California Energy Commission

FINAL STAFF REPORT

PROPOSED METHOD TO CALCULATE THE AMOUNT OF NEW RENEWABLE GENERATION NEEDED TO COMPLY WITH POLICY GOALS

CALIFORNIA
ENERGY COMMISSION

Edmund G. Brown, Jr., Governor

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ABSTRACT

California is actively pursuing a policy of integrating large amounts of renewable generation into the electricity grid over the coming decade. Renewable net short estimates are needed to determine the amount of new renewable generation capacity that must be built and/or delivered from out-of-state sources to meet the Renewables Portfolio Standard target, 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 paper presents a standard method for calculating the amount of new renewable generation needed to comply with California energy policy goals. This paper also discusses the source and plausible ranges associated with input variables. A significant result of the uncertainty associated with these ranges is that incremental renewable generation estimates (measured in energy terms, or megawatt-hours) can vary by the equivalent of almost 4,800 megawatts of solar-thermal generation capacity. This is a large range when considering electricity system integration requirements and investments.

Staff prepared this paper in support of the Energy Commission's *2011 Integrated Energy Policy Report*.

Keywords: Renewable, net short, incremental, generation, Renewables Portfolio Standard, Renewable Electricity Standard, electricity, system integration, *2011 Integrated Energy Policy Report*

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EXECUTIVE SUMMARY

This paper includes a method for calculating the *renewable net short* for California load-serving entities and identifies data sources and input values for the calculation. 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. Estimates of renewable net short are needed to determine the amount of new renewable generation capacity that must be built and/or delivered from out-of-state sources to meet the Renewables Portfolio Standard (RPS) target, evaluate the electricity infrastructure requirements for integrating new generation additions, and identify market mechanisms that may need to be modified to provide the ancillary services that would be required to maintain reliable system operations.[1]

Stakeholders in various forums dealing with resource planning issues have repeatedly expressed a desire to be able to import detailed information from one proceeding, such as the transmission options considered in the Renewable Energy Transmission Initiative (RETI), into another proceeding, such as the renewable integration study that the California Independent System Operator (California ISO) is conducting for the long-term procurement proceeding (LTPP). However, this is difficult to do if the studies use different assumptions and estimates of the amounts of renewable generation needed to meet policy goals.

Several studies evaluated the integration requirements for implementing a 33 percent renewable energy generation policy goal in 2009 and 2010, some of which are still under development. Many of these studies used different accounting conventions and assumptions about implementing future load reduction programs to estimate the need for incremental new renewable generation. The renewable net short estimates used in these studies ranged from 45 to 65 terawatt[2] hours (TWh). The difference in these estimates is equivalent to potential generation from more than 8,000 megawatts (MW) of solar-thermal or 6,500 MW of wind projects[3].

There are legitimate reasons for the study assumptions to differ, particularly when new information becomes available and thus improves the knowledge base. 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

1 The California ISO is considering a redesign of the market to develop bidding rules that would create the incentive for generators and loads to respond to grid constraints and offer the ancillary services needed integrate new renewable generation. Ancillary services include operating reserves, regulation, and load following.

2 A terawatt is 1 trillion watts.

3 A solar thermal power plant operates at an average 28 percent annual capacity factor. One MW of solar thermal capacity can generate about 2,450 gigawatt hours of electricity a year.

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.

California Energy Commission staff examined the assumptions used to calculate the renewable net short in several electricity system studies. Some of the renewable net short calculations now have dated input values and assumptions. Other studies did not include key variables and policy programs that could reduce electricity retail sales in the future, thereby potentially overstating the amount of renewable energy needed to satisfy the policy goal. There are also important uncertainties regarding how the variables used for the renewable net short calculation can be measured or assumed to exist in the future. It is important to remember that all values, regardless of the source, are estimates for 10 years into the future.

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

> ***Renewable Net Short (TWh) = ((Projected Retail Electricity Sales – Energy Efficiency Programs – Combined Heat & Power Customer Services – Distributed Generation Additions – Other Demand Reduction Programs) x Policy Goal Percent) – Generation From Existing Eligible Renewable Facilities***

Applying the staff-proposed equation and set of input values results in a 33 percent renewable net short by 2020 estimate shown in **Table 1** that ranges between 35.3 TWh to 47 TWh. This renewable net short range has an 11.7 TWh (32 percent) difference.

Table 1: Estimated Range of 33 Percent Renewable Net Short for 2020

	All Values in TWh for the Year 2020	Formula	Low Demand Renewable Net Short	Mid Demand Renewable Net Short	High Demand Renewable Net Short
1	Statewide (Retail Sales-Updated 5/2011)		292.6	297.9	305.3
2	Non RPS Deliveries (CDWR, WAPA, MWD)		13.6	13.6	13.6
3	Small LSE Sales (<200 GWh)		0.0	0.0	0.0
4	Retail Sales for RPS	4=1-2-3	279.0	284.3	291.7
5	Additional Energy Efficiency		19.9	17.1	15.2
6	Additional Rooftop PV		4.1	3.2	2.3
7	Additional Combined Heat and Power		16.2	7.2	0.0
8	Adjusted Statewide Retail Sales for RPS	8=4-5-6-7	238.8	256.9	274.2
9	**Total Renewable Energy Needed For 33% RPS**	**9=8*33%**	**78.8**	**84.8**	**90.5**
	Existing and Expected Renewable Generation				
10	Total Instate Renewable Generation		34.3	34.3	34.3
11	Total Out-of-State Renewable Generation		9.2	9.2	9.2
12	**Total Existing Renewable Generation for CA RPS**	**12=10+11**	**43.5**	**43.5**	**43.5**
13	**Total RE Net Short to meet 33% RPS In 2020 (TWh)**	**13=9-12**	**35.3**	**41.3**	**47.0**

Source: Energy Commission staff.

The estimated values that staff uses for the renewable net short calculation are based on the most current electricity system assessments and projections. These inputs and the underlying assumptions are constantly being revised and updated as new information becomes available. There are numerous studies and proceedings underway that will ultimately update some of the key input assumptions. The Energy Commission plans to post updated renewable net short estimates on August 1 of each year, matching the expected date when information on new generation is submitted under data collection regulations.

Energy Commission staff held a workshop on March 8, 2011, to seek comments on the proposed renewable net short calculations and preliminary set of input values.

Stakeholders’ comments were used to update and revise many portions of the draft paper. Specific comments are summarized along with staff responses in the appendix.

Definition of the Renewable Net Short

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 *renewable net short*. Since the Renewables Portfolio Standard (RPS), 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), defines the required amount of renewable generation as a percentage of electricity retail sales, the renewable net short 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 renewable net short is:

> ***Renewable Net Short (TWh) = (Projected Retail Electricity Sales – Energy Efficiency Programs – Combined Heat & Power Customer Services – Distributed Generation Additions – Other Demand Reduction Programs) x Policy Goal Percent) – Generation from Existing Eligible Renewable Facilities***

The renewable net short metric can be applied to any target year and any renewable energy policy goal. Using the term renewable net short with no additional modifiers provides insufficient information about what is referenced. 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 renewable net short estimate in 2010 from the 33 percent renewable net short estimate in 2020. To avoid confusion, this paper will follow the convention of using the term renewable net short as shorthand for referring to the 33 percent renewable net short in 2020 unless otherwise stated.

Study Purpose

This paper presents a standardized method for calculating the renewable net short for California load-serving entities and future electricity system infrastructure studies, including a set of information sources and assumptions used for the calculation. Renewable net short estimates are used to determine the amount of new renewable generation capacity that needs to be built and/or delivered from out-of-state sources to meet the RPS target, 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.

Stakeholders in policy and resource planning proceedings have repeatedly expressed a desire to import the detailed information from one proceeding, such as a renewable environmental assessment, into another proceeding, such as an electricity system infrastructure assessment or renewable generation integration studies. However, this is difficult to do if the studies use different assumptions and estimates of the renewable generation amounts needed to meet policy goals.

There are a number of studies to evaluate the integration requirements for implementing a 33 percent renewable energy generation policy goal. Many of these studies used different accounting conventions and assumptions about the implementation of future load reduction programs to estimate the need for incremental new renewable generation. Some of the studies did not include key policy goals and programs that will reduce electricity retail sales in the future, possibly overstating the likely amounts of renewable energy needed to satisfy the policy goal. The renewable net short estimates used in these studies range from 45 TWh to 65 TWh, which is equivalent to potential generation from more than 8,000 MW solar-thermal or 6,500 MW wind projects. Different, and possibly conflicting, methods create confusion for regulators when making decisions regarding system renewable procurement, establishing transmission requirements, identifying regulation and ramping needs, determining criteria pollutant and greenhouse gas (GHG) emission implications, and considering other infrastructure requirements to ensure electricity system reliability.

There are legitimate reasons for the study assumptions to differ, particularly when new information becomes available and thus improves the knowledge base. However, it is important to disclose why certain assumptions were selected or applied, and whether a study is based on publicly reviewed and validated inputs. Developing a standardized approach and set of assumptions to estimate the renewable net short will improve the ability to understand the context for policy decisions and to transfer findings from one research area to another.

The goal of the paper is to develop a single method and coordinated set of assumptions for calculating the renewable net short that will promote consistency and improve analytical links among the different infrastructure studies, leading to better informed policy development.

Energy Commission staff held a workshop on March 8, 2011, to seek comments on the proposed renewable net short calculation and preliminary set of assumptions. Overall stakeholders thought it important to develop a single renewable net short approach that should be used for related electricity system infrastructure studies. However, recommendations diverged on what variables should be used for the calculation. Stakeholders provided comments on specific topic areas and focused on the amounts of energy efficiency (EE), combined heat and power (CHP), distributed generation (DG), roof-top photovoltaic (PV), and the existing, or soon to be on-line, renewable generation. Specific comments are summarized along with staff responses in the appendix. The staff responses include an explanation of the changed assumptions that are applied to the renewable net short estimates.

Comparison of Recent Renewable Net Short Estimates

Several recently completed and ongoing studies evaluate the electricity system requirements for implementing renewable generation policies. The calculation of the renewable net short is a key factor in each of these studies. Renewable net short estimates vary depending on which demand forecast is applied and the consideration of other load reduction measures and policies. Different input assumptions in the various studies result in a range of renewable net short estimates that differ by as much as 45 percent. Conversely, some of these studies derive a very similar renewable net short estimate but calculate the value with different assumptions and methods.

Table 2 and the following section provide a summary of the different studies that include renewable net short estimates. The order of the studies from the left to right in **Table 2** is based on the study vintage.

California Energy Commission Staff Report on *Impacts of AB 32* (AB 32) *Scoping Plan Electricity Resource Goals on Natural Gas-Fired Generation* (Column 1): As part of the *2009 IEPR* process, staff was tasked with producing estimates for the impact of Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006, AB 32). (April 2009)

California Air Resources Board (ARB) Impact Assessment of the 33 Percent Renewables Energy Standard (RES) (Column 2a, 2b): In response to Executive Order S-21-09 requiring the ARB to adopt regulations limiting carbon dioxide (CO_2) emissions by increasing renewable energy, estimates of the renewable net short were produced. These estimates included both high and low electricity demand (load) scenarios. (March 2010)

Western Electricity Coordinating Council (WECC) Transmission Expansion Planning Policy Committee (TEPPC) Renewables Net Short Estimate (Column 3a, 3b): TEPPC creates a publically available WECC-wide data set for use in transmission expansion planning studies. As part of this effort, the working group is developing renewable scenarios with specified amounts for each state. The working group reference case for California was developed in 2010 and included a 65.2 TWh renewable net short estimate. Energy Commission and California Public Utilities Commission (CPUC) staff helped develop the state-adjusted case, which includes assumptions about incremental energy efficiency and combined heat and power. The state-adjusted load reduction assumptions results in a 56.4 TWh renewable net short. (August 2010)

California Independent System Operator (California ISO) and California Public Utilities Commission 33 Percent Renewables Operational Study (Column 4): The study was provided to the CPUC as background for the Long-Term Procurement Proceeding (LTPP). This study determined the generation resources needed to integrate various scenarios of 33 percent renewables into a reliable California grid, assuming that many of the renewables will be variable wind or solar. The study focused on the need for conventional generation under many renewable supply variations. The study included a 54.2 TWh renewable net short estimate. (June 2010-July 1, 2011)

California Transmission Planning Group (CTPG) 2011 Study Plan (Column 5): This study and scenarios focused on identifying any transmission infrastructure additions essential to attain the state-mandated renewable portfolio standard requirement of 33 percent by 2020. The group's 2011 Study Plan includes nine scenarios designed to investigate various means by which renewable resources will be made available to California for meeting the 33 percent RPS. Each study scenario includes a 45.1 TWh renewable net short estimate. (July 2011)

California Independent System Operator and California Public Utilities Commission 2011-2012 Transmission Planning Process (Column 6): The CPUC staff developed multiple scenarios of renewables net short that the California ISO will include in its transmission assessment. This assessment will serve as the basis for their annual transmission plan that serves as a formal and board-approved roadmap guiding infrastructure requirements for the California ISO Balancing Authority. Each CPUC-provided scenario includes a 54.2 TWh renewable net short estimate. CPUC scenarios included four renewable buildouts based on current development activity (trajectory), cost constraints, environmental constraints, and time constrained. (July 2011)

Staff Mid-Range Estimate of Renewable Net Short (Column 7): Energy Commission mid-range estimate of renewable net short produced through the data sources and methods described in this report. (July 2011)

Table 2: Comparison of 33 Percent Renewable Net Short Calculations Used in Different Electricity Infrastructure Studies

			1	2a	2b	3a	3b	4	5	6	7
	All Values in TWh for the Year 2020	**Formula**	**CEC IEPR 09 Impact of AB32**	**ARB 33% RES Low Load Case**	**ARB 33% RES High Load Case**	**WECC/TEPPC 2020 Reference Case**	**WECC/TEPPC 2020 State Adjusted Case**	**CAISO/CPUC LTPP 33% RPS Integration Study**	**CTPG 2011 Study Plan Renewable Net Short**	**CAISO 2011/2012 TPP Basecase**	**CEC Staff Mid Range RNS**
1	Net Energy For Load		341.8			326.5	328.2				
2	Statewide Total Deliveries (Retail Sales)		320.4	303.3	303.3	303.7	305.2	303.3	305.3	303.3	297.9
3	Non RPS Deliveries (CDWR, WAPA, MWD)		12.3	4.5	4.5	13.6	13.6	13.6	13.6	13.6	13.6
4	Small LSE Sales (<200 GWh)		0.0	0.0	0.0	2.3	2.3	2.3	0.0	2.3	0.0
5	Retail Sales for RPS	5=2-3-4	308.1	298.8	298.8	287.8	289.4	287.4	291.7	287.4	284.3
6	Additional Energy Efficiency		34.7	22.0	0.0	0.0	19.4	17.0	15.2		17.1
7	Additonal Combined Heat and Power		32.3	14.0	0.0	0.0	7.0	7.6	0.0		7.2
8	Additional Rooftop PV		4.8	2.0	0.0	0.0	1.8	0.0	2.3		3.2
9	**Adjusted Statewide Retail Sales for RPS**	9=5-6-7-8	236.3	260.8	298.8	287.8	261.3	263.0	274.1	287.4	256.9
	Existing Renewable Generation										
10	Total Instate Renewable Generation		29.8	28.8	28.8	29.8	29.8	29.8	36.1	34.3	34.3
11	Out of State Claims		2.7	3.7	3.7	0.0	0.0	2.8	9.2	9.2	9.2
12	**Total Existing Renewable Generation for CA RPS**	**12=10+11**	**32.5**	**32.5**	**32.5**	**29.8**	**29.8**	**32.6**	**45.3**	**43.5**	**43.5**
13	**Total RE Net Short to meet 33% RPS In 2020**	**13=(9*33%)-12**	**45.5**	**53.6**	**66.1**	**65.2**	**56.4**	**54.2**	**45.1**	**51.4**	**41.3**
14	**Total RE Net Short modeled to meet 33% RPS In 2021**									**54.2**	

Notes: 1 CPUC 2010 LTPP uses Final IEPR09 Demand Forecast, dated January 2010.

2 Uses selected CPUC 2010 LTPP assumptions.

3. CAISO TPP uses the CPUC estimate of RNS and resulting renewable build out even though there are significant inconsistencies in existing generation, uncommitted EE, and new demand-side CHP.

Source: Energy Commission staff.
Column 1: CEC IEPR 09 Impact of AB 32 - http://www.energy.ca.gov/2009publications/CEC-200-2009-011/CEC-200-2009-011.PDF.
Column 2a and 2b: ARB 33 percent RES - http://www.arb.ca.gov/energy/res/meetings/040510/e3-presentation.pdf. Final version of the RES calculator was prepared by Joseph Fisher jofische@arb.ca.gov of ARB staff but not posted to the ARB website.
Column 3a and 3b: WECC TEPPC Reference and State-Adjusted – contact Angela Tanghetti at atanghet@energy.state.ca.us for WECC Studies Work Group working papers. High Load Case work papers provided during work group meeting March 10, 2010.
Column 4: CAISO/CPUC 33 percent RPS Integration Study RNS based on CPUC LTPP TechnicalAttachmentSpreadsheetv5.xls at http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/2010+LTPP+Tools+and+Spreadsheets.htm.

Column 5: CTPG 2011 joint California balancing authorizes transmission planning study at http://ctpg.us/images/stories/ctpg-plan-development/2011/07-Jul/2011-07-29_2011_CTPG_Draft_2_Study_Plan.pdf.
Column 6: 2011-2012 CAISO Transmission Planning Process http://www.caiso.com/planning/Pages/TransmissionPlanning/2011-2012TransmissionPlanningProcess.aspx.
Column 7: CEC staff renewable net short estimate found in Table 7.

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 PV additions, and other customer-side-of-the-meter DG) will reduce the California statutory renewable 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, 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 will also depend on how much renewable power is already flowing into the system. Estimates of existing 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 when electricity supply contracts expire. For example, there are a number of contracts with wind generation facilities in the Pacific Northwest that are set to expire in the next few years; these may not be renewed or instead serve other regional renewable obligations. The wide variation between estimates, shown in **Table 2**, illustrates the need for common assumptions and accounting conventions so that the public can be confident in both the goals and reported progress.

The variables critical to calculating the renewable net short 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. For example, the expected electricity demand reductions from EE programs vary between 15.2 TWh to 19.9 TWh by 2020, depending on the level of expected expenditures and changes to consumptions behavior patterns.

Prudent consideration of these kinds of uncertainties should be applied in a renewable net short 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 renewable net short goal. 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 renewable net short 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 *CED Forecast (IEPR)*
    - Treatment of Transmission and Distribution Losses
- Demand Reduction Programs
    - EE Impacts
    - Incremental DG PV Goals
    - Incremental CHP
- Generation From Existing Eligible Renewable Facilities
    - Estimating Existing Renewable Generation

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 for the biennial *IEPR*, which is the appropriate starting point for calculating the renewable net short. This forecast, known as the *California Energy Demand Forecast (CED)*, includes estimates of demand reductions, such as EE, roof-top PV, and self-generation such as CHP. The *CED* includes an assessment of eight transmission planning areas, which include:

- Burbank/Glendale
- Imperial Irrigation District
- Los Angeles Department of Water and Power
- Pacific Gas and Electric
- Pasadena
- Sacramento Municipal Utility District
- San Diego Gas & Electric
- Southern California Edison

Different models[4] are used to project total electricity consumption by end users for each of these California planning areas. Output from the models is calibrated to match historical

4 Separate models are employed for the residential, commercial, industrial, agricultural, and transportation, communication, and utility sectors.

consumption in each sector, equal to retail sales plus private electricity supply provided to end users.[5] 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 on-site 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. Staff adds these losses back when estimating net energy for load (energy that needs to be produced by generators to meet demand), using loss factors provided by the utilities.

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.[6]

The key drivers for the electricity retail sales forecast remain population, household, and economic growth. Electricity retail sales forecasts also include assumptions for electrifying the transportation sector, such as the Governor's one million electric vehicles goal. Economic growth remains highly uncertain, and conditions could change markedly within the next few years. To illustrate, the *2007 IEPR* demand forecast, with relatively optimistic assumptions regarding economic growth, projected statewide electricity sales of approximately 314 TWh in 2020. In the *2009 IEPR* forecast, incorporating the recent recession and more pessimistic economic growth assumptions, projected statewide sales in 2020 fell to roughly 301 TWh. Current economic projections for California are even more

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5 Large self-generators report directly to the Energy Commission and utilities report estimates of aggregate smaller-scale self generation as part of routine *Quarterly Fuel and Energy Reports* submissions. Additional self-generation installations are reported through incentive programs such as the California Solar Initiative and the New Solar Homes Partnership.

6 Projections of sales to California customers from load-serving entities in control areas within the state are provided in *Statewide Form 1.1b*, while projections for all sales to California customers are provided in *Statewide Form 1.1c*. These and other forms for the *2009 IEPR* forecast are available on the Energy Commission's website: http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html.

pessimistic than those used in the *2009 IEPR*. The updated *2009 IEPR* electricity sales forecast for 2020 is now 297.9 TWh and reflects a decline from the *2009 IEPR*.[7]

Staff also developed alternative retail electricity sales forecasts using more optimistic and pessimistic economic projections than used in the mid case forecast, escalating the projection by 2.3 percent for a high case and -1.9 percent for the low end of the range.[8] The resulting retail electricity sales range is 292.6 TWh to 305.3 TWh for 2020.

The statewide retail electricity sales projection includes water delivery, which must be subtracted for the renewable net short calculation. Statewide Form 1.1c 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, and Western Area Power Administration).

Table 3 summarizes the values described above. The adjusted range of electricity retail sales for 2020 is 279.0 TWh to 291.7 TWh and will be used as part of the renewable net short estimate presented later in the report. The mid case electricity retail sales value is used for the renewable net short estimate.

Table 3: Range of Retail Sales in 2020 for Use in Renewable Net Short Calculations

2020	**Low Sales Alternative**	**Mid Case**	**High Sales Alternative**
Total Retail Electricity Sales Updated IEPR 2009	292.6	297.9	305.3
Pumping Loads Exclusion	13.6	13.6	13.6
Adjusted Retail Sales Subject to 33% RPS	279.0	284.3	291.7

Source: Energy Commission staff.

Treatment of Transmission and Distribution Losses

California's 33 percent RPS policy requires utilities procure an amount of generation *equal* to a percentage of retail sales, not the amount of generation needed to cover the associated losses for delivering the electricity to a consumer. The associated transmission and distribution losses are ignored in the renewable policy goal.

The Energy Commission's forecast of retail electricity sales represents the customer-side-of-the-meter and is therefore energy after transmission and distribution losses. The Energy Commission also prepares a forecast of energy needed to be produced by generators, called

7 The March 2011 staff draft renewable net short paper applied the *2009 CED* for the net short calculation. This final staff report now uses an updated retail sales forecast from the Demand Analysis Office at the California Energy Commission.

8 Kavalec, Chris, Tom Gorin. 2009. *California Energy Demand 2010-2020, Adopted Demand Forecast*, CEC-200-2009-012-CMF. Page 6.

net energy for load, which includes both end-use energy consumption and system losses between the generator and the end user.

Some analysts use the net energy for load forecast instead of the retail electricity sales projections for the renewable net short calculations. Net energy for load is used by WECC since retail electricity sales are not calculated consistently among all members. A transmission and distribution loss factor is then applied to the WECC net energy for load forecast for use in the renewable net short calculation in the TEPPC dataset.

Table 4 presents the loss factors used in the load-serving entity demand forecasts.

Table 4: Loss Factors Included in the Net Peak and Net Energy for Load Tables

	Peak	Energy
PG&E	1.097	1.096
SMUD	1.077	1.064
SCE	1.076	1.068
LADWP	1.112	1.135
SDG&E	1.096	1.0709
Burbank, Glendale, Pasadena	1.051	1.064
IID	1.06	1.128
DWR	1.06	1.038

Source: California Energy Demand 2010 – 2020.

The difference between the *CED Forecast* net energy for load forecast and retail electricity sales implies a 1.078 (7.8 percent) transmission and distribution loss factor. This loss factor should be applied if a net energy for load forecast is used for a California renewable net short calculation. If any additional load reduction programs are included in a renewable net short calculation, losses associated with these programs should not be included.

Demand Reduction Programs

There are other demand reduction policy goals and an expectation that some progress toward those goals will likely occur. These additional programs are *not* included in the *CED* Forecast and must be considered as an adjustment to the electricity retail sales estimate for the renewable net short calculation. Other programs to consider include uncommitted EE programs, incremental DG PV goals, and CHP policy goals.

Energy Efficiency Impacts

Not all load reductions expected to occur or required by policy are included in the Energy Commission retail electricity sales forecast. As in the case of retail electricity sales, EE impacts estimated for and incorporated in the demand forecast reflect the customer side of the meter. The inclusion of incremental (also referred to as uncommitted) EE impacts in the renewable net short calculation indicates that it is reasonable to expect EE savings beyond what is already embedded in the *IEPR* demand forecast.

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. The *2009 IEPR* forecast incorporated committed utility efficiency programs through 2012 (the end of the current three-year CPUC program cycle) for the investor-owned utilities (IOUs) and through 2009 for publicly owned utilities (POUs), along with codes and standards implemented through 2005.

At the time of any *IEPR* forecast, there are potential efficiency impacts from future initiatives that are less firm, yet still reasonably likely. Examples in the case of the *2009 IEPR* process included IOU efficiency programs beyond 2012 and Assembly Bill 1109 (Huffman, Chapter 534, Statutes of 2007). Impacts from these initiatives are referred to as *uncommitted* energy efficiency. Beginning with the *2009 IEPR*, staff estimates potential uncommitted efficiency impacts that are *incremental* to committed impacts incorporated in the demand forecast. In the *2009 IEPR* analysis, high-, medium-, and low-goal scenarios for uncommitted efficiency were examined.[9] This work included IOU service territories only; staff plans to expand the analysis to non-IOU areas in the next forecast cycle. Energy Commission staff recommends that the range of uncommitted EE estimates that are reported in each *IEPR* be used for the calculating the renewable net short.

For the three major IOUs combined, estimated incremental energy savings in 2020 total between 10.7 TWh and 14.4 TWh.[10] An additional 1.9 TWh[11] are added to the savings to capture the CPUC directives that require IOUs to replace 50 percent of program savings that decay as efficiency measures wear out, starting in 2006.

Since the uncommitted EE scenarios did not include estimates for the POUs, a ratio of the utility retail electricity sales is applied. The IOU retail electricity sales represent about 75

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9 *Incremental Impacts of Energy Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast* at http://www.energy.ca.gov/2010publications/CEC-200-2010-001/index.html.

10, *Ibid*, Table 1, page 2.

11 I*bid*, page 4.

percent[12] of the statewide forecast of consumption, and POUs cover the remaining 25 percent. Applying the POU sales ratio to the uncommitted EE scenario goals provides a range between 2.7 TWh and 3.6 TWh.

The proposed range of uncommitted energy efficiency for both the IOU and POUs are:

- Low Range = 10.7 TWh + 1.9 TWh + 2.7 TWh = 15.2 TWh.
- Mid Range = 12.2 TWh + 1.9 TWh + 3.1 TWh = 17.1 TWh.
- High Range = 14.4 TWh + 1.9 TWh + 3.6 TWh = 19.9 TWh.

These uncommitted EE forecasts represent a decline in consumption and are already adjusted for losses. If an uncommitted energy efficiency forecast includes losses, the estimates must be adjusted for the renewable net short calculation.

Forecasts of uncommitted EE impacts are subject to a great deal of uncertainty, given lack of firm funding. Estimates of committed utility program net impacts, both historical and projected, are also fairly uncertain. For example, efficiency measures might be purchased but not installed, or may not perform as expected. The most recent CPUC evaluation measurement and verification study[13] for 2006–2008 IOU programs found utility-reported savings to be overstated. In fact, the study found that net-to-gross ratios and realization rates (which adjust the reported savings) were lower than assumed in the *2009 IEPR* forecast. Staff estimates that replacing the *2009 IEPR* forecast adjustment rates with the lower percentages estimated in the CPUC study during the forecast period would reduce projected IOU program savings by more than 2,000 GWh in 2020.

Since the *2009 IEPR* forecast relied on adjusted utility-reported savings to develop projected impacts through 2020, this means that program impacts may be overstated in the forecast. In the case of codes and standards, the primary source of uncertainty comes from compliance rates, for which very little empirical data are available.

Staff believes that it is appropriate to include some amount of incremental EE measures beyond those embedded in the *IEPR* demand forecast. Staff proposes that the number used in a renewable net short calculation should be the mid-case (17.1 TWh) incremental EE forecast.

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12 *Ibid,* page 4.

13 http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/EM+and+V/2006-2008+Energy+Efficiency+Evaluation+Report.htm.

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 on-site 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 renewable net short calculation if it is deemed prudent to plan on more than what is already included in the demand forecast.

DG can now be categorized in the demand forecast in two ways, self-generation and wholesale deliveries to the grid. Self-generation DG is produced on site, 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 a DG project affects the calculation of renewable net short 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 on-site electricity needs. The primary self-generation DG considered in the renewable net short calculation is the amount of electricity expected from small-scale rooftop PV systems.

The California Global Warming Solutions Act (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006) requires the California Air Resources Board (ARB) to develop regulations and market mechanisms that will reduce California's greenhouse gas (GHG) emissions by 25 percent by 2020. On December 11, 2008, the ARB issued a *Scoping Plan* for the implementation of AB 32. The *AB 32 Scoping Plan* calls for 3,000 MW [14] of additional self-generation rooftop PV beyond what was identified in the *2007 IEPR CED Forecast.* To use this in a renewable net short calculation, the *AB 32 Scoping Plan* rooftop PV capacity goal must be converted into an energy forecast. The *AB 32 Scoping Plan* includes an assumption that the rooftop PV will operate at a 17 percent capacity factor,[15] resulting in an energy goal of 4.5 TWh in 2020. New rooftop PV has been built since 2007 and adjusted in the updated *2009 IEPR* demand forecast, and more will likely be included in the upcoming forecast. The *Scoping Plan* rooftop PV energy goal must thereby be adjusted down by 2.6 TWh to account for the differences between the *2007 IEPR* and the *updated 2009 IEPR*. The remaining amount of rooftop PV needed to meet the *AB 32 Scoping Plan* goal is estimated to be 1.9 TWh.

In 2010, the *California Clean Energy Future,* a multiagency effort among state energy and environmental agencies and the California ISO to expand collaboration on state energy

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14 *Climate Change Proposed Scoping Plan Appendices, Volume I: Supporting Documents and Measure Detail*, Page C-121.

15 CPUC, *California Solar Initiative, 2009 Impact Evaluation*, Final Report. The average capacity factor of all systems that received Expected Performance-Based Buydown funding was 19.2 percent.

policies, set a new goal of 5,000 MW by 2020 for renewable DG.[16] If fully subscribed, existing programs for renewable DG would meet or exceed 5,000 MW by 2020:

- 3,000 MW of self-generation rooftop PV through the programs associated with Senate Bill 1 (Murray, Chapter 132, Statutes of 2006).
- 500 MW of wholesale generation DG PV through PG&E (half of the MW will be utility-owned; half will be provided by independent energy producers).
- 500 MW of wholesale generation DG PV through SCE (half of the MW will be utility-owned; half will be provided by independent energy producers). SCE seeks to modify its PV program, which will decrease the amount of generation procured from 500 MW to 250 MW (half through utility-owned and half through IPPs). However, as part of this modified plan, SCE plans to procure the remaining 250 MW through a separate solicitation in its solar program from ground-mounted systems.[17] (The original plan limits the amount of ground-mounted systems that could be procured.) Approval from the CPUC is pending, and staff will update this information once a decision is made.
- 100 MW of proposed wholesale generation DG PV through SDG&E (26 MW will be utility-owned; 74 MW will be provided by independent energy producers).
- 750 MW of wholesale generation (including non-PV DG, per SB 32) from existing feed-in tariff.
- 1,000 MW of wholesale generation (including non-PV DG) for the Renewable Auction Mechanism (RAM) decision that was adopted by the CPUC.[18]

Given the combined *AB 32 Scoping Plan* and *California Clean Energy Future* goals, increased PV additions are assumed to range between 2.3 TWh and 4.1 TWh (3,500MW – 2,500 MW) in the renewable net short.

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16 California's Clean Energy Future - *An Overview on Meeting California's Energy and Environmental Goals in the Electric Power Sector in 2020 and Beyond* at http://www.cacleanenergyfuture.org/2821/282190a82f940.pdf.

17 Southern California Edison Company's reply to responses filed regarding Edison's petition for modification of Decision 09-06-049 at http://www3.sce.com/sscc/law/dis/dbattach10.nsf/0/A967B0827A7F1C638825785D00809B6E/$FILE/A.08-03-015-Solar+PV-SCEs+Reply+To+Responses+To+Petition+For+Mod.+Of+D.09-06-049.pdf.

18 For more information, please see: http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm.

Incremental Combined Heat and Power

CHP projects are a specific type of DG project that can also combine elements of both self-generation and wholesale DG. CHP reduces the need for an industrial customer to purchase electricity, thereby affecting the retail electricity sales forecast. Some amount of CHP is already included in the demand forecast using the trend analysis method mentioned in the previous section. Any number selected for use in a renewable net short calculation will be in addition to the amount embedded in the demand forecast.

To estimate the amount of 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. Policy goals and regulations are under development to encourage the penetration of CHP projects. CHP policy initiatives are still in the formative stage, so estimated amounts of self-generation CHP that should be subtracted from the retail electricity sales forecast are very uncertain. Furthermore, the current CHP estimates do not use a common accounting convention for measuring existing generation, what amounts of generation may shut down, or what kind of projects may be economically feasible for future industrial and commercial development.

A 2009 market assessment report[19] provided an inventory of existing CHP capacity, as well as estimates of technical and market potential for new CHP in California that took into account the AB 32 mandates. The ARB *AB 32 Scoping Plan* states,

> *The widespread development of efficient CHP systems would help displace the need to develop new, or expand existing power plants. This measure sets a goal of an additional 4,000 MW of installed CHP capacity by 2020, enough to displace approximately 30 TWh of demand from other power generation sources.*[20]

Additionally, the *AB 32 Scoping Plan* assumed that a substantial portion of the operational CHP (projects developed under the Public Utility Regulatory Policies Act of 1978**,** termed qualifying facilities or QFs) in California would continue to operate.

In May 2009, the three major California IOUs, the Independent Energy Producers Association, the Cogeneration Association of California, the Energy Producers and Users Coalition representing the major CHP operators and developers in California, along with the Division of Ratepayer Advocates and The Utility Reform Network, agreed to a settlement to resolve a number of existing disputes, as well as future issues associated with QF contracts. One of the goals of the settlement is to assure that existing QFs would be able to secure new contracts and continue to operate. The three IOUs will be required to procure

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19 ICF International, Inc., prepared the Public Interest Energy Research (PIER) final project report *Combined Heat and Power Market Assessment (2009 Market Assessment)*. CEC-500-2009-094. October 2009.

20 *ARB Scoping Plan*, pp. 42-43.

a minimum of 3,000 MW of CHP, which is the number of existing CHP QF contracts that are expected to expire in the short term, and any additional CHP necessary to meet the ARB GHG emission reductions goals (estimated at 4.3 million metric tons [MMT]). The settlement also supports and recommends proportional MW goals and GHG reduction goals (estimated 1.9 MMT)[21] for all POUs in California.

The IOUs submitted the settlement to the Federal Energy Regulatory Commission (FERC) for final approval on June 16, 2011. The settlement now awaits a final and nonappealable decision by the CPUC that will set the effective date. New opportunities will emerge to stimulate large baseload CHP development, but the needs and opportunities for expanding the market for small CHP projects that are less than 20 MW, and often under 5 MW, are still very limited. The *Combined Heat and Power Market Assessment (Market Assessment Report)* estimated that more than 3,000 MW of small CHP could be developed in California, but barriers like unfavorable utility tariffs related to supplemental, standby, and backup power, and uncertainty associated with air quality and GHG cap and trade regulations still keep CHP developers on the sidelines. Growth in this sector may remain slow for the foreseeable future.

For the interim, Energy Commission staff includes a range of possible CHP additions for the renewable net short calculations based on the *AB 32 Scoping Plan* and the *Market Assessment Report*. The *AB 32 Scoping Plan* includes 4,000 MW to be sold to the grid, which will not reduce retail sales and affect the renewable net short calculation. The *Market Assessment Report* includes incremental CHP capacity ranging from 2,259 MW to 5,532 MW, with the amount serving the customer side of the meter ranging up to 90 percent, which would affect the renewable net short. The capacity factors for the demand-side CHP contributions range from 73.8 percent (*Base Case*) to 81.6 percent (*All-In Case*).

Considering each of these factors, the range of incremental CHP energy to be included in the preliminary renewable net short calculation is between 0 TWh and 16.2 TWh. The lower bound represents the possibility that all new CHP generation will consist of wholesale CHP and will not affect the calculation of renewable net short. The higher bound captures the possibility of greater CHP development levels and increasing amounts of the generation serving owner loads to reduce overall retail electricity sales in California.

With the pending approval of the settlement agreement by the CPUC, staff recommends using some of the outcomes presented for the *All-In Case* in the *Market Assessment Report.* Staff recommends using a 50/50 split assumption for the amount of CHP generation that is sold to the grid and what is consumed on site, consistent with the assumptions used in the CPUC Long-Term Procurement Proceeding, producing a CHP value of 7.2 TWh as a mid-range assumption for the renewable net short calculation. This value includes Governor

21 CHP Program Settlement Agreement Term Sheet. October 1, 2010. Section 6.3.4, 6.3.5, p 32.

Brown's goal for 6,500 MW of new CHP development within 20 years that is contained in the Clean Energy Jobs Plan.[22]

Staff reemphasizes that this assumption will need to be carefully reviewed each time the renewable net short calculation is updated.

Estimating Existing 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 for 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 whether weather conditions are favorable to maximize the amounts of electricity produced by wind or solar.

There are two theoretical approaches to estimating "existing generation" data. The first is to use the most recent historic energy generation data from QFER and the Power Source Disclosure Program (PSDP),[23] which has been the practice to date. The weakness of this approach is that generation from variable resources, such as small hydro and wind, will fluctuate in any given year and is more correlated with atmospheric factors than with installed capacity. The second approach is to use the installed capacity of all RPS-eligible existing renewables and convert that to an expected amount of energy using some fixed planning assumption; for example, a capacity factor of 32 percent for all wind resources multiplied by the nameplate capacity for a year. This approach depends less on annual weather variations. Both approaches suffer from a lack of transparency and predictability in the amount of renewable generation that can be expected from out-of-state renewable imports.

Given the stakeholder feedback from the March 8, 2011, workshop that is summarized in the appendix and further analysis of historical data, staff recommends combining multiple years of historical generation (from QFER and the power source disclosure filings) and installed generation with 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 WECC have renewable portfolio standards of some kind, it is very likely that out-of-state renewable resources currently under short-term contracts (expiring by 2015) will not be available in 2020. Therefore, the short-term out-of-state contracts will be excluded in the existing renewable generation forecast for 2020.

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22 http://www.jerrybrown.org/jobs-california%E2%80%99s-future.

23 Total Electricity System Power: http://energyalmanac.ca.gov/electricity/total_system_power.html.

The following includes the proposed steps for estimating the existing generation.

- An average annual generation value for all renewable projects on-line before the most current full year of QFER energy data availability (currently December 31, 2010):
  - In-state electricity generation from QFER energy data, except small hydroelectric, two non-RPS eligible municipal solid waste facilities, and facilities that came on-line in the most current full year (2009) and report QFER generation
  - Reported out-of-state electricity generation from the most recent full year of PSDP renewable purchase claims, except small hydroelectric, short-term (5 year) out-of-state wind contracts, and claims from facilities that came on-line in the current year with incomplete reporting (currently December 31, 2010)
  - An average annual reported electricity generation from small hydro generation over multiple (up to five) 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 2009 currently)
    - Average of reported out-of-state small hydroelectric PSDP claims (from 2007 to 2009[24])
- For facilities that have come on-line and are generating since the end of the most current complete year of QFER data, use the IOU and POU contract databases to estimate expected annual generation:
  - Electricity generation information from the Investor-Owned Utilities Contract Database for new, restarts, and repower facilities with commercial on-line date during the current calendar year. (The most current estimate will use data between January 1, 2009, and November 30, 2010.[25])
  - Electricity generation information from the Publicly Owned Utilities Contract Database for new facilities with commercial on-line date during the current calendar year. (The most current estimate will use data between January 1, 2009, and November 30, 2010.[26])
- For facilities that are under construction and expected to be on-line by the end of the next calendar year (for this estimate undertaken in 2011, this would mean facilities anticipated to be on-line by December 31, 2012) and have power purchase agreements, apply an average capacity factor by generation technology type.

Table 5 summarizes the staff-proposed method for calculating existing renewable generation.

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24 Years 2005 and 2006 were extreme outliers. Prior to 2007, reporting to PSDP may not have been as strictly enforced, and therefore a lot of small hydro generation may not have been reported.

25 See http://www.energy.ca.gov/portfolio/contracts_database.html.

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

Table 5: Summary of Existing Renewables Calculation (TWh)

			Staff-Proposed Method
Facilities On-Line Prior to the Most Current Full-Year QFER Data Set			
2006-2010 QFER Excluding Small Hydro and 2 Non-RPS MSW Plants			24
2009 Power Source Disclosure Program Out-of-State Renewable Purchase Claims; Excluding Small Hydro			5.2
2009 Power Source Disclosure Program Out-of-State Short-Term Wind Contracts			-1.8
QFER In-State Small Hydro Claims (Average 2005 – 2010)	**2005**	5.3	
	2006	5.9	
	2007	3.7	
	2008	3.6	
	2009	4.0	
	AVERAGE	4.5	4.5
Power Source Disclosure Program Out-of-State Small Hydro Claims (Average 2007 – 2010)	**2007**	1.0	
	2008	1.2	
	2009	1.3	
	AVERAGE	1.2	1.2
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, 2009, Through November 30, 2010			1.2
Out of State Renewables Contracted Annual Generation With COD January 1, 2009, Through November 30, 2010			4.6
Facilities Expected to Begin Generation Before the End of the Next Calendar Year			
Under Construction Renewables COD 12/1/2010, to 12/31/2011, Estimated Annual Generation			4.6
Summary Values for Use in Renewable Net Short Calculations			
IN-STATE RENEWABLE			**34.3**
OUT-OF-STATE RENEWABLE			**9.2**
TOTAL EXISTING RENEWABLE			**43.5**

Source: Energy Commission staff.

Table 6 includes a list of the technology-specific capacity factors that were used to estimate the generation from existing facilities that operated for less than a full year and those that are under construction. These capacity factors were taken from the E3 calculator created for the CPUC to derive different renewable development portfolios.

Table 6: Fuel and Technology Specific Capacity Factors

FUEL/TECHNOLOGY TYPE	CAPACITY FACTOR (PERCENT)
BIOGAS	80
BIOMASS	85
GEOTHERMAL	83
SOLAR THERMAL	27
WIND	32
LARGE SCALE PV	24-27

Source: E3 33% calculator. December 3, 2010.

The total amount of existing renewable generation used for the renewable net short calculation is 34.3 TWh. The amount of electricity imports from renewable generation under long-term contract is 9.2 TWh. The total amount of existing renewable generation for the renewable net short calculation is 43.5 TWh, based on the most current information available and staff's proposed method.

Standardized Renewable Net Short Estimate

Table 7 presents the ranges of input variables, described in the previous section, and the sequence of calculations for estimating the renewable net short. The table divides the estimates by the demand case used to estimate retail sales.

The mid demand renewable net short estimate is based on a selected set of variables, beginning with the updated *2009 IEPR* forecast. The amount of additional energy efficiency measures is based on the mid-case incremental forecast, chosen as a moderate planning assumption. The *AB 32 Scoping Plan* 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 renewable net short results.

Table 7: Range of Renewable Net Short Estimates for 2020

	All Values in TWh for the Year 2020	Formula	Low Demand Renewable Net Short	Mid Demand Renewable Net Short	High Demand Renewable Net Short
1	Statewide (Retail Sales-Updated 5/2011)		292.6	297.9	305.3
2	Non RPS Deliveries (CDWR, WAPA, MWD)		13.6	13.6	13.6
3	Small LSE Sales (<200 GWh)		0.0	0.0	0.0
4	Retail Sales for RPS	4=1-2-3	279.0	284.3	291.7
5	Additional Energy Efficiency		19.9	17.1	15.2
6	Additional Rooftop PV		4.1	3.2	2.3
7	Additional Combined Heat and Power		16.2	7.2	0.0
8	Adjusted Statewide Retail Sales for RPS	8=4-5-6-7	238.8	256.9	274.2
9	**Total Renewable Energy Needed For 33% RPS**	**9=8* 33%**	**78.8**	**84.8**	**90.5**
	Existing and Expected Renewable Generation				
10	Total Instate Renewable Generation		34.3	34.3	34.3
11	Total Out-of-State Renewable Generation		9.2	9.2	9.2
12	**Total Existing Renewable Generation for CA RPS**	**12=10+11**	**43.5**	**43.5**	**43.5**
13	**Total RE Net Short to meet 33% RPS In 2020 (TWh)**	**13=9-12**	**35.3**	**41.3**	**47.0**

Source: Energy Commission staff.

The high and low estimates include the most extreme combination of values identified for each variable are outlined in the report. This means that to estimate the maximum plausible renewable net short, the highest demand forecast is combined with the lowest values of demand reduction measures and existing renewable generation. For the lowest renewable net short value, the lowest demand forecast is combined with the highest values of demand reduction and existing renewable generation.

The calculated estimates for the renewable net short range from 35.3 TWh to 47.0 TWh. This represents a 32 percent difference in the estimates. The range of CHP assumptions accounts for nearly half of the difference between the renewable net short high and low. Electricity demand scenarios account for 36 percent of the renewable net short range, EE contributes 13 percent of the difference, and the PV assumption has a 5 percent effect. This range highlights how uncertainties in key input variables will affect the amount of estimated renewable energy that is needed to meet policy goals.

The total renewable generation (existing plus the renewable net short) needed to meet a 33 percent policy goal floor in 2020 ranges from 78.8 TWh to 90.5 TWh, a difference of 11.7

TWh (15 percent) or equivalent to the generation from about 4,800 MW solar-thermal power plants.

The 33 percent renewable net short by 2020 range of estimates is considered to be a floor range of estimates, allowing for the possibility that additional investments in these generation technologies may occur beyond the policy target. 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. The electricity from existing coal and petroleum coke plants is expected to decline by 61 percent (17.6 TWh) between 2010 and 2020 due to the constraints imposed by the Emission Performance Standard.[27]

Future Updates to the Renewable Net Short

The Energy Commission will post updated renewable net short estimates by August 1 of each year, matching the expected date when information on new generation is submitted under data collection regulations. The renewable net short estimate will also be updated when new electricity demand forecasts are adopted, when questions regarding the RPS eligibility of customer-side generation are resolved, and there is more clarity about the amount of tradable renewable energy credits being used for RPS compliance. When updating a renewable net short calculation, analysts should use the latest demand forecast released by the Energy Commission, noting changes in the level of economic growth, energy efficiency, and self-generation from earlier demand forecasts.

The current renewable net short calculation assumes that renewable self-generation reduces retail sales. As tradable renewable energy credit provisions are implemented, the Energy Commission plans to establish the criteria for TRECs from renewable self-generation to be eligible for the RPS. After this has been completed, RPS-eligible self-generation may be counted both as a reduction in retail sales and as a part of the mix of supply-side generation used to meet the renewable net short.

27 The Emission Performance Standard prohibits California utilities from renegotiating or signing new contracts for baseload generation that exceeds 1,100 lbs of CO2e emission per MWh. A number of contracts with coal generation facilities that exceed the Emission Performance Standard will expire within the decade and cannot be renewed with another long-term contract.

List of Acronyms

ARB	Air Resources Board
BAMx	Bay Area Municipal Transmission Group
California ISO	California Independent System Operator
Energy Commission	California Energy Commission
CED	California energy demand
CEERT	Center for Energy Efficiency and Renewables Technology
CHP	Combined heat and power
COD	Commercial on-line dates
CPUC	California Public Utilities Commission
CTPG	California Transmission Planning Group
DG	Distributed generation
EE	Energy efficiency
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
IEPR	*Integrated Energy Policy Report*
IOUs	Investor-owned utilities
LADWP	Los Angeles Department of Water and Power
LTPP	Long-term procurement planning
MW	Megawatt
NRDC	Natural Resources Defense Council
PG&E	Pacific Gas and Electric
POUs	Publicly owned utilities
PSDP	Power Source Disclosure Program
PV	Photovoltaic
QFER	Quarterly Fuels and Energy Report
QFs	Qualifying facilities
RES	Renewables energy standard
RETI	Renewable Energy Transmission Initiative
RNS	Renewable net short
RPS	Renewables Portfolio Standard
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SMUD	Sacramento Municipal Utilities District
TEPPC	Transmission Expansion Planning Policy Committee
TWh	Terawatt hours
WECC	Western Electricity Coordinating Council

Glossary of Basic Renewable Net Short Terminolgy

Term	Definition
California Solar Initiative	Photovoltaic solar rebate program overseen by the California Public Utilities Commission for California consumers that are customers of the investor-owned utilities – Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric.
Demand response	The ability of an individual electric customer to reduce or shift usage or demand in response to a financial incentive.
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.
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).
Losses	Transmission and distribution losses as a percentage of net energy for load.
Net energy for load	Total generation plus energy received from other areas, less energy delivered to other areas through interchange needed to serve load.
Self-Generation Incentive Program	CPUC program that provides rebates for qualifying distributed energy systems installed on the customer's side of the utility meter.
Retail Sales	Consumption minus self-generation
Transmission Planning Process	ISO and participating transmission owner studies demonstrate how the ISO is planning for infrastructure needs while meeting North American Electric Reliability Corporation and ISO planning standards. The annual transmission plan serves as the formal and board-approved roadmap for infrastructure requirements for the ISO Balancing Authority.
Energy efficiency	Activities or programs that stimulate customers to reduce customer 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.
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
Combined heat and power	The use of a heat engine or a power station to simultaneously generate both electricity and useful heat.

APPENDIX: Summary of the 33 Percent Renewable Net Short Staff Workshop, March 8, 2011

Overall, stakeholders thought that it is important to develop a single renewable net short approach that should be used for related electricity system infrastructure studies. However, there was a divergence in recommendations on what variables should be used for the calculation. Stakeholders did not provide comments on the overall ranges of the net short but did provide comments on specific topic areas. Stakeholder comments focused on the amounts of energy efficiency (EE), combined heat and power (CHP), distributed generation (DG), rooftop photovoltaics (PV), and the existing, or soon to be on-line, renewable generation.

Workshop participants included:

Bay Area Municipal Transmission Group (BAMx)	California Public Utilities Commission (CPUC)
Natural Resources Defense Council (NRDC)	Southern California Edison (SCE)
Pacific Gas and Electric (PG&E)	Sacramento Municipal Utilities District (SMUD)
Sempra	MRW
Los Angeles Department of Water and Power (LADWP)	Center For Energy Efficiency and Renewables Technology (CEERT)
California Building Association	Strategic Decisions Group
California Department of Water Resources	Chena Geothermal Companies

Key Points From Workshop Participants and Staff Responses

The following are some of the main issues that stakeholders identified and a staff response with recommendations. The matrix at the end of the appendix includes a more detailed summary of comments.

1. Timing for Updates:
    a. *Comments*: Many stakeholders asked about the timing for an updated RNS for ongoing system studies. Some of the stakeholders are interested in the most current RNS estimate for use in electricity system infrastructure studies currently underway, such as the California Transmission Planning Group reliability study.
    b. *Response*: There are a number of options to consider regarding the timing for updating the RNS report and/or range of RNS. Many components to the RNS calculation change annually (existing generation), biannually (demand forecast and uncommitted EE), or on some other time frame (CHP regulatory incentive mechanisms).
    c. *Recommendation*: Staff recommends providing annual RNS updates every August 1 to coincide with the release of the utility Power Source Disclosure filings that include the latest amounts of specified renewable generation additions. The RNS would also be updated biannually with the adopted demand and uncommitted EE forecasts.

2. Bottom-Up Vs. Top-Down RNS Analysis:
    a. *Comment*: PG&E recommended a bottom-up approach using the utility Supply S-2 Forms & Instructions resource plan filings instead of the top-down statewide estimates derived by staff for the amount of RNS.
    b. *Response*: Staff investigated the merits of using the utility resource plan filings for a bottom-up approach for the RNS calculation using the *2011 IEPR* resource plan filings submitted via the S-2 form. These filings were prepared in 2010 and can be considered dated since the passage of new legislation has raised the renewable energy targets for all utilities and new generation has been added. A comparison of the implied RNS calculated from utility estimate of retail sales and existing renewables to the statewide RNS estimate in **Table A-1** shows that the utilities estimates are very close to the statewide estimate (staff estimate is 642 GWh higher). Using the utility-submitted estimates, however, generates results that are based on a wide variety of assumptions that are not transparent to those who have not studied the utility filings in detail and are not likely to be submitted in other proceedings. Without the assumptions being visible, stakeholders in these proceedings are unable to produce fully informed responses, undermining the purpose of conducting resource planning activities in a public setting.
    c. *Recommendation:* Staff recommends using the RNS estimates derived from the equation identified in the staff draft paper for current electricity infrastructure studies. However, staff recognizes the value of utility-specific estimates of RNS to evaluate resource development and progress towards achieving the mandated targets.

Table A-1: Estimate of Renewable Energy Production and Retail Sales (GWh)

Utility	2010 Renewable Energy Reported	Total Added Renewable Energy.	2020 Retail Sales	Renewable Energy Percent Target by Utility	Utility Implied Renewable Net Short
PG&E	13,489	13,072	80,370	33.0%	13,033
SCE	14,708	12,133	85,907	31.2%	13,641
SDG&E	1,941	4,800	20,277	33.2%	4,750
Anaheim	257	598	2,590	33.0%	598
Burbank	105	348	1,322	26.7%	331
Glendale	226	188	1,257	32.9%	189
Imperial	276	1,312	3,722	42.7%	952
LADWP	4,596	4,190	26,150	33.6%	4,034
Modesto	436	499	2,783	33.6%	482
NCPA	671	-	2,434	26.6%	132
Pasadena	100	359	1,146	40.0%	278
Redding	17	197	867	24.7%	269
Riverside	414	371	2,377	33.0%	370
Roseville	218	210	1,301	32.9%	211
SMUD	2,406	655	10,691	28.6%	1,122
Turlock	485	264	2,271	33.0%	264
Total	**40,345**	**39,196**	**245,465**	**32.4%**	**40,658**

Source: Energy Commission staff.

3. Demand Forecast and Energy Efficiency Adjustments:
   a. *Comments*: NRDC recommended that new appliance standards and federal building standards should be added to the electricity retail sales forecast.
   b. *Response*: Staff agrees with the NRDC assessment but notes that these programs will be included in the updated electricity demand forecast. At the time when the staff RNS paper was prepared, staff was expecting to have an updated demand forecast as part of the *2011 IEPR* cycle. The demand forecast with the energy efficiency program updates is now shifted to the *2012 IEPR Update* cycle.
   c. *Recommendation:* Staff recommends using the updated econometric demand forecast that the Demand Analysis Office completed in May 2011. This update did not include a new assessment of the committed energy efficiency programs. Therefore, staff recommends using the same uncommitted EE components that were proposed in the draft RNS paper. The only suggested update is to not include the load-serving entity (LSE) < 200 GWh retail sales reduction to demand forecast since the 33 percent renewables legislation that was recently signed by the Governor does not contain this exclusion.

4. Rooftop Photovoltaic Assumption:
    a. *Comment*: BAMx and SMUD supported an upward revision to the capacity factor that is applied to future rooftop PV.
    b. *Response*: Staff agrees with the comments since the assumed capacity factors were based on dated technology characterizations. The staff draft RNS paper included a 14.8 percent capacity factor for new rooftop PV.
    c. *Recommendation*: Staff recommends applying a range for rooftop PV capacity factors between 16.24 percent, 20.0 percent, and 22.9 percent. These capacity factors are the same used for the CPUC Long-Term Procurement Planning (LTPP) 2010 Standardized Renewable Planning Assumptions. The updated capacity factors will increase the electricity contributions from PV systems, thereby reducing the retails sales value for the RNS calculation.

5. Adjustments for Additional Combined Heat and Power:
    a. *Comments:* SMUD indicated it has mostly wholesale (supply side) CHP and commented that staff's recommended 50/50 split between customer-side and wholesale CHP is not accurate. SCE considered staff's new customer-side (CHP) goals too uncertain and recommends using zero as an appropriate goal for all ranges. PG&E recommended new customer-side CHP at 4-5 TWh as the mid range, 7.5 TWh for the high range, and zero for the low range. PG&E also recommended a modified description of incremental CHP or DG additions as "The Generation Serving at Site Load."
    b. *Response*: Staff acknowledges that potential development of new CHP may have a range of applications to provide either customer-side or wholesale electricity services, similar to developments in the SMUD region. Alternatively, some CHP projects may provide a combination of both services. The staff draft paper includes a discussion about these kinds of development uncertainties, which is why a range of customer-side CHP assumptions (0 TWh- 7.2 TWh- 19.8 TWh) were applied to the RNS calculation. These CHP estimates are based on the 2009 market assessments report that was prepared by ICF Consulting and the *AB 32 Scoping Plan* goals. Staff finds that this is the most significant uncertainty for the RNS analysis, which will remain until the proper incentive mechanisms are in place.
    c. *Recommendation:* Staff recommends the continued use of a range of potential customer-side CHP assumptions for the RNS calculation. Staff believes that the ICF Consulting market assessment is reasonable and that the proposed range included in the staff draft paper adequately reflects the associated uncertainties. However, staff recommends a minor adjustment to the new customer-side combined heat and power (CHP) levels. The ICF Consulting report that was used to develop the forecast ranges presented in the draft RNS paper included the assumption that the CHP settlement agreement would begin implementation in 2009. This CHP settlement agreement is not expected to begin until summer 2011. Therefore, staff recommends shifting the new CHP goals back by two years, resulting in lower forecasted goals for new customer-side CHP (proposed 16.2 TWh compared to 19.8 TWh in Draft RNS).

6. Estimation of Existing In-State Renewable Generation:
    a. *Comments:* There was a general agreement that there are difficulties in quantifying existing generation and that the proposed method is on the right track. There were suggestions on additional factors to consider what renewable generation should be considered available by 2020. The Clean Coalition, SCE, and BAMx recommended calculating the amount of existing renewable generation to meet the RPS based on an average of the *Quarterly Fuels and Energy Report* (QFER) reported generation for all in-state generation with the exception of wind and solar. For wind and solar, they recommended that staff use reported installed capacity and capacity factor for the energy from these resources. BAMx agrees with staff's proposed method to count new renewable resources with commercial on-line dates (COD) on or before the end of following calendar year as existing generation. SCE instead recommended staff use all executed renewable contracts for the existing generation, regardless of COD.
    b. *Response*: Staff agrees with the suggestion to use a historical generation average for the in-state renewable generators, except for wind and solar. Given the annual variations in wind and solar, plus the increasing additions of these kind of facilities into the system, staff believes that applying a capacity factor to derive the amount of energy is a reasonable approach for calculating the 2020 RNS. Staff believes that the plants currently under construction and planned to be operational at the end of each update calendar year is reasonable criteria for existing generation. However, staff has concerns with the SCE recommendation, since there is a degree of uncertainty whether all *executed* contracts will come to term and actually provide electricity deliveries. The number of contract failures highlights this concern.
    c. *Recommendation:* Staff recommends calculating the amount of existing renewable generation to meet the RPS based on a five-year average of *Quarterly Fuels and Energy Report* (QFER) historical in-state generation, with the exception of wind and solar. For wind and solar, staff recommends using the QFER reported installed capacity and applying the capacity factor method. Capacity factors would also be applied to the plants currently under construction and expected to be operational by the end of each update calendar year. Staff does not recommend applying the SCE suggestion of using all executed contracts, since this may overstate the actual renewable generation that may be in place by 2020. The overall recommendation will result in a single *existing generation* estimate instead of the range that was included in the RNS staff draft paper. The other existing generation estimates ended up under-counting generation (not including other sources currently under development) and over-counting when only using a capacity factor approach (some plants are older with degrading efficiency levels).

7. Estimation of Existing Renewable Electricity Imports:
    a. *Comment*: Clean Coalition recommended that renewable generation imports that do not have contracts should not be part of the existing generation estimates.

b. *Response:* Staff agrees with this recommendation, since some of the claimed renewable electricity imports are currently spot market purchases. There are no guarantees that these kinds of transactions will occur through 2020.
c. *Recommendation*: Staff recommends applying only the claimed renewable electricity imports that are tied to long-term contracts. Staff will review the Power Source Disclosure filings and contracts database to evaluate which claimed imports have contracts or represent spot market purchases and remove them from the RNS estimate.

8. Grouping of Variables for Range of RNS Estimates:
   a. *Comment:* The Department of Water Resources asked about the reasoning for grouping the different variables used to calculate the range for the RNS estimates and whether the implementation of one program will affect another. Clean Coalition and SMUD also recommended that staff apply probabilities or confidence levels to the variables used for the RNS calculations.
   b. *Response*: The staff draft report included high and low RNS estimates, using the most extreme combination of values identified for each variable in the calculation. The draft report also included an "illustrative" RNS estimate to represent mid-range or reference case assumptions. At the workshop, staff agreed that there should be a rationale for the grouping beyond an attempt to mix the variable to derive bookend RNS estimates. There are a number of factors that will likely affect electricity demand levels and investments in load reduction programs (EE, PV, and CHP). Changing economic conditions and retail rate levels are key drivers that are already applied to the electricity demand forecast scenarios. Price elasticity factors are applied to determine how electricity demand will change with ratepayer costs. Electricity rates will also affect the incentives for the load reduction programs, since higher costs will result in larger savings when investing in EE, PV, or CHP systems. However, there are other key drivers to consider when evaluating the potential success and investment levels for these different load reduction programs. For example, the poor state of the economy has affected the availability and costs for financing CHP systems. The economy has also affected the costs for raw materials, such as steel, that are consequently increasing the investment costs for the CHP systems. New regulatory incentive mechanisms are also under development to encourage load reduction program investments. Many of these issues and uncertainties are discussed in the staff draft paper. Staff is following each of these developments to evaluate the potential success of the program implementations. However, there is currently no source of information available to derive probabilities or confidence measures.
   c. *Recommendation:* Staff recommends that the low and high RNS grouping that was originally presented in the staff draft report remain unchanged. However, staff will expand the discussion to explain the relationship of these combined variables to calculate the RNS range of estimate.

9. Application to Current System Infrastructure Studies:
   a. *Comment*: BAMx recommends that Energy Commission staff be more actively involved in the integrated renewable and generation and transmission planning processes, such as the California Independent System Operator and California Transmission Planning Group (CTPG) transmission planning studies.
   b. *Response*: Staff has been actively involved in the different electricity system studies to help identify resource assumptions for simulation modeling runs. The CTPG members are currently using the range of resource assumptions and RNS estimates that are included in the staff draft paper, but are requesting to know when these values will be updated by the Energy Commission.
   c. *Recommendation*: Permit staff to continue active involvement with the working groups. Staff recommends passing a preliminary set of updated RNS estimate to CTPG.

Summary of Comments Submitted on Draft Renewable Net Short Report and Workshop Presentations

Commenter	Concern	Staff Response
Clean Coalition	The RNS should always be expressed with a level of uncertainty and a standardized confidence interval should be added to this range.	Staff agrees. At this time staff does not have data to develop measurable confidence intervals for each input variable.
	Claimed (Power Source Disclosure) out-of-state renewable generation lacking a contract should not be counted as existing renewable generation.	Staff agrees. Staff will review the Power Source Disclosure filings and contracts database to evaluate which claimed imports have contracts or represent spot market purchases and remove those lacking contracts from the RNS estimate.
	Recommends a reference case study underlie all work for any given year, allowing for direct comparison of results.	Staff agrees. Staff is recommending a mid case that is consistent with the May 2011 demand forecast update.

Commenter	Concern	Staff Response
	The Governor's goals for DG are primarily for wholesale (supply side) DG. They should be defined as a distinct component of the RNS with defined targets and net short estimates within this target.	Staff agrees. Wholesale DG is one way to supply the energy needed to fill the RNS; it does not change the amount of the RNS. Staff will include a discussion of the amount of renewable self-gen and renewable wholesale DG on-line, expected to be on-line within a year, and the amount needed to achieve the Governor's goal of 12,000 MW by 2020 in the Renewable Strategic Plan that is part of the *2011 IEPR*.
	Contract failure rate for prior years should be applied to current projects, including those that are soon-to-be on-line and counted as "existing" in the RNS.	Staff disagrees. Rather than apply a fixed failure rate, staff recommends using the Energy Commission IOU contract database for information on the "current expected" on-line date to determine whether to include contracts with near-term on-line dates in "existing" renewables for RNS planning purposes. Since the proposed RNS estimate includes only projects that will be operational by the end of the following year, failure rates are expected to be near zero.
BAMx	Would like staff to consider how renewable DG, specifically rooftop PV, can be counted as part of the RNS instead of a load modifier, particularly when tradable renewable energy credits are allowed.	Staff agrees; however, this issue cannot be addressed in the RNS forum. BAMx also acknowledges this is not the forum to affect applicable legislation. A renewable DG will ultimately reduce retail sales (the renewable metric), but may also be counted as supply side of the RNS equation.

Commenter	Concern	Staff Response
	Do not exclude new renewables with COD prior to 12/31/2012 in the range of existing generation.	Staff agrees. Staff proposed zero for the low range in the draft RNS report. However, staff closely monitors the small amount of new renewable projects with expected COD by the end of the following year. Beyond that date the amount of new renewable projects with contracts is very large and status details more uncertain. Staff is also recommending that the existing generation value be identical for all proposed RNS scenarios.
	Recommended that staff use a higher than 14.8 percent annual capacity factor for new roof-top PV generation assumptions.	Staff agrees. Staff is recommending an average 21.3 percent capacity factors based on the range 19.6 percent to 22.9 percent included in the CPUC LTPP 2010 Standardized Renewable Planning Assumptions.
SMUD	A range of estimates on the amount of electricity that may be used to recharge electric vehicles should be included in the RNS calculation.	Staff agrees. The EV recharging load is already incorporated into the demand forecast ranges.
	SMUD has mostly wholesale (supply side) CHP and recommended 50/50 split between demand side and wholesale CHP is not accurate.	Staff agrees that SMUD CHP is largely wholesale; however, staff developed a statewide forecast of RNS. The 50/50 split is supported by the ICF report used to develop this assumption.
	Recommended that staff apply probabilities to the variables used in RNS calculation.	Staff agrees. The proposed demand forecasts have associated probabilities and we may use these values when presenting RNS ranges. At this time no data exists to develop probabilities for most other variables in the RNS calculation.

Commenter	Concern	Staff Response
CPUC	Would like to clarify that the CPUC is not a party to the QF Settlement approved by the CPUC in December 2010.	Staff agrees. Staff will remove any reference to CPUC as party to the QF Settlement Agreement in future documents.
	Parties have not yet submitted the CPUC settlement documents to FERC and recommends a summer 2011 assumption be used as an effective date for this settlement.	Staff agrees. The ICF Report used to develop the forecast range for new CHP assumed a QF Settlement Agreement effective in 2009. Staff recommends using the new CHP assumptions for 2018 instead of 2020 due to the delay of the settlement.
	Believes the *AB 32 Scoping Plan* 4,000 MW CHP target is a combination of supply– and demand-side, not solely supply-side as indicated in our low range estimate of zero.	Staff disagrees. ARB staff emphasized that the Scoping Plan is subject to many uncertainties in this assumption and that either one may be correct based on future policy and the CHP Settlement Agreement. Staff's high-demand scenario assumes low electricity prices, which could provide little incentive for new small or large CHP to develop in the future. Staff will include zero as the low scenario but not mention this assumption as based on the *AB 32 Scoping Plan*.
NRDC	Add television and other state/federal building standards in addition to the uncommitted energy efficiency (EE) deduction since they consider this missing from the Energy Commission's *CED* 2010.	Staff agrees and acknowledges these programs are missing. Staff will address these standards in the preliminary *IEPR 2012 Update* forecast.
	The 2011 demand forecast does not include a significant portion of the POUs' energy efficiency savings. It recommends that the demand forecast and the net short calculation include savings from all POUs through 2020.	Staff disagrees that POU committed EE programs will be excluded from the 2011 forecast or are excluded from the last adopted demand forecast. The Incremental Impact report did not included uncommitted EE savings for POUs; however an adjustment of 2.7 to 3.6 TWh, depending on scenario, was made in the calculation of RNS.

Commenter	Concern	Staff Response
CBA	Stated that 2010 building construction levels are about 15 percent of normal levels. The Commission should focus more on this in the 2011 forecast so that by 2020 the building starts should be at about 1 million instead of 2 million as in its current forecast.	Staff agrees. The preliminary *IEPR 2011* demand will include an update of building starts for the year 2020.
SCE	Use all executed renewable contracts for the existing generation, regardless of COD.	Staff disagrees. The RNS is meant to provide an estimate of the gap between the amount of renewable energy needed in 2020 and the amount that is expected to be generated by facilities that are currently operating (or soon to be operating). It may be useful to mention in the text the portion of the RNS that would be filled if all signed contracts were to result in new on-line generation. This would give some indication of the minimum amount of additional energy that should be contracted.
	Approach for calculating high, medium, and low levels of uncommitted EE presented in comments to Energy Commission Joint Committee Workshop on Economic, Demographic, and Energy Price Inputs for Electricity, Natural Gas and Transportation Fuel Demand Forecasts on February 24, 2011, is recommended. This suggests using 2004 peak to energy ratios to adjust the high, medium, and low forecasts.	Staff recommends this proposal be vetted in the *IEPR* demand forecasting process, not in the development of the RNS.
	Staff should include estimates of existing renewable generation that may retire by 2020.	Staff agrees. Regardless of generation type, staff excludes announced generation retirements from all of the calculations and simulation studies. Speculating about renewable generation retirements is not recommended by staff.

Commenter	Concern	Staff Response
	Staff's proposed RNS methodology fails to accounts for flexible RPS compliance.	Staff agrees. RNS indicates the amount of additional renewable energy likely to be needed for a given year for planning purposes, not for RPS compliance purposes. The RNS includes an estimate of the amount of generation that is currently operational (or soon-to-be operational) and may provide energy in 2020. Flexible compliance allows energy generated in one year to be applied toward RPS requirements in another year. Staff believes flexible compliance is not applicable to the RNS estimate.
	Staff's new customer-side combined heat & power (CHP) goals are too uncertain and recommends using zero as an appropriate goal for all ranges.	Staff disagrees since there is a strong policy goal for developing CHP. Staff recommends using the ICF report for the range of new customer-side CHP, as proposed in its draft report, with the exception for the two year delay in the QF Settlement Agreement. The Low RNS Scenario now 16.2 TWh as opposed 19.8 TWh in the draft report.
PG&E	Recommended a bottoms-up approach using the utility S-2 Forms & Instructions resource plan filings instead of the top-down statewide estimates derived by staff for the amount of RNS.	Staff will investigate this option with the new S-2 filings. The 2009 S-2 filings are dated, including their own demand forecasts that have not been vetted and single-year values for existing renewable generation. Staff recommends a range of RNS with a specific accounting for existing and new renewable generation. The S-2 Forms and Instructions require different accounting methods for existing generation that would need to be made consistent with the method recommended for RNS. These S-2 filings can be compared to the mid-range RNS. The IEPR 2009 S-2 filings (some for the 2018, while most reported through 2020) 46.8 TWh RNS compared to the draft RNS of 42.7 TWh. Staff recommends the approach outlined in the next steps to calculate RNS based on demand forecast low-, mid- and high ranges.

Commenter	Concern	Staff Response
	PG&E recommended new customer-side CHP 4-5 TWh as the mid range, 7.5 TWh for the high range, and zero for the low range. Staff's recommended range in the draft RNS report was 0 to 19.9 TWh. PG&E also recommends staff be clearer when describing incremental CHP or DG Additions as "Generation Serving at Site Load From Distributed Generation Additions."	Staff disagrees. PG&E is proposing that the current mid demand be used for the high case and 4-5 TWh in the mid demand. PG&E provides little factual support for their alternative forecast and their forecast is matched with qualifier phrases. Staff sees no supporting evidence in its comments to make further adjustments to the estimates than those already made to account for the delay in the QF Settlement Agreement. The low RNS Scenario now has 16.2 TWh as opposed 19.8 TWh presented in the draft paper.
	Recommends staff assign probabilities to *aspirational* goals	Staff agrees; however, no data is available to create these probabilities for policy goals. Staff could assign probabilities to the demand forecast ranges. Staff is not recommending assigning probabilities based on a single component of RNS.
	Recommends existing renewable generation include projects that might reasonably be expected, have executed contracts, or begun construction.	Staff agrees. Staff recommends that new renewable generation with an executed contract and a COD by the end of the year following the year the RNS is developed is a prudent assumption for reliability and integration modeling.