California Energy Commission

STAFF UPDATE REPORT

NEW RENEWABLE GENERATION NEEDED TO COMPLY WITH POLICY GOALS: UPDATE FOR 2022 PLANNING

CALIFORNIA
ENERGY COMMISSION

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ABSTRACT

California is actively pursuing a policy of integrating large amounts of renewable generation into the electricity grid. Electricity system planning activities require renewable net short estimates to determine the amount of new renewable generation capacity that must be built in state and/or delivered from out-of-state sources to meet the Renewables Portfolio Standard target, to evaluate the electricity infrastructure requirements for integrating new generation additions, and to identify market mechanisms that may need to be modified to provide the ancillary services that would be required to maintain reliable system operations.

This report presents an annual update to the forecasted amount of new renewable generation needed to comply with California energy policy goals, called the *planning renewable net short* throughout this document. The *planning renewable net short* should not be confused with the procurement renewable net short calculation made by each investor-owned utility for the California Public Utilities Commission Renewables Portfolio Standard procurement proceeding. In contrast, this *planning renewable net short* method was developed with stakeholder input during the *2011 Integrated Energy Policy Report* proceeding and is intended for use for statewide electric and transmission infrastructure planning.

Keywords: Planning renewable net short, incremental generation, Renewables Portfolio Standard, Renewable Electricity Standard, electricity, system integration, *2013 Integrated Energy Policy Report*

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EXECUTIVE SUMMARY

This report includes the annual update to the planning renewable net short for California load-serving entities that was originally presented in the *2011 Integrated Energy Policy Report (IEPR)*. Planning renewable net short is an estimate of the gap (or net short) between current levels of renewable energy production and target levels established by state policy for some future date. This update report includes the findings from other Energy Commission technical reports that were prepared in support of the most recent *IEPR*.

Estimates of the planning renewable net short are needed to determine the amount of new renewable generation capacity that can be expected to be built and/or delivered from out-of-state sources to meet the Renewables Portfolio Standard target. This information can then be used to evaluate the electricity infrastructure requirements for integrating these new generation additions and identify market mechanisms that may need to be modified to provide the ancillary services required to maintain system reliability. In addition to the current ancillary service products of operating reserves, regulation and load following, the California Independent System Operator is considering an additional ancillary service, a flexible ramping product that would create the incentive for generators and loads to offer services needed to integrate new renewable intermittent generation.

The method used to develop this planning renewable net short is consistent with the method used by the California Public Utilities Commission (CPUC) in Track II of the Long Term Procurement Planning proceedings. However, the planning renewable net short forecast, at this time cannot be compared to the CPUC Renewables Portfolio Standard procurement proceeding renewable net short for two reasons. First, the procurement renewable net short in the CPUC Renewables Portfolio Standard procurement proceeding is specific for each investor-owned utility's portfolio; the planning renewable net short covers a statewide perspective. Second, some of the variables needed to develop each investor-owned utility procurement renewable net short estimate include signed contracts that are not currently operational and for which details remain confidential. Energy Commission and CPUC staffs are discussing methods to present a common RNS to stakeholders for use in all proceedings.

The procurement renewable net short identifies how many renewable resources may still need to be contracted. The planning renewable net short is indifferent to how much has been contracted for already and instead provides information relevant to preparing the electricity system to accept new renewable resources. Unless otherwise labeled, the remainder of this report focuses on the calculation of a planning renewable net short.

Calculating a range for the planning renewable net short acknowledges the numerous uncertainties that exist regarding future demand and the continued availability of renewable resources currently operational. There are legitimate reasons for study assumptions to change. However, it is important to disclose why certain assumptions were selected or applied, and whether the study is based on publicly reviewed and validated inputs. Using a common approach and set of assumptions to estimate the planning renewable net short will improve stakeholders' ability to understand the context for studies and to transfer findings from one study area to another. This will also promote consistency and establish an analytical link between the different infrastructure studies, leading to better informed policy development.

The equation for calculating the planning renewable net short is as follows:

> ***Planning Renewable Net Short (TWh) = (IEPR Final Projected Retail Electricity Sales – IEPR Incremental Energy Efficiency Programs – New Onsite Combined Heat & Power – New Distributed Generation (Rooftop Photovoltaic) x Policy Goal Percent – Average Generation from Operational Eligible Renewable Facilities***

The focus year for the current renewable net short update is 2022. Applying the above equation with the most recent *IEPR* study values results in a 33 percent renewable net short by 2022 forecast shown in **Table 1** that ranges between 38.6 terawatt hours to 23.4 terawatt hours. The difference between the high and low renewable net short estimates is 15.2 TWh or 40 percent relative to the high case. For comparison, the planning renewable net short report estimates prepared in November 2011 in support of the *2011 IEPR* included a range between 47.0 terawatt hours to 35.3 terawatt hours for 2020, which was an 11.7 terawatt hours difference (33 percent relative to the high case).

A comparison of the updated renewable net short estimate for 2020 to the estimate from last year is provided in **Table 2** for the mid-load case. The author emphasizes that the total amount of renewables needed to achieve 33 percent by 2020 declined by only 0.6 TWh. The significant difference between the 2011 and 2013 planning renewable net short forecasts is in the amount of operational renewable generation.

The main driver for establishing the calculated range of renewable net short estimates that are presented in **Table 1** is variation in electricity retail rates as estimated in the demand forecast. Changes to electricity retail rates will not only affect consumer demand for electricity, but also the incentives for investments in different supply and demand programs. For example, high electricity retail prices are expected to increase the penetration of energy efficiency investments beyond what is already assumed in the electricity demand projections (incremental energy efficiency), thereby lowering the electricity retail sales forecast assumed for the lower renewable net short estimate.

Table 1: Estimated Range of 33 Percent Planning Renewable Net Short for 2022

	All Values in TWh for the Year 2022	Formula	Low Demand Forecast Renewable Net Short	Mid Demand Forecast Renewable Net Short	High Demand Forecast Renewable Net Short
1	Statewide Retail Sales - June 2012 IEPR12 Final		291.1	301.4	317.7
2	Non RPS Deliveries (CDWR, WAPA, MWD)		12.5	12.5	12.5
3	Retail Sales for RPS	3=1-2	278.6	288.9	305.2
4	Incremental Energy Efficiency		22.2	19.5	12.6
5	New Distributed Generation - Rooftop PV		-	0.4	0.7
6	New Onsite Combined Heat and Power		20.7	11.5	9.8
7	Adjusted Statewide Retail Sales for RPS	7=3-4-5-6	235.8	257.4	282.1
8	**Total Renewable Energy Needed For 33% RPS**	**8=7* 33%**	**77.8**	**85.0**	**93.1**
	Operational Renewable Generation - Average				
9	Total In-State Renewable Generation (COD prior to 1/1/2013)		**41.5**	**41.5**	**41.5**
10	Total Out-of-State Renewable Generation (COD prior to 1/1/2013)		**12.6**	**12.6**	**12.6**
11	Renewable Auction Mechanism (RAM)		0.3	0.3	0.3
12	**Total Operational Renewable Generation for CA RPS**	**12=9+10+11**	54.4	54.4	54.4
13	**Total Planning RNS to meet 33% RPS In 2022**	**13=8-12**	**23.4**	**30.5**	**38.6**

Source: Energy Commission staff.

The estimated values staff used for the planning renewable net short calculation presented here are based on the electricity system assessments and projections prepared in support of the *2012 IEPR Update*. These inputs and the underlying assumptions are regularly revised and updated as new information becomes available. There are numerous studies and proceedings underway that will ultimately update some of these key input assumptions. Energy Commission staff plans to post updated planning renewable net short estimates in August of each year, matching the expected date when information on new and operational generation under CEC-1304 Quarterly Fuels and Energy Reporting data (QFER) collection regulations collected becomes available for use.

Energy Commission staff held a webinar on October 1, 2012, to seek comments on the proposed renewable net short calculations and preliminary set of input values. Stakeholders' comments were considered for establishing the assumptions used for the renewable net short estimates presented in this report. Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) recommended referring to this annual update the planning renewable net short to distinguish from the procurement renewable net short. PathFinder/Zephyr recommended staff consider possible retirements of existing combined heat and power (CHP) resources in the upcoming *2013 IEPR* demand forecast. Specific comments are summarized along with staff responses in Appendix A.

Table 2: *2011 IEPR* Planning Renewable Net Short For 2020 Compared to Current Update

	All Values in TWh for the Year 2020	Formula	Mid Demand Forecast Renewable Net Short (vintage 2011)	Mid Demand Forecast Renewable Net Short (vintage 2012)	Difference
1	Statewide Retail Sales		297.9	294.6	(3.3)
2	Non RPS Deliveries (CDWR, WAPA, MWD)		13.6	12.5	(1.1)
3	Retail Sales for RPS	3=1-2	284.3	282.1	(2.2)
4	Incremental Energy Efficiency		17.1	15.4	(1.7)
5	New Distributed Generation - Rooftop PV		3.2	1.2	(2.1)
6	New Onsite Combined Heat and Power		7.2	10.6	3.3
7	Adjusted Statewide Retail Sales for RPS	7=3-4-5-6	256.7	255.0	(1.7)
8	**Total Renewable Energy Needed For 33% RPS**	**8=7* 33%**	**84.7**	**84.1**	(0.6)
	Operational Renewable Generation - Average				
9	Total In-State Renewable Generation (COD prior to 1/1/2013)		34.2	41.5	7.3
10	Total Out-of-State Renewable Generation (COD prior to 1/1/2013)		9.2	12.6	3.5
11	Renewable Auction Mechanism (RAM)		-	0.3	0.3
12	**TotalOperational Renewable Generation for CA RPS**	**12=9+10+11**	**43.4**	**54.4**	11.0
13	**Total RNS to meet 33% RPS In 2020**	**13=8-12**	**41.3**	**29.7**	(11.6)

Source: Energy Commission staff.

CHAPTER 1: Introduction

This report includes an annual update to the *planning renewable net short* (*RNS*) for California load-serving entities that was originally presented in the *2011 Integrated Energy Policy Report (IEPR*). This report applies the standardized method for calculating the planning RNS for all California load-serving entities and future electricity system infrastructure studies. The report also includes a set of information sources and assumptions used for the calculation. This standardized method is intended to provide a transparent assessment of the variables and assumptions that affect the amount of new renewable generation needed to meet mandated targets. This update report includes the findings from other Energy Commission technical reports that were prepared in support of the most recent *IEPR*.

There are legitimate reasons for studies that use a planning RNS to use differing assumptions. However, it is important to disclose why certain assumptions were selected or applied, and whether the study is based on publicly reviewed and validated assumptions. Using a common approach and set of assumptions to estimate the renewable net short will improve stakeholders' ability to understand the context for studies and to transfer findings from one study area to another. This will also promote consistency and establish an analytical link between the different infrastructure studies, leading to better informed policy development.

The calculated planning RNS estimate range that is presented in this report includes variables that change with different electricity retail rate assumptions. For example, the high incremental energy efficiency (EE) forecast is combined with the low retail sales forecast because one of the main drivers in a low retail sales forecast is high electricity prices. High electricity prices are expected to encourage increasing levels of incremental energy efficiency.

There are other plausible policy drivers and variables that may override this price effect assumption for calculating the planning RNS. If a study group chooses to use a different combination of the variables presented in this report, it important to explain the reasons for the changes and effect on market relationships between the program assumptions. Energy Commission staff does not endorse using ranges that differ from those presented in this report. The ranges presented for retail sales, incremental uncommitted energy efficiency , and new amounts of combined heat and power have been vetted through the Energy Commission's most recent *IEPR* proceeding.

CHAPTER 2: Definition of Statewide Planning Renewable Net Short and Comparison to the IOUs Procurement Renewable Net Short Forecast

To estimate the amount of renewable capacity that will be built in the coming decade, electricity generation and transmission infrastructure studies must estimate what amount of new renewable energy is needed to meet policy goals. This amount of incremental new renewable generation is referred to as the planning RNS. Since the Renewables Portfolio Standard (RPS)[1] defines the required amount of renewable generation as a percentage of electricity retail sales, the RNS is expressed as the amount of electricity (terawatt hours – TWh) that is generated from renewable generation resources instead of the capacity (megawatt – MW) of these facilities. Since the mandate and regulations specify that retail sales are the basis for establishing the renewable goals, electricity used for water pumping and sources produced for personal consumption (self-generation) are not subject to the requirements.

The standard equation for estimating the planning renewable net short is:

> ***Planning Renewable Net Short (TWh) = (IEPR Final Projected Retail Electricity Sales – IEPR Incremental Energy Efficiency Programs – New Onsite Combined Heat & Power – New Distributed Generation (Rooftop Photovoltaic) x Policy Goal Percent – Average Generation from Operational Eligible Renewable Facilities***

This standard equation, presented above, is also used by the California Public Utilities Commission (CPUC) in the Long Term Procurement Plan (LTPP) 2012 proceeding.[2] However, a different equation and set of variables are used in the CPUC's RPS procurement proceeding. Throughout this paper the RNS estimate that is derived for the RPS procurement proceeding will be referred to as the RPS procurement RNS.

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1 Established by legislation in 2002 under Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002), accelerated in 2006 under Senate Bill 107 (Simitian, Chapter 464, Statutes of 2006), and expanded under Senate Bill X1 2 (Simitian, Chapter 1, Statutes of 2011).

2 See http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M031/K744/31744240.PDF for a full list of planning scenarios and associated RNS forecasts.

The RPS procurement RNS equation, looking five or more years out from the current year, is:

> ***Procurement Renewable Net Short = (IEPR Retail Electricity Sales x Policy Goal Percent) + Voluntary Margin of Overprocurement) – (On-line Generation + Risk-adjusted Forecast Generation + Preapproved Generic Generation)***

Differences between the planning and procurement RNS calculations are due to the purpose of the respective accounting approaches. The Energy Commission's planning RNS calculation is intended to examine the amount of new renewable generation and/or imports that need to be considered for statewide infrastructure studies. The procurement RNS is a measurement of amount of renewable electricity that each utility must add to their resource portfolio to comply with the RPS requirement. The procurement RNS is calculated by each load-serving entity (LSE), based on its own internal projections, confidential sources of information, and assumptions regarding the risks that a portion of the current set of renewable contracts not currently operational, may fail.

Energy Commission staff agrees with comments from Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE) that each IOU's internal proprietary RNS assessments may be more appropriate for RPS procurement purposes. The Energy Commission/CPUC planning RNS forecasts are based on forecasts and economic factors from findings supporting the most recent *IEPR*. The Energy Commission and CPUC's LTPP common method for developing a planning RNS is not intended to be a prescribed measure of renewable procurement needs for individual IOUs. Rather the Energy Commission and CPUC are providing a target in the LTPP proceeding that any agency, such as the Energy Commission, CPUC, California Independent System Operator (California ISO), National Renewable Energy Laboratory, Lawrence Berkeley National Laboratory, or Western Electric Coordinating Council, can use for transmission planning and production cost modeling studies.

In a future planning RNS update report, Energy Commission staff, in conjunction with the CPUC RPS procurement staff and stakeholders, may consider some type of risk metric for evaluating the development of new renewable projects that have procurement contracts. A number of renewable supply contracts with utilities have failed for numerous reasons, implying that there is a risk that some projects will not be developed in the future. To date, there is no conclusive and objective data-driven method to develop a risk metric for evaluating how many of the existing contracts will lead to actual renewable generation project development. However, the Energy Commission and CPUC staffs are discussing methods to present a common RNS to stakeholders for use in all proceedings.

The planning RNS metric can be applied to any target year and any renewable energy policy goal. Using the term RNS with no additional modifiers provides insufficient information about what is referenced. This is important because an RNS is used in multiple proceedings. The more precise way to use this term is to include both the goal percentage and the year under scrutiny; for example, using this approach will distinguish the 20 percent procurement RNS estimate in 2012 from the 33 percent planning RNS estimate beginning in 2020. To avoid confusion, this paper will follow the convention of using the term RNS as shorthand for referring to the 33 percent planning RNS in 2022 unless otherwise stated.

Sources and Ranges for Key Variables Used in the Renewable Net Short Calculation

Anything that reduces forecasted electricity retail sales (changes to the economy, EE program savings, rooftop photovoltaic [PV] additions, and other customer-side-of-the-meter distributed generation [DG]) will reduce the California statutory renewable generation requirement. This has been noticeable in the last several years as forecasts include the effects of the economic downturn and consideration of the possible timing of a rebound. Similarly the amount of new EE programs, combined heat and power (CHP), and additional rooftop PV achieved in response to state policies will affect the amount of renewable energy ultimately needed.

Additional renewable generation to meet policy goals depends on how much operational renewable power is already in the system. The amount of operational renewable generation will vary depending on the vintage of the estimate and how much of out-of-state renewable generation is included. The amount of electricity produced from renewable generation facilities may also fluctuate depending on weather conditions, such as the persistence of wind or precipitation over the year. There is also the possibility that some existing renewable facilities may retire due to age or an expiring electricity supply contract. For example, there are a number of contracts with wind generation facilities in the Pacific Northwest that are set to expire this year or within the next few years; these may not be renewed or instead may serve the renewable obligations in another state.

The variables critical to calculating the RNS are defined in the RPS legislation, but a precise method on how to estimate these variables is not explicitly defined. All values, regardless of the source, are projections into the future. All future supply and demand estimates are subject to a degree of uncertainty that may affect the trajectories of policy programs and intended infrastructure investments.

Prudent consideration of these retail sales-reducing programs should be considered in RNS calculation and infrastructure studies. The use of a single-point forecast will not reveal potential economic and system reliability risks of an infrastructure investment decision. Allowing for a plausible range of possible future scenarios will result in an array of outcomes for calculating retail electricity sales and the RNS. There are numerous studies and proceedings underway that will ultimately update some of the key input assumptions and address relevant uncertainties, so the calculated net short will change with time.

Each RNS calculation element has contributing sources and uncertainty factors that will be explored in this section and are organized as follows:

- Projected Retail Electricity Sales
  - Retail sales from demand forecast
- Demand Reduction Programs
  - Incremental EE impacts
  - New DG (rooftop PV goals)
  - New onsite CHP
- Generation From Operational Eligible Renewable Facilities
  - Operational renewable generation – average
  - Estimated renewable generation from generators that recently began commercial operation

Energy Commission staff held a webinar on October 1, 2012, to seek comments on the proposed RNS calculations and preliminary set of input values. Stakeholders' comments were considered for establishing the assumptions used for the RNS estimates presented in this report. Specific comments are summarized along with staff responses in Appendix A.

Projected Retail Electricity Sales

Projected retail sales are the building block on which the calculation of renewable net short is based. Energy Commission staff develops a full statewide energy and peak demand electricity forecast every two years, called the *California Energy Demand* (*CED)*, for the biennial *IEPR*. The forecast includes estimates of demand reductions from established programs, such as EE, roof-top PV, and self-generation facilities. The latest demand forecast, *2012 CED*, was adopted as part of the *2012 IEPR Update.*[3] This demand forecast is the appropriate starting point for calculating the renewable net short.

The *2012 CED* forecast includes three full scenarios: a *high energy demand* case, a *low energy demand* case, and a *mid energy demand* case. The primary driver affecting energy demand levels and program investments are variations in retail rates.[4] The *high energy demand* case

3 The forecast began in the *2011 IEPR* but was adopted in June *2012* in the *2012 IEPR Update*. The final adopted *2012 IEPR Update* forecast is referred to as final adopted forecast as *2012 CED*.

4 High electricity costs to consumers are expected to increase incentives for load-reduction expenditures, thereby reducing electricity retail demand. Conversely, a lower electricity cost reduces the incentives for load reduction investments.

incorporates relatively high economic/demographic growth, relatively low electricity and natural gas retail rates, and low efficiency program and self-generation impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed retail rates, and higher efficiency program and self-generation impacts. The *mid* case uses input assumptions at levels between the high and low cases. The retail electricity sales range between the high and low case is 291.1 TWh to 317.7 TWh for 2022. Projected electric vehicle consumption, provided by the Energy Commission's Fossil Fuels Office, is also incorporated into the forecast.

Retail Sales From the *California Energy Demand Forecast*

Forecast retail electricity sales are calculated in the *CED* by subtracting projected private supply consumed onsite from projected consumption. The forecasts for consumption and retail sales represent the customer side of the meter and are therefore net of transmission and distribution losses. When estimating net energy for load, these losses are added back to the consumption forecast (energy that needs to be produced by generators to meet demand). The loss factors are provided by the utilities as part of the *IEPR*.

Retail electricity sales projected in this manner reflect supply provided by load-serving entities located in control areas within California, and the resulting statewide sales figure is the value most commonly reported by the Energy Commission. However, a small amount of electricity is provided to California from entities outside the state. Therefore, staff also projects sales to California from these out-of-state entities, which allows for a forecast of *all* electricity sales within the state.[5]

The statewide retail electricity sales projection includes water delivery, which must be subtracted for the RNS calculation. Statewide Form 1.1c in the *2012 CED* specifically identifies the amount of retail electricity sales included in the demand forecast for the water pumping agencies (Metropolitan Water District, California Department of Water Resources [DWR], and Western Area Power Administration [WAPA]).

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5 Projections of sales to California customers from load-serving entities in control areas within the state are provided in Form 1.1b, while projections for all sales to California customers are provided in Form 1.1c. These and other forms for the *2012 CED* forecast are available on the Energy Commission's website, http://www.energy.ca.gov/2012_energypolicy/documents/index.html, and navigate to the adopted forecast, part of *2012 IEPR Update*.

Table 3 summarizes the values described above. The adjusted range of electricity retail sales for 2022 is 278.6 TWh to 305.2 TWh and will be used as part of the RNS estimate presented later in the report.

Table 3: Range of Retail Sales in 2022 for Use in the Planning Renewable Net Short

2022	Low Retail Sales	Mid Retail Sales	High Retail Sales
Total Retail Electricity Sales	291.1	301.4	317.7
Pumping Loads Exclusion	12.5	12.5	12.5
Adjusted Retail Sales Subject to 33% RPS	278.6	288.9	305.2

Source: CED Form 1.1c.

Demand Reduction Programs

There are other demand reduction policy goals and an expectation that some progress toward those goals will likely occur. Some programs are *not* included in the *CED* forecast and must be considered as an adjustment to the electricity retail sales estimate for the planning RNS calculation. Other programs to consider include incremental EE activities, incremental DG PV goals, and CHP policy goals.

Incremental Energy Efficiency Impacts

Forecasted incremental (also referred to as uncommitted) EE savings are not incorporated in the *2012 CED*[6] forecast that is used as the basis for retail sales in this 2012 planning RNS. Incremental refers to the electricity savings from programs that are net of any overlap with savings already included in the *2012 CED*.[7] These projected incremental savings are separate for the *Final 2012CED* because they lack firm funding and program designs. The authorization incremental savings estimates, shown in **Table 4**, for the four major IOU

6 See http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-CMF-V1.pdf. The forecast began in the *2011 IEPR* process with a final adoption date of June 2012.

7 The demand forecast includes estimated historical and projected savings from committed efficiency initiatives, which consist of utility and public agency programs; codes and standards, and legislation and ordinances that have final authorization; firm funding; and a design that can be readily translated into characteristics that can be evaluated and used to estimate future impacts. However, there are potential efficiency impacts from future initiatives that are less firm, yet still reasonably likely to occur.

service territories were updated July 2012,[8] while the POUs forecasts were last updated August 2011.[9]

Table 4: Incremental Energy Efficiency Savings 2022 (GWh)

	Low EE Savings	Mid EE Savings	High EE Savings
IOU Savings	9,081	14,783	16,494
POU Savings	3,500	4,760	5,676
Statewide Savings	12,581	19,543	22,170

Source: IOU savings posted July 2012 and updated September 2012 http://www.energy.ca.gov/2012_energypolicy/documents/demand-forecast/Memorandum_IUEE-CED2011.pdf. POU saving from http://www.energy.ca.gov/2011publications/CEC-200-2011-007/CEC-200-2011-007-AT.pdf. posted August 2011.

Incremental electricity savings estimates for the IOUs are based on the report titled *Analysis to Update Energy Efficiency Potential Goals and Targets for 2012 and Beyond (2012 Potential Study)*, completed for the CPUC by Navigant Consulting, Inc., in May 2012.[10] The IOU *2012 Potential Study* includes EE savings estimates that could be realized through IOU programs and efficiency and standards beginning in 2006, given current or soon-to-be-available technologies.[11] Energy Commission staff plans to update this incremental EE forecast in 2013 when the CPUC completes its update of the goals and target study.

Incremental energy saving estimates from efficiency codes and standards include the net market potential from the following that were recently adopted or expected for the near future:

- 2011 and future Title 20 standards
- Future federal appliance standards
- 2008 Title 24 (residential) and 2013 Title 24 standards

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8 See memo at http://www.energy.ca.gov/2012_energypolicy/documents/demand-forecast/Memorandum_IUEE-CED2011.pdf and associated spreadsheet at http://www.energy.ca.gov/2012_energypolicy/documents/index.html.Spreadsheet - Estimates of Incremental Uncommitted Energy Savings Relative to the California Energy Demand Forecast 2012-2022 corrected forms dated September 2012.

9 See http://www.energy.ca.gov/2011publications/CEC-200-2011-007/CEC-200-2011-007-AT.pdf.

10 See http://www.cpuc.ca.gov/NR/rdonlyres/6FF9C18B-CAA0-4D63-ACC6-F9CB4EB1590B/0/2011IOUServiceTerritoryEEPotentialStudy.pdf.

11 Energy Commission staff had planned on using a new *CPUC 2012 Goals and Targets Study* to estimate incremental savings, but the goals study has been delayed until 2013.

The high and low savings scenarios differ from the mid EE savings scenario by the following factors:

- The high savings scenario includes a 15 percent increase in incremental program-related measure savings; the low savings case includes a 5 percent drop from the mid EE savings scenario.
- The low savings scenario includes the assumption of a 20 percent lower compliance rate for efficiency codes and standards.
- The low savings scenario includes the assumption that there are no impacts from emerging technologies.

Incremental Distributed Generation Goals

The demand forecast sector models are used to project electricity consumption on the customer side of the meter. Forecasted retail sales are then calculated by subtracting projected private electricity supply consumed onsite from projected consumption. In general, projected DG is developed by trend analysis and then included in the demand forecast. Additional DG may be included in the RNS calculation if it is deemed prudent to plan on more than what is already included in the demand forecast.

DG is categorized in the demand forecast in two ways, self-generation and wholesale deliveries to the grid. Self-generation DG is produced onsite, by consumers for their own use, while wholesale DG is a small generating station meant to serve electrical load elsewhere on the system. New self-generation from an onsite DG project affects the calculation of RNS differently than wholesale DG. New self-generation DG will reduce projected retail sales by the amount of generation. Wholesale DG is sold into the electricity market instead of being used to serve the onsite electricity needs. The primary self-generation onsite DG considered in the RNS calculation is the amount of electricity expected from new small-scale rooftop PV systems.

Senate Bill 1 (Murray, Chapter 132, Statutes of 2006) requires 3,000 MW of self-generation rooftop PV through various programs associated with this bill. The *CED* forecast for high, mid, and low retail sales already includes varying levels of self-generation rooftop PV. The Energy Commission's 2020 mid-case demand forecast includes 2,790 MW of rooftop PV, so 210 MW of incremental generation is needed to achieve the full 3,000 MW California Solar Initiative target. In contrast, the CPUC staff included an additional 1,300 MW of new rooftop PV in the 2012 LTPP scenarios [12] to capture the metering cap and the update to the net energy metering (NEM) decision in D.12-05-036.[13] Energy Commission staff agrees that

12 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M028/K155/28155334.PDF, see pages 12-13.

13 For information on the calculation of the net energy metering cap, (D.)12-05-036, see http://docs.cpuc.ca.gov/published/Final_decision/167591.htm.

this NEM Cap update should be reflected in the calculation, but it will first study any impacts in the upcoming *2013 IEPR* demand forecast workshops. At this time, no change will be made to the proposed ranges of new rooftop PV in the Energy Commission staff planning RNS forecast.

The 3,000 MW goal for rooftop PV is assumed to be realized for the low retail sales forecast. However, the mid case forecast falls short of the target by about 262 MW in 2022. The high demand forecast drops the rooftop PV penetrations 508 MW below the rooftop PV target. Again, the price of electricity is a primary driver in these demand forecast cases and reason why higher amounts of rooftop PV are included in the low retail sales forecast and a smaller penetration of rooftop PVs is included in the high retail sales forecast. Higher electricity prices will create an incentive to invest in rooftop PV systems.

Incremental Combined Heat and Power

Governor Brown's 2011 *Clean Energy Jobs Plan* includes a target of 6,500 MW of additional installed CHP capacity over the next 20 years. CHP projects are a specific type of DG project that can also combine elements of both onsite and wholesale DG. The onsite CHP generation reduces the need for an industrial customer to purchase electricity, thereby affecting the retail electricity sales forecast and, in turn, the RNS. To estimate the amount of onsite CHP incremental to the demand forecast, it is necessary to look for changes in the business landscape for CHP that will push development beyond the "current trend" estimates. A recent ICF report[14] prepared in support of the *2011 IEPR* includes an evaluation of CHP policy goals and regulations under development to encourage the penetration of CHP projects to meet the Governor Brown's CHP goal. Many of these CHP policy initiatives are still in the formative stage, so estimates on the amount of onsite CHP that should be subtracted from the retail electricity sales forecast are very uncertain.

The ICF report included three cases that staff used for calculating the RNS. The first is a base case that reflects a continuation of existing state policies. The two additional cases (medium and high) show the market effects of additional CHP policy actions and incentives. The ICF report is an update to a similar study that the research team conducted in 2009.[15] The report includes CHP estimates for 2020 and 2025, so staff had to interpolate the 2022 estimates for each of the ICF cases for the RNS calculation. **Table 5** provides the resulting CHP capacity estimates for each utility.

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14 Report was released on June 19, 2012 and available at http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf.

15 Darrow, Ken, Bruce Hedman, Anne Hampson, *Combined Heat and Power Market Assessment*, April 2010. ICF International, Inc. CEC-500-2009-094-F.

Since the RPS and RNS are energy requirements, the onsite CHP capacity forecast must be converted to energy and adjusted for avoided transmission losses. The ICF report includes the assumption that 85 percent of the CHP generation serves the customer side of the meter. The capacity factor for this generation is 80 percent with an avoided losses factor of 7.8 percent. Considering each of these factors, the ranges of incremental CHP energy for the RNS calculations are shown in **Table 6**. For comparison, the base scenario for CPUC LTPP planning evaluations does not include any new onsite CHP for 2022 and 6,096 GWh for the High DG and demand-side management scenario.[16] Additional onsite CHP directly lowers the retail sales forecast and in turn lowers the total amount of renewable energy needed to meet the RPS.

Table 5: New Onsite Combined Heat and Power by 2022 Installed Capacity

2022 - Onsite CHP Installed MW	Base	Mid	High
PGE	556	652	1,080
SCE	294	353	881
SDGE	112	132	213
LADWP	198	227	322
SMUD	42	49	80
Other North	38	44	61
Other South	57	67	97
Total	1,297	1,523	2,735

Source: http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf.

Table 6: New Onsite Combined Heat and Power by 2022 Generation

2022 - Onsite CHP GWh	Base	Mid	High
PGE	3,895	4,568	7,569
SCE	2,059	2,471	6,173
SDGE	782	922	1,495
LADWP	1,389	1,590	2,256
SMUD	293	341	564
Other North	269	310	428
Other South	401	471	679
Total	9,089	10,673	19,164
Total - Loss Adjusted Onsite	9,798	11,506	20,659

Source: http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf.

During the October 1 webinar, Andrew Brown of Ellison, Schneider & Harris, LLP, recommended considering potential retirement to existing CHP resources pursuant to the

16 http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M028/K155/28155334.PDF, see pp. 13 and 28.

recent CPUC Qualifying Facility (QF) settlement agreement.[17] Energy Commission staff will study potential retirement impacts triggered by the settlement agreement in the upcoming *IEPR* demand forecast workshops. At this time, no change will be made to the proposed ranges of new onsite CHP in the Energy Commission staff planning RNS forecast.

Estimating Operational Eligible Renewable Generation

To estimate the additional or net renewable energy needed to meet policy goals, renewable generation currently in place and expected to be operational to meet California retail electricity sales in the target year both in- and out-of-state must be considered. New generation is added each year or procured under contract and may fluctuate depending on weather or other operational conditions.

Given the stakeholder feedback provided at last year's RNS methodology workshop, held in March 2011, staff now recommends combining multiple years of historical generation[18] with the installed generation and corresponding capacity factors for generation on-line less than a full year. Furthermore, staff has examined contract information associated with renewable electricity imports to distinguish the deliveries associated with long-term agreements. Since all but two states in the Western Electric Coordinating Council have an RPS of some kind, it is very likely that out-of-state renewable resources currently under short-term contracts (expiring by 2017) will not be available to meet the California RPS in 2022. Rather, these out-of-state resources may be used to meet the renewable requirements established in each region. Therefore, the short-term out-of-state contracts are excluded in the operational renewable generation calculation.

The following includes the steps for estimating operational renewable generation for California LSEs:

- An average annual generation value for all renewable projects on-line before the most current full year of the Quarterly Fuels and Energy Report (QFER) energy data availability (currently 2006–2011):
    - In-state electricity generation from QFER reported energy data, except two non-RPS-eligible municipal solid waste facilities.

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17 QF/CHP Settlement Agreement – CPUC Decision 10-12-035, December 21, 2010, resolved outstanding disputes between utilities and qualifying facilities and established a new CHP procurement program through 2020.

18 Historical generation information is reported to the Energy Commission under the QFER and the Power Source Disclosure Program data collection regulations.

- Reported out-of-state electricity generation from the most recent full year of Power Source Disclosure Program renewable purchase claims (2011), except short-term (expiring prior to 12/31/2017) out-of-state contracts.
- Average annual reported electricity generation from small hydroelectric generation over multiple representative years, excluding extreme outlier (drought or flood) years
  - Average of in-state small hydroelectric, using reported electricity generation data to QFER (from 2005 to 2011 currently)
  - Average of reported out-of-state small hydroelectric Power Source Disclosure Program claims (from 2007 to 2011[19])

- For both in-state and out-of-state resources that have come on-line and are generating since the end of the most current complete year of QFER data, use the IOU[20] and POU[21] renewable contract databases to estimate expected annual generation, or an installed capacity and capacity factor (see **Table 7**) if an energy forecast in missing from the publicly available contract detail.[22]
- Renewable Auction Mechanism: In the CPUC's August 2, 2012, ruling in Rulemaking 11-05-005, it is recommended that the IOUs' solar photovoltaic programs as well as the Renewable Auction Mechanism and the feed-in tariff be counted as meeting the RPS, not only as a reduction to load. The Energy Commission's planning RNS forecast already includes operational solar photovoltaic programs and feed-in-tariff resources but none of the Renewable Auction Mechanism. Energy Commission staff will include the individually named Renewable Auction Mechanism projects as specified by the CPUC.
- Portfolio Content Categories (PCCs) are an important driver for a utility's future RPS obligation. These PCCs are being decided in the RPS Proceeding Dockets 11-RPS-01 and 03-RPS-1078, RPS guidebooks and regulations. Once decided, the Energy Commission will consider dividing operational resources into PCCs in future RNS forecasts.

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19 Prior to 2007, reporting to Power Source Disclosure Program was not strictly enforced.

20 See "status of projects" at http://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm.

21 See http://www.energy.ca.gov/2008publications/CEC-300-2008-005/index.html.

22 For example, if a renewable resource began operation in July 2011, a full year of generation should be considered in the operational renewable forecast for a future year, not a partial year.

Table 7: Fuel and Technology-Specific Capacity Factors Used to Calculate Energy Generation for Resources Operating Less Than a Full Year

FUEL/TECHNOLOGY TYPE	CAPACITY FACTOR (PERCENT)
Biogas	80
Biomass	85
Geothermal	83
Solar Thermal	27
Wind	32
Rooftop PV	20
Large Scale PV	24-27

Source: 33% RPS calculator, April 2012.

A project by project listing for each of the line items shown is available in Appendix B.[23]

23 Also found in spreadsheet format at: http://www.energy.ca.gov/2013_energypolicy/documents/2012-10-01_webinar/presentations/Operational RPS Generation through 12/31/2012.xls.

Table 8: Summary of Operational Renewable

			TWh
2006-2011 QFER Excluding Small Hydro			27.3
2011 Power Source Disclosure Program Out-of-State Long-Term Renewable Purchase Claims			7.5
QFER In-State Small Hydro Claims (Average 2005 – 2011)	**2005**	6.0	5.2
	2006	6.7	
	2007	4.0	
	2008	4.0	
	2009	4.4	
	2010	5.0	
	2011	6.2	
	AVERAGE	5.2	
Facilities That Started Generating Since the End of the Most Current Full-Year QFER Data Set			
Instate Renewables Contracted Annual Generation With COD January 1, 2011, Through December 31, 2011			2.8
Out of State Renewables Contracted Annual Generation With COD January 1, 2011, Through December 31, 2011			0.0
Operational Facilities Before the End of the 2012			
Instate Renewables Annual Generation With COD January 1, 2012, Through December 31, 2012			6.2
Renewable Auction Mechanism			0.3
Out of State Renewables With Long Term Contracts Annual Generation With COD Janury 1, 2012 to December 31,2012			5.1
IN-STATE RENEWABLE (operational with COD prior to 1/1/2013)			**41.8**
OUT-OF-STATE RENEWABLE (operational with COD prior to 1/1/2013))			**12.6**
TOTAL OPERATIONAL RENEWABLES - AVERAGE			**54.4**

Source: Appendix B Operational Renewable Generation.

CHAPTER 3: Planning Renewable Net Short Estimate

Table 9 presents the ranges of input variables that are described in the previous section and the sequence of calculations for estimating the planning RNS. The table divides the estimates by the demand case used to estimate retail sales.

The mid demand RNS estimate is based on a selected set of variables, beginning with the updated *2011 IEPR* forecast. The mid incremental EE forecast is based on the mid-case demand forecast, chosen as a moderate planning assumption. Rooftop PV goals of 3,000 MW are expected to be implemented and result in some reduction of electricity retail sales. A modest amount of load-reducing CHP is applied, recognizing that there is a potential for significant savings if full potential is achieved. These values represent a conservative set of planning assumptions, but it is important to consider the implications of uncertainties that can dramatically affect the RNS results.

Table 9: Estimated Range of 33 Percent Planning Renewable Net Short for 2022

	All Values in TWh for the Year 2022	Formula	Low Demand Forecast Renewable Net Short	Mid Demand Forecast Renewable Net Short	High Demand Forecast Renewable Net Short
1	Statewide Retail Sales - June 2012 IEPR12 Final		291.1	301.4	317.7
2	Non RPS Deliveries (CDWR, WAPA, MWD)		12.5	12.5	12.5
3	Retail Sales for RPS	3=1-2	278.6	288.9	305.2
4	Incremental Energy Efficiency		22.2	19.5	12.6
5	New Distributed Generation - Rooftop PV		-	0.4	0.7
6	New Onsite Combined Heat and Power		20.7	11.5	9.8
7	Adjusted Statewide Retail Sales for RPS	7=3-4-5-6	235.8	257.4	282.1
8	**Total Renewable Energy Needed For 33% RPS**	**8=7* 33%**	**77.8**	**85.0**	**93.1**
	Operational Renewable Generation				
9	Total In-State Renewable Generation (COD prior to 1/1/2013)		**41.5**	**41.5**	**41.5**
10	Total Out-of-State Renewable Generation (COD prior to 1/1/2013)		**12.6**	**12.6**	**12.6**
11	Renewable Auction Mechanism (RAM)		0.3	0.3	0.3
12	**Total Operational Renewable Generation for CA RPS**	**12=9+10+11**	54.4	54.4	54.4
13	**Total Planning RNS to meet 33% RPS In 2022**	**13=8-12**	**23.4**	**30.5**	**38.6**

Source: Energy Commission staff.

The 33 percent RNS by 2022 range of estimates is considered to be a floor target, allowing for the possibility that additional investments in these generation technologies may occur beyond the policy goals. For example, electricity demand may increase beyond current forecasts due to the need to recharge an accelerated penetration of electric vehicles.

Renewable generation may also become a viable alternative to replace some of the fossil generation that is expected to end during the decade, such as the contracts for electricity from coal-fired power plants serving California electricity demand.

Differences Between the 2011 Estimates and Current Update for 2020

Table 10 compares the 2020 RNS estimates that were prepared in 2011 to the current set of estimates, also indexed to 2020.[24] The current mid-demand RNS is significantly lower than the values prepared in 2011, primarily due to the increase in operational renewable generation. The calculation of operational generation relies mainly on the QFER reporting and to a lesser extent the CPUC and Energy Commission IOU and POU renewable contract databases. This calculation of operational generation now includes two additional years of QFER generation, 2010 and 2011, than the calculation completed for the *2011 IEPR*.

24 The *2011 vintage planning RNS* refers to the report developed in support of the *2011 IEPR* and can be found at http://www.energy.ca.gov/2011publications/CEC-200-2011-001/CEC-200-2011-001-SF.pdf.

Table 10: *2011 IEPR* Planning Renewable Net Short For 2020 Compared to Current Update

	All Values in TWh for the Year 2020	Formula	Mid Demand Forecast Renewable Net Short (vintage 2011)	Mid Demand Forecast Renewable Net Short (vintage 2012)	Difference
1	Statewide Retail Sales		297.9	294.6	(3.3)
2	Non RPS Deliveries (CDWR, WAPA, MWD)		13.6	12.5	(1.1)
3	Retail Sales for RPS	3=1-2	284.3	282.1	(2.2)
4	Incremental Energy Efficiency		17.1	15.4	(1.7)
5	New Distributed Generation - Rooftop PV		3.2	1.2	(2.1)
6	New Onsite Combined Heat and Power		7.2	10.6	3.3
7	Adjusted Statewide Retail Sales for RPS	7=3-4-5-6	256.7	255.0	(1.7)
8	**Total Renewable Energy Needed For 33% RPS**	**8=7* 33%**	**84.7**	**84.1**	(0.6)
	Operational Renewable Generation				
9	Total In-State Renewable Generation (COD prior to 1/1/2013)		34.2	41.5	7.3
10	Total Out-of-State Renewable Generation (COD prior to 1/1/2013)		9.2	12.6	3.5
11	Renewable Auction Mechanism (RAM)		-	0.3	0.3
12	**TotalOperational Renewable Generation for CA RPS**	**12=9+10+11**	**43.4**	**54.4**	11.0
13	**Total RNS to meet 33% RPS In 2020**	**13=8-12**	**41.3**	**29.7**	(11.6)

Source: Energy Commission staff.

Future Updates to the Renewable Net Short

The Energy Commission plans to post a draft annual update of the planning RNS by September 1 and host a webinar to discuss this draft. This schedule matches the expected date when information on new generation is available for use from the previous year's compilation of the CEC 1304 QFER database and during an IEPR cycle in which the demand forecasts are adopted. If needed, an update to the September 1 draft planning RNS will be completed and posted by December 1 each year. When updating a RNS calculation, analysts should use the latest demand forecast released by the Energy Commission, applying consistent updates in the level of economic growth, incremental uncommitted EE, and self-generation consistent with the demand forecasts.

List of Acronyms

Acronym	Definition
2012 Potential Study	*Analysis to Update Energy Efficiency Potential Goals and Target for 2012 and Beyond*
California ISO	California Independent System Operator
CED	*California Energy Demand*
CHP	Combined heat and power
COD	Commercial on-line date
CPUC	California Public Utilities Commission
DG	Distributed generation
DWR	Department of Water Resources
EE	Energy efficiency
Energy Commission	California Energy Commission
GHG	Greenhouse gas
GWh	Gigawatt hour
IEPR	*Integrated Energy Policy Report*
IOU	Investor-owned utility
LADWP	Los Angeles Department of Water and Power
LSE	Load-serving entity
LTPP	Long-term procurement planning
MW	Megawatt
NEM	Net energy meeting
PCCs	Portfolio Content Categories
PG&E	Pacific Gas and Electric
POU	Publicly owned utility
PV	Photovoltaic
QF	Qualifying facility
QFER	Quarterly Fuels and Energy Report
RES	Renewable energy standard
RNS	Renewable net short
RPS	Renewables Portfolio Standard
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SMUD	Sacramento Municipal Utilities District
TWh	Terawatt hours
WAPA	Western Area Power Administration

Glossary of Basic Renewable Net Short Terminology

Term	Definition
California Solar Initiative	Photovoltaic solar rebate program overseen by the CPUC for California consumers that are customers of the investor-owned utilities – Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric.
Combined heat and power	The use of a heat engine or a power station to simultaneously generate both electricity and useful heat.
Distributed energy resource	Small-scale power generation technologies (typically <10 MW), located close to where electricity is consumed. The broad definition includes California Solar Initiative, distributed generation, demand response, energy efficiency, and electrical storage.
Energy efficiency	Activities (including standards) or programs that stimulate customers to reduce energy use by making investments in more efficient equipment or controls that reduce energy use while maintaining a comparable level of service as perceived by the customer.
Long-Term Procurement Proceeding	CPUC reviews and approves plans for the utilities to purchase energy. Establishes policies and utility cost recovery for energy purchases. Ensures that the utilities maintain a set amount of energy above what they estimate they will need to serve their customers (called a reserve margin), and implements a long-term energy planning process.
Loss factor	Gross-up or scaling factor defined as (1/1-losses).
Net energy for load	Total generation plus energy received from other areas, less energy delivered to other areas through interchange needed to serve load.
Net energy metering	Small solar, wind, biogas, and fuel cell generation facilities (1 MW or less) that serve all or a portion of onsite electricity needs are eligible for the state's net metering program. **NEM** allows a customer-generator to receive a financial credit for power generated by their onsite system and fed back to the utility.
Portfolio Content Categories	Categories of electricity products procured from an RPS-certified facility.
Retail sales	Consumption minus self-generation.
Planning RNS	The amount of new renewable generation and/or imports that need to be considered for statewide infrastructure studies.
Procurement RNS	The amount of renewable energy that each utility must add to their resource portfolio to comply with the RPS requirement.
RPS Procurement Proceeding	CPUC sets policy and procurement guidelines for investor-owned utilities. Through annual rulemakings, the CPUC addresses requests to change the plans adopted in the previous proceeding. The Energy Commission evaluates and certifies project eligibility.

Term	Definition
Self-Generation Incentive Program	CPUC program that provides rebates for qualifying distributed energy systems installed on the customer's side of the utility meter.
Terawatt hour	Major energy production or consumption is often expressed as terawatt hours for a given period that is often a calendar year or financial year. Tera is a multiplier, 1x10^18 of watts for one hour.
Transmission Planning Process	California ISO and participating transmission owner studies demonstrate how the California ISO is planning for infrastructure needs while meeting North American Electric Reliability Corporation and California ISO planning standards. The annual transmission plan serves as the formal and board-approved roadmap for infrastructure requirements for the California ISO Balancing Authority.

APPENDIX A: Individual Stakeholder Comments in Response to the October 1, 2012, Webinar

1) Comment: PG&E and SCE recommend Energy Commission staff continue to collaborate with the California Public Utilities Commission (CPUC) on RNS methodologies used in the long-term procurement planning (LTPP) and the renewable portfolio standard (RPS) procurement proceeding. Energy Commission and CPUC staff working on the LTPP should use identical methodologies and ranges of variables for all RNS forecasts.

   Discussion: PG&E's comments are referring to the differences between the CPUC RNS forecast developed for the RPS Procurement proceeding and the RNS forecast used in capacity planning under the LTPP proceeding. At this time no common investor-owned utility (IOU) methodology has been developed in the RPS Procurement proceeding. Each IOU's procurement RNS is based on its own internally developed retail sales forecast, its own risk-adjusted portfolio of new renewable generation, and its own forecast of generation from operational renewable projects, plus an additional margin of over-procurement.

   Staff Recommends: Keeping the existing planning RNS method intact with minor changes as spelled out in this document. Energy Commission staff will continue to coordinate with the CPUC and to the greatest extent reasonable. Energy Commission staff will coordinate with CPUC staff working on the RPS Procurement proceeding to develop a common IOU RPS procurement RNS methodology. If needed, Energy Commission staff, in a workshop, will present any changes to the planning RNS methodology.

2) Comment: PG&E and SCE suggest the Energy Commission's RNS forecast may create confusion in the marketplace and should include a risk adjustment for expected output from facilities not yet on-line or rename the RNS to distinguish the purpose of the calculation.

   Discussion: The Energy Commission and the CPUC's LTPP common method for developing a planning RNS is not attempting to prescribe renewable procurement needs to individual IOUs. Rather, the Energy Commission and CPUC are providing a net short target so that an agency, such as the Energy Commission, CPUC, the California Independent System Operator (California ISO), National Renewable Energy Lab, or Western Electricity Coordinating Council, can make simplifying assumptions for transmission planning and production cost modeling studies.

   Staff Recommends: Energy Commission staff agrees with comments from stakeholders that each IOU's internal proprietary procurement RNS assessments may be more accurate for procurement purposes than the Energy Commission/CPUC planning *RNS* forecasts that are developed based on objectively-deterministic factors. Energy Commission staff recommends naming the IOU estimates as the RPS *procurement* RNS forecast. PG&E and SCE staffs were supportive of this proposal. The Energy Commission estimate of RNS will be referred to as the *planning* RNS.

3) Comment: PG&E recommends that Energy Commission and CPUC LTPP staff reconcile cut-off dates for existing generation in the RNS calculation.

   Discussion: Energy Commission staff did provide data to support two cut-off dates on what may be considered operational in the calculation of existing generation. One set applies commercial on-line dates (COD) prior to January 1, 2013, and the second used COD prior to January 1, 2014.

   Staff Recommends: In order to be more consistent with the CPUC LTPP planning RNS, Energy Commission will not include the second set of resources with COD through January 1, 2014. Staff agrees that start of construction is an important milestone, but is not convinced that this metric is without risk. Energy Commission will use the CPUC LTPP convention of the COD through January 1, 2013, as a cut-off for the existing generation calculation.

4) Comment: PG&E recommends that the Energy Commission include certain CPUC-approved procurement programs (specifically the Renewable Auction Mechanism) as existing generation.

   Discussion: The CPUC's Administrative Law Judge's Ruling (Rulemaking 11-05-005 dated August 8, 2012) recommended that the IOUs' Solar Photovoltaic Programs as well as the Renewable Auction Mechanism and the Feed-in-Tariff be counted as meeting the RPS. The Energy Commissions' planning RNS forecast already includes operational Solar Photovoltaic (PV) Programs and Feed-in-Tariff resources, but none of the Renewable Auction Mechanism.

   Staff Recommends: Including the individually named Renewable Auction Mechanism projects as specified by the CPUC in their RPS_Project_Status_Table_2012_Oct.xls spreadsheet (approximately 0.4 TWh).

5) Comment: PG&E notes that the Energy Commission estimates for additional roof-top PV are slightly inconsistent with the CPUC's 2012 LTPP Base scenario and that the additional new onsite combined heat and power (CHP) forecast diverges significantly.

   Discussion: By 2022 there is 2,790 MW of roof-top PV embedded in the Energy Commission's mid case *2012 Integrated Energy Policy Report* (*IEPR*) adopted demand forecast. CPUC staff wants to reflect the metering cap update to the net energy metering (NEM) decision in D.12-05-036.[25] There is 1,300 MW of additional rooftop PV that was included in the CPUC's Base scenario RNS calculation to reflect their assumptions regarding the NEM update decision. The Energy Commission included only the additional 210 MW needed to achieve the full California Solar Initiative of 3,000 MW. Energy Commission staff agrees that this NEM Cap update should be reflected, but will first study any impacts in the upcoming *2013 IEPR* demand forecast workshops. At this time, no change will be made to the proposed ranges of new roof-top PV in the Energy Commission's planning RNS forecast.

Currently, the CPUC LTPP planning Base scenario includes no new onsite CHP for 2022 and about 6,096 GWh for the High Distributed Generation and Demand-Side Management scenario.

Staff Recommends: The CPUC LTPP Base scenario should include the *2012 IEPR* ICF Consultant CHP report's mid case forecast of 11.5 TWh for 2022 and 20.7 TWh in the High Distributed Generation and Demand-Side Management scenario. At this time, no change will be made to the proposed ranges of new onsite CHP in the Energy Commission's planning RNS forecast.

6) Comment: PG&E and Pathfinder/Zephyr are concerned about the inclusion of incremental EE, additional rooftop PV, and new CHP since IOU-contracted new RPS resources are not included.

   Discussion: The Energy Commission planning RNS forecast **does** include operational IOU contracted RPS resources. However, a confidential subset of each IOU's ***nonoperational*** contracted RPS resources is considered in each procurement RNS calculation. The Energy Commission planning RNS is intended to provide a transparent method for planning purposes. Using data and assumptions that are not available to stakeholders undermines the value of the public process, which was used to produce this document.

   In addition, adding contract resources that are not yet in production will lower the RNS estimate in a way that may depress and reduce market signals. Ranges of values from incremental EE and new CHP will be derived from open and public IEPR proceedings that allow transparency throughout.

   Staff Recommends: At this time, no change should be made to the proposed ranges of new incremental EE, rooftop PV or onsite CHP in the Energy Commission's planning RNS forecast. However, if directed, staff could use the subset of IOU contracted resources used in the procurement RNS.

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25 Information on the calculation of the Net Energy Metering Cap, (D.)12-05-036, see http://docs.cpuc.ca.gov/published/Final_decision/167591.htm.

7) Comment: Andrew B. Brown, with Ellison, Schneider & Harris, LLP, recommends that existing onsite CHP that are retiring due the CPUC qualifying facility settlement agreement should be captured in the demand forecast.

   Discussion: Changes to the demand forecast will be considered separately during the *2013 IEPR* demand forecast process.

   Staff Recommends: Energy Commission staff will study any retirement impacts due to the settlement agreement in the upcoming IEPR demand forecast workshops. At this time, no change will be made to the proposed ranges of new onsite CHP in the Energy Commission's planning RNS forecast.

8) Comment: LADWP requests that Energy Commission staff develop a RNS forecast to consider the impacts and future availability of electricity products pursuant to the Portfolio Content Categories (PCCs).

   Discussion: Decisions regarding the PCCs are an important driver for a utilities RPS obligation. These PCCs are being decided in the Energy Commission proceeding on the RPS guidebooks and regulations.

   Staff Recommends: No change to the current RNS estimate at this time. Once decided, these PCCs may be included in future RNS forecasts.

9) Comment: LADWP recommends that the Governor's 12,000 MW distributed generation (DG) goal should not be accounted for in an RNS forecast.

   Discussion: Staff agrees with LADWP; the RNS forecast should not include the entire 12,000 MW DG goal. However, a portion of this DG goal, in the form of rooftop PV, is already implicit to the retail sales forecast developed for the *IEPR*. Programs such as the California Solar Initiative and the CPUC's NEM program allow for additional rooftop PV to be included in further reducing retail sales and also, through the NEM program, to count towards meeting RPS obligations.

   Staff Recommends: Continuing to include between 3,500 MW and 4,500 MW of roof-top PV and NEM programs in the planning RNS forecast. The remaining 7,500 MW to 8,500 MW DG goal will be available for consideration in the supply portfolio as a resource to meet the RPS.

10) Comment: SCE questions the usefulness of extending the planning RNS calculation to 2024 or 2030, given the substantial number of renewable energy projects expected to become operational in the coming years.

    Discussion: Energy Commission staff agrees that the number of new renewable projects expected is substantial and believes this is an even more compelling reason to study the impact that these new projects may have on the electric generation and transmission system infrastructure in the future. The *2012 IEPR Update* recommends an electricity system study through 2030, which will require an evaluation of renewable scenarios.

SCE also recommends that if the Energy Commission does continue to develop a planning RNS forecast for 2030, this effort should then be coordinated with any calculations and relevant staff at the CPUC that are developing a planning RNS forecast for that time period. Energy Commission staff agrees and will coordinate with the CPUC LTPP staff on a 2030 planning RNS forecast.

Staff Recommends: Energy Commission staff will develop a forecast for 2024 based on the methods proposed during the October 1, 2012 webinar. Staff will delay the development of the 2030 forecast until more direction is given for this scenario by the IEPR Committee.

APPENDIX B:
Operational Renewable Generation

Table B-1: 2006-2011 In-State Operational Renewable Generation (Excluding Small Hydro)

Company Name	Plant Name	QFER Fuel Type	Installed Capacity MW	2011 (GWh)	2010 (GWh)	Average 2009-2006 (GWh)	Average (GWh)
CE Generation (CalEnergy)	A W Hoch	Geothermal	35.80	337.36	341.49	344.35	341.06
Solar Tax Partners I, LLC	Aerojet I (3.6MW) Solar Plant	Solar (PV/Thermal)	3.60	6.51			6.51
Solar Tax Partners II	Aerojet II (2.4MW) Solar Plant	Solar (PV/Thermal)	2.40	4.00			4.36
Geysers Power Company, LLC	Aidlin #1, ADST1	Geothermal	11.20	65.57	71.73	72.69	70.00
Geysers Power Company, LLC	Aidlin #1, ADST2	Geothermal	11.20	66.61	77.23	71.41	71.75
South Orange County Wastewater Authority	Aliso Water Management Agency, Gen 1	Other Biomass Gases	0.40	1.95	3.21	2.68	2.61
South Orange County Wastewater Authority	Aliso Water Management Agency, Gen 2	Other Biomass Gases	0.40	2.23	1.75		1.99
South Orange County Wastewater Authority	Aliso Water Management Agency, Gen 3	Other Biomass Gases	0.40	2.37	1.48		1.92
WM Renewable Energy	Altamont Gas Recovery, Unit 1	Landfill Gas	3.50	55.12	50.18	42.70	49.33
Gas Recovery Systems Inc	American Canyon Power Plant, Unit 1	Landfill Gas	0.90	4.40	5.89	6.71	5.67
Geysers Power Company, LLC	Bear Canyon #2, BCST1	Geothermal	11.00	46.64	49.32	50.79	48.92
Geysers Power Company, LLC	Bear Canyon #2, BCST2	Geothermal	11.00	56.12	54.29	57.82	56.08

Table B-1: 2006-2011 In-State Operational Renewable Generation (Excluding Small Hydro) (Continued)

Company Name	Plant Name	QFER Fuel Type	Installed Capacity MW	2011 (GWh)	2010 (GWh)	Average 2009-2006 (GWh)	Average (GWh)
Geysers Power Company, LLC	Big Geyser #13	Geothermal	95.00	468.19	487.11	484.39	479.89
Blue Lake Power LLC	Blue Lake	Wood/Wood Waste Solids	13.80	9.62	27.68		18.65
NRG Energy, Inc.	Blythe 1 Solar	Solar (PV/Thermal)	21.00	51.28			51.28
Integral Energy Management, LLC	Bottle Rock Power	Geothermal	55.00	88.09	67.56	88.23	81.29
Ridgewood Power Management LLC	Brea Power Partners LP (Gen 1-3)	Landfill Gas	5.60	34.92	37.27	34.27	35.49
Burney Forest Power	Burney Forest Products	Wood/Wood Waste Solids	31.00	216.75	222.16	229.56	222.82
Castelanni Bros Dairy	Castelanni Bros Biogas	Agriculture Crop throughout	0.30	1.31	1.31	1.31	1.31
All California Wind Generation	California Wind Generation	Wind	2199.00	7,593.78	5,865.29	4,846.94	N/A
Geysers Power Company, LLC	Calistoga #19, CAST1	Geothermal	48.50	257.42	260.59	236.66	251.56
Geysers Power Company, LLC	Calistoga #19, CAST2	Geothermal	48.50	264.84	278.18	257.68	266.90
Meridian Energy USA, Inc.	CalRENEW-1	Solar (PV/Thermal)	5.00	9.89			9.89
CE Generation (CalEnergy)	CE Turbo LLC	Geothermal	11.50	72.49	14.85	66.18	51.17
SCE	Chino Rooftop Solar (SCE)	Solar (PV/Thermal)	1.22	1.31	1.49		1.40
Ameresco Chiquita Canyon	Chiquita Canyon Castaic	Landfill Gas	9.20	42.70			42.70
Global Ampersand LLC	Chowchilla II Biomass	Wood/Wood Waste Solids	12.50	32.35	16.83		24.59
Geysers Power Company, LLC	Cobb Creek #12	Geothermal	110.00	425.98	415.03	425.81	422.27
Collins Pine Co	Collins Pine Co Project	Wood/Wood Waste Solids	12.00	46.52	57.57	60.73	54.94

Table B-1: 2006-2011 In-State Operational Renewable Generation (Excluding Small Hydro) (Continued)

Company Name	Plant Name	QFER Fuel Type	Installed Capacity MW	2011 (GWh)	2010 (GWh)	Average 2009-2006 (GWh)	Average (GWh)
Coso Operating Company LLC	Coso Energy Developers	Geothermal	33.33	120.35	128.41	154.25	134.34
Coso Operating Company LLC	Coso Energy Developers	Geothermal	33.33	139.44	159.34	176.35	158.38
Coso Operating Company LLC	Coso Energy Developers	Geothermal	33.33	145.88	171.54	179.97	165.79
Coso Operating Company LLC	Coso Finance Partners	Geothermal	35.77	150.65	173.92	193.23	172.60
Coso Operating Company LLC	Coso Finance Partners	Geothermal	33.33	198.37	181.78	204.58	194.91
Coso Operating Company LLC	Coso Finance Partners	Geothermal	33.33	204.61	189.03	210.00	201.21
Coso Operating Company LLC	Coso Power Developers	Geothermal	33.33	214.40	227.86	243.69	228.65
Coso Operating Company LLC	Coso Power Developers	Geothermal	33.33	156.49	184.97	145.98	162.48
Coso Operating Company LLC	Coso Power Developers	Geothermal	33.33	161.87	173.65	191.15	175.56
Covanta Mendota, LP (AES Mendota, LP)	Covanta Mendota LP	Wood/Wood Waste Solids	28.00	165.20	172.73	189.30	175.74
Gas Recovery Systems (Irvine)	Coyote Canyon	Landfill Gas	10.00	49.55	48.68	51.77	50.00
Covanta Delano, Inc.	Delano Energy Co Inc	Wood/Wood Waste Solids	49.5	337	312.02	341.36	330.06
CRES - Dinuba Energy	Dinuba Energy	Agriculture Crop Byproducts/Straw/ Energy Crops	12.00	68.10	80.55	63.35	70.67
Geysers Power Company, LLC	Eagle Rock #11	Geothermal	110.00	569.99	476.74	524.82	523.85
East Bay Municipal Utility District (EBMUD)	EBMUD WWTP Power Generation Station 1	Other Biomass Gases	2.15	3.22	14.91	9.61	9.24

Table B-1: 2006-2011 In-State Operational Renewable Generation (Excluding Small Hydro) (Continued)

Company Name	Plant Name	QFER Fuel Type	Installed Capacity MW	2011 (GWh)	2010 (GWh)	Average 2009-2006 (GWh)	Average (GWh)
East Bay Municipal Utility District (EBMUD)	EBMUD WWTP Power Generation Station 2	Other Biomass Gases	2.15	0.00	11.86	11.17	7.67
East Bay Municipal Utility District (EBMUD)	EBMUD WWTP Power Generation Station 3	Other Biomass Gases	2.15	0.00	9.30	14.08	7.79
Global Ampersand LLC	El Nido Biomass	Wood/Wood Waste Solids	12.50	20.85	65.00		42.93
WM Renewable Energy	El Sobrante Landfill, 1-3	Landfill Gas	1.35	21.70	20.88	13.36	18.65
SCE	Etiwanda Rooftop Solar (SCE)	Solar (PV/Thermal)	2.44	2.66	2.96		2.81
Fiscalini Farms, L.P.	Fiscalini Farms Digester	Biomass	0.70	5.30	5.30	5.30	5.30
City of San Diego	Gas Utilization Facility (Pt. Loma Sewage TP), Unit 1	Other Biomass Gases	2.30	16.58	18.62		17.60
City of San Diego	Gas Utilization Facility (Pt. Loma Sewage TP), Unit 2	Other Biomass Gases	2.30	18.46	17.56		18.01
Ormat Nevada, Inc	GEM II	Geothermal	18.50	86.35	92.19	80.86	86.47
Ormat Nevada, Inc	GEM III	Geothermal	18.50	113.19	150.42	103.95	122.52
Northern California Power Agency	Geothermal 1, Unit 1	Geothermal	55.00	230.90	251.09	471.13	317.71
Northern California Power Agency	Geothermal 1, Unit 2	Geothermal	55.00	204.78	203.53		204.16
Northern California Power Agency	Geothermal 2, Unit 3	Geothermal	55.00	0.12	84.32	431.93	172.12
Northern California Power Agency	Geothermal 2, Unit 4	Geothermal	55.00	422.78	306.86		364.82
Geysers Power Company, LLC	Grant #20	Geothermal	124.00	309.73	329.68	341.97	327.12
Gas Recovery Systems Inc	Guadalupe Power Plant, Unit 1	Landfill Gas	0.50	17.00	11.00	17.57	15.40
Covanta Energy Americas, Inc.	Heber Geothermal Co	Geothermal	52.00	292.04	293.91	317.74	301.23

Table B-1: 2006-2011 In-State Operational Renewable Generation (Excluding Small Hydro) (Continued)

Company Name	Plant Name	QFER Fuel Type	Installed Capacity MW	2011 (GWh)	2010 (GWh)	Average 2009-2006 (GWh)	Average (GWh)
Covanta Energy Americas, Inc.	Heber Geothermal Co	Geothermal	3.50	40.52	42.05	50.08	44.22
Sacramento Municipal Utility District	Hedge PV	Solar (PV/Thermal)	0.20	0.34	0.27	0.34	0.32
HL Power Co	HL Power Company	Wood/Wood Waste Solids	35.50	160.29	168.83	169.67	166.26
CE Generation (CalEnergy)	J J Elmore	Geothermal	35.80	343.75	328.50	337.10	336.45
CE Generation (CalEnergy)	J M Leathers	Geothermal	35.80	347.56	339.34	333.36	340.09
Ameresco Keller Canyon LLC	Keller Canyon Landfill (Pittsburg)	Landfill Gas	4.00	30.51	30.00		30.17
County of Sacramento, Waste Management	Kiefer Landfill Gas-to-Energy Facility, 1	Landfill Gas	3.05	23.56	18.04	21.08	20.89
County of Sacramento, Waste Management	Kiefer Landfill Gas-to-Energy Facility, 2	Landfill Gas	3.05	22.55	21.21	21.10	21.62
County of Sacramento, Waste Management	Kiefer Landfill Gas-to-Energy Facility, 3	Landfill Gas	3.05	22.51	21.19	20.96	21.55
Geysers Power Company, LLC	Lakeview #17	Geothermal	120.00	430.86	418.83	402.39	417.36
Los Angeles Community College District	Los Angeles Community College District	Solar (PV/Thermal)	1.80	1.93			1.93
Madera Power LLC	Madera Power	Wood/Wood Waste Solids	25.00	146.12	123.06	135.32	134.83
Mammoth Pacific LP	Mammoth Pacific I	Geothermal	5.00	11.09	22.12	24.73	19.31
Mammoth Pacific	Mammoth Pacific I	Geothermal	5.00	23.27	26.49	19.25	23.00

Table B-1: 2006-2011 In-State Operational Renewable Generation (Excluding Small Hydro) (Continued)

Company Name	Plant Name	QFER Fuel Type	Installed Capacity MW	2011 (GWh)	2010 (GWh)	Average 2009-2006 (GWh)	Average (GWh)
LP							
Mammoth Pacific LP	Mammoth Pacific II	Geothermal	5.00	29.40	26.87	31.23	29.17
Mammoth Pacific LP	Mammoth Pacific II	Geothermal	5.00	29.40	27.82	31.23	29.48
Mammoth Pacific LP	Mammoth Pacific II	Geothermal	5.00	29.40	27.82	31.23	29.48
Monterey Regional Waste Mgmt Dist	Marina Landfill Gas (Monterey Regional Waste Management Dst) U1	Landfill Gas	0.80	12.54	12.93	11.72	12.40
Monterey Regional Waste Mgmt Dist	Marina Landfill Gas (Monterey Regional Waste Management Dst) U2	Landfill Gas	1.00	7.57	7.94	6.27	7.26
Monterey Regional Waste Mgmt Dist	Marina Landfill Gas (Monterey Regional Waste Management Dst) U3	Landfill Gas	1.00	7.54	7.22	6.92	7.22
Monterey Regional Waste Mgmt Dist	Marina Landfill Gas (Monterey Regional Waste Management Dst) U4	Landfill Gas	1.00	10.55	9.23	5.28	8.35
Gas Recovery Systems Inc	Marsh Road Power Plant, Units 1 and 2	Landfill Gas	1.00	7.23	7.84	8.90	7.99
Geysers Power Company, LLC	McCabe #5-#6, MCST5	Geothermal	55.00	338.94	348.42	347.86	345.08
Geysers Power Company, LLC	McCabe #5-#6, MCST6	Geothermal	55.00	345.13	345.99	341.89	344.34
Greenleaf Power, LLC (formerly Colmac Energy Inc.)	Mecca Plant	Wood/Wood Waste Solids	47.00	342.41	362.92	357.02	354.12
Minnesota Methane, LLC	MM Lopez Energy LLC	Landfill Gas	6.06	45.78	46.63	47.48	46.63
Fortistar Methane Group	MM Prima Deshecha Energy LLC, Unit 1	Landfill Gas	3.05	38.20	42.69	40.15	40.35
Minnesota Methane,	MM San Diego LLC - Miramar	Landfill Gas	6.50	49.20	51.99	50.22	50.47

Table B-1: 2006-2011 In-State Operational Renewable Generation (Excluding Small Hydro) (Continued)

Company Name	Plant Name	QFER Fuel Type	Installed Capacity MW	2011 (GWh)	2010 (GWh)	Average 2009-2006 (GWh)	Average (GWh)
LLC	Landfill						
Minnesota Methane, LLC	MM San Diego LLC - North City	Landfill Gas	3.80	28.36	28.82	30.15	29.11
Fortistar Methane Group	MM Tajiguas Energy LLC	Landfill Gas	3.05	23.72	23.99	23.36	23.69
Minnesota Methane, LLC	MM Tulare Energy LLC	Landfill Gas	1.80	0.04	5.80	9.61	5.15
Minnesota Methane, LLC	MM West Covina LLC, Gen 1	Landfill Gas	4.90	1.01	26.86	27.59	18.49
Minnesota Methane, LLC	MM West Covina LLC, Gen 2	Landfill Gas	6.80	44.95	21.84	25.34	30.71
Minnesota Methane, LLC	MM Yolo Power LLC Facility, 1-5	Landfill Gas	2.85	19.17	18.01	20.86	19.35
Fortistar Methane Group	MN Colton Genco LLC	Landfill Gas	1.30	6.72	7.04	7.06	6.94
Fortistar Methane Group	MN Mid Valley Genco LLC, 1	Landfill Gas	1.30	13.10	13.31	13.42	13.28
Fortistar Methane Group	MN Milliken Genco LLC, Unit 1	Landfill Gas	1.10	11.58	11.70	12.54	11.94
MRWPCA	Monterey Regional Water Pollution Control Cogen, Unit 1	Landfill Gas	0.58	2.64	2.54	2.11	2.43
MRWPCA	Monterey Regional Water Pollution Control Cogen, Unit 2	Landfill Gas	0.58	2.64	2.54	2.11	2.43
MRWPCA	Monterey Regional Water Pollution Control Cogen, Unit 3	Landfill Gas	0.58	2.64	2.54	2.11	2.43
Covanta Power Pacific, Inc.	Mt Lassen Power	Wood/Wood Waste Solids	11.40	32.86	65.75	57.76	52.12
Gas Recovery Systems Inc	Newby Island I, Unit 1	Landfill Gas	0.50	13.49	14.66	15.30	14.48
Ormat Technologies, Inc.	North Brawley	Geothermal	49.90	187.74	180.56		184.15
Republic Services, Inc. (Nove	Nove Power Plant	Landfill Gas	1.00	4.15	5.12	4.72	4.67

Table B-1: 2006-2011 In-State Operational Renewable Generation (Excluding Small Hydro) (Continued)

Company Name	Plant Name	QFER Fuel Type	Installed Capacity MW	2011 (GWh)	2010 (GWh)	Average 2009-2006 (GWh)	Average (GWh)
Investments I)							
Republic Services, Inc. (Nove Investments I)	Nove Power Plant	Landfill Gas	1.00	4.03	5.17	4.88	4.69
Republic Services, Inc. (Nove Investments I)	Nove Power Plant	Landfill Gas	1.00	3.22	2.77	3.96	3.31
Ormesa Geothermal 1H Trust	Ormesa 1 E	Geothermal	14.40	0.00	0.00	23.48	7.83
Ormesa Geothermal 1H Trust	Ormesa 1H	Geothermal	14.40	40.04	41.61	51.65	44.43
Ormesa Geothermal 1H Trust	Ormesa Geothermal II	Geothermal	24.00	143.40	129.05	142.26	138.24
Ormesa Geothermal 1H Trust	Ormesa I	Geothermal	31.20	131.42	136.52	129.49	132.48
Silicon Valley Power	Ostrom Road aka G2 Energy Project	Landfill Gas	1.60	9	10		9.49
Covanta Otay 3 Company	Otay 3 Power Station	Other Biomass Gases	3.70	23.45	20.90	24.25	22.87
Covanta Power Pacific, Inc.	Otay, Unit 1	Landfill Gas	1.85	12.44	10.85	23.28	15.52
Covanta Power Pacific, Inc.	Otay, Unit 2	Landfill Gas	1.85	11.87	10.64		11.25
Ameresco Ox Mountain	Ox Mountain Landfill aka Half Moon Bay	Wood/Wood Waste Solids	11.40	86.46	86.93	73.73	82.37
Covanta Power Pacific, Inc.	Pacific Oroville Power Inc, Gen 1	Wood/Wood Waste Solids	9.38	59.27	34.74	65.28	53.10
Covanta Power Pacific, Inc.	Pacific Oroville Power Inc, Gen 2	Wood/Wood Waste Solids	9.38	59.27	34.74	65.28	53.09
Covanta Power Pacific, Inc.	Pacific Ultrapower Chinese	Wood/Wood Waste Solids	25.00	136.32	112.91	126.86	125.36
LA County Sanitation Districts	Palos Verdes Gas to Energy Facility	Landfill Gas	13.00	13.00	19.37	20.21	17.53

Table B-1: 2006-2011 In-State Operational Renewable Generation (Excluding Small Hydro) (Continued)

Company Name	Plant Name	QFER Fuel Type	Installed Capacity MW	2011 (GWh)	2010 (GWh)	Average 2009-2006 (GWh)	Average (GWh)
Orange County Sanitation District	Plant No 2, Gen 1-6	Other Biomass Gases	16.00	42.89	40.79	42.31	41.99
Mammoth Pacific LP	Ples I – aka Mammoth Pacific II	Geothermal	5.00	35.33	33.81	34.53	34.56
Mammoth Pacific LP	Ples I – aka Mammoth Pacific II	Geothermal	5.00	36.33	33.81	34.53	34.89
Mammoth Pacific LP	Ples I – aka Mammoth Pacific II	Geothermal	5.00	36.33	33.81	34.53	34.89
LA County Sanitation Districts	Puente Hills Energy Recovery, Gen 1	Landfill Gas	50.00	394.73	396.80	369.77	387.10
LA County Sanitation Districts	Puente Hills Energy Recovery, Gen 2	Landfill Gas	2.80	12.01	11.93	11.65	11.86
LA County Sanitation Districts	Puente Hills Gas-to-Energy Facility, Phase II, Gen 3	Landfill Gas	2.70	10.65	15.82	12.31	12.93
LA County Sanitation Districts	Puente Hills Gas-to-Energy Facility, Phase II, Gen 4	Landfill Gas	2.70	6.82	10.49	12.57	9.96
LA County Sanitation Districts	Puente Hills Gas-to-Energy Facility, Phase II, Gen 5	Landfill Gas	2.70	10.89	11.06	12.52	11.49
Geysers Power Company, LLC	Quick Silver #16	Geothermal	120.00	383.28	396.23	407.50	395.67
County of Riverside Waste Management Department	RCWMD Badlands Power Plant	Landfill Gas	1.30	3.70	6.28	6.31	5.43
Geysers Power Company, LLC	Ridge Line #7-#8	Geothermal	55.00	310.10	312.98	291.55	304.88
Geysers Power Company, LLC	Ridge Line #7-#8	Geothermal	55.00	321.22	323.51	297.99	314.24
Rio Bravo Rocklin	Rio Bravo Fresno	Wood/Wood Waste Solids	24.30	195.58	177.97	183.12	185.55
Rio Bravo Rocklin	Rio Bravo Rocklin	Wood/Wood Waste Solids	24.30	185.22	172.28	181.31	179.60
South San Joaquin Irr District	Robert O. Schulz Solar Farm #1 and #2	Solar (PV/Thermal)	1.40		0.76		0.76

Table B-1: 2006-2011 In-State Operational Renewable Generation (Excluding Small Hydro) (Continued)

Company Name	Plant Name	QFER Fuel Type	Installed Capacity MW	2011 (GWh)	2010 (GWh)	Average 2009-2006 (GWh)	Average (GWh)
CE Generation (CalEnergy)	Salton Sea Unit 1	Geothermal	10.00	73.08	77.13	79.62	76.61
CE Generation (CalEnergy)	Salton Sea Unit 2, Gen 1	Geothermal	11.65	67.54	65.79	73.15	68.83
CE Generation (CalEnergy)	Salton Sea Unit 2, Gen 2	Geothermal	5.70	32.52	31.67	35.22	33.14
CE Generation (CalEnergy)	Salton Sea Unit 2, Gen 3	Geothermal	4.40	25.02	24.37	27.09	25.49
CE Generation (CalEnergy)	Salton Sea Unit 3	Geothermal	53.97	369.65	380.14	387.88	379.22
CE Generation (CalEnergy)	Salton Sea Unit 4	Geothermal	51.00	330.39	311.54	354.21	332.05
CE Generation (CalEnergy)	Salton Sea Unit 5	Geothermal	49.90	348.73	350.63	367.54	355.63
Gas Recovery Systems (Irvine)	San Marcos, Unit 1	Landfill Gas	0.90	5.52	3.55	5.20	4.76
Fortistar Methane Group	Santa Cruz Energy LLC	Landfill Gas	1.60	11.50	12.00		11.75
Covanta Energy Americas, Inc.	Second Imperial Geothermal Co SIGC Plant, Gen 1-12	Geothermal	48.00	259.96	250.56	258.64	256.38
Covanta Energy Americas, Inc.	Second Imperial Geothermal Co SIGC Plant, Gen 13	Geothermal	16.00	14.54	22.41	16.77	17.91
Covanta Energy Americas, Inc.	Second Imperial Geothermal Co SIGC Plant, Gen 14	Geothermal	16.00	112.90	120.62	117.78	117.10
Sunray Energy Inc	SEGS I	Solar (PV/Thermal)	13.80	14.06	13.47	11.46	13.00
Sunray Energy Inc	SEGS II	Solar (PV/Thermal)	30.00	38.04	34.69	30.94	34.55
FPL Energy	SEGS III	Solar (PV/Thermal)	30.00	81.50	72.95	83.72	79.39
FPL Energy	SEGS IV	Solar (PV/Thermal)	30.00	74.52	75.89	83.41	77.94
FPL Energy	SEGS IX	Solar (PV/Thermal)	92.00	222.20	232.46	197.06	217.24
FPL Energy	SEGS V	Solar (PV/Thermal)	30.00	78.78	67.03	77.46	74.42
FPL Energy	SEGS VI	Solar (PV/Thermal)	30.00	83.77	83.56	86.90	84.74

Table B-1: 2006-2011 In-State Operational Renewable Generation (Excluding Small Hydro) (Continued)

Company Name	Plant Name	QFER Fuel Type	Installed Capacity MW	2011 (GWh)	2010 (GWh)	Average 2009-2006 (GWh)	Average (GWh)
FPL Energy	SEGS VII	Solar (PV/Thermal)	30.00	81.71	78.46	82.67	80.95
FPL Energy	SEGS VIII	Solar (PV/Thermal)	92.00	214.01	219.72	186.88	206.87
Sierra Pacific Industries Inc	Sierra Pacific Industries- SPI - Anderson	Wood/Wood Waste Solids	4.00	26.60	28.66	30.40	28.55
eSolar, Inc.	Sierra SunTower	Solar (PV/Thermal)	7.50	0.27	0.60		0.44
WM Renewable Energy	Simi Valley Landfill, 1	Landfill Gas	1.35	15.99	13.30	11.83	13.71
Geysers Power Company, LLC	Socrates #18	Geothermal	120.00	372.39	381.77	394.32	382.83
Sacramento Municipal Utility District	Solar, Unit 1	Solar (PV/Thermal)	1.00	1.02	1.21	1.42	1.22
Sacramento Municipal Utility District	Solar, Unit 2	Solar (PV/Thermal)	1.00	0.23	0.43	0.45	0.37
Geysers Power Company, LLC	Sonoma #3	Geothermal	78.00	304.22	309.05	299.43	304.23
CCSF Public Utilities Commission, Hetch Hetchy Water & Power	Southeast Digester Gas Cogen Plant	Other Biomass Gases	2.10	3.44	N/A	N/A	3.44
LA County Sanitation Districts	Spadra Landfill Gas to Energy	Landfill Gas	10.60	40.72	41.06	44.82	42.20
Sierra Pacific Industries Inc	SPI - Burney	Wood/Wood Waste Solids	20.00	107.50	112.25	108.09	109.28
Sierra Pacific Industries Inc	SPI - Lincoln	Wood/Wood Waste Solids	19.20	116.47	116.47	124.86	119.27
Sierra Pacific Industries Inc	SPI - Loyalton	Wood/Wood Waste Solids	20.00	43.56	43.56	55.45	47.52
Sierra Pacific Industries Inc	SPI - Quincy, Gen 1	Wood/Wood Waste Solids	20.00	115.45	115.45	123.17	118.02

Table B-1: 2006-2011 In-State Operational Renewable Generation (Excluding Small Hydro) (Continued)

Company Name	Plant Name	QFER Fuel Type	Installed Capacity MW	2011 (GWh)	2010 (GWh)	Average 2009-2006 (GWh)	Average (GWh)
Sierra Pacific Industries Inc	SPI - Quincy, Gen 2	Wood/Wood Waste Solids	7.50	20.07	20.07	21.36	20.50
Covanta Stanislaus, Inc.	Stanislaus Resource Recovery Facility	Municipal Solid Waste	24.00	118.12	122.59	132.37	124.36
Geysers Power Company, LLC	Sulphur Springs #14	Geothermal	117.50	422.59	419.52	420.98	421.03
City of Sunnyvale, Water Pollution Control Plant	Sunnyvale Water Pollution Control Plant	Landfill Gas	0.80	4.78	5.23	5.10	5.03
City of Sunnyvale, Water Pollution Control Plant	Sunnyvale Water Pollution Control Plant	Landfill Gas	0.80	4.25	5.36	5.22	4.94
Gas Recovery Systems (Irvine)	Sycamore Landfill San Diego, Unit 1	Landfill Gas	0.90	14.97	13.29	15.49	14.58
Tollennar Dairy	Tollenaar Holsteins Dairy - Generating Unit #1	Digester Gas	0.20	1.40	1.40	1.40	1.40
LA County Sanitation Districts	Total Energy Facilities	Other Biomass Gases	9.90	48.80	50.36	33.11	44.09
LA County Sanitation Districts	Total Energy Facilities	Other Biomass Gases	9.90	41.90	42.12	44.67	42.90
LA County Sanitation Districts	Total Energy Facilities	Other Biomass Gases	9.90	41.48	42.18	54.10	45.92
Greenleaf Power, LLC (Town of Scotia)	Town of Scotia (formerly Pacific Lumber), #3	Wood/Wood Waste Solids	7.50	5.04	5.02	4.32	4.79
Greenleaf Power, LLC (Town of Scotia)	Town of Scotia (formerly Pacific Lumber), Gen A	Wood/Wood Waste Solids	12.50	76.23	66.06	58.62	66.97
Greenleaf Power, LLC (Town of Scotia)	Town of Scotia (formerly Pacific Lumber), Gen B	Wood/Wood Waste Solids	12.50	39.30	51.79	42.64	44.57
Toyon Landfill Gas Conversion, LLC	Toyon Landfill	Landfill Gas	1.88	3.31	2.82	4.92	3.68

Table B-1: 2006-2011 In-State Operational Renewable Generation (Excluding Small Hydro) (Continued)

Company Name	Plant Name	QFER Fuel Type	Installed Capacity MW	2011 (GWh)	2010 (GWh)	Average 2009-2006 (GWh)	Average (GWh)
Toyon Landfill Gas Conversion, LLC	Toyon Landfill	Landfill Gas	1.88	3.31	7.33	7.22	5.95
Thermal Energy Dev Partner LP	Tracy Biomass Plant	Wood/Wood Waste Solids	23.00	148.50	137.87	132.92	139.76
University of California, San Diego	UCSD Solar PV System	Solar (PV/Thermal)	1.20	1.78	1.69		1.73
PG&E	Vaca Dixon Solar Station	Solar (PV/Thermal)	2.00	4.27	4.12		4.19
CE Generation (CalEnergy)	Vulcan, Gen 1	Geothermal	30.16	200.94	225.65	229.16	218.58
CE Generation (CalEnergy)	Vulcan, Gen 2	Geothermal	9.56	63.46	71.26	72.37	69.03
Enpower Management Corp.	Wadham	Agriculture Crop Byproducts/Straw/Energy Crops	29.00	204.14	175.65	173.68	184.49
Geysers Power Company, LLC	West Ford Flat #4, WFST1	Geothermal	14.40	111.66	112.97	111.87	112.16
Geysers Power Company, LLC	West Ford Flat #4, WFST2	Geothermal	14.40	109.48	111.90	110.62	110.67
PG&E	Westside Solar Station	Solar (PV/Thermal)	15.00	8.35			8.35
Wheelabrator Technologies Inc.	Wheelabrator Shasta	Wood/Wood Waste Solids	62.75	391.35	397.59	395.38	394.77
Woodland Biomass Power Ltd	Woodland Biomass Power Ltd	Wood/Wood Waste Solids	28.00	179.41	175.58	159.53	171.51
Yolo County General Services	Yolo County Solar Project	Solar (PV/Thermal)	1.00	2.03			2.03
Imperial Irrigation District	Niland Gas Turbine Plant Unit 1	Biogas	N/A	24.99	9.40	4.04	12.81
Pacific Gas & Electric	Gateway Generating Station	Biogas	N/A		220.19	347.23	283.71
		Totals:	**6,245.13**	**26,709.10**	**25,107.63**	**24,209.46**	**27,333.93**

Source: QFER 2006 – 2011, California Energy Commission.

Table B-2: Out-of-State Operational Renewable Generation

Facility Name	Plant Name	Fuel Type	State	COD or Contract Date	Installed (MW)	2011 Net GWh Purchase	2010 Net GWh Purchase	2009 Net GWh Purchase	2009-2011 Ave Gen (GWh)	Owner
Various (Shell McCormmas Bluff)	Aggregated LFG purchase	Biomethane	TX	2009-2011	47.56	354.00	354.00	354.00	354.00	POU
Iberdrola Renewables	Big Horn 1 and Big Horn 2	Wind	Klickitas, WA	11/1/2010	249	684.9			684.91	POU
Shell	EDF Biomethane	Biomethane	TX	12/22/2008	3.10	948.62	948.62	948.62	948.62	POU
Thermo Geothermal Raser Technologies	Thermo No.1 BE-01	Geothermal	UT	1/23/2009	15.00	100.45			100.45	POU
Naturener - Glacier Wind Energy 1 and 2	Glacier Wind Energy 1 and 2 McCormick Ranch	Wind	MT	10/21/2009	210.00	639.70	427.27		533.49	POU
Goshen Phase II LLC	Goshen Phase II	Wind	ID	11/4/2010	90.00	297.94			297.94	IOU
Simpson Tacoma KRAFT Company - Tacoma Cogen	Iberdrola Renewables, Inc. (Simpson Biomass, Tacoma, WA)	Biomass	WA	7/1/2009	34.00	243.06	269.14		256.10	N/A
Judith Gap	Judith Gap Wind Farm Project	Wind	MO	N/A		0.30			0.30	N/A
Iberdrola Renewables (PPM Klondike)	Klondike I-III	Wind	OR	1/1/2008	176.00	479.80	431	449.58	453.53	N/A
Cannon Power	Linden Ranch	Wind	Klickitas, WA	5/25/2010	50.00	151.20			151.24	POU
Iberdrola Renewables	Milford Wind Corridor Phase I and Phase II	Wind	Beaver, UT	2009-2011	305.50	590.10			590.10	POU

Table B-2: Out-of-State Operational Renewable Generation (Continued)

Facility Name	Plant Name	Fuel Type	State	COD or Contract Date	Installed (MW)	2011 Net GWh Purchase	2010 Net GWh Purchase	2009 Net GWh Purchase	2009-2011 Ave Gen (GWh)	Owner
Ivenrgy LLC Vantage	Vantage Wind	Wind	WA	9/7/2010	90.00	290.80			290.76	IOU
Oregon Trail Windfarm LLC - Oregon Trail Windfarm LLC	Oregon Trail Windfarm LLC	Wind	OR	N/A		3.36			3.36	N/A
Pacific Canyon Windfarm LLC - Pacific Canyon Windfarm LLC	Pacific Canyon Windfarm LLC	Wind	OR	N/A		1.93			1.93	N/A
Iberdrola Renewables	Pebble Springs	Wind	Gilliam County, OR	3/31/2009	98.70	240.00	217.71		228.86	POU
Iberdrola Renewables	Pleasant Valley (Wyoming Wind Energy Center)	Wind	Uinta County, WY	2009	127.40	371.41	294.63	311.60	325.88	POU
Arlington Wind (Rattlesnake Road)	Rattlesnake Road Wind Farm	Wind	OR	12/26/2008	102.90	236.35	202.37	225.35	221.36	IOU
Iberdrola Renewables	Star Point	Wind	Sherman County, OR	4/21/2010	98.70	245.57	291.72		268.65	POU
Caithness Dixie Valley, LLC	Terra-Gen Dixie Valley, LLC	Geothermal	Nevada	7/5/2018	50.00	474.10	428.00		451.06	IOU
Tuolumne Wind Project Authority	Tuolumne Wind Project (Windy Point Phase 1)	Wind	Klickitas, WA	3/1/2009	136.60	391.40	301.79		346.60	POU
Tuolumne Wind Project Authority	Tuolumne Wind Project (Windy Point Phase 2)	Wind	Klickitas, WA	12/31/2009	262.20	751.30	579.27		665.39	POU
Sempra Cooper Mountain/El Dorado Energy	Cooper Mountain/El Dorado	Solar PV	NV	2010 and 3/31/2013	150.00	279.50			279.49	IOU

Table B-2: Out-of-State Operational Renewable Generation (Continued)

Facility Name	Plant Name	Fuel Type	State	COD or Contract Date	Installed (MW)	2011 Net GWh Purchase	2010 Net GWh Purchase	2009 Net GWh Purchase	2009-2011 Ave Gen (GWh)	Owner
Yakima-Tieton Irrigation Dist	Tieton	**hydro**	WA	**N/A**			**38.86**	**40.5**	**39.68**	N/A
Sub-total:									**7,493.57**	

Note: Highlighted cells indicate no generation reported.

Source: California Energy Commission, Power Source Disclosure, Reporting Years 2009-2011.

Table B-3: In-State Hydro Generation

Company Name	CEC Plant ID	Plant Name	2011 (GWh)	2010 (GWh)	2009 (GWh)	2008 (GWh)	2007 (GWh)	2006 (GWh)	2005 (GWh)	2004 (GWh)	8-Year Average
PG&E	H0005	Alta	3.55	3.61	4.13	3.56	2.71	4.58	3.92	4.39	3.81
Utica Power Authority	H0008	Angels	6.92	6.66	6.20	4.96	3.28	6.90	6.69	5.40	5.87
City of Pasadena	H0014	Azusa	10.37	0.00	5.02	2.05	0.06	2.73	2.16	0.00	2.80
City of Escondido	H0021	Bear Valley	0.02	0.45	2.24	5.55	0.97				1.84
Tri-Dam Project & Tri-Dam Power Authority	H0022	Beardsley	77.47	54.76	59.75	37.20	27.55	83.12	48.67	44.17	54.09
LADWP	H0040	Big Pine	8.21	8.52	14.74	13.73	10.82	14.86	11.95	11.91	11.84
SCE	H0041	Bishop Creek 2	40.86	35.11	27.92	22.28	13.88	40.05	29.36	25.51	29.37
SCE	H0042	Bishop Creek 3	43.92	33.06	29.14	23.92	19.16	36.61	25.89	28.79	30.06
SCE	H0043	Bishop Creek 4	51.74	50.20	40.97	32.83	18.77	52.68	50.16	44.36	42.71
SCE	H0044	Bishop Creek 5	19.00	15.50	12.36	12.08	10.16	21.03	17.34	14.17	15.21
SCE	H0045	Bishop Creek 6	13.37	3.67	9.22	6.98	7.21	11.52	8.21	8.01	8.52
Silicon Valley Power	H0046	Black Butte	15.96	24.37	5.47	22.09	7.99	23.74	23.74	13.46	17.10
SCE	H0048	Borel	61.01	44.04	54.71	45.36	38.31	71.04	76.61	52.64	55.46
Yuba County Water Agency	H0053	Fish Power	1.09	1.11	1.06	7.23	1.09	1.03	1.15		1.96
Nevada Irrigation District	H0054	Combie South (3 @ 500kW = 1.5MW)	7.41	7.09							7.25
California Department of Water Resources	H0058	Alamo	105.00	78.17	54.93	64.33	66.78	86.84	103.86	124.29	85.52

Table B-3: In-State HydrGeneration on (Continued)

Company Name	CEC Plant ID	Plant Name	2011 (GWh)	2010 (GWh)	2009 (GWh)	2008 (GWh)	2007 (GWh)	2006 (GWh)	2005 (GWh)	2004 (GWh)	8-Year Average
Modesto Irrigation District	H0073	Hogan	14.03	4.31	5.13	8.24	7.95	17.81	9.58	6.29	9.17
Calleguas Municipal Water District	H0076	Springville Reservoir	1.14	1.55	0.77	2.34	2.57	1.77	1.11	2.27	1.69
Calleguas Municipal Water District	H0078	East Portal Generator	5.81	3.97	6.68	7.01	6.83	4.58	4.90	6.41	5.77
East Bay Municipal Utility District (EBMUD)	H0080	Camanche	56.96	41.28	17.62	8.54	17.80	59.84	57.65	21.78	35.19
Sacramento Municipal Utility District	H0083	Camp Far West	38.37	27.79	22.15	11.72	11.81	34.26	26.60	21.57	24.28
PG&E	H0092	Centerville	1.58	0.00	4.76	7.53	11.85	16.84	24.31	24.21	11.39
Isabella Partners	H0094	Isabella	70.40	40.47	12.76	16.69	9.22	38.13	46.36	7.82	30.23
PG&E	H0096	Chili Bar	42.57	31.79	26.05	17.59	20.49	40.80	38.20	26.18	30.46
PG&E	H0106	Coleman	64.68	33.01	48.07	55.24	60.15	22.92	58.50	61.62	50.52
LADWP	H0110	Control Gorge	65.14	81.46	50.99	68.61	67.37	136.72	107.77	51.02	78.64
PacifiCorp	H0111	Copco 1	113.11	67.54	79.74	97.31	95.32	133.93	81.04	71.93	92.49
PacifiCorp	H0112	Copco 2	142.88	88.80	97.92	120.29	119.85	172.65	100.53	90.52	116.68
Metropolitan Water District	H0114	Corona	12.03	18.85	18.31	15.98	10.24	5.94	13.39	10.54	13.16
LADWP	H0116	Cottonwood	11.48	12.29	7.97	7.79	2.90	6.97	8.33	6.30	8.00
PG&E	H0118	Cow Creek	3.46	1.25	5.95	5.57	8.46	12.28	9.94	10.77	7.21

Table B-3: In-State HydrGeneration on (Continued)

Company Name	CEC Plant ID	Plant Name	2011 (GWh)	2010 (GWh)	2009 (GWh)	2008 (GWh)	2007 (GWh)	2006 (GWh)	2005 (GWh)	2004 (GWh)	8-Year Average
Metropolitan Water District	H0119	Coyote Creek	3.06	5.78	10.05	16.36	6.48	0.00	0.95	0.00	5.33
PG&E	H0120	Crane Valley	3.77								3.77
PG&E	H0130	De Sabla	96.63	79.55	68.60	64.12	85.17	97.29	96.34	96.15	85.48
PG&E	H0133	Deer Creek	11.77	17.00	23.23	20.92	21.33	19.20	18.90	21.52	19.23
Desert Water Agency	H0136	Whitewater Hydroelectric Plant	5.86	3.78	1.37	0.55	0.48	3.11	3.84		2.71
LADWP	H0142	Division Creek	4.90	4.65	3.77	6.19	4.03	5.56	4.43	4.60	4.77
Imperial Irrigation District	H0147	Drop 1	26.43	20.07	0.00	13.97	19.55	20.66	18.21	19.24	17.27
Imperial Irrigation District	H0149	Drop 2	52.46	49.39	46.48	49.64	51.42	52.21	59.87	49.99	51.43
Imperial Irrigation District	H0150	Drop 3	52.25	49.07	48.47	48.57	45.92	50.73	44.79	48.38	48.52
Imperial Irrigation District	H0151	Drop 4	105.10	99.45	100.17	106.65	104.87	106.63	95.60	104.62	102.89
Imperial Irrigation District	H0152	Drop 5	12.27	14.11	16.24	14.36	14.23	16.45	25.55	15.54	16.09
PG&E	H0156	Dutch Flat #1	100.99	89.88	86.31	66.55	76.55	116.18	114.63	92.54	92.96
Nevada Irrigation District	H0157	Dutch Flat 2	100.18	105.82	82.62	75.77	47.89	101.87	107.15	80.15	87.68
Imperial Irrigation District	H0160	East Highline	3.17	3.71	4.10	1.10	4.19	3.83	3.49	4.32	3.49

Table B-3: In-State HydrGeneration on (Continued)

Company Name	CEC Plant ID	Plant Name	2011 (GWh)	2010 (GWh)	2009 (GWh)	2008 (GWh)	2007 (GWh)	2006 (GWh)	2005 (GWh)	2004 (GWh)	8-Year Average
El Dorado Irrigation District	H0167	El Dorado	105.35	79.79	73.26	60.26	62.18	96.52	111.31	63.57	81.53
TKO Power, Inc.	H0168	Montgomery Creek Hydro	12.38	12.38	6.43	6.30	5.85	11.63	10.54	9.28	9.35
Metropolitan Water District	H0174	Etiwanda	58.43	30.14	30.43	61.04	127.70	142.85	96.01	99.16	80.72
PacifiCorp	H0177	Fall Creek	11.65	11.09	14.70	13.72	13.05	14.77	14.05	12.82	13.23
SCE	H0187	Fontana	7.81	7.79	5.43	6.50	4.58	8.41	7.69	4.27	6.56
Metropolitan Water District	H0188	Foothill Feeder	50.69	48.13	49.06	60.10	45.46	52.13	65.58	57.78	53.62
LADWP	H0189	Foothill	51.56	46.73	46.09	16.00	25.35	68.24	60.45	28.75	42.90
H&M Engineering, Inc.	H0192	Forks of Butte Hydro Project	56.32	63.55	39.60	27.69	19.66	60.51	52.92	39.27	44.94
LADWP	H0193	Franklin	10.67	9.33	8.60	5.91	2.02	0.64	0.99	3.43	5.20
Placer County Water Agency	H0195	French Meadows	93.28	57.64	54.34	27.67	32.11	97.50	69.75	46.98	59.91
Friant Power Authority	H0198	Friant-Kern Hydro Facility (River Outlet, Madera Canal, F-K)	106.74	76.34	97.85	49.49	36.15	115.42	129.49	62.70	84.27
Northern California Power Agency	H0209	Graeagle	2.90	7.52	2.35	1.99	1.97				3.35

Table B-3: In-State HydrGeneration on
(Continued)

Company Name	CEC Plant ID	Plant Name	2011 (GWh)	2010 (GWh)	2009 (GWh)	2008 (GWh)	2007 (GWh)	2006 (GWh)	2005 (GWh)	2004 (GWh)	8-Year Average
Metropolitan Water District	H0211	Greg Avenue	3.31	1.24							2.28
Silicon Valley Power	H0213	Grizzly	52.08	28.84	26.87	0.90	27.88	103.03	55.16	40.33	41.88
LADWP	H0216	Haiwee	20.50	26.40	7.57	8.27	5.36	20.26	19.53	13.31	15.15
PG&E	H0217	Halsey	38.87	56.48	49.33	46.35	47.93	58.35	62.13	61.21	52.58
PG&E	H0218	Hamilton Branch	20.20	15.52	8.05	7.67	8.26	22.59	20.95	20.06	15.41
PG&E	H0221	Hat Creek #1	29.66	29.34	30.64	33.01	35.79	40.69	32.56	36.20	33.49
PG&E	H0222	Hat Creek #2	41.39	37.61	41.80	46.03	49.49	55.38	47.39	51.62	46.34
Northbrook Power Management LLC	H0226	Haypress Hydroelectric Inc	29.73	17.26	14.91	10.84	10.79	24.49	18.05	16.82	17.86
Placer County Water Agency	H0228	Hell Hole	4.19	2.98	3.31	3.51	3.58		3.62		3.53
Turlock Irrigation District	H0234	Hickman	4.68	4.36	3.65	3.77	4.17	3.89	4.20	4.67	4.17
Ida-West Energy	H0236	Cove Hydroelectric	20.02	19.40	9.76	11.00	10.02	22.00	18.58	14.87	15.71
Ida-West Energy	H0237	Ponderosa Bailey Creek	3.70	1.98	1.21	0.57	0.83	5.72	2.38	2.17	2.32
Ida-West Energy	H0238	Lost Creek 1	4.83	4.65	5.26	5.98	6.36	6.51	5.65	5.73	5.62
Ida-West Energy	H0240	Burney Creek	8.09	4.58	3.83	2.20	2.45	11.87	6.73	6.01	5.72

Table B-3: In-State HydrGeneration on (Continued)

Company Name	CEC Plant ID	Plant Name	2011 (GWh)	2010 (GWh)	2009 (GWh)	2008 (GWh)	2007 (GWh)	2006 (GWh)	2005 (GWh)	2004 (GWh)	8-Year Average
Humboldt Bay Municipal Water District	H0241	Gosselin Hydroelectric Plant	5.79	6.97	3.73	4.90	4.57	6.18	7.39	4.59	5.52
Yolo County Flood Control & Water Conservation District	H0243	Indian Valley Dam	4.29	2.46	1.31	5.07	9.89	21.00	11.00	14.00	8.63
PG&E	H0244	Inskip	40.65	44.61	37.87	36.03	44.29	56.18	46.87	51.12	44.70
PacifiCorp	H0245	Iron Gate	119.84	96.26	112.65	125.38	119.21	130.72	98.98	96.18	112.40
Sacramento Municipal Utility District	H0255	Jones Fork	38.17	19.96	16.11	11.30	6.72	39.12	25.71	15.68	21.59
SCE	H0259	Kaweah 1	10.84	7.90	7.07	8.96	6.60	10.40	11.15	10.21	9.14
SCE	H0260	Kaweah 2	13.85	12.56	11.39	10.96	7.02	11.11	12.87	11.71	11.43
SCE	H0261	Kaweah 3	4.10	27.86	23.30	18.27	15.19	20.62	28.64	22.63	20.07
Kaweah River Power Authority	H0262	Terminus Hydroelectric Project	76.55	52.80	34.77	30.82	24.58	71.24	56.07	30.00	47.10
South Feather Water and Power	H0263	Kelly Ridge	74.14	77.68	72.38	68.64	70.24	80.51	81.23	84.30	76.14
PG&E	H0267	Kern Canyon	20.72	22.73	52.46	36.68	44.65	50.87	55.95	55.48	42.44
SCE	H0268	Kern River 1	203.24	48.42	51.26	44.26	102.74	100.90	98.83	120.83	96.31
PG&E	H0271	Kilarc	17.39	16.82	11.33	12.88	16.05	21.42	18.55	17.84	16.54
Turlock Irrigation District	H0276	La Grange	35.85	23.25	9.38	10.03	15.62	34.55	30.33	15.41	21.80

Table B-3: In-State HydrGeneration on (Continued)

Company Name	CEC Plant ID	Plant Name	2011 (GWh)	2010 (GWh)	2009 (GWh)	2008 (GWh)	2007 (GWh)	2006 (GWh)	2005 (GWh)	2004 (GWh)	8-Year Average
Metropolitan Water District	H0282	Lake Mathews	22.78	28.44	31.76	32.79	18.16	9.96	21.89	16.49	22.78
City of Ukiah	H0283	Lake Mendocino	10.20	4.48	5.50	8.91	3.25				6.47
Siskiyou County	H0284	Box Canyon	25.83	22.95	14.05	12.40	11.18	25.57	23.70	20.87	19.57
United States Bureau of Reclamation	H0286	Lewiston	3.35	3.25	1.92	3.29	2.67	3.19	2.73	0.00	2.55
PG&E	H0287	Lime Saddle	5.88	4.91	5.04	4.81	5.29	6.26	5.44	5.92	5.44
SCE	H0296	Lundy	13.05	9.19	3.64	4.89	4.42	13.46	12.67	8.68	8.75
SCE	H0298	Lytle Creek	2.97	3.21	2.39	3.08	2.51	3.27	1.80	1.62	2.61
Madera-Chowchilla Water Power Authority	H0310	Madera Canal (Station 980, 1174, 1302, 1923)	10.97	11.70	9.02	6.65	5.08	12.30	11.73	6.51	9.25
Malacha Hydro Ltd Partnership	H0311	Muck Valley Hydroelectric	104.59	30.56	32.07	42.39	22.35	111.58	70.97	66.65	60.14
Merced Irrigation District	H0316	McSwain	54.22	32.50	105.40	20.25	28.66	50.98	41.23	26.13	44.92
Mega Renewables	H0321	Hatchet Creek Project	25.03	25.79	12.42	14.28	14.40	28.55	23.48	18.44	20.30
Mega Renewables	H0322	Roaring Creek	8.46	8.46	3.69	5.27	5.27	8.09	7.75	5.46	6.56
Mega Renewables	H0323	Bidwell Ditch	9.83	10.58	11.65	12.57	12.79	12.69	11.85	12.21	11.77
PG&E	H0324	Merced Falls	16.72	12.50	10.89	8.93	11.39	14.34	13.88	11.36	12.50

Table B-3: In-State HydrGeneration on (Continued)

Company Name	CEC Plant ID	Plant Name	2011 (GWh)	2010 (GWh)	2009 (GWh)	2008 (GWh)	2007 (GWh)	2006 (GWh)	2005 (GWh)	2004 (GWh)	8-Year Average
Merced Irrigation District	H0325	Merced ID (Parker)	7.91	5.29	5.82	4.58	6.32	6.97	6.49	6.58	6.24
LADWP	H0328	Middle Gorge	99.14	101.50	52.09	69.94	68.68	139.86	112.77	52.16	87.02
SCE	H0331	Mill Creek 1	5.12	0.97	0.00	1.90	3.10	5.72	4.73	3.88	3.18
SCE	H0332	Mill Creek 2	12.61	10.96	7.46	10.73	12.67	12.47	11.72	8.42	10.88
CCSF Public Utilities Commission, Hetch Hetchy Water & Power	H0336	Moccasin Low Head	10.86	8.71	4.33	2.76	0.03	6.78	6.89	3.75	5.51
Monterey County Water Resources Agency	H0341	Nacimiento Hydro Project	17.89	12.35	9.96	14.45	14.93	20.05	20.05	6.70	14.55
Solano Irrigation District	H0343	Monticello	27.07	36.21	38.73	40.24	43.99	67.72	44.00	54.66	44.08
Utica Power Authority	H0346	Murphys	17.87	16.33	15.48	12.87	10.54	16.65	15.78	15.00	15.07
Nevada Irrigation District	H0347	Scotts Flat (860kW Nameplate Capacity)	3.79	4.09	4.04	3.76	5.25	3.19	3.14	3.29	3.82
PG&E	H0348	Narrows 1	71.59	55.95	77.13	41.81	18.93	76.88	27.53	15.18	48.13
Sierra Pacific Industries Inc	H0349	Nelson Creek	4.01	4.07	2.20	2.44	1.65	4.38	3.62	2.63	3.13

Table B-3: In-State HydrGeneration on (Continued)

Company Name	CEC Plant ID	Plant Name	2011 (GWh)	2010 (GWh)	2009 (GWh)	2008 (GWh)	2007 (GWh)	2006 (GWh)	2005 (GWh)	2004 (GWh)	8-Year Average
Nevada Irrigation District	H0351	Bowman	17.81	15.06	12.55	7.99	8.09	20.24	14.51	11.66	13.49
K. S. Dunbar & Associates	H0356	Spicer	29.97	19.75	15.24	12.39	13.54	29.86	27.98	14.35	20.38
PG&E	H0357	Newcastle	19.40	32.34	21.84	17.73	24.26	37.03	36.59	32.93	27.76
United States Bureau of Reclamation	H0360	Nimbus	81.00	59.70	58.75	34.41	43.81	77.73	72.32	51.98	59.96
United States Bureau of Reclamation	H0363	O'Neill	0.02	1.43	5.94	8.93	5.40	0.03	0.31	5.96	3.50
PG&E	H0364	Oak Flat	6.68	5.55	6.20	4.87	5.33	5.19	3.81		5.37
Kern Hydro Partners	H0367	Rio Bravo Hydroelectric	51.19	34.11	32.20	31.92	21.87	51.61	54.56	31.02	38.56
Synergics Energy Services, LLC	H0371	Olsen	16.02	9.42	5.06	4.18	4.65	17.65	9.22	11.49	9.71
SCE	H0372	Ontario 1	2.78	3.40	3.17	4.48	2.07	5.18	5.24	1.02	3.42
SCE	H0373	Ontario 2	1.70	1.85	1.38	1.07	0.42	1.93	1.60	1.26	1.40
Placer County Water Agency	H0374	Oxbow	36.51	31.72	26.67	15.91	15.86	35.61	35.00	28.91	28.27
Metropolitan Water District	H0382	Perris	22.98	14.85	13.24	13.10	26.86	34.39	21.43	38.45	23.16
PG&E	H0383	Phoenix	11.20	10.08	9.42	10.41	6.33	0.00	9.41	10.35	8.40

Table B-3: In-State HydrGeneration on (Continued)

Company Name	CEC Plant ID	Plant Name	2011 (GWh)	2010 (GWh)	2009 (GWh)	2008 (GWh)	2007 (GWh)	2006 (GWh)	2005 (GWh)	2004 (GWh)	8-Year Average
Imperial Irrigation District	H0385	Pilot Knob	23.92	25.16	27.89	27.61	12.61	13.73	5.37	16.82	19.14
LADWP	H0394	Pleasant Valley	6.91	7.95	4.10	6.19	5.62	11.97	9.72	4.06	7.06
SCE	H0398	Poole	37.31	32.33	29.08	22.11	18.69	43.95	38.22	29.94	31.45
PG&E	H0401	Potter Valley	32.92	27.31	19.71	23.08	20.85	38.26	41.37	43.71	30.90
Metropolitan Water District	H0408	Red Mountain	32.85	31.39	15.50	20.98	14.93	31.05	22.27	20.61	23.70
Sacramento Municipal Utility District	H0414	Robbs Peak	76.73	61.11	38.90	24.64	26.57	75.56	64.04	35.87	50.43
TKO Power, Inc.	H0422	Rock Creek L.P.	5.88	3.85	1.29	0.63	0.91	6.99	4.11	1.03	3.09
Nevada Irrigation District	H0424	Rollins	76.26	68.54	66.72	57.82	53.58	83.23	85.61	46.25	67.25
SCE	H0426	Rush Creek	48.39	54.05	56.09	16.07	22.60	63.32	42.11	11.30	39.24
Northbrook Power Management LLC	H0427	Kanaka	3.07	1.61	0.77	0.51	0.66	4.45	2.17	1.31	1.82
Northbrook Power Management LLC	H0428	Kekawaka	8.88	15.15	5.29	5.80	5.44	13.43	13.26	8.35	9.45
Metropolitan Water District	H0437	San Dimas Hydro Recovery Plant	53.09	37.07	0.00	23.67	49.71	63.86	55.72	65.43	43.57
LADWP	H0438	San Fernando	23.63	6.71	0.02	11.74	8.20	31.18	39.68	24.18	18.17
LADWP	H0440	San Francisquito 2	103.83	51.95	5.99	36.47	17.84	50.14	101.54	58.31	53.26

Table B-3: In-State HydrGeneration on (Continued)

Company Name	CEC Plant ID	Plant Name	2011 (GWh)	2010 (GWh)	2009 (GWh)	2008 (GWh)	2007 (GWh)	2006 (GWh)	2005 (GWh)	2004 (GWh)	8-Year Average
LADWP	H0441	San Francisquito 1	268.77	181.75	111.09	94.69	57.90	232.77	279.76	153.39	172.52
Los Angeles County Dept of Public Works	H0442	San Gabriel Hydroelectric Project	22.34	22.78	4.43	13.20	0.00	8.15	10.89	5.35	10.89
San Gabriel Valley MWD	H0443	San Dimas Wash	2.28	3.24	0.00	0.00	0.00	0.00	2.62	3.24	1.42
PG&E	H0448	San Joaquin #1A	1.93								1.93
PG&E	H0449	San Joaquin #2	15.36	13.69	8.81	6.34	2.65	13.24	16.80	8.71	10.70
PG&E	H0450	San Joaquin #3	16.14	18.65	11.10	9.18	3.61	19.76	16.95	11.46	13.36
SCE	H0460	Santa Ana 1	3.46	6.86	3.75	5.16	4.58	9.15	8.10	1.96	5.38
SCE	H0462	Santa Ana 3	7.17	4.99	3.12	2.70	2.36	12.40	9.89	4.09	5.84
LADWP	H0467	Sawtelle	1.08	1.89	1.98	1.42	0.00	0.00	0.00	1.61	1.00
Metropolitan Water District	H0472	Sepulveda Canyon	35.75	20.86	17.83	7.95	41.50	60.48	59.42	61.70	38.19
SCE	H0479	Sierra	3.74	3.81	2.60	3.44	1.39	3.65	2.93	2.21	2.97
Sacramento Municipal Utility District	H0482	Slab Creek	1.77	2.08	2.38	1.04	1.02	1.07			1.56
TKO Power, Inc.	H0483	Slate Creek	14.81	15.77	7.86	8.66	0.16	14.60	15.25	11.12	11.03
South Feather Water and Power	H0484	Sly Creek	53.53	37.01	32.21	21.19	17.55	52.73	36.21	33.97	35.55
Sonoma County Water Agency	H0485	Warm Springs	13.34	14.42	9.80	14.02	11.79	14.81	13.36	14.10	13.21

Table B-3: In-State HydrGeneration on (Continued)

Company Name	CEC Plant ID	Plant Name	2011 (GWh)	2010 (GWh)	2009 (GWh)	2008 (GWh)	2007 (GWh)	2006 (GWh)	2005 (GWh)	2004 (GWh)	8-Year Average
PG&E	H0486	South	49.97	17.22	42.67	43.11	48.58	51.64	51.56	53.59	44.79
South San Joaquin Irr District	H0488	Frankenheimer	14.48	13.78	15.14	15.72	15.46	14.59	12.93	16.03	14.76
South San Joaquin Irr District	H0489	Woodward	5.45	5.00	5.23	5.72	5.56	5.52	5.01	5.40	5.36
PG&E	H0490	Spaulding #1	26.64	28.24	30.35	21.28	22.31	36.34	27.39	26.79	27.42
PG&E	H0491	Spaulding #2	20.57	19.62	15.18	12.16	14.72	25.03	17.44	14.49	17.40
PG&E	H0492	Spaulding #3	39.24	32.38	32.98	26.29	24.44	42.15	43.03	30.05	33.82
PG&E	H0495	Spring Gap	40.70	41.71	38.57	33.87	24.08	42.98	44.24	37.61	37.97
United States Bureau of Reclamation	H0497	Stampede	18.05	8.36	8.48	13.72	11.10	16.30	7.25	12.94	12.02
SCE	H0499	Portal	8.80	23.73	25.43	20.73	39.23	25.04	35.02	36.30	26.78
Silicon Valley Power	H0500	Stony Gorge	14.26	14.21	5.60	10.09	7.23	17.33	18.63	16.51	12.98
Lower Tule River & Pixley Irrigation District	H0503	Tulare Success	2.37	2.47	1.22	0.31	0.16	3.51	3.18	0.51	1.72
TKO Power, Inc.	H0507	Bear Creek	7.46	1.81	1.85	2.54	2.44	9.61	4.01	4.49	4.28
Metropolitan Water District	H0509	Temescal	13.70	19.52	18.37	16.45	10.54	6.97	13.80	11.43	13.85
California Department of Water Resources	H0511	Thermalito Diversion Dam	11.33	9.19	22.67	0.00	18.97	8.75	14.17		12.15

Table B-3: In-State HydrGeneration on (Continued)

Company Name	CEC Plant ID	Plant Name	2011 (GWh)	2010 (GWh)	2009 (GWh)	2008 (GWh)	2007 (GWh)	2006 (GWh)	2005 (GWh)	2004 (GWh)	8-Year Average
Norman Ross Burgess	H0512	Three Forks	7.84	8.89	5.93	6.22	6.01	7.39	8.24	5.84	7.04
PG&E	H0518	Toadtown	5.85	5.33	3.31	3.48	4.03	5.97	5.73	5.80	4.94
Tri-Dam Project & Tri-Dam Power Authority	H0519	Sand Bar	131.64	78.62	89.97	51.96	50.10	114.47	94.78	88.50	87.51
PG&E	H0523	Tule	27.25	25.77	17.80	20.37	9.69	25.63	27.73	17.32	21.44
SCE	H0525	Tule River	0.00	0.00	10.24	14.39	10.49	12.81	-0.14	10.87	7.33
Tri-Dam Project & Tri-Dam Power Authority	H0527	Tulloch	105.71	95.63	95.37	93.28	108.85	138.73	90.17	89.27	102.13
Turlock Irrigation District	H0530	Turlock Lake	10.15	10.00	7.93	7.04	9.54	9.85	10.21	10.15	9.36
United Water Conservation District	H0533	Santa Felicia	0.00	0.00	0.00	0.74	1.41	3.78	3.74	0.07	1.22
Turlock Irrigation District	H0535	Upper Dawson	11.88	12.18	9.86	9.41	10.99	11.31	12.24	11.86	11.22
LADWP	H0536	Upper Gorge	100.07	99.42	51.69	67.29	67.73	140.50	106.60	48.81	85.26
Metropolitan Water District	H0539	Valley View	9.34	8.85	4.93	0.00	1.28	6.96	2.00	0.00	4.17
Metropolitan Water District	H0541	Venice	14.33	8.66	11.27	0.00	22.46	40.24	34.72	31.79	20.43
PG&E	H0545	Volta #1	53.02	41.74	31.28	36.73	44.55	54.67	44.27	50.30	44.57
PG&E	H0546	Volta #2	6.15	4.98	2.25	3.76	0.47	4.46	5.24	5.93	4.15

Table B-3: In-State HydrGeneration on (Continued)

Company Name	CEC Plant ID	Plant Name	2011 (GWh)	2010 (GWh)	2009 (GWh)	2008 (GWh)	2007 (GWh)	2006 (GWh)	2005 (GWh)	2004 (GWh)	8-Year Average
PG&E	H0558	West Point	94.86	84.26	86.53	63.79	60.20	100.00	101.13	88.71	84.93
City of Redding	H0564	Whiskeytown	26.08	26.69	27.03	17.59	24.80	21.02	27.11	24.61	24.37
PG&E	H0569	Wise	63.22	87.55	80.47	83.10	73.00	92.81	96.93	93.64	83.84
PG&E	H0570	Wishon Powerhouse	87.86	90.00	40.09	48.76	22.78	97.74	103.35	52.30	67.86
Metropolitan Water District	H0577	Yorba Linda	16.84	7.31	20.75	30.21	31.57	25.83	31.27	30.52	24.29
Metropolitan Water District	H0611	Diamond Valley Lake	34.55	4.03	12.18	30.18	41.61	33.83	11.33	40.10	25.98
San Diego County Water Authority	H0612	Rancho Penasquitos	15.08	20.21	20.35	22.89	13.36				18.38
		Total	**6,181.64**	**4,957.81**	**4,363.07**	**4,033.06**	**4,014.40**	**6,659.11**	**6,000.39**	**4,848.84**	**5,184.05**

Note: Highlighted cells indicate no generation reported.

Source: 2004 – 2011 California Energy Commission QFER.

Table B-4: Recently Operational Renewables In-State

LSE	Facility Name	Technology	Min. Installed Size (MW)	QFER Plant ID	Online Date	Min. Expected Deliveries (GWh/Yr)	Contract Term	Location
SCE	Navy I (Upgarde Coso Facility)	Geothermal	32.00	T0009, T0010, T0011	10/01/11	252.00	20	Inyo County
PG&E	Avenal Solar Park	Solar PV	6.00	S0126	08/07/11	10.00	20	Kings County
PG&E	Five Points	Solar PV	15.00	S0140	9/24/2011	31.00	N/A	Fresno County
PG&E	Sand Drag	Solar PV	19.00	S0131	8/5/2011	10.00	20	Kings County
SCE	SPVP 005 - Redlands #1	Solar PV	3.40	S0158	2012	5.40	N/A	Redlands
SCE	SPVP 006 - Ontario Bldg #2	Solar PV	2.55	S0136	2012	4.00	N/A	Ontario
SCE	SPVP 007 - Redlands #3	Solar PV	3.20	S0158	2012	5.00	N/A	Redlands
SCE	SPVP 008 - Ontario Bldg #4	Solar PV	2.85	S0136	2012	4.50	N/A	Ontario
SCE	SPVP 009 - Ontario Bldg #3	Solar PV	1.41	S0136	2012	2.20	N/A	Ontario
SCE	SPVP 012 - Ontario Bldg #5	Solar PV	0.77	S0136	2012	1.20	N/A	Ontario
SCE	SPVP 022 - Redlands #6	Solar PV	3.09	S0158	2012	4.90	N/A	Redlands
SCE	SPVP 042 - Porterville	Solar PV	6.70		2012	10.70	N/A	Porterville
PG&E	Stroud	Solar PV	20.00	S0139	10/26/2011	41.00	N/A	Fresno County
PG&E	Sun City	Solar PV	20.00	S0127	8/5/2011	32.00	20	Kings County
PG&E	Westside	Solar PV	15.00	S0138	8/31/2011	31.00	N/A	Fresno County
Burbank	Customer Solar	Solar PV	0.32		2012	1.20	N/A	Burbank
Corona	Solar Power at WRF1	Solar PV	<1		2012	0.10	N/A	Corona
Glendale	Photovoltaic Grid Connected-various	Solar PV	0.40		2012	0.60	Various	Glendale
Hercules	Commercial Solar	Solar PV	0.18		2012	0.40	20	Hercules
San Francisco	Sunset Reservoir North Basin	Solar PV	4.96		12/07/10	6.80	N/A	San Francisco
SCE	Alta Wind Energy Center	Wind	570.00		11/16/11	1,498.00	20	Tehachapi
SCE	Caithness Ridgetop II (repower at existing 46.8 MW site)	Wind	5.00		07/01/11	12.00	20	Mojave
SCE	Clear Vista Ranch	Wind	20.00		8/30/2011	55.00	20	Tehachapi

Table B-4: Recently Operational Renewables In-State (Continued)

LSE	Facility Name	Technology	Min. Installed Size (MW)	QFER Plant ID	Online Date	Min. Expected Deliveries (GWh/Yr)	Contract Term	Location
SCE	Windstar (Aero Energy)	Wind	120.00		11/11/11	311.70	20	Tehachapi
PG&E	Vasco Winds	Wind	78.00		12/1/2011	211.00	20	Contra Costa County
PG&E	Shiloh Phase III	Wind	102.5		12/22/2011	275.70	20	Birds Landing Solano County
SCE	Flex Bernadino	Biogas	2.00		6/1/12	12.00	20	
SCE	Flex Kern	Biogas	5.00		6/1/12	31.00	20	
SCE	Flex LA	Biogas	2.00		10/1/12	12.26	20	
SCE	Flex Riverside	Biogas	2.00		10/1/12	12.26	20	
SMUD	Buena Vista Biomass Power, LLC	Biomass	16.00		2012	122.00	20	
PG&E	Kiara Anderson Biomass	Biomass	6.00		12/1/12	43.00	15	
PG&E	Mt Poso Cogeneration (coal conversion)	Biomass	44.00	E0232	1/30/12	328.00	15	
SCE	ORNI #21	Geothermal	30.00		6/1/12	250.00	20	
Alameda	Butte County Neal Road Landfill (Paradise)	LFG	1.90		Sep-12	14.15	20	
Palo Alto	Crazy Horse Canyon Landfill (Salinas)	LFG	2.90		2012	21.60	20	
Silicon Valley Power	Forward Landfill (Manteca)	LFG	4.60		2012	36.00	20	
Palo Alto	San Joaquin Landfill (Linden)	LFG	4.30		2012	32.00	20	
Silicon Valley Power	Vasco	LFG	4.60		2012	36.00	20	
LADWP	Adelanto Solar	Solar PV	11.60		5/30/2012	22.46	N/A	
PG&E	Alpaugh North	Solar PV	20.00		11/1/12	27.00	25	
PG&E	Alpine Suntower (aka Alta Vista)	Solar PV	66.00		9/30/12	145.00	20	
PG&E	NextLight Antelope Valley (AV Solar Ranch) PV1	Solar PV	115.00		10/31/12	296.00	25	
SDG&E	BAP Power Corporation	Solar PV	1.50		06/01/2013	2.89	20	

Table B-4: Recently Operational Renewables In-State (Continued)

LSE	Facility Name	Technology	Min. Installed Size (MW)	QFER Plant ID	Online Date	Min. Expected Deliveries (GWh/Yr)	Contract Term	Location
PG&E	CHSP	Solar PV	0.31		12/29/11	0.40	20	
PG&E	Cantua Creek SPVP	Solar PV	20.00		3/1/12	38.72	N/A	
PG&E	FSEC1	Solar PV	1.50		12/23/11	2.10	20	
PG&E	FSEC2	Solar PV	1.50		12/23/11	2.10	20	
PG&E	High Plains Ranch II	Solar PV	22.70		9/13/12	63.63	25	
PG&E	High Plains Ranch III	Solar PV	40.00		12/31/12	112.00	25	
PG&E	Jack Roddy	Solar PV	0.94		12/29/11	1.30	20	
SDG&E	NRG Solar Borrego I	Solar PV	26.00		7/31/12	60.00	25	
SCE	RE Rio Grande	Solar PV	5.00		12/1/12	11.00	20	
SDG&E	Sol Orchard 1-4, 6-10, 12-17	Solar PV	22.50		12/31/12	67.80	25	
SCE	Solar Power, Inc	Solar PV	8.00		7/16/12	15.49	20	
SDG&E	SolarGen 2	Solar PV	150.00		9/30/12	390.00	25	
SCE	SunEdison Utility Solutions, LLC	Solar PV	0.99		1/25/12	1.73	20	
SCE	SunEdison Utility Solutions. LLC	Solar PV	1.09		1/25/12	1.94	20	
SCE	Golden Solar, LLC 2513E Santa Fe Springs 1	Solar PV	1.82		7/16/12	3.52	20	
SCE	Golden Solar, LLC 2513E Santa Fe Springs 2	Solar PV	1.26		7/16/12	2.44	20	
PG&E	Topaz Solar Farms	Solar PV	150.00		12/1/12	290.39	25	
SCE	TA High Desert aka Antelope	Solar PV	20.00		10/1/12	42.00	20	
Gridley	Gridley Main PV	Solar PV	1.00		2012	2.03	25	
LADWP	Pine Tree Solar	Solar PV	8.50		2012	17.00	n/a	
Modesto	Sun Power McHenry Solar Farm	Solar PV	25.00		9/30/2012	40.72	25	
Imperial	SunPeak Solar Project	Solar PV	20.00		8/1/2012	26.28	30	
SCE	Alta Wind Energy Center	Wind	300.00		12/31/12	946.08	20	
PG&E	Coram Ridge Tehachapi aka	Wind	102.00		3/30/12	286.00	20	

Table B-4: Recently Operational Renewables In-State (Continued)

LSE	Facility Name	Technology	Min. Installed Size (MW)	QFER Plant ID	Online Date	Min. Expected Deliveries (GWh/Yr)	Contract Term	Location
	Brodie							
PG&E	Shilo IV	Wind	100.00		12/31/12	269.00	25	
SCE	Mountain View IV	Wind	49.00		2/23/12	165.00	20	
PG&E	North Sky	Wind	163.20		12/31/12	597.00	25	
SDG&E	Pacific Wind LLC	Wind	140.00		9/30/12	392.00	20	
SMUD	Solano Wind Phase 3	Wind	127.80		4/29/2012	392.45	N/A	
N/A	North Palm Springs 1	Solar PV	2.50		4/30/2012	4.84	N/A	
	SS 15710 San Antonio West LLC	Solar PV	1.90		7/16/2012	3.60	N/A	
SCE	City of Industry Solar (MetroLink PV1))	Solar PV	1.50		4/26/2012	2.90	N/A	
PG&E	FPL Montezuma Hills aka High Winds	Wind	78.20		2/1/2012	210.37	N/A	
PG&E	Griffen Solar	Solar PV	10.00		5/1/2012	19.360	N/A	Fresno
PG&E	Huron Solar Station	Solar PV	20.00		6/25/12	38.72	N/A	Fresno
SCE	Sequoia Solar Farm Meridian	Solar PV	20.00		1/1/12	38.72	N/A	Tulare
		2011 In-State Totals	1,009.50			2,783.07		
		2012 In-State Totals	1,938.90			6,036.61		
Estimated Capacity and Energy for Operational Feed-In Tariff Projects								
PG&E	Parreira Almond Processing Co	Biomass	0.95			6.70	15	
SCE	One Miracle Property	Solar PV	0.75			1.30	10	
SCE	Temescal Canyon RV	Solar PV	1.50	S0133	5/17/2011	2.50	20	Riverside
SMUD	Sacramento Municipal District at Lawrence	Solar PV	1.175	S0154	12/22/11	2.10	20	Elk Grove
SMUD	Recurrent Bruceville Solar PV1 – PV3	Solar PV	19.95		01/13/12	35.00	N/A	Elk Grove
SMUD	Recurrent Dillard Solar PV1 – PV4	Solar PV	12.50	S0205	12/26/11	21.90	N/A	Sloughouse

Table B-4: Recently Operational Renewables In-State (Continued)

LSE	Facility Name	Technology	Min. Installed Size (MW)	QFER Plant ID	Online Date	Min. Expected Deliveries (GWh/Yr)	Contract Term	Location
SMUD	Sacramento Municipal District at Fleshman	Solar PV	2.90	S0155	12/09/11	5.10	N/A	Galt
SMUD	Sacramento Municipal District at Grundman PV1 – PV6	Solar PV	18.00	S0156	12/20/11	31.50	N/A	Elk Grove
SMUD	Sacramento Municipal District at Van Conett PV1 – PV2	Solar PV	3.00	S0157	12/09/11	5.30	N/A	Galt
SMUD	Recurrent McKenzie Solar PV1 – PV6	Solar PV	30.00		11/08/12	52.60	N/A	Galt
SMUD	Green Solar Acres PV1	Solar PV	3.00	S0203	09/01/12	5.30	N/A	Elk Grove
SMUD	Green Solar Acres PV2	Solar PV	1.00	S0204	09/01/12	1.80	N/A	Elk Grove
		In-State Totals	114.68			205.8		

Source: California Energy Commission, IOU/POU RPS Contract Databases, CPUC October 2012 RPS Project Status Table, CEC QFER, Ventyx/ABB Energy Velocity Data CEC S1 and S2 Filings.

Table B-5: Recently Operational Out-of-State Projects With Long-Term Contracts (Commercial On-Line Date 10/1/11–12/31/12)

LSE	Facility Name	Technology	Location	Installed Min. Size (MW)	Min. Expected Deliveries (GWh/Yr)	Expected Online	Contract Term
SMUD	Patua (Vulcan)	Geothermal	NV	60.00	446.76	12/31/2012	N/A
PG&E	SEMPRA MESQUITE SOLAR - SGS-1	Solar PV	AZ	150.00	305.00	12/28/2011-2/28/2013	20
PG&E	NextLight Agua Caliente	Solar PV	AZ	245.00	581.60	2012-2013	25
SCE	Caithness Dixie Valley, LLC	Geothermal	NV	50.00	394.00	7/5/18	12
SCE	Caithness Shepherd's Flat (North and South Hurlburt)	Wind	OR	800.00	1850.11	12/31/2011 - 8/31//2012	20
SDG&E	Rim Rock Naturener, Glacier County	Wind	MT	300.00	1053.00	11/1/2012	15
PG&E	Greengate Halkirk Wind Project I	Wind	Alberta	149.40	482.00	8/30/2012	20
	Total			1,754.40	5,112.50		

Source: California Energy Commission, Renewable Energy Action Team, S-2 filings, POU database and California Public Utilities Commission RPS_ProjectStatus_Table_2012_Oct.xls.

Table B-6: Renewable Auction Mechanism Program

Pacific Gas & Electric										
Commission Approval Date	**Approved Contracts in Development**	**PPA**	**Status**	**IOU**	**Min MW**	**Min Expected GWh/yr**	**Technology**	**Vintage**	**Contract Term (years)**	**Location**
04/29/12	TUUSO Energy, LLC	RAM Pro Forma PPA	On Schedule	PG&E	20.00	53.00	Solar PV	New	20	Lancaster, Los Angeles County
04/29/12	Western Antelope Blue Sky Ranch A	RAM Pro Forma PPA	On Schedule	PG&E	20.00	48.00	Solar PV	New	20	Lancaster, Los Angeles County
Southern California Edison										
Commission Approval Date	**Approved Contracts in Development**	**PPA**	**Status**	**IOU**	**Min MW**	**Min Expected GWh/yr**	**Technology**	**Vintage**	**Contract Term (years)**	**Location**
04/30/12	Victor Mesa Linda A		On Schedule	SCE	2.00	5.00	Solar PV	New	20	Victorville, CA
04/30/12	Expressway Solar A		On Schedule	SCE	2.00	5.00	Solar PV	New	20	Victorville, CA
04/30/12	Expressway Solar B		On Schedule	SCE	2.00	5.00	Solar PV	New	20	Victorville, CA
04/30/12	Placer Solar		On Schedule	SCE	20.00	46.00	Solar PV	New	20	San Joaquin, CA
04/30/12	Joshua Tree Solar		On Schedule	SCE	20.00	49.00	Solar PV	New	20	Joshua Tree, CA
04/30/12	SEPV8		On Schedule	SCE	12.00	31.00	Solar PV	New	20	Twenty Nine Palms, CA
04/30/12	SEPV9		On Schedule	SCE	9.00	24.00	Solar PV	New	20	Twenty Nine Palms, CA

Table B-6: Renewable Auction Mechanism Program
(Continued)

San Diego Gas & Electric										
Commission Approval Date	**Approved Contracts in Development**	**PPA**	**Status**	**IOU**	**Min MW**	**Min Expected GWh/Yr**	**Technology**	**Vintage**	**Contract Term (Years)**	**Location**
05/03/12	Victor Mesa Linda B	Model PPA	On Schedule	SDG&E	5.00	8.60	Solar PV	New	20	Victorville, San Bernardino
05/03/12	Western Antelope Dry Ranch	Model PPA	On Schedule	SDG&E	10.00	17.10	Solar PV	New	20	Lancaster, Los Angeles
Total GWh Statewide						**291.70**				

Source: CPUC RPS_Project_Status_Table_2012_Nov.xls.

The Renewable Auction Mechanism is a simplified and market-based procurement mechanism for renewable distributed generation (DG) projects up to 20 MW on the system side of the meter. The Commission adopted Renewable Auction Mechanism as the primary procurement tool for system-side renewable DG because it will promote competition, elicit the lowest costs for ratepayers, encourage the development of resources that can utilize existing transmission and distribution infrastructure, and contribute to RPS goals in the near term.

To begin the program, the Commission authorized the utilities to procure 1,000 megawatts through Renewable Auction Mechanism (see, D.10-12-048). Going forward, the capacity authorization will reflect each utility's need for system-side DG under 20 MW. Two recent Commission Decisions (see, D.12-02-035 and D.12-02-002) authorized SCE and SDG&E, respectively, to move MWs from their solar photovoltaic programs into Renewable Auction Mechanism, thus increasing the authorized procurement under Renewable Auction Mechanism to 1,299 MW.

Renewable Auction Mechanism is a unique program because it streamlines the procurement process for developers, utilities, and regulators. It allows bidders to set their own price, provides a simple standard contract for each utility, and allows all projects to be submitted to the CPUC through an expedited regulatory review process.