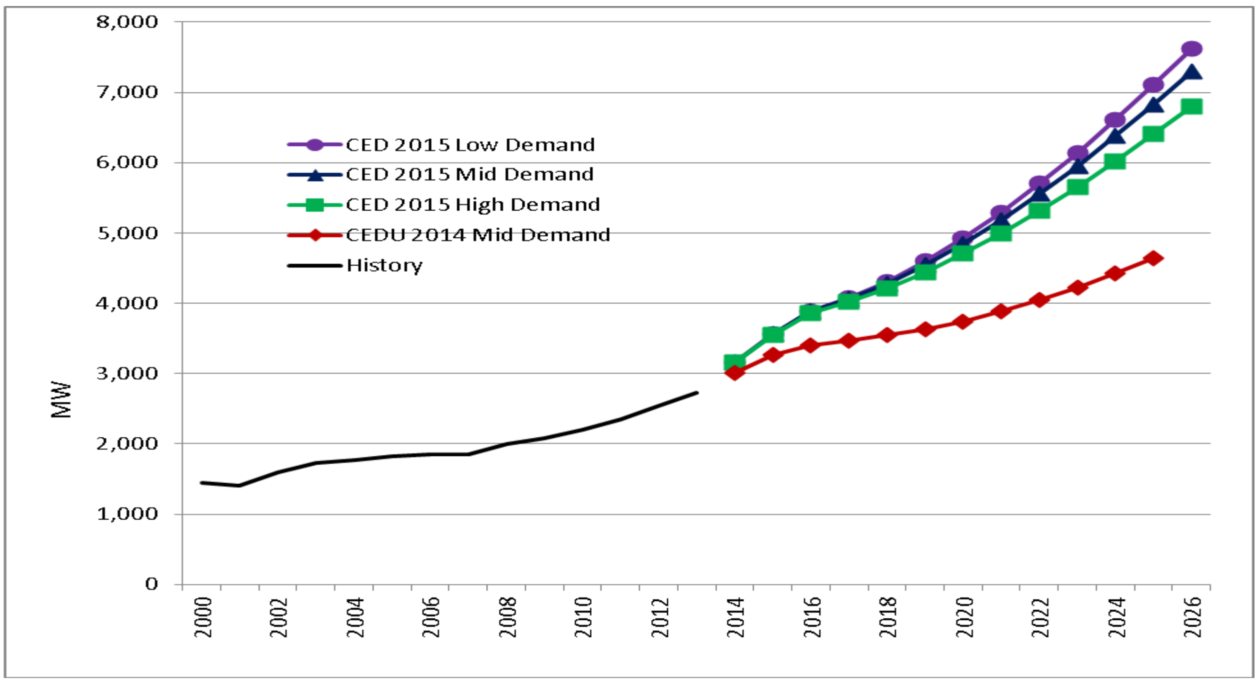
---

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

Historical and projected peak reduction impacts of self-generation for the three *CED 2015 Preliminary* demand cases and the *CEDU 2014* mid case are shown in **Figure 10**. Self-generation is projected to reduce peak load by more than 6,800 MW in the new mid case by 2025, an increase of more than 2,000 MW compared to *CEDU 2014*. Residential PV is responsible for this increase, as shown in **Figure 11**. By 2026, residential PV peak impacts reach more than 3,600 MW in the *CED 2015 Preliminary* mid case, corresponding to more than 10,000 MW of installed capacity.

The demand forms accompanying this report[23] provide annual results for energy and peak impacts for each planning area and statewide.

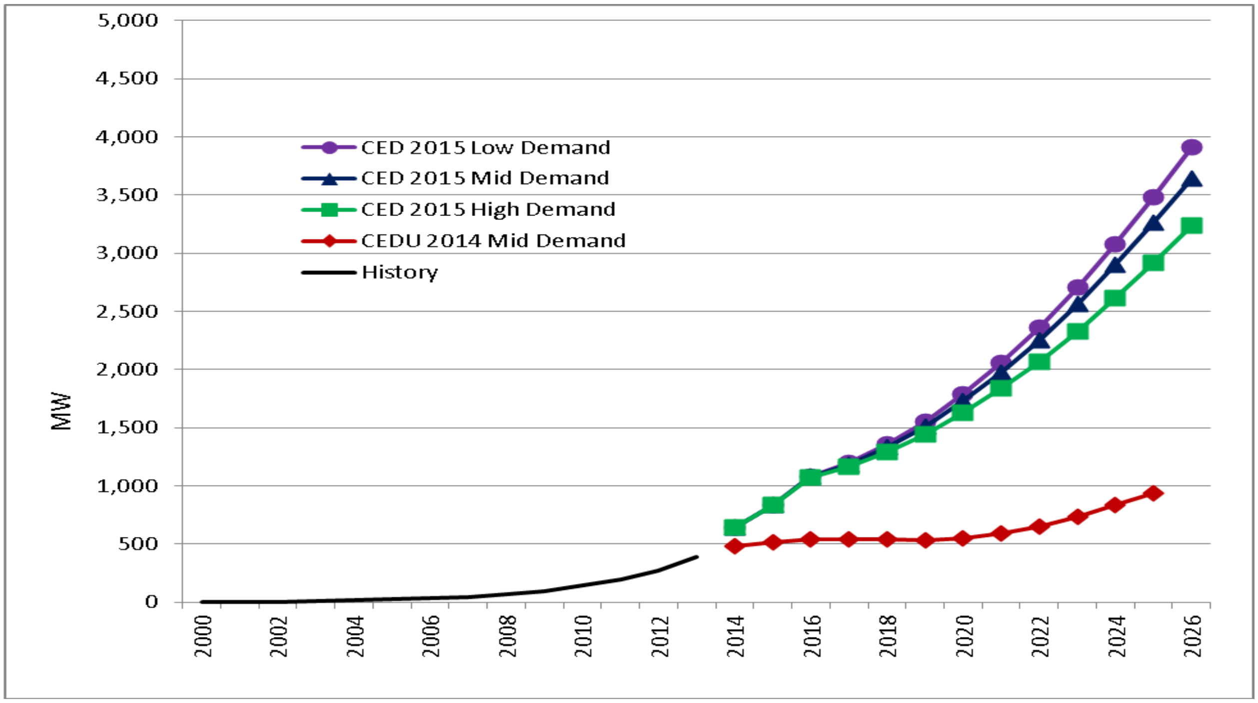
Figure 10: Statewide Self-Generation Peak Reduction Impact



Source: California Energy Commission, Demand Analysis Office, 2015.

23 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03.

Figure 11: Statewide Residential PV Peak Reduction Impact



Source: California Energy Commission, Demand Analysis Office, 2015.

Conservation/Efficiency Impacts

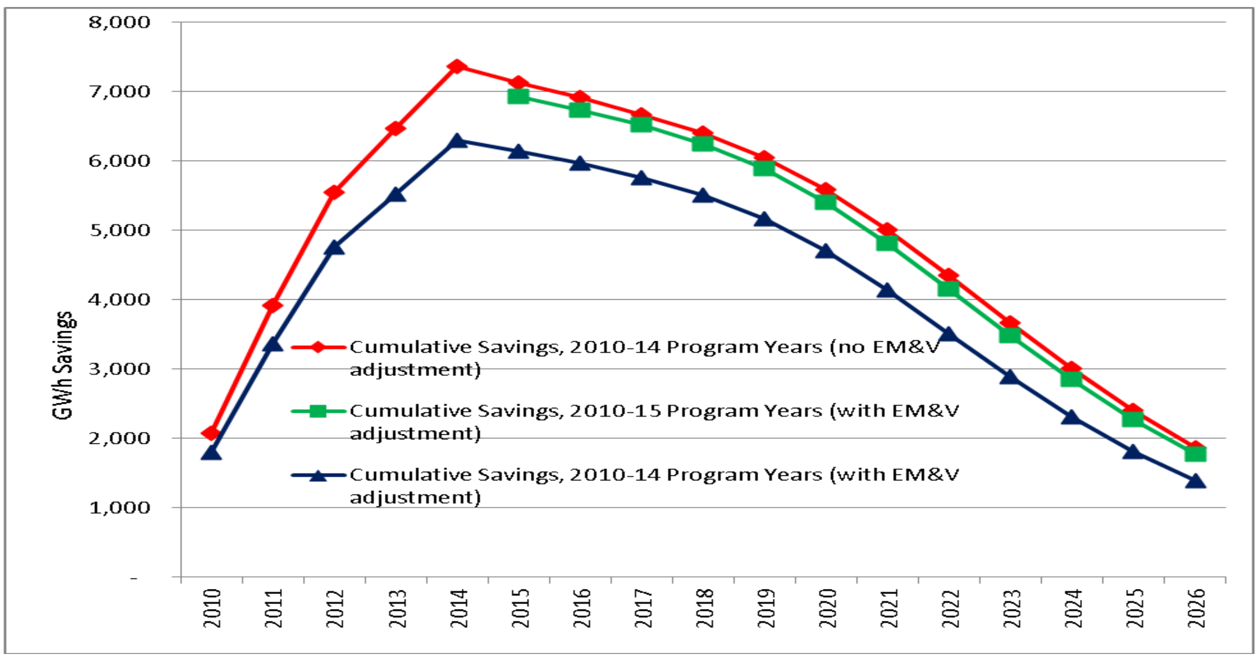
Energy Commission demand forecasts seek to account for efficiency and conservation *reasonably expected to occur.* Reasonably expected to occur initiatives have been split into two types: committed and additional achievable energy efficiency. The *CED 2015 Preliminary* baseline forecasts continue that distinction, with only committed efficiency included. Committed initiatives include utility and public agency programs, codes and standards, and legislation and ordinances having final authorization, firm funding, and a design that can be readily translated into characteristics capable of being evaluated and used to estimate future impacts (for example, a package of IOU incentive programs that has been funded by CPUC order). In addition, committed impacts include price and other market effects not directly related to a specific initiative.

No new Energy Commission standards have been implemented since *CED 2013;* the revised version of this forecast will incorporate a new set of appliance standards, approved in May 2015. The revised forecast will also include estimated historical and projected savings from all implemented building and appliance standards.[24]

24 Due to lack of time, staff is not able to provide these estimates for *CED 2015 Preliminary*.

CED 2015 Preliminary includes estimated committed efficiency impacts not included in *CEDU 2014*, from 2015 IOU programs and from 2014 programs administered by POUs. In addition, staff has revised downward the estimated savings from 2010-2014 IOU programs based on the most recent CPUC Evaluation, Measurement, and Verification (EM&V) study.[25] The study showed that actual realization of savings was below that anticipated for the 2010-2012 IOU programs, and staff applied adjustment factors to 2010-2015 savings embedded in the forecast to account for this difference. The impact of these adjustments on the 2010-2014 accumulated net (of free ridership) program savings incorporated in *CEDU 2014* is shown in **Figure 12**. The difference reaches a maximum of more than 1,000 GWh in 2015. Also shown in **Figure 12** is the impact of the addition of 2015 program year savings (also adjusted by EM&V results), which offset the reduction in 2010-2014 savings almost exactly.

Figure 12: Adjusted IOU Efficiency Program Savings, 2010-2026



Source: California Energy Commission, Demand Analysis Office, 2015.

A demand forecast for resource planning requires a baseline forecast combined with additional achievable energy efficiency savings; savings not yet considered committed but deemed likely to occur, including impacts from future updates of building codes and appliance standards and utility efficiency programs expected to be implemented after 2015. For the revised forecast, additional achievable energy efficiency impacts for the IOUs will be incorporated, based on the

25 http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/EM+and+V/Energy_Efficiency_2010-2012_Evaluation_Report.htm.

CPUC's ongoing *2015 California Energy Efficiency Potential and Goals Study*.[26] In addition, the revised forecast will incorporate staff estimates of POU additional achievable energy efficiency savings.

Light-Duty Plug-In Electric Vehicles

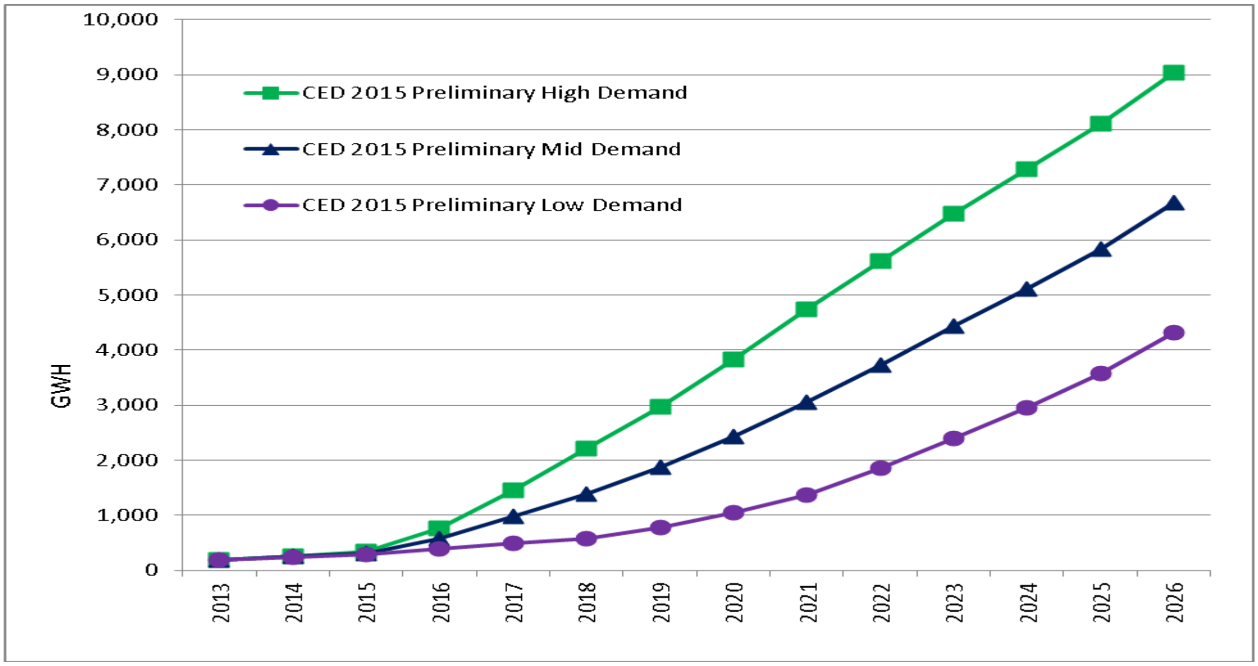
CED 2015 Preliminary incorporates scenarios for electric vehicle fuel consumption based on scenarios developed by the Energy Commission's Transportation Energy Forecasting Unit in early 2012. These scenarios have been updated and incorporated into the *CED 2013* and the *CEDU 2014*. Light-duty EV purchases are comparable to *CEDU 2014* having only been adjusted by near term sales. Details on these scenarios are available in the report for the *California Energy Demand 2012-2022 Final Forecast* (*CED 2011*).[27] The low case for EVs was developed to be consistent with a scenario that matches with a "most-likely" compliance scenario developed by California Air Resources Board staff. The revised forecast will consider feedback and comments from the June 24, 2015 workshop on the preliminary transportation energy forecast. The resulting projected electricity usage in the three *CED 2015 Preliminary* cases are shown in **Figure 13** and is slightly lower than *CEDU 2014* reflecting an adjustment for recent vehicles sales information.

---

26 Information available at http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Energy+Efficiency+Goals+and+Potential+Studies.htm.

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

Figure 13: Light-Duty EV Electricity Consumption



Source: California Energy Commission, Demand Analysis Office, 2015.

The statewide EV forecast was distributed to planning areas and climate zones using regression analysis. EV ownership by county from Department of Motor Vehicle records was specified as a function of per capita income and whether the county could be considered mainly urban or rural. Predicted county results for the forecast period were then mapped to the planning areas and climate zones.

Given the zero-emissions vehicle mandates, the EV forecast will no doubt create much discussion in the coming months. The Energy Commission held a transportation workshop on June 24, 2015, where Transportation Energy Forecasting Unit staff presented and discussed the transportation light-duty vehicle stock, scenarios, and fuel consumption.[28]

Potentially significant increases in transportation-related electricity use in California are expected to occur through port, rail, truck stop, and other electrification. In particular, regulations implemented by the California Air Resources Board[29] are aimed at reducing emissions from container, passenger, and refrigerated cargo vessels docked at California ports. The Transportation Energy Forecasting Unit has hired a consultant to develop projections of off-

28 For more information, see http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-10/TN204619_20150514T144845_Notice_of_IEPR_Commissioner_Workshop_on_Preliminary_Transportat.pdf.

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

road transportation electrification, which will be incorporated in the revised version of this forecast.

Demand Response

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

Non-event based-program impacts are likely to increase in the coming years, and expected impacts incremental to the last historical year for peak (2013) affect the demand forecast.[30] Staff, in consultation with the IOUs and the CPUC, identified impacts from current committed demand response programs in these planning areas, which include real-time or time-of-use pricing and permanent load shifting. Impacts are shown in **Table 7**.

Table 7: Estimated Non-Event-Based Demand Response Program Impacts (MW)

Year	PG&E	SCE	SDG&E
2014	8	4	0
2015	21	20	0
2016	35	20	0
2017	37	30	3
2018	39	36	3
2019	39	36	3
2020	40	36	3
2021	40	36	3
2022	40	36	3
2023	42	34	3
2024	42	34	3
2025	42	34	3
2026*	42	34	3
*Program cycles end in 2025; 2026 values assumed the same as 2025.			

Source: California Energy Commission, Demand Analysis Office, 2015.

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

Energy or peak load saved from dispatchable or event-based programs has traditionally been treated as a resource and, therefore, not accounted for in the demand forecast. However, the CPUC and California ISO support a "bifurcation," or splitting in two, of such programs based on whether the resource can be integrated into the California ISO's energy market. This means that event-based demand response resources will be divided into load-modifying (demand-side) and California ISO-integrated supply-side programs. Currently, the demand forecast incorporates two types of programs, critical peak pricing and peak time rebates, designated as load-modifying. More programs may be assigned this designation in the future.

Projected peak impacts from critical peak pricing and peak-time rebate programs, based on IOU demand response filings,[31] are shown in **Table 8** by IOU. Combined impacts from these two programs and non-event-based reductions reach 125 MW for PG&E, 90 MW for SCE, and 46 MW for SDG&E by 2026. The total (noncoincident) reduction over all utilities from critical peak pricing, peak-time rebate, and non-event programs amounts to 261 MW in 2026.

Table 8: Estimated Demand Response Program Impacts: Critical Peak Pricing and Peak-Time Rebate Programs (MW)

Year	PG&E	SCE	SDG&E
2014	60	61	34
2015	75	47	30
2016	91	45	38
2017	96	72	41
2018	83	58	42
2019	83	58	43
2020	83	59	43
2021	83	58	43
2022	83	58	43
2023	83	57	43
2024	83	57	43
2025	83	56	43
2026	83	56	43
*Program cycles end in 2025; 2026 values assumed the same as 2025.			

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

31 PG&E, SCE, and SDG&E *2014 Portfolio Summary Load Impact Reports*, 4/1/2015.

CHAPTER 2:
Planning Area Results

This chapter summarizes forecast results for the five largest planning areas in California: PG&E, SCE, SDG&E, NCNC, and LADWP. Climate zone results are provided for those planning areas with multiple zones. Comprehensive results for the planning areas and climate zones, including economic/demographic assumptions, rates, self-generation and PV impacts, and EV results are available electronically as a set of forms posted with this report.[32] In general, planning area results for the IOUs mirror those at the statewide level, with a significant reduction in sales and peak demand because of higher self-generation projections.

Pacific Gas and Electric Planning Area

The PG&E planning area includes:

- PG&E bundled retail customers.
- Customers served by energy service providers and community choice aggregators using the PG&E distribution system to deliver electricity to end users.
- Customers of POUs and other providers in the PG&E TAC area. (See **Table 3.**)

The *CED 2015 Preliminary* high, mid, and low demand case results for electricity consumption and peak demand for selected years are shown in **Table 9**. Consumption results are not shown for *CEDU 2014* since this variable was not forecast for the now redefined planning area. The discussion therefore uses the *CEDU 2014* mid case for the PG&E planning area under the older definition as a point of comparison for annual growth. *CEDU 2014* did provide postprocessed peak demand and sales projections for the PG&E TAC area.

Average annual growth in consumption (2013-2025) in the new mid case is slightly lower than in the *CEDU 2014* mid case for the old PG&E planning area, 1.25 percent compared to 1.29 percent, mainly as a result of higher PV. The new high demand case is lower than the mid case in the early years of the forecast because projected manufacturing output, the key driver for industrial consumption, is lower during this period. A higher self-generation forecast reduces peak demand growth in the *CED 2015 Preliminary* mid case versus *CEDU 2014*. Peak impacts from residential PV are projected to be more than 1,400 MW in 2025 in the *CED 2015 Preliminary* mid case, compared to around 350 MW in *CEDU 2014*.

32 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03.

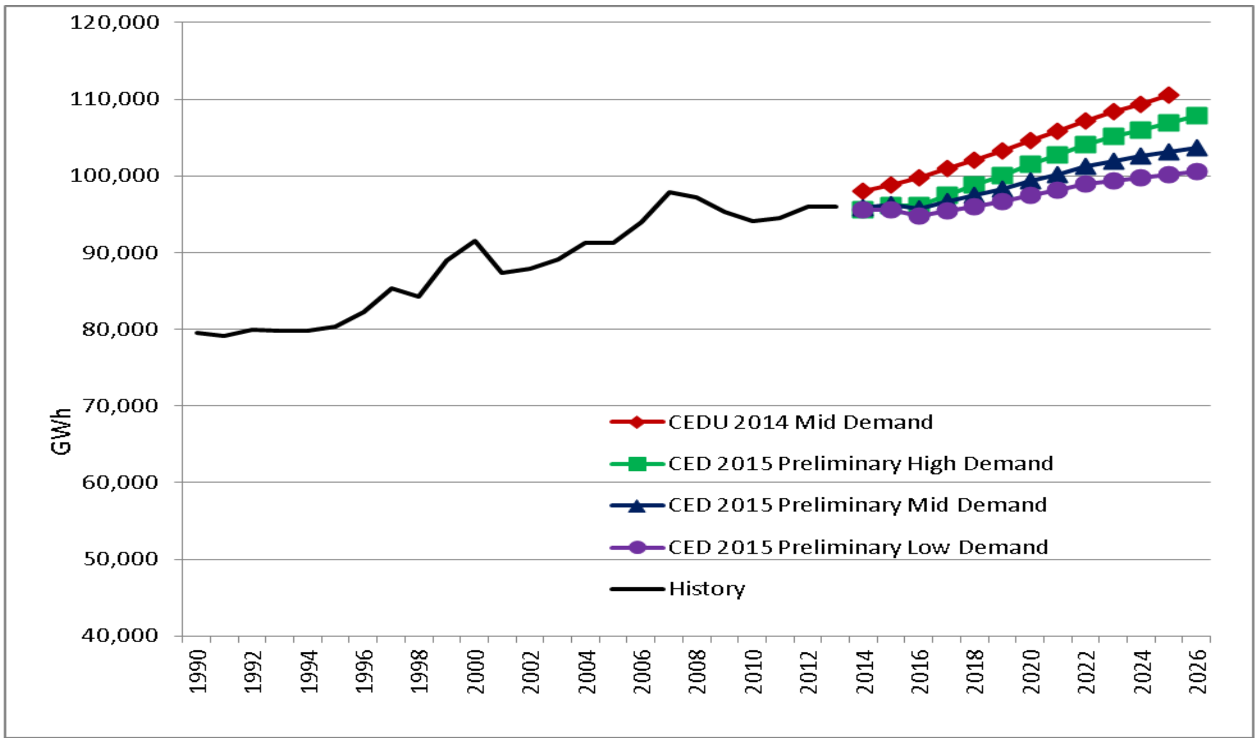
Table 9: Comparison of *CED 2015 Preliminary and CEDU 2014* Mid Case Demand Baseline Forecasts for the PG&E Planning Area

Consumption (GWh)				
	CEDU 2014 Mid Energy Demand	***CED 2015 Preliminary High Energy Demand***	***CED 2015 Preliminary Mid Energy Demand***	***CED 2015 Preliminary Low Energy Demand***
1990	_--_	83,401	83,401	83,401
2000	--	96,047	96,047	96,047
2013	--	102,613	102,613	102,613
2015	--	104,634	104,879	104,090
2020	--	112,861	110,891	109,155
2025	--	122,246	119,143	116,554
2026	--	124,057	120,708	118,030
	Average Annual Growth Rates			
1990-2000	--	1.42%	1.42%	1.42%
2000-2013	--	0.51%	0.51%	0.51%
2013-2015	--	0.98%	1.10%	0.72%
2013-2025	--	1.47%	1.25%	1.07%
2013-2026	--	1.47%	1.26%	1.08%
Coincident Peak (MW)				
	CED 2013 Mid Energy Demand	***CEDU 2014 High Energy Demand***	***CEDU 2014 Mid Energy Demand***	***CEDU 2014 Low Energy Demand***
1990	16,124	16,124	16,124	16,124
2000	19,201	19,201	19,201	19,201
2014*	22,053	22,032	22,032	22,032
2015	22,425	22,367	22,238	22,178
2020	23,807	23,639	23,257	22,545
2025	25,027	24,803	24,250	23,047
2026	--	25,000	24,404	23,105
	Average Annual Growth Rates			
1990-2000	1.76%	1.76%	1.76%	1.76%
2000-2014	0.99%	0.99%	0.99%	0.99%
2014-2015	1.69%	1.52%	0.93%	0.66%
2014-2025	1.16%	1.08%	0.88%	0.41%
2014-2026	--	1.06%	0.86%	0.40%
Actual historical values are shaded.				
*Weather normalized: *CEDU 2014* and *CED 2015 Preliminary* use a weather-normalized peak value derived from the actual 2014 peak for calculating growth rates during the forecast period.				

Source: California Energy Commission, Demand Analysis Office, 2015.

Projected electricity sales for the three *CED 2015 Preliminary* cases and the *CEDU 2014* mid demand case for the PG&E planning area are shown in **Figure 14**. All three new forecast cases are lower than the *CEDU 2014* mid case throughout the forecast period, reflecting higher projected self-generation energy impacts. By 2025, residential PV reduces sales by around 6,000 GWh in the *CED 2015 Preliminary* mid case compared to *CEDU 2014*. Annual growth from 2013-2025 for the *CED 2015 Preliminary* forecast averages 0.91 percent, 0.61 percent, and 0.36 percent in the high, mid and low cases, respectively, compared to 1.12 percent in the *CEDU 2014* mid case.

Figure 14: Historical and Projected Sales, PG&E Planning Area



Source: California Energy Commission, Demand Analysis Office, 2015.

Projected electricity consumption by climate zone for the PG&E planning area is shown in **Table 10**. (See **Table 4** for a description of the climate zones.) Healthy commercial growth in the Bay Area, particularly the Silicon Valley, induces the highest growth in Climate Zone 1 in all three demand cases. Projected resumption of migration inland after the Great Recession pushes consumption growth in the Central Valley climate zones (4 and 5) above that the coastal climate zones (2 and 6).

Table 10: Projected Electricity Consumption by Climate Zone (GWh), PG&E Planning Area

Climate Zone	1	2	3	4	5	6
	High Demand					
2013	46,665	7,348	3,671	16,536	20,830	7,562
2015	48,102	7,450	3,710	16,783	21,009	7,580
2020	52,402	7,964	3,925	18,056	22,383	8,131
2026	57,790	8,691	4,229	19,858	24,697	8,792
Average Annual Growth 2013-2026	1.66%	1.30%	1.09%	1.42%	1.32%	1.17%
	Mid Demand					
2013	46,665	7,348	3,671	16,536	20,830	7,562
2015	48,182	7,454	3,719	16,812	21,126	7,587
2020	51,300	7,833	3,869	17,749	22,183	7,957
2026	55,977	8,475	4,132	19,333	24,282	8,509
Average Annual Growth 2013-2026	1.41%	1.10%	0.91%	1.21%	1.19%	0.91%
	Low Demand					
2013	46,665	7,348	3,671	16,536	20,830	7,562
2015	47,828	7,405	3,691	16,686	20,965	7,515
2020	50,241	7,726	3,831	17,568	21,962	7,826
2026	54,367	8,325	4,087	19,113	23,793	8,345
Average Annual Growth 2013-2026	1.18%	0.97%	0.83%	1.12%	1.03%	0.76%

Source: California Energy Commission, Demand Analysis Office, 2015

Projected peak demand for the PG&E planning area by climate zone is shown in **Table 11**. Growth is most significant in the Central Valley (climate zones 4 and 5), as migration inland means an increase in new home construction almost always accompanied by air conditioning. Significant growth in self-generation in the Bay Area reduces peak demand growth compared to consumption.

Table 11: Projected Electricity Peak Demand by Climate Zone (MW), PG&E Planning Area

Climate Zone	1	2	3	4	5	6
	High Demand					
2014	7,725	1,362	1,167	4,715	5,650	1,413
2015	7,824	1,369	1,176	4,800	5,768	1,431
2020	8,136	1,405	1,227	5,120	6,272	1,480
2026	8,406	1,427	1,290	5,499	6,856	1,521
Average Annual Growth 2014-2026	0.71%	0.39%	0.84%	1.29%	1.63%	0.62%
	Mid Demand					
2014	7,725	1,362	1,167	4,715	5,650	1,413
2015	7,776	1,360	1,169	4,773	5,737	1,423
2020	8,017	1,384	1,209	5,034	6,156	1,456
2026	8,224	1,395	1,265	5,369	6,665	1,485
Average Annual Growth 2014-2026	0.52%	0.20%	0.68%	1.09%	1.39%	0.41%
	Low Demand					
2014	7,725	1,362	1,167	4,715	5,650	1,413
2015	7,758	1,357	1,166	4,760	5,718	1,419
2020	7,698	1,348	1,177	4,899	6,013	1,411
2026	7,617	1,337	1,214	5,144	6,390	1,403
Average Annual Growth 2014-2026	-0.12%	-0.15%	0.33%	0.73%	1.03%	-0.06%
NOTE: Climate zone peaks are coincident with planning area peak.						

Source: California Energy Commission, Demand Analysis Office, 2015

Southern California Edison Planning Area

The SCE planning area includes:

- SCE bundled retail customers.
- Customers served by energy service providers using the SCE distribution system to deliver electricity to end users.
- Customers of the various Southern California municipal and irrigation district utilities within the SCE TAC area. (See **Table 3**.)

The *CED 2015 Preliminary* high, mid, and low demand case results for electricity consumption and peak demand for selected years for the SCE planning area are shown in **Table 12**. As with PG&E, consumption results are not shown for *CEDU 2014* due to redefinition of the planning area. *CEDU 2014* again provided postprocessed peak demand and sales projections for the SCE TAC area.

Average annual growth in consumption from 2013-2025 in the new mid case is slightly lower than in the *CEDU 2014* mid case for the old SCE planning area, 1.06 percent compared to 1.13 percent, because of higher PV and a slightly lower light-duty EV forecast. By 2025, *CEDU 2014* assumed more than 2,300 GWh of electricity consumption from EVs in the mid case, compared to around 1,800 GWh for *CED 2015 Preliminary*. Growth in peak demand is also slower in the *CED 2015 Preliminary* mid case versus *CEDU 2014*, a difference of more than 1,000 MW by 2025, because of higher self-generation projections in the new forecast. Peak impacts from residential PV amount to more than 1,200 MW in 2025 in the *CED 2015 Preliminary* mid case, compared to just over 350 MW in *CEDU 2014*.

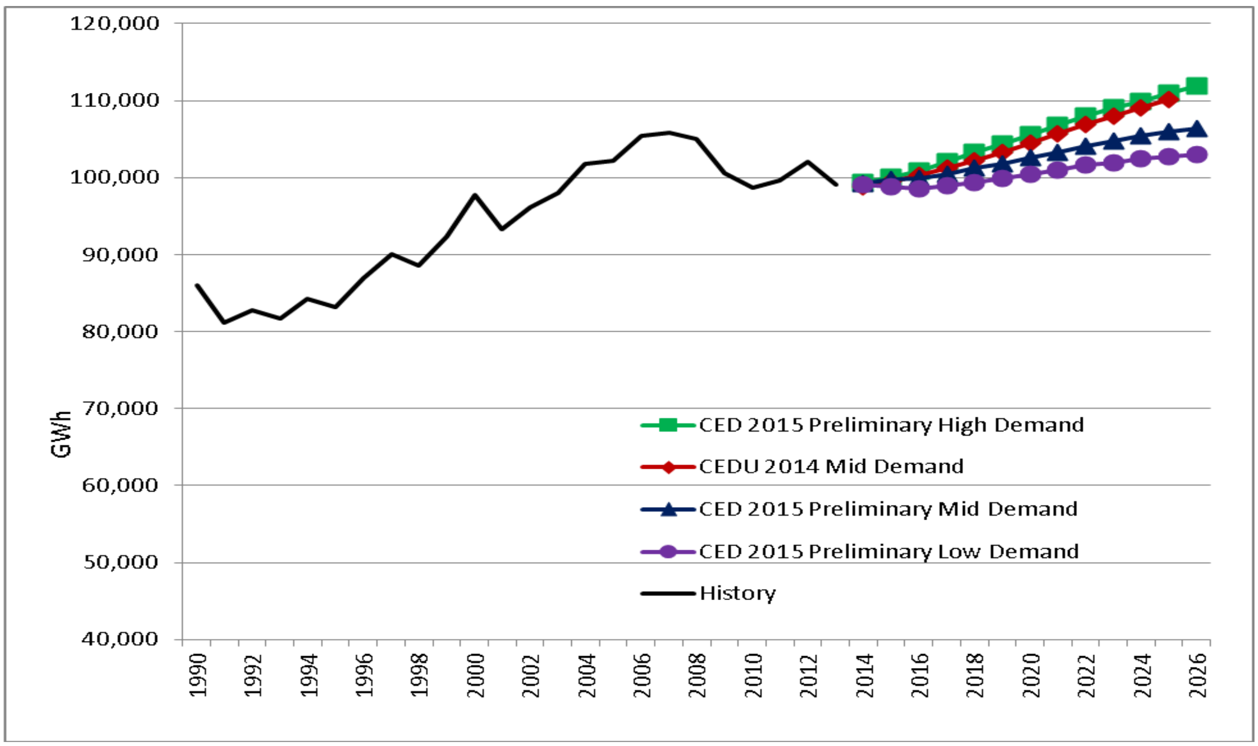
Table 12: Comparison of *CED 2015 Preliminary and CEDU 2014* Mid Case Demand Baseline Forecasts for the SCE Planning Area

Consumption (GWh)				
	CEDU 2014 Mid Energy Demand	***CED 2015 Preliminary High Energy Demand***	***CED 2015 Preliminary Mid Energy Demand***	***CED 2015 Preliminary Low Energy Demand***
1990	_--_	89,041	89,041	89,041
2000	--	100,840	100,840	100,840
2013	--	105,102	105,102	105,102
2015	--	107,332	107,153	106,230
2020	--	114,985	112,237	110,304
2025	--	123,267	119,236	116,669
2026	--	124,915	120,575	117,925
	Average Annual Growth Rates			
1990-2000	--	1.25%	1.25%	1.25%
2000-2013	--	0.32%	0.32%	0.32%
2013-2015	--	1.06%	0.97%	0.54%
2013-2025	--	1.34%	1.06%	0.87%
2013-2026	--	1.34%	1.06%	0.89%
Coincident Peak (MW)				
	CED 2013 Mid Energy Demand	***CEDU 2014 High Energy Demand***	***CEDU 2014 Mid Energy Demand***	***CEDU 2014 Low Energy Demand***
1990	17,970	17,970	17,970	17,970
2000	19,830	19,830	19,830	19,830
2014*	23,386	23,347	23,347	23,347
2015	23,749	23,981	23,799	23,629
2020	25,177	25,314	24,626	24,008
2025	26,491	26,606	25,446	24,579
2026	--	26,823	25,549	24,630
	Average Annual Growth Rates			
1990-2000	0.99%	0.99%	0.99%	0.99%
2000-2014	1.19%	1.17%	1.17%	1.17%
2014-2015	1.55%	2.72%	1.93%	1.21%
2014-2025	1.14%	1.19%	0.79%	0.47%
2014-2026	--	1.16%	0.75%	0.45%
Actual historical values are shaded.				
*Weather normalized: *CEDU 2014* and *CED 2015 Preliminary* use a weather-normalized peak value derived from the actual 2014 peak for calculating growth rates during the forecast period.				

Source: California Energy Commission, Demand Analysis Office, 2015.

Projected electricity sales for the three *CED 2015 Preliminary* cases and the *CEDU 2014* mid demand case for the SCE planning area are shown in **Figure 15**. Higher self-generation projections reduce the new mid case compared to *CEDU 2014* mid, which roughly tracks the new high demand case. In 2025, residential PV reduces sales by more than 5,000 GWh in the *CED 2015 Preliminary* mid case compared to *CEDU 2014*. Annual growth from 2013-2025 for the *CED 2015 Preliminary* forecast averages 0.094 percent, 0.55 percent, and 0.30 percent in the high, mid and low cases, respectively, compared to 0.99 percent in the *CEDU 2014* mid case.

Figure 15: Historical and Projected Sales, SCE Planning Area



Source: California Energy Commission, Demand Analysis Office, 2015.

Projected electricity consumption by climate zone for the SCE planning area is shown in **Table 13.** (See **Table 4** for a description of the climate zones.) Growth is fastest in the inland climate zones (9, 10, and 11), particularly in Riverside County (Climate Zone 9), which combines projections of resumption of inland migration with a booming commercial sector.

Table 13: Projected Electricity Consumption by Climate Zone (GWh), SCE Planning Area

Climate Zone	7	8	9	10	11
			High Demand		
2013	60,106	7,064	10,734	14,362	12,837
2015	60,789	7,136	11,422	14,703	13,281
2020	65,216	7,654	11,934	15,692	14,489
2026	70,638	8,342	12,752	16,994	16,189
Average Annual Growth 2013-2026	1.25%	1.29%	1.33%	1.30%	1.80%
			Mid Demand		
2013	60,106	7,064	10,734	14,362	12,837
2015	60,665	7,137	11,446	14,678	13,227
2020	63,428	7,489	11,830	15,292	14,199
2026	67,868	8,083	12,556	16,355	15,713
Average Annual Growth 2013-2026	0.94%	1.04%	1.21%	1.00%	1.57%
			Low Demand		
2013	60,106	7,064	10,734	14,362	12,837
2015	60,099	7,075	11,394	14,544	13,117
2020	62,217	7,287	11,736	15,057	14,007
2026	66,274	7,784	12,337	16,064	15,466
Average Annual Growth 2013-2026	0.75%	0.75%	1.08%	0.87%	1.44%

Source: California Energy Commission, Demand Analysis Office, 2015

Projected peak demand for the SCE planning area by climate zone is shown in **Table 14**. As with consumption, growth is most significant in the inland climate zones, although growth is now highest in the southern Central Valley (Climate Zone 9). This reflects higher projected PV adoption in Climate Zones 10 and 11 compared to Climate Zone 9.

Table 14: Projected Electricity Peak Demand by Climate Zone (MW), SCE Planning Area

Climate Zone	7	8	9	10	11
	High Demand				
2014	12,690	1,488	1,386	5,351	2,433
2015	13,033	1,514	1,434	5,488	2,512
2020	13,609	1,584	1,586	5,821	2,714
2026	14,186	1,677	1,772	6,233	2,956
Average Annual Growth 2014-2026	0.93%	1.00%	2.07%	1.28%	1.64%
	Mid Demand				
2014	12,690	1,488	1,385	5,351	2,433
2015	12,933	1,502	1,423	5,447	2,494
2020	13,229	1,546	1,543	5,666	2,642
2026	13,482	1,608	1,691	5,948	2,819
Average Annual Growth 2014-2026	0.51%	0.65%	1.68%	0.89%	1.24%
	Low Demand				
2014	12,690	1,488	1,385	5,351	2,433
2015	12,842	1,491	1,412	5,408	2,476
2020	12,905	1,498	1,508	5,523	2,574
2026	13,018	1,534	1,626	5,737	2,715
Average Annual Growth 2014-2026	0.21%	0.25%	1.34%	0.58%	0.92%
NOTE: Climate zone peaks are coincident with planning area peak.					

Source: California Energy Commission, Demand Analysis Office, 2015

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. The definition of this planning area has not changed from previous forecasts.

The *CED 2015 Preliminary* high, mid, and low demand case results for electricity consumption and peak demand for selected years for the SDG&E planning area are shown in **Table 15**. Average annual growth in consumption from 2013-2025 in the new mid case is slightly higher than in the *CEDU 2014* mid case. Higher projections for number of households combined with increased EV consumption result in an overall growth in consumption. As with the other two IOU planning areas, growth in peak demand is slower in the *CED 2015 Preliminary* mid case versus *CEDU 2014* because of higher self-generation projections in the new forecast. Peak impacts from residential PV are estimated at almost 400 MW in 2025 in the *CED 2015 Preliminary* mid case, compared to around 175 MW in *CEDU 2014*.

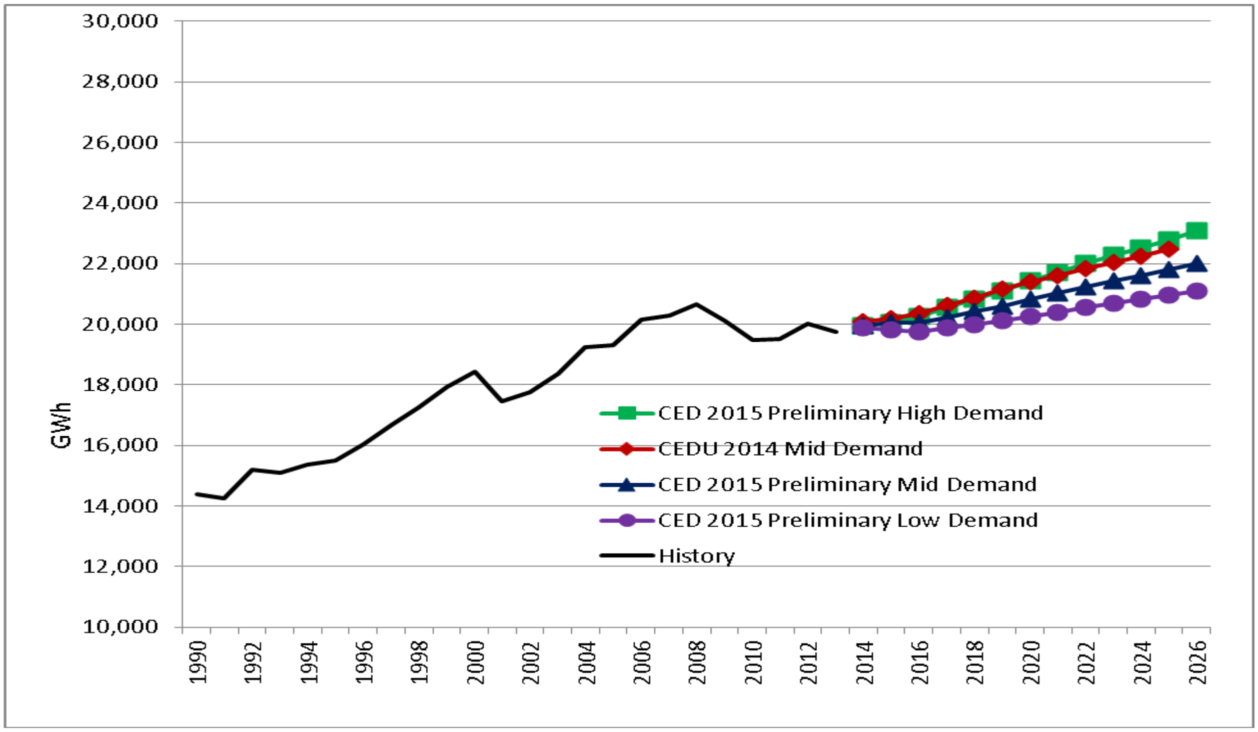
Table 15: Comparison of *CED 2015 Preliminary and CEDU 2014* Mid Case Demand Baseline Forecasts for the SDG&E Planning Area

Consumption (GWh)				
	CEDU 2014 Mid Energy Demand	***CED 2015 Preliminary High Energy Demand***	***CED 2015 Preliminary Mid Energy Demand***	***CED 2015 Preliminary Low Energy Demand***
1990	14,857	14,857	14,857	14,857
2000	18,784	18,784	18,784	18,784
2013	20,817	20,721	20,721	20,721
2015	21,432	21,364	21,344	21,133
2020	22,914	23,490	22,936	22,400
2025	24,523	25,646	24,803	24,045
2026	--	26,078	25,172	24,369
	Average Annual Growth Rates			
1990-2000	2.37%	2.37%	2.37%	2.37%
2000-2013	0.79%	0.76%	0.76%	0.76%
2013-2015	1.47%	1.54%	1.49%	0.99%
2013-2025	1.37%	1.79%	1.51%	1.25%
2013-2026	--	1.78%	1.51%	1.26%
Coincident Peak (MW)				
	CED 2013 Mid Energy Demand	***CEDU 2014 High Energy Demand***	***CEDU 2014 Mid Energy Demand***	***CEDU 2014 Low Energy Demand***
1990	2,978	2,978	2,978	2,978
2000	3,485	3,485	3,485	3,485
2014*	4,669	4,675	4,674	4,674
2015	4,774	4,770	4,743	4,720
2020	5,070	4,981	4,904	4,788
2025	5,246	5,210	5,063	4,865
2026	--	5,254	5,094	4,882
	Average Annual Growth Rates			
1990-2000	1.58%	1.58%	1.58%	1.58%
2000-2014	2.11%	2.12%	2.12%	2.12%
2014-2015	2.25%	2.03%	1.48%	0.99%
2014-2025	1.06%	0.99%	0.73%	0.37%
2014-2026	--	0.98%	0.72%	0.36%
Actual historical values are shaded.				
*Weather normalized: *CEDU 2014* and *CED 2015 Preliminary* use a weather-normalized peak value derived from the actual 2014 peak for calculating growth rates during the forecast period.				

Source: California Energy Commission, Demand Analysis Office, 2015.

The increase in self-generation impacts also reduces sales compared to *CEDU 2014* in the SDG&E planning area, as shown in **Figure 16**. By 2025, residential PV reduces sales by almost 1,000 GWh in the *CED 2015 Preliminary* mid case compared to *CEDU 2014*. Annual growth from 2013-2025 for the *CED 2015 Preliminary* forecast averages 1.20 percent, 0.82 percent, and 0.49 percent in the high, mid, and low cases, respectively, compared to 1.03 percent in the *CEDU 2014* mid case.

Figure 16: Historical and Projected Sales, SDG&E Planning Area



Source: California Energy Commission, Demand Analysis Office, 2015.

Northern California Non-California ISO Planning Area

The NCNC planning area includes the Turlock Irrigation District control area and the BANC. By far the largest utility in this planning area is SMUD. Separate demand forms are provided for NCNC and SMUD.[33]

The *CED 2015 Preliminary* high, mid, and low demand case results for electricity consumption and peak demand for selected years for the NCNC planning area are shown in **Table 16**. As with PG&E and SCE, consumption cannot be compared directly with the previous forecast. Average annual growth in consumption is higher compared to the IOUs because of relatively

33 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03.

higher growth in population and number of households projected for the Sacramento and San Joaquin Valleys. The new high demand case is lower than the new mid in the early years of the forecast because projected manufacturing output, the key driver for industrial consumption, is lower during this period. Peak demand growth for the *CED 2015 Preliminary* mid case is higher compared to *CEDU 2014* as a result of faster growth the number of households and a slight reduction in self-generation impacts.

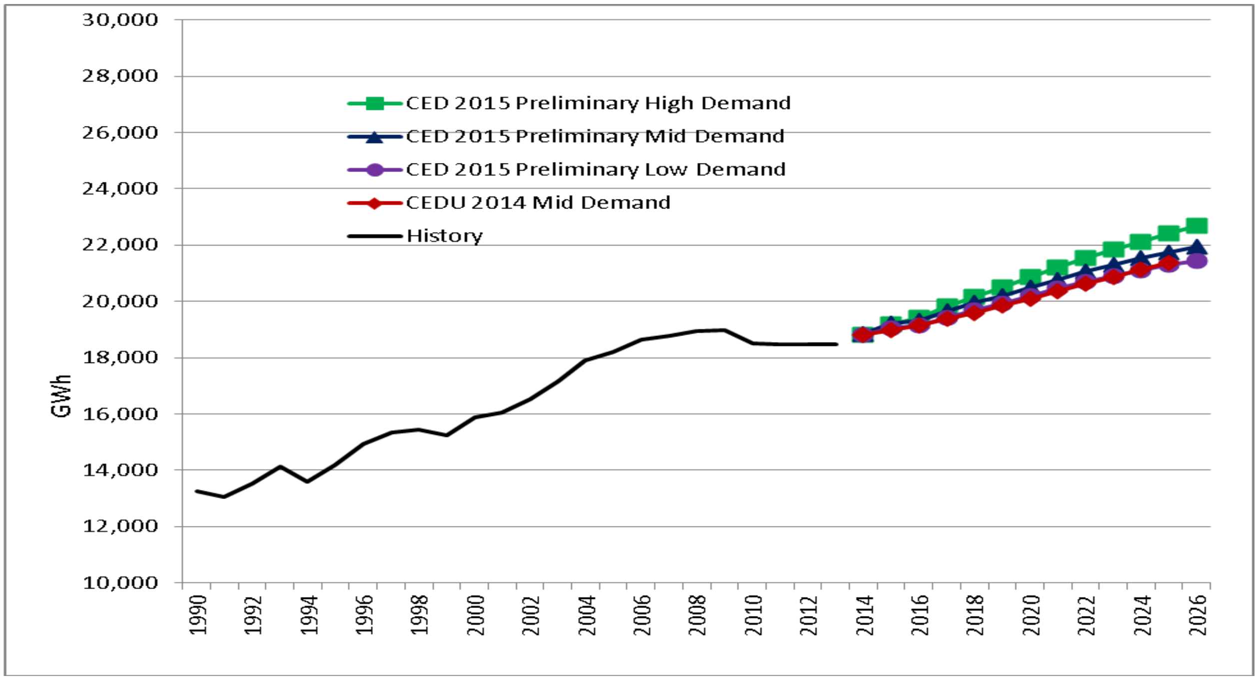
Table 16: Comparison of *CED 2015 Preliminary and CEDU 2014* Mid Case Demand Baseline Forecasts for the NCNC Planning Area

Consumption (GWh)				
	CEDU 2014 Mid Energy Demand	***CED 2015 Preliminary High Energy Demand***	***CED 2015 Preliminary Mid Energy Demand***	***CED 2015 Preliminary Low Energy Demand***
1990	_--_	13,249	13,249	13,249
2000	--	15,868	15,868	15,868
2013	--	18,663	18,663	18,663
2015	--	19,448	19,473	19,331
2020	--	21,219	20,880	20,614
2025	--	23,060	22,512	22,160
2026	--	23,424	22,825	22,463
	Average Annual Growth Rates			
1990-2000	--	1.82%	1.82%	1.82%
2000-2013	--	1.26%	1.26%	1.26%
2013-2015	--	2.08%	2.15%	1.77%
2013-2025	--	1.78%	1.57%	1.44%
2013-2026	--	1.76%	1.56%	1.44%
Coincident Peak (MW)				
	CED 2013 Mid Energy Demand	***CEDU 2014 High Energy Demand***	***CEDU 2014 Mid Energy Demand***	***CEDU 2014 Low Energy Demand***
1990	3,731	3,731	3,731	3,731
2000	4,520	4,520	4,520	4,520
2014*	5,021	5,021	5,020	5,020
2015	5,096	5,122	5,101	5,085
2020	5,389	5,587	5,509	5,397
2025	5,676	6,059	5,863	5,684
2026	--	6,145	5,931	5,740
	Average Annual Growth Rates			
1990-2000	1.94%	1.94%	1.94%	1.94%
2000-2014	0.75%	0.75%	0.75%	0.75%
2014-2015	1.49%	2.03%	1.60%	1.30%
2014-2025	1.12%	1.72%	1.42%	1.14%
2014-2026	--	1.70%	1.40%	1.12%
Actual historical values are shaded.				
*Weather normalized: *CEDU 2014* and *CED 2015 Preliminary* use a weather-normalized peak value derived from the actual 2014 peak for calculating growth rates during the forecast period.				

Source: California Energy Commission, Demand Analysis Office, 2015.

Projected electricity sales for the three *CED 2015 Preliminary* cases and the *CEDU 2014* mid demand case for the NCNC planning area are shown in **Figure 17**. Sales are slightly higher in the new mid case compared to *CEDU 2014* reflecting faster growth in consumption along with much less increase in self-generation compared to the IOU planning areas. Annual growth from 2013-2025 for the *CED 2015 Preliminary* forecast averages 1.61 percent, 1.36 percent, and 1.18 percent in the high, mid and low cases, respectively, compared to 1.14 percent in the *CEDU 2014* mid case.

Figure 17: Historical and Projected Sales, NCNC Planning Area



Source: California Energy Commission, Demand Analysis Office, 2015.

Projected electricity consumption by climate zone for the NCNC planning area is shown in **Table 17**. (See **Table 4** for a description of the climate zones.) The SMUD service territory (Climate Zone 13) yields the fastest growth as a result of more growth in number of households. On the other hand, peak demand growth (**Table 18**) is slowest for SMUD, reflecting less growth in PV adoption in Climate Zones 14 and 15.

Table 17: Projected Electricity Consumption by Climate Zone (GWh), NCNC Planning Area

Climate Zone	13	14	15
	High Demand		
2013	10,564	2,514	5,585
2015	10,942	2,627	5,880
2020	12,079	2,825	6,315
2026	13,416	3,100	6,907
Average Annual Growth 2013-2026	1.86%	1.63%	1.65%
	Mid Demand		
2013	10,564	2,514	5,585
2015	10,943	2,636	5,894
2020	11,883	2,778	6,219
2026	13,078	3,013	6,733
Average Annual Growth 2013-2026	1.66%	1.40%	1.45%
	Low Demand		
2013	10,564	2,514	5,585
2015	10,867	2,615	5,848
2020	11,726	2,744	6,144
2026	12,853	2,970	6,640
Average Annual Growth 2013-2026	1.52%	1.29%	1.34%

Source: California Energy Commission, Demand Analysis Office, 2015

Table 18: Projected Electricity Peak Demand by Climate Zone (MW), NCNC Planning Area

Climate Zone	13	14	15
		High Demand	
2014	2,950	619	1,452
2015	3,002	635	1,486
2020	3,256	702	1,630
2026	3,566	780	1,800
Average Annual Growth 2014-2026	1.59%	1.95%	1.80%
		Mid Demand	
2014	2,950	619	1,452
2015	2,989	632	1,479
2020	3,218	690	1,601
2026	3,457	750	1,724
Average Annual Growth 2014-2026	1.33%	1.62%	1.44%
		Low Demand	
2014	2,950	619	1,452
2015	2,980	630	1,475
2020	3,148	676	1,573
2026	3,336	726	1,679
Average Annual Growth 2014-2026	1.03%	1.35%	1.22%
NOTE: Climate zone peaks are coincident with planning area peak.			

Source: California Energy Commission, Demand Analysis Office, 2015

Los Angeles Department of Water and Power Planning Area

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.

CED 2015 Preliminary high, mid, and low demand scenarios are compared with the *CEDU 2014* mid demand scenario in **Table 19** for electricity consumption and peak demand for selected years. For consumption, the new high demand case is lower than the mid case in the early years of the forecast because projected manufacturing output, the key driver for industrial consumption, is lower during this period. Consumption growth (2013-2025) is faster in the new mid demand case versus *CEDU 2014,* while peak demand (2014-2025) is slower in new mid demand case versus *CEDU 2014* because of lower projected manufacturing growth for Los Angeles County. Peak demand is also affected by higher PV adoption, a function of higher assumed rate escalation.

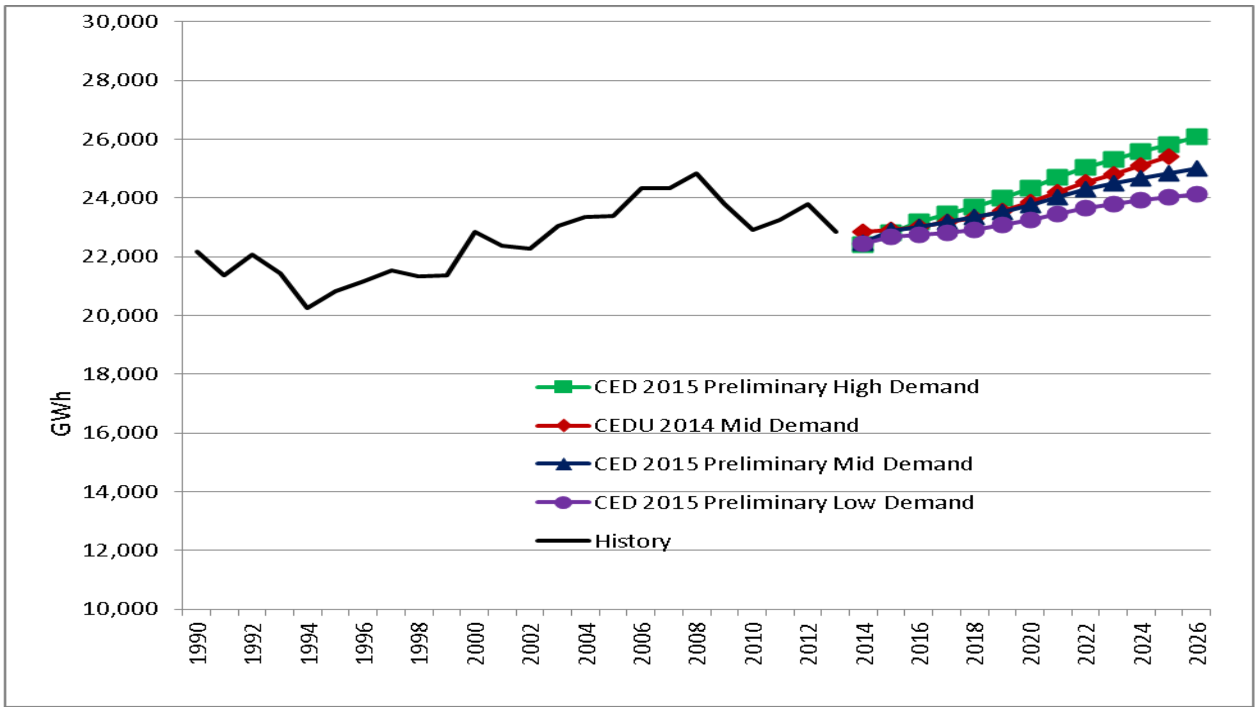
Table 19: Comparison of *CED 2015 Preliminary and CEDU 2014* Mid Case Demand Baseline Forecasts for the LADWP Planning Area

Consumption (GWh)				
	CEDU 2014 Mid Energy Demand	***CED 2015 Preliminary High Energy Demand***	***CED 2015 Preliminary Mid Energy Demand***	***CED 2015 Preliminary Low Energy Demand***
1990	23,038	23,038	23,038	23,038
2000	24,018	24,018	24,018	24,018
2013	24,355	24,355	24,355	24,355
2015	24,583	24,527	24,579	24,386
2020	25,622	26,270	25,747	25,283
2025	27,268	28,200	27,382	26,746
2026	--	28,590	27,704	27,044
	Average Annual Growth Rates			
1990-2000	0.42%	0.42%	0.42%	0.42%
2000-2013	0.11%	0.11%	0.11%	0.11%
2013-2015	0.47%	0.35%	0.46%	0.06%
2013-2025	0.95%	1.23%	0.98%	0.78%
2013-2026	--	1.24%	1.00%	0.81%
Coincident Peak (MW)				
	CED 2013 Mid Energy Demand	***CEDU 2014 High Energy Demand***	***CEDU 2014 Mid Energy Demand***	***CEDU 2014 Low Energy Demand***
1990	5,341	5,341	5,341	5,341
2000	5,344	5,344	5,344	5,344
2014*	5,739	5,739	5,739	5,739
2015	5,808	5,890	5,872	5,833
2020	6,059	6,224	6,097	5,940
2025	6,353	6,510	6,276	6,048
2026	--	6,552	6,291	6,046
	Average Annual Growth Rates			
1990-2000	0.01%	0.01%	0.01%	0.01%
2000-2014	0.51%	0.51%	0.51%	0.51%
2014-2015	1.20%	2.62%	2.32%	1.64%
2014-2025	0.93%	1.15%	0.82%	0.48%
2014-2026	--	1.11%	0.77%	0.44%
Actual historical values are shaded.				
*Weather normalized: *CEDU 2014* and *CED 2015 Preliminary* use a weather-normalized peak value derived from the actual 2014 peak for calculating growth rates during the forecast period.				

Source: California Energy Commission, Demand Analysis Office, 2015.

Projected electricity sales for the three *CED 2015 Preliminary* cases and the *CEDU 2014* mid demand case for the LADWP planning area are shown in **Figure 18**. Sales are down in the new mid case compared to *CEDU 2014* for the same reasons as consumption as well as from an increase in self-generation. Annual growth from 2013-2025 for the *CED 2015 Preliminary* forecast averages 1.02 percent, 0.69 percent, and 0.42 percent in the high, mid and low cases, respectively, compared to 0.88 percent in the *CEDU 2014* mid case.

Figure 18: Historical and Projected Sales, LADWP Planning Area



Source: California Energy Commission, Demand Analysis Office, 2015.

Projected electricity consumption and peak demand for the two climate zones in the LADWP planning area are shown in **Table 20** and **Table 21**, respectively. (See **Table 4** for a description of the climate zones.) The inland climate zone (17) shows slightly faster growth for both consumption and peak, reflecting faster population and household growth in both inland Los Angeles and the Owens Valley (Inyo County).

Table 20: Projected Electricity Consumption by Climate Zone (GWh), LADWP Planning Area

Climate Zone	16	17
	High Demand	
2013	8,295	16,060
2015	8,372	16,155
2020	8,880	17,390
2026	9,581	19,009
Average Annual Growth 2013-2026	1.11%	1.31%
	Mid Demand	
2013	8,295	16,060
2015	8,396	16,183
2020	8,704	17,042
2026	9,281	18,423
Average Annual Growth 2013-2026	0.87%	1.06%
	Low Demand	
2013	8,295	16,060
2015	8,333	16,053
2020	8,551	16,731
2026	9,063	17,980
Average Annual Growth 2013-2026	0.68%	0.87%

Source: California Energy Commission, Demand Analysis Office, 2015

.

Table 21: Projected Electricity Peak Demand by Climate Zone (MW), LADWP Planning Area

Climate Zone	16	17
	High Demand	
2014	1,552	4,187
2015	1,588	4,302
2020	1,675	4,549
2026	1,769	4,783
Average Annual Growth 2014-2026	1.09%	1.12%
	Mid Demand	
2014	1,552	4,187
2015	1,583	4,289
2020	1,639	4,458
2026	1,695	4,596
Average Annual Growth 2014-2026	0.73%	0.78%
	Low Demand	
2014	1,552	4,187
2015	1,571	4,262
2020	1,590	4,351
2026	1,617	4,429
Average Annual Growth 2014-2026	0.34%	0.47%
NOTE: Climate zone peaks are coincident with planning area peak.		

Source: California Energy Commission, Demand Analysis Office, 2015

List of Acronyms

Acronym	Definition
BANC	Balancing Authority of Northern California
BUGL	Burbank-Glendale
California ISO	California Independent System Operator
CED	*California Energy Demand*
CED 2011	*California Energy Demand 2012-2022 Final Forecast*
CED 2013	*California Energy Demand 2014-2024 Final Forecast*
CED 2015 Preliminary	*California Energy Demand 2016-2026, Preliminary Electricity Forecast*
CEDU 2014	*California Energy Demand Updated Forecast, 2015-2025*
CPUC	California Public Utilities Commission
CEUS	Commercial End-Use Survey
CHP	Combined heat and power
DOF	Department of Finance
DWR	Department of Water Resources
Energy Commission	California Energy Commission
EV	Electric vehicle
GWh	Gigawatt-hour
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
IOU	Investor-owned utility
kW	Kilowatt
kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water and Power
MW	Megawatt
NEM	Net energy metering
NCNC	Northern California Non-California ISO
PG&E	Pacific Gas and Electric Company
POU	Publicly owned utility
PV	Photovoltaic
QFER	Quarterly Fuel and Energy Report
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SMUD	Sacramento Municipal Utility District
TAC	Transmission Access Charge

APPENDIX A: Regression Results

This appendix provides estimation results for the econometric models used in the analysis for *CED 2015 Preliminary*.

Table A-1: Residential Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Persons per Household	0.3935	0.1142	3.44
Per capita income (2013$)	0.1419	0.0471	3.01
Unemployment Rate	-0.0042	0.0009	-4.57
Residential Electricity Rate (2013¢/kWh)	-0.0870	0.0108	-8.09
Number of Cooling Degree Days (70º)	0.0323	0.0026	12.20
Number of Heating Degree Days (60º)	0.0181	0.0044	4.13
Dummy: 2001	-0.0449	0.0077	-5.87
Dummy: 2002	-0.0372	0.0076	-4.89
Constant: Burbank/Glendale	-0.5528	0.0161	-34.23
Constant: IID	0.1655	0.0265	6.24
Constant: LADWP	-0.5784	0.0154	-37.45
Constant: Pasadena	-0.6617	0.0276	-24.00
Constant: PG&E	-0.3491	0.0136	-25.75
Constant: SCE	-0.4736	0.0180	-26.32
Constant: SDG&E	-0.4528	0.0196	-23.13
Overall Constant	7.1881	0.4645	15.48
Trend Variables			
Time: Burbank/Glendale	0.0085	0.0014	5.89
Time Squared: Burbank/Glendale	-0.0001	0.0000	-2.87
Time: IID	0.0065	0.0007	8.77
Time: LADWP	0.0055	0.0008	6.61
Time: Pasadena	0.0187	0.0032	5.92
Time Squared: Pasadena	-0.0003	0.0001	-2.99
Time: PG&E	0.0011	0.0009	1.21
Time: SCE	0.0038	0.0009	4.02
Time: SDG&E	0.0023	0.0010	2.29
Time: SMUD	-0.0052	0.0017	-3.09
Time Squared: SMUD	0.0001	0.0000	2.12
Adjusted for autocorrelation and cross-sectional correlation. Wald chi squared = 25,561 Dependent variable = natural log of electricity consumption per household by planning area, 1980-2013 All variables in logged form except time and unemployment rate.			

Source: California Energy Commission, Demand Analysis Office, 2014.

Table A-2: Commercial Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Commercial Employment	0.8248	0.0119	69.59
Commercial Electricity Rate (2013¢/kWh)	-0.0161	0.0132	-1.23
Number of Cooling Degree Days (65^{o})	0.0464	0.0082	5.69
Dummy: 2001 (LADWP)	-0.0485	0.0222	-2.18
Dummy: 2001 (PG&E)	-0.0391	0.0152	-2.56
Dummy: 2001 (SDG&E)	-0.0682	0.0167	-4.09
Constant: Burbank	-0.2164	0.0303	-7.15
Constant: LADWP	0.1795	0.0230	7.80
Constant: PG&E	0.2388	0.0316	7.55
Constant: SCE	0.2737	0.0278	9.84
Overall Constant	2.6479	0.1052	25.17
Trend Variables			
Time: Burbank	0.0460	0.0037	12.51
Time Squared: Burbank	-0.0009	0.0001	-8.98
Time: IID	0.0321	0.0033	9.62
Time Squared: IID	-0.0006	0.0001	-6.31
Time: LADWP	0.0192	0.0028	6.94
Time Squared: LADWP	-0.0004	0.0001	-5.39
Time: PASD	0.0311	0.0089	3.49
Time Squared: PASD	-0.0004	0.0003	-1.49
Time: PG&E	0.0235	0.0015	15.22
Time Squared: PG&E	-0.0003	0.0000	-8.09
Time: SCE	0.0188	0.0012	15.75
Time Squared: SCE	-0.0002	0.0000	-7.73
Time: SDG&E	0.0211	0.0021	10.01
Time Squared: SDG&E	-0.0003	0.0001	-6.35
Time: SMUD	0.0068	0.0009	7.54
Adjusted for autocorrelation and cross-sectional correlation.			
Wald chi squared = 278,879			
Dependent variable = natural log of commercial consumption by planning area, 1980-2013.			
All variables in logged form except time.			

Source: California Energy Commission, Demand Analysis Office, 2014.

Table A-3: Manufacturing Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Manufacturing Output (million 2013$)	0.4958	0.0548	9.04
Manufacturing Output/Manufacturing Employment	-0.3474	0.0433	-8.02
Output Textiles, Fiber, Printing/Manufacturing	0.6708	0.3113	2.16
Output Chemicals, Energy, Plastic/Manufacturing	-0.3426	0.1173	-2.92
Industrial Electricity Rate (2013¢/kWh)	-0.1092	0.0227	-4.82
Constant: Burbank/Glendale	0.5295	0.1589	3.33
Constant: IID	-0.2932	0.2225	-1.32
Constant: LADWP	1.2849	0.2059	6.24
Constant: PASD	-0.4812	0.1595	-3.02
Constant: PG&E	2.5460	0.2429	10.48
Constant: SCE	2.3752	0.2544	9.34
Constant: SDG&E	0.4814	0.1660	2.90
Overall Constant	3.8803	0.2654	14.62
Trend Variables			
Time: Burbank/Glendale	-0.0430	0.0060	-7.16
Time: IID	-0.0584	0.0172	-3.41
Time Squared: IID	0.0022	0.0005	4.72
Time: Pasadena	-0.0713	0.0153	-4.66
Time Squared: Pasadena	0.0008	0.0004	2.00
Time: PG&E	-0.0044	0.0021	-2.04
Time: SDG&E	0.0376	0.0042	9.01
Time Squared: SDG&E	-0.0010	0.0001	-10.29
Time: SMUD	0.0795	0.0144	5.52
Time Squared: SMUD	-0.0017	0.0004	-4.50
Adjusted for autocorrelation and cross-sectional correlation.			
Wald chi squared = 36,517			
Dependent variable = natural log of industrial consumption by planning area, 1980-2013.			
All variables in logged form except time, output textiles, fiber, printing/manufacturing output and output chemicals, energy, plastic/manufacturing output.			

Source: California Energy Commission, Demand Analysis Office, 2014.

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

Variable	Estimated Coefficient	Standard Error	t-statistic
Output, Resource Extraction (million 2009$)	0.1299	0.0402	3.23
Employment in Construction (thousands)	0.2293	0.0821	2.79
Percent Employment Resource Extraction	2.3129	0.9555	2.42
Industrial Electricity Rate (2013 cents/kWh)	-0.1250	0.0614	-2.04
Dummy: 2002	-0.0661	0.0320	-2.06
Dummy: 1997 SDG&E	-1.0680	0.0881	-12.12
Dummy: 1980 and 1981 PG&E	-1.0468	0.0722	-14.50
Constant: BUGL	-1.2298	0.1564	-7.86
Constant: IID	-1.4130	0.2970	-4.76
Constant: LADWP	1.0914	0.2571	4.25
Constant: PASD	-3.5856	0.3143	-11.41
Constant: PG&E	2.9873	0.3913	7.63
Constant: SCE	2.9109	0.3675	7.92
Overall Constant	2.8931	0.3097	9.34
Trend Variables			
Time: BUGL	0.1148	0.0110	10.40
Time squared: BUGL	-0.0025	0.0003	-9.12
Time: IID	0.1105	0.0307	3.60
Time squared: IID	-0.0015	0.0008	-1.81
Time: PASD	0.3237	0.0351	9.22
Time squared: PASD	-0.0083	0.0010	-8.64
Time: PG&E	-0.0234	0.0148	-1.58
Time squared: PG&E	0.0008	0.0004	1.96
Time: SDG&E	0.1115	0.0282	3.96
Time Squared: SDG&E	-0.0027	0.0008	-3.58
Time: SMUD	0.0698	0.0166	4.22
Time Squared: SMUD	-0.0013	0.0004	-2.92
Adjusted for autocorrelation and cross-sectional correlation.			
Wald chi squared = 33,042			
Dependent variable = natural log of construction & resource extraction consumption by planning area 1980-2013.			
All variables in logged form except time and percentage employment resource extraction.			

Source: California Energy Commission, Demand Analysis Office, 2014.

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

Variable	Estimated Coefficient	Standard Error	t-statistic
Agricultural Electricity Rate (2013 cents/kWh)	-0.1146	0.0704	-1.63
Agricultural Output per Capita	0.0718	0.0601	1.19
Precipitation (inches)	-0.0519	0.0140	-3.71
Constant: Burbank/Glendale	-1.2549	0.1753	-7.16
Constant: IID	1.6332	0.1520	10.74
Constant: LADWP	-1.0859	0.1594	-6.81
Constant: PG&E	1.6636	0.1068	15.58
Constant: SCE	1.0948	0.1165	9.40
Overall Constant	5.1464	0.4169	12.34
Trend Variables			
Time: IID	0.0179	0.0047	3.79
Time Squared: IID	-0.0006	0.0001	-4.75
Time: LADWP	0.0304	0.0122	2.49
Time Squared: LADWP	-0.0010	0.0003	-3.09
Time: PG&E	-0.0324	0.0069	-4.71
Time Squared: PG&E	0.0007	0.0002	3.74
Time: SDG&E	-0.0660	0.0112	-5.88
Time Squared: SDG&E	0.0018	0.0003	5.34
Adjusted for autocorrelation and cross-sectional correlation.			
Wald chi squared = 20,066			
Dependent variable = natural log of agriculture and water pumping electricity consumption per capita by planning area 1980-2013.			
All variables in logged form except time.			

Source: California Energy Commission, Demand Analysis Office, 2015.

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

Variable	Estimated Coefficient	Standard Error	t-statistic
Commercial Electricity Rate (2013 cents/kWh)	-0.2165	0.0472	-4.58
Per capita income (2013$)	0.0760	0.0483	1.57
Constant: Burbank/Glendale	-1.6606	0.1152	-14.42
Constant: IID	0.9813	0.1584	6.20
Constant: LADWP	-0.3759	0.0536	-7.01
Constant: Pasadena	-1.2221	0.0633	-19.31
Constant: PG&E	-0.1377	0.0442	-3.12
Constant: SCE	-0.4904	0.0397	-12.35
Constant: SDG&E	-0.0801	0.0428	-1.87
Overall Constant	6.1373	0.5083	12.07
Trend Variables			
Time Squared: BUGL	0.0032	0.0004	8.27
Time: IID	-0.0559	0.0102	-5.50
Time: Pasadena	0.0480	0.0135	3.56
Time Squared: PASD	-0.0013	0.0005	-2.42
Time: PG&E	-0.0362	0.0041	-8.84
Time Squared: PG&E	0.0014	0.0001	9.23
Time: SMUD	-0.0438	0.0073	-5.99
Time Squared: SMUD	0.0009	0.0003	2.99
Adjusted for autocorrelation and cross-sectional correlation.			
Wald chi squared = 2,693			
Dependent variable = natural log of TCU electricity consumption per capita by planning area 1990-2013.			
All variables in logged form except time.			

Source: California Energy Commission, Demand Analysis Office, 2014.

Table A-7: Street Lighting Sector Electricity Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Per Capita Income (2013$)	0.2408	0.0892	2.70
Constant: Burbank/Glendale	-1.0794	0.0723	-14.93
Constant: IID	-2.6927	0.1659	-16.23
Constant: LADWP	1.2344	0.1054	11.72
Constant: Pasadena	-1.2730	0.0501	-25.41
Constant: PG&E	1.7199	0.0453	37.97
Constant: SCE	1.9387	0.0773	25.07
Overall Constant	6.6419	0.9264	7.17
Trend Variables			
Time Squared: BUGL	-0.0003	0.0002	-1.17
Time: IID	0.1080	0.0295	3.66
Time Squared: IID	-0.0028	0.0011	-2.47
Time: LADWP	0.0639	0.0177	3.60
Time Squared: LADWP	-0.0038	0.0007	-5.71
Time: Pasadena	0.0091	0.0030	3.00
Time: PG&E	0.0065	0.0064	1.01
Time Squared: PG&E	-0.0005	0.0002	-2.54
Time: SCE	0.0189	0.0101	1.87
Time Squared: SCE	-0.0011	0.0004	-2.92
Time: SDG&E	0.0233	0.0049	4.78
Time: SMUD	0.0211	0.0056	3.76
Time Squared: SMUD	-0.0007	0.0002	-3.53
Adjusted for autocorrelation and cross-sectional correlation.			
Wald chi squared = 48,785			
Dependent variable = natural log of street lighting electricity consumption by planning area 1990-2013			
All variables in logged form except time.			

Source: California Energy Commission, Demand Analysis Office, 2014.

Table A-8: Peak Demand Econometric Model

Variable	Estimated Coefficient	Standard Error	t-statistic
Per Capita Income (2013$)	0.1579	0.0340	4.65
Unemployment Rate	-0.0027	0.0011	-2.58
Persons per Household	-0.6911	0.1787	-3.87
Residential Electricity Rate	-0.0252	0.0239	-1.05
Commercial Electricity Rate	-0.0279	0.0169	-1.66
Annual Max *Average631*	1.0633	0.0557	19.11
Residential Consumption per Capita	0.2083	0.0344	6.05
Commercial Consumption per Capita	0.1095	0.0261	4.20
Dummy: 2001	-0.0616	0.0111	-5.57
Constant: IID	0.1902	0.0410	4.64
Constant: LADWP	-0.1696	0.0150	-11.28
Constant: Pasadena	-0.0996	0.0154	-6.48
Constant: PG&E	-0.1671	0.0135	-12.39
Constant: SCE	-0.1246	0.0187	-6.66
Constant: SDG&E	-0.4339	0.0197	-22.03
Overall Constant	-7.4037	0.4035	-18.35
Trend Variables			
Time: Burbank/Glendale	0.0035	0.0007	5.07
Time: Imperial Irrigation District	0.0020	0.0008	2.57
Time: LADWP	0.0048	0.0016	2.95
Time Squared: LADWP	-0.0001	0.0000	-2.85
Time: Pasadena	0.0216	0.0018	11.80
Time Squared: Pasadena	-0.0005	0.0000	-11.09
Time: SCE	0.0038	0.0019	2.00
Time Squared: SCE	-0.0001	0.0000	-1.85
Time: SDG&E	0.0058	0.0007	8.51
Adjusted for autocorrelation and cross-sectional correlation.			
Wald chi squared = 25,433			
Dependent variable = natural log of annual peak per capita by planning area, 1980-2013.			
All variables in logged form except time and unemployment rate.			

Source: California Energy Commission, Demand Analysis Office, 2014.

APPENDIX B:
Self-Generation Forecasts

Compiling Historical Distributed Generation Data

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

- The California Solar Initiative (CSI).[34]
- New Solar Homes Partnership (NSHP).[35]
- Self-Generation Incentive Program (SGIP).[36]
- CSI Thermal Program for Solar Hot Water (SHW).[37]
- Emerging Renewables Program (ERP).[38]
- POU programs.[39]

In addition, power plants with a generating capacity of at least 1 MW are required to submit fuel use and generation data to the Energy Commission under the Quarterly Fuel and Energy Report (QFER) Form 1304.[40] QFER data includes fuel use, generation, onsite use, and exports to the grid. These various sources of data were used to quantify distributed generation activity in California and to build a comprehensive database to track distributed generation activity. One concern in using incentive program data along with QFER data is the possibility of double-counting generation if the project has a capacity of at least 1 MW. This can occur since the publicly available incentive program data do not list the name of the entity receiving the distributed generation incentive for confidentially reasons while QFER data collects information from the plant owner. Therefore, it is not possible to determine if a project from a distributed generation incentive program is already reporting data to the Energy Commission under QFER. For example, the SGIP has 130 completed projects that are at least 1 MW and about 55 pending projects that are also 1 MW or larger. Given the small number of distributed generation projects

34 Downloaded on 6/25/14 from (http://www.californiasolarstatistics.org/current_data_files/).

35 Program data received on 7/10/14 from staff in the Energy Commission's Renewables Office.

36 Downloaded on 07/02/14 from (https://energycenter.org/index.php/incentive-programs/self-generation-incentive-program/sgip-documents/sgip-documents). Data cover up to second quarter of 2014.

37 Downloaded on 7/02/14 from (http://www.gosolarcalifornia.org/solarwater/index.php).

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

39 Program data submitted by POU's in July 2014. http://www.energy.ca.gov/sb1/pou_reports/index.html.

40 Data received from Energy Commission's Supply Analysis Office on 7/16/14.

meeting the QFER reporting size threshold, double-counting may not be significant but could become an issue as an increasing amount of large SGIP projects come on-line.

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

Projects from incentive programs were classified as either completed or uncompleted. This was accomplished by examining the current status of a project. Each program varies in how it categorizes a project. CSI projects having the following statuses are counted as completed projects: "Completed," "PBI – In Payment," "Pending Payment," "Incentive Claim Request Review," and "Suspended – Incentive Claim Request Review." For the SGIP program, a project with the status "Completed" is counted as completed. For the ERP program, there was no field indicating the status of a project. However, there was a column labeled "Date_Completed," and this column was used to determine if a project was completed or uncompleted. For the NSHP, a project that has been approved for payment is counted as a completed project. For SHW, any project having the status "Paid" was counted as a completed project. POU PV data provided installations by sector. Staff then projected when uncompleted projects will be completed based on how long it has taken completed projects to move between the various application stages. The next step was to assign each project to a county and sector. For most projects, the mapping to a county is straightforward since either the county information is already provided in the data or a ZIP code is included. For nonresidential projects, when valid North American Classification System (NAICS) codes are provided in the program data, the corresponding NAICS sector description was used; otherwise, a default "Commercial" sector label was assigned. Each project was then mapped to one of 16 demand forecasting climate zones based on utility and county information. These steps were used to process data from all incentive programs in varying degrees to account for program-specific information. For example, certain projects in the SGIP program have an IOU as the program administrator but are interconnected to a POU; these projects were mapped directly to forecasting zones. For the ERP program, PV projects less than 10 kilowatt (kW) were mapped to the residential sector while both non-PV and PV projects greater than 10 kW were mapped to the commercial sector. Finally, capacity and peak factors from DG evaluation reports were used to estimate energy and peak impacts.[41] [42]

---

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

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

Staff then needed to make assumptions about technology degradation. PV output is assumed to degrade by 1 percent annually; this rate is consistent with other reports examining this issue.[43] Staff decided to not degrade output for non-PV technologies, given the uncertainty in selecting an appropriate factor and the implication of using these factors in a forecast with a 10-year horizon. This decision was based on information from a report focused on combined heat and power projects funded under the SGIP program[44]. The report found significant decline in energy production on an annual basis by technology; however, the reasons for the decline varied and ranged from improper planning during the project design phase, a lack of significant coincident thermal load (for combined heat and power applications), improper maintenance, and fuel price volatility. Also, some technologies, such as fuel cells and microturbines, were just beginning to be commercially sold in the market, and project developers did not have a full awareness of how these technologies would perform in a real-world setting across different industries. This does not mean that staff will not use degradation factors in future reports, and once better data have been collected, staff will revisit this issue. Another issue with projects funded under SGIP is the need to account for decommissioned projects. Currently, the publicly available SGIP data set does not identify if a previously funded project has been decommissioned.

For the *CED 2015 Preliminary* demand forecast, staff requested monthly PV interconnection data by ZIP code and sector from utilities pursuant to data collection regulations under IEPR for installations occurring between 2012 through 2014. This was initiated primarily due to informal comments staff received from utility forecasters suggesting that a number of PV projects were being installed and where customer-generators were not seeking a rebate from an incentive program. Since staff's historical record of PV installation is based on participation through rebate programs, this issue could significantly understate staff's understanding of trends in PV adoption particularly given the step cost reductions of PV systems in recent years. Table B-1 below shows the discrepancy between staff's estimate of annual PV additions and the interconnection data submitted by the IOUs for the *2015 IEPR*.

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

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

Table B-1: PV Interconnection 2012-2013

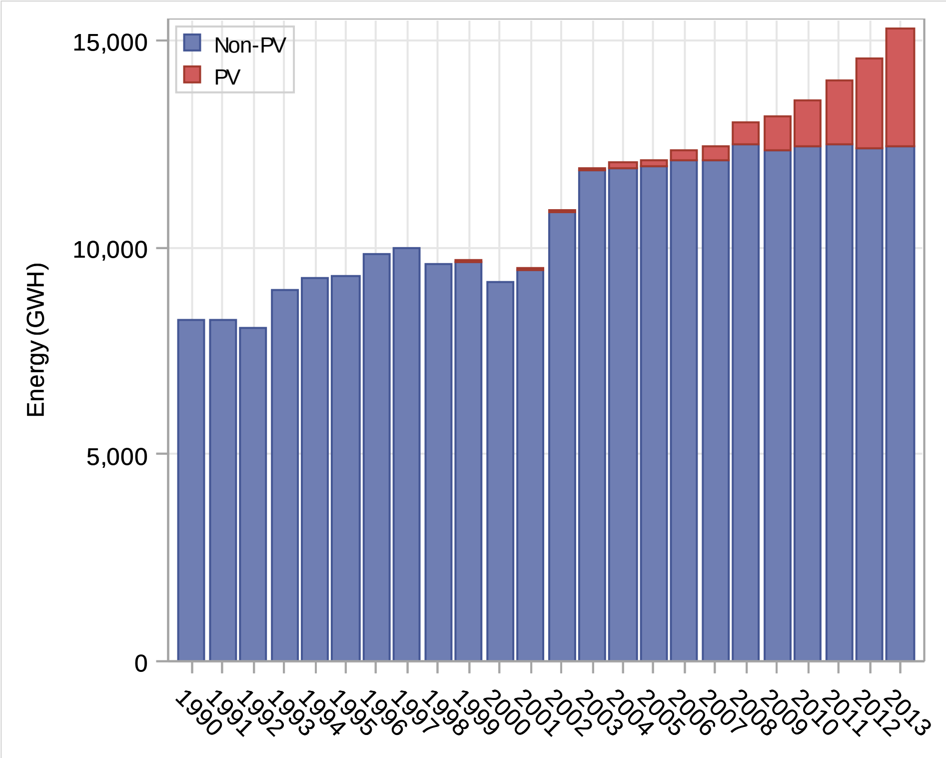
Annual PV Additions (MW)			
Utility	Year	Utility 2015 IEPR Filing	CEC
PG&E	2012	180	184
PG&E	2013	260	163
SCE	2012	136	163
SCE	2013	184	161
SDG&E	2012	37	31
SDG&E	2013	67	33

Source: California Energy Commission, Demand Analysis Office, 2015

As **Table B-1** makes clear, the difference in PV installation between staff's compilation of publically available data and utility interconnection data is significant. Around the fall of 2014, staff recommended that the Energy Commission make changes to its data collection regulations to better capture PV installations in the state. This effort may be consolidated into a broader reform of data collection regulations under proposal at the Energy Commission.

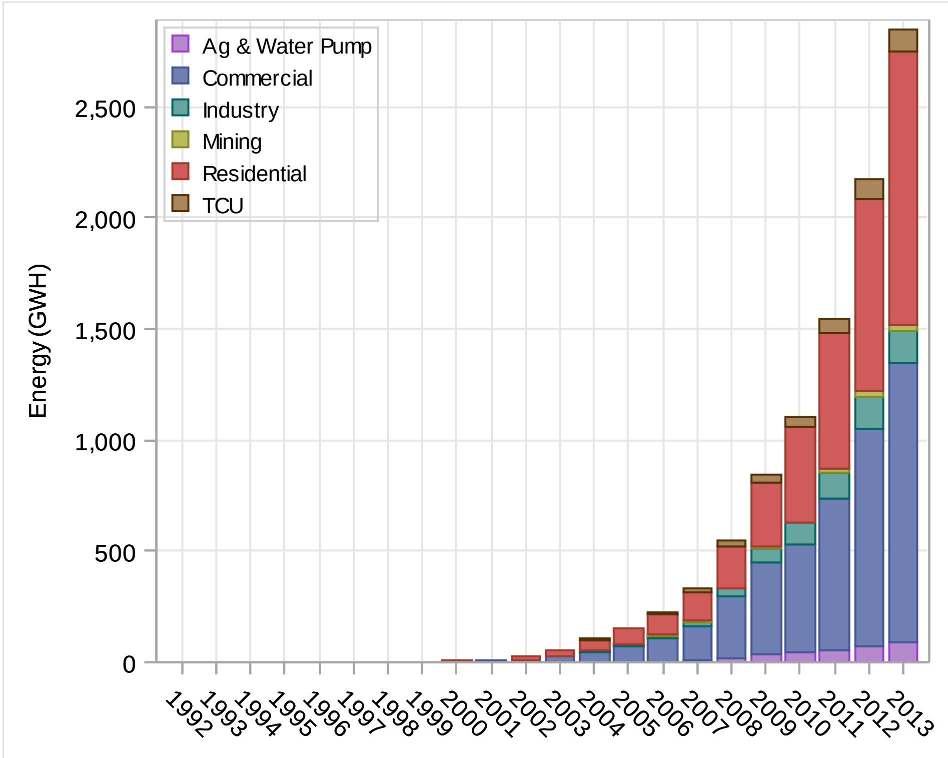
Figure B-1 shows statewide energy use from PV and non-PV technologies. While PV constitutes a small share of total onsite usage, PV use begins to show a sharp increase as the CSI program started to gain momentum after 2007. **Figure B-2** shows PV self-generation by sector from 1998 to 2013. PV adoption is generally concentrated in the residential and commercial sectors. The growth in PV adoption was initially driven by the CSI program and shows no sign of slowing down even though CSI rebates have largely expired. **Figure B-3** provides the statewide median costs and incentives (utility rebates) associated with PV installation over all customer sectors on a per kW basis since 1998.

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



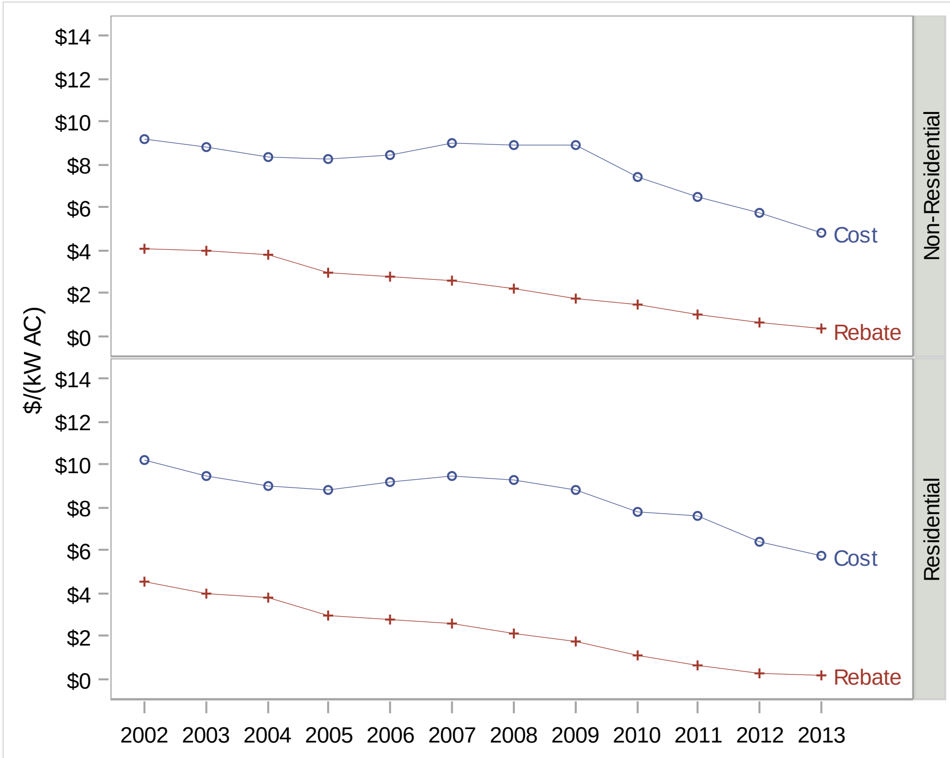
Source: California Energy Commission, Demand Analysis Office, 2015

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



Source: California Energy Commission, Demand Analysis Office, 2015

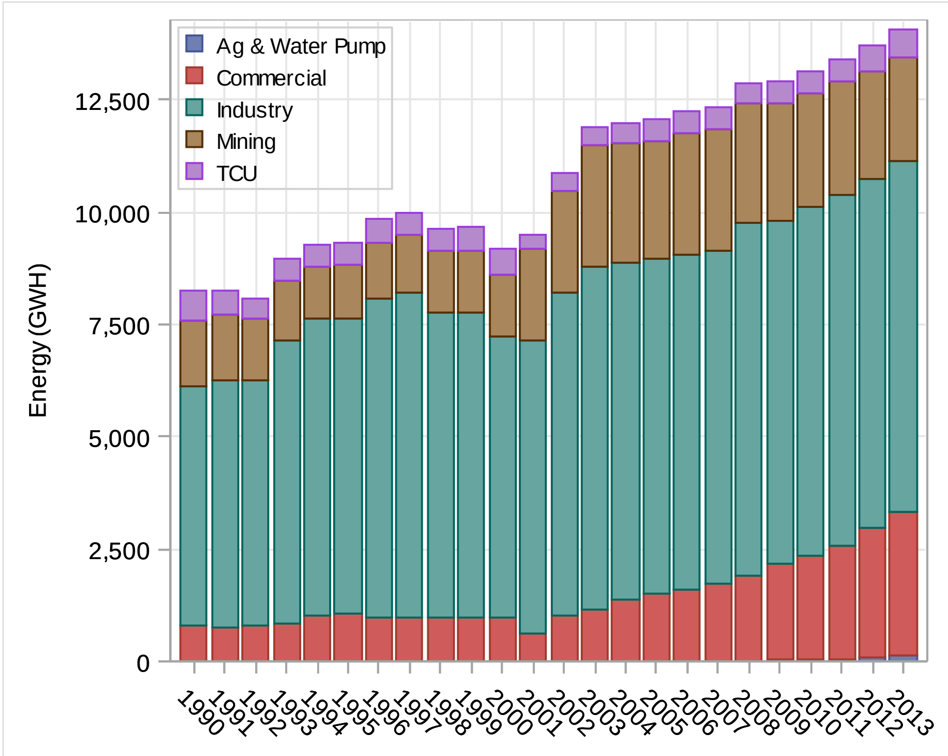
Figure B-3: Median PV Installation Costs and Subsidies, Statewide



Source: California Energy Commission, Demand Analysis Office, 2015

For self-generation as a whole, residential sector use is still a very small component of the total (around 8 percent in 2013). **Figure B-4** gives a breakout of self-generation by nonresidential category for the state and shows a continued overall dominance by the industrial and mining (resource extraction) sectors, although commercial adoptions are clearly trending upward in recent years.

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



Source: California Energy Commission, Demand Analysis Office, 2015

Residential Sector Predictive Model

The residential sector self-generation model was designed to forecast PV and SHW adoption using estimated times for full payback, which depends on fuel price, system cost, and performance assumptions. The model is similar in structure to the cash flow-based distributed generation model in the National Energy Modeling System as used by the Energy Information Administration[45] and the *SolarDS* model developed by the National Renewable Energy Laboratory.[46]

Several changes to the residential sector model were made for *CED 2015 Preliminary* based on the need to account for the impact of net metering and the design of residential retail rates. Staff collected data on historical retail rates for the IOUs. Due to time constraints, staff will continue to use average sector rates as developed for *CED 2015 Preliminary* forecast for POUs.

---

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

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

Due to limited participation from the multifamily segment of the residential sector, staff limited its modeling of PV adoption to single-family homes.[47]

PV cost and performance data were based on analysis performed by Energy and Environmental Economics (E3) for the CPUC.[48] [49] Historical PV prices were developed from incentive program data. To forecast the installed cost of PV, staff adjusted the base year mean PV installed cost compiled from DG program data to be consistent with the PV price forecast developed by E3.

SHW cost and performance data were based on analysis conducted by Itron in support of a CPUC proceeding examining the costs and benefits of SHW systems.[50] Adjustments were made for incentives offered by the appropriate utility to obtain the net cost.

Residential electricity and gas rates consistent with those used in *CED 2015 Preliminary* were used to calculate the value of bill savings. Historical and current retail rates were used for IOUs up until 2015. After 2015, these rates were escalated at a rate consistent with the forecast of average residential sector electric rates developed for *CED 2015 Preliminary.* Bill savings, including net metering calculation, also incorporates data on annual electric consumption from the Commission's Residential Appliance Saturation Survey (RASS) and residential load shape data submitted by utilities as part of the *2015 IEPR* data request. The useful life for both PV and SHW was assumed to be 30 years, which is longer than the forecast period. PV surplus generation was valued at a uniform rate of $0.04/kilowatt-hour (kWh).[51]

Projected housing counts developed for *CED 2015 Preliminary* were allocated to two space heating types – electric and gas. The allocation is based on saturation levels from RASS. PV systems were sized based on RASS floor space data, assumptions regarding roof slope, and factors to account for shading and orientation.[52] PV system size was constrained to be no more

47 The existing participation by multifamily segment generally tends to be limited to low-income units. Using adoption from this segment as a basis for generalizing adoption to the broader multifamily segment may not be appropriate.

48 PV installed cost and operating cost come from the draft version of the NEM Public Tool available at http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm.

49 Energy and Environmental Economics, Inc. November 2013. *California Solar Initiative 2012 Impact Evaluation.* Report is forthcoming, but staff was provided a draft copy of the report and the simulated PV production data.

50 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.

51 A CPUC proposed decision on surplus compensation estimated that the surplus rate for PG&E 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.

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

than 4 kW CEC AC[53] for single-family homes (retrofit) and 2 kW CEC AC for new construction. For PV systems, hourly generation over the life of the system was estimated based on data provided to staff by CPUC. For SHW systems, energy saved annually was used directly to estimate bill savings. PV and SHW energy output were degraded at the same rate based on the PV degradation factor estimated by ICF for EIA.[54]

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

The payback calculation was based on the internal rate of return (IRR) method used in the *SolarDS* model. The IRR approach takes an investment perspective and takes into account the full cash flow resulting from investing in the project. The cash flow is first converted to an annuity stream before the IRR is calculated. This is necessary since outlays to handle inverter replacement may cause issues in solving for the IRR.[55] In general, the higher the IRR of an investment, the more desirable it is to undertake. Staff compared the IRR to a required hurdle rate (5 percent) to determine if the technology should be adopted. If the calculated IRR was greater than the hurdle rate, then payback was calculated; otherwise, the payback was set to 25 years. The formula for converting the calculated IRR (if above 5 percent) to payback is:

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

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

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

Payback sensitivity was set to 0.3.[56] To estimate actual penetration, maximum market share was multiplied by an estimated adoption rate, calculated using a Bass Diffusion curve, to estimate

---

53 Rating of solar modules in real-world conditions as determined by the Energy Commission.

54 ICF International. June 2010. *Photovoltaic (PV) Cost and Performance Characteristics for Residential and Commercial Applications*. Report prepared for U.S. Energy Information Administration and available as Appendix A at http://www.eia.gov/analysis/studies/distribgen/system/pdf/full.pdf.

55 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 and is a nonlinear function of the cash flow stream. The annuity approach also has merit in ranking technologies with unequal lives which is the case in the Commercial sector distributed generation model.

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

annual PV and SHW adoption. The Bass Diffusion curve is often used to model adoption of new technologies and is part of a family of technology diffusion functions characterized as having an "S" shaped curve to reflect the different stages of the adoption process.

The adoption rate is given by the following equation:

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

The terms *p* and *q* represent the impact of early and late adopters of the technology, respectively. Staff used mean values for *p* (0.03) and *q* (0.38), derived from a survey of empirical studies.[57]

Self-Generation Forecast, Nonresidential Sectors

Commercial Combined Heat and Power and Photovoltaic Forecast

CED 2015 Preliminary continues to use the predictive model developed for the *2013 Integrated Energy Policy Report* (*2013 IEPR*) demand forecast to model adoption of CHP and PV in the commercial sector. This model uses the same basic payback framework as in the residential predictive model. Staff began by allocating energy use to different building types using the *2006 Commercial End-Use Survey* (CEUS).[58] The survey contains information on each site that participated in the survey, including:

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

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

Next, the "DrCEUS" building energy use simulation tool, developed in conjunction with the CEUS, was used to create load shapes by fuel type and end use. DrCEUS uses the eQUEST building energy use software tool as a "front-end" to the considerably more complex U.S.

---

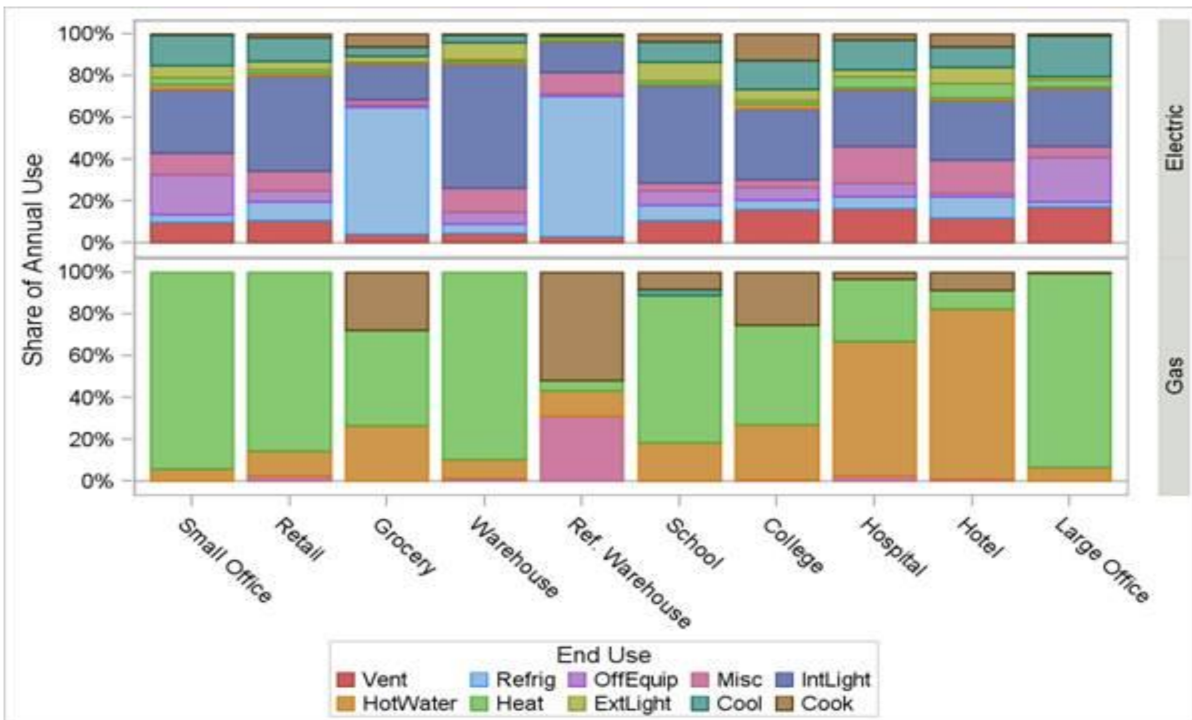
57 Meade, Nigel and Towidul Islam. 2006. "Modeling and forecasting the diffusion of innovation – A 25-year review," *International Journal of Forecasting*, Vol. 22, Issue 3.

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

Department of Energy 2.2 building energy use simulation tool, which does much of the actual building energy demand simulation.

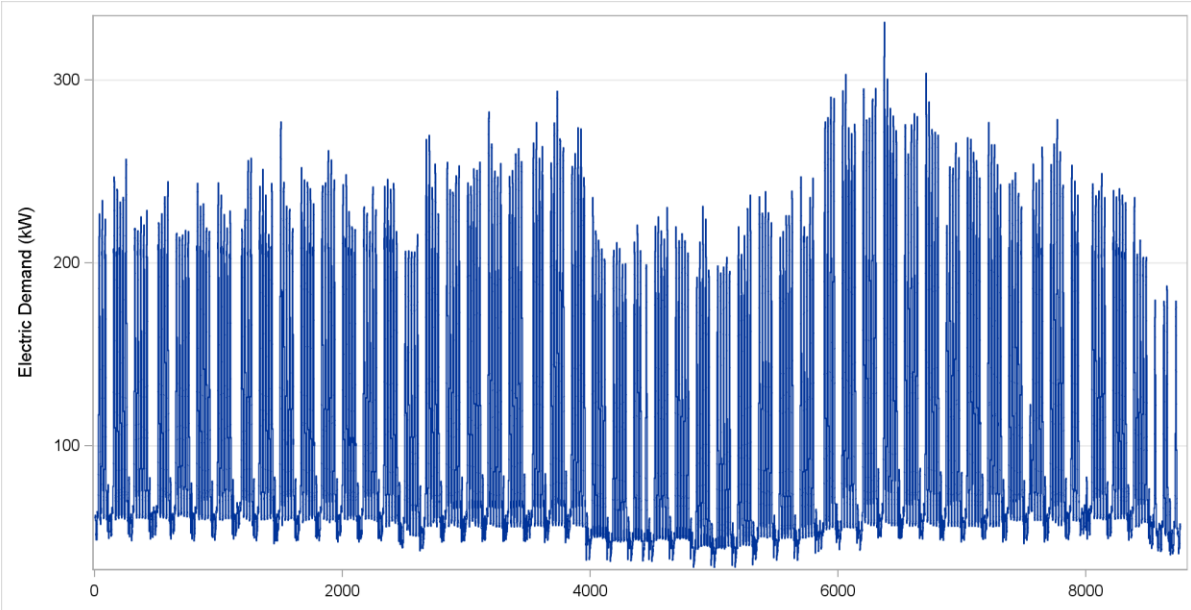
Staff grouped small and medium-size buildings together since the CEUS survey had a limited number of sample points for these building sizes. In addition, because of small sample sizes, staff grouped inland and coastal climate zones together. Four geographic profiles were created: north inland, north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

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



Source: California Energy Commission, Demand Analysis Office, 2015

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



*In chronological order.
Source: California Energy Commission, Demand Analysis Office, 2015

Next, the commercial sector model output was benchmarked to the 2013 QFER data. The distribution of energy use by fuel type and end use was then applied to the CEUS site level data and expanded by the share of floor space stock represented by the site. This essentially "grows" the site level profile from the CEUS survey to match the QFER calibrated commercial model output by end use, fuel type, forecast zone, demand scenario, and year.

For CHP, staff assumed that waste heat will be recovered to meet the site demand for hot water and space heating and that this will displace gas used for these two purposes.[59] Based on this assumption, the power-to-heat ratio was then calculated for each building type and size category by forecast climate zone and demand scenario.

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

---

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

sized to meet the base load thermal demand. Thermal factors were less than one for most building types.

Finally, cost and benefits were developed to derive payback. Staff applied the same set of assumptions used in a prior Energy Commission-sponsored report to characterize CHP technology operating characteristics such as heat rate, useful heat recovery, installed capital cost, and operating costs.[60] PV technology details such as installed cost and operating cost were based from the same E3 dataset used for the residential sector predictive model. Avoided retail electric and gas rates were derived from utility tariff sheets and based on estimated premise-level maximum demand. Current retail electric and gas rates were escalated based on the rates of growth for fuel prices developed for the *CED 2015 Preliminary*. In addition, CHP technologies may face additional costs such as standby and departing load charges. Details for these charges were also collected and used in the economic assessment. Staff examined details surrounding the applicability of these charges and applied them as appropriate. The fuel cost for using gas by the different CHP technologies also had to be estimated. Staff began with border prices and then added a transportation charge. Staff from the Energy Commission's Supply Analysis Office supplied the historical border prices. The Malin border price was used for PG&E, and the Topock-Needles border price was used for both SoCal Gas and SDG&E. For the forecast period, staff escalated average 2013 border prices at a rate consistent with Supply Analysis Office's gas rate scenarios. Staff also identified federal tax credits for installing CHP and PV and assessed the eligibility for utility rebate programs such as the SGIP and CSI.

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

Other Sector Self-Generation

Staff used a trend analysis for forecasting adoption of PV in the noncommercial/nonresidential sectors. For SHW, staff assumed that nonresidential sector adoption would follow a ratio similar to residential versus nonresidential PV adoption.

PV Peak Impact

For *CED 2015 Preliminary*, staff spent time refining the peak factors used to translate PV installed capacity to impact during the utility annual peak hour. **Table B-2** shows factors used in prior IEPR demand forecasts and those used in *CED 2015 Preliminary*.

60 See footnote 24.

Table B-2: PV Peak Factors

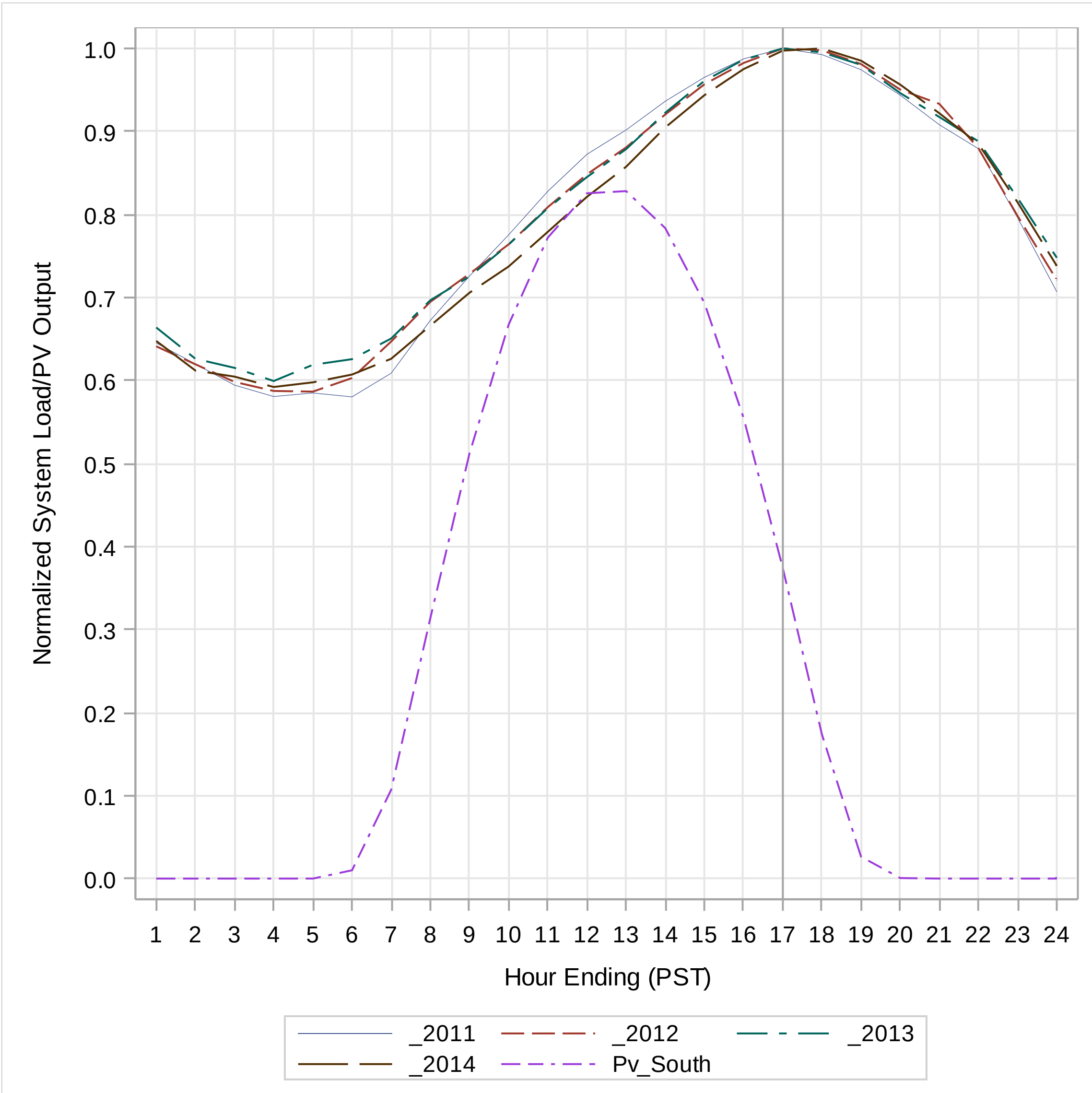
Utility	CED 2011	CED 2013	CED 2015
PG&E	55%	50%	37%
SCE	62%	50%	40%
SDG&E	68%	50%	40%

Source: California Energy Commission, Demand Analysis Office, 2015

Factors used in support of *CED 2011* came from a CPUC-sponsored study of impacts of its CSI program.[61] Utility staff commented that the factors were too high especially in the case of SDG&E. To address these concerns, staff used a uniform factor of 50 percent for *CED 2013*. To refine PV peak factors further in support of *CED 2015 Preliminary*, staff examined simulated PV production profiles provided by CPUC relative to utility annual peak day between 2011 through 2014.

61 See footnote 9. Factors come from Table C-3.

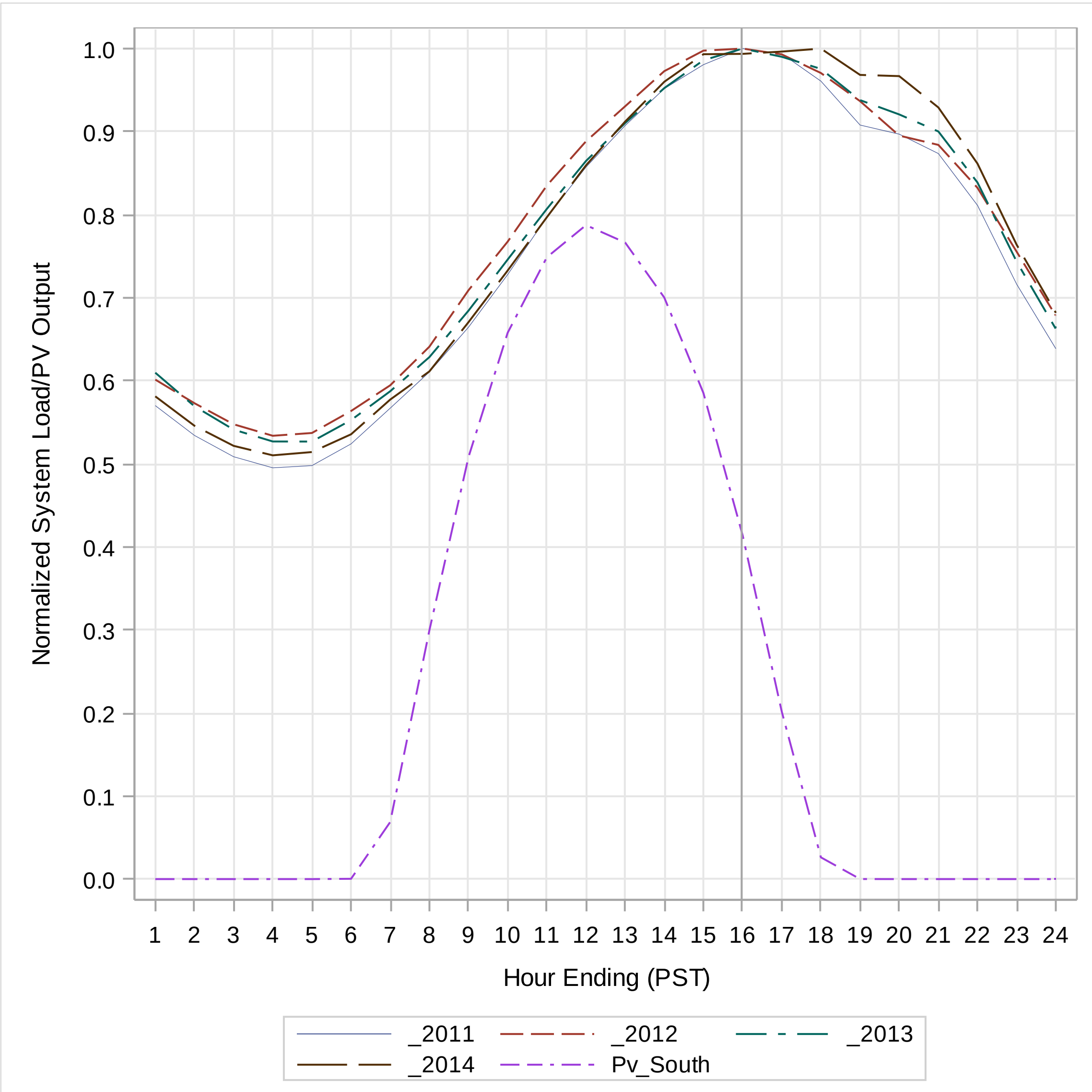
Figure B-7: PG&E System Load vs PV Production



Source: California Energy Commission, Demand Analysis Office, 2015

Figure B-7 shows the hourly load for PG&E annual peak day for 2011 through 2014. The load for each hour was normalized by the annual peak so that the hour corresponding to a value of 1 shows the time of system peak for the given year. The peak occurred on June 21 for 2011, August 13 for 2012, and July 3 and 25 for 2013 and 2014, respectively. The peak hour was 5 p.m. for all years except for 2014 where the peak occurred on 6 p.m. Based on additional historical data, staff characterized PG&E as typically having an annual peak on July at 5 p.m. The curve labeled "PV_South" shows the normalized PV output (kWh/kW) in July (averaged over all days) for a representative south-facing PV system in PG&E Forecasting Zone 2 (Sacramento). A vertical reference line corresponding to 5 p.m. is drawn to show the coincidence of PV output relative to the expected time of the system peak for PG&E. A similar analysis was done for the other four zones which make up the PG&E planning area and based on the result, staff lowered the PG&E PV peak factor from 50 percent to 37 percent. Staff performed similar analyses for SCE and SDG&E, which are shown in **Figures B-8** and **B-9**.

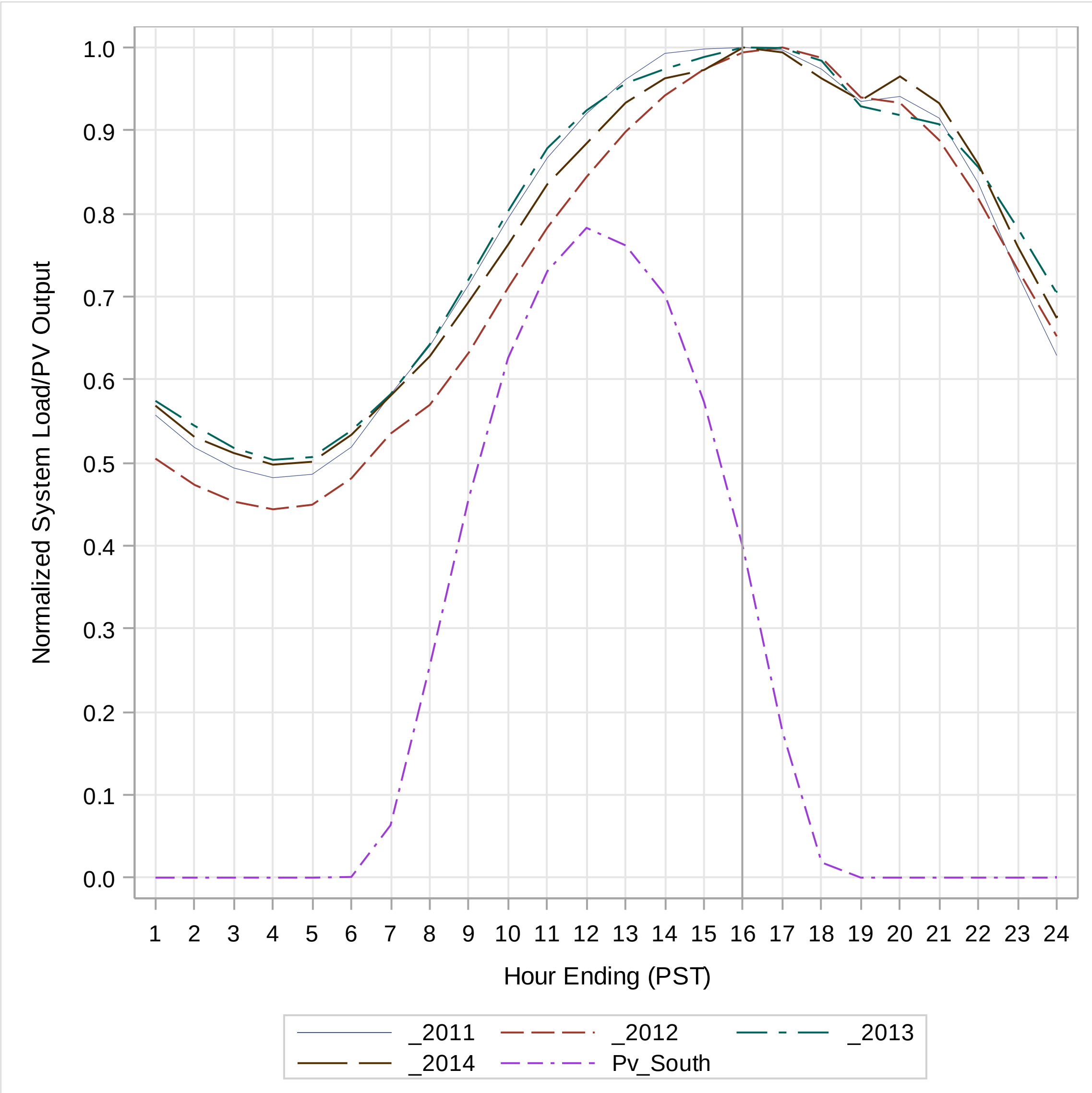
Figure B-8: SCE System Load vs PV Production



Source: California Energy Commission, Demand Analysis Office, 2015

Figure B-8 shows the hourly load for SCE annual peak day for 2011 through 2014. SCE's annual peak occurred on September 7 for 2011, August 13 for 2012, and the 5th and 15th of September for 2013 and 2014, respectively. Based on additional historical data, staff characterized SCE as typically have an annual peak on September 16 at 4 p.m. The curve labeled "PV_South" shows the normalized PV output (kWh/kW) in September (averaged over all days) for a representative south-facing PV system in SCE forecasting zone 7 (Fresno). A vertical reference line corresponding to 4 p.m. is drawn to show the coincidence of PV output relative to the expected time of the system peak for SCE. A similar analysis was done for the other three zones that make up the SCE planning area and, based on the result, staff lowered the SCE PV peak factor from 50 percent to 40 percent.

Figure B-9: SDG&E System Load vs PV Production



Source: California Energy Commission, Demand Analysis Office, 2015

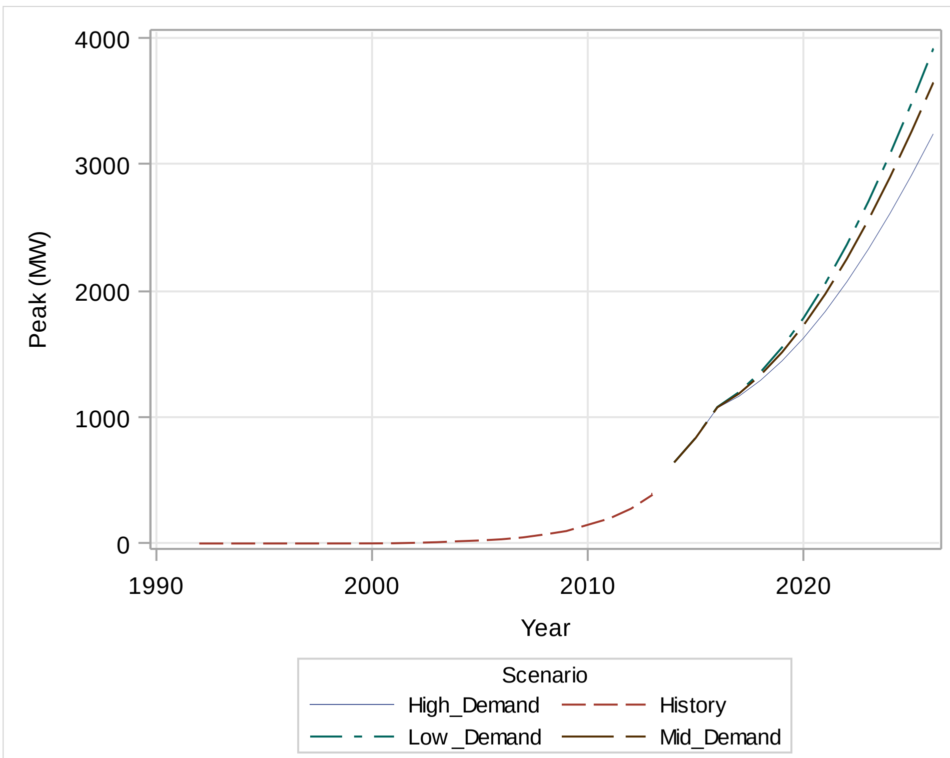
Figure B-9 shows the hourly load for SDG&E annual peak day for 2011 through 2014. SDG&E's peak occurred on September 7 for 2011, September 14 for 2012, August 30 for 2013, and September 16 for 2014. Based on additional historical data, staff characterized SDG&E as typically having an annual peak on September 16 at 4 p.m. The curve labeled "PV_South" shows the normalized PV output (kWh/kW) in September (averaged over all days) for a representative south-facing PV system in the SDG&E territory. A vertical reference line corresponding to 4pm is drawn to show the coincidence of PV output relative to the expected time of the system peak for SDG&E. Based on this result, staff lowered the SDG&E PV peak factor from 50 percent to 40 percent.

These adjustments to the PV peak factor on the utility system peak is based on a retrospective assessment and does not account for potential shifts in the timing of the utility peak as additional behind-the-meter PV is added on the utility distribution system.[62]

Statewide Modeling Results

The following figures show results from the predictive models at the statewide level by demand scenario. **Figure B-10** shows the PV peak demand impact in the residential sector, which reaches more than 3,600 MW in the mid demand case and just under 4,000 MW in the low demand case by 2026. Additions decrease substantially with the expiration of the federal tax credit, which occurs in the middle of the forecast period, but then begin to increase as rates increase and PV installed costs decrease.

Figure B-10: Residential Sector PV Peak Impact, Statewide

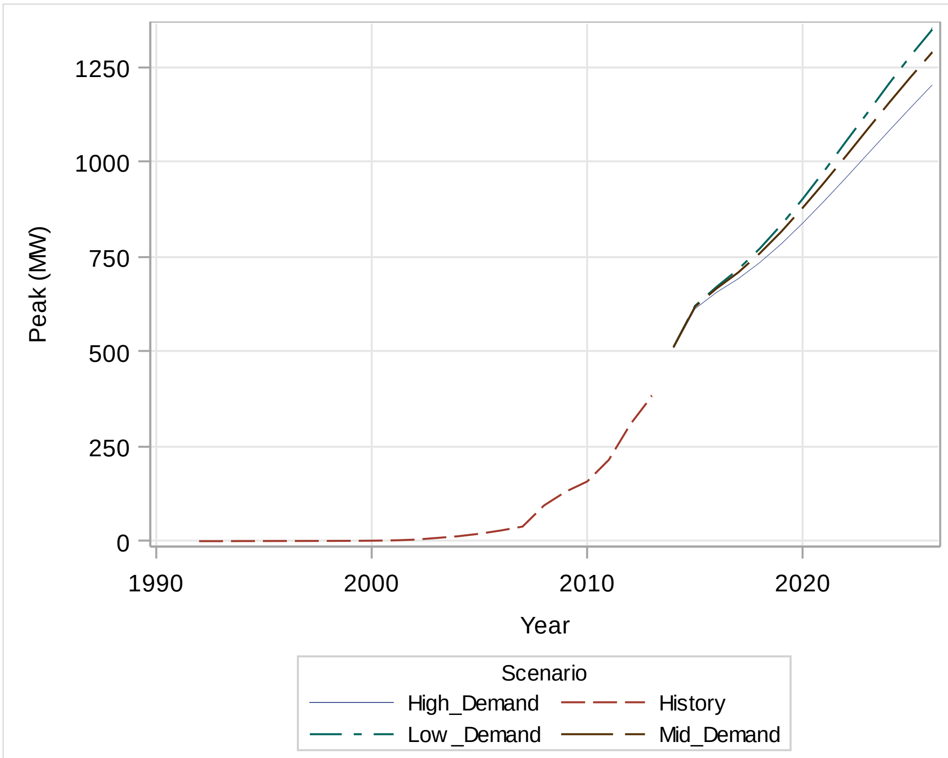


Source: California Energy Commission, Demand Analysis Office, 2015

62 Staff is making changes to the peak load model used to forecast long term peak to account for these impacts. It is anticipated that these changes will be ready for the *2017 IEPR* demand forecast.

Figure B-11 shows the PV peak demand impact in the commercial sector, which reaches just under 1,300 MW in the mid demand case and nearly 1,400 MW in the low demand case by 2026.

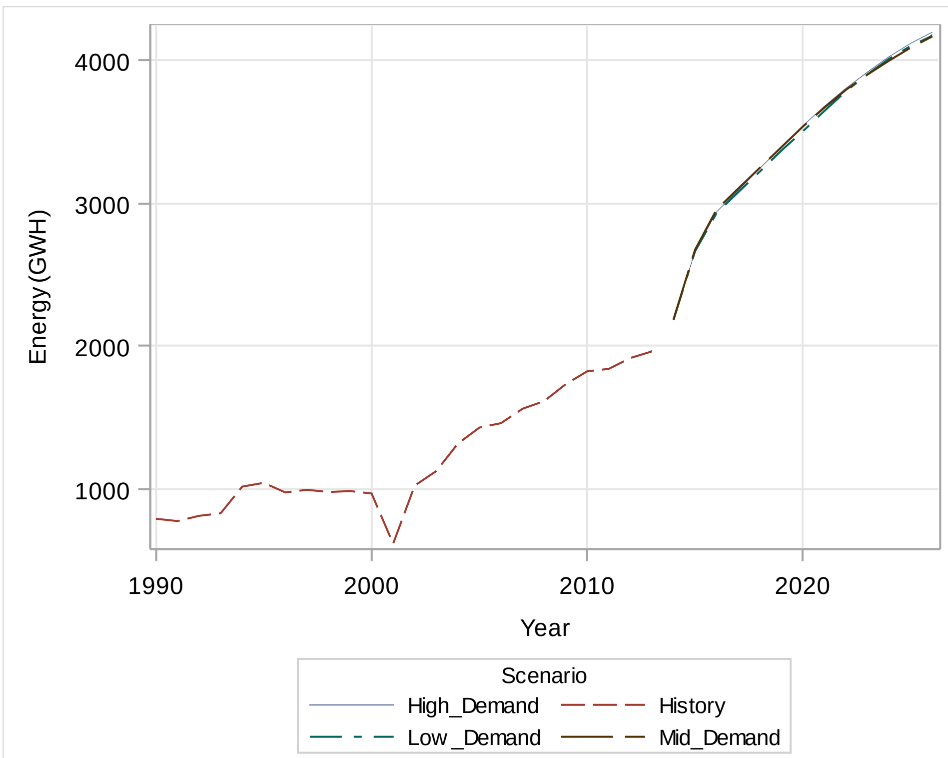
Figure B-11: Commercial Sector PV Peak Impact, Statewide



Source: California Energy Commission, Demand Analysis Office, 2015

Figure B-12 shows the CHP energy impact in the commercial sector, which reaches more than 4,100 GWh by 2026 in all three scenarios. The rapid jump between 2012 and 2014 occurs because of the need to account for pending projects currently moving through the SGIP program. CHP additions in the SGIP slowed because of changes in program design, which limited participation mainly to fuel cells; however, SGIP now provides incentives for conventional CHP technologies, and this has led to many pending projects moving through the various application stages. Higher commercial floor space projections in the high demand case increase adoption relative to the other cases, while higher rates in the low case have the same effect. The net result is that all three scenarios are very similar throughout the forecast period, with the low demand scenario yielding slightly more impact than the mid and low cases.

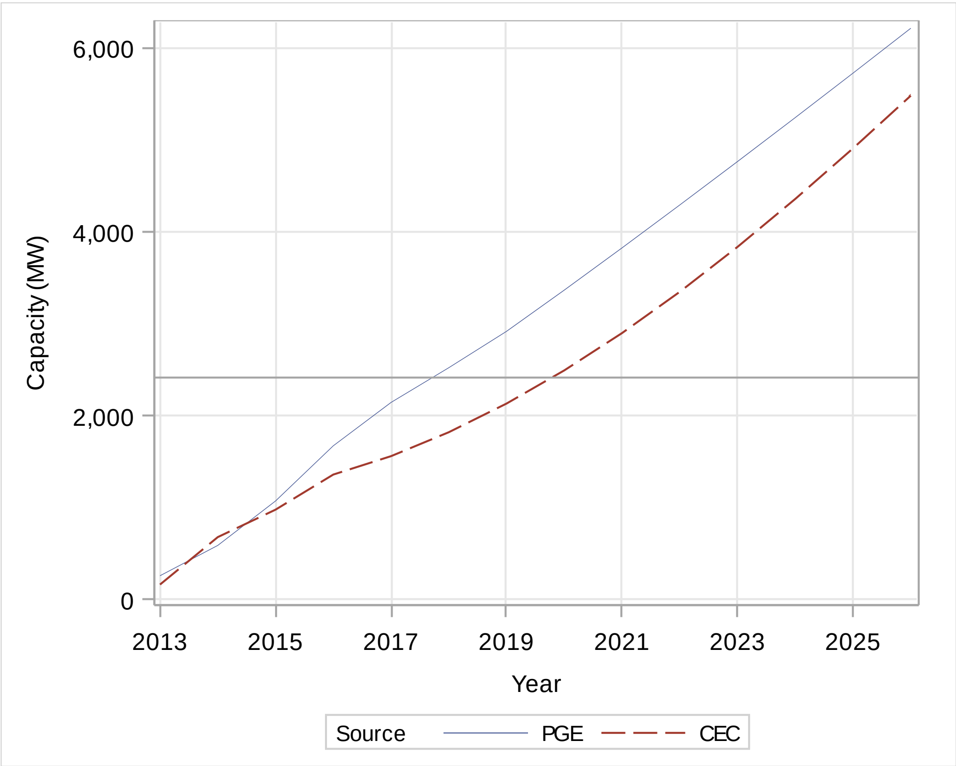
Figure B-12: Commercial Sector CHP Energy Impact, Statewide



Source: California Energy Commission, Demand Analysis Office, 2015

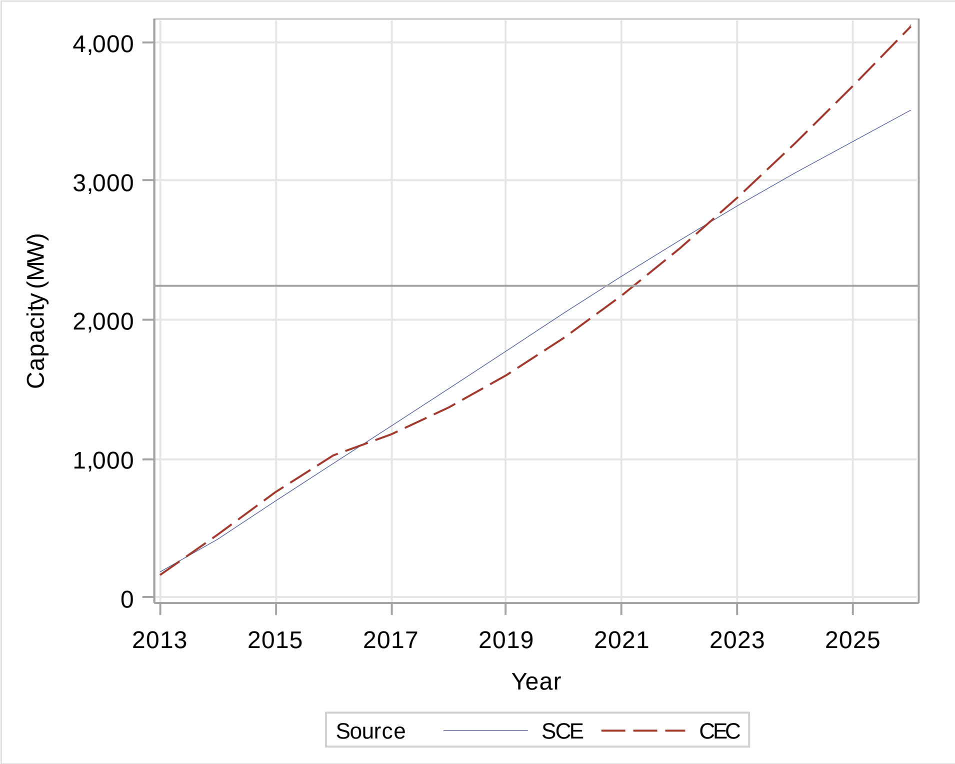
As part of the regular IEPR data collection, each utility submits a long-term demand forecast that includes impacts of distributed generation, energy efficiency, and demand response programs. **Figures B-13** through **B-15** compare staff's mid demand case PV forecast to the PV forecast submitted by the IOUs (cumulative incremental to 2013). A horizontal reference line is drawn to represent the current NEM limit for each utility (5 percent of noncoincident peak demand).

Figure B-13: Comparison of PV Forecast, PG&E



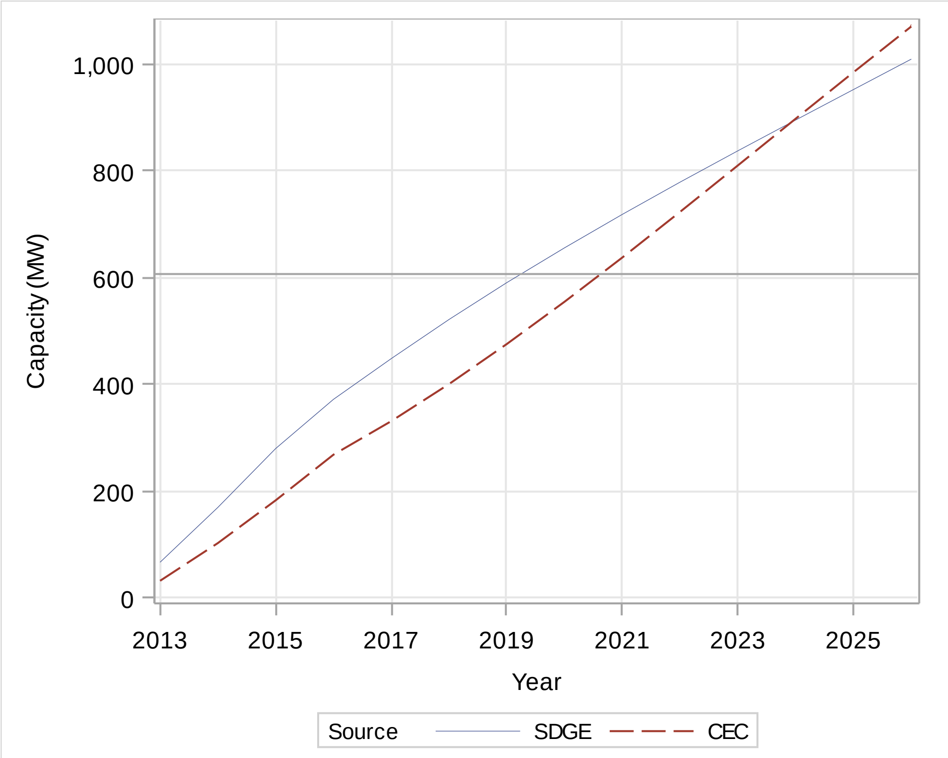
Source: California Energy Commission, Demand Analysis Office, 2015

Figure B-13: Comparison of PV Forecast, SCE



Source: California Energy Commission, Demand Analysis Office, 2015

Figure B-13: Comparison of PV Forecast, SDG&E



Source: California Energy Commission, Demand Analysis Office, 2015

Staff's forecast of PV adoption in the mid demand case is lower than PG&E's forecast over the forecast period and is more than 700 MW lower by 2026. Staff's forecast of PV adoption is initially lower than SCE and SDG&E for most of the forecast period but is higher than both utilities by 2026. In general, both the utilities' and staff's forecast expect future PV adoption to exceed the existing net energy metering (NEM) limit.

Optional Scenario

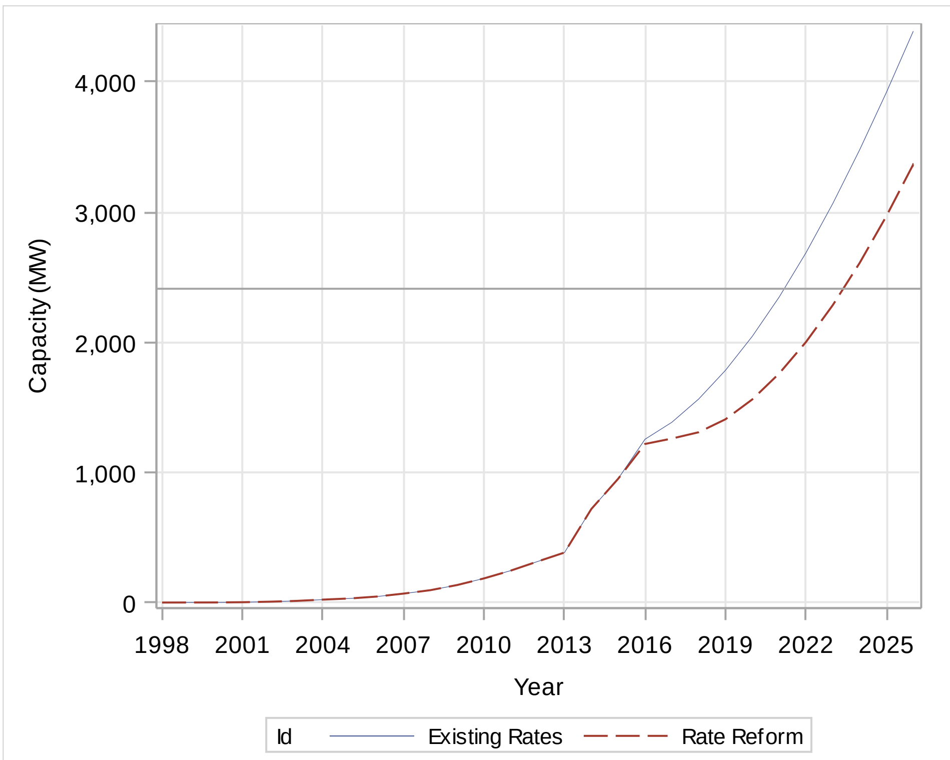
The passage of Assembly Bill 327 (Perea, Statutes of 2013) may bring about significant changes to the design of residential retail rates for the IOUs.[63] In particular, the tiered rate structure, with rates being progressively higher as consumption increases, may be limited to two tiers and could include a monthly customer charge or a minimum bill. A proposed decision from the CPUC provided an example of how retail residential rates may be set.[64] Staff used the rate

63 http://www.cpuc.ca.gov/NR/rdonlyres/66CCE840-F464-42F5-8B6A-D9F0FC649F67/0/Integrated_ResidentialRateReform.pdf.

64 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M151/K305/151305677.PDF.

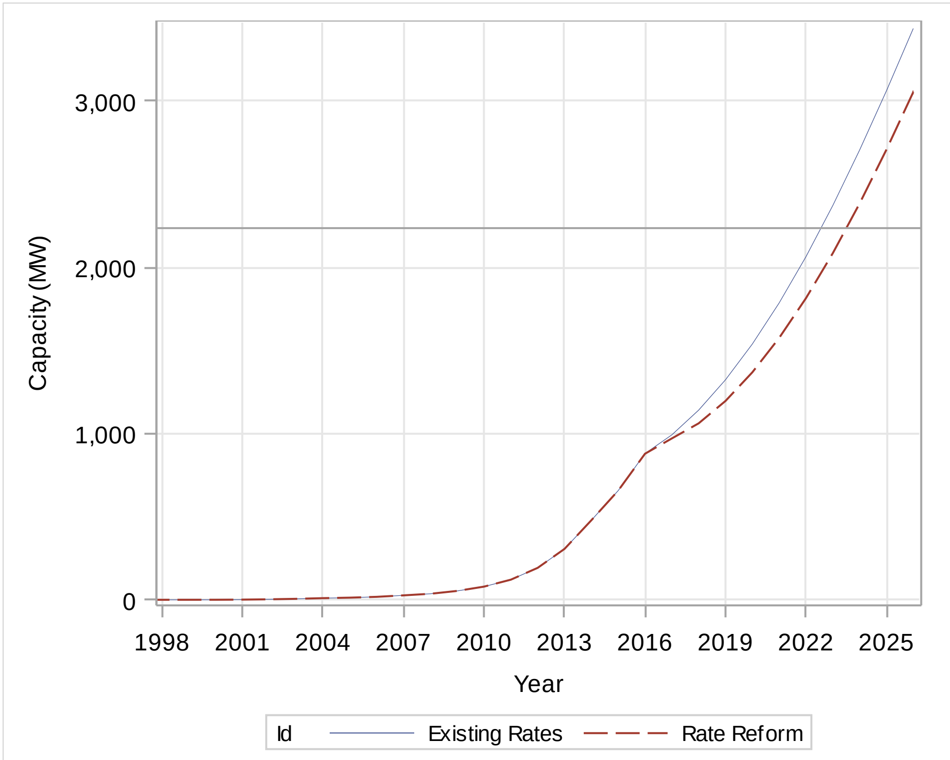
structure from the proposed decision ("glide paths") and modeled the impact of these proposed rates on PV adoption in the residential sector for the IOUs. The rates after 2018 used 2018 rates but were escalated based on the retail rate forecast prepared for *CED 2015 Preliminary*. Staff also assumed that customer-generators will still be compensated a full retail rate for their NEM exports. **Figure B-14** to **Figure B-16** show the impact on PV adoption to the preliminary mid demand scenario with a horizontal reference bar set at each utilities NEM capacity limit.

Figure B-14: Impact of Proposed Residential Retail Rates Changes, PG&E



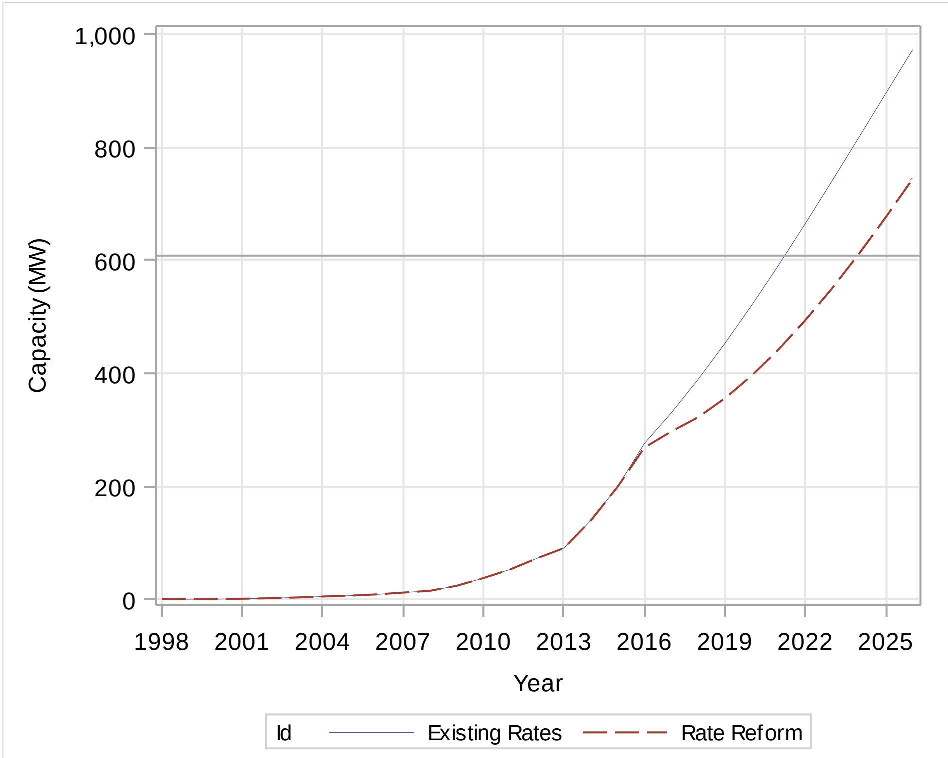
Source: California Energy Commission, Demand Analysis Office, 2015

Figure B-15: Impact of Proposed Residential Retail Rates Changes, SCE



Source: California Energy Commission, Demand Analysis Office, 2015

Figure B-16: Impact of Proposed Residential Retail Rates Changes, SDG&E



Source: California Energy Commission, Demand Analysis Office, 2015

The flattening of the residential rate tiers and the introduction of a monthly minimum bill charge reduce the value of bill savings, resulting in lower adoption of PV. For PG&E, these changes may reduce PV adoption by 1,000 MW, nearly 400 MW for SCE, and more than 200 MW for SDG&E. Another issue is the future structure of NEM compensation. Currently, customer-generators receive the full retail credit for their exports. The CPUC is reviewing the structure of NEM compensation in a separate proceeding.[65]

65 See footnote 15.