VALLEY CLEAN ENERGY ALLIANCE

Staff Report – Item 7

To: Valley Clean Energy Alliance Board of Directors

From: Mitch Sears, City of Davis Sustainability Manager
Shawn Marshall, LEAN Energy US

Subject: Regulatory & Legislative Update

Date: May 9, 2017

RECOMMENDATION:

1. Receive regulatory and legislative updates and provide feedback/direction as desired.

BACKGROUND & DISCUSSION:

Tracking and participating in regulatory proceedings at the CA public Utilities Commission is one of the most important aspects of forming and operating a CCA program. At present, LEAN Energy is providing regulatory monitoring and reporting on key regulatory issues affecting emergent CCAs. Cal-CCA, the newly formed statewide trade association in which VCEA is an affiliate member, also provides legislative support and monthly reports for its members.

Regulatory Proceedings/Priorities: Attached please find LEAN's most recent regulatory memo (dated May 2, 2017) which provides a summary report and supporting documents regarding key regulatory issues currently before the CPUC, including but not limited to:

1) PCIA/Exit Fee Reform (instructional paper attached)
2) Diablo Canyon Power Plant Closure
3) Integrated Resource Planning
4) CCA Bond Requirements
5) PG&E's General Rate Case, Phase 2
6) Residential Rate Setting

Legislative Report/Potential Actions

Cal-CCA is a new California trade association representing the interests of California's community choice electricity providers in the legislature and at the relevant regulatory agencies

VCEA is an affiliate member of Cal-CCA which is tracking over 40 bills with direct and indirect impact on current and future CCA programs. The most pressing bill, SB 618, that presented a threat to CCA's independent decision-making and procurement autonomy was amended in late April and Cal-CCA has subsequently removed its opposition. Other key bills include:

SB 692 – Transmission Access Charge (with amendments, CCAs are generally favorable)
SB 79 – Hourly GHG Reporting (CCAs are concerned; requested amendments not in print as yet)
SB 584 – 100% Renewable Energy through 2045 – CCAs are generally supportive
SB 700 - Storage Mandates for Peak Periods – CCAs still evaluating

To:	LEAN Energy Clients:
	Central Coast Clean Power (Santa Barbara County as lead)
	Contra Costa County
	East Bay Community Energy
	Monterey Bay Community Power (Santa Cruz County as lead)
	Redwood Coast Energy Authority
	Peninsula Clean Energy
	Silicon Valley Clean Energy
	Valley Clean Energy Alliance
From:	Steve McCarty, Regulatory Consultant, LEAN Energy US
Cc:	Shawn Marshall, Executive Director
Date:	May 2, 2017
Subject:	Regulatory Update #10, March-April, 2017

Each month, LEAN focuses on the key regulatory activities likely to have broad impact on the CCA community. This memo provides an update on key CPUC proceeding developments in the past month and covers priority topics including, but not limited to PCIA reform, General Rate Case, Residential Rate Rulemaking, Integrated Resource Planning, and CCA Bond requirements.[1]

CPUC DEVELOPMENTS

Joint CPUC CEC En Banc Meeting: Friday, May 19th at Cal-EPA in Sacramento, CA

To Do:

LEAN Energy will distribute a copy of the staff white paper on retail electric choice when it becomes available, and will send out a summary of this meeting and will monitor any CPUC or CEC developments that result from this En Banc.

Issues:

As reported last month, the CPUC held a well-attended En Banc on February 1st. On April 11, the CPUC and the California Energy Commission (CEC) announced that they will hold will hold a joint *En Banc* hearing on May 19 at the Cal EPA building in Sacramento with Commissioners of both agencies attending to discuss the changing state of retail electric choice in California.

[1] This monthly memo is designed to provide LEAN's clients with a current snapshot of key regulatory activities related to CCA to help them make informed decisions about whether and how to engage in the regulatory and legislative process during their program formation and early operations. It is not a comprehensive inventory of all the regulatory and statutory requirements impacting operational CCAs. Regulatory and statutory compliance requires a much more comprehensive inventory than the subset of activities described herein and must be tailored to the specific circumstances of each CCA.

The Commission notes that by the end of this year, 40 percent of California's investor-owned electric utility customers will be receiving some type of electricity service from an alternative source and/or provider, such as CCAs, rooftop solar, or Direct Access providers and that this number is expected to grow to more than 80 percent by the middle of the next decade.

The goal of this joint En Banc is to identify and begin to develop an understanding of the challenges and opportunities that the CPUC and the CEC must address as a result of these changes. Staff will be issuing a white paper prior to the meeting.

The preliminary agenda includes:

- Staff Presentation on Retail Choice White Paper
- State of Customer Choice in California
- Panel Discussion: IOU Perspective on Current State of Retail Electricity Market and Coming Changes
- Panel Discussion: What Customers Want
- Thought Leaders and the Future of Retail Electricity Service
- Impressions and Reflections from CPUC, California Energy Commission and Legislature

It is our understanding that seats for this event are fully subscribed. However, an overflow room will be available. Visit http://www.cpuc.ca.gov/retailchoiceenbanc to pre-register. To watch the live stream from your computer, log on at http://video.calepa.ca.gov

No official CPUC or California Energy Commission action will be taken at this meeting.

KEY REGULATORY CASE DEVELOPMENTS

PCIA Working Group

To Do:
LEAN will report on next steps as the Commission responds to the working group report, utility joint proposal, and consolidation of the ERRA proceedings to the current PCIA methodology.

Issues:
On April 5, SCE filed the final working group report on behalf of the entire working group. A copy of that report was attached to last month's memo. The working group documented a number of issues with the current method of calculating the PCIA, a description of the PCIA calculation process, and a list of ideas to improve transparency and predictability. Participants identified several alternatives to the current PCIA: (1) the Portfolio Allocation Method (PAM), which we have reported on before, supported by the IOUs, (2) a lump sum buy out for CCAs and ESPs, and (3) assignment of individual IOU contracts to Load Serving Entities (LSEs). On April 5, Joint IOUs and CCA Parties also filed a Petition for Modification of D.06-07-030 to direct the IOUs to include a common PCIA calculation workpaper template in their ERRA applications. Responses to Petitions for Modification are due May 5th.

On April 25, the IOUs filed a Joint Application with Testimony for approval of SCE's Portfolio Allocation Methodology (PAM). A copy of the application is attached. Responses to PAM Application are due May 30th.

Also, in each of the IOU's 2017 ERRA proceedings, parties disputed the termination of the PCIA and retirement of the negative indifference amount for pre-2009 DA customers following the expiration of DWR contracts. The Commission deferred the issues to a consolidated second phase for 2017, in an effort to treat the associated indifference amounts consistently. We are awaiting consolidation for the 2017 ERRA proceedings.

Status:
LEAN is monitoring this proceeding.

PG&E's Diablo Canyon Power Plant Closure

To Do:
LEAN will continue to monitor this proceeding.
https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:A1608006

Issues:
As we reported last month, on February 27, PG&E announced that after reviewing opening testimony by intervenors on the Diablo Canyon replacement proposal, PG&E withdrew the Diablo Canyon Tranches #2 and #3 replacement proposals, as well as the proposal to implement the "Clean Energy Charge" to recover the costs associated with Tranches #2 and #3. PG&E's withdrawal of its Tranch 2 and Tranch 3 proposal left as major issues in the case: its Tranch 1 proposal that additional energy efficiency investments ($1.3 billion through 2025, and additional costs for employee retention, community impact payments, and plant relicensing costs.

Next Steps:

- Evidentiary Hearings: April 19-29, 2017
- Briefs: May 26, 2017
- Reply Briefs/Record submitted: June 9, 2017

CCA Bond Requirements

To Do:
LEAN will monitor this proceeding.

Issues:
As reported last month, on January 30th, ALJ Anne Simon issued a ruling in A.03-10-003 that addresses issues related to the bond required of CCAs pursuant to Pub. Util. Code Section 394.25 that requires the CCA to post bonds to cover the costs of involuntary re-entry frees of CCA customers to bundled IOU service. On April 5, a workshop was held at the CPUC to address a number of questions raised by the ALJ in her ruling.

Next Steps:

EVENT	DATE
Post-workshop comments filed and served	**April 24, 2017**
Opening Testimony/Proposals served	**July 7, 2017**
Rebuttal Testimony served	**August 4, 2017**
Evidentiary Hearings	**September 12-13, 2017** **Commission Courtroom** **505 Van Ness Avenue** **San Francisco, California**

Closing Briefs	**October 4, 2017**
Reply Briefs	**October 25, 2017**
Any Requests for Final Oral Argument	**Concurrent with Closing Briefs**

Status:
LEAN is monitoring this proceeding.

SDG&E request to establish a Marketing Affiliate (Advice Letter 2822-E)

To Do:
Join with other parties in supporting CalCCA's letter to the Commission asking for full Commission review of the Advice Letter and an Order to Show Cause.

Issue:
On January 27th, SDG&E filed compliance plan Advice Letter 3053 to enable its Independent Marketing Division (IMD). On February 16th, LEAN joined with other parties in protesting this latest advice letter on grounds similar to our earlier objections. On April 6, the Energy Division issued a Disposition Letter approving AL 3035. On April 17, CalCCA sent a letter to the Commission requesting full Commission review of the Disposition Letter, and reiterating an earlier request for an Order to Show Cause regarding lobbying activity by SDG&E/Sempra before the Advice Letter was approved.

Status:
LEAN is monitoring this proceeding.

CPUC Resolution E-4805

To Do:
LEAN will monitor developments of new Tree Mortality Nonbypassable Charge and advise accordingly.

Issues:
There is no change from last month. We are still awaiting a ruling establishing the scope of issues and possibly a hearing scheduled.

Status:
LEAN is monitoring this proceeding.

PG&E General Rate Case (GRC) Phase 2 (A.16-06-013)

PG&E's Phase 2 Application is used to determine where the revenue requirement will be allocated among all customer classes and where new rate designs will be considered.

To Do:
LEAN is monitoring this proceeding. Consider intervening in this case.

Issues:
ORA filed testimony last week. Other parties filed testimony on March 15th. Hearings are scheduled for late May and early June. The earliest that rates are expected to change from this proceeding is in the fourth quarter of 2018.

Status:
LEAN is monitoring this proceeding and will send out a summary of issues in our next report.

Residential Rate Rulemaking (R.12-06-013)

To Do:
LEAN will monitor developments in this proceeding and advise accordingly. Consider joining CCA Parties in asking that TOU Marketing, Education and Outreach (ME&O) costs be allocated to generation rates.

Issues:
On April 5, Draft Resolutions for SCE and SDG&E's Default TOU Pilots were issued. Under the resolutions, 400,000 SCE customers and 120,000 SDG&E customers would be defaulted to TOU rates in March of 2018. A draft resolution on PG&E's pilot is expected soon. On April 14, SCE filed an Application and Testimony to approve its Default TOU rates for residential customers. Starting in the fourth quarter of 2018, a limited number of customers would be put on TOU rates.

Also on April 14, a ruling was issued accelerating consideration of implementing the statewide ME&O for the TOU rollout and inviting comments regarding an ME&O consultant. CCA parties are considering a joint response, emphasizing the need to apply TOU-related ME&O costs through generation rates. Opening comments are due April 24 and Reply Comments May 5.

Integrated Resource Planning (IRP) R.16-02-007):

To Do:
Consider forming a working group to address CCA IRP issues. Review the following link for background on the proceeding and access the staff whitepaper: http://www.cpuc.ca.gov/LTPP

Issues:
The CPUC is expected to issue their proposal on the IRP planning process this week. This will be followed by a workshop, and parties will have an opportunity for formal comments. Then, the Commission will formally adopt a planning process. As of now, a Proposed Decision adopting guidance for the 2017 IRP filings is expected in August of this year.

Status:
LEAN is monitoring this proceeding.

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Adoption of Electric Revenue Requirements and Rates Associated with its 2015 Energy Resource Recovery Account (ERRA) and Generation Non-Bypassable Charges Forecast (U 39-E)	A.14-05-024 (Filed May 30, 2014)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) SUBMISSION OF THE FINAL REPORT OF THE PCIA WORKING GROUP

FADIA R. KHOURY
RUSSELL A. ARCHER

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-2865
Facsimile: (626) 302-3990
E-mail: Russell.Archer@sce.com

Dated: **April 5, 2017**

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SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) SUBMISSION OF THE FINAL REPORT OF THE PCIA WORKING GROUP

Pursuant to the direction[1] in California Public Utilities Commission (Commission) Decision (D.) 16-09-044, Southern California Edison Company (SCE) respectfully submits this Final Report of the PCIA Working Group (Final Report) on behalf of itself and Sonoma Clean Power (SCP).[2] The Final Report is attached hereto as Exhibit A.

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[1] D.16-09-044 directed SCE and SCP to lead a six-month Working Group on issues related to the Power Charge Indifference Adjustment (PCIA). The parties were directed to file either petitions for modifications of existing Commission decisions or petitions for a rulemaking. Several of the Working Group parties have concurrently filed a Petition for Modification of D.06-07-030. This Final Report addresses issues outside of that Petition for Modification, and is provided to document to the Commission an overview of the issues explored by the parties during the Working Group process.

[2] Commission Rule of Practice and Procedure 1.8(d).

Respectfully submitted,

FADIA R. KHOURY
RUSSELL A. ARCHER

/s/ Russell A. Archer
By: Russell A. Archer

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-2865
Facsimile: (626) 302-3990
E-mail: Russell.Archer@sce.com

April 5, 2017

ATTACHMENT

Final Report of the PCIA Working Group

Final Report of the PCIA Working Group

Prepared by

Southern California Edison Company and Sonoma Clean Power Authority

With contributions from:

Pacific Gas and Electric Company, Marin Clean Energy, and

Blaising, Braun McLaughlin & Smith, P.C.

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About this report

This report has been prepared to document the Power Charge Indifference Adjustment (PCIA) Working Group process and to provide an overview of the key information, issues, and ideas that were shared and discussed among participants during the six-month effort. The report also summarizes the outcomes that were achieved toward the group's objective of improving transparency, certainty and data access related to the PCIA calculation.[1] The report's authors have attempted to accurately describe the issues and ideas, and in some cases, practical considerations related to the various ideas that were discussed in the PCIA Working Group meetings. However, this report is not intended to provide a comprehensive assessment of any of the proposals that were presented by participants in the PCIA Working Group.

This report was prepared by Southern California Edison Company (SCE) and the Sonoma Clean Power Authority (SCP), with portions of the report drafted by Blaising Braun McLaughlin and Smith, Marin Clean Energy (MCE), and Pacific Gas and Electric Company (PG&E). Portions of this report have been drafted by individual PCIA Working Group participants and were not edited or modified by other PCIA Working Group participants. Therefore, this report does not necessarily represent a consensus of the PCIA Working Group but instead, in certain sections, reflects the views of one or more PCIA Working Group participants. Conclusions or statements made in this report should not be attributed to the entire PCIA Working Group, nor should it be assumed that all PCIA Working Group participants agree with all of the statements in this report.

[1] D.16-09-044, p.20

Glossary of acronyms

BNI	Binding notice of intent
CAISO	California Independent System Operator
CCA	Community Choice Aggregator
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CRS	Cost Responsibility Surcharges
CTC	Competition Transition Charge
DA	Direct Access
DG	Distributed generation
DOE	Department of Energy
DWR	Department of Water Resources
EE	Energy efficiency
ERRA	Energy Resource Recovery Account
ESP	Energy Service Provider
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
GRC	General Rate Case
IE	Independent Evaluator
IOU	Investor Owned Utility
IRP	Integrated Resource Plan

LCD	Least-cost dispatch
LSE	Load-serving entity
LTPP	Long-Term Procurement Plan
MCE	Marin Clean Energy
MDL	Municipal departing load
MPB	Market Price Benchmark
NBC	Non-bypassable charge
NDA	Non-Disclosure Agreement
NWDL	New Western Area Power Administration Departing Load
ORA	Office of Ratepayer Advocates
PAM	Portfolio Allocation Methodology
PCIA	Power Charge Indifference Adjustment
PFM	Petition for Modification
PG&E	Pacific Gas and Electric Company
POU	Publicly-Owned Utility
PPA	Power purchase agreement
PRG	Procurement Review Group
PWRPA	Power and Water Resources Pooling Authority
QF	Qualifying Facility
RA	Resource adequacy
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standard

SCE	Southern California Edison Company
SCP	Sonoma Clean Power Authority
UOG	Utility-owned generation

Executive summary

Pursuant to Decision (D.) 16-09-044 of the California Public Utilities Commission (CPUC or Commission), the Sonoma Clean Power Authority (SCP) and Southern California Edison Company (SCE) jointly led a six-month working group effort with participation of over 25 stakeholders, including Community Choice Aggregators (CCAs) in California, Investor Owned Utilities (IOUs) and other interested parties to discuss transparency, certainty, and access to data used in the calculation of the Power Charge Indifference Adjustment (PCIA).

The PCIA Working Group held five full-day, in-person meetings between October 2016 and February 2017. In these meetings, the IOUs described the current PCIA calculation, the type of inputs used to calculate the PCIA and available sources of information that the CCA and Energy Service Provider (ESP) parties can use to develop their own PCIA forecasts. While the primary focus of the PCIA Working Group was to identify issues and develop improvement ideas related to transparency of the PCIA calculation and access to information used to calculate the PCIA, the PCIA Working Group also discussed a broader set of related issues such as those relating to accuracy, predictability of the PCIA, and consistency of information provided by the IOUs. In addition, PCIA Working Group members identified and discussed some potential alternatives to the current PCIA framework, although no consensus on any of these alternatives was reached.

As outcomes of the six-month effort, the PCIA Working Group identified and documented a comprehensive list of issues related to the current PCIA; a detailed description of the process steps and input data used in the PCIA calculation; a list of ideas to improve transparency, data access, consistency and predictability related to the PCIA; and a list of sources of publicly available information on input data used in the PCIA calculation. The PCIA Working Group proposed to create a central database where all of the links to the multiple data sources are available in one place and has built a consensus to prepare and submit a Petition for Modification to develop a unified format for PCIA workpapers submitted by the IOUs in their respective annual Energy Resource Recovery Account (ERRA) Forecast proceedings.

Finally, participants in the PCIA Working Group also discussed several alternative concepts to replace the current PCIA framework. These alternatives included ideas such as (1) a "Portfolio Allocation Methodology (PAM)" proposal to allocate a share of the cost and attributes of utility portfolios to the load-serving entities (LSEs) and their customers; (2) a lump-sum buyout option for CCAs or ESPs; (3) the assignment of individual IOU contracts to LSEs. While the PCIA Working Group discussed the feasibility of these ideas, no consensus was reached by the group, and the PCIA Working Group does not propose any modifications to the PCIA calculation methodology.

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Section 1. Background and overview

PCIA Working Group requirements

In D.16-09-044, the Commission directed SCP and SCE to lead a six-month working group effort to facilitate discussion among interested parties on issues of transparency and certainty related to the PCIA and access to data used in the PCIA calculation. Concerns over transparency of the current PCIA framework were raised by a number of parties in the 2016 PCIA Workshop held by the Energy Division on March 8, 2016, but were unable to be resolved because the issues were outside the scope of that workshop. D.16-09-044 directs the PCIA Working Group to develop and present recommendations to the Commission within six months, or by April 5, 2017, as petitions for modification of existing decisions or a petition for a rulemaking proceeding filed in Rulemaking (R.) 02-01-011, R.03-10-003, R.06-02-014, or R.07-05-025.

Scope of the PCIA Working Group discussions

The scope of discussions covered by the PCIA Working Group over the six-month engagement placed substantial emphasis on the issues of transparency and access to data that the Commission highlighted in D.16-09-044, but also included a range of broader issues of interest to the participating parties, such as issues relating to the accuracy of the benchmarks used in the PCIA calculation, the predictability of the PCIA, and the consistency of information provided by the IOUs. Participants considered the issues raised to develop a list of potential modifications to consider in addressing these concerns with the PCIA.

Much effort was spent during initial meetings to inform PCIA Working Group participants on the process, inputs, calculation methodologies and sources of data currently used in the existing PCIA determination. The IOUs also informed the parties of other topics relevant to the PCIA determination, including confidentiality of certain information, methodology for forecasting CCA load, and the IOUs' respective procurement strategies and key limitations and requirements of procurement contracts. The purpose of this information sharing was to build a common understanding of the PCIA and direct the CCAs and other interested participants to publicly available information to aid them in developing their own PCIA forecast.

Throughout the engagement, the PCIA Working Group participants discussed a number of broader concerns about the PCIA - in particular the volatility, duration, and costs included in the PCIA. Based on these broader concerns and the concepts for desired alternatives raised by CCA and Direct Access (DA) parties in the working group meetings, PCIA Working Group participants made an effort to outline and identify important practical considerations related to several cost allocation alternatives to the existing PCIA framework.

Objectives of the PCIA Working Group

Based on the Commission's direction in D.16-09-044, and input from the participants, the PCIA Working Group agreed upon the following objectives for the six-month effort:

- Facilitate constructive discussions of issues related to PCIA transparency, certainty and data access among a broad group of PCIA stakeholders in an open and collaborative forum;
- Share information to build a common understanding of the PCIA;
- Identify and describe common concerns relating to transparency, access to data, accuracy, predictability, and consistency of the PCIA;

- Direct CCAs and ESPs to publicly available information to assist them in developing their own PCIA forecasts;
- Discuss several conceptual ideas for alternative cost allocation methodologies and identify practical considerations;
- Provide the Commission with recommendations to improve PCIA transparency and data access in the form of a Petition for Modification or Petition for Rulemaking within six months; and,
- Complete a final report summarizing the PCIA Working Group process and key information and proposals that have been shared among participants during the six-month process.

PCIA Working Group participants

The co-lead facilitators, SCE and SCP, engaged a broad range of interested parties in the PCIA Working Group meetings, with outreach to other utilities and CCAs, local government entities engaged in CCA feasibility studies, DA representatives, ESPs, the Office of Ratepayer Advocates (ORA), and other interested stakeholders including environmental groups, labor, and research institutions. Facilitators invited participants in the 2016 PCIA Workshop (A.14-05-024 service list) and leveraged networks including the California Community Choice Association. PCIA Working Group meetings were held in both the Bay Area and in Southern California to encourage a high level of stakeholder participation. A total of 32 organizations participated in five meetings over a period of six months. The participating organizations are listed on the following page.

PCIA Working Group Participants	
Co-Lead Facilitators: Southern California Edison (SCE) & Sonoma Clean Power (SCP) IOUs • Pacific Gas and Electric Company • San Diego Gas and Electric Company • Southern California Edison Company CCA parties and representatives • Braun Blaising McLaughlin & Smith • Californians for Energy Choice • City and County of San Francisco • City of Lancaster • Community Choice Partners • EES Consulting • Local Energy Aggregation Network • Marin Clean Energy • Peninsula Clean Energy • Placer County • Silicon Valley Clean Energy • Sonoma Clean Power Authority	Direct Access & ESP parties and representatives • Commerce Energy, Inc. • Constellation Energy • Energy Management Services / Energy Users Forum • MRW & Associates Other participating parties • Californians for Energy Choice • Carbon Free Silicon Valley • Center for Climate Protection • IBEW 1245 • Local Clean Energy Alliance • Office of Ratepayer Advocates • San Francisco Public Utilities Commission • Sierra Club • South San Joaquin Irrigation District • StopWaste • Sustaenable • The Utility Reform Network (TURN) • University of California

Overview of the PCIA Working Group process and meetings

Over the six-month period, the PCIA Working Group facilitators hosted five full-day meetings in Northern and Southern California. These group meetings were held once a month from October 27, 2016 through February 8, 2017. The facilitators' overall approach to meeting the PCIA Working Group's objectives was to focus the initial meetings on information sharing among parties to begin to build a common understanding of the PCIA and identify the key concerns. The focus was shifted in later meetings toward presenting multiple proposals to modify and improve the PCIA and identifying practical considerations. The final month of the process was primarily spent collaborating with the PCIA Working Group participants to clarify outcomes, including the preparation of a Petition for Modification filed jointly by multiple parties.

A brief summary of each Working Group meeting and the topics covered is documented below.

PCIA Working Group meeting 1 – October 27, 2016

The first meeting of the PCIA Working Group was held on October 27, 2016 at the Commission and the opening presentations by PG&E and SCE focused on topics directly related to data access and transparency.

Agenda October 27, 2016

(1) PCIA and ERRA Forecast
(2) PCIA 101
(3) Confidentiality in the PCIA
(4) Review of PCIA Workpapers
(5) PCIA Data Access Discussion
(6) Parties' Perspectives and Discussion
(7) Closing and Next Steps

The opening presentations included a foundational overview of more than ten years of regulatory and legislative history that preceded the current form of the Indifference Rate calculation and highlighted the legislative mandates that require the Commission to ensure customers remain financially indifferent to departing load.   Aside from reviewing the regulatory and legislative history of the customer indifference principle, PG&E's and SCE's presentations also described the annual ERRA Forecast proceeding and the calculation methodology and inputs currently used to calculate the total portfolio Indifference Rate, Competition Transition Charge (CTC), and the PCIA. The presentations also highlighted data used in the Indifference Rate calculation that are confidential, the length of time they are considered confidential, and the differentiation of market participants (e.g. buyers and sellers) and non-market participants (e.g. the CPUC, environmental non-governmental organizations (NGOs)).

There were questions and answers throughout the opening two presentations by PG&E and SCE. While much of the discussion was related to transparency and data access, a fair amount of discussion went beyond that limited scope. More specifically, topics discussed fell into two main categories: (1) PCIA information sharing, and (2) potential modifications related to managing Indifference Rate volatility. A summary of those topical discussions is presented below.

1. *Information sharing*. Participants expressed an interest in more information about a variety of different PCIA topics:

    a. Information about PCIA calculation: PG&E and SCE presented an overview of the "Indifference Calculation" methodology, including a description of the data inputs and sources.
    b. Confidentiality. Further information about confidentiality designations, the process of signing a Non-Disclosure Agreement (NDA) and using a reviewing representative.
    c. Standardizing PCIA data and workpapers. Standardizing the presentation of PCIA information in the IOUs' ERRA Forecast proceeding filings and workpapers.
    d. Contract management process. Additional details on how the IOUs assess new contracts and must abide by the terms and conditions of existing contracts.
    e. Mid-term forecast. PG&E gave a high-level overview of an illustrative five-year forecast of the PCIA.

2. *Potential Modifications:*

    a. Changing inputs to the Market Price Benchmark
    b. True-up of PCIA
    c. Assigning contracts
    d. Contract duration limits
    e. Contract buy-out
    f. Large CCA departure

Overall, the PCIA Working Group discussions were positive, collaborative, and productive. CCA and DA parties raised a number of key concerns about the PCIA, specifically related to data access and transparency, that they would like to see addressed by the PCIA Working Group. The meeting ended with a list of desired analyses, policy proposals, and topics for further discussion. These items formed the basis for developing the agenda for the second meeting.

PCIA Working Group meeting 2 – November 17, 2016

The PCIA Working Group held its second meeting on November 17, 2016 at PG&E's Offices (77 Beale St, San Francisco). The agenda for the PCIA Working Group Meeting 2 is shown below and had two main objectives: (1) continuing information sharing regarding the inputs to the PCIA calculation and topics selected based on follow-up items identified during the first meeting, and (2) hearing directly from the CCA and DA participants about their ideas related to potential modifications to the PCIA framework.

Agenda November 17, 2016

(1) IOU load forecasting methodology
(2) November Update to the Indifference Calculation, and overview of the calculation of final PCIA and CTC rates
(3) IOU Contracts – requirements and limitations
(4) IOU procurement strategy & cost minimization protocols
(5) Consider potential PCIA solutions (lump-sum payment, PCIA sunset, contract assignment, etc.)

Topics that garnered the most discussion included the IOUs' assumptions in forecasting CCA load, the lifecycle of a power purchase agreement (PPA), the utilities' incentives when making procurement decisions, and the feasibility of modifying, terminating, and transferring IOU contracts. The content of each of these presentations are briefly summarized in Section 3 of this report and the presentations are in the attached Appendix.

SCE also made a presentation that illustrated how the total portfolio indifference amounts, by vintage, are translated into rates. SCE and PG&E responded to a number of questions from parties regarding the pros and cons of applying different methods for allocating the total portfolio indifference amount to customer classes.

SCP presented a case study of the buyout between MGM Resorts and Nevada Power Company to encourage thoughts about how an "exit fee" for CCAs might be structured. SCP described the municipal departing load (MDL) bilateral agreements between IOUs and certain municipalities as another potential example to draw from in developing a structure for a buy-out.

Similar to the first PCIA Working Group meeting, this second meeting was positive, collaborative, and productive, although participants' familiarity with the PCIA framework varied. As with the first meeting, participants discussed several potential modifications to the existing PCIA framework such as a buy-out of future liabilities, limiting the duration of on-going liabilities, and a true-up of forecast energy revenues reflected in the Market Price Benchmark (MPB) to the actual energy revenues.

PCIA Working Group meeting 3 – December 14, 2016

The third PCIA Working Group meeting was held on December 14, 2016, at 1537 Webster St. Oakland, CA. The discussion topics for this meeting shifted from general overview and identification of issues to more in-depth discussions about how to improve access to data and increase transparency. One idea in particular that seemed to gain traction was improved consistency in the format of PCIA calculation workpapers presented in each utility's respective ERRA Forecast proceedings to facilitate more consistent and easily digestible content for interveners and Commission staff reviewing the PCIA calculations. The group also discussed a range of perspectives and ideas for modifications or alternatives to the PCIA mechanism. SCP presented an alternative market price benchmark (MPB) framework which assumed that load departure not only results in stranded assets, but avoided procurement costs as well. The agenda for the third PCIA Working Group meeting is shown below:

Agenda December 14, 2016

(1) PCIA historical changes and general drivers
(2) Ideas for improving data access and transparency
    a. Review of PG&E contract-specific data
    b. ERRA Forecast proceeding workpapers: Consistent presentation across IOUs
    c. Existing sources of data
(3) Modifications within the existing PCIA framework – discussion
(4) Alternatives to PCIA: Develop common understanding of potential alternatives to PCIA – deeper evaluation of lump-sum buyout, contract assignment, and potential other alternatives identified by PCIA Working Group participants
(5) Wrap up & next steps

PCIA Working Group meeting 4 – January 23, 2017

The objective of the PCIA Working Group's fourth meeting hosted on January 23, 2017 at SCE's offices (2244 Walnut Grove Ave, Rosemead, CA) was to begin to build a consensus on specific improvements to be included in a Petition for Modification or Petition for Rulemaking delivered at the end of the working group process. This meeting also provided an opportunity for deeper discussion and feedback on the conceptual PCIA alternatives proposed in previous meetings. In preparation for the meeting, the three IOUs worked to develop a description and identify some practical considerations related to three alternative ideas offered by the PCIA Working Group participants to replace the PCIA framework. The three alternatives discussed were: (1) pro rata allocation of attributes and costs; (2) buy-out of PCIA obligation; and (3) assignment of IOU contracts to CCAs/ESPs. In reviewing the practical considerations, the IOUs expressed that a pro rata allocation of attributes and costs was their preferred alternative and planned to develop a more detailed proposal for discussion in the next meeting.

Agenda January 23, 2017

(1) Ideas related to changing the current PCIA benchmark
(2) Alternatives to current PCIA framework and practical considerations
(3) Areas to improve data access and transparency – potential areas to include in a petition for modification
(4) Focus of the Working Group through end of March

PCIA Working Group meeting 5 – February 8, 2017

The final PCIA Working Group meeting was hosted by Marin Clean Energy (MCE) in San Rafael, CA on February 8, 2017. The focus of the final meeting was twofold. The first objective was to begin to draw the PCIA Working Group process to a conclusion by agreeing upon potential consensus items for Petitions to Modify and a timeline and assignments to prepare the petitions. The group made efforts to build a consensus to prepare petitions for a uniform documentation of PCIA information in the IOUs' ERRA Forecast proceeding workpapers and to consider enhancing access to confidential PCIA-related data for Reviewing Representatives of CCAs and ESPs, subject to an NDA. The PCIA Working Group participants also agreed to recommend a common host location (website) for publicly-available PCIA data.

The second objective of the final meeting was to provide further opportunity to discuss the IOUs' Portfolio Allocation Methodology (PAM) proposal in greater detail, which was introduced as the IOUs' preferred PCIA alternative and replacement, and obtain feedback from CCA and DA parties on the proposal. The agenda for the fifth Working Group meeting is shown below:

Agenda February 8, 2017

(1) Welcome, goal setting
(2) Update on consensus items for Petition for Modification
(3) Barriers and opportunities for non-profit LSEs to have enhanced data access
(4) PCIA alternatives
(5) Timeline and process for Petition to Modify, potential Petitions for Rulemaking, and Final Report capturing process and feedback

Section 2. Identification of key issues related to the existing PCIA mechanism

One of the key objectives of the PCIA Working Group was to identify and describe common concerns relating to transparency, access to data, accuracy, predictability, and consistency of the PCIA. While a number of these issues had also been raised previously in the 2016 PCIA Workshop, D.16-09-044 formed the PCIA Working Group for the purpose of providing a forum for stakeholders to further discuss these issues and others in greater detail. During the five PCIA Working Group meetings, the facilitators solicited all parties to raise issues and concerns relating to PCIA transparency, certainty and data access, problems with the existing benchmarks used in the PCIA calculation, and other broader concerns with the PCIA framework. Discussion of these issues helped build the common understanding necessary for various participants to provide ideas for improving the PCIA.

Table 1 lists some of the common issues that were highlighted in the PCIA Working Group discussions. While not a comprehensive list of all issues raised by participants, the key concerns that were discussed in detail in the PCIA Working Group meetings are included. The list includes key issues raised by CCAs, ESPs, IOUs, and other participants.

Table 1
Summary of key issues raised by participants in the PCIA Working Group

Issues related to transparency and data access	• All CCA employees, whether or not they participate in procurement, are currently restricted from being designated as authorized reviewing representatives for the purpose of reviewing confidential IOU workpapers that include certain confidential information used in utilities' PCIA calculations, including contract terms and pricing. CCAs also have difficulty identifying and retaining consultants who are not market participants, are qualified to opine on the utility filings, and can meet IOUs' non-disclosure rules allowing them to review confidential information used to calculate the PCIA. This is a barrier to CCA parties' ability to verify IOU PCIA calculations and access data helpful in forecasting trends.[2] • The need for greater consistency in format of PCIA workpapers among the IOUs present CCAs with difficulty understanding PCIA calculations. • CCA and DA parties argue that there was a lack of transparency and consistency regarding what PCIA information is considered confidential. • CCA and DA parties lack a comprehensive resource for obtaining public information related to IOU resource procurement.
Issues related to existing PCIA benchmark[3]	• The benchmarks used in the PCIA calculation are administratively-set and do not accurately reflect market value of generation resources. The benchmark data sources have not been updated since 2011. • The Market Price Benchmark for renewables, referred to as the "green adder", does not accurately reflect current market price. The "green adder" is not updated regularly and uses Department of Energy (DOE) data based on prices for voluntary renewable programs. Furthermore, some of the DOE data is taken from tariffs that are not currently in use. • The green adder is not based on a publicly available data source, but instead, is based on IOU-specific confidential contract information and is updated annually in late October. • The capacity benchmark used in the PCIA calculation is based upon a California Energy Commission (CEC) study that has not been updated as frequently as was contemplated when it was adopted in 2011. The benchmark does not reflect current market value of Resource Adequacy (RA) capacity.
Broader concerns with the PCIA	• The PCIA is highly volatile and difficult to predict. This presents a substantial challenge for CCAs to forecast long-term PCIA cost trends and manage their customers' total bills. • CCA parties have expressed concern with the long duration of the highly volatile PCIA, which continues for the full duration of contracts in the vintaged portfolio. CCA parties note it is unclear whether contract extensions or other amendments resulting in increased cost are included in the original vintage.

[2] D.16-09-044 acknowledges that this is a key issue raised by CCA and DA participants in the CPUC's 2016 PCIA Workshop. Several PCIA Working Group participants have continued to express this same concern during the PCIA Working Group meetings.

[3] The December 14, 2016 PCIA Working Group Meeting Presentation in Appendix C describes a summary of these concerns related to the existing benchmark raised by Working Group participants.

Section 3. Overview of information shared by IOUs to address transparency & data access related issues, and increase CCAs' capacity to develop their own PCIA forecast

One of the main objectives set by the PCIA Working Group was to share information between the IOUs and CCA and DA parties in order to build a common understanding of the PCIA process, inputs and calculations, and its limitations and issues. The PCIA Working Group facilitators thought that this focus on information sharing was a necessary step in highlighting the level of transparency, as well as understanding the rationale for preserving confidential information to prevent market manipulation. Much of the time during the first two PCIA Working Group meetings was spent sharing information and addressing participants' questions about the PCIA process along with other closely interrelated topics.

During the Energy Division's March 2016 PCIA Workshop, CCA parties had identified a desire for a five-year forecast of the PCIA to address volatility. The IOUs worked for several months to try to develop a methodology to perform such a forecast. While PG&E was considering release of a five-year internal PCIA forecast in November 2016, PG&E ultimately came to the conclusion that the results of its internal forecast would not have the appropriate degree of accuracy to be useful to CCA parties in making budgeting decisions. The IOUs sought to provide information to help direct CCAs and ESPs to relevant non-confidential data that they could use to develop their own PCIA forecasts. PG&E also explained how a forecast can be done given assumptions for uncertain variables like IOU Renewables Portfolio Standard (RPS) Premium, using the FERC Form 1 and PG&E's ERRA Forecast public workpapers (which were circulated to the PCIA Working Group).

The following section includes a number of high-level summaries of topics discussed to inform the PCIA Working Group participants about the PCIA and other relevant data necessary to develop a PCIA forecast. More detail is included in the presentation slides in the Appendix.

Information sharing with parties regarding the existing PCIA development, process, data inputs, calculation methodologies and available data sources

Overview of ERRA Forecast proceeding

SCE began the information sharing process with PCIA Working Group participants with an overview presentation on the annual ERRA Forecast proceeding in the October 2016 kickoff meeting. The presentation covered the purpose and process of the annual ERRA Forecast proceeding, an explanation of how the annual forecast of fuel and purchased power costs is developed, and how that data is used in the Indifference Rate calculation. Discussion focused on how the Cost Responsibility Surcharge for DA, CCA, and other departing load customers is determined in the annual ERRA Forecast proceeding.

In the annual ERRA Forecast proceeding the IOUs forecast energy production and revenue requirements for all resources in their portfolios. This process includes determining the annual Fuel and Purchased Power revenue requirement for bundled service customers, the New System Generation revenue requirement for all IOU customers and setting both the PCIA and CTC for departing load customers. Per Commission requirement, the IOUs complete an initial forecast in the spring between April and June, and provide an updated forecast in November. Once the CPUC issues a decision on the ERRA Forecast application, often in December, new rates become effective on January 1st of the following year.[4]

To forecast the cost of dispatchable resources, the IOUs use proprietary models that simulate the least-cost-dispatch (LCD) of each IOU's respective portfolio of resources. The LCD model is designed to take into account an hourly forecast of market prices (using forecasts of power prices, and fuel and greenhouse gas (GHG) emissions) along with physical and contractual constraints of each generating unit and seeks to dispatch resources where the marginal operating cost is less than the market price of power.[5] The model outputs (variable costs) are added to the fixed/capacity contract costs of the dispatchable resources. For non-

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[4] SCE presentation to the PCIA Working Group, October 27th 2016. See Attachment A
[5] SCE Updated 2017 ERRA Forecast Testimony, A-16-05-001, p. 13

dispatchable resources, contractually expected deliveries are multiplied by the contracted cost of power and added to any fixed/capacity costs. The annual ERRA Forecast proceeding forecasts of generation and costs from the IOU's resource portfolio provide the basis for the Total Portfolio Costs and forecast generation that is used in the Indifference Amount calculation.

SCE's presentation on the ERRA Forecast proceeding can be found in Attachment A.

Overview of the PCIA

Representatives from PG&E and SCE presented an overview of the Indifference Amount calculation – what it is, its purpose, who it applies to, the guiding principles that established the Indifference Amount calculation, and the evolution of the calculation. The presenters also walked through the calculation in detail. In reviewing the calculation, the presenters described the details of the market price benchmark or "MPB" calculation and how the MPB is used in the Indifference Amount calculation. The presentation in Attachment A provides further details.

Relevance of November update to PCIA calculation

As noted previously, the IOUs are required to file an ERRA Forecast application between April and June, and then an update in November. The ERRA November Update incorporates changes to the generation resource portfolio such as changes to expected online dates of resources and addition of new contracts as well as updates to fuel and power price forecasts used in the IOUs' respective LCD models. The IOUs also include an updated RPS adder in the MPB, which is calculated annually by the CPUC's Energy Division in October, to update the Indifference Rate.[6]

[6] The methodology for calculating the MPB is described in D.11-12-018 and Resolution E-4475. The CPUC's Energy Division calculates the RPS adder annually using IOU data filed through informational Advice Letters on October 1 of each year.

SCE shared its November Update to the PCIA calculations by vintage with the PCIA Working Group, which showed a significant change in the 2017 MPB components since SCE's May filing and highlighted the volatility of the benchmark. In this case, a decrease in the RPS adder resulted in a substantial increase in the Indifference Amount for later vintages that include large proportions of renewable resources. For more information, see Attachment B, SCE's presentation to the PCIA Working Group on the November update to the PCIA Rate.

Historical changes in PCIA and general drivers of PCIA

PG&E presented historical changes in the PCIA and the drivers for those changes. PG&E specifically discussed its historical PCIA for the 2012 vintage and showed how it changed over time and how the different components of the MPB affected the PCIA. In addition, PG&E presented how the PCIA changed from 2012 to 2017 (both in cost and percentage), PG&E's total portfolio costs from 2012 to 2017, PG&E's total portfolio generation from 2012 to 2017, and PG&E's MPB from 2012 to 2017. See the presentation in Attachment C for further details.

Confidentiality of data used in the PCIA calculation

Overview of rationale and guiding regulations

The IOUs provided PCIA Working Group participants an overview of the rationale and guiding regulations governing the confidentiality of PCIA data sources. The applicability of confidentiality protections to electric procurement information including cost, generation and net Qualifying Capacity forecasts of procured resources that are used in the PCIA calculation is discussed in D.06-06-066 and D.14-10-033 (for GHG information). D.06-06-066, which is intended to implement California Public Utilities Code Section 454.5(g), establishes a rationale that "confidentiality protections are essential to avoid…electricity market manipulation," and its impacts on customer rates, but that need for confidentiality should be well balanced with broader needs for transparency in the regulated utility industry.[7] As such, the Decision identifies and protects certain general categories of market-sensitive procurement information that could impact a procuring party's market price for electricity if made public (i.e. the D.06-06-66 confidentiality matrix).[8] The protections provided in D.06-06-066 are applicable to IOUs, CCAs, and ESPs and are relied on by all three parties in various filings at the CPUC.

Overview of confidential and publicly available information

The D.06-06-066 confidentiality matrix allows confidential treatment for IOU generation cost forecasts and forecasts of energy output of individual resources.[9] The IOUs' cost and generation forecasts for individual resources use contract terms and proprietary forecasts for natural gas and electricity prices that themselves receive confidential treatment pursuant to the D.06-06-066 confidentiality matrix. However, the IOUs do release aggregated data by vintage including the total costs, generation and net qualifying capacities, in the annual ERRA Forecast work-papers.

SCE presented the following Table 2 to the PCIA Working Group listing the IOU data used in the PCIA calculation, by resource type, that is confidential and the data that is public. The table also indicates the source of each type of data to help indicate whether the data is derived from confidential or proprietary information.

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[7] D.06-06-066 at p. 4.

[8] D.06-06-066 includes a matrix of general categories of IOU and ESP/CCA procurement information that the Commission has determined should receive confidentiality protections. D.06-06-066 places the burden of proof on the party seeking confidential treatment to demonstrate that the information the party claims to be confidential falls under one of the protected categories in the matrix. Also relevant to the PCIA Working Group's conversations around PCIA data access, D.06-06-066 provides that "intervenor groups that are non-market participants shall not be precluded access to any ESP or IOU data as long as they agree to a protective order or confidentiality agreement where there is a need to protect the data (p. 84)"

[9] This type of data is protected under Sections II (Cost Forecast Data), IV (Resource Planning Information, and VII (Bilateral Contract Terms) of the D.06-06-066 confidentiality matrix.

Table 2

List of confidential and non-confidential data used in PCIA calculation

Data	Source of Data	Public / Confidential
UOG		
Capital and O&M Costs	GRC Phase 1	Public
Fuel Costs	ERRA Model	Confidential
Energy	ERRA Model	Confidential
NQC	CAISO	Public
Bilateral Contracts		
Fixed Costs	Contract Terms	Confidential
Variable Costs	ERRA Model	Confidential
Energy	ERRA Model	Confidential
NQC	CAISO	Public
Renewable Contracts		
Capacity Costs	Contract Terms	Confidential
Energy Costs	Contract Terms x IOU probability adjustment	Confidential
Energy	Contract Terms x IOU probability adjustment	Unadjusted deliveries public; adjusted deliveries confidential
NQC	CAISO	Public

Source: Southern California Edison presentation to PCIA Working Group, October 27, 2016

SCE also presented Tables 3 and Table 4 below, using the 2016 ERRA Forecast (May 2015 filing) as an example, to show what data is confidential and must be redacted from the annual ERRA Forecast proceeding workpapers, and how this data is aggregated to provide it publicly. The first chart below lists the confidential inputs the IOU uses to forecast the total portfolio costs eligible for inclusion in the Cost Responsibility Surcharge (CRS), the confidential inputs to forecast total energy production of those resources and the inputs used to calculate the Net Qualifying Capacity. As shown in Table 3, this confidential data is aggregated to provide a forecast of the total portfolio costs by vintage (line 11), forecasted energy production by vintage (line 18) and the Net Qualifying Capacity by vintage (line 20). This aggregated data is deemed non-confidential.

Table 3

		Pre-2002 CTC-Eligible	Pre-2002 CTC-ineligible	2010	2016
1.	**CRS Eligible Portfolio Costs ($000)**				
2.	UOG Capital and O&M (2015 GRC Phase 1)		575,498		
3.	SONGS Settlement Revenue Requirement		250,000		
4.	UOG Fuel				
5.	QF-Eligible CHP				
6.	Renewable QF				
7.	Bilateral/RFO/IU				
8.	Common				
9.	FF&U				
10.	Total	402,874	891,191	285,973	270
11.	**Vintaged Costs**	**402,874**	**1,294,065**	**2,571,299**	**3,570,828**
12.	**GWhs - Excludes CAM-eligible**				
13.	UOG				
14.	QF-Eligible CHP				
15.	Renewable QF				
16.	Bilateral/RFO/IU				
17.	Subtotal				
18.	TOTAL Vintaged GWh @ Generator				
19.	**Vintaged GWhs @ Meter**	**6,081**	**14,334**	**26,276**	**35,745**
20.	**Net Qualifying Capacity - Excludes CAM-eligible**				
21.	UOG	-	1,650	-	-
22.	QF-Eligible CHP	207	-	-	-
23.	Renewable QF	695	-	280	-
24.	Bilateral/RFO/IU	309	-	-	-
25.	Subtotal	1,211	1,650	280	-
26.	TOTAL Vintaged GWh @ Generator	1,211	2,861	3,637	11,141

Source: Southern California Edison presentation to PCIA Working Group, October 27, 2016

Table 4 is an example taken from SCE's 2016 ERRA Forecast (May 2015 filing) showing how aggregated, non-confidential data is presented in the ERRA workpapers and how the MPBs are applied to these inputs to determine the total market value and the Indifference Amount for an IOU's vintaged portfolio.

Table 4

Line	Description		2001		2010		2016
1	Total Portfolio Cost ($000)	$	1,294,065	$	2,571,299	$	3,570,828
2	"Brown" Energy (GWh)		9,840		9,840		10,830
3	Brown MPB ($/MWh)	$	28.18	$	28.18	$	28.18
4	Market Value of "Brown" Energy ($000) - Line 2 x Line 3	$	277,299	$	277,302	$	305,200
5	"Green" Energy (GWh)		4,493		16,436		24,915
6	Green MPB ($/MWh) - 2016 Benchmark	$	76.96	$	76.96	$	76.96
7	Market Value of "Green" Energy ($000) - Line 5 x Line 6	$	345,821	$	1,264,932	$	1,917,504
8	Average Monthly Capacity (MW)		2861		3637		11,141
9	Capacity MPB ($/kW-Year) - 2016 Benchmark	$	58.26	$	58.26	$	58.26
10	Market Value of Capacity ($000)	$	166,682	$	211,892	$	649,075
11	Total Market Value of Portfolio (Line 4 + Line 7 + Line 10)	$	789,802	$	1,754,125	$	2,871,779
12	Line Loss Adjusted Market Value of Portfolio (Line 11 x 1.053)	$	831,662	$	1,847,094	$	3,023,984
13	Indifference Amount (Line 1 - Line 12)	$	462,403	$	724,205	$	546,845

Source: Southern California Edison presentation to PCIA Working Group, October 27, 2016

Information shared with parties regarding IOUs' CCA load forecast methodology

PG&E presented the load forecast methodology it employs to develop year-ahead bundled service customer and CCA load forecasts for use in the annual ERRA Forecast proceedings. PG&E provided two PowerPoint slides, which summarized the data, forecast methodology, and process for engaging with CCA parties on a yearly basis to reconcile forecasts (see Attachment B). The purpose of this presentation was to provide CCAs with additional information about how IOUs modify their bundled service customers' load forecasts in order to account for CCA formations and not procure resources they would not need to serve their bundled service customers.

In summary, a three-step process is used:

Step 1: Determine CCAs in service territory in three categories: (1) current CCAs serving load, (2) CCAs that have a binding notice of intent (BNI), and (3) CCAs that have submitted a resource adequacy (RA) implementation plan to the Commission.

Step 2: Gather and adjust historical data for bundled service, CCA, and Direct Access customers, including assumptions about opt-out rates for load served in CCA territories.
Step 3: Forecast load based on most recent total system load growth rate and shape the load according to recorded sales by class.

PG&E responded to questions from various parties, relating to the following topics:

- PG&E's criteria for forecasting CCA departures
- Sources of recorded data
- Assumptions regarding behind-the-meter distributed generation (DG) and energy efficiency (EE)
- Opt-out rate assumptions

Information shared with parties regarding IOU contract requirements and limitations

SCE and PG&E made presentations during the PCIA Working Group's November 17, 2016 meeting focused on the contract review and approval process, which included an overview of the role of the Long-term Procurement Plan (LTPP) process, the bundled procurement plan (BPP) and the RPS plan in setting overall procurement targets for the utilities as well as the role of the Commission, the Procurement Review Group (PRG), and the Independent Evaluator (IE) in the contract review and approval process, and where and how the various types of contracts are reviewed and ultimately approved. The purpose of these presentations was to share information about IOUs' procurement practices and provide more insight into the requirements and obligations of IOUs under their existing energy procurement contracts. These presentations can be found in Attachment B.

SCE and PG&E each presented an overview of their contract administration processes, including the role confidentiality plays in protecting market sensitive information among other things. SCE and PG&E also reviewed general philosophies around contract management, which includes active monitoring of their respective PPAs to ensure compliance with the terms and conditions of the contracts, and good faith negotiation of contract amendments that are in the best interest of customers. There was also discussion around the role that California's energy policy plays in determining the obligations of the utilities to contract for resources, and the role of the Commission in reviewing the utilities' management of the contracts in the annual ERRA Compliance proceedings to ensure that generation resources are managed consistent with the contractual terms and conditions, and that the resources are prudently managed to minimize overall costs for customers.

CCA representatives asked whether the IOUs had in place any systematic procedure for reviewing above-market generation contracts to evaluate whether there was some basis for terminating the contracts or renegotiating the price terms of the contract. SCE indicated that it had an active contract management system in place that included this type of review. PG&E actively monitors its contracts to make sure Sellers remain in compliance with their contractual obligations throughout the delivery term. If a Seller is not in compliance, or if a dispute arises, this creates the possibility for renegotiation or a termination event. PG&E stated that when disputes or termination events arise during the contract administration process, PG&E considers the value of the contract when determining whether to terminate or renegotiate the contract.

Finally, the presentations included a discussion of practical considerations for an idea previously raised by PCIA Working Group participants to allow utilities to assign procurement contracts to the CCAs and ESPs as an alternative to the PCIA.

SCE identified several contractual limitations and hurdles that would need to be overcome in order for an IOU to assign its contracts to a CCA or ESP. These challenges include:

a) <u>Consent by counterparties may be needed for assignment</u>: PPAs often specify that counterparties have a right to give consent for the utility to assign the contract to a third party, and that the right to consent may not be unreasonably withheld. This limitation may provide a challenge to using contract assignment as a replacement for the PCIA in the event that some counterparties refuse to consent to the assignment, for any reason.

b) Creditworthiness of the CCA, particularly a newly-formed CCA may provide a barrier to contract assignment: Presenters suggested that one potential reason that a counterparty may not consent to assignment of the PPA from the utility to a CCA is that the counterparty may not deem the CCA to be creditworthy. The IOUs expressed concerns that counterparties to existing PPAs would likely focus on the creditworthiness of any assignee of the contract by the IOUs.[10]

c) PPA Rights and Obligations: All rights and obligations under the PPA, including managing payments, operational aspects of the energy resource, and other requirements, would need to be assigned to the third party. The IOU and counterparty would need to be assured that a new CCA is capable of managing all obligations under the contract.

The PCIA Working Group participants also discussed that a reasonable approach would need to be identified by which PPAs are chosen for assignment to a CCA or ESP. Because individual procurement contracts vary by size, term, price and resource type, and load may depart from the IOUs at different times, it is not clear how parties could determine which contracts to assign that would treat all CCAs and ESPs equitably and would maintain bundled service customer indifference.

[10] At the CPUC's February 1, 2017 En Banc hearing on Community Choice Aggregation, a number of CCA parties also discussed challenges that CCAs face in building good credit, which in turn presents a challenge with their capacity to enter into longer-term contracts, particularly during their first formative years.

Section 4. Ideas presented for improving data access and transparency

Participants in the PCIA Working Group presented several potential ideas to consider for improving data access and transparency relating to the PCIA. This section summarizes three primary ideas that were explored by the PCIA Working Group participants and discussed in the meetings.

The ideas were contributed by individual PCIA Working Group participants and were not edited or modified by other PCIA Working Group participants. Therefore, the ideas below do not necessarily represent a consensus of the PCIA Working Group but instead reflect the views of one or more PCIA Working Group participants. Therefore, conclusions or statements made in this section should not be attributed to the entire PCIA Working Group, nor should it be assumed that all PCIA Working Group participants agree with all of the statements in this section.

Uniform template for PCIA workpapers in IOUs' ERRA Forecast proceedings

Summary contributed by PG&E

At the October 27, 2017 meeting, on behalf of all IOUs, PG&E presented a draft of uniform IOU PCIA workpapers and walked parties through the details, requesting feedback throughout. This discussion continued through all PCIA Working Group meetings and has resulted in a Petition for Modification (PFM) of D.06-07-030 supported by PG&E, SCE, SDG&E, SCP, Marin Clean Energy, Peninsula Clean Energy and Silicon Valley Clean Energy. The PFM requests the Commission to add a requirement that IOUs submit their PCIA related workpapers in their annual ERRA Forecast proceedings using the uniform template that was collaboratively developed by the parties listed above. The purpose of requiring a standard template is to make the workpapers a more helpful source of information for intervening parties to review publicly-available data in the PCIA calculations and make comparisons and analyses across IOUs. That PFM is being filed concurrently with this report.

Consolidation of relevant publicly available data in one document with links

Summary contributed by Southern California Edison

Early in the PCIA Working Group process, CCA and DA parties requested access to a comprehensive document containing links to relevant public information related to IOU electric generation resource procurement. A document containing a compiled website list was prepared by PG&E and shared with the Working Group participants in the group's December 14, 2016 meeting. The document that was shared in the Working Group is enclosed as Attachment D.

To address data access concerns, CCA parties in the PCIA Working Group recommended that a CPUC-administered website with links to relevant PCIA data sources would be a valuable resource for CCAs to more easily access publicly available information necessary to develop their own PCIA forecasts. This would also facilitate review by Energy Division staff and ratepayer advocates such as ORA.

Enhancing confidential data access for reviewing representatives of CCAs and ESPs

Summary contributed by Dan Griffiths, Braun Blaising McLaughlin & Smith, P.C.

In D.16-09-044, the Commission recognized DA and CCA parties' "legitimate interest in increased transparency and the ability to forecast long term PCIA trends" and directed the PCIA working group to examine "issues of improved transparency and certainty related to [the] PCIA." To improve transparency and PCIA certainty, the Joint CCAs[11] propose enhanced data access to protected PCIA-related materials through a modification to the existing Commission-approved Model Protective Order and Model Non-Disclosure Agreement.

The proposed modification would permit certain employees of a non-profit load serving entity (LSE) to serve as a "Reviewing Representative" and review protected materials subject to a Non-Disclosure Agreement. The employee must be participating in the affected Commission proceeding and be requesting information related to the employee's review of the PCIA. These modifications would allow for increased PCIA transparency, while preserving the Commission-approved document retention structure that ensures the protection of market sensitive materials. For example, the Reviewing Representatives would be able to access historical executed PCIA-related contracts that are several years old but are presently restricted from review. These historical contracts would be reviewed in a protected manner subject to a Non-Disclosure Agreement.

The Joint CCA's proposed modification is consistent with the language in FERC's Model Protective Order which permits an employee participating in a proceeding to serve as a reviewing representative and access protected materials. The Commission has, in the past, permitted access to protected materials by employees in telecommunications and natural gas contexts. Further, since the proposed modification only pertains to non-profit LSEs, the for-profit rationale given in D.11-07-028 for restricting employee access to protected materials does not apply. Thus, the proposal is a tailored means to improve transparency, while remaining consistent with past Commission practice in ensuring protection of accessed materials.

[11] The idea was supported by a variety of representatives from CCAs and DA providers participating in the PCIA Working Group

Section 5. Ideas presented to address issues related to existing Market Price Benchmark (MPB)

Participants in the PCIA Working Group presented several ideas for addressing issues related to the existing MPB. This section summarizes several ideas that were explored by the Working Group participants and discussed in the meetings.

The ideas were contributed by individual PCIA Working Group participants and were not edited or modified by other PCIA Working Group participants. Therefore, the ideas below do not necessarily represent a consensus of the PCIA Working Group but instead reflect the views of one or more PCIA Working Group participants. Therefore, conclusions or statements made in this section should not be attributed to the entire PCIA Working Group, nor should it be assumed that all PCIA Working Group participants agree with all of the statements in this section.

Applying an alternative method to derive the Market Price Benchmark

Summary contributed by Sonoma Clean Power

Some of the PCIA Working Group participants maintained that the MPB should be constructed to value the change in the utility's portfolio created by the departure of customers to CCAs or DA. In 2003, when the CRS was set to recover the change in value, the utilities and Department of Water Resources (DWR) held a portfolio of mid- and long-term PPAs and resources for nearly 99% of the current load. DA customers were leaving behind these assets with the costs to be recovered from remaining bundled customers. The appropriate benchmark was the value of the excess generation when sold into the marketplace. Because long-term sales were rare (and often individually negotiated rather than through formal procurement), the resulting MPB reflected a series of annual transactions with its various terms that were codified first in the 2006 decision and updated in 2011.

However, with the end of most DWR contracts by 2011, the retirement of certain generation assets, and with the incremental extensions of the RPS from 20% to 33% to 50%, the IOUs moved back into acquiring new generation for growing loads and/or compliance mandates. In this circumstance, a departing load does not necessarily result in increased sales into the bulk power market, but rather may result in a reduction of IOU purchases from the bulk power market. Put simply, departing customers should only be liable for exit fees if their particular departure leaves bundled customers paying for stranded assets.

With regards to RPS compliance, load departures directly reduce the IOUs renewable net short and corresponding financial liabilities. That is, the existing RPS portfolio held by bundled customers represents a higher percentage of RPS generation and reduces the incremental procurement needed to meet RPS targets.

And the MPB should reflect this change in market perspective instead of always assuming that IOUs are net sellers.

Further, since the IOUs are buying long-term PPAs, the MPB should reflect those long-term prices. Bundled ratepayers will avoid having to pay for procurement costs due to departure of load, for which CCAs take on the procurement burden. The market is not entirely represented by short-term sales, as presumed in the existing MPB, but rather by long-term purchases. And the MPB should be set to equal the market price in the year that the IOU avoided having to procure because of the CCA departed load.

Table 5 shows in a simple manner how bundled customers save procurement costs, and how the appropriate MPB is the long-term procurement price for new resources. Two important results should be highlighted.

1) When the avoided procurement cost is above the average bundled portfolio cost, bundled customers see a decrease in their average cost when CCA customers depart. This leads to the PCIA being negative.

2) The average cost of the avoided new generation is equal to the MPB so long as the departing load is less than the incremental amount of avoided new generation.

Table 5

Bundled ratepayer savings			
Sales/Loads	**Initial**	**All Bundled**	**CCA departed**
Bundled Sales	60,000	63,100	54,100
CCA/DA Sales			9,000
Total Sales	60,000	63,100	63,100
Generation Portfolio			
Existing GWH	60,000	54,000	54,000
Retirements/Expirations		6,000	
Additional Total RPS GWH		9,100	
Additional **Bundled RPS GWH**			100
Existing Cost	$4,200	$3,780	$3,780
Existing $/MWH	*$70*	*$70*	*$70*
New RPS Cost		$728	$8
RPS $/MWH = MPB		***$80***	***$80***
Total **Bundled** Cost	**$4,200**	**$4,508**	**$3,788**
Average Cost per MWH	*$70.00*	*$71.44*	*$70.00*
Portfolio Cost Difference			-$720
Avg. Difference/MWH = PCIA			***-$1.44***

As noted above, the current PCIA method assigns a "vintage" to departed load for purposes of assigning portfolio costs to a departed load (based on the year of departure), but does not recognize that market conditions at the time of load departure also determine the economic impact of the departure on bundled customers. Because the IOUs are only able to recover "unavoidable" costs under the PCIA, in principle when a given CCA load departs, the IOU should *immediately* liquidate (sell) a portion of its portfolio corresponding to that no longer needed to serve the departed load. Evidently this would result in a PCIA calculation based upon the difference between IOU portfolio cost and the "market price" *at the time of departure* or shortly thereafter. In contrast, the current PCIA methodology sets a MPB that is calculated in the current year rather than for the market conditions for the year in which the customer departed. SCP proposes an alternative MPB valuation calculation method that is consistent with vintaged portfolio costs computed in the PCIA. Recognizing not just the portfolio costs, but also the market prices, are associated with a given vintage a PCIA calculation is necessary to preserve indifference across customer classes based on when their load departed.

Table 6 illustrates an example of how the MPB would be calculated over a five-year period using this method. It values avoided new procurement at the MPB by vintaged year in which the load departs because that's when the relevant market transactions occurred. The avoided long-term contracts should not be marked to market in subsequent years because bundled customers are not entering the market each year to again purchase that amount of generation—they already avoided those purchases in year 1. That differs from a MPB based on making short-term sales each year. For stranded existing assets, the generation cost amount is the departing load minus the avoided long-term procurement in the vintage year valued at the short-term MPB.

Table 6

	MPB concept example					
1	**Year**	**2016**	**2017**	**2018**	**2019**	**2020**
2	**Sales**					
3	Bundled Sales	60,000	58,100	56,200	54,300	53,100
4	**CCA/DA Sales**	0	2,500	5,000	7,500	10,000
5	Total Sales	60,000	60,600	61,200	61,800	63,100
6	**Resources**					
7	***For All Sales***					
8	Existing Conventional	45,000	44,238	43,452	42,642	42,277
9	Existing RPS	15,000	13,500	12,000	10,500	9,000
10	Total RPS	15,000	16,362	17,748	19,158	20,823
11	% RPS Target	25%	27%	29%	31%	33%
12	New RPS	0	2,862	5,748	8,658	11,823
13	***After CCA/DA Sales***					
14	Existing Bundled RPS	15,000	13,500	12,000	10,500	9,000
15	New Bundled RPS	0	2,187	4,298	6,333	8,523
16	*% RPS Bundled*	*25%*	*27%*	*29%*	*31%*	*33%*
17	*Bundled RPS Difference*	*0*	*-675*	*-1,450*	*-2,325*	*-3,300*
18	Bundled Conventional	45,000	42,413	39,902	37,467	35,577
19	*Bundled Conventional Difference*	*0*	*-1,825*	*-3,550*	*-5,175*	*-6,700*
20	CCA/DA RPS	0	1,400	3,100	5,100	7,500
21	CCA/DA Conventional	0	1,100	1,900	2,400	2,500
22	*% RPS CCA/DA*	*50%*	*56%*	*62%*	*68%*	*75%*
23	**MPB Calculation**					
24	Avoided New Bundled RPS	0	-675	-1,450	-2,325	-3,300
25	*RPS PPA $/MWH*	*$100*	*$95*	*$90*	*$85*	*$80*
26	Change in Bundled Conventional	0	-1,825	-3,550	-5,175	-6,700
27	*"Brown" $/MWH Value*	*$50.00*	*$47.50*	*$45.00*	*$42.50*	*$40.00*
28	***MPB by Vintage***	**2016**	**2017**	**2018**	**2019**	**2020**
29	2017 Vintage		$60	$59	$57	$55
30	2018 Vintage			$58	$56	$55
31	2019 Vintage				$56	$54
32	2020 Vintage					$53

Section 6. Ideas presented to address other concerns related to PCIA

Participants in the PCIA Working Group presented several potential ideas for addressing broader concerns related to the PCIA. This section summarizes several ideas that were explored by the Working Group participants and discussed in the meetings.

The ideas were contributed by individual PCIA Working Group participants and were not edited or modified by other PCIA Working Group participants. Therefore, the ideas below do not necessarily represent a consensus of the PCIA Working Group but instead reflect the views of one or more PCIA Working Group participants. Therefore, conclusions or statements made in this section should not be attributed to the entire PCIA Working Group, nor should it be assumed that all PCIA Working Group participants agree with all of the statements in this section.

Reduce stranded asset cost recovery

Summary contributed by Jeremy Waen, Marin Clean Energy

Presently, stranded cost recovery for resources included within the PCIA is limited to 10-years for both conventional and UOG resources, while stranded cost recovery for renewable resources is granted for the full contract duration. Renewable resource contract lengths can extend up to 25 years in duration. As such renewable procurement significantly contributes to the excessively long cost recovery duration that individual vintages of departing load are responsible for paying.

The Commission allowed for these differences in stranded cost recovery for these differing resource types within the PCIA as part of D.04-12-048. This decision explains that renewable resources should have stranded cost recovery for the contract duration due to the nescience of the renewable electricity market during that time. MCE believes that the renewable electricity market is clearly well established now, more than twelve years after the issuance of that decision. As such the stranded cost recovery for new renewable resources committed to by the IOUs should be limited to 10-years just like conventional and UOG resources.

During the course of these PCIA working group sessions, MCE staff raised arguments to this effect. Consensus among the PCIA Working Group participants was not reached on this matter.

Modify "Top 100 hours" method

Summary contributed by Jeremy Waen, Marin Clean Energy

During the course of these PCIA Working Group sessions, numerous participants questioned the basis by which PCIA rates are established for different customer groups. Among these participants, MCE staff raised questions regarding why the "Top 100 hours" methodology is presently used to assign these costs by class, citing that this methodology results in residential customers paying significantly higher PCIA rates than other customer groups. Other participants within the PCIA Working Group explained that the use of the "Top 100 hours" methodology comes from the IOUs' GRC Phase 2 proceedings, where individual IOU's revenue requirements are allocated across the different customer groups. However, generation costs for bundled customers are not allocated based on the top-100 hour method—it applies only to the PCIA cost allocation. Certain parties believe it would be problematic to assign the PCIA rates to customer classes through a differing methodology than whatever methodology is currently used to assign costs in GRC Phase 2 proceedings because it would change the original allocations in the applicable settlements.

As such, it was recommended to the PCIA Working Group participants that if they wish to change the methodology by which PCIA rates are assigned to customer classes that they raise this request concurrently with a proposal for how the IOUs should change the manner in which costs are assigned to customer classes within each IOU's GRC Phase 2.

Sunset of PCIA

Summary contributed by Marin Clean Energy and Sonoma Clean Power

The framework for today's exit fees can be traced back to the mid 1990's, when the Commission introduced the CTC to protect customers in a new era of competitive markets. The intent was to collect transition costs in a fashion that was competitively neutral, fair to all ratepayer classes, and did not increase rates.[12] At the time, the Commission intended the CTC to eventually terminate once the transition period to a fully competitive market was over. The Commission also recognized that, while utilities should have an opportunity to recover costs which they must incur, there should be balance with the need to ensure that ratepayers were not paying for costs that no longer existed.[13]

Assembly Bill (AB) 1890 (1996) codified the CTC and indicated an expiration date consistent with the Commission's anticipation that the CTC would eventually terminate when the transition period ended in March 2002. The Legislature reiterated that the transition should provide utilities with a fair opportunity to fully recover costs associated with their generation–related assets and obligations and that the transition should be completed as expeditiously as possible.[14] However, during this competitive transition, crisis struck the electricity market in California. Shortages and blackouts triggered an emergency proclamation whereby DWR would purchase electricity on behalf of IOU customers.

AB 1X provided for the reimbursement of costs to DWR, laying the groundwork for non–bypassable charges related to the DWR Bond and the DWR Power Charge. Additionally, to provide DWR with a stable customer base from which to recover the cost of the power it purchased, the statute directed the Commission to set a DA suspension date to prevent customers from leaving bundled service and avoiding costs incurred by DWR. The Commission set the DA suspension date for September 20, 2001, and in allowing DA customers to keep contracts valid prior to that date, determined that a DA surcharge or exit fee would be

[12] D.95-12-063 at p. 110.
[13] D.97-08-056 at p. 24.
[14] CA Pub. Util. Code § 330(t)

appropriate in order to prevent cost–shifting of DWR costs to remaining bundled service customers.[15] The Commission also confirmed that DA customers would continue to be responsible for CTC obligations.[16] Soon thereafter, the recovery of costs from DA customers would be consolidated into the CRS, consisting of DWR costs, a tail CTC, and an indifference charge.[17] The indifference charge, based on the methodology of maintaining bundled service customer indifference, covered the ongoing above–market portion of utility–related generation costs related to the deregulation transition and subsequent crisis for the specified time period. This concept of bundled customer indifference would become the mainstay for imposing exit fees on departing load customers, including customers of CCAs.

AB 117 (2002) enabled CCA formation, and provided for the recovery of costs from CCA customers to prevent cost-shifting to remaining bundled customers. The costs included those related to DWR's procurement during the energy crisis, IOU purchase obligations as of the date of the statute, and additional unavoidable contract costs attributable to the departing CCA customer. The unavoidable contract costs imposed on departing load customers is today known as the PCIA. AB 117 also instructed that these contract costs would only be recoverable if the costs were unavoidable and were attributable to the customer. To date, the Commission has considered all contracts entered into by IOUs as both unavoidable and attributable to the customer.

Pursuant to AB 117, the Commission adopted an initial approach of the CRS for CCAs. The Commission used the same indifference methodology adopted for DA customers.[18] This methodology analyzed the liabilities that would be assumed by bundled utility ratepayers and would be incorporated in the CRS to avoid cost–shifting. The Commission emphasized its policy goals to maintain accuracy, equity and certainty for CCAs and utilities when creating CRS liability. Furthermore, the Commission noted that its complementary objective was to

[15] D.02-03-055 at p. 33.
[16] D.02-04-067 at p. 11.
[17] D.02-11-022 at pp. 3-4.
[18] D.04-12-046 at p. 24.

minimize the CRS and promote good resource planning by the utilities. The Commission also anticipated that the CRS for CCAs would terminate at some point.[19]

The current PCIA is based on a framework first established to facilitate competition while providing temporary protection to IOUs. Over time, the types of applicable costs have grown in magnitude from set, pre-determined categories to include an on-going list of legislative and policy preferences. As such, the current PCIA will persist for decades into the future – for LSEs that have already departed service. In addition, it is unclear whether contract extensions and/or modifications are deemed “unavoidable” stranded assets subject to cost-recovery throughout their lifespans.

As a result of the 2000–2001 energy crisis and subsequent legislation and Commission decisions, the scope of stranded costs have expanded to include certain energy crisis related costs and additional exit fees initially intended to maintain bundled customer indifference during restructuring. However, these policies and protocols have since been extended to allow an extensive range of cost–recovery mechanisms for IOU investments and the amount of stranded costs from non–bundled customers have become highly variable and uncertain.

The extended nature of the liabilities presents a challenge to new CCAs, these small government agencies come into existence with a significant debt burden from day one. By capping the amount of time the PCIA could persist to a set time frame (e.g. 10 years after the departure of a particular vintage), certainty for LSEs and IOUs would be increased, with fewer on-going Commission resources required. Given a ten-year time horizon, IOUs could – if properly motivated – amend and/or terminate above-market contracts with applicable clauses to reduce the on-going liability. Any remaining burdens beyond the ten-year period could be rolled into a single lump-sum amount to be paid by an LSE in year eleven.

[19] D.04-12-046 at p. 27.

Cap on annual PCIA amount

Summary contributed by Sonoma Clean Power

The volatility of PCIA charges, lack of forecast, and confidential treatment of underlying liabilities puts CCA customers at risk. The charges are not only volatile but significant, and represent approximately 1/3 of generation costs in PG&E territory. This creates additional challenges for CCAs seeking to make long-term procurement and budgeting decisions while protecting customers from rate-shock. Disadvantaged customers taking CCA service have been particularly affected by recent volatility and modified allocations of PCIA by customer class.

In the case of the CRS costs to be borne by DA customers, the Commission declined to adopt a levelized annual charge of the CRS. Rather, the charge would fluctuate over time.[20] However, the Commission did adopt a CRS cap to ensure that Direct Access would not become wholly uneconomic.[21] The initial CRS cap was set at 2.7 cents/kWh. As the actual cost of CRS declines over time, any underpayment of CRS would be made up in future years.[22] D.02–12–045 subsequently defined the allocation methodology for the DWR 2003 revenue requirement and continued the 2.7 cents/kWh CRS cap.

Treating PCIA charges in a balancing-account type fashion with a cap as was done for the CRS would eliminate upside volatility in a given year, enabling more efficient planning by CCAs. However, if the PCIA persisted above the cap for an extended period of time, this growing liability would extend the overall time frame of PCIA recovery, as any costs above a pre-determined annual amount would be rolled into future years' liabilities.

[20] D.02-11-022 at p. 36.
[21] D.02-11-022 at p. 115.
[22] D.02-11-022 at p. 120.

Section 7. Ideas presented to replace the existing PCIA framework

Participants in the PCIA Working Group process presented several alternative concepts to replace the current PCIA framework. These alternatives included ideas to allocate a share of the utility portfolio's attributes to the LSEs in exchange for their customers paying for the net costs of that portfolio, offer a lump-sum buyout, or the assignment of IOU contracts to LSEs. To advance the discussion of all three alternatives, the IOUs developed a high-level description of each alternative to ensure common understanding within the PCIA Working Group, and SCP presented several case studies of buy-outs in comparable situations relating to departing load. Some practical considerations were also identified for all three approaches to be examined in assessing whether these alternatives are viable options to replace the current PCIA framework. The IOU presentation of alternatives and practical considerations given in the January 23, 2017 Working Group meeting is included in Attachment E. SCP's presentation of buy-out case studies is included in Attachment B.

The ideas were contributed by individual PCIA Working Group participants and were not edited or modified by other PCIA Working Group participants. Therefore, the ideas below do not necessarily represent a consensus of the PCIA Working Group but instead reflect the views of one or more PCIA Working Group participants. Therefore, conclusions or statements made in this section should not be attributed to the entire PCIA Working Group, nor should it be assumed that all PCIA Working Group participants agree with all of the statements in this section.

Pro rata share of contracts or Portfolio Allocation Methodology (PAM)

Summary contributed by Southern California Edison

The Portfolio Allocation Methodology (PAM) approach is a pro-rata allocation of the IOU's resource portfolio to the LSEs – i.e. through PAM, IOUs would allocate annually to each CCA or ESP and their customers a proportionate share of both the net costs and attributes of the IOU's portfolio, based upon vintage. Existing contracts would remain on the IOU's balance sheet, and the IOU would retain contract and resource management and payment obligations, thereby avoiding a number of the complications of selecting and assigning existing contracts. The IOUs presented PAM conceptually at the January 23, 2017 PCIA Working Group meeting, and discussed it in detail with the PCIA Working Group at the February 8, 2017 meeting. The February 8, 2017 presentation is included in Attachment F.

PAM is intended to replace the "above-market" construct of the PCIA, which is based on administratively-set benchmarks, in order to ensure bundled service customer indifference.[23] Under the PAM approach, net costs are allocated to customers on a vintaged portfolio basis and the portfolio attributes are allocated to the CCAs and ESPs on a pro-rata basis. The net costs are based on the difference between forecast resource costs and offsetting CAISO energy market revenues of the IOU's portfolio of contracts in a given vintage.

Resource Costs – Offsetting Revenues = PAM Amount

The PAM Amount is calculated for each annual vintage resource portfolio, and allocated to departing load customers based on their date of departure (or vintage).

The PAM proposal then incorporates an annual true-up to reflect both actual costs and CAISO energy market revenues. The annual true-up of net costs would be completed in the ERRA Forecast proceeding using a balancing account (similar to the true-up process for bundled service customers' generation rates and delivery service customers' CAM[24] rates). An annual true-up was a key improvement recommended by several parties in the Working Group, which does not exist in the current PCIA framework.

[23] AB 117, D.04-12-048, and SB 350 require that bundled retail customers remain indifferent to load departure.
[24] CAM costs are collected through the New System Generation Charge.

A detailed list of the resources and the costs and revenues that are included in the calculation of net costs under PAM is shown in Attachment F.

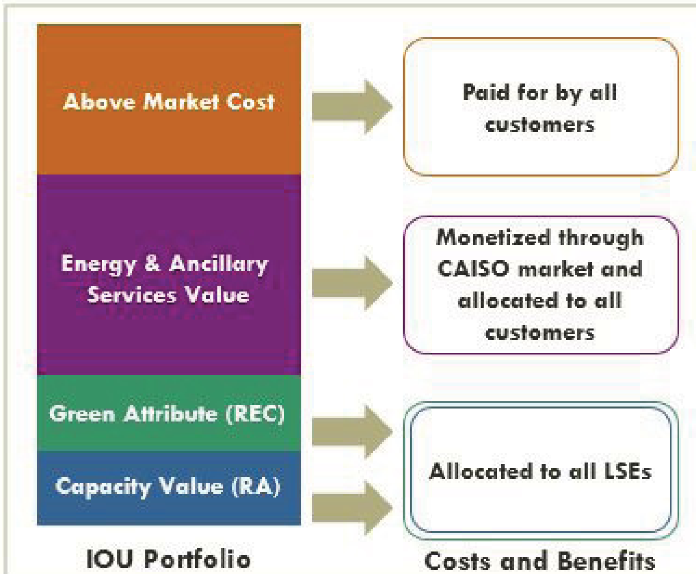
Under PAM, LSEs would receive a pro-rata allocation of resource attributes from the vintaged portfolio, including Resource Adequacy (RA), Renewable Energy Credits (RECs), and any future attributes.

The IOUs propose to allocate resource attributes in the following ways:

- RECs would be allocated to LSEs based on their annual energy load share (not peak load). RECs would be forecasted and allocated each year and trued-up annually to reflect changes to actual load share and actual changes to REC generation.
- System, Local and Flexible RA credit would be allocated to LSEs based on forecast peak load share, consistent with current CAM RA allocations. RA credit would be forecast annually and RA credits would be re-allocated based on updates to monthly peak loads.

Figure 1

Illustration of allocation of resource portfolio costs and attributes under PAM



The IOUs described the rationale behind PAM and its potential value over the current PCIA framework. First, the proposal offers a practical alternative to replace the administratively-set benchmarks in the PCIA calculation. Participants in the PCIA Working Group have identified a number of concerns about the current PCIA benchmarks, which do not accurately reflect the current market and have proven difficult and contentious to update regularly. Second, the IOUs argued that PAM offers a more transparent alternative to the PCIA, as the calculations of the net costs under PAM do not require reliance upon an RPS benchmark that is heavily based on confidential data. Third, through an annual true-up mechanism, which is not present in the PCIA, PAM would reflect actual costs and revenues of the portfolio. Finally, the proposal meets the statutory requirement that bundled service customers remain indifferent to departing load. The IOUs also expressed their opinion that the PAM approach is scalable, and would remain effective and equitable to all customers at any level of load departure in the future.

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PAM BENEFITS
• Eliminates administratively-set benchmarks
• Clear, transparent, and effective
☑ *No longer based on confidential data and market estimates*
• Includes a true-up to reflect actual costs and value
• Meets statutory indifference requirement

Attachment F includes an illustrative example presented to the PCIA Working Group on February 8, 2017.

Lump-sum buyout

Summary contributed by Sonoma Clean Power

A fixed "lump-sum buyout" would entail an LSE paying the net present value of their future net obligations to the IOU through contracts and UOG based on a particular LSE's load and vintage. LSEs have highlighted that the current PCIA is volatile, very difficult to forecast and plan around, is not calculated in a transparent manner, and requires ongoing regulatory intervention. The lump-sum buyout would alleviate the majority of these problems by calculating a one-time fee that the LSE would pay to avoid future charges. This would allow LSEs to budget for programs and procurement, while preventing rate shock. Moreover, LSEs considering formation could accurately assess and potentially finance their customer's future obligations to the incumbent IOU.

Buyouts have occurred in a variety of environments, including:

Publicly-owned utilities in California

Commission Resolutions E-3999 and E-4604 directed the investor-owned utilities to offer bilateral agreements to publicly-owned utilities (POUs) as an alternative to the Municipal Departing Load tariff to departing load customers. Between 2006-2016, PG&E and SCE entered into bilateral agreements with the following POUs: Power and Water Resource Pooling Authority (PWRPA), Merced Irrigation District, Modesto Irrigation District, Turlock Irrigation District, and the Cities of Azusa, Rancho Cucamonga, Moreno Valley, and Victorville. Only 3 of the 8 have publicly available costs: which range from a low of $1.5M under Modesto Irrigation District's agreement to a high of $6.9M under the Turlock Irrigation District's agreement in 2016.

D.09-08-015 concluded that the PG&E/PWRPA agreement fully satisfied the departing load obligations of PWRPA's customers, and that PG&E has no right to seek further payment or pursue any claim against PWRPA's customers for charges under PG&E's departing load tariff. Thus, the Commission has previously approved an agreement that resolves past, present, and future non-bypassable charge (NBC) obligations by payment of amounts that may differ from tariffed charges, that relieves an IOU of its obligations to bill or collect NBCs, and that releases the departing load customers of a POU from liability for the payment of NBCs. (D.10-11-011 at 15-16.)

Corporate customers

MGM Resorts in Nevada left bundled service form Nevada Power Company in 2015 for a lump-sum of $87M. MGM represents 4.86% of the utilities annual sales with 59 accounts at 19 different locations. Another firm, Switch, was denied the ability to exit by the Nevada PUC on the grounds that it violated the principle of indifference by failing to allocate a share of legislated energy policies into the exit calculation. Nevada, unlike California, is not decoupled, thought the utility may recoup lost revenues and administrative costs to run demand side management programs. Like California, Nevada has an aggressive RPS (25% by 2025), additional renewable procurement required by legislation, and requires Commission approval for new generation. In the MGM buyout, the Nevada PUC directed Nevada Power Company

(NPC) to perform production cost simulations to show the total costs with, and without, MGM. The PUC directed NPC to include resources required by legislation procured while MGM was a customer, but to exclude future compliance obligations and "placeholder resources" not seeking specific approval. In addition, the Nevada PUC directed NPC to include O&M savings resulting from reduced operating due to MGM's departure. The net present value of all costs and savings were calculated based on NPC's cost of capital. It was calculated over a 6 year period to allow for two IRP cycles and to allow for QF contracts to drop off. See Nevada PUC docket No. 15-05017 for MGM Application, Testimony, and Staff response.

IOUs have noted that a buy-out option as a bilateral agreement is currently an option. However, to ensure indifference and transparency, an established methodology that can be overseen and audited is critical. This will prevent any perceived or real lack of fairness in bilateral agreements between IOUs and various LSEs. To reduce burden on all customers, any reductions in outstanding liabilities should first be pursued. To that end, contracts with clauses acknowledging Commission jurisdiction and/or assignment and termination provisions should be evaluated by a neutral third party to identify opportunities to reduce on-going above market costs. After the amount and duration of contracts is reduced through contract provisions, the remaining contracts could be liquidated by a third party instructed - or financially incented - to generate the maximum amount of value. Once liabilities have been limited and liquidated, the net present value of any future net costs would be used to calculate an LSE's buy-out price.

Contract assignment

Summary contributed by Sonoma Clean Power

One potential option that was discussed was a mutually aggregable assignment of certain contracts from an IOU to an LSE could be undertaken. IOUs would have to seek counterparty consent for assignment of the contract to a new entity (e.g. from the IOU to a CCA). Given that neither counterparties nor IOUs have an existing incentive to modify their existing contracts, this could pose a challenge without some sort of regulatory modification. In addition, the IOUs and LSEs would have to agree upon which contract(s) and at what terms the assignment would be made. As individual contracts have unique characteristics in terms of generation profile, REC production, RA value, long-term nature, etc. these transactions would be relatively illiquid and subject to negotiation. Contracts could be selected based on how these characteristics match a given LSE's needs. However, IOUs would be challenged to treat all LSEs equally given the irregular timing of departure and varied characteristics in the underlying liabilities. Finally, larger contracts may exceed the appetite of any existing CCAs, reducing the viable pool of contracts to select from. However, granting an individual contract to an LSE would provide for a high level of certainty and control of the underlying asset.

Section 8. Conclusions and next steps

Pursuant to the direction given in D.16-09-044, SCP and SCE facilitated a six-month PCIA Working Group for the purpose of convening interested stakeholders to discuss issues with the PCIA framework related to transparency, certainty and data access. D.16-09-044 directed the Working Group to provide recommendations to the Commission within six months of the decision in the form of petitions for modification or a petition for rulemaking to improve PCIA transparency, certainty and data access.

The PCIA Working Group facilitators held five monthly Working Group meetings to convene a total of 32 organizations as participants, including utilities, CCA parties and representatives from entities considering CCA formation, ESPs and DA customer representatives, ORA, and various other interested stakeholders. The co-lead facilitators of the PCIA Working Group attempted successfully to engage interested parties in constructive discussions of issues related to PCIA transparency, certainty and data access in an open, collaborative forum. The forum allowed for valuable information sharing among the parties in order to build common understanding of the PCIA and the various concerns and issues that have been raised about the PCIA framework. As an example, in response to concerns raised about access to IOU data relevant to the PCIA, much effort was spent with the PCIA Working Group to share non-confidential information with CCA and ESP parties to facilitate their development of their own PCIA forecast. In addition, there was robust discussion around confidentiality of data, including a proposal from several CCA parties which was not resolved to allow employees of publicly owned LSEs, under an NDA, to have enhanced access to confidential PCIA-related data.

Throughout the six-month process, participants discussed a wide range of PCIA issues and potential solutions which included ideas to address broader issues with the PCIA framework and several proposals for a replacement to the PCIA in the future. Discussions about these ideas were constructive and efforts were made to describe and identify practical considerations related to many of these ideas. While the PCIA Working Group participants were unable to come to a consensus on many of these ideas that have been summarized in this report, the facilitators have attempted to provide an accurate description of these ideas and the key questions and practical considerations that were discussed so that they may be assessed further in other forums.

The PCIA Working Group has built a consensus to develop and file a Petition for Modification of D.06-07-030 with a specific proposal to require the IOUs to use a common workpaper template for PCIA calculations in the IOUs' respective ERRA Forecast proceedings. The purpose of requiring a standard template is to make the workpapers a more helpful source of information for intervening parties to review publicly-available data in the PCIA calculations and make comparisons and analyses across IOUs. The PFM is being filed jointly by PG&E, SCE, SDG&E, SCP, Marin Clean Energy, Peninsula Clean Energy and Silicon Valley Clean Energy concurrently with this report.

List of Attachments

Attachment A: Presentations from PCIA Working Group meeting #1, October 27, 2016

Attachment B: Presentations from PCIA Working Group meeting #2, November 17, 2016

Attachment C: Presentations from PCIA Working Group meeting #3, December 14, 2016

Attachment D: Website List with Public Information for Electric Generation Resources

Attachment E: Presentations from PCIA Working Group meeting #4, January 23, 2017

Attachment F: Presentations from PCIA Working Group meeting #5, February 8, 2017

Attachment G: PCIA Working Group Q&A between Community Choice Partners, Southern California Edison and Sonoma Clean Power, December 9, 2016

Attachment A

Presentations from PCIA Working Group Meeting #1, October 27, 2016

PCIA WORKING GROUP

October 27, 2016

SAFETY AND EVACUATION INFORMATION

DIAL-IN INFORMATION

Phone dial-in is available:

626-543-6758

Conference ID: 73660573#

OBJECTIVES

The objective of these working groups are to meet the requirements of Ordering Paragraphs 7 and 8 of Decision 16-09-044:

> *7. Southern California Edison Company and Sonoma Clean Power will co-lead a working group with participation from other interested parties on* ***improving transparency and access to Power Charge Indifference Adjustment related information.***
>
> *8. The working group shall present its recommendation as Petitions to Modify or a Petition for a Rulemaking within six months of this decision [by March 29, 2017]. The Petitions to Modify should be filed in Rulemaking (R.) 02-01-011, R.03-10-003, R.06-02-013, or R.07-05-025.*

Today's objective is to build a common understanding about PCIA, specifically related to transparency and data access.

AGENDA

Time	Duration	Topic	Presenter
10:00 – 10:15	15 min	Introduction	Erin Childs (SCE) and Neal Reardon (SCP)
10:15 – 10:30	15 min	PCIA and ERRA Forecast	Desiree Wong (SCE)
10:30 – 11:15	45 min	PCIA 101	Donna Barry (PG&E)
11:15 – 11:45	30 min	Confidentiality in the PCIA	Russell Archer and Desiree Wong (SCE)
11:45 – 12:15	30 min	Review of PCIA Workpapers	Donna Barry (PG&E)
12:15 – 1:15	60 min	Lunch	
1:15 – 2:15	60 min	PCIA Data Access Discussion	Sienna Rogers (PG&E), Miscellaneous
2:15 – 3:45	90 min	Parties Perspective and Discussion	Neal Reardon (SCP), Miscellaneous
3:45 – 4:00	15 min	Closing and Next Steps	Erin Childs (SCE) and Neal Reardon (SCP)

INTRODUCTIONS BY ORGANIZATION

PCIA AND ERRA FORECAST

Desiree Wong

PCIA OVERVIEW

What is it?

The Power Charge Indifference Adjustment (PCIA) is a rate applied to customers who choose to receive electric commodity service from third-party service providers, such as community choice aggregators (CCAs) or energy service providers (ESPs) serving direct access (DA) load, to ensure those customers continue to pay their proportion of the above-market costs associated with resource commitments made by the utility on their behalf prior to their departure.

What is its purpose?

Protects bundled customers from financial harm due to load departures.

Intended to maintain bundled customer indifference by ensuring that above-market costs associated with prior resource commitments are not shifted from departing load customers to the utility's bundled customers.

Do bundled customers pay their share of the costs captured in the PCIA?

Yes. Bundled customers pay their proportion of above-market costs through the utility's generation rate.

GUIDING PRINCIPLES

<u>The Power Charge Indifference Adjustment should:</u>

- Adhere to the bundled customer indifference principle[1]
- Reflect current market value[2]
- Be transparent, while maintaining confidentiality[3]
- Be durable
- Be administratively feasible[4]

[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*
[2] CPUC Decision 11-12-018
[3] Public Utilities Code Section 454.5(g) and D.06-06-066
[4] CPUC Decision 11-12-018

ERRA FORECAST PROCESS

Purpose of ERRA Forecast is to forecast the energy production and costs from the IOUs' portfolio of generation resources

- Sets the Fuel and Purchased Power revenue requirement for bundled service customers
- Sets the New System Generation (*i.e.*, CAM) revenue requirement for all customers
- Sets the Power Charge Indifference Adjustment (PCIA) and Competition Transition Charge (CTC) for departing load customers

Procedural Schedule:

- Initial forecast is filed between April and June
- Advice letter submitting relevant data for the Green Market Price Benchmark (MPB) is filed on October 1
- Update to the initial forecast is filed in November
- Revenue requirements and rates are effective January 1 (or as soon as practicable upon receiving a final decision)

HOW THE FORECAST IS DEVELOPED

IOUs use proprietary models to forecast the economic least-cost-dispatch of its portfolio of resources using hourly forecasts of market prices and operating characteristics of the resources

Energy forecast for each resource is determined in the following manner:

- For dispatchable resources: Model outputs
- For renewable and must-take (non-dispatchable) resources: Contractually expected deliveries[1/]

Cost forecast for each resource is determined in the following manner:

- For dispatchable resources: Sum of its fixed/capacity contract costs and model outputs
- For non-dispatchable resources: Sum of its fixed/capacity contract costs and contractually expected deliveries multiplied by contract cost

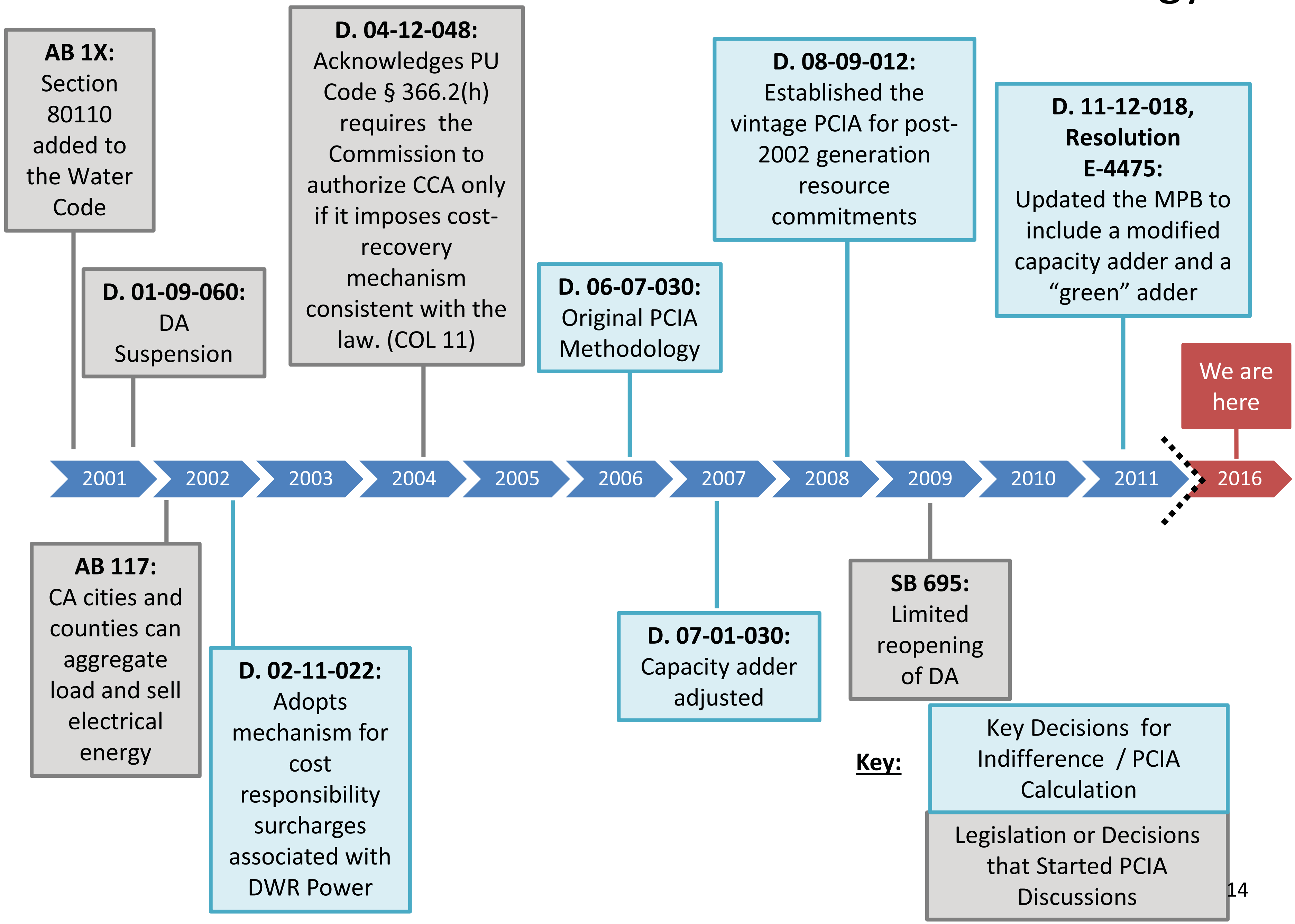
1/ Forecast of contractually expected deliveries may be adjusted based on historical performance and/or project-specific intelligence

PCIA 101

Donna Barry

Historical Overview

CPUC Decisions that Created the PCIA Methodology



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Mechanics of PCIA Calculation

PCIA Calculation Overview

For each vintage year (based on the timing of a customer's departure and the timing of resource commitments), a vintaged indifference amount is calculated using the following simplified formula:

Portfolio Costs[1]	–	Market Value[2]	=	Indifference Amount
A forecast of generation costs associated with the utility's vintage resource portfolio		Value of utility's vintage resource portfolio based on a Market Price Benchmark (MPB) times the forecasted generation in the portfolio		The amount that ensures that no costs are shifted from customers participating in CCA or DA to bundled customers

The costs associated with the PCIA rate is then derived as follows:

Indifference Amount	=	Ongoing CTC	+	Vintaged PCIA
The amount that ensures that no costs are shifted from customers participating in CCA or DA to bundled customers		Ongoing Competition Transition Cost revenue requirement associated with legacy (pre-1996) contracts commitments		The revenue requirement used to generate the vintaged PCIA rate applicable to non-exempt departing customers

[1] See Slides 8-9 for additional details
[2] See slide 10 for additional details

Details on the Portfolio Costs Calculation

Non-Vintaged and Vintaged Resources

Portfolio (Costs & Generation) = Non-Vintaged Resources + Vintaged Resources

Non-Vintaged Resources = DWR Revenue Requirement + Legacy UOG + Legacy Contracts

DWR Revenue Requirement

If applicable, Department of Water Resources (DWR) revenue requirement and expected generation

Legacy UOG

Pre-1996 utility-owned generation (UOG)

(includes hydro and nuclear authorized revenue requirements, associated fuel costs, and expected generation output)

Legacy Contracts

-Qualifying facility (QF) contract costs, fuel costs and expected generation output
-Irrigation district and water agency (IDWA) agreements costs and expected generation output

Vintaged Resources = Post-2002 UOG + Post-2002 Contracts

Post-2002 UOG

Post-2002 utility-owned generation authorized revenue requirement, associated fuel costs, and expected generation output

Post-2002 Contracts

Post-2002 renewable contract costs and expected generation output

Post-2002 conventional generation costs, associated fuel costs and expected generation output

Details on the Portfolio Costs Calculation

Other Inputs that Impact the Total Portfolio Indifference Calculation

Examples of One-Time Pass Through Credits That Benefit Customers Paying the PCIA:

- Utility-Owned Generation (UOG) photovoltaic (PG&E)
- San Onofre Nuclear Generating Station (SONGS) costs (SCE, SDG&E)
- Department of Water Resources return of reserves
- Department of Energy litigation

Details on the Market Price Benchmark Calculation

Market Value = Market Price Benchmark x Generation in Portfolio

$$\left(\boxed{BROWN} * BROWN\,\% + \boxed{GREEN} * RPS\,\% + \boxed{CAP\ ADDER}\right) x\ (LOSSES) =$$

$BROWN$ = energy value

- *Weighted average of a 1-year forward strip of on-peak and off-peak power from Platts*
- *Based on IOU specific peak and off-peak weighting factors*

$GREEN$ = RPS-compliant resources value, net of capacity

- *Energy Division updates based on formula*
- *IOUs provide RPS data to support the calculation*

$CAP\ ADDER$ = resource adequacy (RA) value

- *Utilizes the going forward costs of a combustion turbine as determined by the California Energy Commission (CEC) times net qualifying capacity associated with each vintaged portfolio divided by generation (MWh) in vintaged portfolio.*

Appendix

Details on the Market Price Benchmark Calculation

$\boldsymbol{BROWN}$ ("Energy") Details

$$\{1 - \boldsymbol{RPS\%_{v}})\ x\ \boxed{\boldsymbol{BROWN}} + (\boldsymbol{RPS\%_{v}})\ x\ \boldsymbol{GREEN} + \boldsymbol{CAP\ ADDERv}\}\ x\ (\boldsymbol{LOSSES}) =$$

Revised MPB for year ***n*** and Vintage Total Portfolio ***v***[(1)]

Intended to represent the energy value of the vintage portfolio

- *Value is updated based on a weighted average of a 1-year forward strip of on-peak and off-peak power based on October quotes provided by Platts.*
- *IOU specific peak and off-peak weighting factors are used, based on most recent publicly available load*

[(1)] *Calculation per D.11-12-018*

Details on the Market Price Benchmark Calculation

"*GREEN*" Details

$$\{1 - \boldsymbol{RPS\%_v}) \; x \; \boldsymbol{BROWN} + (\boldsymbol{RPS\%_v}) \; x \; \boxed{\boldsymbol{GREEN}} + \boldsymbol{CAP\ ADDERv}\} \; x \; (\boldsymbol{LOSSES}) =$$

Revised MPB for year ***n*** and Vintage Total Portfolio ***v***[(1)]

Intended to represent the market value, incremental to the energy and capacity value, associated with RPS-compliant resources in the vintage portfolio

- *Energy Division updates the GREEN Adder based on formula approved in D.11-12-018 and implemented via Resolution E-4475.*
- On an annual basis, the IOUs submit data to support the calculation via an October 1 advice letter. The information provided by the IOUs includes:
  - *Projected costs, net qualifying capacity, and volumes (MWh) for all RPS-compliant resources that are used to serve customers during the current year (i.e., most recent 12 months) and those projected to serve customers during the next year, which is weighted at 68%; and*
  - *Most recent 12-month figures derived from US Department of Energy survey of Western US renewable energy premiums in calculating a weighted proxy for the Market Price Benchmark compiled by the National Renewable Energy Laboratory, which is weighted at 32%.*

[(1)] *Calculation per D.11-12-018*

"*Capacity Adder*" Details

$$\{1 - \boldsymbol{RPS\%_v}) \; x \; \boldsymbol{BROWN} + (\boldsymbol{RPS\%_v}) \; x \; \boldsymbol{GREEN} + \boxed{\boldsymbol{CAP\ ADDERv}} \; x \; (\boldsymbol{LOSSES}) =$$

Revised MPB for year ***n*** and Vintage Total Portfolio ***v***[(1)]

Intended to represent the market value of the resource adequacy (RA) that is provided by the portfolio

- Adder is based on the going forward costs (sum of insurance, ad valorem, and fixed operation and maintenance costs) of an existing combustion turbine as determined by the California Energy Commission (CEC)
- = {Sum of Net Qualifying Capacity (NQC) for all resources in the Total Portfolio for Vintage year v * Capacity Value)/forecast of the sum of MWh supplied by Total Portfolio for PCIA Vintage year v}

[(1)] *Calculation per D.11-12-018*

Market Price Benchmark Calculation

$$\{1 - \boldsymbol{RPS\%_v}) \; x \; \boldsymbol{BROWN} + (\boldsymbol{RPS\%_v}) \; x \; \boldsymbol{GREEN} + \boldsymbol{CAP\ ADDERv}\} \; x \; (\boldsymbol{LOSSES}) =$$

Revised MPB for year ***n*** and Vintage Total Portfolio ***v***[(1)]

MPB Component	Description	Reference Decision	Reference Slides
n	The year covered by the calculation, e.g., n=2012 for MPB for 2012		n/a
v	PCIA vintage year		n/a
$\boldsymbol{RPS\%}$	The fraction of RPS-compliant electric energy in the URG (Utility Resource Generation) Total Portfolio for PCIA Vintage year v in year n	D.11-12-018	n/a
$\boldsymbol{BROWN}$ ("$\boldsymbol{Energy}$")	Weighted average of peak and off-peak forward prices for year n, weighting based on, for each IOU, the IOU bundled load profile data for the most recent year that is publically available. Peak and off-peak forward prices based on published data for NP15/SP15.	D.06-07-030	7
$\boldsymbol{GREEN}$ ("$\boldsymbol{Green\ Adder}$")	0.68 x URGgreen + 0.32 x (BROWN + DOEadder)	D.11-12-018	8-9
$\boldsymbol{CAP\ ADDER}$ ("$\boldsymbol{Capacity\ Adder}$")	{Sum of NQC for all resources in the URG Total Portfolio for PCIA Vintage year *v* * CAP VALUE)/forecast of the sum of MWh supplied by URG Total Portfolio for PCIA Vintage year *v*}	D.11-12-018	10
$\boldsymbol{LOSSES}$	Line loss factors: PG&E 1.06, SCE 1.053, SDG&E 1.043	D.07-01-030	n/a

[(1)] *Calculation per D.11-12-018*

CONFIDENTIALITY IN THE PCIA

Russell Archer and Desiree Wong

CONFIDENTIALITY BACKGROUND

Purpose of confidentiality rules: Protect confidential procurement information for the benefit of IOUs' customers; uphold integrity of energy markets; adhere to contractual confidentiality obligations.

D.06-06-066 (as modified by D.08-04-023) and D.14-10-033.

CONFIDENTIALITY IN THE PCIA

Forecast of costs and generation for individual resources are protected under Sections II (Cost Forecast Data), IV (Resource Planning Information), and VII (Bilateral Contract Terms) of the D.06-06-066 confidentiality matrix

- Forecasts are based on confidential contract terms and proprietary forecasts of natural gas and power prices

Resources are aggregated by vintage; total costs, generation, and net qualifying capacities, by vintage, are included in their entirety in the IOUs' ERRA Forecast work-papers

Data	Source of Data	Public/ Confidential
UOG		
Capital and O&M Costs	GRC Phase 1	Public
Fuel Costs	ERRA Model	Confidential
Energy	ERRA Model	Confidential
NQC	CAISO	Public
Bilateral Contracts		
Fixed Costs	Contract Terms	Confidential
Variable Costs	ERRA Model	Confidential
Energy	ERRA Model	Confidential
NQC	CAISO	Public
Renewable Contracts		
Capacity Costs	Contract Terms	Confidential
Energy Costs	Contract Terms x IOU probability adjustment	Confidential
Energy	Contract Terms x IOU probability adjustment	Unadjusted deliveries public; adjusted deliveries confidential
NQC	CAISO	Public

CONFIDENTIAL DATA

		Pre-2002 CTC-Eligible	Pre-2002 CTC-ineligible	2010	2016
1.	**CRS Eligible Portfolio Costs ($000)**				
2.	UOG Capital and O&M (2015 GRC Phase 1)		575,498		
3.	SONGS Settlement Revenue Requirement		250,000		
4.	UOG Fuel				
5.	QF-Eligible CHP				
6.	Renewable QF				
7.	Bilateral/RFO/IU				
8.	Common				
9.	FF&U				
10.	Total	402,874	891,191	285,973	270
11.	**Vintaged Costs**	**402,874**	**1,294,065**	**2,571,299**	**3,570,828**
12.	**GWhs - Excludes CAM-eligible**				
13.	UOG				
14.	QF-Eligible CHP				
15.	Renewable QF				
16.	Bilateral/RFO/IU				
17.	Subtotal				
18.	TOTAL Vintaged GWh @ Generator				
19.	**Vintaged GWhs @ Meter**	**6,081**	**14,334**	**26,276**	**35,745**
20.	**Net Qualifying Capacity - Excludes CAM-eligible**				
21.	UOG	-	1,650	-	-
22.	QF-Eligible CHP	207	-	-	-
23.	Renewable QF	695	-	280	-
24.	Bilateral/RFO/IU	309	-	-	-
25.	Subtotal	1,211	1,650	280	-
26.	TOTAL Vintaged GWh @ Generator	1,211	2,861	3,637	11,141

NON-CONFIDENTIAL DATA

Line	Description		2001		2010		2016
1	Total Portfolio Cost ($000)	$	1,294,065	$	2,571,299	$	3,570,828
2	"Brown" Energy (GWh)		9,840		9,840		10,830
3	Brown MPB ($/MWh)	$	28.18	$	28.18	$	28.18
4	Market Value of "Brown" Energy ($000) - Line 2 x Line 3	$	277,299	$	277,302	$	305,200
5	"Green" Energy (GWh)		4,493		16,436		24,915
6	Green MPB ($/MWh) - 2016 Benchmark	$	76.96	$	76.96	$	76.96
7	Market Value of "Green" Energy ($000) - Line 5 x Line 6	$	345,821	$	1,264,932	$	1,917,504
8	Average Monthly Capacity (MW)		2861		3637		11,141
9	Capacity MPB ($/kW-Year) - 2016 Benchmark	$	58.26	$	58.26	$	58.26
10	Market Value of Capacity ($000)	$	166,682	$	211,892	$	649,075
11	Total Market Value of Portfolio (Line 4 + Line 7 + Line 10)	$	789,802	$	1,754,125	$	2,871,779
12	Line Loss Adjusted Market Value of Portfolio (Line 11 x 1.053)	$	831,662	$	1,847,094	$	3,023,984
13	Indifference Amount (Line 1 - Line 12)	$	462,403	$	724,205	$	546,845

PCIA WORKPAPERS

Donna Barry

PCIA MID-TERM FORECAST

Andrea Clatterbuck and
Sienna Rogers

Attachment B

Presentations from PCIA Working Group Meeting #2, November 17, 2016

PG&E'S COMMUNITY CHOICE AGGREGATION (CCA) LOAD FORECAST METHODOLOGY

Sam Wray
Vijay Bhaskaran, PG&E

PG&E'S YEAR-AHEAD CCA LOAD FORECAST

Step 1: Determine CCAs in service territory

- Three criteria for determine CCAs:
  (1) CCA is currently serving load
  (2) CCA has submitted a Binding Notice of Intent to serve load
  (3) CCA has submitted a Resource Adequacy plan

Step 2: Gather and adjust historical data

- 12 months recorded sales by customer class for existing CCAs or new CCA roll-outs in targeted cities/counties
- Remove Direct Access (DA) customer load
- Apply Opt-Out rate assumption

Step 3: Forecast

- Grow most recent 12 months by total system load growth rate
- Shape according to recorded sales by customer class in each new CCA community

CCA LOAD FORECAST IN REGULATORY PROCEEDINGS

Year-Ahead CCA Forecast

- PG&E has proposed a process for collaboratively working with CCAs to develop year-ahead load forecasts
- Year-ahead forecast submitted in ERRA Forecast proceeding in June and updated in November

Long-Term CCA Forecast (ERRA + 10-year long-term forecast)

- Will be addressed in Integrated Resource Planning Proceeding
- Annual Renewable Portfolio Standard (RPS) Plan filing also includes a load forecast that is adjusted for CCAs

NOVEMBER UPDATE AND PCIA RATE CALCULATION

Desiree Wong, SCE

PURPOSE OF NOVEMBER UPDATE

Refresh generation resource portfolio

- Update to project expected online dates, success factors, expected deliveries (for renewable and must-take resources), etc. based on latest information
- Removal of contracts that are no longer expected to deliver in the next year
- Addition of newly executed contracts
- Update to resources' Net Qualifying Capacity based on CAISO report

Update natural gas, GHG, and power price forecasts used in the least-cost-dispatch model

- Update to the fuel and variable O&M cost forecast for dispatchable resources
- Update to the expected energy forecast for dispatchable resources

Update balancing account balances (no impact to PCIA)

Update PCIA benchmarks

MAY FORECAST INDIFFERENCE AMOUNT CALCULATION

Line	Description		2001		2010		2016
1	Total Portfolio Cost ($000)	$	1,294,065	$	2,571,299	$	3,570,828
2	"Brown" Energy (GWh)		9,840		9,840		10,830
3	Brown MPB ($/MWh)	$	28.18	$	28.18	$	28.18
4	Market Value of "Brown" Energy ($000) - Line 2 x Line 3	$	277,299	$	277,302	$	305,200
5	"Green" Energy (GWh)		4,493		16,436		24,915
6	Green MPB ($/MWh) - 2016 Benchmark	$	76.96	$	76.96	$	76.96
7	Market Value of "Green" Energy ($000) - Line 5 x Line 6	$	345,821	$	1,264,932	$	1,917,504
8	Average Monthly Capacity (MW)		2,861		3,637		11,141
9	Capacity MPB ($/kW-Year) - 2016 Benchmark	$	58.26	$	58.26	$	58.26
10	Market Value of Capacity ($000)	$	166,682	$	211,892	$	649,075
11	Total Market Value of Portfolio (Line 4 + Line 7 + Line 10)	$	789,802	$	1,754,125	$	2,871,779
12	Line Loss Adjusted Market Value of Portfolio (Line 11 x 1.053)	$	831,662	$	1,847,094	$	3,023,984
13	Indifference Amount (Line 1 - Line 12)	$	462,403	$	724,205	$	546,845

NOVEMBER UPDATE INDIFFERENCE AMOUNT CALCULATION

Line	Description		2001		2010		2016
1	Total Portfolio Cost ($000)	$	1,299,207	$	2,560,806	$	3,584,727
2	"Brown" Energy (GWh)		10,202		10,202		11,293
3	Brown MPB ($/MWh)	$	33.73	$	33.73	$	33.73
4	Market Value of "Brown" Energy ($000) - Line 2 x Line 3	$	344,138	$	344,140	$	380,918
5	"Green" Energy (GWh)		4,304		16,194		25,234
6	Green MPB ($/MWh) - 2016 Benchmark	$	66.38	$	66.38	$	66.38
7	Market Value of "Green" Energy ($000) - Line 5 x Line 6	$	285,733	$	1,075,005	$	1,675,123
8	Average Monthly Capacity (MW)		2,695		3,417		10,852
9	Capacity MPB ($/kW-Year) - 2016 Benchmark	$	58.26	$	58.26	$	58.26
10	Market Value of Capacity ($000)	$	157,030	$	199,081	$	632,226
11	Total Market Value of Portfolio (Line 4 + Line 7 + Line 10)	$	786,901	$	1,618,227	$	2,688,266
12	Line Loss Adjusted Market Value of Portfolio (Line 11 x 1.053)	$	828,607	$	1,703,993	$	2,830,744
13	Indifference Amount (Line 1 - Line 12)	$	470,600	$	856,813	$	753,983

INDIFFERENCE AMOUNT → RATES

Indifference Amounts (Line 13) represent the total above-market cost of the vintaged portfolio (total to be collected if all customers depart bundled service)

Indifference Amounts are allocated to rate groups based on a "Top 100 Hours Allocation"

- Rate group contributions during the top 100 hours of IOU system demand
- Similar to generation allocators determined in IOU GRC Phase 2 proceedings

Rate group-level Indifference Amounts ÷ rate group-level system sales (kWh) = Indifference Rate

NOVEMBER UPDATE – 2016 VINTAGE INDIFFERENCE RATE EXAMPLE

Total Indifference Amount: $753,983

Rate Group[1]	Top 100 Hour Allocation	Rate Group-Level Indifference Amount	Rate Group-Level System Sales	Indifference Rate
Domestic	45.3%	$ 341,554	29,031	$ 0.01177
GS-1 (Small Commercial)	6.2%	$ 46,747	4,750	$ 0.00984
GS-2 (Med Commercial)	18.0%	$ 135,717	13,274	$ 0.01022
GS-3 (Large Commercial)	9.0%	$ 67,858	6,255	$ 0.01085
TOU-8-Sec (>500 kW; <2kV)	7.8%	$ 58,811	6,109	$ 0.00963
TOU-8-Pri (>500 kW; 2-50kV)	4.5%	$ 33,929	3,789	$ 0.00895
TOU-8-Sub (>500 kW; >50kV)	4.3%	$ 32,421	4,102	$ 0.00790
TOU-PA-2 (Small and Med Ag&Pump)	1.9%	$ 14,326	1,692	$ 0.00847
TOU-PA-3 (Large Ag&Pump)	1.0%	$ 7,540	1,149	$ 0.00656

1/ In addition to the rate groups listed here, SCE has three standby rate groups, one traffic control rate group, and one street-light rate group with Top 100 Hour allocations <1%

CONTRACT REQUIREMENTS AND LIMITATIONS

Lizette Amaro
William Cano,

AGENDA

1. Confidentiality
2. Active Monitoring
3. Key Pro Forma Provisions
4. Contract Assignments

CONFIDENTIALITY

Commission Decision 06-06-066 (as modified by D.08-04-023) and D.14-10-033 established the confidentiality rules for Power Purchase Agreements (PPAs).

Purpose of confidentiality rules: Protect confidential procurement information for the benefit of IOUs' customers; uphold integrity of energy markets; adhere to contractual confidentiality obligations

Basic PPA information is public (project size, location, etc.)

- Forecast of costs and generation for individual resources are protected under Sections II (Cost Forecast Data), IV (Resource Planning Information), and VII (Bilateral Contract Terms) of the D.06-06-066 confidentiality matrix

- Resources are aggregated by vintage; total costs, generation, and net qualifying capacities, by vintage, are included in their entirety in the IOUs' ERRA Forecast work-papers

SCE'S CONTRACT MANAGEMENT PHILOSOPHY

SCE's Energy Contract Management group actively monitors SCE's portfolio to ensure that it acts reasonably and in good faith on behalf of its customers.

- Manage PPAs and negotiate amendments in good faith — PPAs tie SCE and developers together for the long term
- Support California policy goals — SCE partners with developers to bring <u>viable</u> projects online to meet state policy goals
- Track compliance with PPA terms and termination rights
- Maintain value for SCE's customers — Do not enter into amendments that make non-viable projects viable
  - Because of falling PPA prices, many developers seek contract amendments to make non-viable projects viable or to increase higher-than-current-market energy deliveries to SCE
- Seek commensurate customer benefit — Amendments that meaningfully increase costs or risks to customers are typically rejected unless offsetting benefits are offered

*See back up slide (Pg. 7)

KEY PRO FORMA PROVISIONS

Specific terms and language vary by PPA, but the following types of PPA provisions help maintain the value of the PPA for SCE's customers:

- Performance obligations — SCE closely monitors its contracts to ensure the projects are meeting their minimum performance obligations. Requirements reflect inherent variability of the resource
- Excess Delivery Caps — Many of SCE's more recent contracts provide for limits on how much energy can be sold to SCE under the contract
- Covenants — PPA counterparties are subject to many specific obligations that are intended to limit risk to SCE's customers and to facilitate effective administration of the PPA
- Events of Default – If SCE's counterparties don't meet their obligations as set forth in the contract, SCE may have a right to terminate the PPA.
- Termination Rights — There are several reasons why a contract may be terminated early, including inability to obtain CPUC approval or project permits in a timely manner
- Consent rights — SCE has rights and obligations regarding financing and transfer of the project under a PPA

CONTRACT ASSIGNMENTS

Assignment of a PPA from SCE to a third parties would need to overcome several hurdles to be successful.

- Language varies by PPA, but it is common for counterparties have a right to consent to the assignment of the PPA from SCE to another party, which right may not be unreasonably withheld in many cases
- Counterparties are likely to focus on creditworthiness of any potential third party assignee
  - The third party assignee will need to take on the same rights/obligations as SCE, including managing the operational aspects of the resource and processing payments
  - Logistics of transfer from SCE during the term of a PPA have not been addressed before

BACKUP

REGULATORY BASIS FOR SCE'S CONTRACT MANAGEMENT PHILOSOPHY

D. 88-10-032: Summary Rulemaking to establish guidelines for the administration of Power Purchase Contracts

D. 88-10-032 gives the IOUs the discretion to choose to enter into an amendment with any counterparty. In the event an amendment is elected, the IOU should negotiate in good faith. The decision also provides that an IOU is to seek concessions in response to requests for contract modifications which are commensurate with the change being sought. The details of D.88-10-032 provide further guidance to the IOUs to restrict modifications to PPAs with viable projects, and reject modifications that would result in creating an essentially new project.

D. 90-09-088: In part: Review of the Reasonableness Operations and Payments

"Utilities are expected to engage in those practices, methods, and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. The prudence standard is intended to include a range of acceptable practices, methods, or acts."

Sonoma Clean Power

Local. Renewable. Ours.

Buyout Case Study
MGM Resorts and Nevada Power Company

Neal Reardon, Regulatory Affairs Manager
PCIA Vintaging Workgroup Presentation
November 17, 2016

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MGM Resorts International

- 59 accounts at 19 different locations
- 174 MW coincident peak
- 4.86% of Nevada Power Company’s annual sales
- Remains T&D customer
- Nevada PUC approves exit fee of $86.9M in Dec. 2015
    - (Switch application denied in 14-11007 as Nevada PUC found it violated principle of indifference by failing to allocate share of legislated energy policies)

Nevada Power Company

Investor Owned Utility

- RPS Standard (includes EE) established post restructuring that ratchets up over time:
  - 20% in 2015-19
  - 22% in 2020-2024
  - 25% in 2025 and onwards
- Portfolio energy credits (PECs) can be used to meet RPS
- Additional renewable procurement required in legislation
- Offer demand side management programs
- Require Commission approval for new generation

- Not Decoupled: But can recoup lost revenues and administrative costs from DSM programs

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MGM Buyout Process

- Nevada PUC directs Nevada Power Company to perform ten year production cost simulations to determine impact of MGM's departure on remaining bundled customers
  - Two methodologies used: Lump sum & Non-bypassable, difference is roughly MGM's load based share of costs to comply with legislated energy policies
  - Modeling evaluates IRP base case with and without MGM, based on actual billing for one year
  - PUC provides inputs and criteria for NPC to use: includes resources mandated by legislature procured while MGM was customer, excludes future compliance obligations and "placeholder resources" not seeking specific approval
  - Calculated over 6-year period to encapsulate two IRP cycles and allow for QF contracts to drop off

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MGM Buyout Considerations

- Nevada PUC recommends following cost components:
  - Base tariff general rate (BTGR): revenue burden on remaining customers due to MGM no longer paying for gen. assets
    - BTGR costs associated with departure borne by shareholders until next GRC
  - Out-of-the-money RPS costs: substitute average monthly costs for contractual prices for each RPS contract, subtract that from actual costs of same RPS contract
    - RPS does not include other legislation (e.g. SB 123), those costs allocated via non-bypassable charges
    - Staff recommends true-up mechanism

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MGM Buyout Findings

- Nevada PUC makes recommendations to modify results:
  - O&M savings: NPC generation units operate less, and incur lower variable O&M costs, results in credit of $8.7M
  - Demand-side Management recapture: Incentives provided by NPC to MGM over past 5 years and associated implementation costs returned to NPC, results in cost of $3.2M
  - Energy Efficiency: program implementation costs for 6 month period in 2016, results in costs of $1.3M
  - NPV of 6 year impact fee based on utility cost of capital

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Additional Resources

- Relevant Nevada PUC Dockets:
  - Switch Exit Application (denied) Nos. 14-11007 & 15-06015
  - MGM Application, Testimony, Staff Response No.15-05017

Access to Data Needs to be Improved

SCP suggests an annually-produced ten-year schedule of data showing PCIA for each vintage year:

1. Longer-term data is necessary for CCAs to forecast PCIA and avoid rate shock; CCA rates are set partly in response to utility rates to stabilize.

2. Reproducing PCIA calculation is technically complex & requires onerous NDA, could this be independently reviewed.

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Transparency Needs to be Improved

Current confidentiality rules limit ability of CCAs to check calculation of PCIA

1. Change strict NDA that CPUC approved to allow regulatory/legal staff to view confidential information after agreeing to creation of “wall” between procurement and regulatory/legal staff.

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Need Deeper Policy Review of PCIA

Example questions:

- Why does PCIA method compare long-term contracts against short-term price benchmark?
- How long should PCIA last?
- Does current PCIA methodology leave value with bundled customers that should be monetized and credited?
- Is it possible to compute a PCIA "buy out" price with repayment over time to allow CCAs to have certainty about PCIA obligation?
- Possible to develop process for assignment of contracts?

Attachment C

Presentations from PCIA Working Group Meeting #3, December 14, 2016

PCIA WORKING GROUP MEETING

December 14, 2016

SAFETY AND EVACUATION

AGENDA

10:00 – 10:45	#1	PCIA historical changes and general drivers
10:45 – 11:45	#2	Ideas for improving data access and transparency • Review of PG&E contract-specific data • ERRA Forecast workpapers: Consistent presentation across IOUs and inclusion of contract-specific data • Existing sources of data
11:45-1:15pm		*Lunch break*
1:15-2:30 pm	#3	Modifications within the Existing PCIA Framework – Discussion
2:30-3:30 pm	#4	Alternatives to PCIA: Develop common understanding of potential alternatives to PCIA – Deeper evaluation of lump-sum buyout, contract assignment, and potential other alternatives identified by Working Group participants
3:30-3:45 pm		Wrap up & next steps

DIAL-IN INFORMATION

Phone dial-in information:

<u>Morning : 10:00 – 11:45</u>

Call-in: 626-543-6758

Conference ID: 10235362

<u>Morning : 10:00 – 11:45</u>

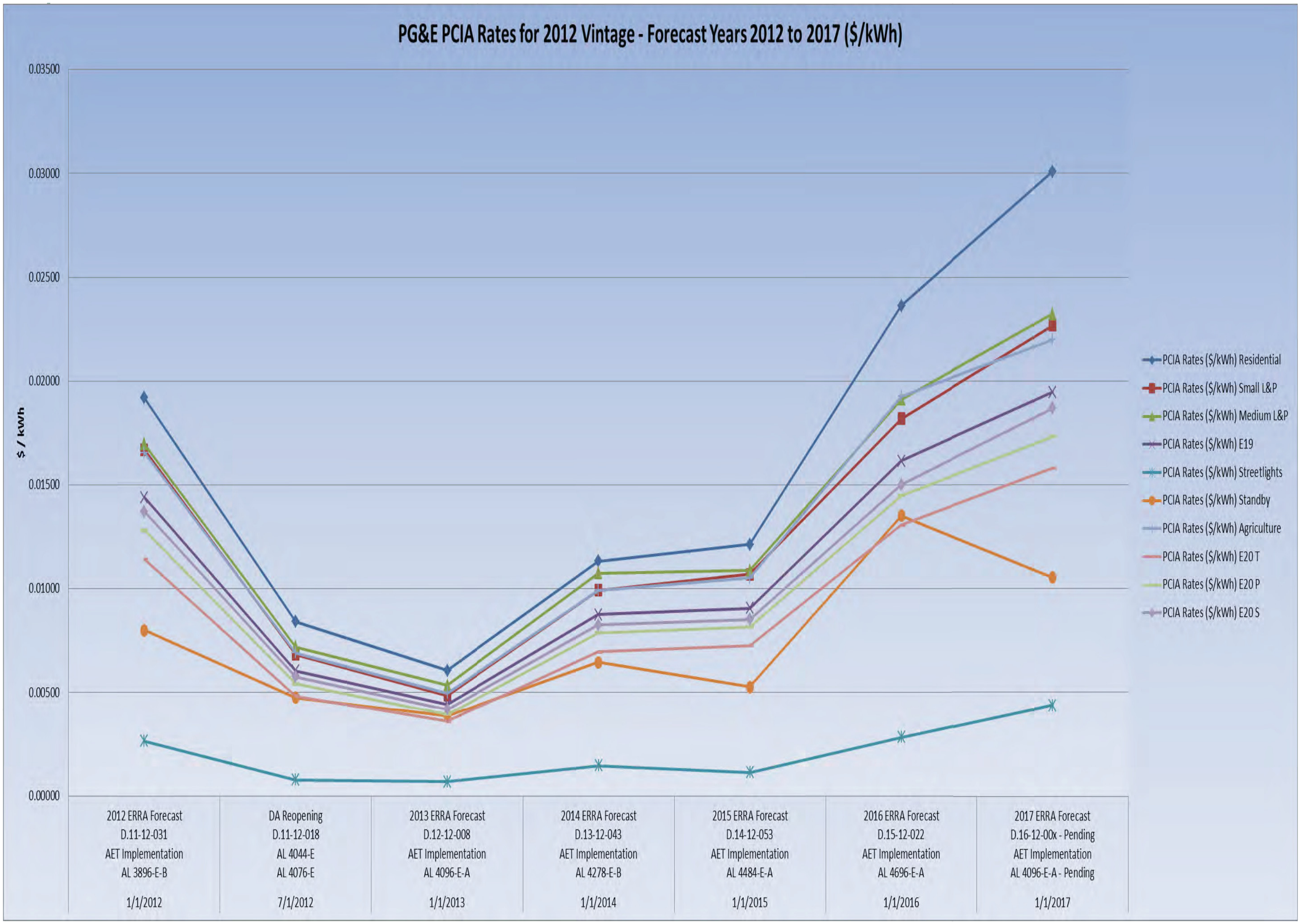
Call-in: 626-543-6758

Conference ID: 92082573

Location: December 14th in Oakland at the StopWaste offices (1537 Webster St. Oakland, CA 94612)

1 – PCIA HISTORICAL CHANGES AND GENERAL DRIVERS

PG&E PCIA RATE FOR 2012 VINTAGE



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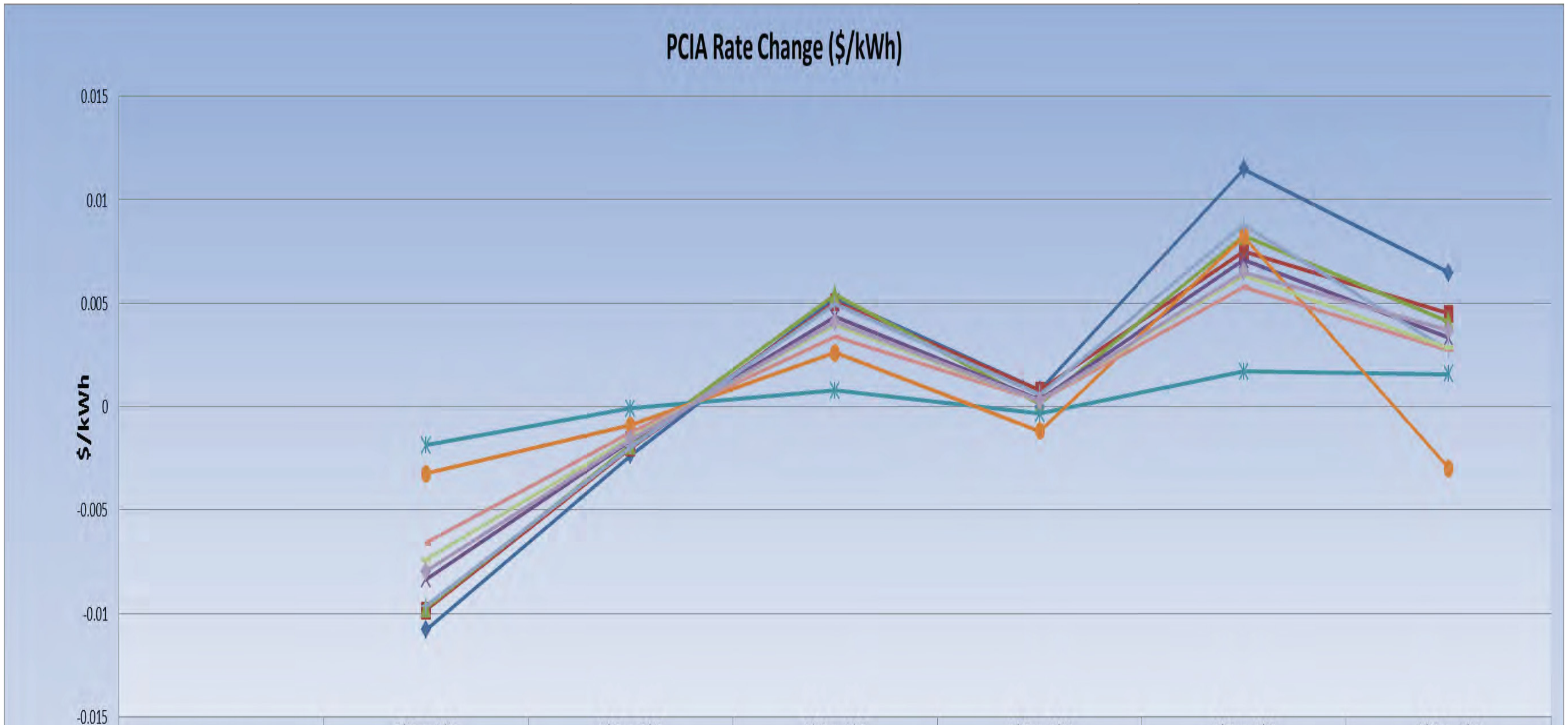
PG&E PCIA RATE FOR 2012 VINTAGE

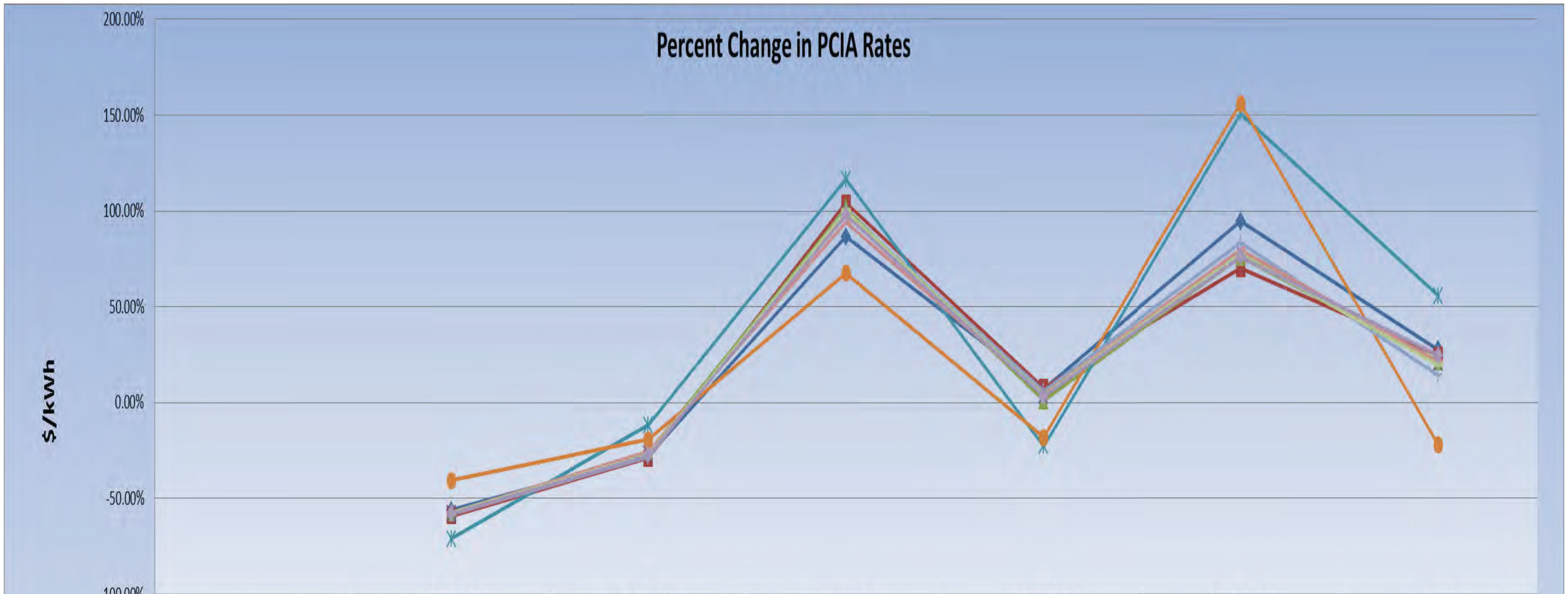
PCIA Rates ($/kWh)												
PCIA Rate Effective	Decision / Advice Letter	Residential	Small L&P	Medium L&P	E19	Streetlights	Standby	Agriculture	E20 T	E20 P	E20 S
1/1/2012	2012 ERRA Forecast D.11-12-031 AET Implementation AL 3896-E-B	0.01920	0.01670	0.01696	0.01440	0.00263	0.00800	0.01655	0.01142	0.01281	0.01372
7/1/2012	DA Reopening D.11-12-018 AL 4044-E AL 4076-E	0.00841	0.00684	0.00720	0.00605	0.00076	0.00476	0.00691	0.00483	0.00541	0.00576
1/1/2013	2013 ERRA Forecast D.12-12-008 AET Implementation AL 4096-E-A	0.00607	0.00486	0.00534	0.00442	0.00067	0.00385	0.00496	0.00359	0.00393	0.00417
1/1/2014	2014 ERRA Forecast D.13-12-043 AET Implementation AL 4278-E-B	0.01133	0.00992	0.01075	0.00876	0.00145	0.00645	0.00992	0.00697	0.00787	0.00825
1/1/2015	2015 ERRA Forecast D.14-12-053 AET Implementation AL 4484-E-A	0.01214	0.01069	0.01087	0.00907	0.00112	0.00528	0.01051	0.00726	0.00816	0.00852
1/1/2016	2016 ERRA Forecast D.15-12-022 AET Implementation AL 4696-E-A	0.02363	0.01818	0.01912	0.01615	0.00281	0.01352	0.01927	0.01306	0.01448	0.01501
1/1/2017	2017 ERRA Forecast D.16-12-00x - Pending AET Implementation AL 4096-E-A - Pending	0.03010	0.02267	0.02323	0.01947	0.00437	0.01053	0.02200	0.01580	0.01732	0.01869

PG&E PCIA RATE CHANGE 2012 - 2017



	1/1/2012	7/12 vs. 1/12 7/1/2012	1/13 vs. 7/12 1/1/2013	1/14 vs. 1/13 1/1/2014	1/15 vs. 1/14 1/1/2015	1/16 vs. 1/15 1/1/2016	1/17 vs. 1/16 1/1/2017
Residential		-0.01079	-0.00234	0.00526	0.00081	0.01149	0.00647
Small L&P		-0.00986	-0.00198	0.00506	0.00077	0.00749	0.00449
Medium L&P		-0.00976	-0.00186	0.00541	0.00012	0.00825	0.00411
E19		-0.00835	-0.00163	0.00434	0.00031	0.00708	0.00332
Streetlights		-0.00187	-0.00009	0.00078	-0.00033	0.00169	0.00156
Standby		-0.00324	-0.00091	0.00260	-0.00117	0.00824	-0.00299
Agriculture		-0.00964	-0.00195	0.00496	0.00059	0.00876	0.00273
E20 T		-0.00659	-0.00124	0.00338	0.00029	0.00580	0.00274
E20 P		-0.00740	-0.00148	0.00394	0.00029	0.00632	0.00284
E20 S		-0.00796	-0.00159	0.00408	0.00027	0.00649	0.00368

PG&E PCIA RATE PERCENT CHANGE 2012 - 2017

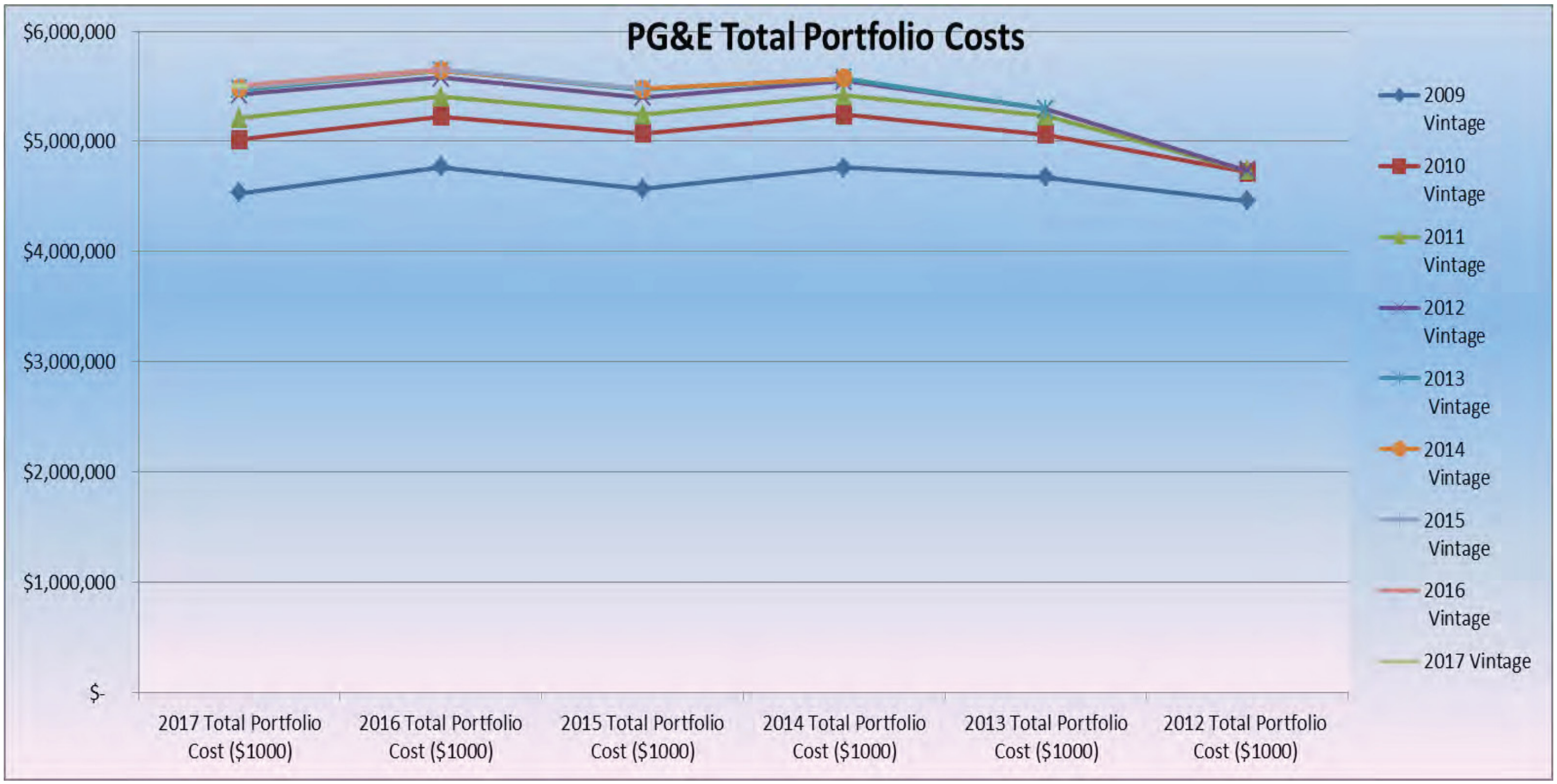


	1/1/2012	7/12 vs. 1/12 7/1/2012	1/13 vs. 7/12 1/1/2013	1/14 vs. 1/13 1/1/2014	1/15 vs. 1/14 1/1/2015	1/16 vs. 1/15 1/1/2016	1/17 vs. 1/16 1/1/2017
Residential		-56.2%	-27.8%	86.7%	7.1%	94.6%	27.4%
Small L&P		-59.0%	-28.9%	104.1%	7.8%	70.1%	24.7%
Medium L&P		-57.5%	-25.8%	101.3%	1.1%	75.9%	21.5%
E19		-58.0%	-26.9%	98.2%	3.5%	78.1%	20.6%
Streetlights		-71.1%	-11.8%	116.4%	-22.8%	150.9%	55.5%
Standby		-40.5%	-19.1%	67.5%	-18.1%	156.1%	-22.1%
Agriculture		-58.2%	-28.2%	100.0%	5.9%	83.3%	14.2%
E20 T		-57.7%	-25.7%	94.2%	4.2%	79.9%	21.0%
E20 P		-57.8%	-27.4%	100.3%	3.7%	77.5%	19.6%
E20 S		-58.0%	-27.6%	97.8%	3.3%	76.2%	24.5%

PG&E TOTAL PORTFOLIO COSTS 2012 - 2017

PG&E Portfolio Costs

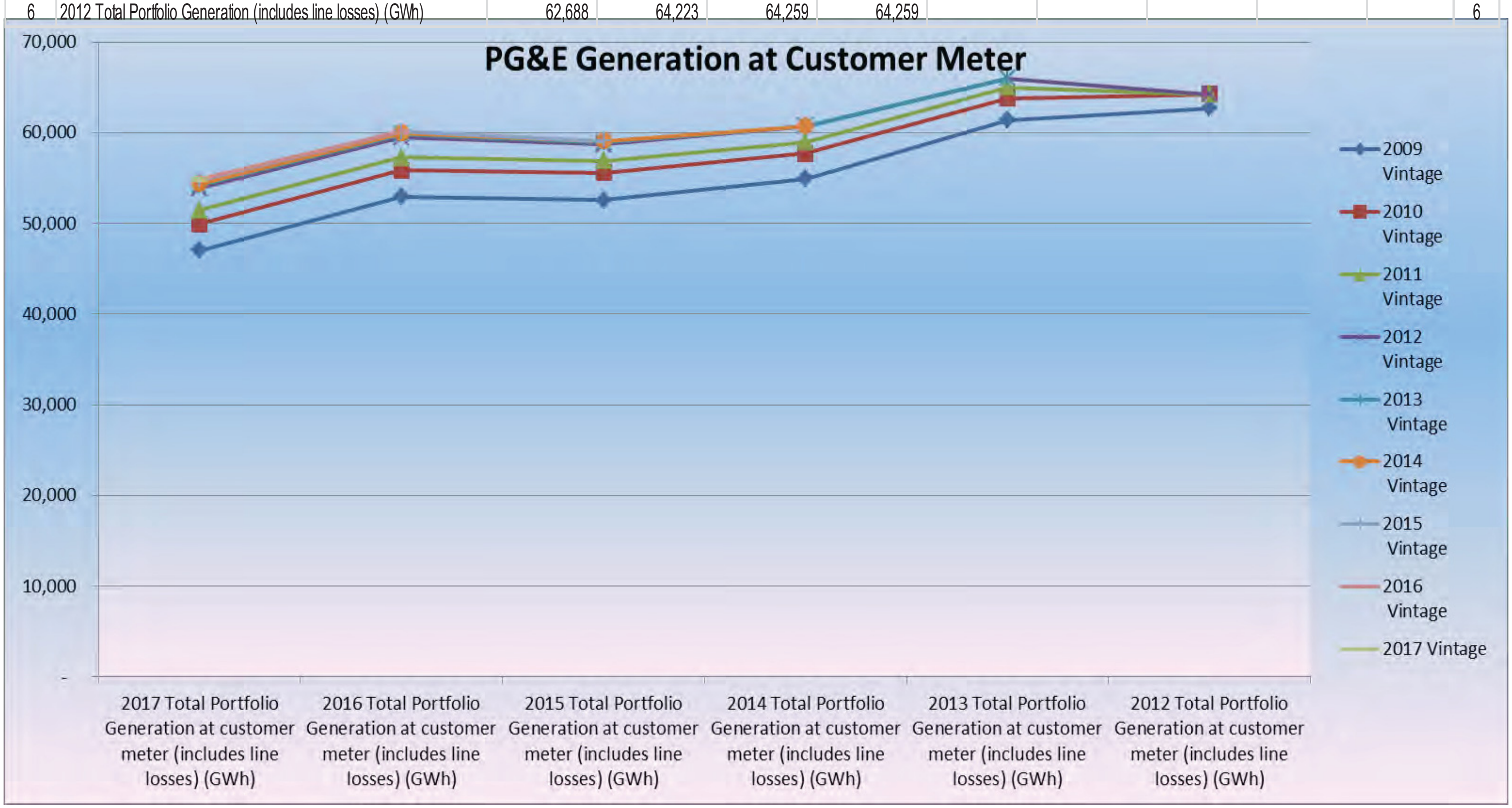
Line No.	Description	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	Line No.
1	2017 Total Portfolio Cost ($1000)	$ 4,533,577	$ 5,018,455	$ 5,210,752	$ 5,427,798	$ 5,470,301	$ 5,488,465	$ 5,495,279	$ 5,506,002	$ 5,506,002	1
2	2016 Total Portfolio Cost ($1000)	$ 4,766,664	$ 5,225,679	$ 5,405,749	$ 5,580,328	$ 5,639,105	$ 5,646,227	$ 5,656,460	$ 5,656,460		2
3	2015 Total Portfolio Cost ($1000)	$ 4,569,127	$ 5,075,160	$ 5,244,160	$ 5,400,076	$ 5,466,710	$ 5,480,004	$ 5,480,004			3
4	2014 Total Portfolio Cost ($1000)	$ 4,764,593	$ 5,244,445	$ 5,416,464	$ 5,549,322	$ 5,575,988	$ 5,575,988				4
5	2013 Total Portfolio Cost ($1000)	$ 4,677,650	$ 5,066,254	$ 5,234,684	$ 5,291,548	$ 5,291,548					5
6	2012 Total Portfolio Cost ($1000)	$ 4,463,277	$ 4,721,738	$ 4,739,035	$ 4,739,035						6



PG&E TOTAL PORTFOLIO GENERATION 2012 - 2017

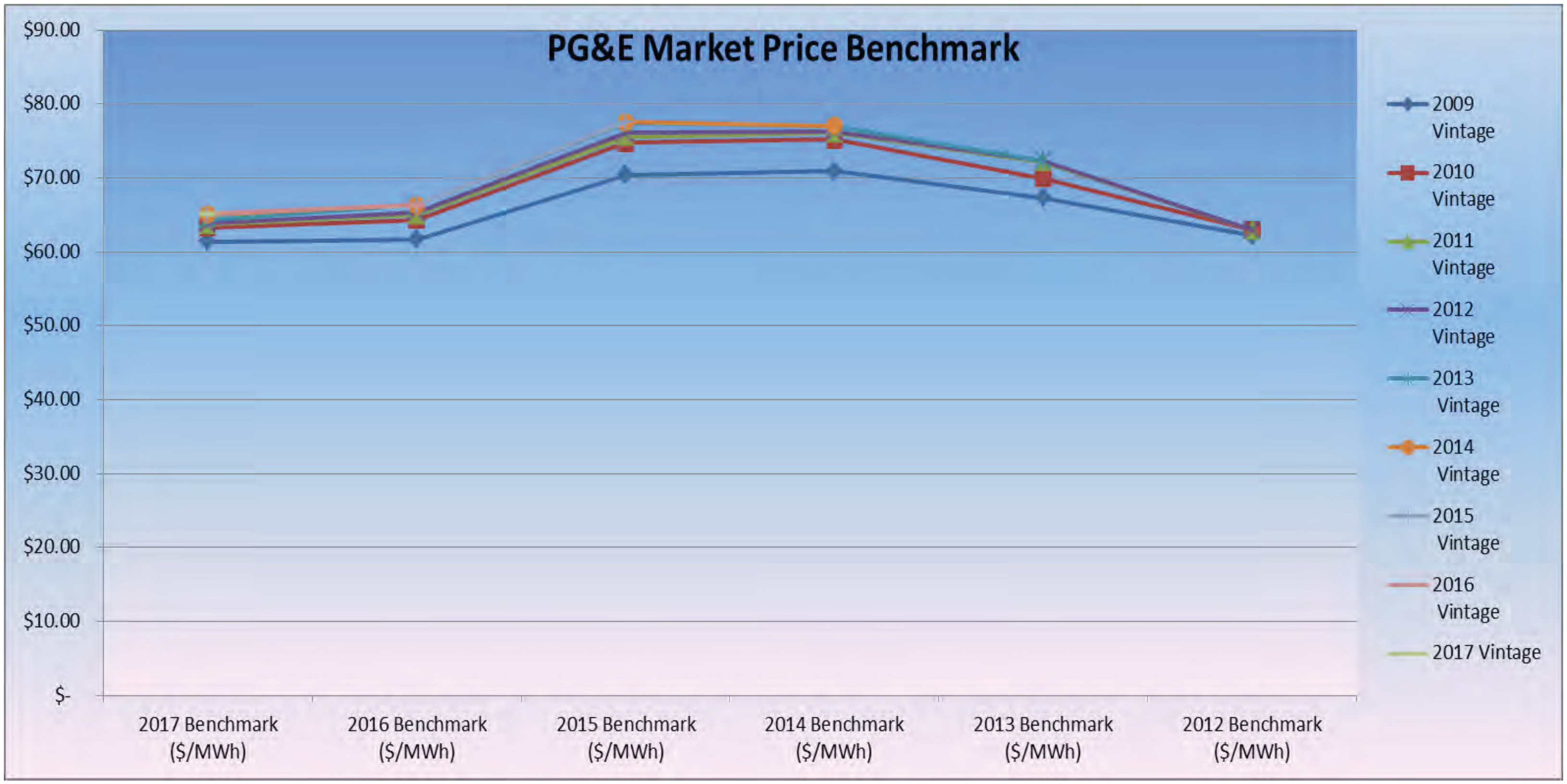
PG&E Generation at Customer Meter

Line No.	Description	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	Line No.
1	2017 Total Portfolio Generation (includes line losses) (GWh)	47,011	49,938	51,479	53,857	54,209	54,366	54,782	54,837	54,837	1
2	2016 Total Portfolio Generation (includes line losses) (GWh)	52,969	55,862	57,299	59,437	59,830	59,966	60,098	60,098		2
3	2015 Total Portfolio Generation (includes line losses) (GWh)	52,586	55,565	56,880	58,701	58,889	59,108	59,108			3
4	2014 Total Portfolio Generation (includes line losses) (GWh)	54,915	57,732	58,997	60,725	60,727	60,727				4
5	2013 Total Portfolio Generation (includes line losses) (GWh)	61,383	63,773	64,992	65,992	65,992					5
6	2012 Total Portfolio Generation (includes line losses) (GWh)	62,688	64,223	64,259	64,259						6



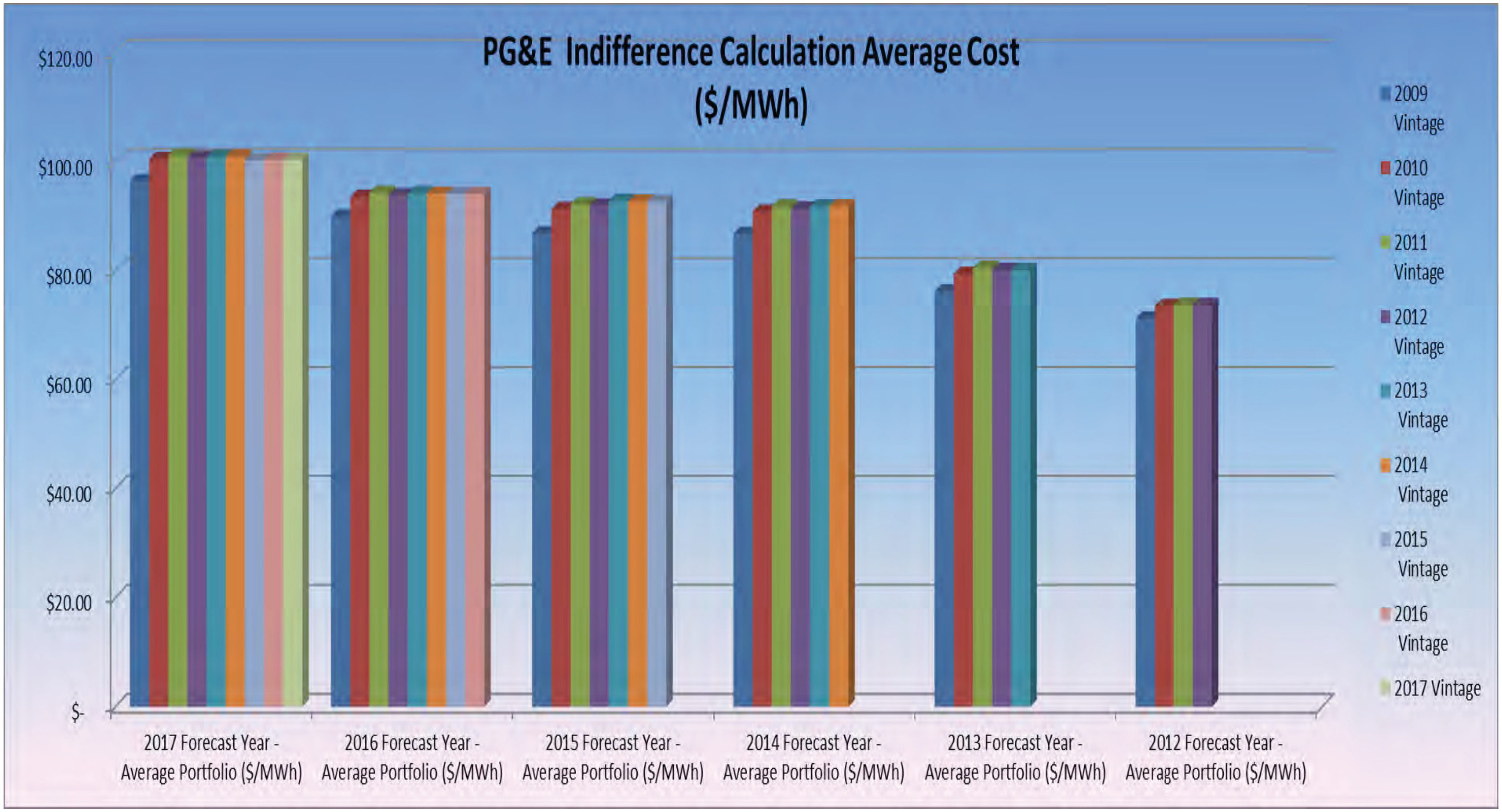
PG&E MARKET PRICE BENCHMARK 2012 - 2017

PG&E Market Price Benchmark										
Line No.	Description	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	Line No.
1	2017 Benchmark ($/MWh)	$ 61.40	$ 63.29	$ 63.68	$ 63.81	$ 64.34	$ 65.09	$ 65.18	$ 65.19	$ 65.19	1
2	2016 Benchmark ($/MWh)	$ 61.69	$ 64.35	$ 65.00	$ 65.36	$ 66.33	$ 66.34	$ 66.36	$ 66.36		2
3	2015 Benchmark ($/MWh)	$ 70.39	$ 74.77	$ 75.60	$ 76.06	$ 77.48	$ 77.56	$ 77.56			3
4	2014 Benchmark ($/MWh)	$ 70.89	$ 75.17	$ 76.09	$ 76.25	$ 77.08	$ 77.08				4
5	2013 Benchmark ($/MWh)	$ 67.31	$ 69.96	$ 72.14	$ 72.35	$ 72.35					5
6	2012 Benchmark ($/MWh)	$ 62.23	$ 62.96	$ 62.97	$ 62.97						6



PG&E AVERAGE PORTFOLIO COSTS ($/MWH), BY VINTAGE)

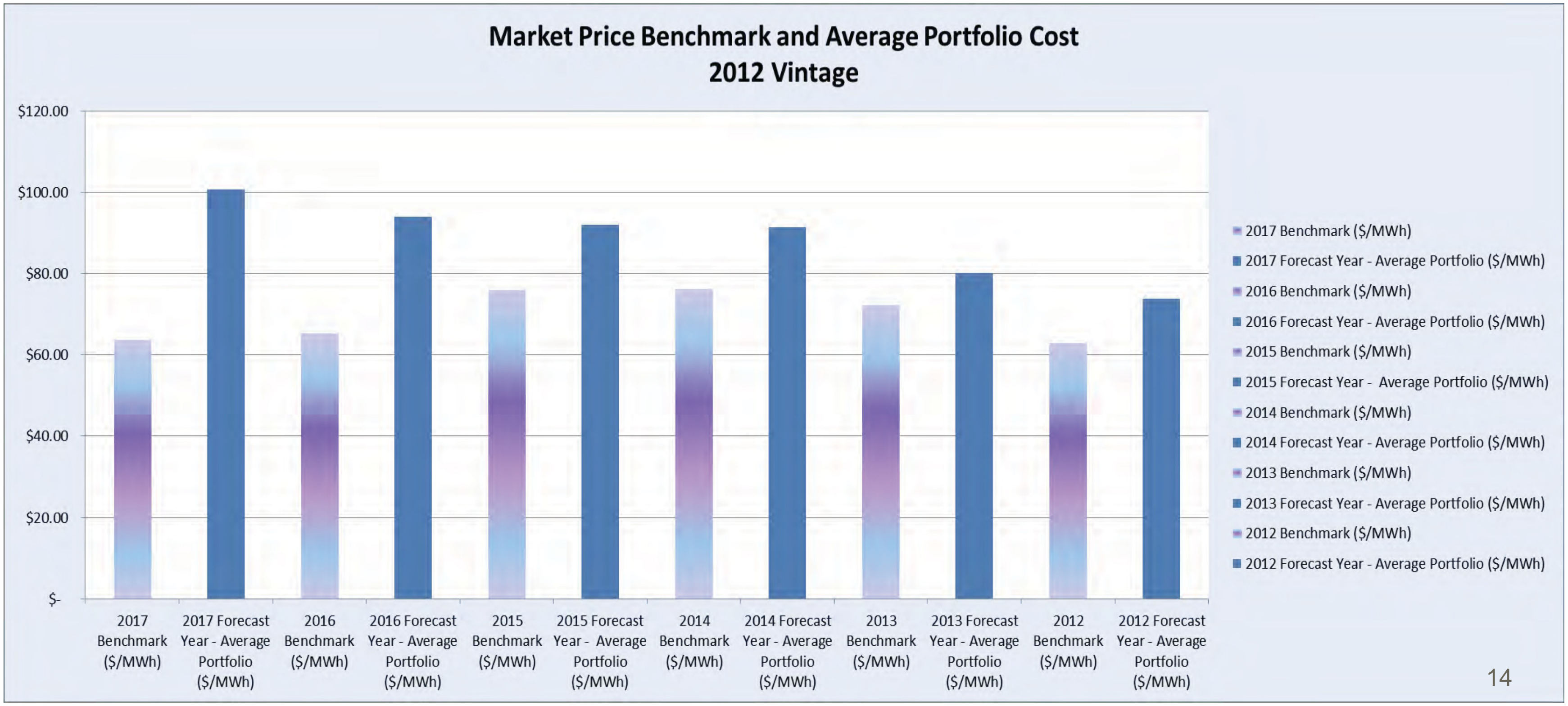
PG&E Indifference Calculation Average Portfolio Costs											
Line No.	Description	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	Line No.
1	2017 Forecast Year - Average Portfolio ($/MWh)	$ 96.44	$ 100.49	$ 101.22	$ 100.78	$ 100.91	$ 100.95	$ 100.31	$ 100.41	$ 100.41	1
2	2016 Forecast Year - Average Portfolio ($/MWh)	$ 89.99	$ 93.55	$ 94.34	$ 93.89	$ 94.25	$ 94.16	$ 94.12	$ 94.12		2
3	2015 Forecast Year - Average Portfolio ($/MWh)	$ 86.89	$ 91.34	$ 92.20	$ 91.99	$ 92.83	$ 92.71	$ 92.71			3
4	2014 Forecast Year - Average Portfolio ($/MWh)	$ 86.76	$ 90.84	$ 91.81	$ 91.38	$ 91.82	$ 91.82				4
5	2013 Forecast Year - Average Portfolio ($/MWh)	$ 76.20	$ 79.44	$ 80.54	$ 80.19	$ 80.19					5
6	2012 Forecast Year - Average Portfolio ($/MWh)	$ 71.20	$ 73.52	$ 73.75	$ 73.75						6



PG&E MPB VS. AVERAGE PORTFOLIO COSTS 2012 VINTAGE

Market Price Benchmark and Indifference Calculation Average Total Portfolio Costs

Line No.	Description	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	Line No.
1	2017 Benchmark ($/MWh)	$ 61.40	$ 63.29	$ 63.68	$ 63.81	$ 64.34	$ 65.09	$ 65.18	$ 65.19	$ 65.19	1
2	2017 Forecast Year - Average Portfolio ($/MWh)	$ 96.44	$ 100.49	$ 101.22	$ 100.78	$ 100.91	$ 100.95	$ 100.31	$ 100.41	$ 100.41	2
3	2016 Benchmark ($/MWh)	$ 61.69	$ 64.35	$ 65.00	$ 65.36	$ 66.33	$ 66.34	$ 66.36	$ 66.36		3
4	2016 Forecast Year - Average Portfolio ($/MWh)	$ 89.99	$ 93.55	$ 94.34	$ 93.89	$ 94.25	$ 94.16	$ 94.12	$ 94.12		4
5	2015 Benchmark ($/MWh)	$ 70.39	$ 74.77	$ 75.60	$ 76.06	$ 77.48	$ 77.56	$ 77.56			5
6	2015 Forecast Year - Average Portfolio ($/MWh)	$ 86.89	$ 91.34	$ 92.20	$ 91.99	$ 92.83	$ 92.71	$ 92.71			6
7	2014 Benchmark ($/MWh)	$ 70.89	$ 75.17	$ 76.09	$ 76.25	$ 77.08	$ 77.08				7
8	2014 Forecast Year - Average Portfolio ($/MWh)	$ 86.76	$ 90.84	$ 91.81	$ 91.38	$ 91.82	$ 91.82				8
9	2013 Benchmark ($/MWh)	$ 67.31	$ 69.96	$ 72.14	$ 72.35	$ 72.35					9
10	2013 Forecast Year - Average Portfolio ($/MWh)	$ 76.20	$ 79.44	$ 80.54	$ 80.19	$ 80.19					10
11	2012 Benchmark ($/MWh)	$ 62.23	$ 62.96	$ 62.97	$ 62.97						11
12	2012 Forecast Year - Average Portfolio ($/MWh)	$ 71.20	$ 73.52	$ 73.75	$ 73.75						12



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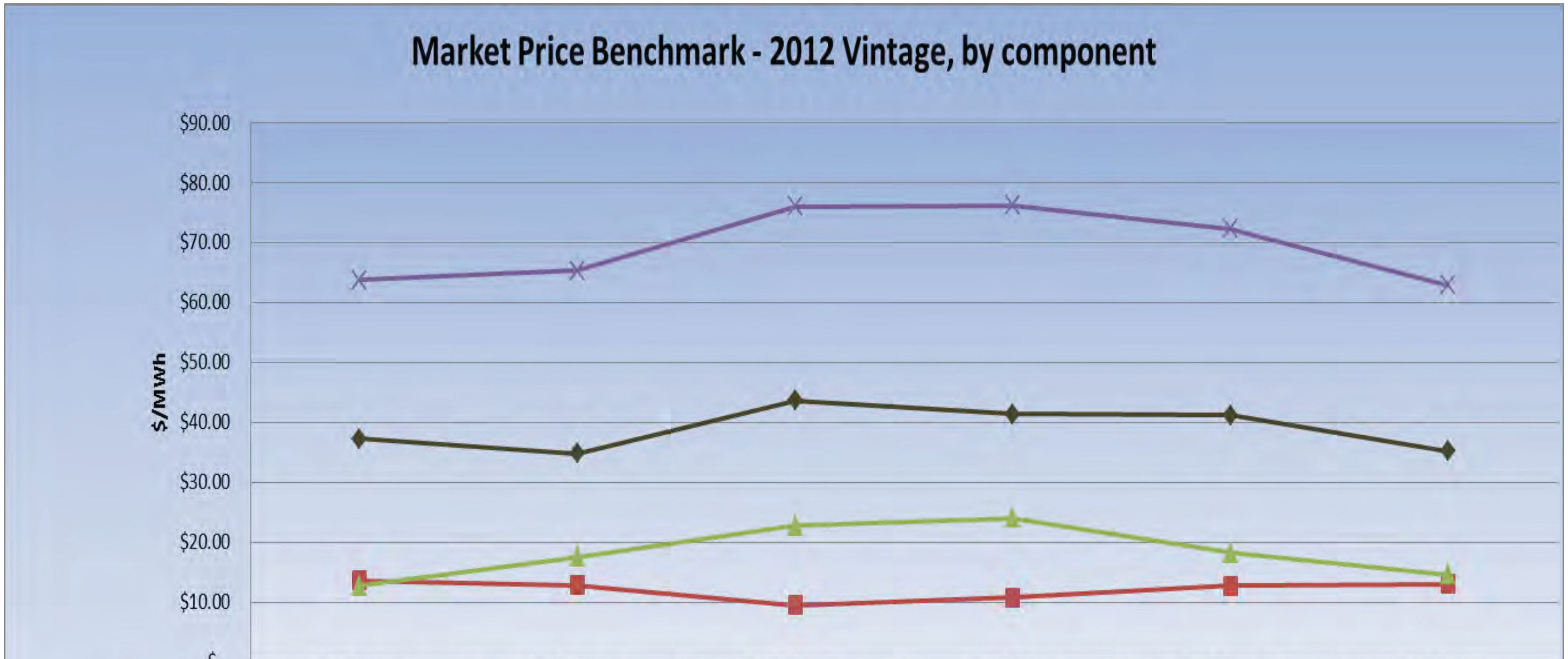
PG&E MARKET PRICE BENCHMARK, BY COMPONENT 2012-2017

Line No.	MPB - 2012 Vintage, by Component	2017 Forecast	2016 Forecast	2015 Forecast	2014 Forecast	2013 Forecast	2012 Forecast	Line No.
1	Brown	$ 37.33	$ 34.87	$ 43.73	$ 41.39	$ 41.27	$ 35.23	1
2	Capacity Adder	$ 13.67	$ 12.88	$ 9.55	$ 10.77	$ 12.79	$ 13.07	2
3	Green Adder	$ 12.80	$ 17.61	$ 22.78	$ 24.09	$ 18.29	$ 14.66	3
4	MPB at Generator	$ 63.81	$ 65.36	$ 76.06	$ 76.25	$ 72.35	$ 62.97	4



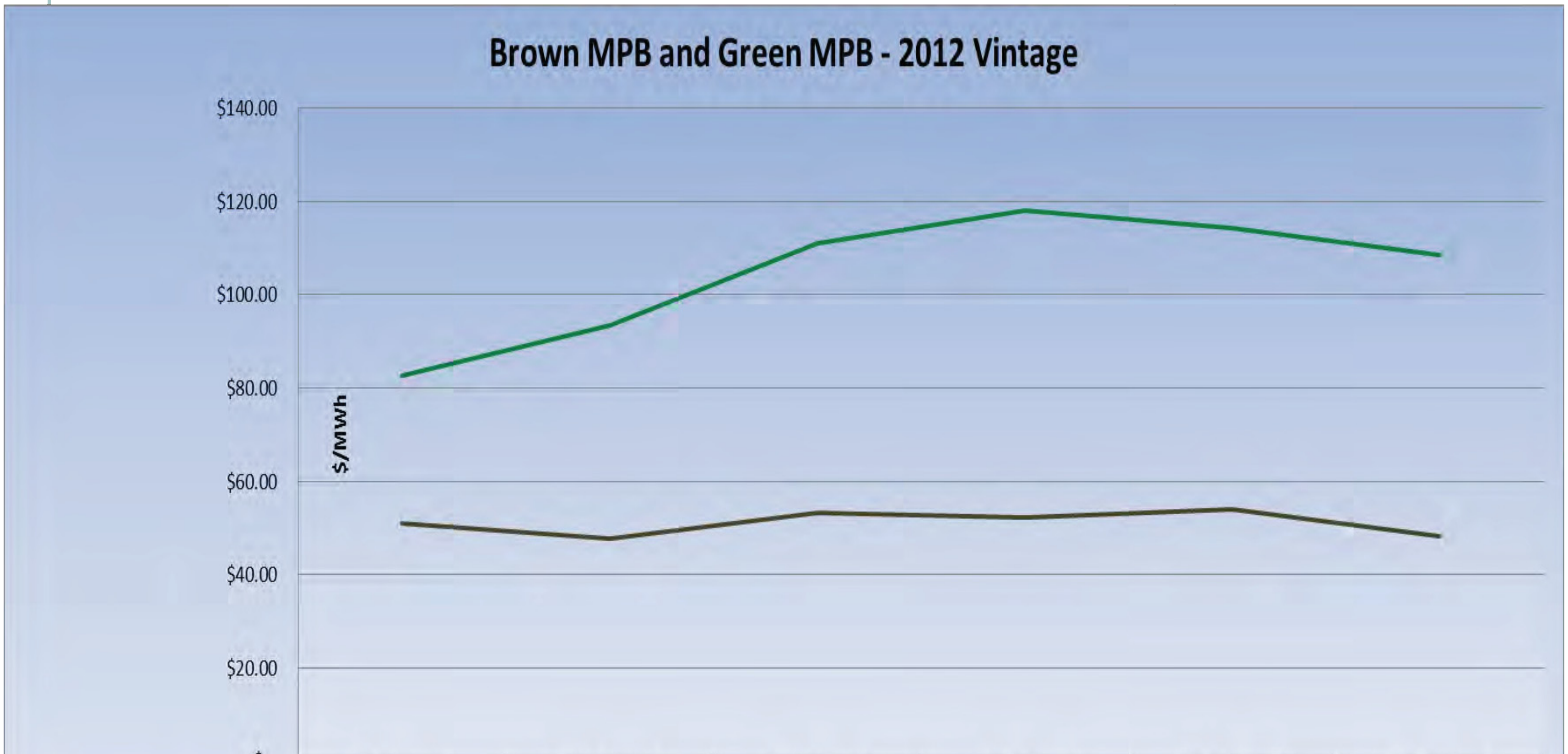
	2017 Forecast	2016 Forecast	2015 Forecast	2014 Forecast	2013 Forecast	2012 Forecast
Brown	$37.33	$34.87	$43.73	$41.39	$41.27	$35.23
Capacity Adder	$13.67	$12.88	$9.55	$10.77	$12.79	$13.07
Green Adder	$12.80	$17.61	$22.78	$24.09	$18.29	$14.66
MPB at Generator	$63.81	$65.36	$76.06	$76.25	$72.35	$62.97

PG&E MARKET PRICE BENCHMARK 2012 - 2017

Line No.	Brown MPB - 2012 Vintage	2017 Forecast	2016 Forecast	2015 Forecast	2014 Forecast	2013 Forecast	2012 Forecast	Line No.
1	Brown Energy only	$ 37.33	$ 34.87	$ 43.73	$ 41.39	$ 41.27	$ 35.23	1
2	Capacity adder	$ 13.67	$ 12.88	$ 9.55	$ 10.77	$ 12.79	$ 13.07	2
3	Brown MPB - 2012 Vintage	$ 51.01	$ 47.75	$ 53.28	$ 52.16	$ 54.06	$ 48.30	3
Line No.	Green MPB - 2012 Vintage, by Component							Line No.
1	Brown MPB	$ 51.01	$ 47.75	$ 53.28	$ 52.16	$ 54.06	$ 48.30	1
2	Green Premium (excludes energy & capacity)	$ 31.64	$ 45.57	$ 57.69	$ 65.81	$ 60.17	$ 60.32	2
3	Green MPB - 2012 Vintage	$ 82.65	$ 93.32	$ 110.97	$ 117.97	$ 114.23	$ 108.62	3

BROWN AND GREEN MARKET PRICE BENCHMARK 2012 - 2017

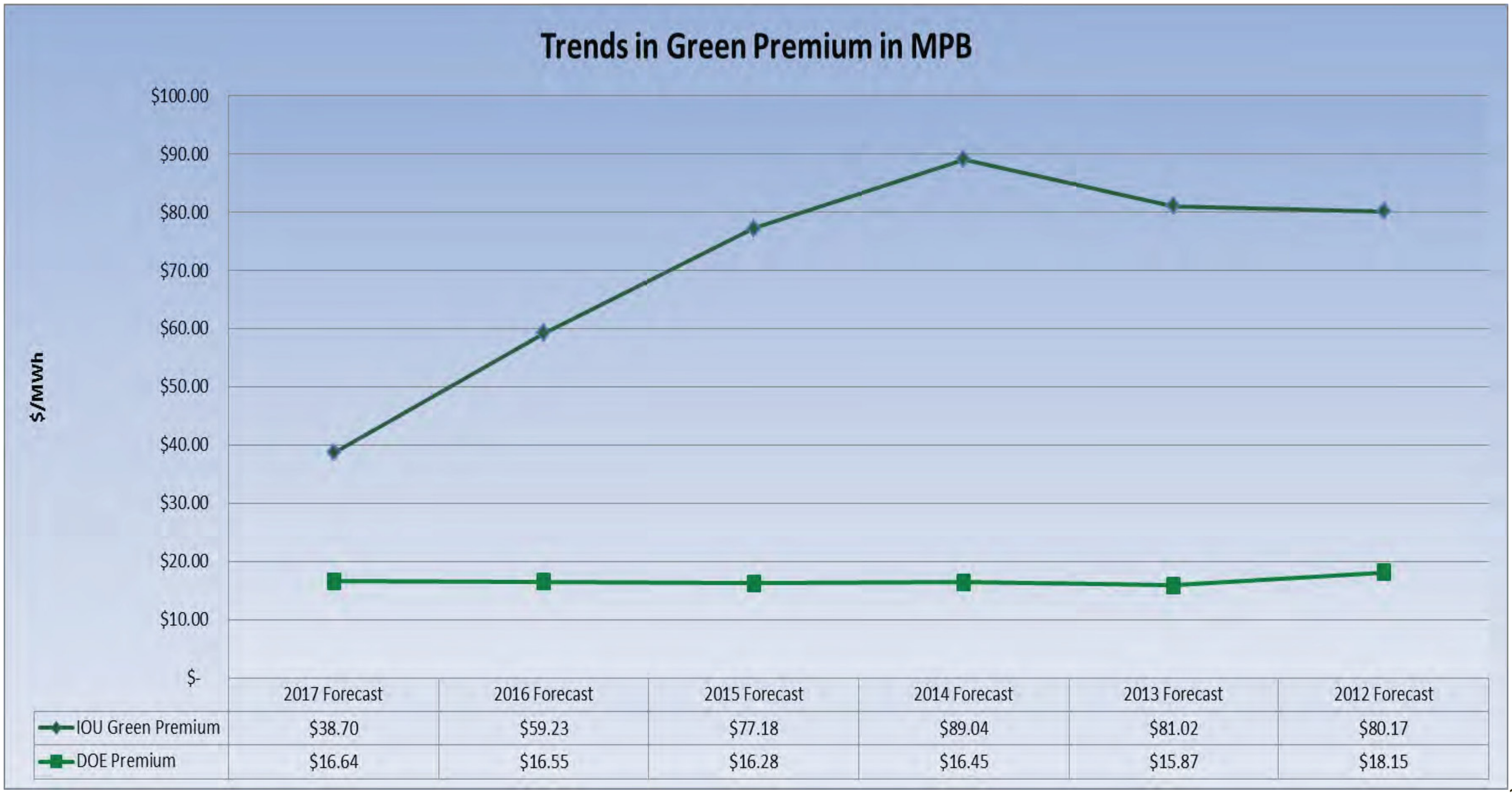
Line No.	Brown MPB and Green MPB - 2012 Vintage	2017 Forecast	2016 Forecast	2015 Forecast	2014 Forecast	2013 Forecast	2012 Forecast	Line No.
1	Brown MPB - 2012 Vintage	$ 51.01	$ 47.75	$ 53.28	$ 52.16	$ 54.06	$ 48.30	1
2	Green MPB - 2012 Vintage	$ 82.65	$ 93.32	$ 110.97	$ 117.97	$ 114.23	$ 108.62	2



	2017 Forecast	2016 Forecast	2015 Forecast	2014 Forecast	2013 Forecast	2012 Forecast
1 Brown MPB - 2012 Vintage	$51.01	$47.75	$53.28	$52.16	$54.06	$48.30
2 Green MPB - 2012 Vintage	$82.65	$93.32	$110.97	$117.97	$114.23	$108.62

GREEN MPB INPUTS AND 2012 VINTAGE PORTFOLIO RENEWABLE %

Line No.	MPB Inputs	2017 Forecast	2016 Forecast	2015 Forecast	2014 Forecast	2013 Forecast	2012 Forecast	Line No.
1	IOU Green Premium	$ 38.70	$ 59.23	$ 77.18	$ 89.04	$ 81.02	$ 80.17	1
2	DOE Premium	$ 16.64	$ 16.55	$ 16.28	$ 16.45	$ 15.87	$ 18.15	2
4	IOU Green Premium @ 68%	$ 26.32	$ 40.28	$ 52.48	$ 60.55	$ 55.09	$ 54.51	4
5	DOE Premium @ 32%	$ 5.32	$ 5.30	$ 5.21	$ 5.26	$ 5.08	$ 5.81	5
6	Green Premimum	$ 31.64	$ 45.57	$ 57.69	65.81	60.17	60.32	6
7	Portfolio Renewable Percentage	38.2%	36.5%	37.3%	34.5%	28.7%	22.9%	7
8	Green Adder	$ 12.08	$ 16.62	$ 21.49	$ 22.72	$ 17.26	$ 13.83	8



TOTAL PORTFOLIO INDIFFERENCE RESULTS AND DRIVERS FOR CHANGE

2017 ERRA Forecast
Total Portfolio Indifference
Table 9-4

Line No.	Description	Vintaged 2017 Vintage	Line No.
1	Total Portfolio Generation at generator (GWh)	58,338	1
2	Total Portfolio Generation at customer meter (includes line losses) (GWh)	54,837	2
3	Total Portfolio Cost ($1000)	$ 5,506,002	3
4	Benchmark ($/MWh)	$ 65.19	4
5	Market Value ($1000)	$ 3,574,847	5
6	NBC Vintaged Portfolio of Above Market Costs (Line 3 - Line 5)	$ 1,931,155	6
7			7
8	**Indifference Results, current year (excludes ff&u) ($1000)**	$ 1,931,155	8
9	2016 Cummulative Indifference Amount	$ -	9
10	2017 Cumulative Indifference Amount (prior year(s) + current year results)	$ 1,931,155	10
11	2017 Cumulative Indifference Amount w/ ff&u	$ 1,954,107	11
12	Indifference Amount Revenue Requirement	$ 1,954,107	12
13	Ongoing CTC Cost RRQ ($1000)	$ 76,668	13
14	Ongoing CTC - EOY MTCBA Balance ($1000)	$ -	14
15	PCIA RRQ ($1000) = Indifference - Ongoing CTC (Line 12 - line 13)	$ 1,877,438	15

Drivers for Rate Change

	Variance 2017 vs. 2016	PCIA Impact ($1000s)	% Contribution to Total Change
Total Portfolio Cost ($1000)	-$150,458	-$150,458	-51.7%
Benchmark Price Change ($/MWh)	-$1.17	$70,314	24.2%
Market Value - Quanity Change (MWh)	(5,260)	$342,912	117.9%
		$262,769	90.3%
Change in ff&u	$259,273	$3,123	1.1%
Ongoing CTC Cost RRQ ($1000)	-$25,078	$25,078	8.6%
Indifference net of OCTC ($1000s)		$290,969	100.0%
Indifference net of OCTC (% Change)		18%	

TOTAL PORTFOLIO INDIFFERENCE RESULTS AND DRIVERS FOR CHANGE

2016 ERRA Forecast
Total Portfolio Indifference

Line No.	Description	2015 Vintage	Line No.
1	Total Portfolio Generation at generator (GWh)	63,934	1
2	Total Portfolio Generation at customer meter (includes line losses) (GWh)	60,098	2
3	Total Portfolio Cost ($1000)	$ 5,656,460	3
4	Benchmark ($/MWh)	66.36	4
5	Market Cost ($1000)	$ 3,988,073	5
6	NBC Vintaged Portfolio of Above Market Costs (Line 3 - Line 5)	$ 1,668,386	6
7			7
8	**Indifference Results, current year (excludes ff&u) ($1000)**	$ 1,668,386	8
9	2015 Cumulative Indifference Amount	$ -	9
10	2016 Cumulative Indifference Amount (prior year(s) + current year results)	$ 1,668,386	10
11	2016 Cumulative Indifference Amount w/ ff&u	$ 1,688,215	11
12	Indifference Amount Revenue Requirement	$ 1,688,215	12
13	Ongoing CTC Cost RRQ ($1000)	$ 101,746	13
14	Ongoing CTC - EOY MTCBA Balance ($1000)	$ -	14
15	PCIA RRQ ($1000) = Indifference - Ongoing CTC (Line 12 - line 13)	$ 1,586,469	15

Variance 2016 vs. 2015		PCIA Impact ($1000s)	% Contribution to Total Change
Total Portfolio Cost ($1000)	$176,455	$176,455	24.7%
Benchmark Price Change ($/MWh)	-$11.20	$662,011	92.8%
Market Value - Quanity Change (MWh)	989	-$65,659	-9.2%
		$772,807	108.3%
Change in ff&u	$782,012	$9,205	1.3%
Ongoing CTC Cost RRQ ($1000)	$68,282	-$68,282	-9.6%
Indifference net of OCTC ($1000s)		$713,730	100.0%
Indifference net of OCTC (% Change)		78%	

2015 ERRA Forecast
Total Portfolio Indifference

Line No.	Description	2015 Vintage	Line No.
1	Total Portfolio Generation at generator (GWh)	62,881	1
2	Total Portfolio Generation at customer meter (includes line losses) (GWh)	59,108	2
3	Total Portfolio Cost ($1000)	$ 5,480,004	3
4	Benchmark ($/MWh)	77.56	4
5	Market Cost ($1000)	$ 4,584,425	5
6	NBC Vintaged Portfolio of Above Market Costs (Line 3 - Line 5)	$ 895,580	6
7			7
8	**Indifference Results, current year (excludes ff&u) ($1000)**	$ 895,580	8
9	2014 Cumulative Indifference Amount	$ -	9
10	2015 Cumulative Indifference Amount (prior year(s) + current year results)	$ 895,580	10
11	2015 Cumulative Indifference Amount w/ ff&u	$ 906,203	11
12	Indifference Amount Revenue Requirement	$ 906,203	12
13	Ongoing CTC Cost RRQ ($1000)	$ 33,464	13
14	Ongoing CTC - EOY MTCBA Balance ($1000)	$ -	14
15	PCIA RRQ ($1000) = Indifference - Ongoing CTC (Line 12 - line 13)	$ 872,739	15

Variance 2015 vs. 2014		PCIA Impact ($1000s)	% Contribution to Total Change
Total Portfolio Cost ($1000)	-$95,983	-$95,983	-239.1%
Benchmark Price Change ($/MWh)	$0.48	-$29,149	-72.6%
Market Value - Quanity Change (MWh)	(1,619)	$125,569	312.8%
		$436	1.1%
Change in ff&u	$1,401	$965	2.4%
Ongoing CTC Cost RRQ ($1000)	-$38,741	$38,741	96.5%
Indifference net of OCTC ($1000s)		$40,142	100.0%
Indifference net of OCTC (% Change)		5%	

TOTAL PORTFOLIO INDIFFERENCE RESULTS AND DRIVERS FOR CHANGE

2014 ERRA Forecast
Total Portfolio Indifference

Line No.	Description	2013 Vintage	Line No.
1	Total Portfolio Generation at generator (GWh)	64,603	1
2	Total Portfolio Generation at customer meter (includes line losses) (GWh)	60,727	2
3	Total Portfolio Cost ($1000)	$ 5,575,988	3
4	Benchmark ($/MWh)	77.08	4
5	Market Cost ($1000)	$ 4,680,844	5
6	NBC Vintaged Portfolio of Above Market Costs (Line 3 - Line 5)	$ 895,143	6
7			7
8	**Indifference Results, current year (excludes ff&u) ($1000)**	$ 895,143	8
9	2013 Cumulative Indifference Amount	$ -	9
10	2014 Cumulative Indifference Amount (prior year(s) + current year results)	$ 895,143	10
11	2014 Cumulative Indifference Amount w/ ff&u	$ 904,802	11
12	Indifference Amount Revenue Requirement	$ 904,802	12
13	Ongoing CTC Cost RRQ ($1000)	$ 72,205	13
14	Ongoing CTC - EOY MTCBA Balance ($1000)	$ -	14
15	PCIA RRQ ($1000) = Indifference - Ongoing CTC (Line 12 - line 13)	$ 832,597	15

	Variance 2014 vs. 2013	PCIA Impact ($1000s)	% Contribution to Total Change
Total Portfolio Cost ($1000)	$284,440	$284,440	71.5%
Benchmark Price Change ($/MWh)	$4.73	-$312,140	-78.5%
Market Value - Quanity Change (MWh)	(5,264)	$405,784	102.0%
		$378,084	95.0%
Change in ff&u	$382,163	$4,080	1.0%
Ongoing CTC Cost RRQ ($1000)	-$15,623	$15,623	3.9%
Indifference net of OCTC ($1000s)		$397,786	100.0%
Indifference net of OCTC (% Change)		91%	

2013 ERRA Forecast
Total Portfolio Indifference

Line No.	Description	2013 Vintage	Line No.
1	Total Portfolio Generation at generator (GWh)	70,204	1
2	Total Portfolio Generation at customer meter (includes line losses) (GWh)	65,992	2
3	Total Portfolio Cost ($1000)	$ 5,291,548	3
4	Benchmark ($/MWh)	72.35	4
5	Market Cost ($1000)	$ 4,774,488	5
6	NBC Vintaged Portfolio of Above Market Costs (Line 3 - Line 5)	$ 517,060	6
7			7
8	**Indifference Results, current year (excludes ff&u) ($1000)**	$ 517,060	8
9	2012 Cumulative Indifference Amount	$ -	9
10	2013 Cumulative Indifference Amount (prior year(s) + current year results)	$ 517,060	10
11	2013 Cumulative Indifference Amount w/ ff&u	$ 522,639	11
12	Indifference Amount Revenue Requirement	$ 522,639	12
13	Ongoing CTC Cost RRQ ($1000)	$ 87,828	13
14	Ongoing CTC - EOY MTCBA Balance ($1000)	$ -	14
15	PCIA RRQ ($1000) = Indifference - Ongoing CTC (Line 12 - line 13)	$ 434,811	15

	Variance 2013 vs. 2012	PCIA Impact ($1000s)	% Contribution to Total Change
Total Portfolio Cost ($1000)	$552,513	$552,513	-318.8%
Benchmark Price Change ($/MWh)	$9.38	-$602,960	347.9%
Market Value - Quanity Change (MWh)	1,733	-$125,367	72.3%
		-$175,813	101.5%
Change in ff&u	-$177,710	-$1,897	1.1%
Ongoing CTC Cost RRQ ($1000)	-$4,411	$4,411	-2.5%
Indifference net of OCTC ($1000s)		($173,299)	100.0%
Indifference net of OCTC (% Change)		-28%	

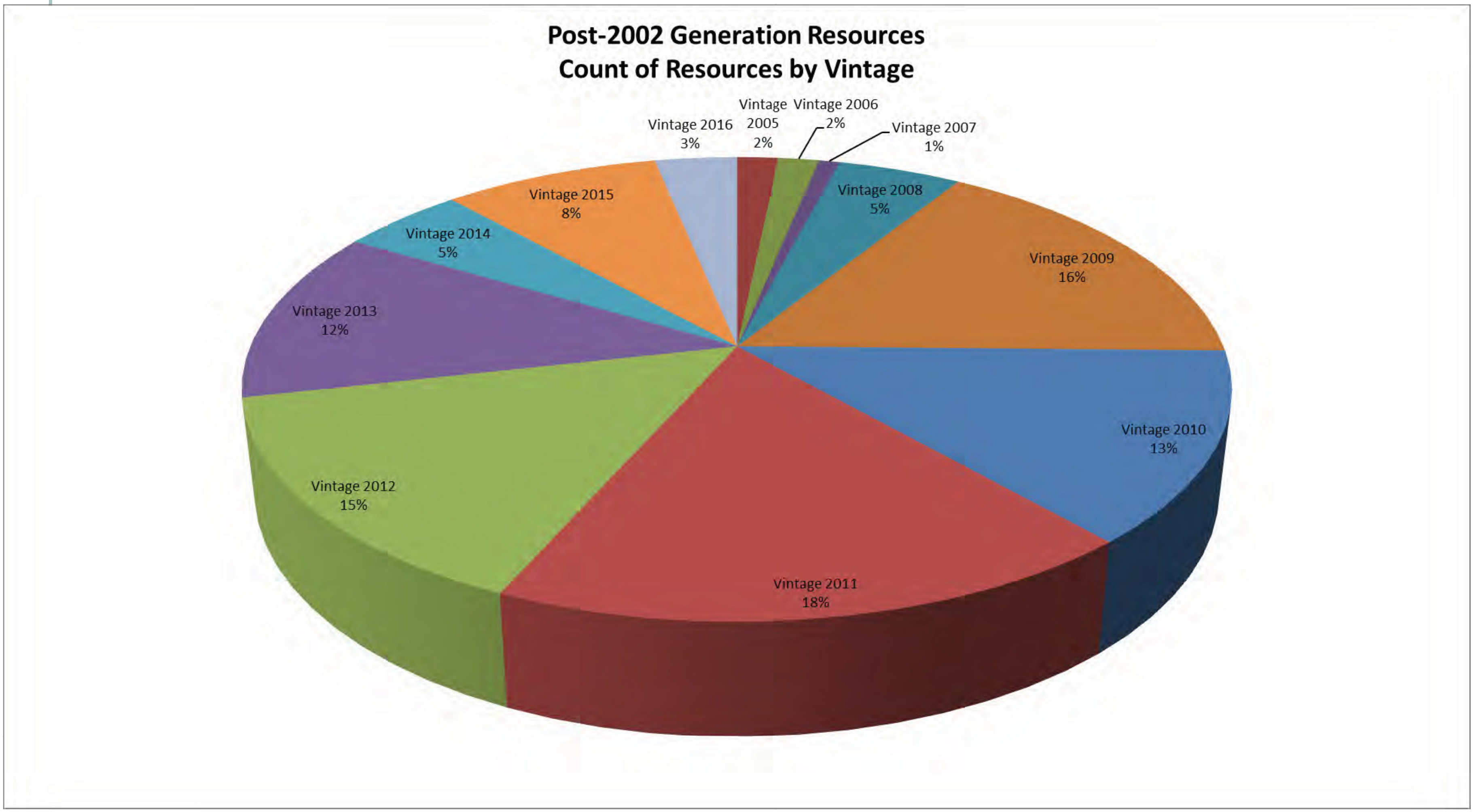
2 – IDEAS FOR IMPROVING DATA ACCESS AND TRANSPARENCY

PG&E TOTAL PORTFOLIO CONTRACTS – POST 2002-GENERATION

PG&E - 2017 PCIA Forecast: Post-2002 Gener														
Resource Type	Vintage 2005	Vintage 2006	Vintage 2007	Vintage 2008	Vintage 2009	Vintage 2010	Vintage 2011	Vintage 2012	Vintage 2013	Vintage 2014	Vintage 2015	Vintage 2016	Total	Percentage by Contract Type
Conventional	**0**	**3**	**0**	**1**	**15**	**0**	**2**	**3**	**2**	**5**	**1**	**3**	**35**	14%
< 5 Years		1			4		2	2	2	5		3		
< 15 Years		2		1	11						1			
< 25 Years								1						
Renew	***4***	***0***	***2***	***10***	***25***	***26***	***40***	***31***	***28***	***7***	***20***	***5***	**198**	80%
<= 5 Years	1			2	10		3							
<= 15 Years	3		2	6	8				6	4	2			
<= 25 Years				2	7		37		22	3	18	5		
UOG	**0**	**1**	**0**	**1**	**1**	**7**	**3**	**3**	**0**	**0**	**0**	**0**	**16**	6%
<= 5 Years		1		1	1	7	3							
<= 10 Years								3						
Total	**4**	**4**	**2**	**12**	**41**	**33**	**45**	**37**	**30**	**12**	**21**	**8**	**249**	100%
Percent by Count	2%	2%	1%	5%	16%	13%	18%	15%	12%	5%	8%	3%	100%	

PG&E TOTAL PORTFOLIO CONTRACTS – POST-2002 GENERATION

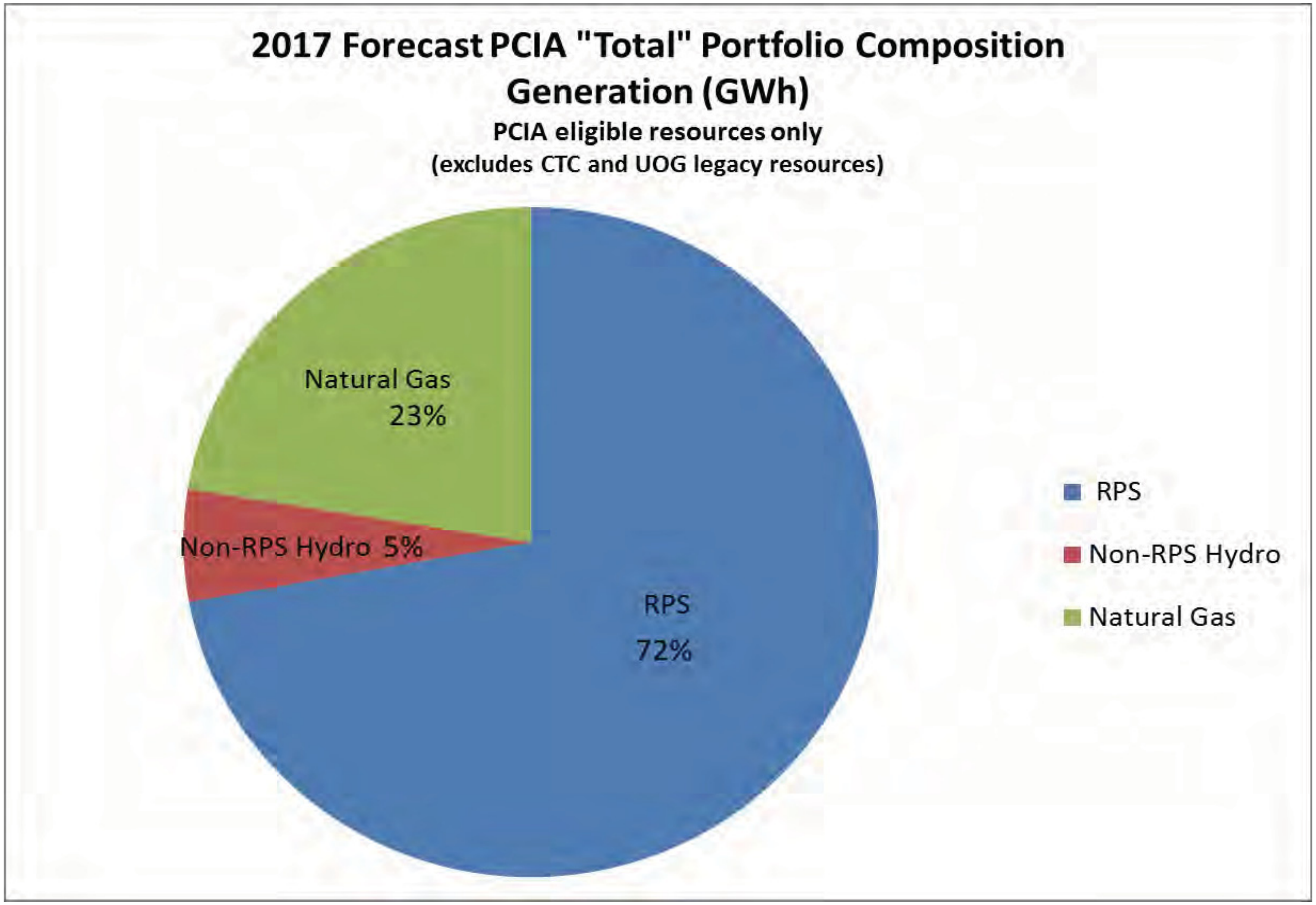
PG&E - 2017 PCIA Forecast: Post-2002 Generation	Vintage 2005	Vintage 2006	Vintage 2007	Vintage 2008	Vintage 2009	Vintage 2010	Vintage 2011	Vintage 2012	Vintage 2013	Vintage 2014	Vintage 2015	Vintage 2016	Total
	2%	2%	1%	5%	16%	13%	18%	15%	12%	5%	8%	3%	100%



PG&E TOTAL PORTFOLIO COMPOSITION -
Post-2002 Generation

PG&E - 2017 PCIA														
Above Mkt Cost by Resource Type	Vintage 2005	Vintage 2006	Vintage 2007	Vintage 2008	Vintage 2009	Vintage 2010	Vintage 2011	Vintage 2012	Vintage 2013	Vintage 2014	Vintage 2015	Vintage 2016	Total	Percentage by Contract Type
Conventional	$ 0	$ 57,527	$ 0	$ 141,332	$ 199,798	$ 0	$ 13,615	$ (8,664)	$ 13,595	$ 7,434	$ (34)	$ 7,208	**$ 431,811**	23%
Renew	*$ 6,538*	*$ 0*	*$ 14,426*	*$ 202,581*	*$ 518,941*	*$ 254,643*	*$ 51,221*	*$ 43,189*	*$ 6,095*	*$ 553*	*$ (45)*	*$ (120)*	***$ 1,098,022***	60%
UOG	$ 0	$ 78,925	$ 0	$ 101,311	$ 34,438	$ 39,398	$ 27,007	$ 27,463	$ 0	$ 0	$ 0	$ 0	**$ 308,543**	17%
Total	**$ 6,538**	**$ 136,452**	**$ 14,426**	**$ 445,225**	**$ 753,177**	**$ 294,041**	**$ 91,842**	**$ 61,988**	**$ 19,690**	**$ 7,987**	**$ (79)**	**$ 7,088**	**$ 1,838,375**	100%
Total Portfolio %	0.36%	6.20%	0.78%	21.88%	44.53%	15.99%	5.00%	3.37%	1.07%	0.43%	0.00%	0.39%	100%	

PG&E TOTAL PORTFOLIO COMPOSITION – POST 2002-GENERATION



3 – MODIFICATIONS WITHIN THE EXISTING PCIA FRAMEWORK

FOR DISCUSSION

RENEWABLE BENCHMARK IMPROVEMENTS

Identified Concerns*	Potential Changes
DOE data: • DOE data is not updated regularly (i.e. out of 74 tariffs on the website, only 63 tariffs are used by the IOUs) • DOE data is based on price of voluntary renewable programs—not necessarily a measurement for "market price of renewables"	• Manually update DOE data and only use current tariffs used today
IOU-specific data: • IOU data is confidential and not aggregated until October—should use a publicly available source	

Note: The objective of the session is to identify and define potential changes

* Concerns raised in the first two Working Group meetings

ALTERNATIVE DATA SOURCE FOR CAPACITY BENCHMARK

Identified Concerns*	Potential Changes
• CEC value is not updated regularly • Ongoing Combustion Turbine costs are not an appropriate proxy for current market price of capacity • Potential missing element of ISO administered capacity payment (RUCC) not included in current benchmark calculation impacting the market price (?) • Tracking CPM • Comparison of capacity values and valuation methodology used in LTPP, GRC Phase 2 and PCIA calculation and understand the rationale behind the differences	

Note: The objective of the session is to identify and define potential changes

* Concerns raised in the first two Working Group meetings

PCIA TRUE-UP

Identified Concerns*	Potential Changes
• Forecast errors present cost-shift risk • How to define the "true up" – elements of a true up, the methodology to compare forecast vs. actual costs and revenues, and frequency to do it	

Note: The objective of the session is to identify and define potential changes

* Concerns raised in the first two Working Group meetings

ALTERNATIVE METHODOLOGY TO ALLOCATE INDIFFERENCE AMOUNT

Identified Concerns*	Potential Changes
• Top 100 hours not necessarily representative of rate group contribution to generation costs - Does not represent median or average customer usage • Does not reflect geographic differences in generation costs [CCA] • Results in a disproportionately high PCIA for residential customers [CCA]	

Note: The objective of the session is to identify and define potential changes

* Concerns raised in the first two Working Group meetings

CAP ON ANNUAL PCIA AMOUNTS

Identified Concerns*	**Potential Changes**
• Limits volatility • Should existing liability of departing customers follow them? Who would finance any amount still owed over the cap?	

Note: The objective of the session is to identify and define potential changes

* Concerns raised in the first two Working Group meetings

FOR DISCUSSION

OTHER CONCERNS AND/OR RECOMMENDATIONS?

Identified Concerns	Potential Changes

4 – ALTERNATIVES TO PCIA: DEVELOP COMMON UNDERSTANDING OF POTENTIAL ALTERNATIVES TO PCIA

PCIA ALTERNATIVE: CONTRACT ASSIGNMENT

Identified Concerns*	Potential Changes
• Selecting individual contracts presents legal (contract terms), financial (credit), and equity (which contracts) challenges. • Many contracts were signed at a much higher price than LSEs would pay for the same asset. • Some LSEs may have appetite for these contracts, while others may not.	

Note: The objective of the session is to identify and define potential changes

* Concerns raised in the first two Working Group meetings

PCIA ALTERNATIVE: LUMP SUM PAYMENT

Identified Concerns*	Potential Changes
• Determining which costs and savings should be included is potentially complex. • Is lump sum amount based on future NBCs under current rules, the cost of contracts less their value if sold, etc. • True-up mechanism ensures indifference but reduces certainty. • How are future legislative/policy requirements implemented?	

Note: The objective of the session is to identify and define potential changes

* Concerns raised in the first two Working Group meetings

Attachment D

Website List with Public Information for Electric Generation Resources

PCIA Working Group Meeting
December 14, 2016
Website List with Public Information for Electric Generation Resources

Federal Energy Regulatory Commission

FERC Form 1 Viewer

1. PG&E 2012 FERC Form 1
2. PG&E 2013 FERC Form 1
3. PG&E 2014 FERC Form 1
4. PG&E 2015 FERC Form 1

Electronic Quarterly Report

1. Report Viewer
   - Searches can be done for PG&E as seller into ISO Market or for PG&E as a buyer

California Public Utilities - Energy

Contract Resource Links

1. Renewable Project List: Renewable Contracts by IOU – *PCIA Eligible*
2. Resource Adequacy Report

Proceedings Documents

1. Energy Resource Recovery Forecast Proceedings
2. PG&E's ERRA Forecast – Forecast of Generation Procurement Costs and Non-bypassable Charges
   a. A1606003 – 2017 ERRA Forecast Application and Testimony – Pending
   b. A1506001 – 2016 ERRA Forecast Application and Testimony – D.15-12-022
   c. A1405024 – 2015 ERRA Forecast Application and Testimony – D.14-12-053
   d. A1305015 – 2014 ERRA Forecast Application and Testimony – D.13-12-043
   e. A1206002 – 2013 ERRA Forecast Application and Testimony – D.12-12-008
   f. A1106004 – 2012 ERRA Forecast Application and Testimony – D.11-12-031
   g. A1005022 – 2011 ERRA Forecast Application and Testimony – D.10-12-007
3. PG&E's ERRA Compliance Review Proceedings - Reviews Contract Administration
   a. A1602019 – 2015 ERRA Compliance Review Application and Testimony – Pending
   b. A1502023 – 2014 ERRA Compliance Review Application and Testimony – Pending
   c. A1402008 – 2013 ERRA Compliance Review Application and Testimony – Pending
   d. A1302023 – 2012 ERRA Compliance Review Application and Testimony – D.16-04-006
   e. A1202010 – 2011 ERRA Compliance Review Application and Testimony – D.14-01-011

Integrated Resource Plan

1. R1602007 - 2016 Integrated Resource Plan Proceeding
2. R1312010 – 2014 Long Term Procurement Plan

General Rate Case: GRC

PG&E's GRC

1. 2017 GRC - A.15-09-001 Test Year 2017
2. 2014 GRC - A.12-11-009 Test Year 2014

   D.14-08-032 (Revenue Requirement for 2014, 2015, and 2016)

3. 2011 GRC – A.09-12-090 Test Year 2011

   D.11-05-018 (Revenue Requirements for 2011, 2012, and 2013)

4. 2007 GRC - A.05-12-002

   D.07-03-044 (Revenue Requirements for 2007, 2008, 2009, and 2010)

Historical Cost Data for the CPUC Jurisdictional Utilities

1. Overview
2. Bundled System Average Rates, Bundled Sales, RRQ, RateBase, ROR, ROE, Capital Structure

Independent System Operator

1. Final Net Qualifying Capacity Report for Compliance Year 2017

PG&E Website

1. Bundled Procurement Plan
2. 2015 FERC Form 1
3. PG&E Advice Letter List
4. Procurement Review Group
5. ReMat FIT Program
6. Renewable
   a. Tariff Book
   b. Special Study RPS Portfolios
   c. RPS Calculator
7. PG&E Wholesale Power Procurement
   a. Existing Public Water and Wastewater Facilities (E-PWF) and Small Renewable Generators (E-SRG).

California Energy Commission

Electric Almanac

1. California Electricity Data, Facts, and Statistics
2. *Cost of Generation Report*
   i. *March 2015 Report*
   ii. *April 2010 Report*
3. *2017 Integrated Energy Policy Report (IPER)*

Power Content Label

1. Overview of Power Content Label

a. 2014 Power Content Mix – All Utilities
   - i. PG&E 2014

b. 2013 Power Content Labels
   - i. PG&E 2013

c. 2012 Power Content Labels
   - i. PG&E 2012

d. 2011 Power Content Labels
   - i. PG&E 2011

e. 2010 Power Content Labels
   - i. PG&E 2010

Attachment E

Presentations from PCIA Working Group Meeting #4, January 23, 2017

PCIA WORKING GROUP MEETING

January 23, 2017

SAFETY AND EVACUATION

AGENDA

10:00 – 10:15	Welcome, introduction, safety moment
10:15 – 10:45	Ideas related to changing the current PCIA benchmark
10:45 – 11:45	Alternatives to current PCIA framework – Part I
11:45 – 12:30	*Lunch break*
12:30 – 13:30	Alternatives to current PCIA framework – Part II
13:30 – 14:30	Areas to improve data access and transparency – potential areas to include in a petition for modification • Outline of the proposed final report documenting topics discussed and information shared within the Working Group • Uniform documentation of some of the PCIA work papers • Uniform interpretation of confidentiality in the PCIA • Other proposals
14:30 – 15:00	Wrap up & next steps – Focus of the Working Group through end of March

DIAL-IN INFORMATION

Phone dial-in information:

10:00 – 15:00

Call-in: 626-543-6758

Conference ID: 55136706

Location: Los Angeles - SCE Building - 2244 Walnut Grove Ave., Rosemead

IDEAS RELATED TO CHANGING THE CURRENT PCIA BENCHMARK

MPB ALTERNATIVE
SONOMA CLEAN POWER

Identified Concerns	**Recommendation/Improvement Ideas**
• The current MPB based on an outdated premise that the IOUs must sell existing resources to accommodate the loss of CCA/DA load. The MPB originally addressed departing load leaving stranded DWR contracts. Now IOUs are procuring for load growth and new RPS.	- MPB should be based on the bundled procurement avoided by CCA/DA load - The correct premise is that the CCA/DA load has departed and removed the obligation of the IOUs to procured ADDITIONAL resources, thus saving bundled customers those costs into the future. - The MPB should be based on the avoided costs of those additional resources. - IOUs have solid data on those costs—the mix of PPAs and UOG resource costs incrementally acquired since the departure of the CCA/DA customer. - The MPB then changes by vintage to reflect the entire stream of PPA/UOG contracts since the initial exit year for each CCA or DA customer, not just the average of PPAs signed over the last year. - This method had computational and transparency advantages over the current method.

Sonoma Clean Power
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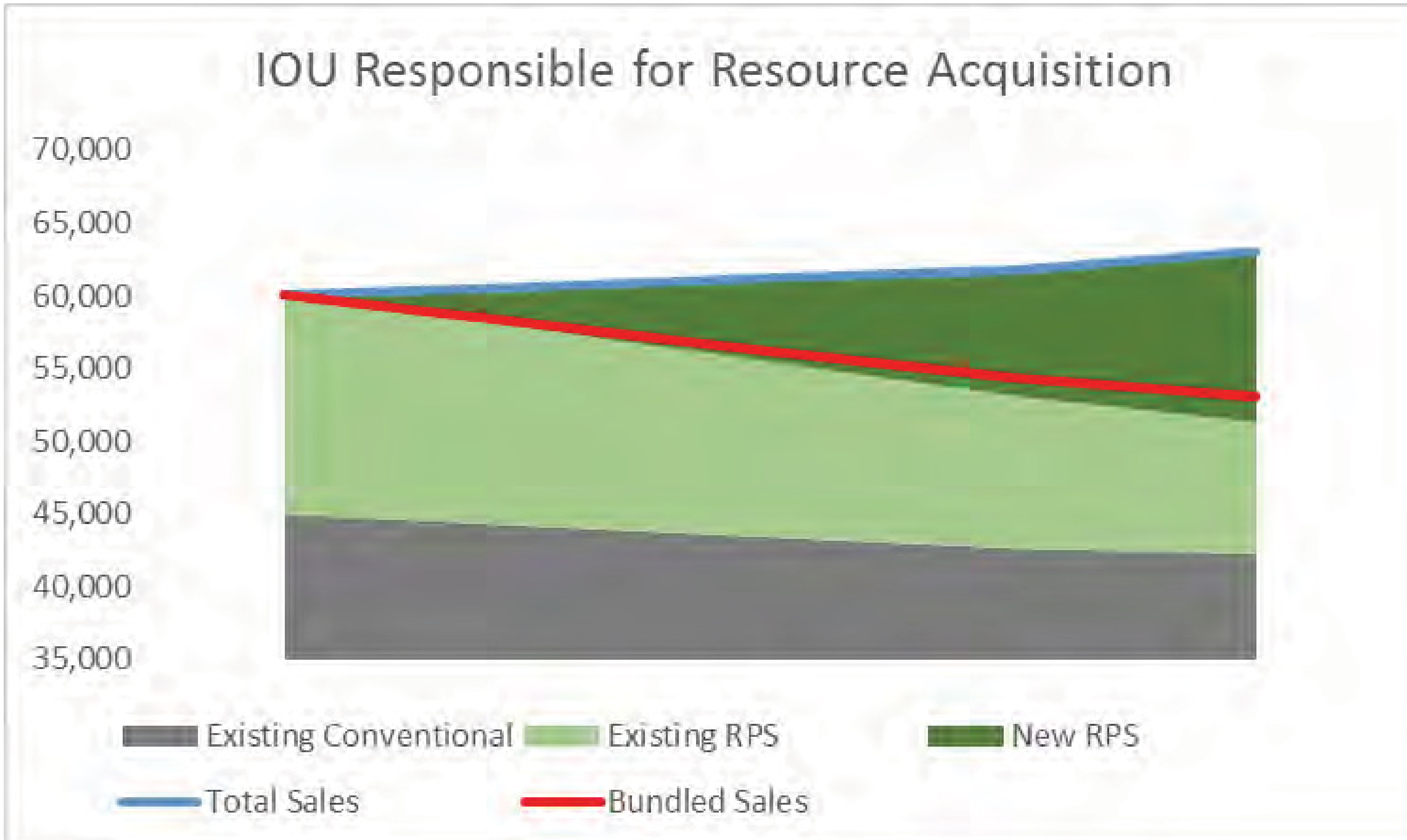
6

Bundled ratepayer savings			
<u>Sales/Loads</u>	**Initial**	**All Bundled**	**CCA departed**
Bundled Sales	60,000	63,100	54,000
CCA/DA Sales			9,100
Total Sales	60,000	63,100	63,100
<u>Generation Portfolio</u>			
Existing GWH	60,000	54,000	54,000
Retirements/Expirations		6,000	
Additional Total RPS GWH		9,100	
Additional **<u>Bundled RPS GWH</u>**			0
Existing Cost	$4,200	$3,780	$3,780
Existing $/MWH	*$70*	*$70*	*$70*
New RPS Cost		$728	$0
RPS $/MWH = MPB		***$80***	***$80***
Total **<u>Bundled</u>** Cost $MM	**$4,200**	**$4,508**	**$3,780**
Average Cost per MWH	*$70.00*	*$71.44*	*$70.00*
Portfolio Cost Difference $MM			-$728
Avg. Difference/MWH = PCIA			***-$1.44***

MPB ALTERNATIVE – MERGED PROCUREMENT



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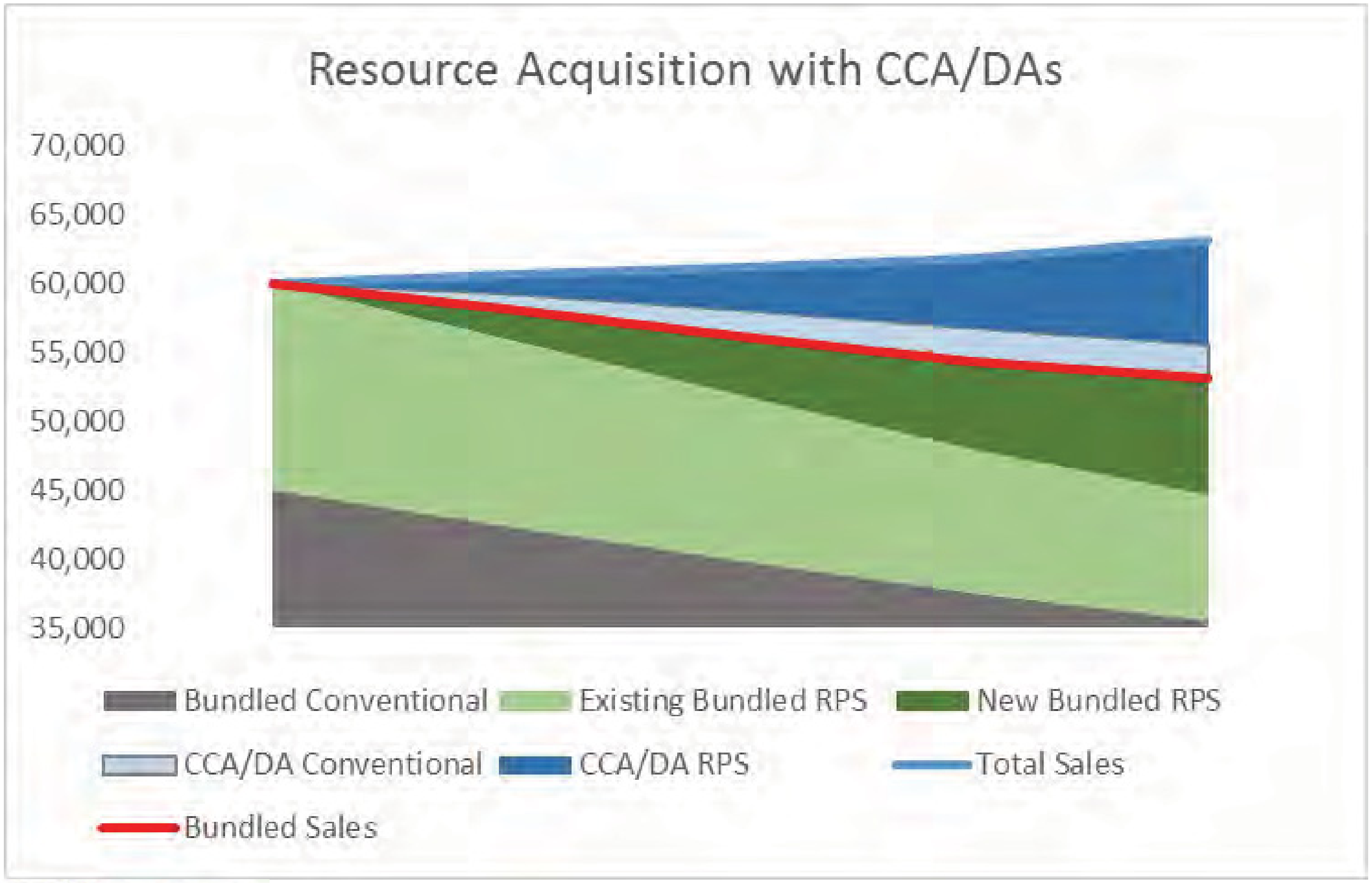
MPB ALTERNATIVE – ACTUAL PROCUREMENT



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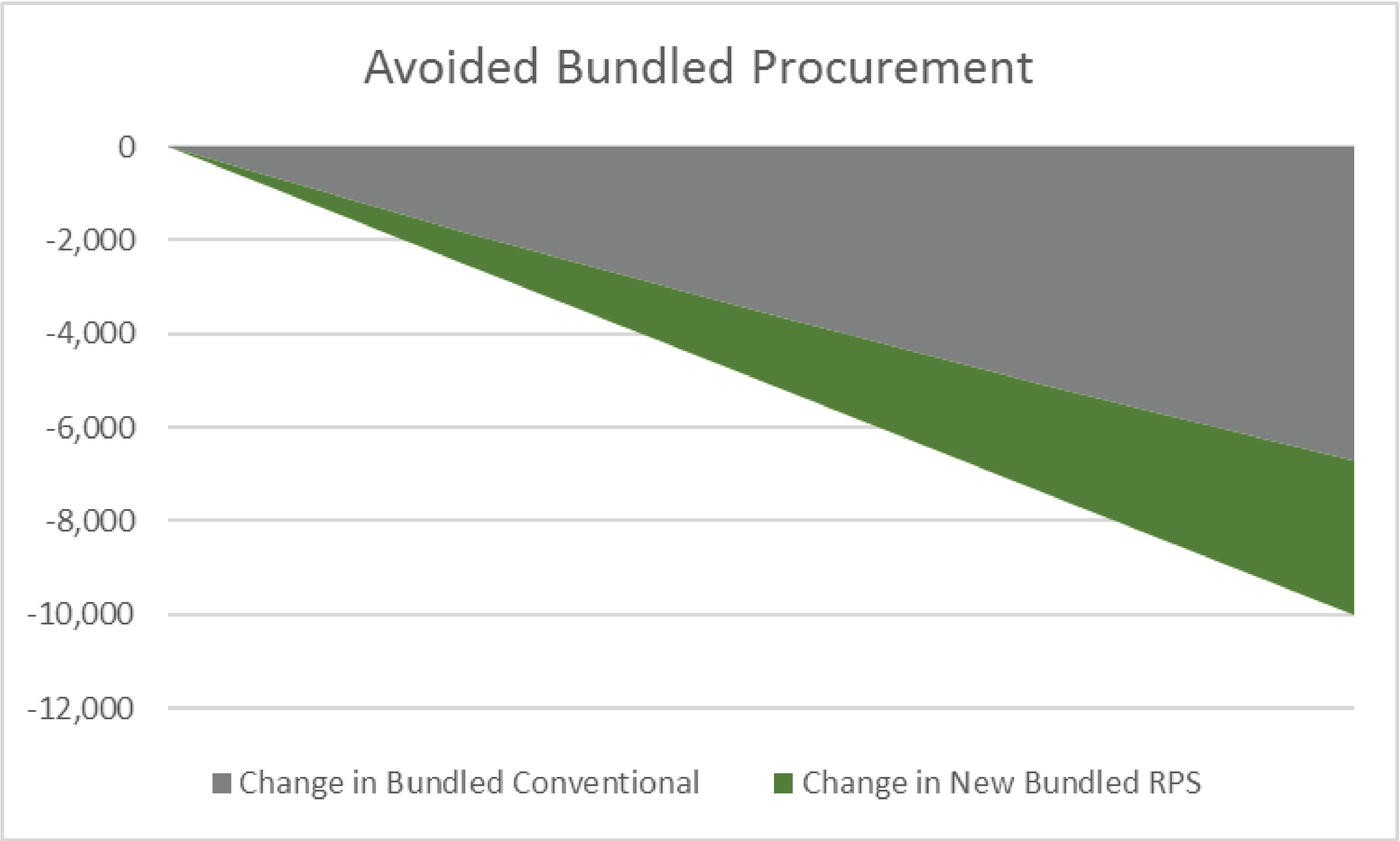
MPB ALTERNATIVE – AVOIDED COSTS



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MPB ALTERNATIVE EXAMPLE

	MPB concept example					
1	**Year**	**2016**	**2017**	**2018**	**2019**	**2020**
2	**Sales**					
3	Bundled Sales	60,000	58,100	56,200	54,300	53,100
4	**CCA/DA Sales**	0	2,500	5,000	7,500	10,000
5	Total Sales	60,000	60,600	61,200	61,800	63,100
6	**Resources**					
7	***For All Sales***					
8	Existing Conventional	45,000	44,238	43,452	42,642	42,277
9	Existing RPS	15,000	13,500	12,000	10,500	9,000
10	Total RPS	15,000	16,362	17,748	19,158	20,823
11	% RPS Target	25%	27%	29%	31%	33%
12	New RPS	0	2,862	5,748	8,658	11,823
13	***After CCA/DA Sales***					
14	Existing Bundled RPS	15,000	13,500	12,000	10,500	9,000
15	New Bundled RPS	0	2,187	4,298	6,333	8,523
16	*% RPS Bundled*	*25%*	*27%*	*29%*	*31%*	*33%*
17	*Bundled RPS Difference*	*0*	*-675*	*-1,450*	*-2,325*	*-3,300*
18	Bundled Conventional	45,000	42,413	39,902	37,467	35,577
19	*Bundled Conventional Difference*	*0*	*-1,825*	*-3,550*	*-5,175*	*-6,700*
20	CCA/DA RPS	0	1,400	3,100	5,100	7,500
21	CCA/DA Conventional	0	1,100	1,900	2,400	2,500
22	*% RPS CCA/DA*	*50%*	*56%*	*62%*	*68%*	*75%*
23	**MPB Calculation**					
24	Avoided New Bundled RPS	0	-675	-1,450	-2,325	-3,300
25	*RPS PPA $/MWH*	*$100*	*$95*	*$90*	*$85*	*$80*
26	Change in Bundled Conventional	0	-1,825	-3,550	-5,175	-6,700
27	*"Brown" $/MWH Value*	*$50.00*	*$47.50*	*$45.00*	*$42.50*	*$40.00*
28	***MPB by Vintage***	**2016**	**2017**	**2018**	**2019**	**2020**
29	2017 Vintage		$60	$59	$57	$55
30	2018 Vintage			$58	$56	$55
31	2019 Vintage				$56	$54
32	2020 Vintage					$53

SUMMARY OF ALTERNATIVES TO PCIA

OVERVIEW

During the PCIA Working Group Meetings, a number of parties have raised proposals to replace the PCIA with other alternatives for cost allocation

This presentation summarizes some of the proposed PCIA alternatives suggested by various PCIA Working Group participants and considers issues with each of these alternatives

ALTERNATIVE #1: PRO RATA ALLOCATION OF ATTRIBUTES AND COSTS

Description:

Allocate annually the proportionate ESP/CCA share of net costs and attributes of the IOU portfolio, based upon vintage:

- Net cost is based on the difference between actual portfolio cost and market revenues
- CCA/ESP receives proportional allocation of RECs and RA capacity but IOU remains the contract counterparty and retains contract, resource management, and payment obligations
- Uses annual forecast and annual true-up of both costs and actual market revenues[(1)]

Allocation approach applies to all eligible customers,[(2)] vintaged based on departure date.

Net portfolio costs and attributes that are allocated to LSEs will be removed from the IOU portfolio; bundled service generation rates will be based on the remaining portfolio costs and attribute value.

Addressing Bundled Customer Indifference:[(3)]

Costs and benefits are allocated to all customers based on actual net costs and benefits incurred.

1) While CAM includes a true-up for actual costs incurred, this alternative would also include a true-up for actual revenues received.
2) Direct Access customers that did not receive bundled service procurement services during the 2000-01 Energy Crisis are excluded.
3) AB 117, D 04-12-048, and SB 350 require that bundled retail customers remain indifferent to load departure.

PRO RATA ALLOCATION OF ATTRIBUTES AND COSTS CONSIDERATIONS

Allocation Issues

- Benefits (e.g., Resource Adequacy and Renewable Energy Credits) will be allocated in the same manner that net costs are allocated.
- If CCA/ESP does not want to maintain their full pro rata share of attributes, the CCA/ESP is able to sell them directly as opposed to an administratively established valuation as used in today's PCIA.

Regulatory approval

- CPUC approval is required for a new approach
- Regulatory changes may be required to ensure IOUs retain and CCAs/ESPs receive full value of attributes (e.g., transfer of PCC 1 RECs)

ALTERNATIVE #2: BUY-OUT OF PCIA OBLIGATION

Description

Mutually agreeable buy-out negotiated by a CCA/ESP and IOU

- For example: Structured tariff offering or a negotiated agreement between the CCA/ESP and IOU that is submitted to the Commission via an Application for approval

Buy-out amount would be:

- Based on the payment required for bundled customer indifference, to include a risk premium to be paid for by the CCA/ESP to account for the possibility of underestimation
- Based on defined load within geographical service territory

Additional service phase-in (load and/or geographical territory expansion) would require additional negotiated lump sum buy-out payments

IOUs retain existing contract obligations and attributes

Buy-out payments reduce the total portfolio costs used to determine bundled service generation rates and PCIA rates for customers served by non-participating LSEs

Addressing Bundled Customer Indifference:

Risk premium is included to prevent against underestimation of the required buy-out amount for indifference. Potential periodic refunds to the CCA/ESP could be used in the case of overestimation.

BUY-OUT OPTION CONSIDERATIONS

How to estimate the payment

- Payment could be calculated to reflect NPV of forecasted PCIA requirements attributable to the CCA/ESP through the life of the contracts and UOG resources , to include a risk premium for market price uncertainty.
- Buy-out may be structured in $/MW or $/MWh and would not be adjusted down later if CCA/ESP were to experience load loss. Parties will need to agree upon:
  - Long-term discount rate and confidence interval used for risk premium. Risk premium will need to consider possibility that IOUs may not be able to sell all of the excess resources in their portfolios resulting from load departure at forecasted market prices.
  - Whether and how often the IOUs would provide periodic refunds to the CCA/ESP
  - Updated PCIA market benchmarks to more accurately reflect forecasted market values

BUY-OUT OPTION CONSIDERATIONS (CONT.)

How to collect payment

- Parties could agree to either a one-time lump sum payment or a payment plan, plus interest. Parties will need to agree upon:
  - Interest rate and term for potential payment plan
  - Level and type of credit support required under a payment plan
  - How potential periodic refunds from the IOU to the CCA/ESP would affect payment plan
  - How would opt-out payments be distributed annually to prevent rate volatility to bundled service and non-participating LSEs' customers.

Impact of numerous individual negotiations and additional departing load

- To ensure regulatory approval and transparency, buy-out principles and framework would need to be largely the same across individual negotiations
- Buy-out terms (e.g. interest rate) may vary between individual negotiations and increases in load departure would be subject to new negotiations and terms
- Parties will need to agree upon frequency of negotiations for additional load departure

BUY-OUT OPTION CONSIDERATIONS (CONT.)

Regulatory approval

- CPUC approval of any buy-out is required
- CPUC approval and timing of approval is not certain and will need to be considered when parties agree upon frequency of negotiations and potential refunds

ALTERNATIVE #3: ASSIGNMENT OF IOU CONTRACTS TO CCAs/ESPs

Description:

- Mutually agreeable assignment of subset of IOU contracts to CCA/ESP
- IOUs would identify potential contracts and seek counterparty consent for disclosure in order to include them in assignment discussions
- CCAs/ESP would assume contract and resource management, as well as payment obligations going forward
- IOUs would have no future rights or obligations in those contracts for the period after the assignment

Addressing Bundled Customer Indifference:

Given unlikely ability to match contract obligations with departing load obligations, additional negotiated payments from the CCA/ESP to the IOU would be required

ASSIGNMENT OF IOU CONTRACTS CONSIDERATIONS

How to select contracts for assignment

- Contracts could be selected based on size of load departure and could mirror the average contract price, tenor, and resource mix of the portfolio at the time of load departure. Parties will need to agree upon:
  - The process for contract selection and maintaining commercial confidentiality of portfolio not assigned to CCA/ESP
  - The process should a supplier not agree to disclose the contract terms (required first to market to the LSE) or to the contract assignment
  - Payment of legal fees required to negotiate contract assignments.

- Composition of IOU portfolio may present challenges in identifying contracts to assign.
  - IOUs cannot assure equitable treatment to LSEs (i.e., counterparty quality, contract terms)
  - IOU contract selection would not be able to reflect vintaging.
  - Partial assignment of contracts is not possible.

ASSIGNMENT OF IOU CONTRACTS CONSIDERATIONS (CONT.)

Regulatory and legislative approval

- CPUC approval of any contract assignment is required
- CPUC approval and timing of approval is not certain and will need to be factored in when parties agree upon frequency of negotiations
- Additional regulatory and/or legislative changes may be required to ensure IOU compliance with state procurement mandates

AREAS TO IMPROVE DATA ACCESS AND TRANSPARENCY

OUTLINE OF THE PROPOSED FINAL REPORT

Background and overview

Issues related to existing PCIA mechanism identified by parties and discussed during the 6-months engagement

- List of transparency & data access related issues
- List of issues related to the existing benchmark
- List of broader concerns related to PCIA

Overview of information shared by IOUs to address transparency & data access related issues

- Education of parties regarding the existing PCIA development, process, data inputs, calculation methodologies and available data sources
  - Relevance of November update in PCIA rate calculation
  - Historical changes of PCIA
  - General drivers of PCIA
- Education of parties regarding IOU's CCA load forecast methodology
- Education of parties regarding IOU's IOU contract requirements and limitations
- Consolidation of relevant publicly available data in one document with links.

Overview of ideas presented to address issues related to the existing benchmark

Overview of ideas presented to address broader concerns related to PCIA

Conclusions and next steps

- Recommendations to Improvement Data Access & Transparency:
  - Improve consistency of some of the IOU work papers in IOUs' annual ERRA Forecast applications (IOUs to propose uniform format)
  - CPUC maintained webpage with links to relevant PCIA data sources

POTENTIAL WORK PAPERS TO IMPROVE CONSISTENCY AMONG IOUS

- Table of Benchmarks, Pursuant to Resolution E-4475
- Vintaged Portfolio (costs, energy, and RA)
- Indifference Calculation by Portfolio
- Proposed PCIA and CTC Rates

PCIA DOCUMENTATION

Proposal for Consistent and Transparent PCIA Documentation

Objectives

- The documentation process should increase efficiency and transparency for all, while maintaining confidentiality
- Consistent documentation should be provided for all estimated, updated and final PCIA calculations
- Consistent format across IOUs should be provided
- Documentation should include the data used, working formulas, and detailed source of data.
- Proposal is based on information already provided by the IOUs
  - Spreadsheet provides sample format
- Documentation process should be expandable and useful for forecasting purposes

Requests for PCIA Documentation

- Provide similar tables and information every time
- Provide a summary of what has changed and why
- Provide the information related to all the steps in the PCIA calculation
- Provide indicative bundled and unbundled rates that go with PCIA estimates

PCIA Calculation Process – 5 steps

- Calculation of the Portfolio Unit Cost
- Calculation of the Market Price Benchmark
- Calculation of the Indifference Amount
- Allocation of Indifference Amount to Customer Classes and Vintages
- Indicative Rates

Step 1 – Portfolio Unit Cost and Quantity

- Some information is Confidential
- Provides
  - Total CRS Eligible Portfolio GWH by vintage
  - Total CRS Eligible Portfolio Cost by vintage
  - Sum of total CRS Eligible Portfolio Cost and GWH for the year
  - Calculates Portfolio unit cost by vintage and for the year
- Referenced Documents
  - SCE: 2017 ERRA filing Public Version, May 2, 2016, Appendix B
  - PG&E: 2017 ERRA filing Update to Prepared Testimony, Public Version, November 2, 2016.
  - "November Update and PCIA Rate Calculation" presentation to PCIA workgroup by SCE 11/17/2016

Step 1 – Portfolio Unit Cost and Quantity*

	Portfolio Costs and Quantities Summary		1/1/2017							
Line No.	Description	Equation	Units	2012	2013	2014	2015	2016	2017	Source of Data
1	**Cost of Portfolio**									
2	CRS Elegible Portfolio Costs		$000	$64,703	$291,018	$165,483	$177,175	$970	0	Provide Source & Reference/link
3	Cumulative Portfolio Costs	Previous year + line 2	$000	$2,950,082	$3,241,100	$3,406,583	$3,583,758	$3,584,728	$3,584,728	
4	**Supply at Meter**									
5	Vintaged GWH @ meter	Line 6 - Previous Year Line 6	GWh	723	1,744	1,868	2,619	20	0	
6	Vintaged GWH @ meter Cummulative		GWh	30,276	32,020	33,888	36,507	36,527	36,527	Provide Source & Reference/link
7	**Net Qualifying Capacity**		MW	18	3,391	2,156	1,408	27	0	Provide Source & Reference/link
8	**Cumulative Capacity**	Previous year + line 7	MW	3,871	7,262	9,418	10,826	10,853	10,853	
9	**Capacity Factor**	Line 6/8760/Line 13/1000		89.3%	50.3%	41.1%	38.5%	38.4%	38.4%	
10	**Portfolio Unit Cost Incremental**	Line 2/Line 5	$/MWh	$89.49	$166.87	$88.59	$67.65	$48.50	-	
11	**Portfolio Unit Cost**	Line 3/Line 6	$/MWh	$97.44	$101.22	$100.52	$98.17	$98.14	$98.14	

* Years from 2001 – 2011 are hidden in the table above.

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Step 2 – Indifference Calculation

- Some data is confidential
- Provides
  - On-peak & Off-peak Load Weights
  - Weighted Market Price
  - Portfolio Renewable share
  - Calculation of IOU Green Benchmark
  - Weighted Average Renewable Benchmark

Step 2 – Indifference Calculation

	Indifference Calculation Inputs & Sources			**1/1/2017**	
Line No.	**Description**	**Equation**	**Units**	**Data**	**Source of Data**
1	On Peak SP 15 Price		$/MWh	[redacted]	Platts (Date)
2	Off Peak SP 15 Price		$/MWh	[redacted]	Platts (Date)
3	On Peak Load Weight		%	62%	Provide Source & Reference/link
4	Off Peak Load Weight		%	28%	Provide Source & Reference/link
5	Load Weighted Average Price	Line 1* Line 3+Line 2* Line 4	$/MWh	$33.73	
6	IOU Green Benchmark	Line 19	$/MWh	$73.92	
7	IOU RPS Premium	Line 6-Line 5	$/MWh	$40.19	
8	DOE Renewable Adder		$/MWh	$16.64	DOE website
9	Weighted Average Renewable Premium	68% * line 7 +32%*line 8	$/MWh	$32.65	
10	Weighted Average Renewable Benchmark	Line 9 plus line 5	$/MWh	$66.38	
11	Capacity Benchmark		$/MWh	$58.26	Provide Source & Reference/link
12	Line Loss Adjustment Factor			1.053	Resolution E-4475
13	**IOU Green Benchmark**				
14	Total IOU Renewable Resource Cost		$000	$536,211	Provide Source & Reference/link
15	Total IOU Renewable Resource Capacity		MW	823	Provide Source & Reference/link
16	Total IOU Renewable Resoource Capacity Value	Line 15*line 11	$000	$47,948	
17	Revised IOU Renewable Resource Cost	Line 14 - Line 16	$000	$488,263	
18	Total IOU Renewable Energy		MWH	6,605,179	Provide Source & Reference/link
19	**IOU Green Benchmark**	Line 17/Line 18 *1000	$/MWh	**$73.92**	

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Step 3 – Indifference Amount - Total

- Provides Cost of Portfolio by vintage
- Provides Market Value of Portfolio
  - Value of Brown Portfolio
  - Value of Green Portfolio
  - Value of Capacity
- Calculated Indifference Amount by Vintage
- Provides place for adjustments
  - SCE examples: Nuclear Decommissioning Trust, NEIL Settlement

Step 3 – Indifference Amount – Total*

Line Number	Description	Equation	Unit	2012	2013	2014	2015	2016	2017	Source of Data
1	**Cost of Portfolio**									
2	Total Portfolio Cost	Portfolio Cost and Quantities Line 3	$000	$2,950,082	$3,241,100	$3,406,583	$3,583,758	$3,584,728	$3,584,728	
3	Supply at Customer Meter	Portfolio Cost and Quantities Line 6	GWH	30,276	32,020	33,888	36,507	36,527	36,527	
4	Renewable Supply at Customer Meter	Input	GWH	20,074	20,728	22,595	25,214	25,234	25,234	Provide Source & Reference/link
5	Renewable Percentage in Portfolio	Line 4/line 3		66.3%	64.7%	66.7%	69.1%	69.1%	69.1%	
6	Average Monthly Net Qualifying Capacity	Portfolio Cost and Quantities Line	MW	3,871	7,262	9,418	10,826	10,853	10,853	
7	**Portfolio Unit Cost**	Line 1/line 3	**$/MWH**	**$97.44**	**$101.22**	**$100.52**	**$98.17**	**$98.14**	**$98.14**	
8	**Market Value of Portfolio**									
9	**Market Value of Brown Portfolio**									
10	Non-Renewable Energy	Line 3-Line 4	GWH	10,202	11,292	11,293	11,293	11,293	11,293	
11	Platt's weighted Price (Brown Benchmark)	Portfolio Cost and Quantities Line	$/MWh	$33.73	$33.73	$33.73	$33.73	$33.73	$33.73	
12	Brown Share of Portfolio	1-line 5	%	33.7%	35.3%	33.3%	30.9%	30.9%	30.9%	
13	**Market Value of Brown Portfolio**	Line 10*Line 11	$000	**$344,113**	**$380,879**	**$380,913**	**$380,913**	**$380,913**	**$380,913**	
14	**Market Value of Green Portfolio**									
15	Renewable Energy	Line 4	GWH	20,074	20,728	22,595	25,214	25,234	25,234	
16	Weighted Average Green Benchmark	Portfolio Cost and Quantities Line	$/MWh	$66.38	$66.38	$66.38	$66.38	$66.38	$66.38	
17	Green Share of Portfolio	Line 5	%	66.3%	64.7%	66.7%	69.1%	69.1%	69.1%	
18	**Market Value of Green Portfolio**	Line 15* Line 16	$000	**$1,332,609**	**$1,376,025**	**$1,499,966**	**$1,673,827**	**$1,675,155**	**$1,675,155**	
19	**Capacity Adder**									
20	Average Monthly NQC	Line 6	MW	3,871	7,262	9,418	10,826	10,853	10,853	
21	Capacity value per resolution E-4475	Portfolio Cost and Quantities Line	$/kW-yr	$58.26	$58.26	$58.26	$58.26	$58.26	$58.26	3
22	**Market Value of Capacity**	Line 20 * Line 21	$000	**$225,524**	**$423,084**	**$548,693**	**$630,723**	**$632,296**	**$632,296**	

Step 3 – Indifference Amount – Total*

Line Number	Description	Equation	Unit	2012	2013	2014	2015	2016	2017	Source of Data
23	**Portfolio Unit Value**	Line 13 + Line 18 + Line 22	$000	**$1,902,247**	**$2,179,988**	**$2,429,571**	**$2,685,463**	**$2,688,364**	**$2,688,364**	
24	**Line Loss Adjusted Portfolio Value**	Line 23* Indifference Calculation Input	$000	**$2,003,066**	**$2,295,528**	**$2,558,338**	**$2,827,793**	**$2,830,847**	**$2,830,847**	
25	**Indifference Amount**									
26	Portfolio Total Cost	Line 1	$000	$2,950,082	$3,241,100	$3,406,583	$3,583,758	$3,584,728	$3,584,728	
27	Portfolio Total value	Line 24	$000	$2,003,066	$2,295,528	$2,558,338	$2,827,793	$2,830,847	$2,830,847	
28	**Indifference Amount (Unadjusted)**	Line 26- Line 27	$000	**$947,016**	**$945,572**	**$848,245**	**$755,965**	**$753,881**	**$753,881**	
29	**Adjustments**									
30	Adjustment 1		$000	$0	$0	$0	$0	$0	$0	Provide Source & Reference/link
31	Adjustment 2		$000	($130,000)	($130,000)	($130,000)	($130,000)	($130,000)	($130,000)	Provide Source & Reference/link
32	Adjustment 3		$000	($150,000)	($150,000)	($150,000)	($150,000)	($150,000)	($150,000)	Provide Source & Reference/link
33	**Adjusted Indifference Amounts**	Line 28 - Line 30 -Line 31- Line 32	$000	**$667,016**	**$665,572**	**$568,245**	**$475,965**	**$473,881**	**$473,881**	

*Years from 2001 – 2011 are hidden in the table above.

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Step 4 – Indifference Amount Allocated

- Provides Adjusted Indifference Amount by Vintage
- Provides Allocator by Rate Schedule
- Provides Allocated Indifference Amount
- Provides Billing Determinant
- Provides Calculated PCIA by vintage by rate schedule

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Step 4 – Indifference Amount Allocated*

Line Number	Description	Equation	Unit	2012	2013	2014	2015	2016	2017	Source of Data
1	**Indifference Amount**									
2	Portfolio Total Cost	Indifference Amount - Total line 26	$000	$2,950,082	$3,241,100	$3,406,583	$3,583,758	$3,584,728	$3,584,728	
3	Portfolio Total value	Indifference Amount - Total line 27	$000	$2,003,066	$2,295,528	$2,558,338	$2,827,793	$2,830,847	$2,830,847	
4	**Indifference Amount (Unadjusted)**	Line 2 - Line 3	$000	**$947,016**	**$945,572**	**$848,245**	**$755,965**	**$753,881**	**$753,881**	
5	Adjustments	Indifference Amount - Total line 33	$000	($280,000)	($280,000)	($280,000)	($280,000)	($280,000)	($280,000)	
6	**Adjusted Indifference Amounts**	**Line 4 + Line 5**	$000	**$667,016**	**$665,572**	**$568,245**	**$475,965**	**$473,881**	**$473,881**	
7	**Allocator (%)**									
8	Domestic		%	45.3%	45.3%	45.3%	45.3%	45.3%	45.3%	Provide Source & Reference/link
9	GS-1		%	6.2%	6.2%	6.2%	6.2%	6.2%	6.2%	Provide Source & Reference/link
10	GS-2		%	18.0%	18.0%	18.0%	18.0%	18.0%	18.0%	Provide Source & Reference/link
11	TOU-GS-3		%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	Provide Source & Reference/link
12	TOU-8-SEC		%	7.8%	7.8%	7.8%	7.8%	7.8%	7.8%	Provide Source & Reference/link
13	TOU-8-PRI		%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	Provide Source & Reference/link
14	TOU-8-SUB		%	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%	Provide Source & Reference/link
15	Small AG		%	1.9%	1.9%	1.9%	1.9%	1.9%	1.9%	Provide Source & Reference/link
16	Large AG		%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	Provide Source & Reference/link
17	**Allocated Indifference Amount**									
18	Domestic	Line 6 * Line 8	$000	$302,158	$301,504	$257,415	$215,612	$214,668	$214,668	
19	GS-1	Line 6 * Line 9	$000	$41,355	$41,265	$35,231	$29,510	$29,381	$29,381	
20	GS-2	Line 6 * Line 10	$000	$120,063	$119,803	$102,284	$85,674	$85,299	$85,299	
21	TOU-GS-3	Line 6 * Line 11	$000	$60,031	$59,902	$51,142	$42,837	$42,649	$42,649	
22	TOU-8-SEC	Line 6 * Line 12	$000	$52,027	$51,915	$44,323	$37,125	$36,963	$36,963	
23	TOU-8-PRI	Line 6 * Line 13	$000	$30,016	$29,951	$25,571	$21,418	$21,325	$21,325	
24	TOU-8-SUB	Line 6 * Line 14	$000	$28,682	$28,620	$24,435	$20,467	$20,377	$20,377	
25	Small AG	Line 6 * Line 15	$000	$12,673	$12,646	$10,797	$9,043	$9,004	$9,004	
26	Large AG	Line 6 * Line 16	$000	$6,670	$6,656	$5,682	$4,760	$4,739	$4,739	
	Total	**Sum of Lines 18-26**		**$653,675**	**$652,261**	**$556,880**	**$466,446**	**$464,403**	**$464,403**	

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Step 4 – Indifference Amount Allocated*

Line Number	Description	Equation	Unit	2012	2013	2014	2015	2016	2017	Source of Data
27	**Billing Determinant**									
28	Domestic		GWH	29,031	29,031	29,031	29,031	29,031	29,031	Provide Source & Reference/link
29	GS-1		GWH	4,750	4,750	4,750	4,750	4,750	4,750	Provide Source & Reference/link
30	GS-2		GWH	13,274	13,274	13,274	13,274	13,274	13,274	Provide Source & Reference/link
31	TOU-GS-3		GWH	6,255	6,255	6,255	6,255	6,255	6,255	Provide Source & Reference/link
32	TOU-8-SEC		GWH	6,109	6,109	6,109	6,109	6,109	6,109	Provide Source & Reference/link
33	TOU-8-PRI		GWH	3,789	3,789	3,789	3,789	3,789	3,789	Provide Source & Reference/link
34	TOU-8-SUB		GWH	4,102	4,102	4,102	4,102	4,102	4,102	Provide Source & Reference/link
35	Small AG		GWH	1,692	1,692	1,692	1,692	1,692	1,692	Provide Source & Reference/link
36	Large AG		GWH	1,149	1,149	1,149	1,149	1,149	1,149	Provide Source & Reference/link
37	**PCIA**									
38	Domestic	Line 18 / Line 28	$/kWh	$0.1041	$0.1039	$0.0887	$0.0743	$0.0739	$0.0739	
39	GS-1	Line 19 / Line 29	$/kWh	$0.0871	$0.0869	$0.0742	$0.0621	$0.0619	$0.0619	
40	GS-2	Line 20 / Line 30	$/kWh	$0.0904	$0.0903	$0.0771	$0.0645	$0.0643	$0.0643	
41	TOU-GS-3	Line 21 / Line 31	$/kWh	$0.0960	$0.0958	$0.0818	$0.0685	$0.0682	$0.0682	
42	TOU-8-SEC	Line 22 / Line 32	$/kWh	$0.0852	$0.0850	$0.0726	$0.0608	$0.0605	$0.0605	
43	TOU-8-PRI	Line 23 / Line 33	$/kWh	$0.0792	$0.0790	$0.0675	$0.0565	$0.0563	$0.0563	
44	TOU-8-SUB	Line 24 / Line 34	$/kWh	$0.0699	$0.0698	$0.0596	$0.0499	$0.0497	$0.0497	
45	Small AG	Line 25 / Line 35	$/kWh	$0.0749	$0.0747	$0.0638	$0.0534	$0.0532	$0.0532	
46	Large AG	Line 26 / Line 36	$/kWh	$0.0581	$0.0579	$0.0495	$0.0414	$0.0412	$0.0412	

*Years from 2001 – 2011 are hidden in the table above.

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Step 5 – Indicative Rates

- Provide Indicative revenue & rates by rate schedule & rate component
  - Bundled Customers
  - Unbundled Customers
- Provides for Bundled and CCA/DA customers
  - Total Sales by rate schedule
  - Revenue at present rates by rate schedule
  - Unbundled rate components by rate schedule (projected revenue & rates)
  - PCIA by rate schedule
- Provides Generation rate for Bundled Customers

Step 5 – Indicative Rates

Bundled Customers														
Class/Schedule	**Total Sales (kWh)**	**Revenue at Present rates**	**Generation Rate**	**TO Rates**	**TAC Rates**	**TRBBA Rates**	**Dist Rates**	**PPP Rates**	**ND Rates**	**DWR Bond Rates**	**CTC Rates**	**ECRA Rates**	**Total Proposed Rates**	**Percent Change**
RESIDENTIAL														
E-1		$0.2244	0.09838	0.01883	0.00719	-0.00247	0.08236	0.01501	0.00149	0.00525	0.0013	-0.00001	0.22742	1.3%
EL-1		$0.1264	0.09837	0.01883	0.00719	-0.00247	0.01138	0.00776	$0.00149	$0.00000	0.0013	-0.00001	0.13001	2.8%
TOTAL RES		**$0.1966**	**0.09838**	**0.01883**	**0.00719**	**-0.00247**	**0.06217**	**0.01295**	**$0.00149**	**$0.00376**	**0.0013**	**-0.00001**	**0.19971**	**1.6%**

DA/CCA Customers																	
Class/Schedule	**Total Sales (kWh)**	**Revenue at Present rates**		**TO Rates**	**TAC Rates**	**TRBBA Rates**	**Dist Rates**	**PPP Rates**	**ND Rates**	**DWR Bond Rates**	**CTC Rates**	**ECRA Rates**	**NSGC**	**CIA Rates**	**PCIA Rates**	**Total Proposed Rates**	**Percent Change**
RESIDENTIAL																	
E-1		0.15849		0.01883	0.00719	-0.00247	0.08267	0.01501	0.00149	0.00531	0.00130	-0.00001	0.00322	0.01035	0.02916	0.16587	4.7%
EL-1		$0.0462		0.01861	0.00710	-0.00244	0.00963	0.00767	0.00147	0.00000	0.00130	-0.00001	0.00322	-0.01188	0.02926	0.05610	21.6%
TOTAL RES		**0.14535**		**0.01881**	**0.00718**	**-0.00247**	**0.07413**	**0.01415**	**0.00148**	**0.00469**	0.00130	**-0.00001**	**0.00322**	**0.00775**	**0.02918**	**0.15302**	**5.3%**

Source: http://www.pge.com/nots/rates/tariffs/tm2/pdf/ELEC_4902-E-B.pdf 3

Questions

Contact:
Anne Falcon, Senior Associate
EES Consulting, Inc

A registered professional engineering and management consulting firm with offices in Kirkland, WA and Portland, OR

Telephone (425) 889-2700, ext. 227
falcon@eesconsulting.com www.eesconsulting.com

EES Consulting, Inc.

Attachment F

Presentations from PCIA Working Group Meeting #5, February 8, 2017

PCIA WORKING GROUP MEETING

February 8, 2017

SAFETY AND EVACUATION

AGENDA

10:00 – 10:15	Welcome, introduction, safety moment
10:15 – 11:15	Update on consensus items for Petition to Modify 1) Uniform documentation of PCIA work papers in ERRA 2) Uniform interpretation of confidentiality in the PCIA 3) Host location (CPUC website) and format of PCIA data
11:15 – 11:45	Barriers and opportunities for non-profit LSEs to have enhanced data access
11:45 – 12:45	*Lunch break*
12:45 – 14:30	PCIA Alternatives 1) Pro rata allocation: Clarify whether this is collective workgroup proposal or IOU-only a. If part of workgroup, identify necessary regulatory mechanisms for benefit allocation, ability of LSEs to monetize 2) Update on items for Petition for Rulemaking: should pro-rata allocation, buy-out, or contract assignment be addressed?
14:30 – 15:00	Timeline and process for Petition to Modify, potential Petitions for Rulemaking, and White Paper capturing process and feedback

DIAL-IN INFORMATION

Phone dial-in information:

10:00 – 15:00

Call-in: 626-543-6758

Conference ID: 90691795

Location: Marin Clean Energy: 1125 Tamalpais Ave, San Rafael, CA 94901

OVERVIEW OF THE PORTFOLIO ALLOCATION METHODOLOGY APPROACH

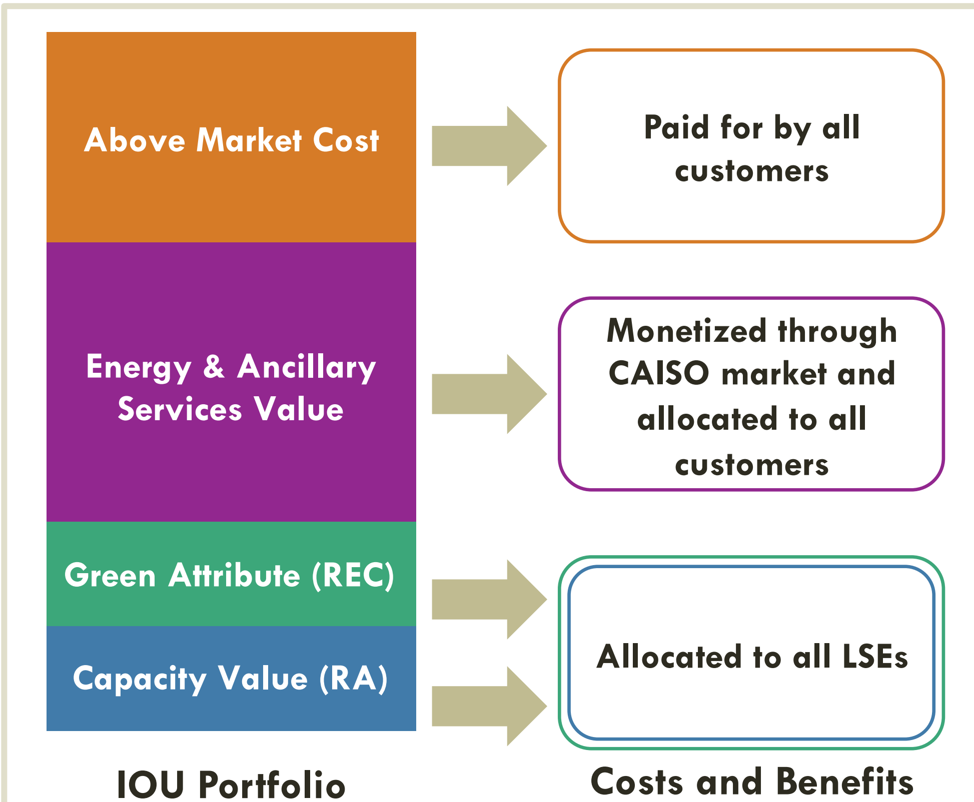
Joint presentation of PG&E, SCE, SDG&E

February 8, 2017

EXECUTIVE SUMMARY

OBJECTIVE	The Portfolio Allocation Methodology (PAM) approach is intended to replace the "above-market" construct, which is based on administratively-set benchmarks, in order to ensure bundled customer indifference.
MARKET-BASED DETERMINATION OF ACTUAL COSTS	Pro-rated net costs allocated to customers would be determined on a vintaged portfolio basis, based on forecast portfolio costs and market revenues, and would be trued up to reflect actual costs and revenues.
EQUITABLE ALLOCATION OF ACTUAL BENEFITS	Load Serving Entities (LSEs) would receive a pro-rated allocation of resource attributes, including Resource Adequacy (RA), Renewable Energy Credits (RECs), and any future attributes.

PAM OVERVIEW



BENEFITS

- Eliminates administratively-set benchmarks
- Clear, transparent, and effective
  - ☑ *No longer based on confidential data and market estimates*
- Includes a true-up to reflect actual costs and value
- Meets statutory indifference requirement

A Portfolio Allocation Methodology (PAM) replaces inaccurate and contentious administrative prices with true market valuation and an allocation of attributes. It is consistent with State Law, equitable to all customers and is effective at any level of load departure.

RESOURCES

INCLUDED RESOURCES	EXCLUDED RESOURCES

• Contracts
– PPAs that are ineligible for CAM (ex: RPS)
– New contracts > 1 year
– CTC-Eligible Contracts
  • Pre-1996 QF Legacy
  • Legacy Water district contracts
• UOG Facilities
– Pre-1997 (Nuclear & Hydro)
– Post-2002 (Fossil, Solar, Fuel Cells, Non-Distribution storage)
	• CAM Resources
	• Contracts $\leq$ 1 year
	• Resources eligible for broad allocation (e.g., BioRAM/Tree Mortality)

SUMMARY: Include all resources in bundled service generation portfolio, including CTC-eligible resources; exclude CAM-eligible resources.

CALCULATION OF NET COSTS

COSTS	Market Revenues
• Contract Costs – PPA costs – GHG compliance instrument costs • Indirect Costs – Fuel (e.g., natural gas, water, etc.) – Hedging • UOG Costs – Capital – O&M – New Capital Upgrades **Excluded Costs:** • Congestion Revenue Rights • Gas Storage	• Energy and Ancillary Service Revenues (all markets) • Net CAISO grid management revenues/ costs, unit commitment revenues/costs, and “make whole” revenues/costs

SUMMARY: Initial rate based on forecast of resource costs and revenues/charges from CAISO market; trued-up annually.

ALLOCATION AND TRUE-UP OF NET COSTS

Resource Costs – Offsetting Revenues = PAM Amount

- PAM Amount is calculated for each vintage resource portfolio, and allocated to departed customers based on assigned vintage consistent with D.16-09-044.
- Net costs are trued-up in the ERRA Forecast proceeding based on actual portfolio performance and market settlement data using a balancing account (like CAM).

SUMMARY: Consistent with the current PCIA vintaging, costs are calculated and allocated to customers based on their date of departure. Customers are responsible for their pro-rata share of the net costs of their vintaged portfolio.

ALLOCATION OF BENEFITS: RECs

ALLOCATION OF REC ATTRIBUTES	
ALLOCATION	RECs allocated to ~~the~~ LSEs based on load share (not peak load)
TIMING	• Forecasted yearly • Allocated annually
TRUE-UP	Annually, to reflect changes to actual load share and actual changes to REC generation

SUMMARY: RECs allocated to LSEs based on their annual energy load share.

ALLOCATION OF BENEFITS: RA ATTRIBUTES

ALLOCATION OF RA ATTRIBUTES	
ALLOCATION	RA credit allocated to ~~the~~ LSEs based on forecast peak load share
TIMING	• System, Local, and Flex RA credit forecasted annually
RE-ALLOCATION	Based on updates to monthly peak loads, amounts of RA credit are re-allocated: • Details on timing to be developed

SUMMARY: Consistent with current CAM RA allocations, credit for System, Local, and Flexible RA will be allocated to LSEs based on forecast peak load share.

EXAMPLE – ILLUSTRATIVE PROPOSAL FOR DISCUSSION PURPOSES ONLY

- LSE X departs in 2001
  - Annual load of approximately 1,000 GWh and peak load of 185 MW
  - LSE X represents approximately 10% of IOU retail sales and 7% of peak load

- CCA Y departs in 2010
  - Annual load of approximately 2,000 GWh and peak load of 600 MW
  - CCA represents approximately 20% of IOU retail sales and 24% of peak load

- CCA Z departs in 2014
  - Annual load of approximately 3,000 GWh and peak load of 800 MW
  - LSE X represents approximately 30% of IOU retail sales and 32% of peak load

ALLOCATION OF COSTS – ILLUSTRATIVE

	Forecast									
	Load Forecast (GWh)		**2001 Portfolio**		**2010 Portfolio**		**2014 Portfolio**	**...**		**2017 Portfolio[1/]**
1.	LSE X Load Forecast		1,000					...		
2.	CCA Y Load Forecast		2,000		2,000			...		
3.	CCA Z Load Forecast		3,000		3,000		3,000	...		
4.	Remaining Bundled Load Forecast		4,000		4,000		4,000	...		4,000
5.	Total Load Responsible		10,000		9,000		7,000	...		4,000
6.	Incremental Forecast Net Costs ($M)	$	200	$	160	$	120	...	$	40
7.	**Incremental Rate by Vintaged Portfolio**	**$**	**0.0200**	**$**	**0.0178**	**$**	**0.0171**	**...**	**$**	**0.0100**
8.	**Final PAM Rate**	**$**	**0.0200**	**$**	**0.0378**	**$**	**0.0549**	**...**	**$**	**0.0649**
	True Up									
	Actual Load (GWh)		**2001 Portfolio**		**2010 Portfolio**		**2014 Portfolio**	**...**		**2017 Portfolio[1/]**
9.	LSE X Load Actual		1,200					...		
10.	CCA Y Load Actual		1,900		1,900			...		
11.	CCA Z Load Actual		3,300		3,300		3,300	...		
12.	Remaining Bundled Load Actual		3,900		3,900		3,900	...		3,900
13.	Total Load Responsible		10,300		9,100		7,200	...		3,900
14.	Actual Net Costs	$	233	$	147	$	127	...	$	33
15.	Actual Revenues Collected from Customers	$	206	$	162	$	123	...	$	39
16.	True Up Amount to add to Next Year's Forecast Net Cost	$	27	a		$	4	...	$	(6)

1/ 2017 Portfolio costs and attributes are only assigned to bundled service customers and customers who depart after 2017

ALLOCATION OF RECS – ILLUSTRATIVE

	Forecast					
	Load Forecast (GWh)	**2001 Portfolio**	**2010 Portfolio**	**2014 Portfolio**	**...**	**2017 Portfolio[1/]**
1.	LSE X Load Forecast	1,000			...	
2.	CCA Y Load Forecast	2,000	2,000		...	
3.	CCA Z Load Forecast	3,000	3,000	3,000	...	
4.	Remaining Bundled Load Forecast	4,000	4,000	4,000	...	4,000
5.	Total Load Responsible	10,000	9,000	7,000	...	4,000
	Forecast REC Allocations					
6.	**Forecast RECs in Portfolio**	1,500 GWh	2,000 GWh	2,000 GWh	...	1,000 GWh
7.	LSE X Load Forecast	10%	0%	0%	...	0%
8.	CCA Y Load Forecast	20%	22%	0%	...	0%
9.	CCA Z Load Forecast	30%	33%	43%	...	0%
10.	Remaining Bundled Load Forecast	40%	44%	57%	...	100%

	True Up					
	Actual Load (GWh)	**2001 Portfolio**	**2010 Portfolio**	**2014 Portfolio**	**...**	**2017 Portfolio[1/]**
11.	LSE X Load Actual	1,200			...	
12.	CCA Y Load Actual	1,900	1,900		...	
13.	CCA Z Load Actual	3,300	3,300	3,300	...	
14.	Remaining Bundled Load Actual	3,900	3,900	3,900	...	3,900
15.	Total Load Responsible	10,300	9,100	7,200	...	3,900
	Final REC Allocations					
16.	**Actual Delivered RECs in Portfolio**	1,600 GWh	1,900 GWh	2,100 GWh	...	950 GWh
17.	LSE X Load Actual	12%	0%	0%	...	0%
18.	CCA Y Load Actual	18%	21%	0%	...	0%
19.	CCA Z Load Actual	32%	36%	46%	...	0%
20.	Remaining Bundled Load Actual	38%	43%	54%	...	100%

1/ 2017 Portfolio costs and attributes are only assigned to bundled service customers and customers who depart after 2017

ALLOCATION OF RA[1] – ILLUSTRATIVE

	Forecast					
	Peak Load Forecast for Q1 (MW)	**2001 Portfolio**	**2010 Portfolio**	**2014 Portfolio**	**…**	**2017 Portfolio[2/]**
1.	LSE X Peak Load Forecast	185			…	
2.	CCA Y Peak Load Forecast	600	600		…	
3.	CCA Z Peak Load Forecast	800	800	800	…	
4.	Remaining Bundled Load Forecast	950	950	950	…	950
5.	Total Load Responsible	2,535	2,350	1,750	…	950
	RA Allocation for Q1					
6.	**Q1 RA in Portfolio**	700 MW	650 MW	500 MW	…	200 MW
7.	LSE X Load Forecast	7%	0%	0%	…	0%
8.	CCA Y Load Forecast	24%	26%	0%	…	0%
9.	CCA Z Load Forecast	32%	34%	46%	…	0%
10.	Remaining Bundled Load Forecast	37%	40%	54%	…	100%

	Re-Allocation at End of Q1 for Q2					
	Peak Load Forecast for Q2 (MW)	**2001 Portfolio**	**2010 Portfolio**	**2014 Portfolio**	**…**	**2017 Portfolio[2/]**
11.	LSE X Peak Load Forecast	215			…	
12.	CCA Y Peak Load Forecast	550	550		…	
13.	CCA Z Peak Load Forecast	850	850	850	…	
14.	Remaining Bundled Load Forecast	900	900	900	…	900
15.	Total Load Responsible	2,515	2,300	1,750	…	900
	RA Allocation Q2					
16.	**Q2 RA in Portfolio**	700 MW	650 MW	500 MW	…	200 MW
17.	LSE X Load Forecast	9%	0%	0%	…	0%
18.	CCA Y Load Forecast	22%	24%	0%	…	0%
19.	CCA Z Load Forecast	34%	37%	49%	…	0%
20.	Remaining Bundled Load Forecast	36%	39%	51%	…	100%

1/ Timing of re-allocation in this example is based on existing CAM process

2/ 2017 Portfolio costs and attributes are only assigned to bundled service customers and customers who depart after 2017

Attachment G

PCIA Working Group Q&A between Community Choice Partners, Southern California Edison and Sonoma Clean Power, December 9, 2016

PCIA Working Group Q&A — Table of Contents

Note on formatting – the following Q&A between Community Choice Partners and Southern California Edison and Sonoma Clean Power has been organized by indenting in the format below:

Original Question

[Text]

SCE or SCP Response: [Text]

CCPartners: [comment or request for further clarification]

Question for all stakeholders & the Commission:

Quantifying IOU Portfolios vs. Departing Load Forecast

Given the magnitude of expected load to depart to CCA service over the near-term (i.e. up to ~70% of IOU load over one to three years by some estimates), it would be prudent for stakeholders to understand the volume of power supplied by UOG and under contract to the IOUs versus freely available in the market (i.e. for the CCAs to contract with bilaterally). What are the most up-to-date sources of data for this calculation? Should this be tracked and regularly updated in a formal capacity?

SCE's Response: This exercise does not seem to provide much value as the electricity market is dynamic and availability of resources and power "freely available in the market" for CCAs to contract with can change materially from one year to the next due to such factors as resource additions and maintenance, transmission constraints, weather conditions, etc. Moreover, if the purpose of this analysis is a concern that there will not be enough power in the marker for CCAs to contract with when approximately 70% of the IOUs' load moves to CCA, the IOUs will continue to dispatch their resources as long as market revenues are sufficient to cover the variable costs of those resources making their energy production available to the market even though their bundled service customers' sales have declined.

CCPartners: While it is true that availability is dynamic and fluctuates based upon the factors such as those mentioned by SCE, how great is this variability? The magnitude of this fluctuation is likely small when compared to the volume of load expected to depart to CCA service over the near-term.

More importantly, the question was seeking clarification not on whether there will be "enough power", but rather the point at which CCAs must purchase power from IOUs to be able to launch or grow to full enrollment. Such a process inherently raises issues of oversight and fairness.

Below is a relevant excerpt from our PCIA Homework filing:

"Structural Considerations for CCA Power Supply Contracting

As the volume of load departing to CCA service grows, at some point CCAs will need to purchase power and dispatch facilities currently owned by or under contract with the IOUs. ***CCAs to date have procured power several months in advance of program launch*** *and prudently minimized market price exposure - which is especially critical during the initial period of operations after program launch, prior to the point at which the CCA has been able to build up a reserve fund. Depending on the timing of the launch of an individual CCA versus the overall penetration of departing load statewide, the CCA may or may not be able to procure power from resources outside the control of an IOU. This may become a barrier to the practical launch of new CCA programs, or the gradual enrollment of customers in a large CCA program."*

The question is motivated by the structural concern that at some point in the near-term, CCAs will need to procure power from facilities owned by or under contract to IOUs prior to program launch. The current regulatory structure doesn't anticipate this, and will need to — or otherwise severely disadvantage "large" CCAs and the broader CCA industry past a certain point.

Therefore, it would be prudent to seek quantitative clarification regarding at what point the availability of competitive supply will become sufficiently constrained as to drive up procurement costs, or preclude the launch of new CCAs (or phase-in of "large" CCA load) absent a mechanism to procure power **in advance** from contracts or assets under IOU control.

Questions for the Investor Owned Utilities (IOUs)

Varying PCIA Charges by CCA

1. Slide 8 of the Joint IOU Presentation states that the indifference amount is allocated across rate groups in proportion to each group's contribution during the top 100 hours of system demand. Such a methodology is essentially using load patterns as a proxy for marginal generation costs. Does this methodology represent cost-based rate design in the context of the PCIA? I.e. are marginal generation costs the primary cost component of the PCIA? If not, what are alternative methodologies that could be employed? Additionally, rate group load patterns vary to a non-trivial degree by geographic location (e.g. a residential customer in the Central Valley will have a very different profile as compared to one on the coast). Not taking this into consideration when allocating PCIA costs, while having the benefit of simplicity, effectively means that the current methodology is not cost-based or fair from the individual CCA's perspective. How could the cost allocation methodology be refined to reflect these geographic differences? Note that recent regulatory filings in R.15-12-012 (Time-Of-Use rate design) have identified datasets and methodologies that would support this refinement.

SCE's Response: The Indifference Amount that is allocated to rate groups consists of the above-market generation costs. The rate group contribution to the top 100 highest hours of system demand is the allocator typically used for generation capacity costs. Because the Indifference Amount includes both the above-market capacity and energy costs, it may be more appropriate to allocate the indifference Amount to rate groups based on the generation cost allocators determined in each IOUs' respective GRC Phase 2 proceeding. This ensures that the allocation of the Indifference Amount aligns directly with the manner in which generation costs are allocated to bundled service customers.

CCPartners: thank you for the clarification.

[**SCE, cont.]** SCE not currently allocate its generation costs to rate groups by geographic area and its bundled service generation rates are not differentiated by area. Therefore, it does not make sense to only have one IOU rate component (PCIA) differentiated by area.

CCPartners: Please explain why the fact that SCE currently does not differentiate its own generation rates by geography (as it does distribution rates using baseline tiers) means that doing so for the PCIA "does not make sense".

If the methodology to allocate costs is each group's contribution to the top 100 hours of system demand, and individual CCAs contribute to these top 100 hours in different proportions, then does it not stand to reason that each CCA (and the rate groups therein) should be allocated costs on a pro rata basis?

[**SCE, cont.]** Lastly, the November 1 Proposed Decision in R.15-12-012 considered and rejected the establishment of geographically-differentiated TOU periods within an IOU service territory, noting that, from a customer perspective, it would be "confusing, costly, and would require more complex energy management planning," and from a utility operations perspective, it would "increase costs of billing system maintenance, training customer- facing staff, and performing rate education and outreach" (PD at p.28).

CCPartners: the above quotations are selective and have the unfortunate effect of distorting ALJ Kloptin's reasoning in the matter, which, as explained below, is inapplicable outside the context of TOU ratesetting. The full quotation is below (emphasis below on key text omitted):

> *"We also agree with PG&E and the other IOUs, however, that imposing different TOU peak periods geographically within an IOU's service territory could be confusing and costly* ***for customers with multiple accounts and centrally managed operations, requiring more complex energy management planning.*** *From a utility operations perspective, geographically differentiated rates increase the costs of maintaining the billing system, training customer-facing support staff, and performing rate education and outreach. Accordingly, we do not require or recommend geographically-differentiated TOU time periods within an IOU's service territory."*

Specifically, geographically-differentiated TOU rates would be difficult for "customers with multiple accounts and centrally managed operations". The reasoning behind this judgement, in the context of TOU rates, is expounded under Findings of Fact (p.51):

> *"Setting different TOU peak periods based on geographic variations within an IOU's service territory could be confusing and costly for customers with multiple accounts and centrally managed operations,* ***requiring more complex energy management planning."***

Specifically, the Commission is seeking to avoid requiring a certain subset of customers to engage in "more complex energy management planning". This makes sense, when one considers that the point of TOU rates is to provide price signals to induce customers to manage their energy usage temporally to reduce overall costs. The PCIA is not designed to induce such customer behavior and is a static volumetric charge; consequently, the underlying reasoning of the PD does not apply (in any way) to the issues at hand. Similarly, the issues of "training customer-facing support staff, and performing rate education and outreach" are anticipated only in the context of TOU ratesetting (in that managing the aforementioned subset of customers would have imposed these additional costs for IOUs).

[**SCE, cont.]** SCE's billing system is currently not capable of billing customers based on area-differentiated rates and updating that system just for this one purpose will not be cost effective.

CCPartners: lists of CCA customers are already handled differently by SCE, and Utility User Tax (UUT) rates capture different tax rates and rate methodologies for each taxing authority already (i.e. both the rate structure and the rates are often different across each city and county). Since the PCIA is a simple volumetric calculation, it stands to reason that SCE's billing system should have the functionality to accommodate this calculation. Regardless, CCAs have this ability and could calculate PCIA charges if need be without incurring much, if any, additional costs.

<u>Tracking PCIA 'True Up'</u>

2. It was stated that there is no true-up process to reconcile the forecasted PCIA charge with the actual cost impact on IOU portfolios from CCA departing load. Is the actual cost impact tracked and recorded? If not, what are the obstacles to doing so? If so, how accurate is the PCIA forecast in comparison year over year? Is this data available for each IOU?

SCE Response: SCE does not track the difference between its forecast and actual portfolio costs due only to the "CCA departing load." In 2006, the Commission moved away from the "DA-in/DA-out" modeling approach to determining cost responsibility, which measured the "cost impact" due to defined levels of departing load, in favor of the existing futures-based benchmark methodology. The current methodology measures the above- or below-market costs of the entire generation portfolio, not the "cost impact" due to a specified amount of CCA departing load.

Although SCE does not currently true-up the PCIA, SCE does track the difference between its forecast and actual portfolio costs in the form of an under- or over-collection in the ERRA Balancing Account due to all factors that affect such costs. In the Commission proceedings that adopted the current PCIA methodology, parties representing departing load interest desired certainty in the PCIA and did not want the ERRA under- or over-collection to be reflected in the PCIA by recalculating the PCIA in year n or even reflecting the ERRA under- or over-collection in year n in the PCIA calculation for year n+1.

SCE is not opposed to revisiting this issue, but notes that any true-up of portfolio costs must be accompanied by a true-up of the portfolio "market value." This will also add a certain amount of complexity as the difference between forecast and actual portfolio costs and value must be disaggregated by vintage to calculate the PCIA true-up by vintage.

CCPartners: thank you for the clarification.

<u>Market Price Benchmark vs. Observed Actuals</u>

3. The energy cost component of the Market Price Benchmark is forecasted based upon Platt's forward strips; historically (i.e. for the past several years) how accurate are these forecasts on an annual basis compared to the observed on and off peak prices (OASIS)? Note that this should be

calculated on a weighted basis, to properly reflect the magnitude of any inaccuracy as computed by the PCIA mechanism.

SCE's Response: Platt's on- and off-peak forward prices are based on NERC definitions (on-peak = 6 days x 16 hours/day; off peak = 6 days x 8 hours/day, 1 day x 24 hours/day). A comparison of the observed CAISO day-ahead SP-15 hourly prices (aggregated for on- and off-peak periods) and Platt's forward prices for SP-15 (measured in October) is included below:

Year	On/Off	Average Price	Platt's Forecast SP-15
2013	On	49.28	45.87
2013	Off	39.36	32.52
2014	On	52.40	44.12
2014	Off	42.47	34.94
2015	On	34.76	44.84
2015	Off	29.78	36.05
2016	On	30.76	34.03
2016	Off	25.44	28.01

CCPartners: thank you for the price matrix; could you also provide 2012 prices and a disposition of SCE's on- and off- peak load factors for 2012 through 2016 (which is required to approximate the calculation under the PCIA methodology)?

[**SCE, cont.]** As described above, truing up the PCIA calculation for only one factor such as the difference between the forward and observed "brown" energy prices would be inappropriate. A true-up of the energy portion of the PCIA calculation must include a true-up of hourly prices, generation output by hour, and generation costs.

CCPartners: to clarify, the question was not intended to imply otherwise.

__**Production Cost Modeling of Total Portfolio Cost**__

4. In forecasting the Total Portfolio Cost using a production cost dispatch model, an IOU representative in the workshop alluded to the fact that there are different modeling input choices that impact the results. The example cited was whether the dispatch model was run for only California or for the entire Western Electricity Coordinating Council region (WECC). This would presumably impact market prices and the dispatch of assets under IOU control. There are additional modeling input choices that impact dispatch modeling, such as natural gas prices and weather and climactic conditions (which impact load as well as hydrological inflows and hydroelectric generation), etc. Are there standardized datasets and assumptions used in these simulations (if so, which)? Which scenario is selected to calculate the PCIA — is it the same scenario selected to forecast IOU revenue requirements in ERRA filings? What discretion do the IOUs have in selecting these inputs and scenarios that impact the Total Portfolio Cost calculation? Please detail this process for each IOU.

SCE Response: SCE dispatches its resources against prices, and not to a load. Therefore, the modeling assumptions above would not have an impact on the dispatch of resources. The prices are those reviewed and approved by the CPUC for ERRA forecasting purposes, and the dispatch process and results are also the same. This ensures that SCE adheres to the CPUC's standard for its portfolio modeling.

CCPartners: are the price forecasts against which SCE dispatches set by forward prices? If so, please describe the data source and methodology used, and provide a disposition of these prices (preferably, in the same format as the table provided above). If not, what methodology and data sources are used?

Additionally, this response appears to conflict with a statement in the previous workshop, when an IOU representative briefly discussed how the choice of whether the dispatch model was run for only California or for the entire Western Electricity Coordinating Council region (WECC) could impact the results. Was this a misstatement, or is there another explanation?

[**SCE, cont.]** The same production cost model run that is used to forecast SCE's ERRA revenue requirement for bundled service customers is also used for the calculation of PCIA. SCE presents its modeling results and ERRA revenue requirements in annual proceedings for the Commission's review and approval. Therefore, although SCE exercises a certain amount of discretion in selecting the inputs and scenarios used to forecast its portfolio costs and the ERRA revenue requirement, those inputs and assumptions are subject to parties' review and Commission approval.

CCPartners: thank you for the clarification.

Selection of Production Cost Model

5. What production cost dispatch models do each of the IOUs employ in the calculation of their respective Total Portfolio Cost? To what degree does the choice of model impact the results of the calculation? Are these simulations conducted in-house, or through subcontractors (and if so, which)?

SCE Response: SCE uses ProSym, and the choice of model should have very little to no impact on the dispatch results if properly structured. The calculation is performed by SCE staff.

CCPartners: thank you for the clarification.

IOU Power Sales to CCAs

6. Has any IOU sold power products directly to a CCA, or to a CCA's primary supplier for resale to the CCA? If so, please provide additional details on the products and processes.

SCE Response: SCE will need additional time to respond to this question.

Provider of Last Resort Issues & Costs

7. After the launch of a CCA, what authorities and responsibilities continue to be imposed on the IOUs (for the CCA territory) by virtue of being the Provider of Last Resort (POLR)? At a high level, please provide examples of the potential cost impacts to CCA customers of these POLR

functions. The type of CCA that has evolved in California appears prepared to reliably service their respective territory's load on a long-term basis; what additional processes, compensation and cost recovery mechanisms would be required for CCAs to act as the POLR for their respective regions?

SCE Response: Please see Rule 23 of the SCE's Tariffs and, in particular, Sections L, S and T of that Rule, for IOU and CCA customers' responsibilities under the current CCA market structure adopted by Assembly Bill (AB) 117. For the IOU to be relieved of its POLR obligations, or for a CCA to assume the POLR obligation for its customers, legislative action is required. For example, under AB 117 (P.U. Code Section 366.2), the customers in the CCA service territory are provided with an option to opt out of CCA service and remain on Bundled Procurement Service (BPS) offered by the IOU. CCA acting as the POLR will eliminate this opt-out option for CCA customers, which will be inconsistent with AB 117.

CCPartners: thank you for the clarifications.

[**SCE, cont.]** Lastly, even if legislation were passed to transfer the POLR obligation from the IOU to the CCA, it would have no impact on the CCA customers' responsibility for above-market costs of generation procured prior to their departure (*i.e.*, it would not impact the PCIA). The transfer of the POLR obligation would only eliminate the securitization (bond) requirement designed to prevent cost shifting in the event of a mass involuntary return of CCA customers to IOU BPS.

CCPartners: thank you for the clarification, though the original question was not implying that assuming POLR responsibilities would somehow mitigate PCIA cost obligations.

Per AB117, customers that return to IOU service outside of the 60 day opt-out period (post enrollment) are bound by the same terms and conditions as Direct Access customers that return to IOU service (as determined by the Commission). Currently, customers that return with less than 6 months' notice are placed on their respective IOU's Transitional Bundled Service (TBS) tariff, under which the customer's commodity rate is set through a formula that matches their class profile against variable market prices and adds in costs incurred for RA, RPS etc. for the remainder of the 6-month period. After this point, the customer receives basic service under the IOUs managed portfolio.

(Note that the reason why the securitization requirement / bond is relatively low is partially because CCAs have been competently structured and executed to date — so the risk of default and involuntary return of customers is judged slight.)

Thus, our understanding is that the primary activity of the POLR, absent the unexpected return of customers, is to ensure capacity sufficient to maintain system reliability in the event that an individual CCA or a ESP ceases operations for any reason or otherwise exits the market – thereby defaulting a significant customer base to the POLR. Is this an accurate and complete understanding?

To provide further context for why we posed this question in the first place, our PCIA Homework filing noted that the POLR issue was raised by PG&E in its December 2014 Long Term Procurement Plan (LTPP) filings:

> *"The Commission and California policy makers should consider how to ensure that all LSEs are prepared to reliably service their load on a long-term basis, and that there is appropriate compensation and cost recovery for entities that act as a provider of last resort."*[1]

PG&E refers to the necessity for the POLR to receive "appropriate compensation and cost recovery". Could you clarify 1) what activities the POLR responsibility entails and 2) whether CCA customers are currently compensating the IOUs for POLR activities?

RPS Contract Transference Provisions

8. Regarding RPS contracts, are there buyout or ownership flip provisions during or at the end of the contract term? Would including these provisions in future contracts be prohibited for any reason, or negatively impact costs or other aspects of procurement and contract negotiations?

SCE Response: Project owners are free to sell to anyone for the period after the contract term ends. Project owners generally prefer to arrange a new contract/buyer in advance of the expiration of existing contracts, but a project may become a market resource if it is unable to secure a new contract before the end of its contract term. RPS contracts generally do not have buyout provisions that would allow the IOU to exercise an option to terminate the contract before the anticipated end of the term. Provisions related to transferring an IOU's rights and obligations under RPS contracts vary based on the specific RPS contract. Some RPS contracts are silent on the issue, while many require the consent of the project owner in order to assign or transfer the RPS contract. In some contracts, the project owner's consent to the assignment or transfer by the IOU cannot be unreasonably withheld. It would not be prohibited to include provisions allowing IOUs more flexibility to assign or transfer RPS contracts. However, such provisions are likely to hinder contract negotiations or financing and/or increase costs of new projects if they are too permissible. If project owners do not have a consent right, they may want objective criteria that a transferee (potentially a CCA) would need to satisfy, with creditworthiness requirements being the most likely request.

CCPartners: thank you for the clarifications; compiling a disposition of RPS contracts with provisions allowing transference may be useful at some point.

Going forward, including provisions that allow IOUs more flexibility to assign or transfer RPS contracts (without incurring undue costs etc.) should be investigated further and prioritized.

Extension of Cost Recovery for Utility Owned Generation (UOG)

9. Per D.04-12-048, IOUs are allowed to request an extension of cost recovery beyond 10 years for Utility Owned Generation (UOG); to what extent have IOUs sought or received such contract extensions for UOG?

SCE Response: D.04-12-048 established a ten-year cost recovery period for new world generation (i.e., generation acquired after 2004). Specifically, the Commission clarified that

[1] See"Pacific"Gas"and"Electric"Company's"(U"39"E)"Proposed"2014"Bundled"Procurement"Plan"

the ten-year cost recovery period would apply to both contracted and utility-owned resources, but would not apply to legacy resources acquired prior to the energy crisis (UOG and QF contracts) or RPS-eligible resources. SCE has not sought extensions for its new world UOG.

CCPartners: thank you for the clarification.

Questions for Sonoma Clean Power (SCP)

Examination of the Legal Foundation of SCP's Proposal

Does this proposal have a sufficiently strong legal foundation post-SB350? Presumably, SCP is basing the legal rationale for a "buy out" exit fee on Public Utilities Code Section 366.2(f)(2), which was added by AB117 in 2002 and states (emphasis added):

> *"A retail end-use customer purchasing electricity from a community choice aggregator pursuant to this section shall reimburse the electrical corporation that previously served the customer for all of the following: ... Any additional costs of the electrical corporation recoverable in commission- approved rates, equal to the share of the electrical corporation's estimated net unavoidable electricity purchase contract costs attributable to the customer, **as determined by the commission**, for the period commencing with the customer's purchases of electricity from the community choice aggregator, **through the expiration of all then existing electricity purchase contracts entered into by the electrical corporation."***

The phrase "as determined by the commission" appears to grant the CPUC latitude in creating cost recovery mechanisms such as the one proposed by SCP.

However, Public Utilities Code Section 366.3 was subsequently added by SB350 in 2015 and states:

> ***"Bundled retail customers of an electrical corporation shall not experience any cost increase as a result of the implementation of a community choice aggregator program.** The commission shall also ensure that departing load does not experience any cost increases as a result of an allocation of costs that were not incurred on behalf of the departing load."*

The limitation of the "buy out" exit fee proposal is that it relies on a <u>simulated forecast of cost impacts</u>, projecting years into the future, to calculate a payment upfront. Such modeling is invariably inaccurate, and usually increasingly inaccurate over the forecast time horizon. The recent volatility of the PCIA calculation year-to-year is instructive in this regard. Cost recovery of RPS contracts under the current PCIA mechanism is allowed for the length of the contract term (i.e. 20 to 25 years). As such, a "buy-out" mechanism based on forecasting may risk violating the provisions of Section 366.3. Does SCP agree?

Additionally, if some sort of "true up" mechanisms is proposed to refine the proposal and mitigate the risk of violating Section 366.3, how would this be substantially different than the current PCIA?

It would be unfortunate if stakeholders devote substantial resources to the exploration of this mechanism, only to face legal obstacles and challenges to its implementation at a future date.

What is SCP's legal rationale here, and if future challenges are indeed a risk, what is the best mitigation strategy?

> **SCP Response:** The buy-out concept was suggested at the first workgroup meeting as an alternative solution to the current PCIA. The statute doesn't require that the PCIA be calculated over any specific period. Nothing prohibits the Commission from making an estimate of the long-term future costs of departed load over a period equal to the longest then-existing contract, then requiring the IOU to accept an amount equal to the net present value of those future costs. In principle, the IOU and its remaining bundled customers come out the same. We imagined that if the IOUs and CCAs agreed upon the terms or calculation of a buy-out and brought that to the Commission for approval as a settlement that would be the appropriate vehicle to elevate it. To date, the buy-out concept we've discussed is like the existing PCIA in that it does not have a true-up mechanism. We think the Commission has the same latitude under 366.3 as they do under 366.2.
>
>> **CCPartners:** how do we definitively determine if the Commission does, in fact, have the same latitude under 366.3 as they do under 366.2? (This appears to be what the practicality of the proposal hinges upon.) If not, then the inevitable forecast error in the NPV calculation risks indifference amounts in future years (which, if it results in indifference costs, would either have to be paid by utility shareholders or remaining bundled customers). Given the risk, would either the IOUs or ratepayer advocates support such a settlement?
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>> Compounding the inherent difficulty in relying on a forecast, market price patterns are anticipated to change dramatically over this forecast period, owing to fleet retirements, increased variable resources and DER integration. Regardless, marginal prices are driven by units fueled by natural gas, the price of which is notoriously difficult to predict one year in advance, let alone 5, 10 or 25 years out. In this context, whether or not a forecast is "in principle" the same as what actually happens in future is academic — what really matters is who ends up paying for the inevitable forecast error.
>>
>> Lastly, would such a buyout risk disadvantaging future CCAs in any manner?

Sufficiency of SCP Proposal vs. Magnitude of Departing Load

Given the accelerating rate of CCA formation, and the planned launch of very large CCAs, is this mechanism sufficient? Up to 70% of IOU load is in territories actively exploring CCA, presumably to launch within the next one to three years. Current regulations were not designed to facilitate departing load at this scale, as detailed in *"RESPONSE OF THE COUNTY OF LOS ANGELES TO OPTIONAL HOMEWORK ASSIGNMENT IN PREPARATION FOR THE MARCH 8 WORKSHOP ON PCIA REFORM"* (submitted by Community Choice Partners, 16 February 2016).

The creation of a "buy out" mechanism appears to leave many of these challenges unaddressed, and consequently represents at best a partial solution. Given the near-term growth of the CCA industry, this working group should explore more comprehensive options, and consider the proposed mechanism in that context. Does SCP agree with this characterization?

To take one example, as the volume of load departing to CCA service grows, at some point CCAs will need to purchase power from facilities currently owned by or under contract with the IOUs. Prior to this point, the availability of competitive supply will become sufficiently constrained as to drive up procurement costs for new CCAs, or even preclude the launch of new CCAs (or full phase-in of "large" CCA load). A mechanism to secure power in advance from contracts or assets under IOU control will be necessary, and this poses equity issues not only in terms of cost but other product attributes as well (renewable content, greenhouse gas intensity, capacity, etc.). Arguably, it would be inappropriate for this to be done in an ad-hoc fashion that allows the IOUs discretion in which products to sell to CCAs and which to retain.

How would the proposed mechanism fit in to this context (and the other issues described in the aforementioned filing, if applicable)?

SCP Response: We're also actively evaluating contract assignment. The IOUs detailed several of the existing legal and procedural barriers to this approach at the last workgroup, but I personally am still interested in evaluating a process to assign ownership of assets.

CCPartners: thank you for the clarification.