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BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of the Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, And Recovery of Associated Costs Through Proposed Ratemaking Mechanisms (U 39 E).	Application 16-08-006 (Filed August 11, 2016)

PACIFIC GAS AND ELECTRIC COMPANY NOTICE OF *EX PARTE* COMMUNICATION

[PUBLIC VERSION]

Pursuant to Rule 8.4 of the Commission's Rules of Practice and Procedure, Pacific Gas and Electric Company (PG&E) hereby gives notice of the following *ex parte* communication. The communication occurred on Friday, September 23, 2016, at 10:00 AM at the offices of California Public Utilities Commission (CPUC), and lasted approximately 30 minutes. The communication was oral and a handout was provided, which includes some confidential information. This confidential information is redacted from the Public version of this Notice, but included in the Confidential version (Attachment A).

Erik Jacobson, Director, Regulatory Relations, PG&E, initiated the communication with Scott Murtishaw and David Peck, Advisors to Commission President Michael Picker. Margot Everett, Senior Director, Customer Proceedings and Rates, PG&E, was also in attendance.

Mr. Jacobson stated that PG&E supports revision 1 to the proposed decision of ALJ Tsen in the 2015 Energy Resource Recovery Account proceeding (A.14-05-024) regarding the vintaging methodology for the Power Charge Indifference Adjustment (PCIA). The revisions help clarify the vintaging rules for departing customers in Community Choice Aggregation (CCA) territories where there is a phase-in of service over an extended period of time.

Ms. Everett provided an overview of PG&E's load forecasting methodology. She described PG&E's forecast of cumulative energy efficiency savings, distributed generation (DG), system sales, CCA departures and bundled sales. Ms. Everett and Mr. Jacobson explained the probabilistic approach to determining CCA departures and described CCA activity existing today in PG&E's service territory. They presented PG&E's forecast of expected CCA load growth by 2025 and discussed the significant uncertainty over the magnitude and timing of this CCA load growth. In addition, there is significant uncertainty over the forecast of energy efficiency savings and DG. Nevertheless, by 2030 PG&E expects to serve about half the load in its service area. This forecast is presented in PG&E's Diablo Canyon Power Plant retirement application.

Mr. Jacobson and Ms. Everett discussed the policy implications of this significant level of CCA and DG load departure. As CCA and DG load grows, it will be increasingly important to allocate the cost of reliability services and cost of fulfilling state policies such as BioRAM to all benefiting customers. They explained how the current PCIA methodology overvalues PG&E's generation portfolio and results in artificially low PCIA rates. The estimated 2016 cost shift to PG&E's bundled customers is $91 million due to inaccuracies of the inputs. This equates to a cost shift of about $135 per year assuming higher CCA load.

Respectfully submitted,

/s/ Erik B. Jacobson

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Dated: September 28, 2016

ATTACHMENT A

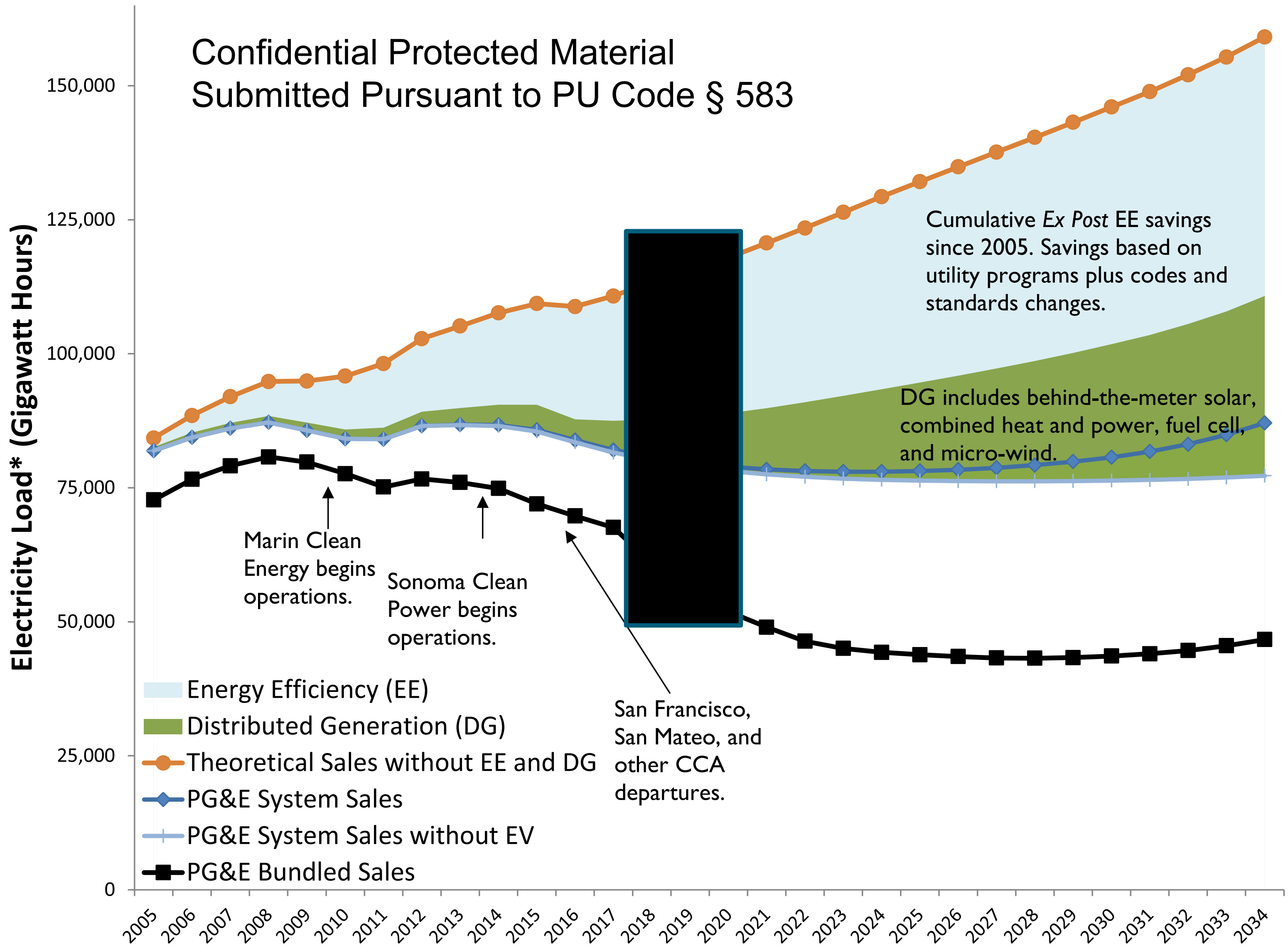
Load Forecast

September 23, 2016

Agenda

- Overview of load forecast and methodology
- Load forecast implications

Historic and Forecast Electricity trends show increased EE, DG, CCA



* 2015 and earlier PG&E recorded/estimated
2016-2034 as filed in DCPP Retirement Application

CCA Forecasting Methodology - Overview

(1) Identification of CCA participation: PG&E identifies the level of public CCA activity observed in its service area

2) Determination of departure probability: Based on observed CCA activity, PG&E assigns a target probability of departure for communities in the service area

(3) Determination of load forecast: Load pertaining to potential CCA departure jurisdiction is identified as an independent variable in the simulation model with no dependencies or correlation

(4) Calculation of load departure (stochastically modeled): For each year, the jurisdiction-specific departure probabilities and load forecasts are stochastically modeled using a distribution comprised of 5,000 iterations.

CCA Activity Today in PG&E's Service Territory

Existing (Currently serving customers)

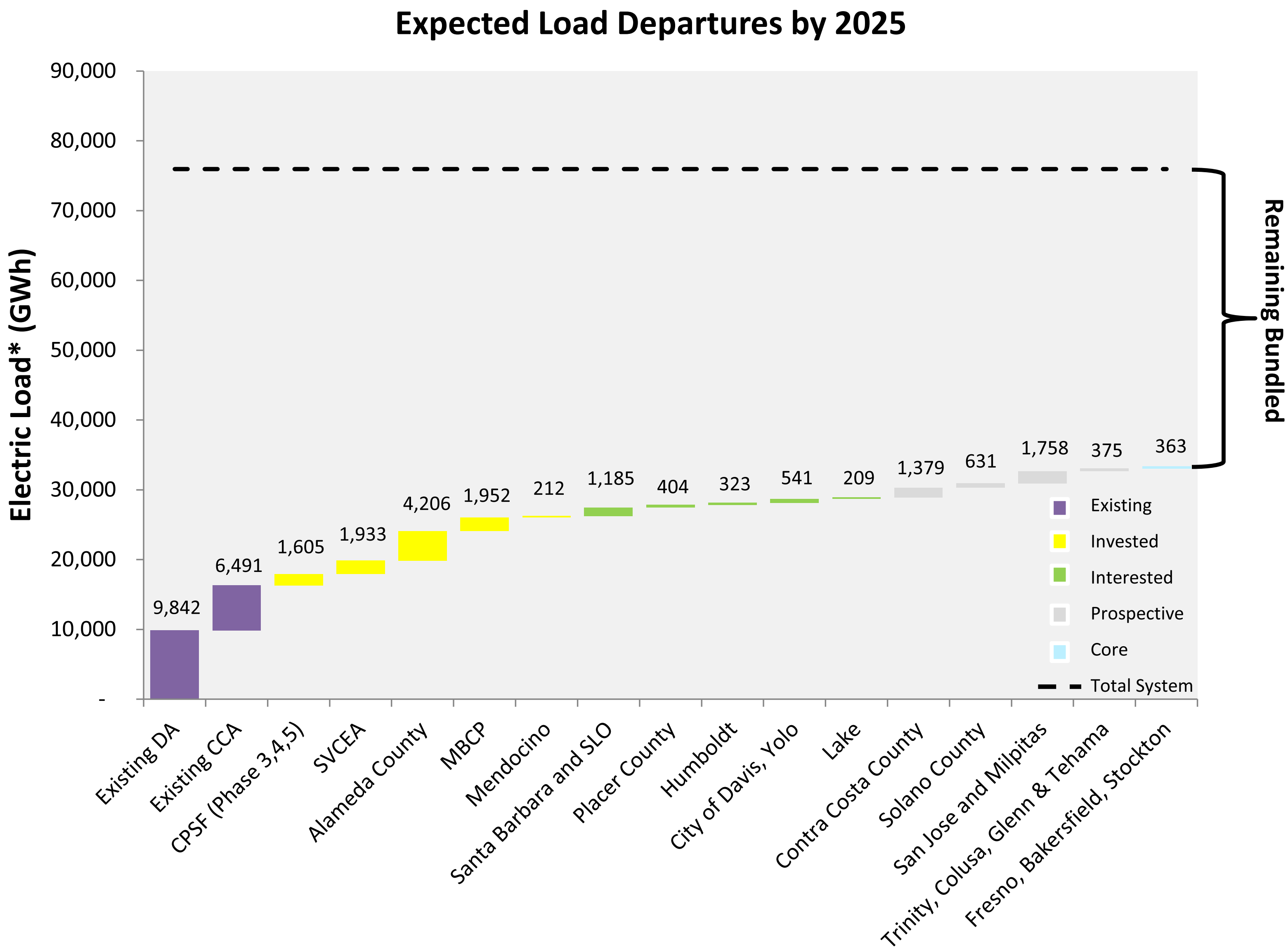
Invested (Financial commitment)

Interested (CCA program evaluation)

Prospective (Proximity/Exploratory)

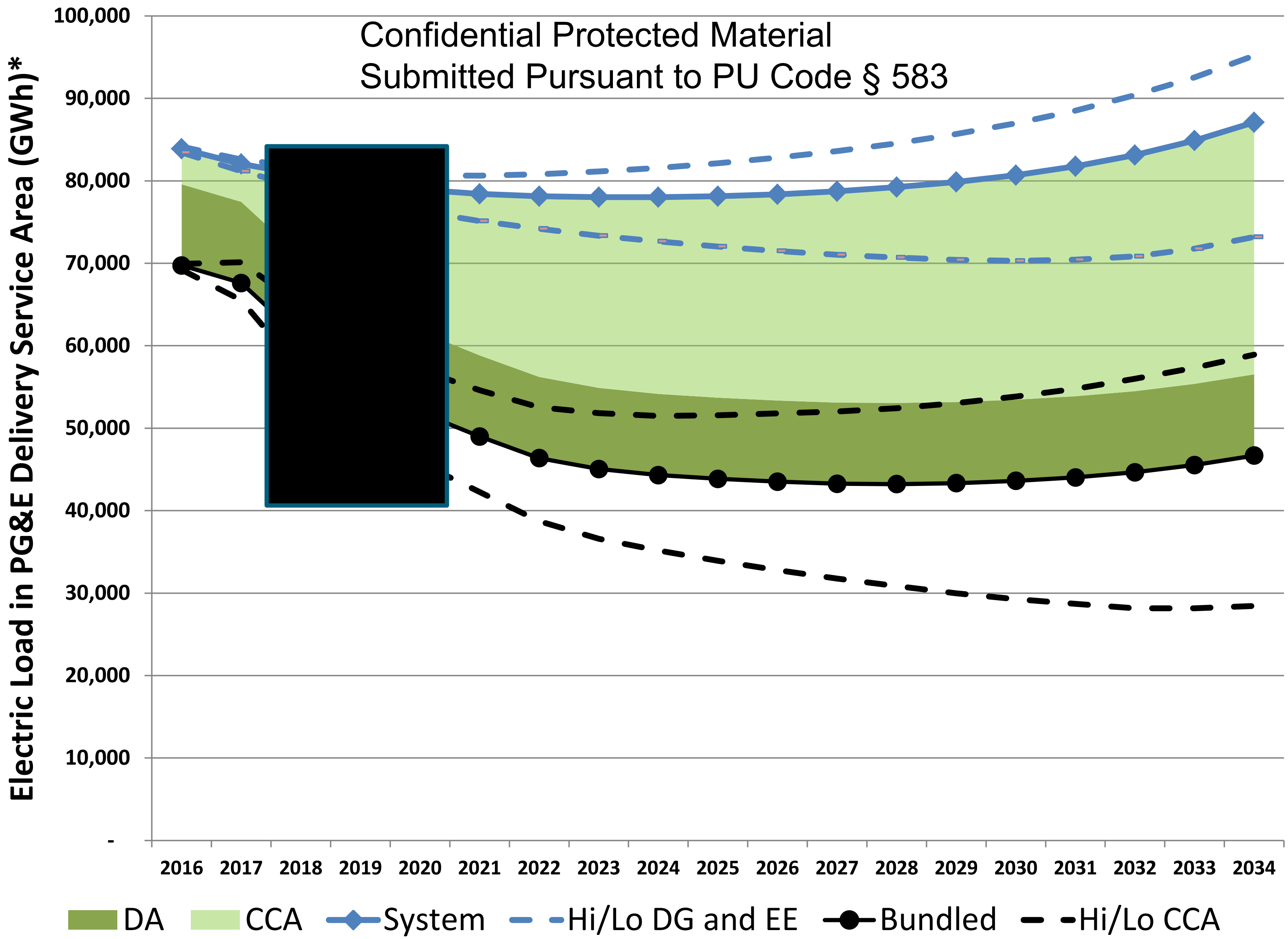
Core (Remaining PG&E territory)

CCAs are expected to expand in PG&E's service territory



*Does not represent total load in each community, but PG&E's probability adjusted estimate of expected load loss

PG&E expected to serve ~50% of system load due to CCA growth by 2030
Further uncertainty driven by DG/EE



*As filed in DCPP Retirement Application

CCA and DG Load Departure Implications and Challenges

- Effectiveness in achieving state policy
- Maintaining reliability
- PCIA cost shifting
- Increasing pressure on rates

Load Loss Implications: Increasing PCIA cost shift

- The currently administratively-determined inputs to calculate market value result in a market value that overvalues vintaged PCIA portfolios.[1]
- This results in a cost shift to bundled customers of approximately $0.35 for every $1 of above-market costs that should be attributable to departed load.
- The cost shift gets worse as more customers depart PG&E bundled service.

2016 PCIA Revenues (market-based inputs):	$226.8 million
2016 PCIA Revenue (2016 ERRA Forecast):	$135.7 million
Estimated Cost Shift to PG&E Bundled Customers:	**$91.1 million**

In 2016, PG&E estimates the imperfect PCIA results in a cost shift of
~$14 per PG&E residential customer per year

All else equal, if communities from CCA map plus some communities proximate to communities interested in CCA had launched CCAs in 2016, PG&E estimates this cost shift could have been
~$135 per PG&E residential customer per year

[1] For purposes of the PCIA, the resource portfolio is "vintaged" based on the timing of a customers departure and the timing of resource commitments. The departed customer is only responsible for resources that were secured prior to the customer's departure from PG&E bundled service.

Appendix

PCIA should ensure bundled customer indifference to load departure

What is the Power Charge Indifference Adjustment (PCIA)?

- A charge intended to ensure bundled customers are indifferent to load departure by allowing an IOU to recover above market costs associated with generation resources acquired prior to a customer's switch to another electric service provider (e.g., CCA, Direct Access).(1)
- PCIA revenues are credited to bundled customer generation rates.

How is the PCIA Calculated?

At a high-level:

Generation Costs	–	Market Value	=	Above Market Costs
Portfolios are "vintaged" and resources included are based on when a customer left PG&E bundled service		Energy, capacity, and renewables values based on *administratively-determined* market value		Used to calculate PCIA rate

(1) Public Utilities Code, Section Nos. 365.2, 366.1(d)(1), 366.2(a)(4), 366.2(c)(7), 366.2, 366.2(d), 366.3; CPUC *Decision 08-09-012*

PCIA methodology overvalues portfolio, especially renewable portfolio

- Renewables in the PCIA Market Price Benchmark (MPB) are valued based on:
  - 68%: Weighted average cost of IOU newly delivering RPS contracts
  - 32%: Western Electricity Coordinating Council-wide survey of price premiums(1)
- Renewable market has evolved since CPUC approved current PCIA methodology.

Sample Prices for Long-Term RPS Contracts
(includes energy, capacity, and REC value)

	2016 PCIA IOU Renewables(2)	2015 Padilla Report(3)	CCA Feasibility Study(4)	Wind PPA (200 MW)(5)
Value ($/MWh)	95.72	69.00	61.19	52.00
Variance from PCIA IOU Renewable	-	(26.72)	(34.53)	(43.72)

PG&E recommends moving to a method that better reflects market values in California for the forecast year (e.g., Platts).

(1) Per methodology described in D. 11-12-018, Resolution E-4475
(2) The Energy Division removes the capacity value of renewable resources when it calculates the PCIA IOU renewables value. In this example, the capacity value ($3.59/MWh) has been added to the green benchmark value ($92.13/MWh) to ensure an apples-to-apples comparison with other values in the table.
(3) Padilla Report to the Legislature: Reporting 2015 Renewable Procurement Costs in Compliance with Senate Bill 836 (Padilla, 2011), May 2016
(4) Peninsula Clean Energy CCA Technical Study, Pacific Energy Advisors, Inc., October 16, 2015. Value derived from “Short Term Renewable Market Purchases and RECs” costs divided by 35% of Load Requirements in Pro Forma Analysis.
(5) *SMUD (Sacramento Municipal Utilities District) Approves Purchase of Wind Power for $52/MWh*, California Energy News Markets, October 16, 2015, No. 1356.

The PCIA methodology also overvalues capacity

- Capacity value in PCIA MBP is based on going-forward costs of a gas-fired combustion turbine as estimated by the California Energy Commission.(1)
- Alternative sources exist to better reflect the current market value of capacity.

Sample Prices for Capacity

	2016 PCIA Capacity	CCA Feasibility Study(2)	CPUC RA Report(3)	CCA Feasibility Study(4)
Value ($/MWh)	58.27	32.93	32.40	7.68
Variance from PCIA Capacity Value	-	(25.34)	(25.87)	(50.59)

PG&E recommends moving to a method that better reflects market values in California for the forecast year.

(1Per methodology described in D. 11-12-018, Resolution E-4475

(2) Lake County Community Choice Program Feasibility Report, California Clean Power, May 2015. Value derived by taking the "Resource Adequacy Costs" ($2.27 million) in Table 6 and dividing by peak demand (58.8 MW) found on page 19, multiplied by 1.15.

(3) CPUC, The 2013-2014 Resource Adequacy Report, August 2015. $32.40/kW-yr is the weighted average price for 2016 capacity in $/kW-month (see Table 10 on p. 23) multiplied by 12.

(4) Draft Silicon Valley Community Choice Energy Technical Study, Pacific Energy Advisors, Inc., November 25, 2015. Value derived from "Resource Adequacy Capacity" costs in Pro Forma Analysis divided by peak demand of 725 MW (631 MW identified on page 40 of the report multiplied by 1.15 to account for the planning reserve margin which sets an LSE's system RA requirement).