REGULAR MEETING of the Board of Directors of the Peninsula Clean Energy Authority (PCEA)
Thursday, April 26, 2018

Peninsula Clean Energy, 2075 Woodside Road,
Redwood City, CA 94061
6:30 p.m.

Meetings are accessible to people with disabilities. Individuals who need special assistance or a disability-related modification or accommodation (including auxiliary aids or services) to participate in this meeting, or who have a disability and wish to request an alternative format for the agenda, meeting notice, agenda packet or other writings that may be distributed at the meeting, should contact Anne Bartoletti, Board Clerk, at least 2 working days before the meeting at abartoletti@peninsulacleanenergy.com. Notification in advance of the meeting will enable the PCEA to make reasonable arrangements to ensure accessibility to this meeting and the materials related to it. Attendees to this meeting are reminded that other attendees may be sensitive to various chemical based products.

If you wish to speak to the Board, please fill out a speaker's slip located on the tables as you enter the Board meeting room. If you have anything that you wish to be distributed to the Board and included in the official record, please hand it to a member of PCEA staff who will distribute the information to the Board members and other staff.

CALL TO ORDER / ROLL CALL

PUBLIC COMMENT
This item is reserved for persons wishing to address the Board on any PCEA-related matters that are as follows: 1) Not otherwise on this meeting agenda; 2) Listed on the Consent Agenda and/or Closed Session Agenda; 3) Chief Executive Officer's or Staff Report on the Regular Agenda; or 4) Board Members' Reports on the Regular Agenda. Public comments on matters not listed above shall be heard at the time the matter is called.

As with all public comment, members of the public who wish to address the Board are requested to complete a speaker's slip and provide it to PCEA staff. Speakers are customarily limited to two minutes, but an extension can be provided to you at the discretion of the Board Chair.

ACTION TO SET AGENDA and TO APPROVE CONSENT AGENDA ITEMS
This item is to set the final consent and regular agenda, and for the approval of the items listed on the consent agenda. All items on the consent agenda are approved by one action.

REGULAR AGENDA

1. Chair Report (Discussion)

2. CEO Report (Discussion)

3. Presentation by STEM Science Fair Award Recipients (Discussion)

4. Citizens Advisory Committee Report (Discussion)

5. Marketing and Outreach Report (Discussion)

6. Regulatory and Legislative Report (Discussion)

7. RFO Renewables Update (Discussion)

8. Local Energy Programs (Action)

    8.1 Authorize the first phase of the Local Energy Programs: Community Pilot Proposals, with funding up to $450,000 for fiscal year 2018-2019.

    8.2 Authorize the first phase of an initial electric vehicle program for FY18-19 intended to increase EV awareness, drive sales, and begin to address key barriers with total funding of $745,000.

9. Update on Power Charge Indifference Adjustment (PCIA) (Discussion)

10. EPA Green Power Partnership Update (Discussion)

11. Board Members' Reports (Discussion)

CONSENT AGENDA

12. Approval of the Minutes for the March 22, 2018 Meeting (Action)

13. Energy Supply Procurement Report (Information Only)

Public records that relate to any item on the open session agenda for a regular board meeting are available for public inspection. Those records that are distributed less than 72 hours prior to the meeting are available for public inspection at the same time they are distributed to all members, or a majority of the members of the Board. The Board has designated the Peninsula Clean Energy office, located at 2075 Woodside Road, Redwood City, CA 94061, for the purpose of making those public records available for inspection. The documents are also available on the PCEA's Internet Web site. The website is located at: http://www.peninsulacleanenergy.com.

PENINSULA CLEAN ENERGY AUTHORITY
Board Correspondence

DATE: April 17, 2018
BOARD MEETING DATE: April 26, 2018
SPECIAL NOTICE/HEARING: None
VOTE REQUIRED: None

TO: Honorable Peninsula Clean Energy Authority (PCE) Board of Directors

FROM: Kirsten Andrews-Schwind, Communications and Outreach Manger, and Leslie Brown, Director of Customer Care

SUBJECT: Update on PCE's Marketing and Outreach Activities

BACKGROUND:
The marketing team has been busy doing outreach, managing our online presence, responding to customer requests, and preparing future campaigns.

DISCUSSION:

Outreach Grant Program Awardees

Peninsula Clean Energy is pleased to announce that we have awarded small outreach grants to the following nonprofit organizations as part of a pilot to communicate with their audiences about PCE services:

Acterra, a longstanding local environmental organization, will be focusing on multilingual outreach about PCE in East Palo Alto.

El Concilio of San Mateo County, which already has a program to explain utility bills and enroll customers in discount programs, will integrate information about PCE in its Spanish language outreach across the County.

Pacifica Resource Center will include information about PCE in its case management and general outreach in Pacifica and North County.

Rebuilding Together Peninsula, which provides repair services for qualifying home owners across the County, will offer PCE information in their extensive outreach.

Sound of Hope Radio Network, with two Chinese radio frequencies serving San Mateo County and the Bay Area, will run messages about PCE and organize a Chinese-language community workshop.

Recent and Upcoming Outreach Events

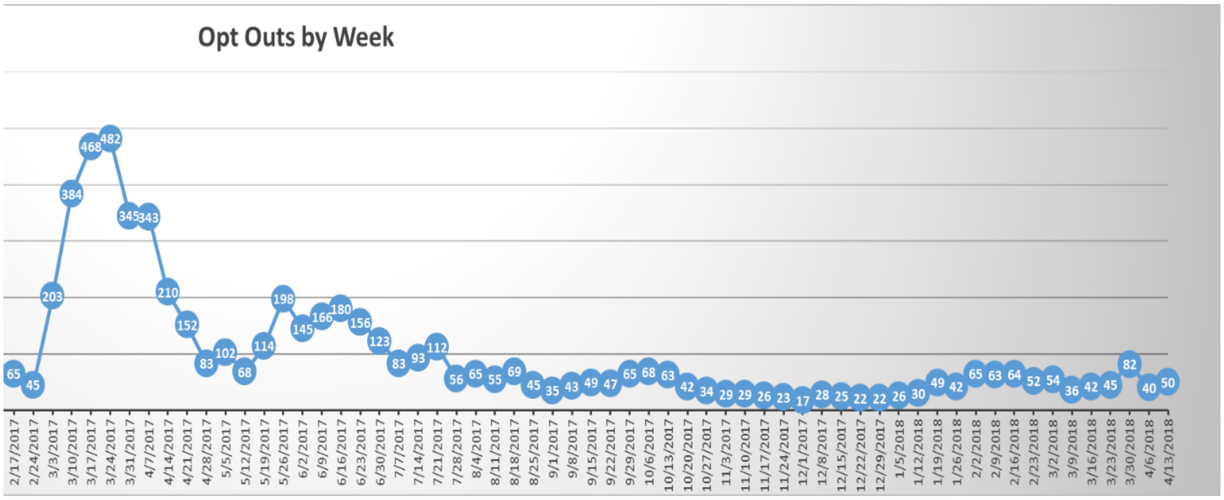
21-Apr	Table Daly City Earth Day
21-Apr	Table at Pacifica Earth Day
21-Apr	Table Belmont Earth Day
21-Apr	Spanish Presentation at East Palo Alto Library
21-Apr	Table at Earth Day at Shoreway in San Carlos
26-Apr	Table at OOS Movie Screening in Daly City
26-Apr	SSF Chamber of Commerce Higher Education Scholarship Luncheon
27-Apr	State of the County Address
28-Apr	San Mateo New Living Expo PCE Panel
28-Apr	Table at San Bruno Dia del Niño Book Fair
28-Apr	Table at Rebuilding Together Annual Volunteer Picnic
28-Apr	Table at Portola Valley Earth Day
28-Apr	Table at STEAM Fest in Redwood City

29-Apr	Table at Kermes Dia del Niño NFO
2-May	Present at Peninsula Family Services Senior Peer Counseling Group
3-May	Table at San Mateo Chamber Business Expo
5-May	Table at Foster City Polynesian Fair in Foster City
5-May	Table at SSF Streets Alive, Parks Alive
6-May	Table at EPA Cinco de Mayo event
6-May	Table at Burlingame Streets Alive, Parks Alive
10-May	Table at SSF Bart Station Bike to Work Day
19-May	Table at San Carlos Hometown Days*
19-May	Table at Daly City Shine Family Day
24-May	Table at Daly City Senior Fitness & Resource Event
25-May	Presentation at Fair Oaks Community Center
2-Jun	Hillsborough Earth Day*
2-Jun	Table at Foster City CityFEST
3-Jun	Table at Foster City CityFEST
3-Jun	Table at San Mateo Sunrise Rotary 5k Color Run
3-Jun	Table at San Bruno Posy Parade and Community Day
9-Jun	Table at Facebook Festival
12-Jun	Table at Senior Day at the County Fair
13-Jun	Joint PCE Mixer with San Carlos Chamber of Commerce
15-Jun	Table at Senior Day on the Redwood City Square
21-Jul	Table at Menlo Summerfest*
22-Jul	Table at Menlo Summerfest*
18-Aug	Table at Burlingame on the Avenue
19-Aug	Table at Burlingame on the Avenue
25-Aug	Table at Senior Showcase in Menlo Park*

*To be confirmed

Enrollment Statistics

Two cities had "0" opt-outs in March: Colma, and Woodside. Our overall opt-out rate is approximately 2.4%.



CITY	Eligible Accts	Total	TOTAL OPT OUT %	WEEKLY INCREASE %
PORTOLA VALLEY INC	1,672	97	5.80%	0.00%
SAN BRUNO INC	16,339	582	3.56%	0.69%
PACIFICA INC	15,409	499	3.24%	1.01%
SO SAN FRANCISCO INC	24,716	788	3.19%	0.77%
DALY CITY INC	33,848	959	2.83%	0.74%
MILLBRAE INC	9,341	244	2.61%	0.00%
HALF MOON BAY INC	4,941	124	2.51%	0.00%
EAST PALO ALTO INC	7,774	194	2.50%	2.11%
UNINC SAN MATEO CO	24,399	607	2.49%	0.66%
SAN MATEO INC	43,836	1000	2.28%	0.50%
BELMONT INC	11,845	267	2.25%	0.00%
SAN CARLOS INC	14,406	324	2.25%	0.31%
BRISBANE INC	2,467	50	2.03%	0.00%
HILLSBOROUGH INC	4,044	80	1.98%	1.27%
REDWOOD CITY INC	34,638	663	1.91%	0.91%
FOSTER CITY INC	14,562	278	1.91%	1.09%
BURLINGAME INC	15,393	290	1.88%	1.05%
WOODSIDE INC	2,281	37	1.62%	0.00%
ATHERTON INC	2,692	42	1.56%	0.00%
COLMA INC	799	[redacted]	1.38%	0.00%
MENLO PARK INC	15,709	212	1.35%	0.47%
Grand Total	301,111	7,348	2.44%	0.69%

There are now over 5,000 accounts in ECO100, with a total number of ECO100 cities at 15 (plus the County). The ECO100 towns and cities as of April 17 include Atherton, Belmont, Brisbane, Burlingame, Colma, Foster City, Half Moon Bay, Hillsborough, Menlo Park, Millbrae, Portola Valley, Redwood City, San Carlos, San Mateo, Woodside, and the

County of San Mateo.

ACTIVE ACCTS BY CITY	Eligible Accts	April '18			
CITY	Full Territory	RES ACT	COM ACT	ACTIVE	ECO100
ATHERTON INC	2,692	2,372	220	2,592	55
BELMONT INC	11,845	10,507	926	11,433	145
BRISBANE INC	2,467	1,898	503	2,401	74
BURLINGAME INC	15,393	12,995	1,958	14,953	300
COLMA INC	799	498	276	774	28
DALY CITY INC	33,848	30,749	1,951	32,700	55
EAST PALO ALTO INC	7,774	7,083	443	7,526	16
FOSTER CITY INC	14,562	13,267	795	14,062	117
HALF MOON BAY INC	4,941	4,141	586	4,727	83
HILLSBOROUGH INC	4,044	3,766	143	3,909	58
MENLO PARK INC	15,709	13,587	1,723	15,310	415
MILLBRAE INC	9,341	8,388	668	9,056	88
PACIFICA INC	15,409	13,971	854	14,825	110
PORTOLA VALLEY INC	1,672	1,418	143	1,561	1,460
REDWOOD CITY INC	34,638	30,173	3,359	33,532	614
SAN BRUNO INC	16,339	14,560	1,102	15,662	80
SAN CARLOS INC	14,406	11,772	2,138	13,910	236
SAN MATEO INC	43,836	38,461	3,907	42,368	568
SO SAN FRANCISCO INC	24,716	20,578	3,228	23,806	68
UNINC SAN MATEO CO	24,399	20,513	2,874	23,387	438
WOODSIDE INC	2,281	1,981	218	2,199	47
Unallocated				-	
Unallocated (cust type)				241	
Grand Total	301,111	262,678	28,015	290,934	5,055

PENINSULA CLEAN ENERGY AUTHORITY
Board Correspondence

DATE: April 19, 2018
BOARD MEETING DATE: April 26, 2018
SPECIAL NOTICE/HEARING: None
VOTE REQUIRED: None

TO: Honorable Peninsula Clean Energy Authority (PCE) Board of Directors

FROM: Joseph Wiedman, Director of Regulatory and Legislative Affairs
Jeremy Waen, Senior Regulatory Analyst

SUBJECT: Update on PCE's March and April Regulatory and Legislative Activities

BACKGROUND:

The end of March and early April were busy on a number of matters both legislative and regulatory. As discussed in more detail below, PCE, as part of CalCCA, submitted one pleading at the California Public Utilities Commission (CPUC). PCE staff attended two other stakeholder meetings.

DISCUSSION:

Regulatory Outreach

On Thursday, March 29th, Joseph Wiedman traveled to Sacramento to attend a workshop at the California Energy Commission (CEC) regarding implementation of AB 1110. Stakeholders discussed their views on staff's proposal to disallow power from Power Content Category (PCC) 2 resources to count as greenhouse gas free (GHG-free) energy on the CEC's Power Content Label. Instead, CEC staff has proposed counting the emissions from the underlying energy for PCC 2 resources. CalCCA and allied stakeholders argued that such a framework was 1) inconsistent with the contractual realities of PCC2 products and treatment of PCC2 products elsewhere within California; 2) likely violated the dormant commerce clause as it would treat out of state PCC2 products differently than in-state PCC2 products; 3) treatment as proposed by CEC was not required by statute and is inconsistent with other state programs; and 4) staff's proposed treatment would lead to customer confusion. The CEC continues to consider the issue. We anticipate a decision on the topic being made in early 2019.

On April 5th, Joseph Wiedman and Pradeep Gupta had an ex parte meeting with Nidhi Thakar, advisor to CPUC President Michael Picker. Mr. Wiedman and Mr. Gupta discussed PCE's interest in utilizing virtual net metering (VNM) to develop a community solar program to serve disadvantaged communities in PCE's service territory. Ms. Thakar's questions focused on understanding why PCE supported community solar over offering a green tariff program. Mr. Wiedman explained that a VNM-based community solar program would be more flexible for PCE's customers and easier for PCE to administer. The Commission continues to consider the issue. We anticipate a vote on the matter at the Commission's April 26th board meeting.

On April 16th, Joseph Wiedman, Jeff Aalfs, and Rick DeGolia participated in a CalCCA tour and discussion session at the California Independent System Operator (ISO). Attendees heard from various members of ISO management and staff on the relationship of the ISO to load serving entities and ISO operations. Beth Vaughan, Executive Director of CalCCA, provided an overview of the growth of CCAs and CCA priorities in serving their communities. Attendees also discussed regionalization, current events related to resource adequacy, demand response opportunities, and also opportunities for CCAs to engage directly with the ISO on areas of common concern.

Regulatory Advocacy

R.17-06-026 – PCIA Order Instituting Rulemaking – On Monday, April 2nd, CalCCA served opening testimony in the PCIA docket. CalCCA's testimony addressed:

- utilizing securitization of utility-owned generation and buy-down/buy-out of existing renewable portfolio standard contracts as means to reduce costs for all ratepayers – bundled and unbundled,
- updating the PCIA benchmark to more accurately reflect the value of the IOUs' portfolios so that departing load customers only pay for IOU portfolio costs that are truly above market, and,
- over the near term, developing an auction process to realign IOU portfolios to match reduced IOU needs and increased CCA needs. CalCCA proposed that prices obtained in the auction could be utilized to update the PCIA benchmark with actual values versus administratively determined values.

Opening testimony was also filed by the IOUs, TURN, Office of Ratepayer Advocates, Energy Users Forum, AReM/DACC, Protect Our Communities, Commercial Energy, and UCAN. Rebuttal testimony is due to be served on April 23rd.

R.17-09-020 - Resource Adequacy – Track 1 of this proceeding continues to consider reform to Resource Adequacy (RA) obligations including (i) the potential creation of a multi-year RA requirement (expanded from the present 1-year framework), (ii) the potential adoption of a central-buyer structure to contract with large assets that would otherwise potentially abuse their market power, and (iii) other potential reform to the RA requirements. PCE remains closely engaged in this proceeding because of the direct impacts it will have on PCE's own procurement and the autonomy of PCE's governing board over procurement matters.

Throughout March and April, the Joint CCAs (including PCE, MCE, SCP, EBCE, SVCE and CPSF) have been meeting with various stakeholders to discuss possible reform to the RA obligations. These meetings included: 1) A teleconference with the Alliance for Retail Energy Markets (AReM) and the Direct Access Customers Coalition (DACC); 2) a meeting with the Center for Renewable Integration; 3) a meeting with CPUC energy division staff (all three of these meetings occurred on March 28th), 4) a meeting with the Office of Ratepayer Advocates

(ORA) on April 3rd, and 5) a meeting with CAISO staff on April 12th. On April 18th the Joint CCAs had an ex parte teleconference with Joanna Gubman, advisor to Commissioner Randolph.

Based on feedback provided by the Joint CCAs, and likely other parties, the CPUC has noticed an all-day Working Group workshop for Tuesday, April 24th to explore in further detail matters relating to RA reform. At this point a Proposed Decision (PD) is anticipated from the CPUC on Track 1 RA reform sometime in May or June.

Legislative Advocacy

CalCCA legislative committee continues to review numerous bills as they move through the committee process this month.

AB 2208 (Aguiar-Curry) – would require procurement of geothermal resources from particular areas around the Salton Sea - CalCCA voted to Oppose.

AB 2726 (Levine) – would move California from an emissions-based GHG-reporting framework to a consumption-based GHG-reporting framework - CalCCA voted to Oppose

FISCAL IMPACT:
Not applicable.

Item No. 7

PENINSULA CLEAN ENERGY
JPA Board Correspondence

DATE: April 17, 2018
BOARD MEETING DATE: April 26, 2018
SPECIAL NOTICE/HEARING: None
VOTE REQUIRED: None

TO: Honorable Peninsula Clean Energy Authority Board of Directors

FROM: Siobhan Doherty, Director of Power Resources

SUBJECT: Update on 2018 RFO for Renewable and Storage Resources

BACKGROUND:
The Power Resources team will present on the progress of PCE's 2018 Request for Offers (RFO) for Renewable and Storage Resources, and next steps of same.

The RFO was launched on January 12, 2018 and bids were due on February 9, 2018. PCE posted all information about the RFO to the PCE website: https://www.peninsulacleanenergy.com/our-power/pce-2018-renewables-rfo/.

PENINSULA CLEAN ENERGY
JPA Board Correspondence

DATE:	April 16, 2018
BOARD MEETING DATE:	April 26, 2018
SPECIAL NOTICE/HEARING:	None
VOTE REQUIRED:	Majority Vote

TO: Honorable Peninsula Clean Energy Authority Board of Directors

FROM: Jan Pepper, Chief Executive Officer, Peninsula Clean Energy

SUBJECT: Local Energy Programs: Community Pilot Proposals – Phase 1

RECOMMENDATION:

Authorize the first phase of the Local Energy Programs: Community Pilot Proposals, with funding up to $450,000 for fiscal year 2018-2019.

BACKGROUND:

In September 2017, the Board approved opening a public process to execute PCE local programs. As part of that direction the Board approved criteria for scoring such proposals. The criteria are divided into those that all proposals would be required to address, and those that would add points to any proposal that chooses to address them. The proposed criteria were as follows:

Required Criteria

1. GHG emissions reductions
2. Cost effectiveness
3. Number of customers served
4. Geographic diversity in San Mateo County communities served
5. Supports PCE's workforce policy
6. Helps PCE match supply to load
7. PCE Implementation Requirements (for example, staff time needed)

Criteria that Add Points to Proposals

8. Contributes to procurement goals: creating 20 MW of new local power by 2025, 100% GHG-free power for 2021, 100% renewable energy by 2025
9. Benefits disadvantaged communities
10. Innovative, scalable, and replicable
11. Supports community resilience
12. Fills a gap in current utility offerings

DISCUSSION:

Broad community solicitations can be effective for smaller scale projects which may be executed relatively quickly and to identify concepts and partners that can be used for defining larger, more strategic investments (six and seven figure investments).

To engage the community while initiating a range of program initiatives staff recommends structuring the proposal process as a set of community pilots. As a set of pilot programs, the scope is proposed to include:

- Funding of up to $75,000 apiece
- Up to 18 months in duration
- Up to 6 projects may be selected but any strong proposal will be highly considered for current or potentially future support.
- Successful pilots may be considered for follow-on support based on performance.

This scope will enable rapid execution with low administrative overhead. The following general objectives are proposed:

- Identifying high-potential projects and programs
- Identifying potential partners for PCE initiatives
- Increasing engagement with members of the community

A scoring matrix is being developed and will be based on a refined version of the September 2017 criteria. It is important to note that the quality of proposals is likely to vary significantly and there will be an inherently qualitative aspect to the evaluations.

It is anticipated that the proposals will open in the May/June timeframe. Any entity will be eligible to participate. Outreach for the proposals is anticipated to include:

- PCE website
- Press release
- PCE newsletter and social media
- City and city manager newsletters
- Chambers of commerce
- Citizens Advisory Committee members
- PCE's outreach team

Board member assistance in distribution will be greatly appreciated.

Likely in September up to 6 high impact concepts will be identified for consideration. Concepts will be presented to the Citizens Advisory Committee (CAC) for their initial input. Based on the CAC input, and staff recommendations, staff will present the final high impact concepts recommended for implementation to the Board. More concepts may be selected if submissions are extremely strong. Proposals not in the top 6 “high impact” concepts but deemed interesting may be retained for further study at a later date. Contracting on projects will be targeted to complete by the end of the 2018 calendar year.

These pilots should be differentiated from strategic investments which will be developed based on a strategic roadmap yet to be developed. The strategic investments will likely have larger funding levels and be initiated with more stringent and narrowly targeted solicitations. It is anticipated that the draft strategic roadmap may be brought to the board this summer.

PENINSULA CLEAN ENERGY
JPA Board Correspondence

DATE: April 16, 2018
BOARD MEETING DATE: April 26, 2018
SPECIAL NOTICE/HEARING: None
VOTE REQUIRED: Majority Vote

TO: Honorable Peninsula Clean Energy Authority Board of Directors

FROM: Jan Pepper, Chief Executive Officer, Peninsula Clean Energy

SUBJECT: Local Energy Programs: Electric Vehicle Program – Phase 1 Concept

RECOMMENDATION:

Authorize the first phase of an initial electric vehicle program for FY18-19 intended to increase EV awareness, drive sales, and begin to address key barriers with total funding of $745,000. The program consists of a ride and drive campaign, dealer promotion with incentives, and apartment building owner technical assistance.

BACKGROUND:

Peninsula Clean Energy's mission is to reduce greenhouse gas (GHG) emissions in San Mateo County. The three main contributors to GHG emissions are electricity use, transportation, and buildings. One of the strategic goals of PCE is to further reduce GHG emissions by investing in programs such as electric vehicles. This memo describes the first phase of an electric vehicle program for PCE that will accelerate the adoption of electric vehicles in San Mateo County, building on the program that Sonoma Clean Power has initiated. The results of this initial phase can inform further expansion of this program for PCE. The target for this first phase is to achieve sales (or leases) of 400 new EVs over a two-to-three month period and 100 used EVs over a 12 month period in San Mateo County.

The core objective is to *increase vehicle sales above the baseline sales*.

Adoption Barrier	Strategy	Budget	Timeframe
Low EV Awareness	**"Ride & Drive" marketing events** with special emphasis on corporate campuses. 6 events reaching ~1,000. Links to dealer promotion.	$90,000	May - Oct
Vehicle Cost	**Dealer Promotion:** Competitive solicitation to dealers to deliver aggressive cost discount.	$85,000	18Q4/19Q1
Vehicle Cost	**Incentive:** Two tiers: • $200/vehicle dealer incentive • Low income used car incentive and outreach	$80,000 $400,000	18Q4/19Q1
Infrastructure	**Apartment EV Technical Assistance**: Assistance program for apartment building owners for EV infrastructure (union labor)	$90,000	May - Dec

DISCUSSION:

The Board and other PCE stakeholders have expressed an interest in starting quickly on an EV program to deliver impact and there is special interest in the innovative approach Sonoma Clean Power (SCP) has taken to lowering EV barriers.

This memo outlines proposed measures by PCE to address the key adoption barriers. The proposed strategies here are intended as a Phase 1 Pilot with prospective annual execution with refinement based on post execution evaluation plus additional measures in future phases such as measures for fleets, fast charging, and vehicle-grid integration.

Key adoption barriers are as follows:

- **Low Awareness**: A major barrier in EV adoption is the very low awareness of EVs and their benefits, even in the Bay Area[1].

- **High vehicle cost**: While more affordable models are beginning to enter the market, overall cost even after incentives remain high. This is a particularly significant barrier for the low-income community.

- **Charging Infrastructure**: Access to charging is an especially significant challenge for residents who do not have a personal garage such as those who live in apartment complexes and condominiums. Roughly half of San Mateo

[1] Research by the nationally respected UC Davis Institute of Transportation Studies (ITS) indicates only 5% report actively shopping (or buying), 13% gathered some information but were not serious and the balance are unaware and not considering it. These figures have not changed noticeably between 2014 and 2017 https://its.ucdavis.edu/blog-post/automakers-policymakers-on-path-to-electric-vehicles-consumers-are-not/

county residents live in some form of multi-family residence including likely a majority of low-income residents.

Low Awareness Measure: Ride and Drive Marketing

Increasing sales above the baseline requires intervening *early* in the sales process with direct experience and peer-to-peer testimonials. UC Davis ITS concludes that among the most important strategies is to "Create real PEV experience: Ride and drive events and the use of PEVs in shared mobility and vehicle rental applications." As a result, the Air Resources Board and others have identified ride and drive events as a key strategy to drive adoption.

The proposed measure is to:

- Contract with a vendor to execute 6 "ride and drive" events (vehicle test rides) beginning in Q2 with an estimated 900-1000 participants.
- Focus on corporate campuses which has yielded strong results in prior similar events. We anticipate that 4 to 5 events would be corporate with 1-2 community events.
- Process will include PCE leading the corporate customer engagement and the ride and drive vendor handling all event logistics including site agreements, insurance, securing vehicles, etc.
- Engage 1-2 community groups for additional outreach support.
- Incorporate pre-event, post-event and trailing surveys (3 to 6 months later) to measure both increases in interest and action taken.
- Include a raffle promotion for a discount towards an EV purchase.
- Link ride & drive participation with dealer promotion.

Budget:

- $70,000 for Ride & Drive vendor
- $10,000 for community group outreach (combined with incentive outreach)
- $10,000 for additional promotions

High Vehicle Cost Measures: Dealer Discount & Incentives

<u>Dealer Discount</u>: The SCP EV program drew on the innovations of Denver County for a competitive process in which dealers are eligible to be selected as the sole provider for the EV sales promotion. The proposal here is to closely follow this model. Features include:

- Solicitation to all dealers in San Mateo county to participate.
- One dealer per automaker selected, possibly constrained to a total of 3 to minimize administration complexity. Selection is based on the best discount from the Manufacturers Suggested Retail Price (MSRP).
- Dealer is required to be a PCE customer.
- Vehicle eligibility is based on minimum all-electric ranges. Possible targets: 25 miles for plug-in hybrid (PHEV) and 200 miles for battery-electric vehicle (BEV).
- Incentive goes through the dealer and is used as an enforcement mechanism – issued only after confirming that the customer received the expected deal.

- Marketing would be tied to the ride and drive participants (possibly including some modest incremental incentive) and broader community.
- 2 to 3 month promotion period for the Dealer incentive.

Extensive outreach would be conducted utilizing PCE's outreach team, the CAC, city and city manager newsletters, and board members.

Incentives

Two tiers are proposed:

- **General Consumer**: $200 per vehicle for participating dealers. This is primarily an enforcement mechanism with the dealers to ensure consumers get the expected deal. Estimated maximum uptake in the promotion period is 400 vehicles.

- **Low-Income**: Low income residents usually do not buy new cars so these incentives would target used plug-in hybrid cars (full battery electric vehicles present challenges of infrastructure and range that would create additional challenges to adoption). The proposal creates a defined pool for rebates for qualifying vehicle for used vehicle purchases. Qualification would likely be tied to low-income as defined by the utility CARE/FERA program. Rebate amount is still to be determined and would likely be combined with low-income used car financing. It may be possible to combine the incentive with a competitive process by used-car dealers as is proposed for the new vehicle element above. Further ground-work is in progress. The estimated uptake during the twelve month promotion period is 100 vehicles.

Budget:

- $85,000 for program administration support
- $80,000 incentive for dealerships
- $400,000 for low income rebates and outreach support

Charging Infrastructure Measure: Apartment Technical Assistance

Charging access in multi-unit dwellings remains a major barrier with roughly half the county population living in some form of multi-unit dwelling. Addressing this barrier is critical for both the low-income residents and nearly half of county residents generally.

The barriers to EV infrastructure in this segment are many and complex and the measure proposed here is a very preliminary measure intended to:

- Foster some adoption of infrastructure,
- Complement PG&E's existing EV Charge Network program which will install infrastructure for free (but has very limited uptake),
- Establish groundwork for improved targeting and expansion of future measures to address this arena including securing funding from BAAQMD, California

Energy Commission or other sources to drive build-out. (Note other measures such as fast charge deployment are also essential to address this need).

The proposed technical assistance would:

- Provide proactive education and technical assistance including apartment policies, site assessments (with union labor), linkages to existing resources, and guidance;
- Develop a detailed apartment stock database of specific apartment complexes, contacts and likely infrastructure adopters;
- Develop a short-list of near-term adopters;
- Assess building stock and barriers and provide recommendations for next steps.

Budget:

- $90,000 for specialist consultant

Again, extensive outreach would be conducted utilizing PCE's outreach team, the CAC, city and city manager newsletters, and board members.

PENINSULA CLEAN ENERGY AUTHORITY
Board Correspondence

DATE: April 19, 2018
BOARD MEETING DATE: April 26, 2018
SPECIAL NOTICE/HEARING: None
VOTE REQUIRED: None

TO: Honorable Peninsula Clean Energy Authority (PCE) Board of Directors

FROM: Joseph Wiedman, Director of Regulatory and Legislative Affairs
Jeremy Waen, Senior Regulatory Analyst

SUBJECT: Update on Power Charge Indifference Adjustment (PCIA) Docket *R.17-06-026*

DISCUSSION:

On Monday, April 2nd, CalCCA served opening testimony in the CPUC's PCIA docket.

CalCCA's testimony addressed utilizing securitization of utility-owned generation and buy-down/buy-out of existing renewable portfolio standard contracts as means to reduce costs for all ratepayers – bundled and unbundled, updating the PCIA benchmark to more accurately reflect the value of the IOUs' portfolios so that departing load customers only pay for IOU portfolio costs that are truly above market, and, over the nearer term, developing an auction process to realign IOU portfolios to match reduced IOU needs and increased CCA needs. CalCCA also proposed that prices obtained in the auction could be utilized to update the PCIA benchmark with actual values versus administratively determined values.

CalCCA's testimony demonstrated that Pacific Gas & Electric Company's (PG&E) above market costs for 2018 were approximately $2.2 billion. However, securitization of PG&E's utility-owned generation currently included within the PCIA would remove $1.2 billion in above market costs. CalCCA testimony also demonstrated that the PCIA "benchmark" undervalues "green" attributes, omits values for GHG-free resources, and undervalues ancillary services. If the PCIA benchmark is updated to reflect Commission approved long-term values for these attributes, above market costs would be reduced by another $500 million leaving approximately $512 million in above market costs.

CalCCA testimony also encouraged development of a Staggered Portfolio Auction which would be held quarterly. Under CalCCA's proposal, each investor-owned utility (IOU) portfolio – both particular resources and products created from those resources – would be made available via an auction open to all load serving entities (including the IOUs). Load serving entities would be able to bid for particular projects or product types within the auction. The prices for products would be utilized to update the PCIA benchmarks so that market prices would be utilized rather than administratively determined benchmarks. During the development of the auction, as noted above, updated benchmark values determined in this docket would be utilized to assess above market costs.

CalCCA's testimony also addressed sunsetting of the PCIA over time, the possibility of a rate cap on the PCIA, long-term forecasting of the PCIA to allow better planning for CCAs, full or partial prepayment of the PCIA, moving the PCIA to a line item on all customer bills, and highlighting the need to consider reforming which entity – the IOU or the CCA – is the provider of last resort.

Opening testimony was also filed by the IOUs, TURN, Office of Ratepayer Advocates, Energy Users Forum, AReM/DACC, Protect Our Communities, Commercial Energy, and UCAN.

The IOUs' testimony was a variant of the Portfolio Allocation Mechanism seen in May 2017. However, instead of forced allocation of all resources contained in the PCIA based on a pro-rata share of LSE load, the IOUs now argue that LSEs should only be allocated the green portion of the IOUs portfolio – renewable and large hydro resources. They called this the Green Allocation Mechanism (GAM). LSEs would not pay a PCIA on these resources as they would be directly allocated to the LSE. Excess brown power (gas fired generation), nuclear, and energy storage resources would be sold into short-term markets with revenues offsetting costs. They called this mechanism the Portfolio Monetization Mechanism (PMM). The PCIA would recover the remaining costs. While the IOUs did respond to CCA concerns over forced allocation of brown power and nuclear resources, the GAM would be allocated on a quarterly-basis with a true-up each subsequent quarter to determine what was actually made available to the LSE from production of intermittent resources. The IOUs argued that state law requires this complex structure with true-ups because the law requires mathematical precision in determining costs and benefits between bundled and unbundled customers, otherwise an illegal cost shift will occur. The IOUs also argued that it was too complex to create an auction to allocate resources over the longer term. In general, the tone of the IOUs' advocacy was that they were passive entities forced to do what they did by state mandates and the outcome needed in this docket was results oriented. IOUs also argued that there should be no sunset or caps on PCIA, that they were complying with all PUC mandates in managing their portfolios, that certain departing load customers that currently pay the PCIA should be exempted, and that the 10-year limit on cost recovery of utility-owned generation should be removed so that recovery continues for the full life of their facilities.

Other parties' testimony was not nearly as detailed or comprehensive as CalCCA or IOU testimony. This is to be expected as they are not directly impacted by the issues in play as much as the CCAs and the IOUs. Commercial Energy offered an auction concept based off of its experience in the natural gas industry. Protect Our Communities argued that the IOUs mismanaged their contracting process and that CPUC oversight was inadequate. TURN generally supported the idea of an auction but noted that only actual revenues or benefits could be considered in drawing the line between bundled and unbundled customers' cost responsibilities.

Rebuttal testimony is due to be served on April 23rd.

Rulemaking 17-06-026
Exhibit ______________________
Date April 2, 2018
Witnesses Various

PREPARED DIRECT TESTIMONY OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

VOLUME 1
Chapters 1, 2A and 2B

Introduction
PCIA Effectiveness in Avoiding Cost Shifts
Revising the Current PCIA Methodology
(Common Outline §I, §II.A, §II.B)

CalCCA
California Community
Choice Association

ORDER INSTITUTING RULEMAKING TO REVIEW, REVISE, AND CONSIDER ALTERNATIVES TO THE POWER CHARGE INDIFFERENCE ADJUSTMENT

R.17-06-026

PREPARED OPENING TESTIMONY OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Table of Contents

Volume 1

Chapter		Witness	Page
1	**INTRODUCTION** (Common Outline §I)		
	I. Introduction	A. Hoekstra	1-1
	II. Executive Summary of Proposal	A. Hoekstra	1-4
	III. Evolution of Departing Load Procurement Cost Responsibility	A. Hoekstra R. Kinosian R. McCann	1-6
	CHAPTER 1 EXHIBITS		
	1-A Existing and Near Operational Community Choice Aggregators		
2A	**PCIA EFFECTIVENESS IN AVOIDING COST SHIFTS** (Common Outline §II.A)	A. Hoekstra	
	I. PCIA Effectiveness in Avoiding Cost Shifts		2A-1
	A. A “Cost Shift” Occurs When a Customer Does Not Shoulder the “Net” Unavoidable Costs Attributable to That Customer		2A-2
	B. Estimating a Cost Shift Requires a Clear but Complex Set of Criteria to Determine Whether a Cost is “Unavoidable”		2A-4
	C. An Unavoidable Cost is “Attributable” to a Departing CCA or DA Customer When the Utility’s Forecast, at the Time an Irrevocable Action Was Taken to Procure the Resource,		2A-8

Chapter				Witness	Page
			Assumed the Customer Would Remain in Bundled Service		
	II.	Public Claims of "Massive" and "Illegal" Cost Shifts are Unsupportable and Based on Arbitrary Assumptions			2A-9
	III.	The Current PCIA Methodology Shifts Costs from Bundled to CCA Customers When Compared with an Analysis Relying on Commission Adopted Resource Values			2A-12
	CHAPTER 2A EXHIBITS				
		2A-A	PG&E and SCE Responses to CalCCA_002-Q14		
2B	**REVISING THE CURRENT PCIA METHODOLOGY** (Common Outline §II.B)				
	I.	The Current PCIA Methodology Can Be Modified to Provide a Reasonable Estimate of CCA/DA Customer Cost Responsibility		A. Hoekstra R. Kinosian R. McCann	2B-1
	II.	Modify the PCIA Benchmark Formulation to Better Align with Portfolio Value			2B-2
		A.	Modify Capacity Values	A. Hoekstra R. Kinosian	2B-6
		B.	Add an Ancillary Services Value	R. McCann	2B-9
		C.	Incorporate the Value of Non-RPS, GHG-Free Resources	R. Kinosian	2B-10
		D.	Modify the Green Benchmark to Remove the Unavailable and Incorrect Department of Energy Referents	R. McCann	2B-12
	III.	Reduce the Scope of PCIA-Eligible Costs			2B-15
		A.	Remove the Costs of Uneconomic Facilities or Modify the PCIA Benchmark to Recognize their Additional Value	R. Kinosian	2B-16

Chapter			Witness	Page
	B.	Correct the Methodology for Calculating Uneconomic Costs for Pumped Hydroelectric Storage Facilities	R. Kinosian	2B-18
	C.	Consider Whether Legacy Utility Owned Generation is Appropriately Included in the PCIA-Eligible Portfolio	A. Hoekstra R. Kinosian	2B-19

CHAPTER 2B EXHIBITS

2B-A Helms Pumped Storage Plant Operation (10/17/08 presentation)

PREPARED OPENING TESTIMONY OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

List of Acronyms

A.	Application
A&G	Administrative and General
AB	Assembly Bill
AS	Ancillary Services
BCR	Bid Cost Recovery
BNI	Binding Notice of Intent
CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
CARB	California Air Resources Board
CCA	Community Choice Aggregation
CCGT	Combined Cycle Gas Turbine
CDWR	California Department of Water Resources
CEC	California Energy Commission
CPM	Capacity Procurement Mechanism
CPUC	California Public Utilities Commission
CRS	Cost Responsibility Surcharge
CT	Combustion Turbine
CTC	Competition Transition Charge
D.	Decision
DA	Direct Access
DG	Distributed Generation
DER	Distributed Energy Resources
DOE	US Department of Energy
DR	Demand Response
EE	Energy Efficiency
ERRA	Energy Resource Recovery Account
ESP	Electric Service Provider
GHG	Greenhouse Gas
GRC	General Rate Case
IEPR	Integrated Energy Resource Plan
IOU	Investor Owned Utility
LCBF	Least Cost Best Fit
LSE	Load Serving Entity
LTTP	Long Term Procurement Plan
MCP	Market Clearing Price
MPB	Market Price Benchmark
NBC	Non Bypassable Charge

NPC	Nevada Power Company
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
PAM	Portfolio Allocation Methodology
PCIA	Power Charge Indifference Adjustment
PDP	Peak Day Pricing
PG&E	Pacific Gas and Electric Company
POLR	Provider of Last Resort
POU	Publicly Owned Utility
PPA	Power Purchase Agreement
PUC	Public Utilities Code
PUCN	Public Utility Commission of Nevada
PX	Power Exchange
R.	Rulemaking
RA	Resource Adequacy
RBY	Resource Balance Year
RFO	Request for Offer
RPS	Renewables Portfolio Standard
SB	Senate Bill
SCE	Southern California Edison Company
SG&A	Sales, General and Administrative
SONGS	San Onofre Nuclear Generating Station
SPA	Staggered Portfolio Auction
T&D	Transmission and Distribution
TPM	Third Party Manager
UOG	Utility Owned Generation
URG	Utility Retained Generation

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

CHAPTER 1

INTRODUCTION

(Common Outline §I)

I. INTRODUCTION

The Power Charge Indifference Adjustment reflects the costs of the utilities' PCIA-eligible portfolios, which are paid by *all* customers – bundled utility, Community Choice Aggregation and Direct Access customers. In this proceeding, the Commission must entertain two opposing views of these costs: either the investor-owned utility resource portfolios are wildly "out of the money" or the benchmark used to evaluate market value requires reform.

Applying the PCIA market-price benchmark to the utilities' 2018 ERRA forecasts, PG&E's portfolio is $2.2 billion (40%) "above market," and SCE's portfolio exceeds "market" value by $1.2 billion (35%). Using the same benchmark, the combined cost of the utility portfolios over the next twelve years would be roughly 59% – a staggering $28.1 billion[1] – "above market." Any proposals to reduce the PCIA benchmark would drive these estimates to even greater extremes. These conclusions naturally call into question utility procurement and portfolio management practices and are linked to important State policies.

CalCCA agrees that there are excess, "avoidable" costs in the utility portfolios, but supports a more rational view of the portfolios. The PCIA benchmark undervalues the resources in the utilities' PCIA-eligible portfolios, making the portfolios appear more uneconomic than they are. This testimony offers recommendations both to reduce PCIA-eligible costs, including benefits for *all* customers, and to reform the PCIA benchmark to more accurately reflect the value of the utilities' portfolios.

---

[1] PG&E's and SCE's "above market" costs are estimated at $18.7 billion and $9.4 billion, respectively.

Bridging the gap between these opposing views must begin with focused efforts to reduce and slow the accrual of stranded costs in the utilities' PCIA-eligible portfolios. CalCCA's testimony proposes measures to reduce costs,[2] including a proposal to remove up to $1.3 billion[3] of costs from PG&E's portfolio and $589 million[4] from SCE's portfolio through securitization of utility owned generation assets for the remaining lives of the assets.[5] Other proposals aimed toward portfolio management and resource redistribution also present an opportunity to reduce stranded costs.

Cost reductions alone, however, do not fully close the gap. The Commission must assess the effectiveness of the current PCIA methodology in allocating PCIA-eligible costs among bundled, CCA and DA customers. CalCCA concludes in this testimony that the PCIA benchmark understates the value of capacity and "green" attributes and omits values for GHG-free attributes and ancillary services. Modifying these benchmark components, together with the proposed cost reductions, would have reduced the portion of the 2018 PCIA-eligible portfolio treated as "stranded" or "above-market" costs[6] by roughly $1.7 billion (leaving stranded costs of $512 million)[7] for PG&E and $908 million (leaving stranded costs of $299 million)[8] for SCE.

The Commission and stakeholders approach these issues to fulfill the Legislature's directives to allocate stranded costs in a manner that prevents "cost shifts"

---

[2] *See infra*, Chapter 2B, §III and Chapter 3, §III and §IV.
[3] See *infra*, Chapter 3, Exhibit 3-A (Sutherland).
[4] *Id.*
[5] *See infra,* Chapter 3.
[6] Throughout this testimony, we refer to net stranded costs, comparing portfolio costs and the benchmark value of the portfolio, as "Net Costs," stranded costs, or above market costs.
[7] *See infra*, Chapter 2A, §III.
[8] *Id.*

from CCA customers to bundled customers and vice versa.[9] In determining the cost responsibility of departing CCA customers, Public Utilities Code §366.2(f)(2) provides useful guidance. To prevent cost shifting from CCA customers to bundled customers, the Commission must answer three central questions: [10]

- ✓ Is there a "net" uneconomic cost, when taking into account both costs, revenues and other benefits?
- ✓ If there is a net cost, is the cost "unavoidable," or are there opportunities to mitigate the cost?
- ✓ If there are net unavoidable costs, did the customer cause the costs to be incurred or, in the language of the statute, is the cost "*attributable to the customer"*?

While the questions are simple, answering them is not, requiring an understanding of history and examination of value measures, timing, forecasting and portfolio management practices and other factors.

The utilities, CCAs and DA providers and their customers have been waiting for the opportunities presented in this rulemaking. CCAs approach this proceeding with key objectives in mind: (1) minimize costs borne by all customers; (2) protect consumers from rate shock through predictable and stable rates; (3) ensure the transparency of any solution to allocate departing load cost responsibility; (4) accurately reflect long-term and short-term value streams in the PCIA-eligible portfolios; (5) encourage prudent IOU resource procurement and portfolio management; (6) provide access for CCAs and ESPs, on a voluntary basis, to the resources in the utilities' portfolios; and (7) enable California to continue its progress toward important environmental goals. With these objectives in mind, it is time to take account of

[9] Cal. Pub. Util. Code §366.3.
[10] Cal. Pub. Util. Code §366.2(f)(2).

changing market dynamics and find solutions that balance the interests of all stakeholders.

II. EXECUTIVE SUMMARY OF PROPOSAL

The utilities' PCIA-eligible resource portfolios contain "above market" costs, and some of these costs may be avoidable. Moreover, the existing PCIA methodology results in a cost shift from bundled customers to departing load customers, estimated for 2018 at $492 million[11] for PG&E and $25 million[12] for SCE. CalCCA proposes reforms to the existing PCIA benchmark that will substantially reduce the excess cost burden borne by departing load customers. This testimony proposes, among other things, to:

1. With the support of the utilities' and other stakeholders, securitize the rate base for all UOG committed to the utilities' PCIA-eligible portfolios for their remaining service lives.

2. Establish a voluntary buydown program for PCIA-eligible power purchase agreements and, with the support of the utilities and stakeholders, securitize the funding required to implement the program.

3. Modify the capacity value in the PCIA benchmark to blend a short-term value for excess capacity sold into the market and, consistent with Commission-adopted planning values, a long-term, Commission-approved capacity value for products remaining in the portfolio.

4. Recognize the value of non-Renewable Portfolio Standard greenhouse gas free resources in the PCIA-eligible Portfolio through the addition of a separate benchmark component.

5. Correct the Green Adder by removing the unsupported and inaccurate Department of Energy referents in the calculation.

6. Either exclude from the PCIA calculation any uneconomic costs of operating UOG resources or recognize value measures missing from the benchmark that render the operation economic.

---

[11] *See infra* Chapter 2A, §III.

[12] *Id.*

7. Correct the calculation of uneconomic costs for pumped storage facilities. Together, these modifications will reduce overall PCIA-eligible costs and realign the PCIA benchmark to more accurately reflect the value of the portfolio serving bundled customers.

CalCCA's testimony does not stop with realignment of the PCIA methodology. It proposes consideration of a Staggered Portfolio Auction in which all of the utility's RPS and GHG-free resources in the PCIA-eligible Portfolio would be offered for purchase by load serving entities serving bundled, CCA and DA, as well as other market participants. To the extent possible, CalCCA proposes reliance on the prices produced in the SPA to determine the "above market" costs paid by all customers, including bundled, CCA and DA customers. CalCCA further suggests changes to forecasting and portfolio management practices.

This testimony addresses other issues identified in the Scoping Memo that are important in the process of ensuring that PCIA rates are reasonable, transparent, stable and predictable over time. The testimony:

- ✓ Examines the question of "sunsetting," from the perspective of both ending the continuing accumulation of stranded costs and ending stranded cost recovery.
- ✓ Concludes, based on an examination of future PCIA costs, that while a PCIA rate cap is not immediately necessary, the Commission should ensure an opportunity to address the question as necessary in future ERRA proceedings.
- ✓ Proposes a methodology to accommodate annual long-term PCIA forecasting as a part of the ERRA proceedings.
- ✓ Proposes a full or partial prepayment option for CCA and DA customers based on market prices produced in the SPA.
- ✓ Requests that the PCIA rate be identified as a separate line item on the bills of all customers, including bundled utility, CCA and DA customers.

Finally, the testimony examines briefly the relationship between this proceeding and the Commission's efforts to respond to the increasingly competitive retail market. It observes that the utility's role as Provider of Last Resort in its service territory – an issue the Commission contemplates addressing through a new rulemaking – will continue to drive the accumulation of stranded procurement costs. CalCCA urges the Commission to examine the issue in the near term, with an eye toward supporting legislative changes necessary to realign the utility's obligation to serve with today's market realities.

III. EVOLUTION OF DEPARTING LOAD PROCUREMENT COST RESPONSIBILITY

It would have been difficult, if not impossible, for the Commission or stakeholders to foresee two decades ago the circumstances that have led to this rulemaking. In 1994, embarking on the road to a competitive electricity market, the Commission concluded in its "Blue Book"[13] that "competition offers a superior means of organizing the development, delivery and consumption of services" when compared with "command-and-control and cost-of-service regulation, and government central planning."[14]

Following this blueprint, the Legislature enacted Assembly Bill 1890 in 1996, which contemplated the possibility of utility divestiture of generation assets[15] and

---

[13] Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation, R.94-04-041 (Blue Book). The Blue Book followed an earlier "Yellow Book" developed by the Commission's Division of Strategic Planning in 1993, which concluded that the then-existing regulatory structure was "ill-suited to govern today's electric services industry," and "incompatible with the industry structure likely to emerge in ensuing decades." California's Electric Services Industry: Perspectives on the Past, Strategies for the Future, February 3, 1993, at 147.

[14] Blue Book at 5-6.

[15] *See* Pub. Util. Code §367(b).

anticipated a full transition to a competitive market by 2002.[16] The statute allowed the utility to recover the above-market sunk costs of resources that would become uneconomic in the transition to competition through a nonbypassable charge to be paid by all electricity customers, regardless of supplier.[17] In implementing AB 1890, the Commission labeled this nonbypassable charge the “Competition Transition Charge” and observed that its goal was to “get through this transition period as quickly as possible so that full competition can begin with minimal market distortions.”[18] It concluded: “With the exception of CTC arising from existing contracts, *no further accumulation of CTC will be allowed after 2003 and collection will be completed by 2005*.”[19]

A full transition to competition did not occur. In the midst of the 2000-2001 energy crisis, the Legislature reverted to central planning for electricity procurement. AB 1X conferred on the California Department of Water Resources the obligation to procure power for utility customers[20] and suspended expansion of “Direct Access” retail competition established by AB 1890.[21] AB 1X provided for the reimbursement of costs to CDWR, but did not establish a nonbypassable charge that would be applied to DA

---

16 Assembly Bill 1890, Section 1(b) (“It is the further intent of the Legislature that during a limited transition period ending March 31, 2002, to provide for all of the following:
(1) Accelerated, equitable, nonbypassable recovery of transition costs associated with uneconomic utility investments and contractual obligations….).

17 Pub. Util. Code §367.

18 D.95-12-063, 64 CPUC 2d 1 at 60.

19 *Id.* at 58 (emphasis supplied).

20 Cal. Water Code §80000 *et seq*.

21 Cal. Water Code §80110 (“the right of retail end use customers pursuant to Article 6 (commencing with Section 360) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code to acquire service from other providers shall be suspended until the department no longer supplies power hereunder.”).

customers.[22] The statutory directive appeared to be based on the conclusion that since DA had been suspended, there would be no further DA departures following long-term CDWR procurement.[23]

Despite the absence of statutory directive, the Commission elected in implementing AB 1X in 2002 to recover the CDWR contract costs from DA customers through a nonbypassable charge, which became the "DWR Power Charge."[24] The DWR Power Charge aimed to determine the uneconomic cost of the CDWR long-term contracts on an annual basis, using "DA In/DA Out" production cost simulations.[25] The Commission's 2002 decision went beyond CDWR contract costs, however, to address Legacy UOG. The Commission had determined earlier that year:

> we find that California is better served by maintaining the September 20, 2001 direct access suspension date and considering a direct access surcharge or exit fee, in lieu of an earlier suspension date, to recover DWR costs from direct access customers….we believe that such a surcharge or exit fee is a viable option and a more moderate alternative to an earlier suspension.[26]

Industrial customer groups complained that imposing above-market CDWR costs on DA customers, while giving bundled customers sole access to below-market Legacy UOG, was inequitable. The Commission recognized the tension this approach created with AB 1890:

---

[22] Pub. Util. Code §360.5. The statute established the California Procurement Adjustment, requiring the Commission to "determine the amount of the California Procurement Adjustment that is allocable to the power sold by the department." It further provided that the amount would be "payable, by each electrical corporation, upon receipt by the electrical corporation of the revenues from its retail end use customers…." No provision was made in the statute for recovery of the charge on a nonbypassable basis.

[23] *See generally* D.02-11-022.

[24] D.02-11-022 at 4-5.

[25] *Id*. at 73-74.

[26] D.02-03-055 at 16-17.

> Certain parties argue that the IOUs' ability to collect utility-related costs from DA customers expired under the provisions of AB 1890 effective after March 30, 2002, and that without specific legislation, the attempt to charge such costs violates the rule on retroactive ratemaking and Public Utilities Code Section 728….These parties claim that AB1X does not give the Commission the authority to impose a new surcharge for non-DWR costs, and do not believe any other statute gives the Commission the authority to impose surcharges that are not in any way related to the delivery of electricity to DA customers.[27]

Relying, in part, on the Commission's general ratemaking authority under Sections 701, 451, and 453, and with no opposition to this approach, the Commission adopted a "separate charge to cover the ongoing above-market portion of utility-related generation costs," allowing for the netting of above-market CDWR and then-below-market Legacy UOG costs in the utility portfolio.[28]

Around the same time, in 2002, the Legislature broadened opportunities for retail competition in another direction, authorizing Community Choice Aggregation through Assembly Bill 117. As with Direct Access, the Legislature sought to prevent cost shifts between bundled and CCA customers.[29] The statute thus expressly required CCA customers to bear cost responsibility for CDWR historical purchases, through the CDWR Bond Charge,[30] and the long-term contracts negotiated by CDWR during the energy crisis,[31] through the CDWR Power Charge. In addition, the Legislature required CCA customers to reimburse the utility for certain balancing accounts[32] and the following utility procurement costs:

---

[27] D.02-11-022 at 13.
[28] *See id.* at 4.
[29] Pub. Util. Code §366.2(c)(5), (d)(1).
[30] Pub. Util. Code §366.2(e)(1). The long-term contracts have since terminated.
[31] Pub. Util. Code §366.2(e)(2).
[32] Pub. Util. Code §366.2(f)(1) ("the electrical corporation's unrecovered past undercollections for electricity purchases, including any financing costs, attributable to that customer, that the commission lawfully determines may be recovered in rates.").

> (2) 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.[33]

AB 117 was implemented by the Commission through D.04-12-046 and D.05-12-041.

Decision 04-12-046 adopted a Cost Responsibility Surcharge model for CCA customers, drawing from prior nonbypassable charge decisions and models developed for DA CRS.[34] It described the scope of the CRS charge, which it stated was undisputed, as follows:

> Such costs include (1) costs associated with power contracts and bonds entered into by DWR during the energy crisis; (2) utility power costs, including those of utility retained generation, purchased power and other commitments in approved resource plans; and (3) CTC and historic revenue undercollections and credits applicable to the customer at the time the CCA transferred the customer.[35]

The Commission observed: "The methodology has been subject to considerable scrutiny in other proceedings and it is reasonable to adopt it here."[36] Efforts to ensure that prior methodologies aligned with the language of AB 117, however, are not apparent in the decision.

Around the same time the Commission was implementing CCA rules, the Commission authorized expansion of the Cost Responsibility Surcharge for both DA and CCA customers. In D.04-12-048, the Commission concluded that the utility may have a need to procure or invest in new long-term resources to ensure reliability or meet

---

33 Pub. Util. Code §366.2(f)(2) (emphasis supplied).

34 D.04-12-046 at 23.

35 *Id.* at 24.

36 *Id.* at 25.

RPS requirements.[37] It further observed that these resources "may become stranded at some point" during their life.[38] Consequently, the Commission concluded that "the utilities should be allowed to recover the net costs of these commitments from all customers, including departing customers."[39] For non-RPS contract resources, cost recovery was limited to the lesser of 10 years or the contract term; for non-RPS investments, recovery was limited to 10 years following commercial operations.[40] RPS contract cost recovery was approved for the life of the contract.[41] The Commission's decision was implemented in D.08-09-012, establishing the "new world generation" surcharge that would apply to DA and CCA customers consistent with D.04-12-048.

In 2006, the indifference calculations for the CDWR Power Charge and Legacy UOG were folded together as the Power Charge Indifference Adjustment, designed for Direct Access,[42] with a methodology similar to what we have today. The PCIA was designed to recover, on an annual basis, the difference between a revised benchmark power cost and "the average cost of the utilities' total portfolio, including both utility retained generation power and allocated DWR power costs, to determine the level of the indifference charge for each year."[43] The 2006 decision also added a capacity value in the indifference calculation, which had until then been based solely on energy costs.[44]

---

37 D.04-12-048 at 55.
38 *Id*. at 58.
39 *Id*. at 60.
40 *Id*., Conclusion of Law 16 at 229-30.
41 *Id*.
42 D.06-07-030 at 7. The decision referred to the changes as the "Prospective DA CRS Market Benchmark Methodology Revisions."
43 *Id.*, Ordering Paragraph 6.
44 *Id.* at 9-10.

In 2010, eight years following enactment of AB 117 and more than four years following full Commission implementation of CCA, Marin Clean Energy became the first CCA to implement service. The Commission and Legislature attributed the slow launch of CCAs, in part, to activities by the investor owned utilities. The Legislature observed in enacting a requirement for a utility code of conduct in SB 790:[45]

> The Public Utilities Commission has found that conduct by electrical corporations to oppose community choice aggregation programs has had the effect of causing community choice aggregation programs to be abandoned.[46]

Following the adoption of a code of conduct in D.12-12-036, CCAs began to develop, with 20 operational or near-operational CCAs to date.[47]

The PCIA has continued to evolve. The Commission made further changes to the PCIA methodology in 2011, adding a Green Adder to the PCIA benchmark.[48] The Commission found that "[t]he current indifference methodology only recognizes the IOUs' cost of renewable resources in the calculation of the Total Portfolio Cost, but does not account for the market value of renewable resources in the MPB."[49] It determined that the Green Adder should reflect "prices paid by buyers and sellers in recent transactions for delivery of RPS compliant power in California for the forecast year."[50] The Commission chose to rely primarily on the utilities' costs of procuring renewable resources, weighted at 68% of the benchmark, supplemented by "western regional

---

45 Pub. Util. Code §707.

46 SB 790 (2012), Section 2(d).

47 A table showing existing CCAs and their original launch dates is provided as Exhibit 1-A.

48 D.11-12-018. The Commission also revised the Capacity Adder, eliminated CAISO load-based costs in calculating the PCIA, replaced the use of a flat MPB weighting with a weighting based on the historical utility bundled load profile, and other DA-related changes.

49 *Id*. at 10.

50 *Id*. at 17.

renewable energy contract premiums published by U.S. DOE" for the remaining 32%.[51] The scope of CCA and DA cost responsibility increased again in 2014, when the Commission authorized the recovery of the utilities' energy storage procurement costs through the PCIA.[52]

The PCIA has developed over many years, affected by the foregoing and many other statutes and decisions. The long, complex history forms the foundation required to understand the current PCIA methodology and to inform long-term solutions.

---

51 *Id*. at 22.

52 D.14-10-045.

Exhibit 1-A

Exhibit 1-A

Existing and Near-Operational Community Choice Aggregators

CCA	Launch Date
MCE	5/1/2010
Sonoma Clean Power	5/1/2014
Lancaster Choice Energy	5/1/2015
CleanPowerSF	5/1/2016
Peninsula Clean Energy	10/1/2016
Silicon Valley Clean Energy	4/1/2017
Apple Valley Choice Energy	4/1/2017
RCEA	5/1/2017
Pico Rivera Innovative Municipal Energy (PRIME)	9/1/2017
Pioneer Community Energy	2/1/2018
Clean Power Alliance	2/1/2018
Monterey Bay Community Power	3/1/2108
City of San Jacinto	4/1/2018
City of Rancho Mirage	5/1/2018
Valley Clean Energy Alliance	6/1/2018
East Bay Community Energy	6/1/2018
Solana Energy Alliance	6/1/2018
King City Community Power	6/1/2018
Desert Community Energy	8/1/2018
San Jose Community Energy	9/1/2018

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

CHAPTER 2A

PCIA EFFECTIVENESS IN AVOIDING COST SHIFTS

(Common Outline §II.A)

I. PCIA EFFECTIVENESS IN AVOIDING COST SHIFTS

AB 117 provides sound guidance on avoiding a cost shift, and this guidance should be applied in answering the Commission's questions about whether the current PCIA methodology results in a cost shift between bundled customers and CCA and DA customers.

The term "cost shift" has been used extensively in Commission decisions and legislation but has no formal definition. Perhaps the closest the Legislature has come is AB 117, where it identified all costs for which CCA customers would bear responsibility to avoid a cost shift.[1] Among those costs, the statute addresses ongoing utility procurement, requiring CCA customers to pay:

> 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.[2]

CCA customer cost responsibility arises for "purchase contract" costs that are, on a "<u>net</u>" basis, "<u>unavoidable</u>" and "<u>attributable</u>" to the CCA departing load customer. These three guideposts provide a reliable framework for assessing whether the departing load customer is bearing the cost responsibility required to avoid a cost shift.

The approach to analyzing cost shifts that has evolved over time departs from close adherence to these guideposts. The existing PCIA methodology "nets" procurement costs and the portfolio's "market value" to derive a Net Cost. The current methodology also appears to assume that if a cost is in a utility portfolio and the

---

[1] Cal. Pub. Util. Code §366.2(e) and (f).
[2] *Id.* §366.2(f)(2).

procurement of the resource underlying the cost was initially deemed prudent by the Commission, the cost is "unavoidable" for the duration of the PPA or the asset book life. Finally, the utilities and the current PCIA methodology consider any plant built or contract executed while a customer was a bundled customer "attributable" to that customer.[3] As discussed below, these long-standing views may appear to follow these guideposts, but ignore important dimensions of portfolio value and the importance of ongoing and prudent utility portfolio management.

This proceeding presents an opportunity for the Commission to clearly define the meaning of cost shift using the guideposts expressed in Public Utilities Code §366.2(f)(2). Focusing on the statute will enable the Commission to mitigate the risk of cost shifts between CCA and utility bundled customers, as the Legislature intended, with an improved process providing transparency, flexibility, accountability, and predictability, while also lowering costs for all customers.

A. A "Cost Shift" Occurs When a Customer Does Not Shoulder the "<u>Net</u>" Unavoidable Costs Attributable to That Customer

AB 117 identifies "net" unavoidable costs as the responsibility of departing CCA customers. While the Legislature did not explain in detail how "net" costs are derived, the clear meaning of the words of the statute and the long history of the PCIA development suggests a clear answer. Net Costs are the <u>costs</u> incurred by the utility in procuring a resource offset by the <u>value</u> retained in the portfolio. While "costs" are straightforwardly measurable, "value" can be harder to establish particularly in the context of California's hybrid market.

[3] *See* PG&E and SCE Responses to CalCCA_002-Q14, attached as Exhibit 2A-A.

Determining portfolio value requires an examination of the products and attributes held in the PCIA-eligible portfolio and identifying term-related value. The following table compares the products and attributes recognized by the PCIA benchmark with the range of products and attributes either traded in the market or identified by the Commission of having unique value:

Table 2A-1

Products and Attributes Recognized in the PCIA Benchmark	**Products and Attributes with Value**
Brown Energy	Energy
Green Attribute	Renewable Energy
System RA	System RA
	Non-RPS GHG-Free
	Local RA
	Flexible RA
	RPS Integration
	Hedge Value
	Diversity Value (LCBF)

Certain of these products or attributes may also have a term-related value, which is most easily seen through the lens of capacity value. As explained in Chapter 2B, §II, the current capacity benchmark reflects only the annual unavoidable costs of maintaining a combustion turbine available to provide capacity – a short-term value measure. The value placed on capacity in the long run, as demonstrated by Commission-adopted capacity values, must reflect *all* costs of that resource, including the development and construction costs.

California's hybrid markets create another layer of complexity in determining portfolio value. Wholesale power generation may be owned or controlled by both utilities and non-utility entities. Utilities recover their costs on a cost-of-service basis from captive customers with assured cost recovery, while non-utility competitors are at risk for cost recovery. Because utilities are not at market risk for UOG, this subset of generation may not be a part of the price-setting dynamic in the markets. In other words, if RA value from a UOG is held in the portfolio for serving bundled load, the value of that RA is never assessed by the market. The result is that the capacity "market" does not reflect the value of all capacity used to serve load.

Assessing portfolio value, one of the two components of "Net Cost," must start with an examination of the full range of products and attributes held in the portfolio, including any term-related attributes. Additionally, in selecting the price used to represent that value in the PCIA benchmark, the assessment must recognize the effect the hybrid market has on market prices.

B. Estimating a Cost Shift Requires a Clear but Complex Set of Criteria to Determine Whether a Cost is "Unavoidable"

As with the word "net," the Legislature chose to rely on the simple word "unavoidable" in AB 117 rather than providing an extended definition. In the context of utility planning, a cost is unavoidable when the utility, despite prudent procurement and portfolio management practices, cannot reduce or eliminate that cost. This assessment has several dimensions.

- ✓ Could procurement of the resources have been avoided by deferring the purchase or by substituting a better alternative?
- ✓ Could the utility have sold the resource to reduce the total cost of the portfolio?
- ✓ If the utility did sell the resource or its output, were the products, terms and conditions of the sale structured to bring the maximum value?

For the purposes of this proceeding, the Scoping Memo does not allow "revisiting prior Commission determinations regarding the reasonableness of the IOUs' past procurement actions."[4] The latter two dimensions, however, fall squarely within the scope of this proceeding. And they highlight a key distinction: A utility's obligation does not stop with a single procurement decision, based on the best information available at the time, but involves many subsequent decisions regarding the ongoing portfolio composition base on new information regarding market developments and changes in demand. Prudent administration of contracts addresses the latter, which is explicitly including as a Guiding Principle in this proceeding.[5]

Fortunately, prudent administration has been clearly addressed by the Commission in setting expectations regarding the role and responsibility of the utility as provider of a public good. The CPUC's Procurement Policy Manual, Standard of Conduct #4 regarding prudent administration of contracts reads:

> In administering contracts, the utilities have the responsibility to dispose of economic long power and purchase economic short power in a manner that minimizes ratepayer costs. Once a contract has been deemed compliant with the utilities' procurement plan, the contract is not subject to a reasonableness review. However, the administration of the contract by the utility remains subject to a reasonableness review and disallowance through ERRA proceedings.[6]

The existence of a resource in the utility portfolio – even if the initial decision to procure it was prudent given the information available at that time – does not alleviate the utility of their responsibility to actively manage those resources to the benefit of all customers. Costs are not "unavoidable" if the utility fails to take advantage of an opportunity to recover some portion of the costs by divesting high-cost resources in a timely manner.

---

[4] Scoping Memo at 19.

[5] Scoping Memo, Guiding Principle 1.h: "[any PCIA methodology] should only include legitimately unavoidable costs and account for the IOUs' responsibility to prudently manage their generation portfolio and take all reasonable steps to minimize above-market costs."

[6] CPUC *AB57, AB 380, and SB 1078 Procurement Policy Manual*, published June, 2010. Available online at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=10906.

The utilities have had opportunities to sell assets, avoiding a continuing stranded cost, as customer departure has occurred. For example, PG&E had the opportunity to sell a portion of its RPS portfolio to SCE and SDG&E in 2010 (and perhaps municipal utilities who also face an RPS mandate) as Marin Clean Energy (later MCE) exited bundled service. According to the Green Adder included in PG&E's 2010 ERRA workpapers, a benchmark that is based on transactions for all three IOUs, PG&E could have sold MCE's share of PG&E's RPS portfolio for $149/MWh. Similarly, the share for Sonoma Clean Power could have been sold in 2013 for $120/MWh based on the reported ERRA index. Even if PG&E did not sell MCE's and SCP's portions immediately, the utility could have sold those portions for more than $92/MWh at any point before 2017. Today, however, those resources are valued by the MPB at only $82/MWh.[7]

Similar opportunities have been available for other CCAs as they exited; and going forward, the utilities can prudently manage these excess resources by participating directly in the rounds of requests for offers issued by the new and existing CCAs.[8] In fact, the failure of the utilities to participate in these RFOs or to offer reasonable terms and conditions could be viewed as withholding of resources from the market.

---

7 PG&E, 2018 ERRA, November Update, Table 9-5.

8 As examples of such RFOs for RPS-eligible power, Peninsula Clean Energy issued RFOs due October 14, 2017, February 9, 2018 and March 29, 2018 (*see* https://www.peninsulacleanenergy.com/our-power/pce-2018-renewables-rfo/); MCE issued an RFO due March 1, 2018 and April 2, 2018 (*see* https://www.mcecleanenergy.org/energy-procurement/); Sonoma Clean Power issued RFOs due September 23, 2015; January 5, 2017; and January 24, 2018 (*see* https://sonomacleanpower.org/request-for-offers/); Los Angeles Community Choice Energy issued an RFP due September 5, 2017 (*see* http://www.cleanpoweralliance.org/#rfp).

The appropriate adjustment is to value the RPS portion of the vintaged portfolio applicable to a CCA at the green MPB in the year of the CCA's departure. In this way, the utilities will be given the correct incentive to reduce their portfolio holdings in a manner that maximizes the value for all ratepayers. Following least cost dispatch for must-take generation with near zero operating costs does not qualify as prudent management — that is simply housekeeping.

Based on this approach, Table 2A-2 shows how the vintaged portfolios' market values increase by using the Green Adder for the year of departure for PG&E since 2012.[9] Because SCE's CCAs formed later, with Lancaster first being established in 2016, these increases are minor for the moment, but SCE also should be held to the same standard going forward.

Table 2A-2

Increased RPS Market Value for PG&E's Vintaged Portfolios	
Vintage	**Increased Market Value**
2012	$67,402,807
2013	$44,151,685
2014	$28,224,660
2015	$27,420,513
2016	$7,615,520
2017	$0

C. An Unavoidable Cost is "Attributable" to a Departing CCA or DA Customer When the Utility's Forecast, at the Time an Irrevocable Action Was Taken to Procure the Resource, Assumed the Customer Would Remain in Bundled Service

Determining whether a cost is attributable to a departing CCA or DA customer requires a more refined analysis than simply observing that a customer was a bundled

[9] The CCA Parties are still working with PG&E's pre-2013 workpapers provided in response to the ALJ's Data Matrix to develop estimates for earlier vintages.

customer when a PPA was executed. Even if the customer was a bundled customer at the time, it may be that the forecast underlying the procurement decision assumed or should have assumed that load would depart in the future. If, for example, a 2018 forecast assumed that the departure of 5 MW of load in that year to be served by a CCA or DA, any procurement decision made in 2018 would not have been made on behalf of that 5 MW of departing load and could not be "attributable" to that 5 MW of departing load.

In addition, attribution requires a careful assessment of when a decision committing the utility to incur the cost was actually made. Assume, for example, that a customer was a bundled customer when an RPS contract for a new resource was originally signed but departed to be served by a CCA a year later. Assume further that the developer anticipated failing to meet its commercial operations date obligation under the contract, and the utility, two years after the customer departed, overlooked the developer's failure and modified the original contract to address the problem. Under these circumstances, the contract modification date, rather than the original contract date, is a more suitable date for determining the customers on whose behalf the resource was procured. If the CCA customer had already departed when the decision to modify the contract and keep the deal alive was made, that latter decision is not "attributable" to the departing customer.

Similarly, if the IOU could have terminated a planned RPS commitment at a cost when additional load departed, provided binding notice of intent to depart or was forecasted to depart, and the IOU chose to continue that project, the decision to continue is not "attributable" to the departing customer. The cost "attributable" to the departing load cannot exceed the cost of terminating the contract in this example.

II. PUBLIC CLAIMS OF "MASSIVE" AND "ILLEGAL" COST SHIFTS ARE UNSUPPORTABLE AND BASED ON ARBITRARY ASSUMPTIONS

The Joint Utilities have gone to great lengths to lead this Commission and public opinion to the conclusion that the success of CCAs in garnering market share has caused an "illegal" cost shift to bundled customers.[10] PG&E, for example, has publicly claimed an annual cost shift of $178 million based on its 2017 ERRA proceeding. The flawed methodology underlying this conclusion relies on the PCIA framework used in the 2017 ERRA but replaces the Capacity and the Green Adder benchmarks with alternative values.[11] As discussed below, the analysis is based on untenable assumptions, and a roughly equivalent cost shift of $173 million in the other direction – from bundled customers to departing load customers – can be calculated by changing only two assumptions using values approved by this Commission for utility procurement planning.

PG&E explained in a data response to CalCCA Data Request 1, Question 2, that the estimate was performed "by comparing the 2017 PCIA system average rate using the Commission-approved market price benchmark (MPB) to a PCIA rate calculated using market-based inputs for the value of renewable and capacity attributes in the MPB." PG&E's methodology values the utility's entire portfolio – a portfolio dominated by long-

---

[10] *See, e.g.,* https://equitablechoice.com/, which was organized by PG&E, as acknowledged in its response to CalCCA Data Request 1, Question 1.

[11] The $178 million cost shift was calculated by PG&E and is drawn from cell E78 on the "PCIA Cost Shift Update – Final" provided in its response to CalCCA Data Request 1, Question 2. According to PG&E, this is the calculation underlying the cost shift conclusions stated on the "Fact Sheet" on the Equitable Choice website, https://equitablechoice.com/fact-sheet/.

term investments and renewable PPAs – at $47.78/MWh.[12] This value is just $12.56/MWh above the $35.22/MWh benchmark price for liquidation of brown power in the spot market.[13] In other words, PG&E valued the sum total of all renewable, greenhouse gas free, Local RA, Flexible RA and other products and attributes at only $12.56/MWh.

While this approach may calculate the liquidation value of small amounts of excess portfolio volumes in a short-term "market," its usefulness stops there; it cannot be used to measure a "cost shift." First, the calculation is limited to only three of the many products and attributes in the utility's portfolio. Second, this approach does not make any attempt to assign an appropriate value to long-term products held to serve bundled customers and to achieve statewide policy goals. Third, it does not consider whether all of the costs were "unavoidable" or whether value above market prices could have been obtained for products sold in the market. Fourth, PG&E's approach fails to consider whether the products and costs left in the portfolio are "attributable" to departing load customers.

The current PCIA market price benchmark calculation sets short-term market prices for three features: energy, capacity and RPS attributes. When alternative, Commission-approved estimates of longer term market values are used just for the capacity and RPS values, the Joint Utilities' conclusion is flipped on its head, leading to the conclusion that costs have been shifted from bundled customers to CCA/DA customers.

---

12 *Id.*

13 PG&E 2017 ERRA, November Update Filing p. 27, Table 9-5.

The Commission's E3 Avoided Cost Calculator relies on values carefully crafted and approved by the Commission for purposes of valuing demand response, energy efficiency and distributed energy resources opportunities presented to the utilities. In addition, the Commission has developed long-term planning values in other proceedings. Table 2A-3 shows the wide range in values and compares them with the current values used in the PCIA benchmark.

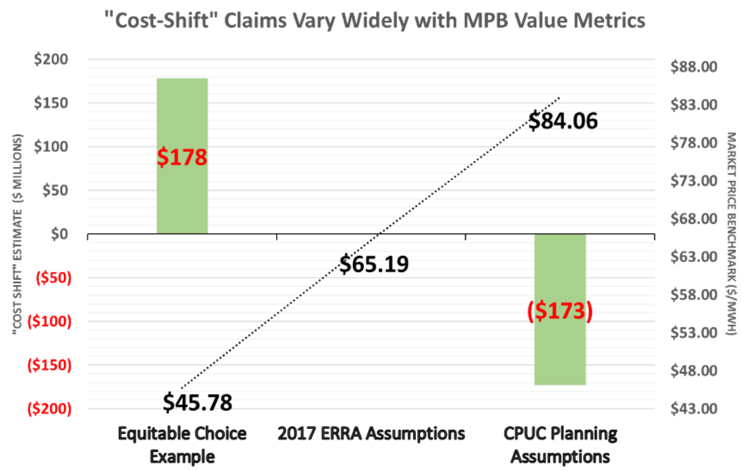
Table 2A-3

Comparison to Marginal Cost/Market Values Indicators Across CPUC/CEC Proceedings

Proceeding	Utility / Region	Model / Source	Capacity $ /kW-Yr	Energy $/MWH	Ancillary Service $/MWH	RPS Cost $/MWH	RPS Premium $/MWH	GHG Value $/tonne	GHG Value $/MWH
PG&E 2018 ERRA	PG&E	ERRA Table 9.5	$58.27	$33.77		$61.47	$24.16		
SCE 2018 ERRA	SCE	ERRA WPs	$58.27	$32.37		$61.47	$25.11		
PG&E 2017 GRC	PG&E	MC/RA WPs	$28.64	$28.30					
SCE 2018 GRC	SCE	MC/RA WPs	$146.85	$36.81					
EE / DRP / LIEE / NEM	North	E3 Avoided Cost	$113.74	$28.03		$79.90	$14.17	$66.37	$29.15
/ DG	South	Calculator	$109.75	$28.06		$79.90	$14.17	$66.37	$29.15
CEC Title 24	SF CZ 3		$145.75	$37.75	$0.19	$126.00	$19.50	$15.72	$9.43
	Fresno CZ 12	2016 TDV	$130.54	$37.75	$0.19	$129.90	$19.50	$15.72	$9.43
	LA/SD--CZ 7	Update Model	$105.70	$38.01	$0.19	$129.90	$19.50	$15.72	$10.31
	LA/SD--CZ 10		$145.58	$38.01	$0.19	$129.90	$19.50	$15.72	$10.31
DCPP Retirement	PG&E	DCPP WPs				$85.62			
CAISO	CAISO	2017 MMC	$74.28	$32.97	$0.54			$12.83	$5.45

Making only two changes to PG&E's calculation – substituting the Capacity and Green Adder assumptions with values from the Commission's 2017 Avoided Cost Calculator – results in a completely different story than the utilities have presented. Costs are shifted from bundled customers to departing load customers by roughly the same amount the utilities claim is being shifted in the reverse direction, as shown in Figure 2A-1.

Figure 2A-1



The wide range of cost shift outcomes emphasizes the importance of re-examining and reforming the current PCIA benchmark.

III. THE CURRENT PCIA METHODOLOGY SHIFTS COSTS FROM BUNDLED TO CCA CUSTOMERS WHEN COMPARED WITH AN ANALYSIS RELYING ON COMMISSION ADOPTED RESOURCE VALUES

CalCCA's testimony will identify proposals and recommendations that are necessary and appropriate and achieve two key results: a) reduce the overall costs of the utilities' PCIA-Eligible portfolios, and 2) apply more appropriate market valuation benchmarks and cost attribution to the portfolios. These proposals, if implemented, would result in significant changes to the projected net costs of the utilities' portfolio and the attribution of those costs between bundled and departing load customers.

CalCCA's analysis, based on the utilities' 2018 ERRAs, demonstrates that, when CalCCA's proposed cost reduction initiatives and market-price benchmark improvements are taken into account, bundled customers currently are imposing a significant cost shift on departing load customers under the current PCIA methodology. This conclusion directly refutes the utilities' assertions that CCA departing load is causing massive cost shifts in the other direction, from CCA customers to bundled customers. Moreover, we believe that it forms a reasonable and appropriate basis on which the Commission can determine that CalCCA's proposals are necessary in order to redress the costs shifts that CCA customers currently are bearing and to prevent them from persisting and growing in the future.

CalCCA's analysis focuses on the following portfolio cost and value metrics:

- Total Generation (in GWh), reflecting the projected supply from the resources in the PCIA-Eligible portfolios
- Total Costs (in $), reflecting the projected costs the utilities will incur to obtain the supply from those resources
- Market Value (in $), reflecting the value of the marketable supply products produced by the resources in the portfolio
- Net Cost (in $), reflecting the amount by which Total Costs exceed Market Value

As detailed below and in the accompanying charts and tables, CalCCA has constructed four distinct scenarios for evaluation, each time comparing the portfolio cost and value metrics across the scenarios. In particular, this analysis uses the Net Cost metric to form conclusions about the level of potential cost shifts between bundled and departing load customers.

The analysis started with the 2018 ERRA portfolio costs and PCIA benchmark values as a baseline. For PG&E, this yields $2.2 billion in Net Costs and, for SCE, $1.2 billion. CalCCA's proposed PCIA reform measures yield the results discussed below.

We then examined the impact of CalCCA's proposal: (1) removing the costs of certain must-run generation from the PCIA-eligible portfolio as described in Chapter 2B (the Humboldt unit for PG&E and the Pebbly Beach unit for SCE); (2) modifying the PCIA benchmark components for capacity and the Green Adder, and adding benchmark components for GHG-free resources and ancillary services as described in Chapter 2B; and (3) securitizing all PCIA-Eligible UOG, excluding "New World" fossil; remaining in the utilities' portfolios as described in Chapter 3. Making these changes reduces PG&E's Net Costs of $2.2 billion by $1.7 billion to $512 million, and SCE's Net Costs of $1.2 billion by $908 million to $299 million.

Comparing the Net Costs resulting from CalCCA's changes to the Net Costs produced by the utilities' 2018 ERRA projections, and assuming the projected level of 2018 CCA departing load[14], the projected 2018 cost shift from bundled customers to departing CCA and DA customers would be as follows:

PG&E $492 Million Cost Shift from Bundled to Departing customers.

SCE $25 Million Cost Shift from Bundled to Departing customers.[15]

The results of this analysis, using the lower departing load values for SCE, are shown below in Figures 2A-2, 2A-3, 2A-4 and 2A-5.

[14] The cost shift estimates are based on projected 2018 departing load of 40.9% for PG&E and 3.9% for SCE.

[15] If SCE's CCA departing load were assumed to rise to 40.9% as it is in PG&E's territory, then the indicative 2018 cost shift for SCE would increase from $25 million to $264 million.

Figure 2A-2

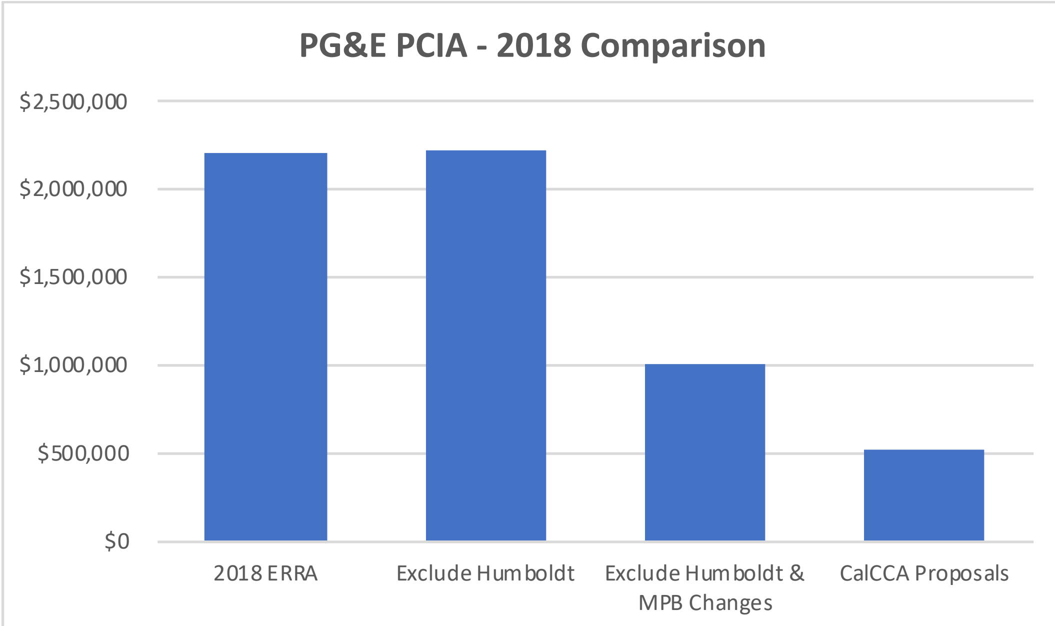


Figure 2A-3

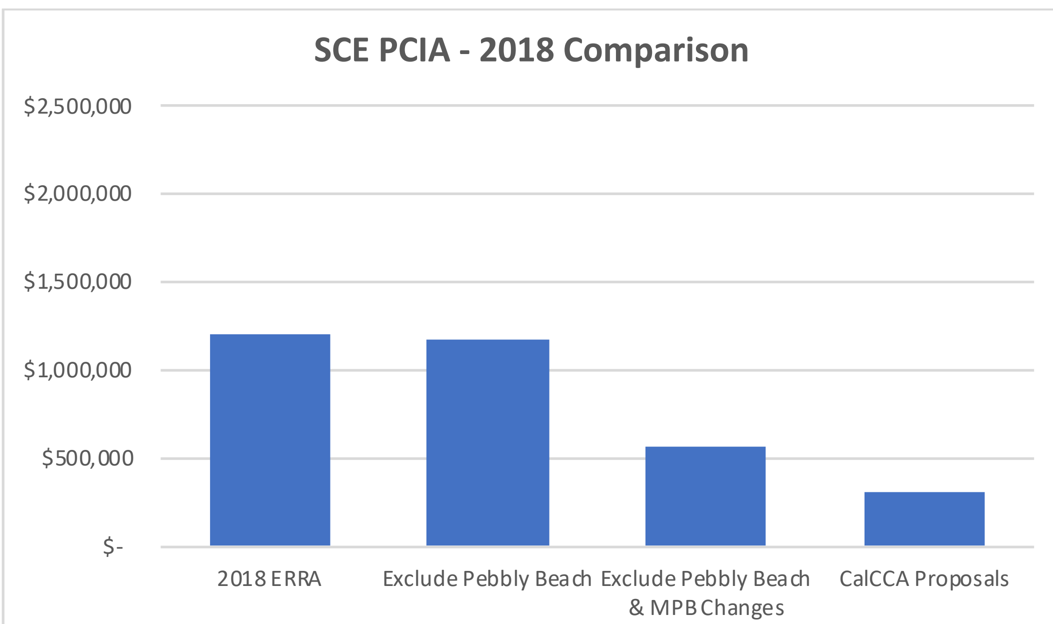


Figure 2A-4

PG&E PCIA-Eligible Portfolio--Impacts of CalCCA Proposals

Portfolio Costs	2018 ERRA	Exclude Humboldt	Exclude Humboldt & MPB Changes	CalCCA Proposals
RPS-Eligible PPAs	$ 2,099,442	$ 2,099,442	$ 2,099,442	$ 2,099,442
UOG GHG-Free	$ 1,879,988	$ 1,879,988	$ 1,879,988	$ 1,879,988
UOG Other	$ 528,952	$ 528,952	$ 528,952	$ 528,952
Other PPA	$ 876,358	$ 876,358	$ 876,358	$ 876,358
Exclude Humboldt	$ -	($29,074)	($29,074)	($29,074)
Securitization	$ -	$ -	$ -	($496,049)
	$ 5,384,740	**$ 5,355,666**	**$ 5,355,666**	**$ 4,859,617**
		($29,074)	($29,074)	($525,123)
Benchmark Value	**2018 ERRA**	**Exclude Humboldt**	**Exclude Humboldt & MPB Changes**	**CalCCA Proposals**
Brown Power	$ 1,301,638	$ 1,301,638	$ 1,301,638	$ 1,301,638
Green Power	$ 1,162,361	$ 1,162,361	$ 1,162,361	$ 1,162,361
Capacity	$ 708,410	$ 708,410	$ 708,410	$ 708,410
Line Losses	$ -	$ -	$ -	$ -
Exclude Humboldt	$ -	($30,904)	($30,904)	($30,904)
Add GHG-Free Value	$ -	$ -	$ 654,587	$ 654,587
Add Capacity Value	$ -	$ -	$ 474,792	$ 474,792
Add A/S Value	$ -	$ -	$ 10,062	$ 10,062
Remove DOE Adder	$ -	$ -	$ 66,986	$ 66,986
	$ 3,172,409	**$ 3,141,504**	**$ 4,347,931**	**$ 4,347,931**
		($30,904)	$1,175,522	$1,175,522
Net Costs	**$2,212,331**	**$2,214,162**	**$1,007,735**	**$511,686**
		$1,831	($1,204,596)	($1,700,645)
Departing Load Shift @	**40.9%**		**($492,155)**	

Figure 2A-5

SCE PCIA-Eligible Portfolio--Impacts of CalCCA Proposals				
Portfolio Costs	**2018 ERRA**	**Exclude Pebbly Beach**	**Exclude Pebbly Beach & MPB**	**CalCCA Proposals**
RPS-Eligible PPAs	$ 2,285,939	$ 2,285,939	$ 2,285,939	$ 2,285,939
UOG GHG-Free	$ 403,205	$ 403,205	$ 403,205	$ 272,407
UOG Other	$ 515,491	$ 515,491	$ 515,491	$ 515,491
Other PPA	$ 258,515	$ 258,515	$ 258,515	$ 258,515
Exclude Pebbly Beach	$ -	($29,074)	($29,074)	($29,074)
Securitization	$ -	$ -	$ -	($130,797)
	$ 3,463,150	**$ 3,434,076**	**$ 3,434,076**	**$ 3,172,482**
		($29,074)	($29,074)	($290,668)
Benchmark Value	**2018 ERRA**	**Exclude Pebbly Beach**	**Exclude Pebbly Beach & MPB Changes**	**CalCCA Proposals**
Brown Power	$ 313,205	$ 313,205	$ 313,205	$ 313,205
Green Power	$ 1,301,998	$ 1,301,998	$ 1,301,998	$ 1,301,998
Capacity	$ 527,191	$ 527,191	$ 527,191	$ 527,191
Line Losses	$ 113,547	$ 113,547	$ 113,547	$ 113,547
Exclude Pebbly Beach	$ -	$0	$0	$0
Add GHG-Free Value	$ -	$ -	$ 218,509	$ 218,509
Add Capacity Value	$ -	$ -	$ 298,418	$ 298,418
Add A/S Value	$ -	$ -	$ 10,375	$ 10,375
Remove DOE Adder	$ -	$ -	$ 90,301	$ 90,301
	$ 2,255,941	**$ 2,255,941**	**$ 2,873,544**	**$ 2,873,544**
		$0	$617,603	$617,603
Net Costs	**$ 1,207,209**	**$ 1,178,135**	**$ 560,532**	**$ 298,938**
		($29,074)	($646,677)	($908,271)
Departing Load Shift @	**3.9%**		**($25,411)**	

The vast difference between CalCCA's and PG&E's perspective on current cost shifts underscores the need for review and reform of the existing PCIA methodology.

EXHIBIT 2A-A

EXHIBIT 2A-A

PACIFIC GAS AND ELECTRIC COMPANY
Power Charge Indifference Adjustment (PCIA) OIR
Rulemaking 17-06-026
Data Response

PG&E Data Request No.:	CalCCA_002-Q14		
PG&E File Name:	PowerChargeIndifferenceAdjustmentPCIA-OIR_DR_CalCCA_002-Q14		
Request Date:	December 15, 2017	Requester DR No.:	002
Date Sent:	January 8, 2018	Requesting Party:	California Community Choice Association
PG&E Witness:	Donna Barry	Requester:	Evelyn Kahl Aldyn Hoekstra

QUESTION 14

Explain how PG&E determines whether procurement is undertaken “on behalf of” a particular customer or customers.

ANSWER 14

PG&E objects to this question to the extent that it calls for a legal conclusion. Notwithstanding that objection, PG&E responds as follows:

Generally, PG&E considers resources that were built or procured during the period before customers depart utility bundled service for an alternative energy service provider (or the period before a CCA provides PG&E and the CPUC with a Binding Notice of Intent (BNI) to begin alternative energy service to customers on a specific date), or otherwise are provided energy from non-utility sources, to be purchased, pro-rata, "on their behalf."

Charges to customers are assigned based on the existing vintaging rules (as set forth in D.08-09-012) where customers that depart bundled service prior to July 1 are assigned the prior year’s vintage and customers that depart on or after July 1 are assigned the current year’s vintage. Generation resource commitments are assigned a vintage based on the year in which the commitment was made.

Southern California Edison
Power Charge Indifference Adjustment OIR R.17-06-026

DATA REQUEST SET R.17-06-026 CalCCA-SCE-002

To: CALCCA
Prepared by: Steven Coulter
Title: Advisory, Regulatory Affairs & Compliance
Dated: 12/18/2017

Question 02-14.:

Explain how SCE determines whether procurement is undertaken “on behalf of” a particular customer or customers.

Response to Question 02-14.:

Generally, SCE considers resources that were built or procured during the period before customers depart utility bundled service for an alternative energy service provider (or the period before a CCA provides SCE and the CPUC with a Binding Notice of Intent (BNI) to begin alternative energy service to customers on a specific date), or otherwise are provided energy from non-utility sources, to be purchased, pro-rata, "on their behalf." SCE's full position on this issue is set forth in the testimony supporting the Portfolio Allocation Methodology application. SCE further reserves its right to refine or change its position on this issue during the pendency of this proceeding as discovery and testimony development continue.

In D.08-09-12 the Commission adopted vintaging rules based on date of departure that apply to customers and load whereby customers leaving bundled utility service before July 1 of a year are assigned the previous year’s vintage, and are responsible for their portion of costs associated with procurement committed on their behalf through the end of the previous year, and customers leaving bundled utility service on or after July 1 are assigned the current year’s vintage, and are responsible for their portion of costs associated with procurement committed on their behalf through the end of the current year. Pursuant to D.08-09-12, generation resource commitments are vintaged based on the year in which the IOU executes a contract or the IOU begins construction of a new generation resource (see pp. 64-67).

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

CHAPTER 2B

REVISING THE CURRENT PCIA METHODOLOGY

(Common Outline §II.B)

I. THE CURRENT PCIA METHODOLOGY CAN BE MODIFIED TO PROVIDE A REASONABLE ESTIMATE OF CCA/DA CUSTOMER COST RESPONSIBILITY

The Commission and stakeholders have invested many years and significant effort in developing and refining the current PCIA benchmark methodology. While the PCIA structurally made sense in the period after the energy crisis, the context has changed significantly with a shift in policy objectives, rapid evolution of technology and emergence of alternative load serving entities. The Commission must recognize these changes and improve the calculation of both PCIA-eligible costs and the PCIA benchmark.

The PCIA benchmark must recognize a broader scope of portfolio products and apply consistent, reasonable value measures for those products. Changes required to achieve these objectives include the following:

1. Modify the capacity value in the PCIA benchmark to blend a short-term value for excess capacity sold into the market and, consistent with Commission-adopted planning values, a long-term, Commission-approved capacity value for products remaining in the portfolio.
2. Recognize the value of non-Renewable Portfolio Standard greenhouse gas-free resources in the PCIA-eligible Portfolio through the addition of a separate benchmark component.
3. Correct the Green Adder by removing the unsupported and inaccurate Department of Energy referents in the calculation.

Collectively, these changes to both PCIA-eligible costs and the PCIA benchmark will result in a PCIA calculation that more accurately identifies the uneconomic or “above market” costs in the utilities’ portfolios.

Along with the benchmark modifications, PCIA-eligible costs should exclude certain costs:

a) Either exclude from the PCIA calculation any uneconomic costs of operating UOG resources or recognize value measures missing from the benchmark that render the operation economic.

b) Correct the calculation of uneconomic costs for pumped storage facilities.

Finally, this testimony examines whether Legacy UOG costs are appropriately recovered in the PCIA, observing that there is no specific statutory basis for its inclusion in the PCIA for CCA customers and that its continuing recovery could result in discrimination. This testimony does not propose removing these costs, however, provided that CalCCA's proposals to include a GHG-free adder to the benchmark component and to make GHG-free generation available to CCAs are adopted.

II. MODIFY THE PCIA BENCHMARK FORMULATION TO BETTER ALIGN WITH PORTFOLIO VALUE

It is important to start the discussion of benchmark modifications by examining the cost responsibility the PCIA aims to allocate. Uneconomic costs – the focus of the PCIA – can be viewed as having two dimensions: (1) the costs of excess supply beyond bundled needs or (2) excess costs for the supply needed to serve bundled needs. Different approaches may be appropriate, as discussed in Section III.A, depending on which dimension of the problem is being addressed.

Determining whether a utility has excess supply is relatively straightforward, requiring an examination by product of whether the utility has more of that product than it needs to serve its load. If the utility portfolio holds excess supply, there may be a loss (or in some markets, a gain) in selling the excess product in the market. If an excess product that was purchased, for example, at $90/MWh is not needed to serve the bundled customers and is sold into the market for $40/MWh, there is an immediate loss to be measured of $50/MWh for the product when it is sold. The uneconomic cost of that supply to be spread among customers through the PCIA is $50/MWh times the volume of product actually sold. It is important to note, however, that in the case of substantial excess above bundled requirements, the utility's portfolio management practices are brought into question.[1]

To determine whether there are excess costs in the portfolio for products actually serving the bundled load requires an estimation of the value of the products. The first step is to identify products in the portfolio with value, whether explicit in the market or implicit in procurement planning. Today's benchmark recognizes three products: brown energy, capacity, and the "green adder" for renewable energy. It is fairly straightforward to conclude that the benchmark scope does not reflect all of the products embedded in the utility portfolios. It fails to recognize traded products, such as GHG-free energy, as well as implicit attributes, such as long-term supply security. The PCIA benchmark can be improved by ensuring that it fully reflects the slate of products in the portfolio.

Once products are identified, product value must be determined. The value of products in the portfolio could be assessed by offering the products into the market under the same terms and conditions held by the portfolio (*i.e.*, offering a 20-year contract for 20 years). Alternatively, the value could be assessed by looking to the value of products sold, again with similar terms and conditions. The Commission adopted this approach in developing the "Green Adder," which values long-term RPS contracts in the portfolio at the current replacement price as measured by actual transactions. As yet another alternative, in the absence of actual market prices for

[1] Portfolio management practices are discussed further in Chapter 3, §V.

comparable products, an administratively determined value used to guide utility procurement.

The value of a product cannot reasonably be determined, however, using a market price for a product with fundamentally different attributes. An egregious conflict arises when using short-term prices to value attributes attached to resources acquired to meet long-term needs. Determining the value of long-term capacity held in the form of utility owned generation using the price obtained in the market for a one-year right to the capacity (or a series of one-year rights to capacity granted one year at a time) undervalues the asset by failing to recognize value in the long-term right. This disconnect is evident in comparing the Commission-approved long-term planning value for capacity of $102.31/kW-year for Southern California or $110.93/kW-year for Northern California[2] to the current PCIA benchmark value of $58.27/kW-year or to the prices paid by the CAISO using its Capacity Procurement Mechanism of $75.72/kW-year.[3] Moreover, using a short-term value for all volumes of a product in the portfolio creates other distortions. This approach implicitly assumes that the utility could replace all of those long-term volumes in the current market at the then-current short-term price. Alternatively, it assumes the utility could replace all of those long-term products with short-term products and still satisfy the Commission's expectation that the utility will

---

[2] *See* Avoided Cost Model ACC_v1.xls dated September 17, 2017, "Market Dynamics" available here: http://www.cpuc.ca.gov/general.aspx?id=5267.

[3] *See* CAISO "Capacity Procurement Mechanism: Capacity Procurement Mechanism Reports 2017," http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=33EB5656-7056-4B8E-87B2-3EA3D816DA62, retrieved March 27, 2018. Note that the Metcalf Energy Center has signed a reliability must-run agreement with the CAISO for an amount greater than the reported CPM value (CAISO Decision on Reliability Must-Run Designation for Metcalf Energy Center, http://www.caiso.com/Documents/Decision_ReliabilityMust-RunDesignation_MetcalfEnergyCenter-UpdatedMemo-Nov2017.pdf, October 30, 2017).

provide customers a secure, reliable supply. It also ignores the reality that LSEs must by law maintain a proportion of long-term products in their portfolio. Finally, using short-term prices for products held in the long-term portfolio retains the option value of the assets for bundled customers but requires departing load to pay the cost of bearing the downside price risk for bundled customers without compensation.

Even with these guidelines, a resource's value cannot be determined exclusively through market sales because of the hybrid nature of the California market. A substantial portion of the generation used to meet bundled needs is not exposed to market pricing. Utilities receive full cost-of-service recovery for their UOG, regardless of what the "market" price is at any time.[4] By shielding utility-owned generation from market price exposure, the explicit "market" is not fully reflecting the value of generation. Rather, any explicit market will be a measure of the value of only "excess" supply exceeding the cost-of-service supply.

Moreover, California's long-term procurement planning paradigm, among other influences, has kept market prices from reflecting actual market value, particularly for capacity. Long-term procurement planning by the CAISO and the Commission aims to prevent capacity scarcity and the high prices that come with such scarcity, using tools like reliability must run contracts and the CPM. In light of these objectives, prices for capacity vary widely with limited price transparency, beyond the CPM and the Commission's administratively determined values used to authorize the utilities to procure additional resources. As discussed further below, it is anomalous for the Commission to use one value for an attribute and authorize utilities to procure additional

---

[4] AB 1890 intended otherwise, in contemplating divestiture and an end-date on stranded UOG cost recovery.

resources *and at the very same time* use a different lower number to value the same products in the IOU portfolio for purposes of determining above market costs to be charged to CCA customers. Yet this is the situation today, producing a shift of cost burden from bundled to departing load customers.

The goal, then, is to ensure that the values used in the PCIA benchmark adequately reflect the opportunity cost of excess supply and reasonably estimate the value of the products remaining in the portfolio. The Commission must consider, however, more specific statutory guidance on departing load cost responsibility, as discussed in Chapter 1, §IV.

A. Modify Capacity Values

The current PCIA reflects a capacity value in the benchmark – $58.27/kW-year for 2018 – intended to capture the value of "resource adequacy" as the capacity metric. It fails to achieve this objective, however, in two respects. First, it values all capacity – whether deployed for bundled customers over the next several decades or sold in the market tomorrow – using the same short-term benchmark. This short-term value reflects only the annual unavoidable costs of having a combustion turbine available: fixed O&M, insurance and property taxes. It does not include any long-term costs associated with capacity, such as the cost of constructing the CT. Second, the short-term benchmark does not reflect the value of an asset that has the capability to provide not only System Resource Adequacy, but Local Resource Adequacy, and Flexible Resource Adequacy and the additional costs of running those resources to meet those demands. In general, and on average, costs for those services exceed the energy-only market clearing prices in the CAISO market used to dispatch resources, so the costs for those services are additive to the capacity value. For these reasons, the PCIA benchmark understates the value of capacity, thereby overstating above market costs and the PCIA rate. [5]

The current PCIA capacity benchmark is at odds with Commission planning values for capacity. The Commission and the utilities continue to use administratively determined long-term market values for making resource procurement and management decisions. For example, the Commission uses a long-term value of capacity to assess cost-effectiveness of demand response, energy efficiency and distributed energy resources using the E3 Avoided Cost Calculator. The Calculator "produces an hourly set of values over a 30-year time horizon that represent costs that the utility would avoid if demand-side resources produce energy in those hours."[6] Earlier versions of the E3 Calculator also have been at the center of the Long-Term Procurement Plan preparation for the utilities. One element of the avoided cost is capacity, which is valued using a combination of short- and long-term capacity values. The Calculator values long-term capacity at $102.31/kW-year for Southern California or $110.93/kW-year for Northern California, compared with the $58.27/kW-year adopted in PG&E's and SCE's 2018 ERRA for PCIA calculation.

Using long-term values for planning and the short-term benchmark for the PCIA can create an untenable fiction. Effectively, it suggests an asset valued at $110/kW-year in the planning process immediately loses value – dropping from $110 to $58 – the moment the asset becomes operational and its costs are included in the PCIA-eligible

[5] It also merits noting that the appropriate benchmark for valuing capacity and associated services appears to be changing. Recently, both SCE and PG&E chose to meet local RA requirements with energy storage and a mix of distributed energy resources, rather than a CT.

[6] Avoided Cost Calculator User Manual at Page 1, available at: http://www.cpuc.ca.gov/General.aspx?id=5267.

portfolio. The result is that contracts become "above market" the moment they are signed.

Apart from the problem with using short-term values for long-term capacity held in the portfolio, the current PCIA capacity value understates actual short-term values reflected in the market. The CAISO Capacity Procurement Mechanism suggests an alternative value. The CPM sets a soft offer price cap for CAISO to exercise its backstop procurement authority when shortfalls arise in RA compliance filings from LSEs and for other reasons, for a maximum of one year. This is the price recently paid by CAISO for certain purchases of RA capacity in both Northern California and Southern California for Calendar Year 2018 to correct for LSEs' collective failure to procure sufficient RA for the 2018 year ahead RA compliance filing requirements. The price is not a planning value; it provides a transparent and variable price benchmark that accurately reflects actual transactions based on the near-term supply and demand balances for RA in both Northern California and Southern California. For calendar year 2018, CAISO exercised its authority to purchase RA capacity and engaged in actual transactions at the price cap of $75.72/kW-year, materially more than the PCIA benchmark of $58.27/kW-year.

CalCCA proposes to avoid the complexities of valuing each product in the capacity market. Instead, this testimony recommends the adoption of a single long-term capacity value and a single short-term capacity value. The long-term capacity value should be the Commission's long-term planning assumption used in the Calculator (currently $110/kW-year for Northern California and $102/kW-year for Southern California) and should be applied to all capacity used to serve bundled load. This value adequately reflects the long-term capability of a capacity resource to provide nearly the full range of products (with the possible exception of Local RA). At the same time, surplus capacity is valued at the going price in the CAISO market using the CPM ($75.72/kW-year). Using a short-term value for excess capacity sales recognizes that capacity not needed to serve bundled load carries a lower value. The impact of this change is to increase the 2018 PCIA benchmark value by an estimated $474.8 million for the PG&E portfolio and $298.4 million for the SCE portfolio.

B. Add an Ancillary Services Value

The utilities hold capacity in their portfolios that provides or is capable of providing ancillary services to support their bundled load or to sell into the market. The current PCIA methodology does not account for this value in any discernable way. To more accurately reflect full portfolio value, we recommend the addition of an ancillary services component to the benchmark.

The Calculator recognizes ancillary services as a separate value in assessing the value of demand side products, at $2.81/kW-year in Northern California and $3.46/kW-year in Southern California.[7] These ancillary service values are derived from the same assessment of capacity values upon which CalCCA's recommended long-term capacity values were derived. We recommend using this value and applying it to all of the resources held in the PCIA-eligible portfolio that provide ancillary services. These resources can be identified by the presence of Automatic Generation Control, which enables these resources to follow load. The impact of this change is to increase the

---

[7] *See* Avoided Cost Model ACC_v1.xls dated September 17, 2017, "Market Dynamics" available here: http://www.cpuc.ca.gov/general.aspx?id=5267.

2018 PCIA benchmark value by an estimated $10.1 million for the PG&E portfolio and $10.4 million for the SCE portfolio.

C. Incorporate the Value of Non-RPS, GHG-Free Resources

PG&E and SCE hold nuclear and hydro generation assets in their portfolios that, while not RPS resources, carry a "GHG free" value. If the Commission elects to retain these assets in the PCIA-eligible portfolio, the PCIA benchmark must explicitly recognize the value of non-RPS,[8] GHG-free resources.

GHG-free generation carries a premium in today's market, although no reliable published market index values for this generation exist. One of the drivers for this value adder is its marketing value when shown in the LSE's Power Content Label.

The Commission also has recognized the value of GHG-free products, apart from the RPS. The Commission values GHG-free energy efficiency at a price above that of compliant brown power in evaluating energy efficiency cost effectiveness, using $66.37/metric ton in 2018 in the Integrated Distributed Energy Resources proceeding.[9] The Commission directed that this value be used as an input to the E3 Calculator and could similarly be applied to all output from all GHG-free, non-RPS resources in the utility portfolio, as well as for distributed energy resources and energy efficiency.[10] This translates to a value of $29.15/MWh for energy efficiency reductions in GHG emissions.

Notably, a prime motivator for the RPS is GHG emission reduction. As the cost of renewables approaches the long-term value of GHG-emitting generation, the cost differential becomes an indicator of the GHG-free premium for non-RPS eligible

---

[8] RPS-eligible resources already carry an implicit GHG value embedded in the RPS target.

[9] D.17-08-022, p. 13.

[10] *Id.*, Ordering Paragraph 1 at 18.

generation as well. While the social cost of emissions may be higher, the compliance costs are capped at the RPS premium.

This conclusion is supported by PG&E. As recently as last year, PG&E stated the GHG-free generation from Diablo Canyon was worth considerably more than brown power, amounting to $85/MWh in 2018 dollars.[11] On this basis, PG&E requested that the Commission require that all Diablo Canyon generation be replaced by GHG-free generation once Diablo Canyon retires. PG&E indicated that it would pay up to the full RPS cost for GHG-free generation. PG&E stated it would pay more than the cost of compliant brown power for GHG-free generation, and that only GHG-free generation should be obtained with no allowance for lower cost compliant brown power.

The Commission directed that the $29.15/MWh value be used as an input to the E3 Calculator and could similarly be applied to all output from all GHG-free, non-RPS resources in the utility portfolio. A reasonable approach, consistent with PG&E's Diablo Canyon testimony, would be to value GHG-free resources the same as RPS generation, using a $24.16/MWh GHG-free adder for PG&E and $25.11/MWh for SCE. Thus, for PCIA purposes, the Green Adder should be applied to all the IOUs' GHG-free generation, not just the RPS generation. The impact of this change is to increase the 2018 PCIA benchmark value by an estimated $654.6 million for the PG&E portfolio and $218.5 million for the SCE portfolio.

---

[11] PG&E, Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, and Recovery of Associated Costs through Proposed Ratemaking Mechanisms, Testimony, A.16-08-006, pp. 4-5. We have discounted PG&E's 2025 value of $98/MWh back to 2018.

D. Modify the Green Benchmark to Remove the Unavailable and Incorrect Department of Energy Referents

The current PCIA benchmark includes a "Green Adder" intended to capture the market value of renewable resources in the California market. The Commission, in D.11-12-018, determined that this component of the benchmark should "reflect prices paid by buyers and sellers in recent transactions for delivery of RPS-compliant power in California for the forecast year."[12] The current benchmark attempts to achieve this goal through weighting an average of utility RPS procurement costs and use of a US Department of Energy survey of reported renewable energy contract premiums in the western United States compiled by the National Renewable Energy Laboratory.

The methodology and data source adopted in 2011 is no longer effective or available. The DOE Green Adder in the Renewables MPB, previously used in the PCIA proposed by PG&E, is based on a selection of Utility Green Pricing Programs in the western United States provided by the Commission's Energy Division. Programs are identified in a database from NREL for the Department of Energy.[13] However, the source of this pricing information is unclear and in many cases the information is either out of date, inaccurate or irrelevant, including programs that should not be included in the calculation of the DOE Green Adder.

The source of the utility green pricing programs information is in doubt. The NREL page on Voluntary Green Power Procurement does not provide any detailed information on individual programs.[14] In communications with NREL staff, they stated

[12] D.11-12-018, p. 17.
[13] PG&E Testimony, Chapter 9, Attachment A, p.1.
[14] *See* https://www.nrel.gov/analysis/green-power.html.

data on individual programs has never been distributed.[15] Moreover, some of the programs that have been relied upon in ERRA proceedings are now defunct and out of date.[16]

Further, data on the list indicates that it has not been updated since 2015 or perhaps even earlier. For example, a reference to Cheyenne Light, Fuel, and Power, which has operated as Black Hills Corporation since 2015, confirms this fact. Many premiums are out of date and it is likely that the list misses entirely any new programs that may have been launched in recent years.

Spot-checking the program information that is incorporated in the Green Adder by the utilities in their last ERRAs uncovered numerous inaccuracies, which included searching each program to confirm the premium pricing information. In many cases, there was no evidence of the program being available from the related utility website. Some of these programs may now be defunct. For other programs, the current information available from utility websites does not match the information provided by the Energy Division shown in PG&E's 2018 ERRA workpapers. [17]

Further, although the guidelines for calculating the DOE Green Adder clearly indicate that IOU renewable programs should not be included,[18] Southern California Edison's Green Rate program is included in the current dataset. This results in double

---

[15] Eric O'Shaughnessy, NREL, email communication, May 25, 2017.

[16] Testimony of Richard J. McCann, Ph.D. on Behalf of Sonoma Clean Power Authority (Revised), A.17-06-005, August 28, 2017, pp. 11-13.

[17] See 09.ERRA_2018-Forecast_WP_PGE_20170601_Ch09-Table 9-5_PUBLIC.xlsm. For example, Cowlitz PUD's Renewable Resource Energy is listed with a premium of 0.8¢/kWh, but the program has a premium of 1.5¢/kWh, according to its website. *See* Cowlitz PUD, https://www.cowlitzpud.org/green-power. Clallam County PUD's Watts Green program is listed with a premium of 1.7¢/kWh, but the premium is only 0.3¢/kWh, according to its website. *See* Clallam PUD, https://www.clallampud.net/watts-green-power/.

[18] Resolution E-4475.

counting of SCE's RPS resources in the DOE Green Adder. In all, there are at least 19 discrepancies out of the 89 programs listed, excluding consideration of other programs that may have been since added.[19] While both PG&E[20] and SCE[21] attempted to update this data in subsequent advice letter filings, the fact of the matter is that the DOE website was adopted as an unbiased third-party source, and there is no guarantee that the utilities have collected data from all of the applicable programs across the western United States.

Finally, the green power premium is calculated incorrectly. While most (but not all) of the identified tariffs supply 100% green power, the premium is calculated against generation mixes that contain a varying mix of brown and green power. In other words, unlike the utility RPS Premium which measures 100% green versus approximately 100% brown power, the DOE Adder measures mostly 100% green versus a varying mix of brown and green power. This error causes the DOE Adder to undervalue the retail green premium by at least $10/MWh. It is not possible to precisely measure this undervaluation without a more exacting review of the power mix for each utility that offers these programs. Such a review would defeat the purpose of using the DOE Adder as a ready metric for this valuation.

For these reasons, the current DOE/NREL portion of the green adder benchmark should be eliminated, and the benchmark should reflect only the average of utility RPS procurement costs. There is no reason why procurement by three large utilities in the

---

19 Because we do not have the resources to survey the utilities in the entire Western Electricity Coordinating Council region, we have not proposed a revised value for this portion of the Green Adder in this proceeding other than to propose that the IOU RPS Green Adder be used to supersede this value.

20 Advice Letter 5151-E.

21 Advice Letter 3667-E.

California and Western market, alone, will not fully reflect a reasonable market value for their purchases. The renewables market has developed substantially since 2011 when the DOE Adder was first adopted. The utilities are direct participants in that market, constantly soliciting and negotiating purchases and sales, so their transactions should be at the market price for renewables. If the utilities are not transacting at the market-going rate, that calls into question whether they are properly managing their procurement and portfolios. The Commission does not need any more market information than what is provided from utility transactions for these reasons. The impact of this change is to increase the 2018 PCIA benchmark value by an estimated $67 million for the PG&E portfolio and $90.3 million for the SCE portfolio.

III. REDUCE THE SCOPE OF PCIA-ELIGIBLE COSTS

The PCIA benchmark is only half of the equation in ensuring that there is no cost shift occurring between bundled and departing load customers. CalCCA proposes modifications to the scope of PCIA-eligible costs. The Commission should either exclude from the PCIA calculation any uneconomic costs of operating UOG resources or recognize value measures missing from the benchmark that render the operation economic. In addition, it should correct the calculation of uneconomic costs for pumped storage facilities. Finally, if the Commission rejects CalCCA's proposal for a GHG-free component to the PCIA benchmark and for an auction that provides CCAs access to GHG-free generation, CalCCA would support removal of Legacy UOG costs from the PCIA-eligible portfolio.

A. Remove the Costs of Uneconomic Facilities or Modify the PCIA Benchmark to Recognize Their Additional Value

The portfolio cost that the PCIA methodology compares to the PCIA benchmark includes variable costs of dispatched resources, including fuel costs and variable O&M. If those resources are out of the money – *i.e.*, their dispatch cost is higher than the "market" price for energy in the benchmark – the utility is creating additional above market cost by their operation. If the utility is operating the resources despite their uneconomic variable cost, the Commission must presume that the resources are being dispatched to provide some additional value not reflected in the MPB, or that the operation is unreasonable. Either the plants should not be operated and the uneconomic costs reduced, or if there is some other value produced in operating the plants, it must be recognized in the benchmark.

Similarly, the PCIA includes all the incremental costs in its portfolio (whether or not all attributes are valued by a market element) of keeping UOG resources available, including fixed O&M, capital additions, ad valorem and insurance costs. If these costs, combined with the variable operating costs, are above the MPB energy and RA value, then keeping these units available is unreasonable and adding to uneconomic costs. Again, either these costs are uneconomic and unreasonable to operate, or they are being operated to provide benefits not quantified in the PCIA. Either way, the uneconomic costs associated with these resources should be reduced or the benchmark should be increased to reflect economic, reasonable operation of the facilities. Examples of these problems include Diablo Canyon, Humboldt and Helms for PG&E and Pebbly Beach and Eastwood facilities for SCE.

Diablo Canyon has incremental costs of continuing operation (fuel, O&M, A&G and capital additions) that are well above the market price benchmark for brown power. Unless, as PG&E asserted in A.16-08-006, continuing to operate Diablo Canyon provides an additional benefit from its generation being GHG free, it is not cost-effective to continue operating. In either case, it is inappropriate to include newly incurred uneconomic costs related to continuing to operate Diablo Canyon in the PCIA. Either there is no GHG value to Diablo Canyon's generation and it should not be operated or a GHG value should be included in the PCIA offsetting the alleged uneconomic costs.

Humboldt and Pebbly Beach are necessary to operate as the locations they serve are isolated and cannot be supplied by other resources. Pebbly Beach is literally located on an island, Catalina Island. There are no other resources available to serve Catalina. There is no excess supply on Catalina, no departing load on Catalina, and none of Pebbly Beach's costs were incurred to serve departed load customers. In addition, if it were not for CPUC regulation, SCE could sell the output from Pebbly Beach at any price it chooses, as there are no alternatives for the customers on Catalina. However, SCE included the $26.4 million annual costs of Pebbly Beach in its 2018 PCIA calculation but as far as CalCCA can discern did not include any value applicable to the PCIA benchmark value — implying that the entire $26.4 million cost of Pebbly Beach is uneconomic for purposes of the PCIA valuation. All forecast uneconomic costs associated with Pebbly Beach should be removed from the PCIA calculation.

Similarly, Humboldt is needed to serve its local area. In approving PG&E's proposal to build Humboldt, the Commission stated: “The area is transmission-constrained so that it cannot be fully supplied by any other plant."[22] PG&E states that Humboldt is only operated when it is necessary for reliability or is "in the money". As with Pebbly Beach, there is no excess supply to serve this area, these costs were not incurred to serve departed load, there are no alternative facilities that could provide the needed generation at a lower price, and absent Commission regulation, PG&E could charge any price it wanted for Humboldt's output. PG&E includes Humboldt's $29.1 million annual costs in the PCIA calculation and appears to impute an estimated $30.9 million contribution to the PCIA benchmark value. As with Pebbly Beach, all uneconomic costs associated with Humboldt should be removed from PG&E's PCIA.

B. Correct the Methodology for Calculating Uneconomic Costs for Pumped-Hydroelectric Storage Facilities

PG&E's Helms[23] and SCE's Eastwood pumped-hydroelectric storage facilities are included in the utilities' respective PCIA-eligible portfolios. The calculation of uneconomic costs for these facilities, however, requires modification.

Helms and Eastwood are operated so that water is pumped uphill, typically during off peak periods when electricity costs for pumping are low.[24] The water is released, and the units typically generate on peak when the electric generation is more valuable. Helms requires 1.5 kWh to pump enough water uphill to provide 1 kWh of generation. The ratio for Eastwood is better, at 1.33 kWh of pumping to 1 kWh of generation. However, both SCE and PG&E fail to reflect the lower cost of pumping

[22] D.06-11-048 at 32.

[23] The October 17, 2008 presentation on the operation of the Helms Pumped Storage Plant is attached as Exhibit 2B-A.

[24] Conclusions regarding Helms rely on PG&E's response to ERRA 2018 PGE - Forecast _DR_CCSF_002-Q004-CONF, which is not attached. Conclusions regarding Eastwood are not based on actual data from SCE; the estimated pumping and generation is based roughly on the size of Eastwood compared to Helms.

compared to the value of the generation. The utilities' PCIA calculations assume that the price for electricity used to pump is the same as the price for the electricity generated. This incorrect assumption makes the operation of Helms and Eastwood appear uneconomic in the PCIA calculation, when in fact, it is not.

PG&E's PCIA calculations contain another significant flaw in that PG&E, for PCIA purposes, assumes that it takes over 3 kWh of pumping to provide 1 kWh of generation, rather than the actual ratio of 1.5 to 1 kWh. Nor does PG&E account for the natural water inflows to Helms that typically allow for 50 GWh or more generation annually with no pumping requirements.

These incorrect assumptions regarding the Helms and Eastwood pumped storage projects result in an overstatement of the uneconomic costs that are included in PG&E's and SCE's PCIA calculations. Moreover, it should be noted that this does not reflect the additional ancillary service, stability, renewable integration and storage values of these facilities, whose inclusion would increase the applicable benchmark values of these units and further reduce the level of uneconomic costs that are included in PG&E's and SCE's PCIA calculations. Both of these types of errors should be corrected.

C. Consider Whether Legacy Utility Owned Generation is Appropriately Included in the PCIA-Eligible Portfolio

The existing PCIA calculation includes all costs of utility owned generation, regardless of the date of commercial operation, but excluding generation managed under the Cost Allocation Mechanism [25] and "New World" generation that has been

---

[25] D.06-07-029.

operating for more than ten years.[26] Including Legacy UOG pre-dating AB 117 in the PCIA, however, is at odds with the Legislature's specific directives regarding CCAs and causes a cost shift from bundled to Departing Load customers.

As a preliminary matter, the Legislature anticipated in the mid-1990s that any above-market costs of the utilities' Legacy UOG would be worked out of their portfolios by 2005. In addition, in the 2002 enactment of AB 117, the Legislature did not attribute cost responsibility for Legacy UOG – indeed, any UOG – to CCA customers. Finally, Legacy UOG costs have recently been removed from the PCIA paid by pre-2009 DA customers, and there is no reasonable basis for discriminating between those customers and other departing load customers with respect to recovery of Legacy UOG costs.

Despite these concerns, retaining the Legacy UOG in the PCIA-eligible portfolios could be found to be reasonable if the Commission adopts CalCCA's proposals to: 1) attribute a premium value to GHG-free resources in this Chapter 2B, 2) securitize UOG assets in Chapter 3, and 3) provide CCAs and other bidders with access to GHG-free resources via an auction in Chapter 4. Departing load customers, particularly CCA customers who did not benefit from any past "below market" Legacy UOG costs offsetting "above market" portfolio costs, have contributed substantially to cost recovery for these resources. As detailed in Table 2B-1 below, the cost of PG&E's Legacy UOG has been higher (on average 23% higher) than the corresponding PCIA Benchmark

---

[26] The Commission provided for allocation of cost responsibility to CCA and DA customers for "New World" utility-owned generation for a period of ten years from the date of Commercial operation. *See* D.03-12-039, D.04-12-048 and D.08-09-012.

Value since 2013, and these resources contributed an estimated $1.86 billion in uneconomic Legacy UOG costs during the past six years.

Table 2B-1

PG&E Legacy UOG Costs (Nuclear and Hydro) Historic Comparison to PCIA Benchark Values	2013	2014	2015	2016	2017	2018	Total/ Average
Brown Power Benchmark Value ($/MWh)	$38.90	$39.05	$41.25	$32.90	$35.22	$33.77	
RA Benchmark Value ($/MWh)	$ 9.31	$11.03	$10.96	$12.63	$11.81	$11.16	
Total PCIA Benchmark Value ($/MWh)	$48.21	$50.08	$52.21	$45.53	$47.03	$44.93	$48.00
Average Cost of Legacy UOG ($/MWh)	$51.52	$54.15	$55.90	$62.41	$66.81	$64.32	$59.19
Legacy UOG Cost as % of PCIA Benchmark Value	107%	108%	107%	137%	142%	143%	123%
Uneconomic Legacy UOC Costs in PCIA ($ Millions)	$94	$110	$100	$454	$552	$545	$1,855

CalCCA is not proposing to remove Legacy UOG costs from the PCIA calculation as a part of its integrated proposal, given CalCCA's proposals reduce their costs, revise their benchmark value and remarket their output as noted above and described further in subsequent chapters of this testimony. If, however, the Commission rejects the securitization of UOG costs, the integration of a GHG-free component to the benchmark and the proposal to make the GHG-free resources available to other LSEs, then the Legacy UOG costs should be removed from the PCIA-eligible portfolio.

EXHIBIT 2B-A

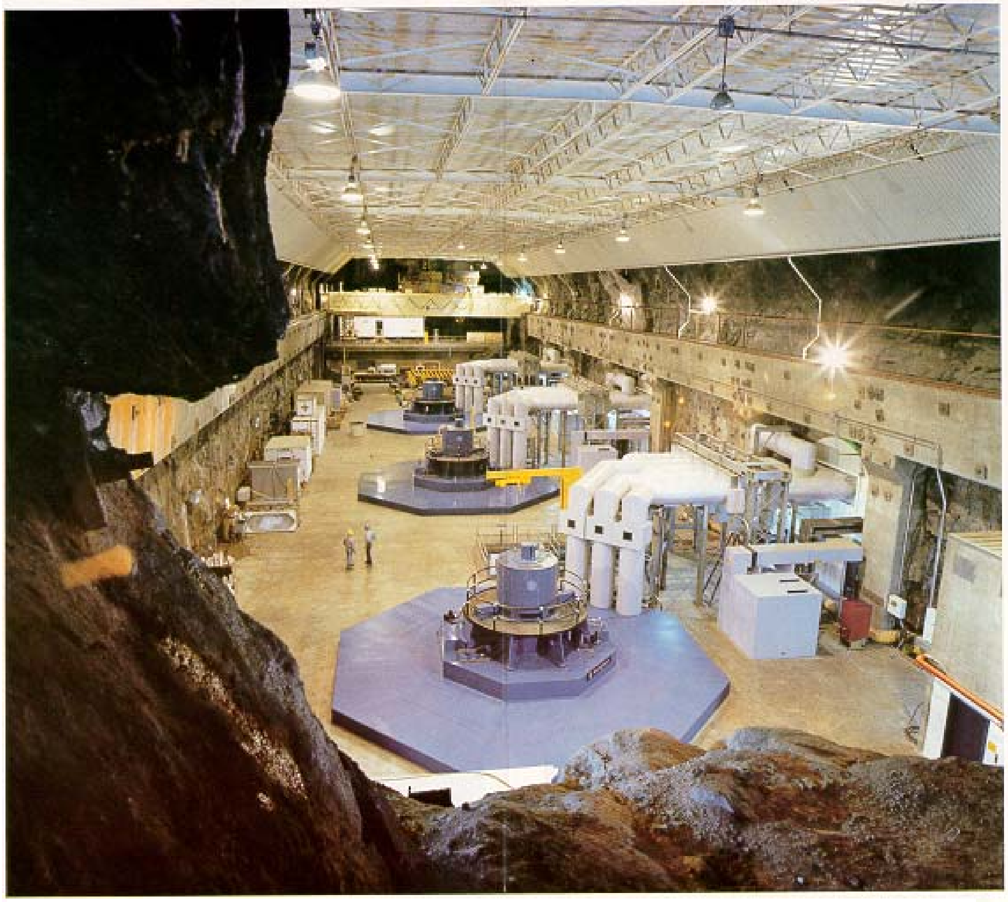
Helms Pumped Storage Plant

Northwest Wind Integration Forum Workshop

Manho Yeung

Pacific Gas and Electric Company

October 17, 2008



Pacific Gas and Electric Company - Overview

Headquarters Location
San Francisco, CA

Service Area
70,000 square miles in northern and central California

Service Area Population
15 million people (or about 1 of every 20 Americans)

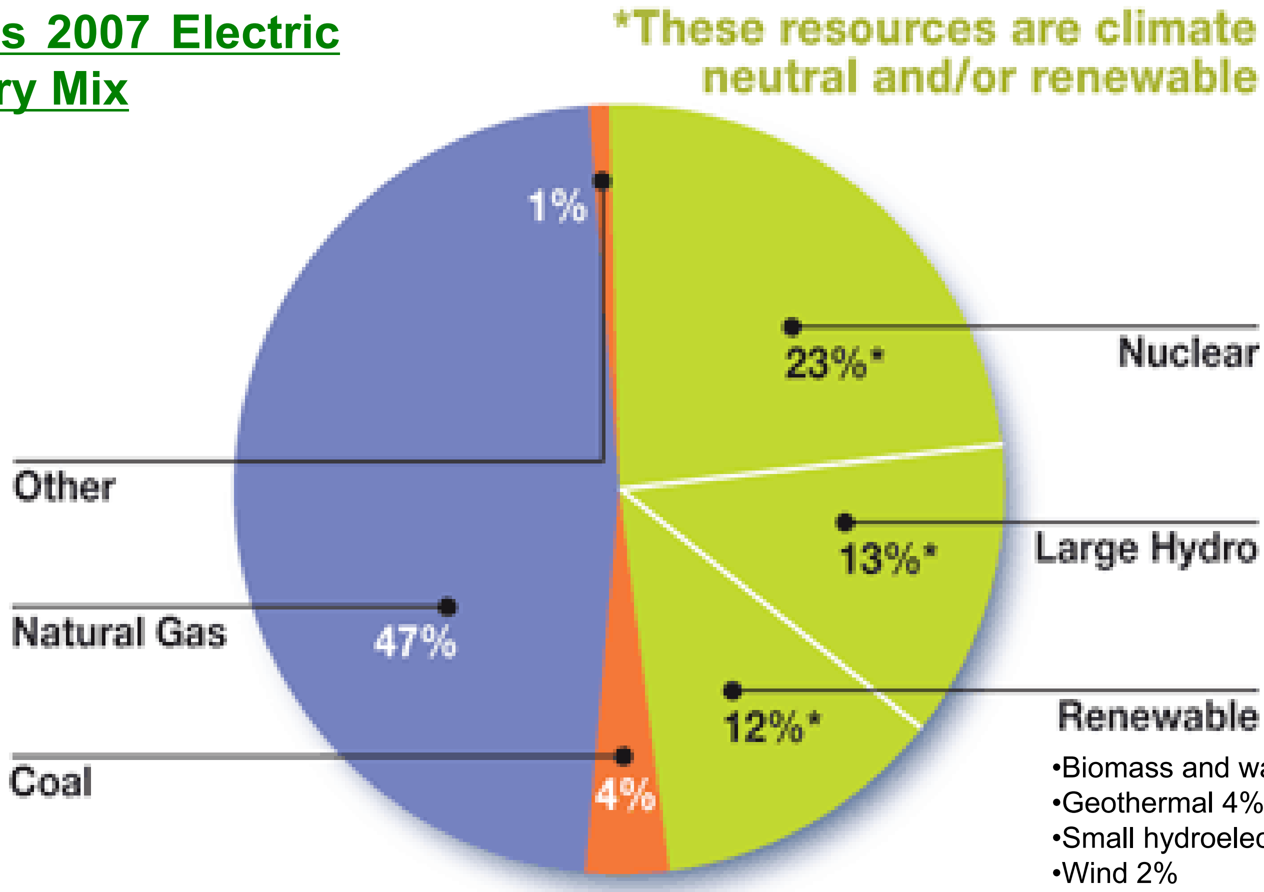
Distribution Customer Accounts
5.1 million electric, 4.3 million gas

Employees
Approximately 20,000

System
- 159,364 miles of electric transmission and distribution lines
- 48,198 miles of natural gas T&D pipelines
- 6,271 megawatts of generation, including
  Diablo Canyon nuclear power plant,
  Helms pumped storage plant, and
  one of the largest hydroelectric systems in the country

On average, More than 50% of PG&E's Portfolio is Carbon-Free

PG&E's 2007 Electric Delivery Mix

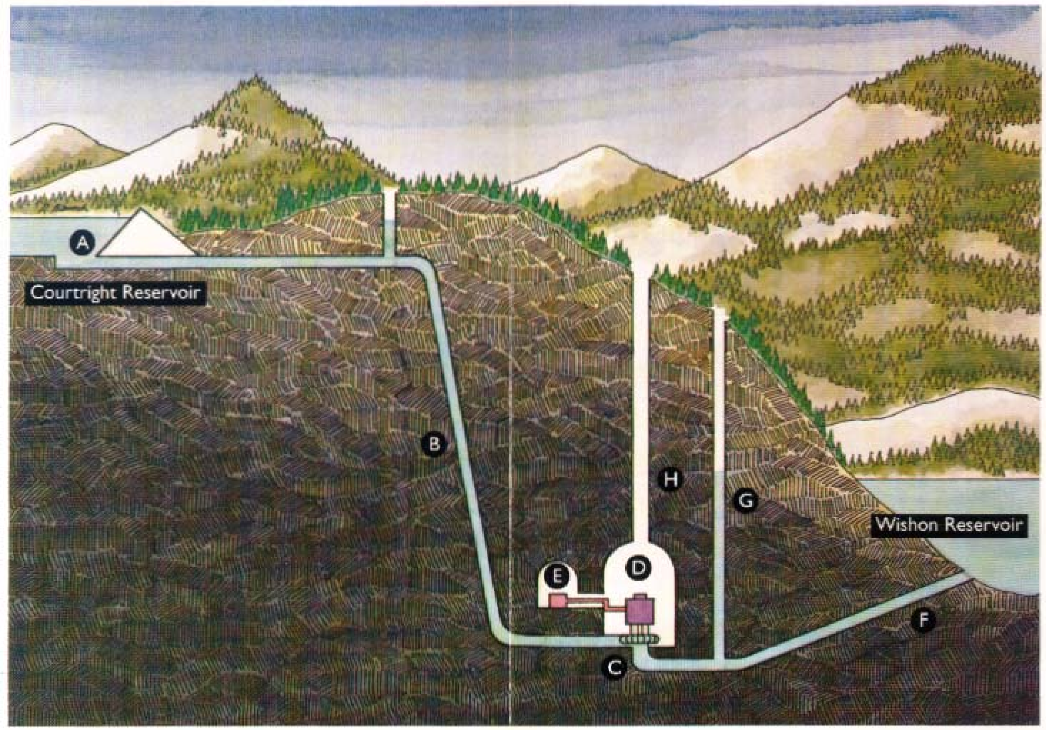


- Biomass and waste 4%
- Geothermal 4%
- Small hydroelectric 2%
- Wind 2%
- Solar <1%

Note: Delivery mix includes all of PG&E's owned generation plus all of PG&E's power purchases. PG&E's direct purchases of coal have not increased and remain at 1.6%. The higher number on the chart is due to state regulations that assume a higher mix of coal in market purchases. Also, 2007 was a below normal hydro year.

Helms Pumped Storage Plant is in its 25th Operating Year

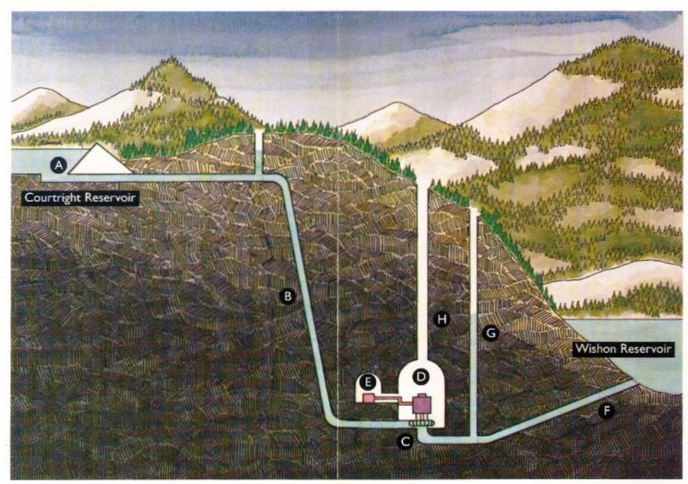
Location	Central California, about 50 miles east of the City of Fresno
Commission	June 30, 1984
Upper Reservoir	Courtright Lake 123,000 Acre Feet
Lower Reservoir	Lake Wishon 129,000 Acre Feet
Installed Capacity	Three units; 1,212 MW generating; 930 MW pumping
Average Energy	<100 GWh per year (natural in-flow)



A-Courtright, B-Supply Tunnel, C-Turbine, D-Generator, E-Transformer, F-Wishon, G-Surge Chamber, H-Elevator

Helms Generates During Day Time and Pumps at Night

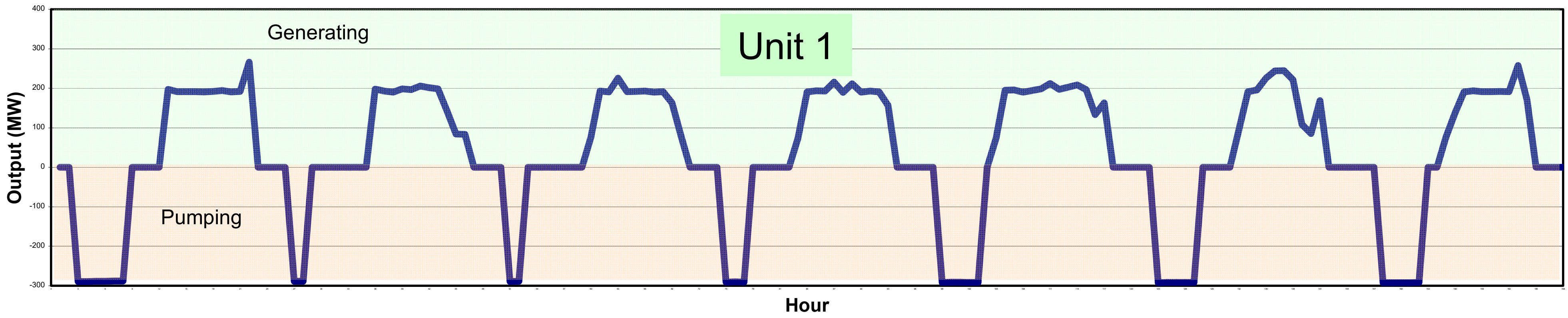
- Helms has three identical reversible pump-turbine motor-generator units
- 1,212 MW total in generation mode, and 930 MW total in pump mode
- Units are housed in a chamber about 1,000 feet underground
- In generating mode, water would
  - release from Courtright Lake
  - travel at 9,000 cubic feet per second
  - through a 22,000 feet long supply tunnel, and
  - drop 1,744 vertical feet before discharging into Lake Wishon
- In pumping mode, the units would reverse and pump water from Lake Wishon into storage at Courtright Lake
- Units have fast operating capability:
  - Dead stop to full generation in eight minutes
  - Dead stop to full pump in twenty minutes (single speed)
  - Generating ramp rate of 80 MW per minute per unit

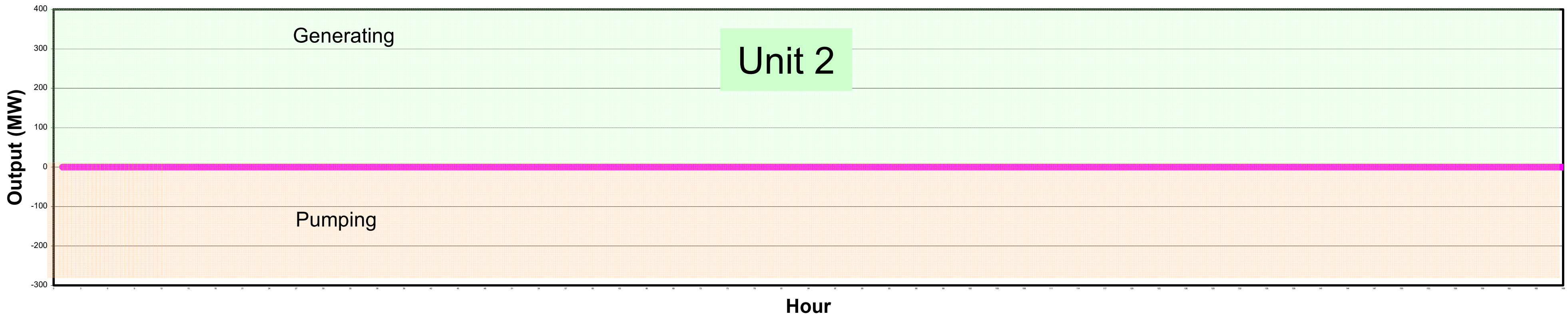


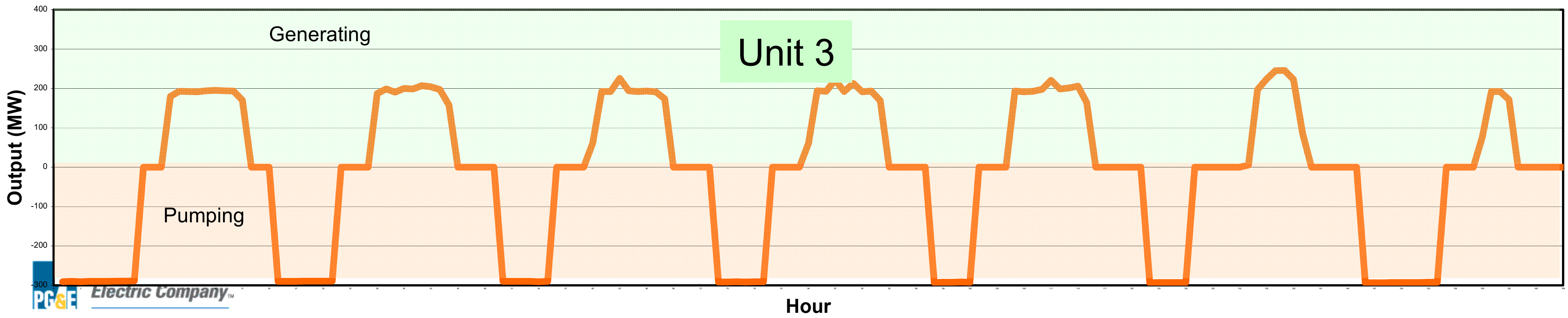
Helms Provides PG&E Customers with Many Benefits

- Storage of economy energy, or surplus or lower cost energy that is sometimes available at night for daily cycling or during Spring runoff conditions for seasonal storage
- A large amount of fast acting spinning reserve and regulation capability, or generating capacity that is immediately available to meet fluctuations in electric demand
- Revenues from CAISO's energy and ancillary markets (regulation, spin and non-spin)
- Helps alleviate over-generation or minimum load condition by using excess energy to pump water into storage
- Allows operation of thermal plants at a more steady output level, resulting in higher efficiencies
- Reduces dependence on fossil fuels and greenhouse gas emissions (environmental benefits)

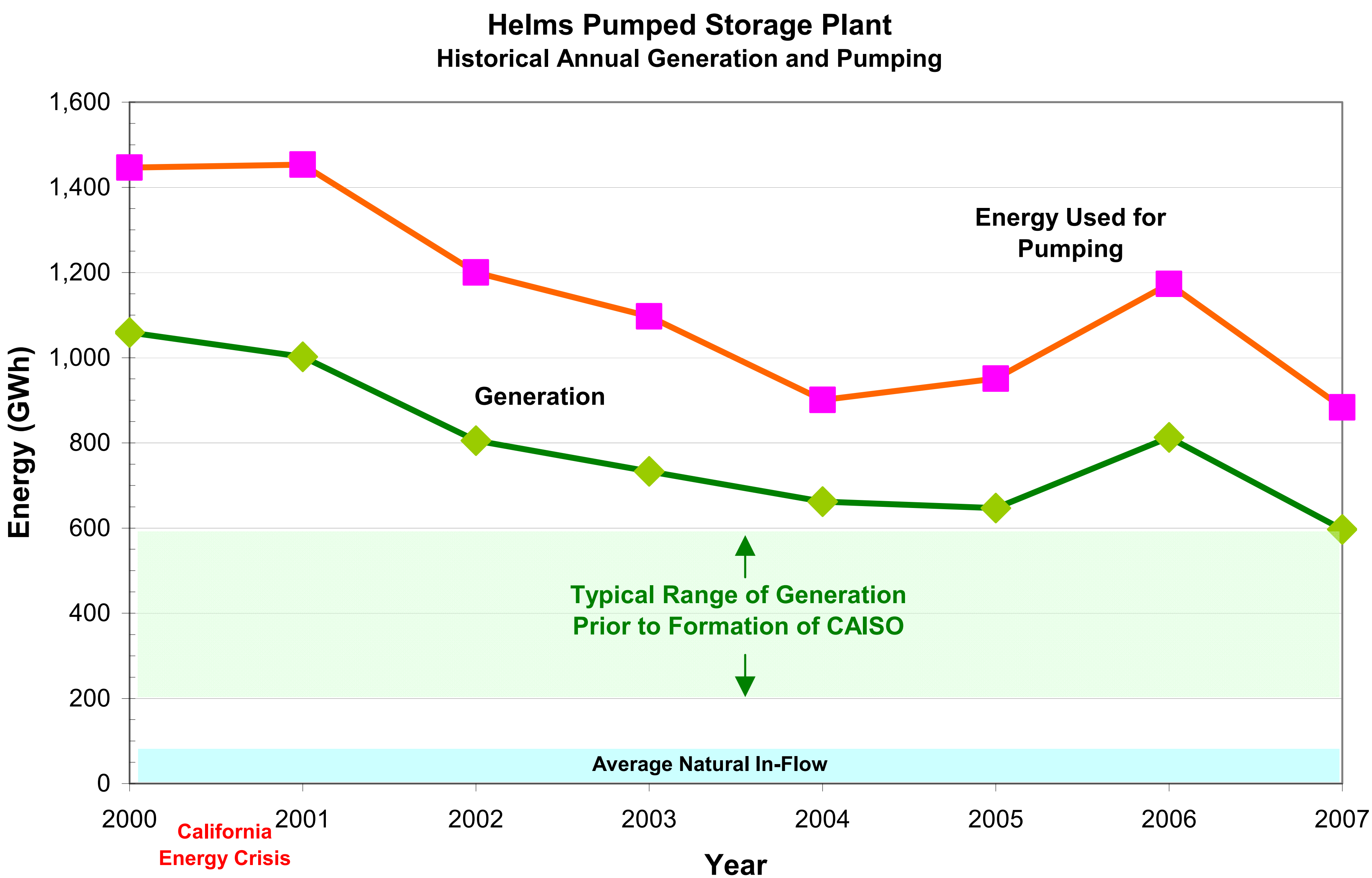
Helms Operation – Typical Summer Week







Helms' Production Substantially Exceeds its Natural Inflow

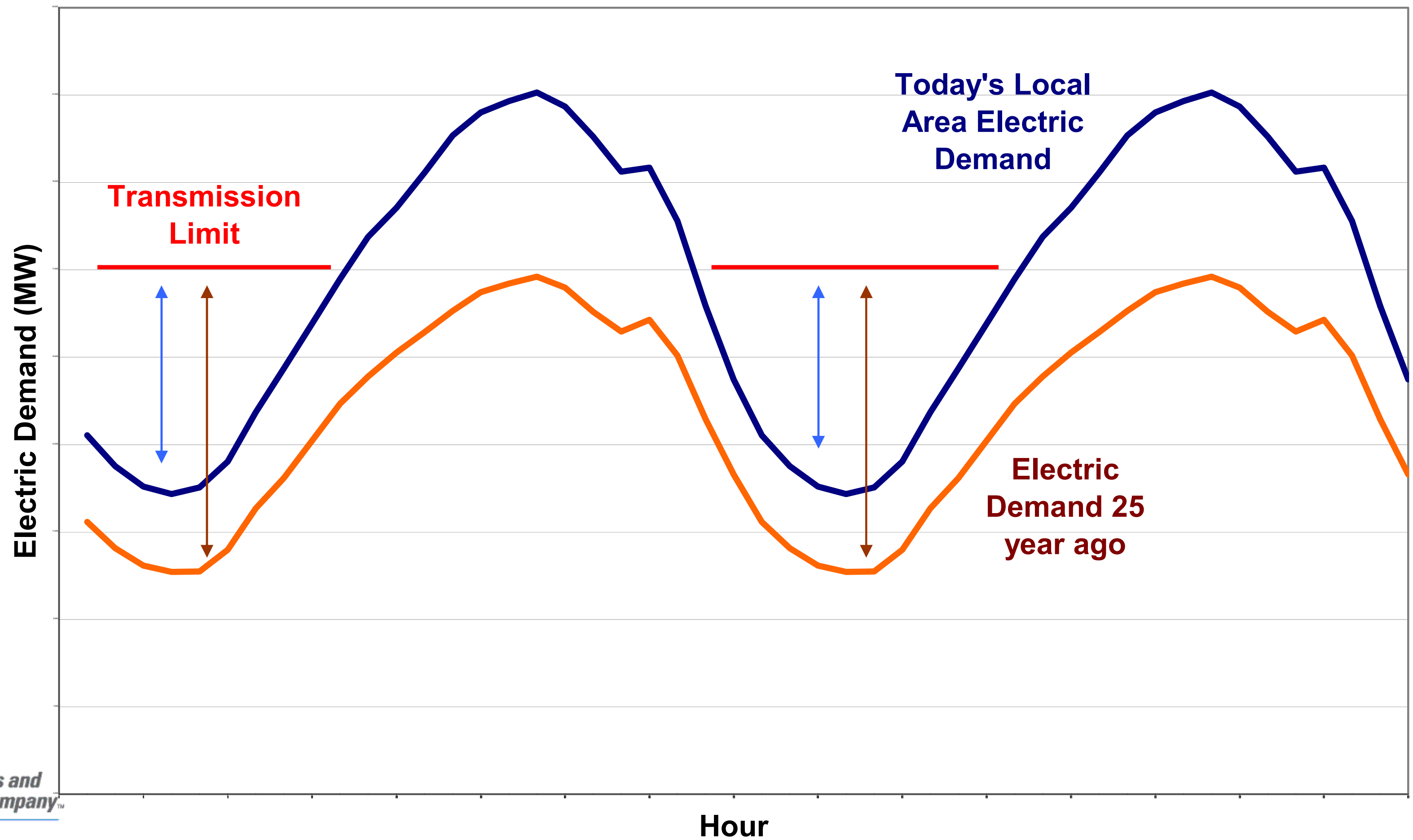


Pacific Gas and Electric Company

Demand Increase has Consumed Transmission for Pumping

- Over the past 25 years, electric demand in central California has increased and has consumed some transmission capacity for pumping at Helms during off-peak hours
- PG&E has plan to construct a new 150 mile long 500 kV transmission line to, among other things, restore Helms' pumping flexibility

Illustrative **Demand vs. Transmission Capability for Pumping**



Future Changes to Helms PSP Operation --- Unclear

Potential drivers are:

- Electric transmission constraints
- Intermittent renewable generation
- CAISO’s Market Redesign and Technology Upgrade initiative and its Nodal and Locational Marginal Pricing
- Western Electricity Coordination Council’s draft Frequency Response Reserve criteria in additional to the current spinning reserve requirement

PG&E is Evaluating New Pumped Storage Opportunities

- More pumped storage plants is good for power system operation
- In 2008, PG&E has sought and received FERC permits to evaluate potential pumped storage hydro facilities at Mokelumne River and Kings River
- PG&E is currently evaluating several potential pumped storage sites based on using a number of existing or new reservoirs

In Summary

- PG&E's Helms Pumped Storage Plant has provided positive economic, reliability, operational and environmental values to PG&E's customers for almost 25 years, with many more to come
- Helms can facilitate storage of economy energy on both a daily and a seasonal basis
- Helms is an effective means to resolve over-generation and minimum load issues
- Helms, with its fast operating characteristics, is a valuable tool for system operators to meet changing demand and system conditions
- Helms is very valuable in the ancillary market as well as the energy market
- Helms can also be an effective tool to accommodate and integrate intermittent renewable resources

QUESTIONS???

Rulemaking	17-06-026
Exhibit	____________________
Date	April 2, 2018
Witnesses	Various

PREPARED DIRECT TESTIMONY OF
THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

VOLUME 2
Chapter 3
Public

Going Forward Utility Portfolio Optimization
(Common Outline §III)

CalCCA
California Community
Choice Association

ORDER INSTITUTING RULEMAKING TO REVIEW, REVISE, AND CONSIDER ALTERNATIVES TO THE POWER CHARGE INDIFFERENCE ADJUSTMENT
R.17-06-026

PREPARED OPENING TESTIMONY OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Table of Contents

Volume 2

Chapter		Witness	Page
3	**GOING FORWARD UTILITY PORTFOLIO OPTIMIZATION** (Common Outline §**III)**		
	I. Securitization and Active Portfolio Management Will Reduce Uneconomic Costs	A. Hoekstra T. Merrinan	3-1
	II. Analysis of Existing Portfolios	A. Hoekstra	3-1
	III. Reduce Portfolio Costs Through Securitized of Utility Owned Generation	B. Abramson J. Fichera R. Kinosian	3-6
	A. Overview of Proposal	H. Schoenblum P. Sutherland	3-6
	IV. Reduce Portfolio Costs Through a Voluntary, Securitized Reverse RFO Program for Buydown of PCIA-eligible PPAs	A. Hoekstra R. Kinosian	3-7
	V. Reduce Stranded Cost Risk and Portfolio Costs through Improved Portfolio Management and Updated Guidance	A. Hoekstra T. Merrinan	3-10
	A. Require Risk Mitigation in Departing Load Forecasting		3-11
	B. Actively Market Portfolio Resources Under Reasonable Terms and Conditions to Reduce Uneconomic Costs		3-13
	C. Recognize and Address Evolving Contract Opportunities		3-15
	VI. Consistency with Overall Goal and Guiding Principles	A. Hoekstra T. Merrinan	3-16

Chapter	Witness	Page

CHAPTER 3 EXHIBITS

3-A Direct Testimony of Paul Sutherland
3-B Direct Testimony of Barry Abramson
3-C Direct Testimony of Joseph Fichera
3-D Direct Testimony of Hyman Schoenblum
3-E CONFIDENTIAL
3-F CONFIDENTIAL
3-G CONFIDENTIAL

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

CHAPTER 3

GOING FORWARD UTILITY PORTFOLIO OPTIMIZATION

(Common Outline §III)

I. SECURITIZATION AND ACTIVE PORTFOLIO MANAGEMENT WILL REDUCE UNECONOMIC COSTS

The enormity of the utilities' forecast procurement costs highlights the critical need to manage portfolio exposure and PCIA-eligible costs. This testimony offers proposals to reduce costs in three ways:

- Securitization of UOG remaining in the PCIA-eligible portfolio for their remaining services lives substantially reduces financing costs for the assets.
- Implementing a PPA buydown program and securitizing the up-front buydown costs offers the potential for additional cost savings.
- Improving forecasting and portfolio management can both reduce the accumulation of new stranded costs and help maximize the value of the existing portfolios.

These proposed changes carry potential benefit for all customers, whether served by the utility, a CCA or an ESP.

II. ANALYSIS OF EXISTING PORTFOLIOS

In Chapter 3, CalCCA presents specific proposals to achieve cost reductions and improve the management and optimization in the utilities' PCIA-eligible portfolios. These proposals include measures to reduce costs charged to customers through securitization of UOG, a voluntary "reverse auction" for existing PPA price reductions, and redistribution of supply in the utilities' portfolios based on a more robust focus on prudent portfolio management principles and risk mitigation strategies.

To provide some overall context for portfolios currently held by the utilities that would be impacted by CalCCA's recommendation, we start by providing some specific quantification of the elements and key characteristics of the portfolios for PG&E and SCE. This will help frame up the size and scope of the portfolios of the generation volumes and costs in the respective portfolios so the nature of CalCCA's proposals can be better understood.

Our process to model and analyze the PG&E and SCE portfolios consisted of several steps.

1) First, we developed long-term forward projections of PG&E's and SCE's aggregate PCIA-eligible supply portfolios, based primarily on the "ALJ Data Matrix" of projected data provided on March 2, 2018.

2) Then, we extended these projections out to 2030, in order to ensure that we develop projections at least 10 years into the future starting in 2019, and then elected to match the current 12-year planning horizon to 2030 of the California Energy Commission's recently-adopted 2017 Integrated Energy Policy Report.

3) We supplemented the ALJ Data Matrix with other sources, primarily material provided by the utilities under the Modified NDA, such as material provided pursuant to the Meet & Confer process, data request responses, and confidential utility resource planning and ERRA filings and workpapers.

4) We then segmented the portfolios into various relevant categories of resource and product types (described further below) for purposes of understanding the supply and costs characteristics of these categories.

The PG&E and SCE PCIA-eligible portfolios provided in the ALJ Data Matrix submissions were segmented as follows:

A) First according to the resource ownership type, either UOG or generation by others sold to the utilities under PPAs.

B) We then segmented the portfolios further into three key resource type categories: RPS-eligible Energy, GHG-free Energy, and "Other" Energy consisting of all other types including fossil-fueled generation sources.

C) Finally, we segmented the portfolio according to the assigned Vintage of each resource. The current portfolio represents the 2018 Vintage, with appropriate resources removed from earlier Vintages.

This segmentation permitted us to develop projections for the PG&E and SCE PCIA-eligible portfolios. These projections include:

- ✓ Total Generation (in GWh)

- ✓ Total Cost (in $)
- ✓ Market Value[1] (in $)
- ✓ Net Cost (in $) — where Net Cost is calculated as Total Cost minus Market Value

In considering alternative proposals to reduce excess volume and costs in the utility portfolios, we analyzed the products and costs in those portfolios through 2030. As an initial matter, we offer the following observations regarding the combined PCIA-eligible portfolios of PG&E and SCE during the 12-year period of 2019-2030, which are supported by the charts below (Figures 3-1, 3-2 and 3-3):

1) Annual average Total Generation volumes of approximately 70,000 GWh/year represent about 45% of the total service territory load of the two utilities (Bundled and Departing load combined).

2) The Total Cost of this generation is nearly $6.3 billion/year, at an average unit cost of about $90/MWh.

3) RPS-eligible Energy from PPAs contributes about 53% of the Total Generation and 65% of the Total Costs in the portfolios, while GHG-free Energy from UOG resources (primarily nuclear and hydro) represents 39% of the Total Generation and 27% of the Total Costs in the portfolios (combined these two Resource Type categories represent 91% of the Total Generation and Total costs of the combined portfolios).

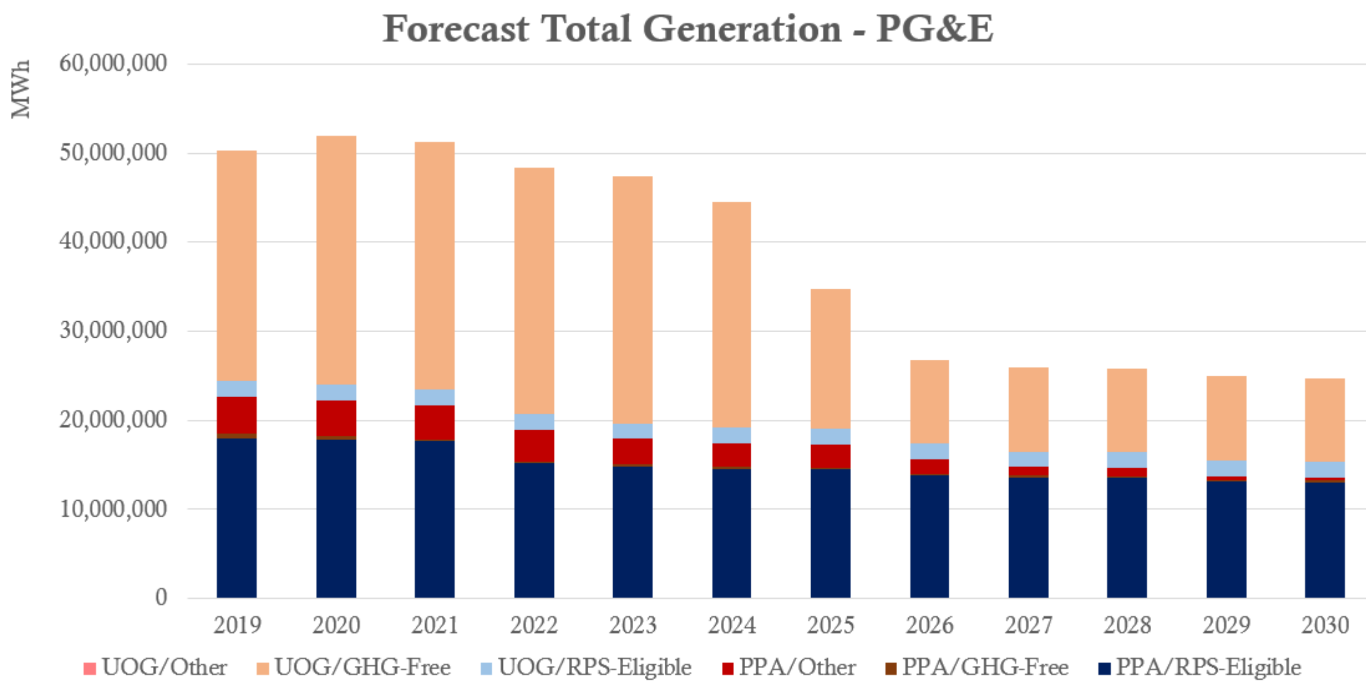
4) We project approximately $28 billion in Net Costs (when valued using the current 2018 market-price benchmark values) of which RPS-eligible PPAs contribute 71% and GHG-free UOG contributes 20%.

Consistent with these quantitative metrics, CalCCA's portfolio optimization and cost reduction proposals will focus on solutions that deal specifically with the primary drivers of costs in the portfolios: RPS-eligible PPAs and GHG-free nuclear and hydro UOG facilities.

---

[1] For illustrative purposes throughout this testimony, the baseline "market value" of each portfolio element is calculated using the applicable market-price benchmark adopted in the 2018 ERRA proceeding and currently effective for 2018.

Figure 3-1


Forecast Total Generation - PG&E
MWh
60,000,000
50,000,000
40,000,000
30,000,000
20,000,000
10,000,000
0
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
UOG/Other
UOG/GHG-Free
UOG/RPS-Eligible
PPA/Other
PPA/GHG-Free
PPA/RPS-Eligible

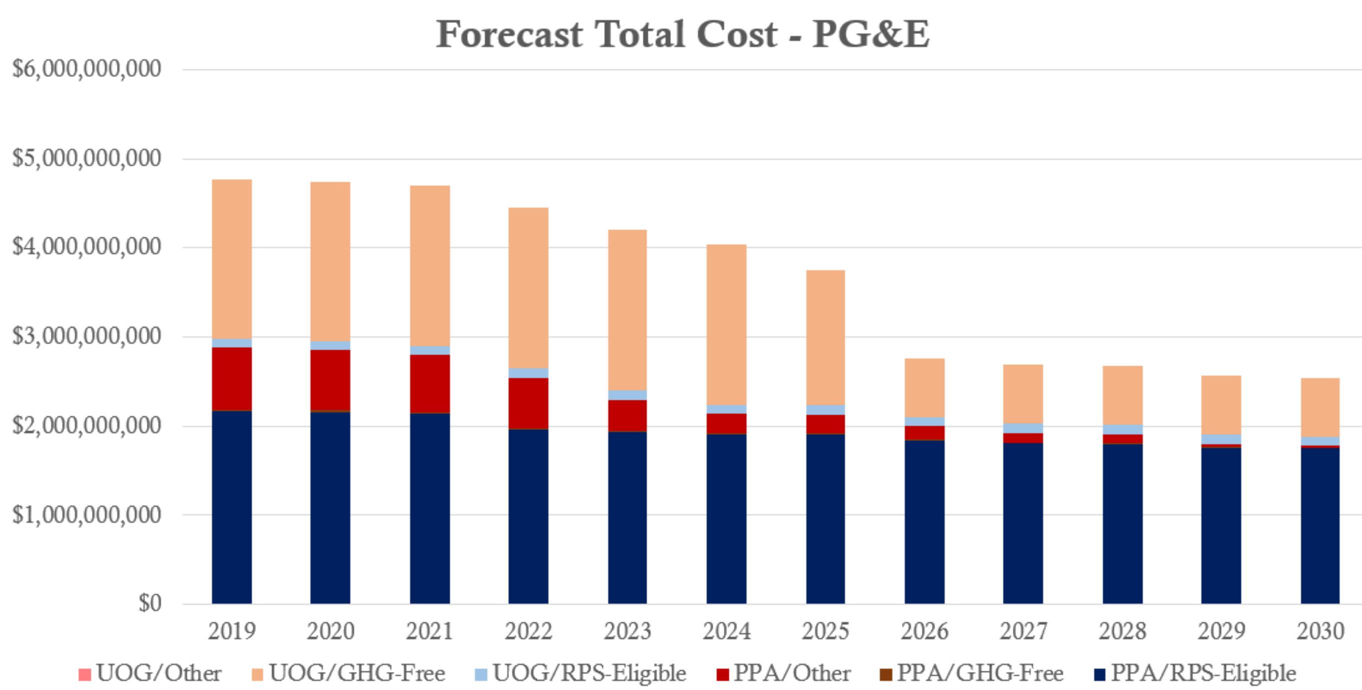
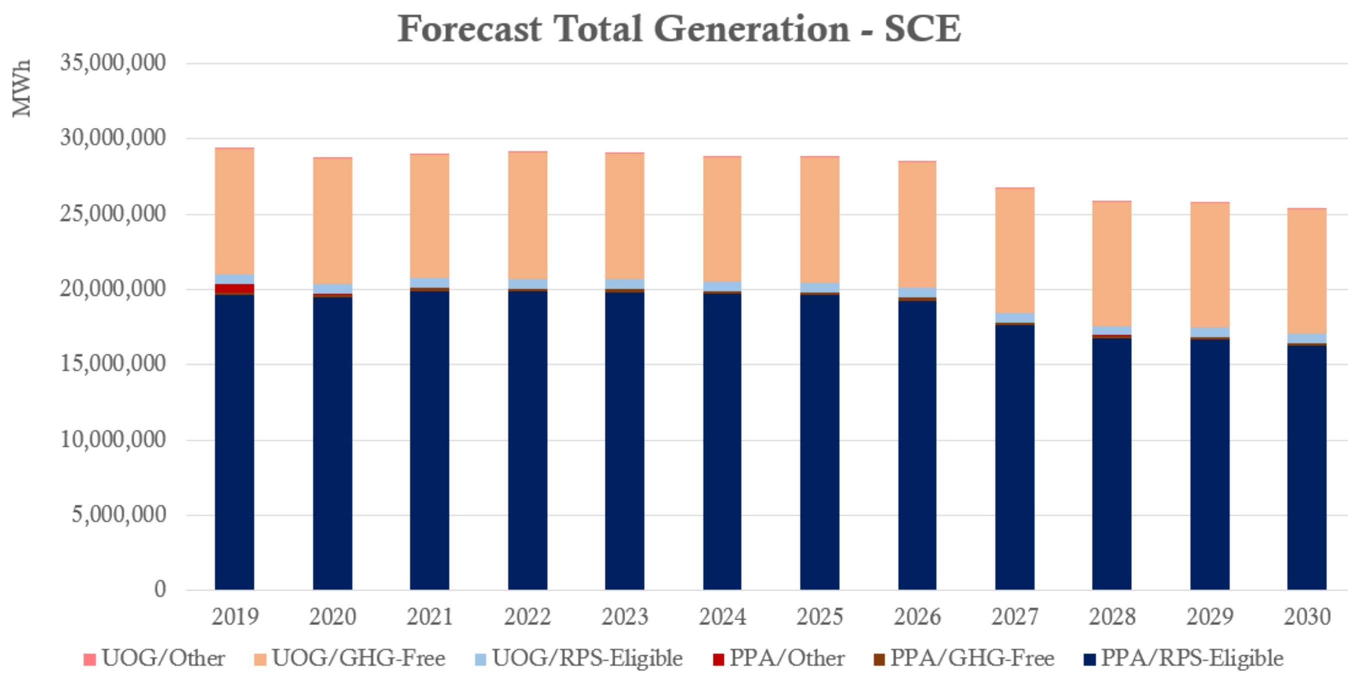

Forecast Total Cost - PG&E
$6,000,000,000
$5,000,000,000
$4,000,000,000
$3,000,000,000
$2,000,000,000
$1,000,000,000
$0
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
UOG/Other
UOG/GHG-Free
UOG/RPS-Eligible
PPA/Other
PPA/GHG-Free
PPA/RPS-Eligible

Figure 3-2


Forecast Total Generation - SCE
MWh
35,000,000
30,000,000
25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
0
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
UOG/Other
UOG/GHG-Free
UOG/RPS-Eligible
PPA/Other
PPA/GHG-Free
PPA/RPS-Eligible

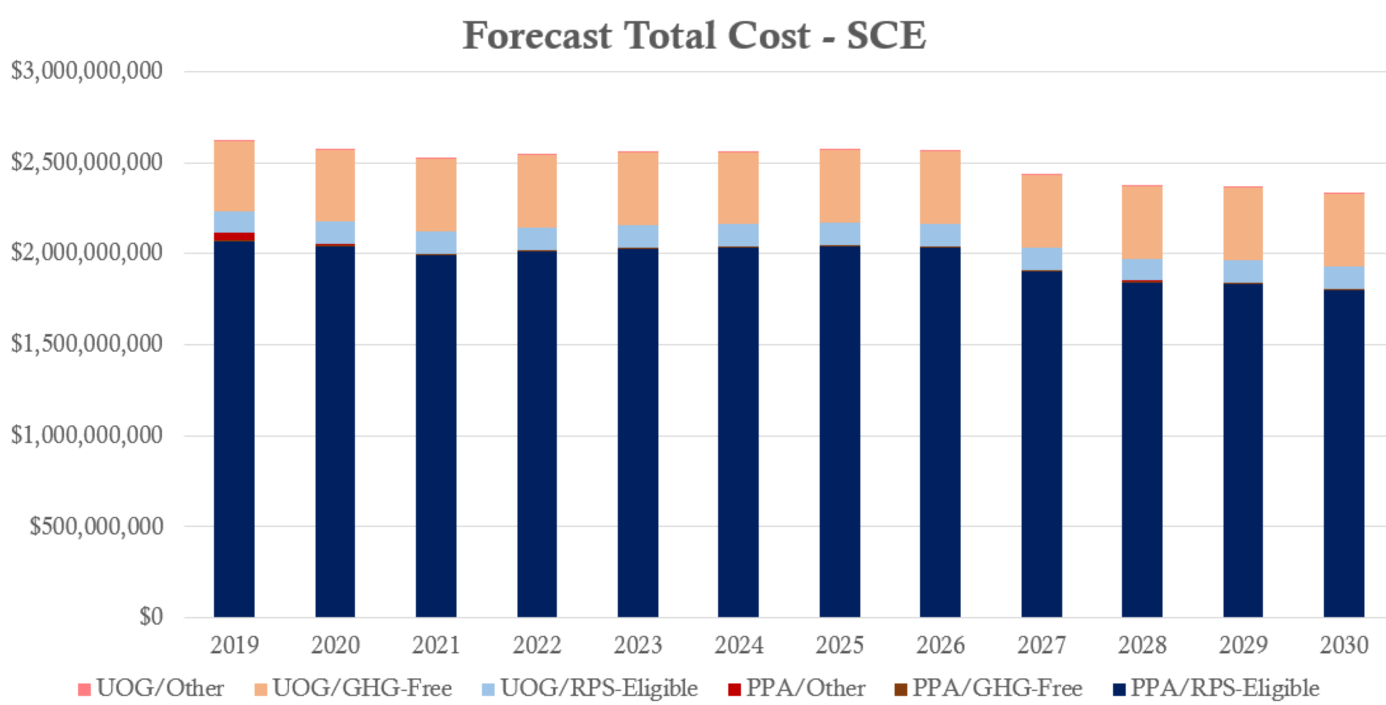
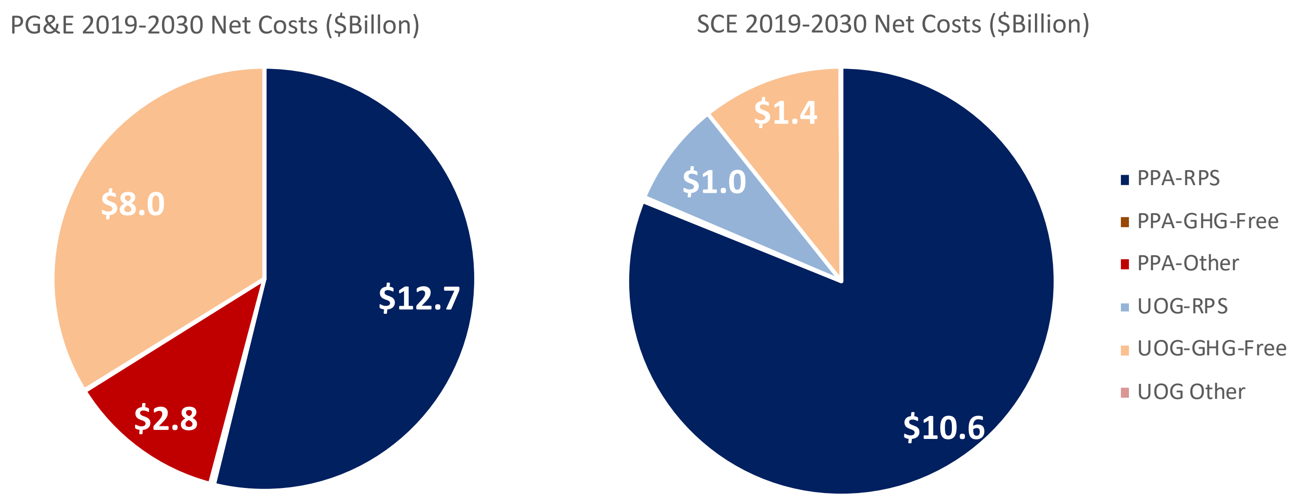

Forecast Total Cost - SCE
$3,000,000,000
$2,500,000,000
$2,000,000,000
$1,500,000,000
$1,000,000,000
$500,000,000
$0
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
UOG/Other
UOG/GHG-Free
UOG/RPS-Eligible
PPA/Other
PPA/GHG-Free
PPA/RPS-Eligible

Figure 3-3



III. REDUCE PORTFOLIO COSTS THROUGH SECURITIZATION OF UTILITY OWNED GENERATION

A. Overview of Proposal

Proceeds from the sale of securitized bonds provide a source of capital that can be used by the utilities at a much lower cost than typical utility financing. CalCCA has evaluated two potential uses for securitized bonds as a means of reducing bundled customers uneconomic costs, providing direct savings to bundled customers: (a) paying off existing utility investment in their generation rate base (UOG securitization) and (b) providing funds to pay generators in exchange for reductions in PPA prices (contract buy down).

With UOG securitization, CalCCA proposes to raise capital through a bond issuance sufficient to repay the utilities for their remaining investment in their generation facilities, the generation rate base: approximately $4.2 billion for PG&E and $1.5 billion for SCE. The current revenue requirements associated with the rate base (depreciation, WACC and taxes on income) would be replaced by the lower interest and principal payments on the securitized bonds. This can provide an initial decrease in the amount charged to bundled customers of over 50%. In addition to the direct savings to bundled customers, the reduction in generation revenue requirements will also reduce the forecasted uneconomic costs of the utilities' generation portfolios, thereby reducing the PCIA. CalCCA proposes to securitize the rate base of all UOG intended to remain in the utilities' PCIA-eligible portfolio for their remaining service lives. The benefits, calculated by Paul Sutherland of Saber Partners (Exhibit 3-A), have a net present value of $1.3 billion for PG&E and $589 million for SCE.

Securitization would not change the ownership or operation of the facilities. They would continue to be owned and operated by the utilities. The bonds would only pay off current rate base. Additional costs of the generation plants, fuel, O&M, A&G and capital additions, would continue to be addressed in standard Commission proceedings and recovered under standard Commission revenue recovery methods. There would be no prepayment of capital additions.

Securitization, in general, and securitization of UOG is explored in detail in the testimony of Paul Sutherland, Barry Abramson, Joseph Fichera and Hyman Schoenblum, attached as Exhibits 3-A through 3-D.

IV. REDUCE PORTFOLIO COSTS THROUGH A VOLUNTARY, SECURITIZED REVERSE RFO PROGRAM FOR BUYDOWN OF PCIA-ELIGIBLE PPAs

A potential means of reducing the uneconomic costs associated with the utilities' RPS-eligible PPAs is to pay willing generators an up-front lump sum in exchange for reducing the contract price for generation in future years, *i.e.* buying down the contract price. Generators may be willing to provide a significant reduction in the contract costs, if they place a higher value than the utilities' ratepayers do on an immediate cash payment rather than earn contracted revenues over time, *i.e.*, if the generators have a higher discount rate for discounting future cash flows than utility ratepayers.

For example, a reduction of $100 million/year for 20 years in contract payments provides ratepayers with a $2 billion nominal savings over the 20 years. Using an illustrative discount rate based on the utilities' weighted average cost of capital (currently 7.69% for PG&E and 7.61% for SCE) the $2 billion nominal reduction would have a value of approximately $1 billion to utility ratepayers on a discounted net present value basis. If the generator has a higher discount rate, for example, 9%, it would attribute a discounted NPV of the same reduction at just $900 million, allowing for a potential reduction of $100 million in ratepayer costs on a present value basis. Discount rates of 10% and 12% show a potential reduction of $850 million and $750 million respectively compared to the utilities' weighted cost of capital. This disparity in buyer and seller discount rates provides potential opportunities for mutually beneficial, voluntary contract buydown transactions for existing RPS-eligible PPAs.

Certain concerns must be addressed by a buydown solution. First, ratepayers may raise concerns about leaving the utility in a position to negotiate a transaction without clear guidance and boundaries. Limiting the scope of negotiation to price reduction per kWh, while possibly reducing potential gains, limits utility discretion and gives greater visibility to the degree of success. Second, the potential value in a buydown program is unknown because the discount rates used by generators are unknown and vary by generator. Consequently, generators may be in a position to offer less in the way of discounts than anticipated in a preliminary analysis. Third, generators may fear being compelled to modify their existing contracts – a problem that can be solved by making participation in the buydown process strictly voluntary. Finally, counterparty credit and performance risks would tend to increase if a seller is paid up front, which may need to be addressed.

A reverse Request for Offers mechanism offers a reasonable approach that could minimize concerns in the quest for generator discounts. The reverse RFO would need to be guided by metrics and parameters set by the Commission, such as setting a floor on buydown value. The Commission would also identify an amount of funding available for the RFO to buy down contract prices. The utility would issue an RFO soliciting proposals from generators for contract price reductions. The generators offering the largest NPV discounts per dollar of upfront funding, perhaps subject to a floor set by the Commission, would be awarded a buydown. This approach addresses potential concerns with a buydown program: participation by the generators is voluntary, utilities are not required to negotiate discounts, and generators must compete with each other to ensure they are one of the winning bids, assuring reasonable discounts. Evaluations of potential PPA buydown securitization opportunities supporting this proposal is attached as Confidential Exhibit 3-E.

Securitization of contract buydown costs could increase the potential for ratepayer savings with buydowns by allowing the up-front payment to be financed at a rate much lower than the utilities' weighted cost of capital, 3% to 4% compared to 7.5%. For example, there would be more value to negotiate with a developer discount rate of 15% and a utility securitized debt rate of 4% than there would be if the delta for negotiation was the difference between that developer’s discount rate and the utility’s weighted average cost of capital.

V. REDUCE STRANDED COST RISK AND PORTFOLIO COSTS THROUGH IMPROVED PORTFOLIO MANAGEMENT AND UPDATED GUIDANCE

The applicable cost-recovery provisions implemented by AB 117 permit allocation of cost responsibility to departing CCA/DA customers only to the extent portfolio costs are "unavoidable." Only in understanding the ways in which the utility is managing its portfolio on an ongoing basis and in consideration of all customers' interests, can the Commission determine which costs are unavoidable and incurred on behalf of or are "attributable" to departing CCA/DA customers. CalCCA believes that it is appropriate to highlight a few key areas in which greater vigilance going forward is warranted to deal adequately with the significant Net Costs in their PCIA-eligible portfolios. Indeed, it is the prudent management of risks and uncertainties on behalf of customers, and the appropriate attribution of those costs to customers, that provide a framework under which cost-of-service regulation and the returns earned by IOUs from customers can be justified.

Despite awareness in 2002 that CCAs presented departing load risk to the utilities, no departing load was forecast by PG&E until 2010 and by SCE until 2015; neither utility performed stochastic modeling forecasts for departing load until 2016 or later.[2] Failing to forecast departing load in the early years of CCA growth may have directionally overstated PG&E's need for RPS supplies. Moreover, despite substantial actual and planned CCA departing load, PG&E and SCE have made only limited efforts to market excess or high-priced supply to mitigate uneconomic costs in the PCIA-eligible portfolio.

[2] *See* Confidential Exhibit 3-F.

The Scoping Memo makes clear that this proceeding is not about revisiting past Commission prudency decisions.[3] Understanding how the utilities have managed through the initial stage of CCA growth, however, can inform future policies. CalCCA proposes the following guidance to manage portfolio risk – on behalf of both bundled and departed customers – going forward.

- Require risk mitigation in departing load forecasting.
- Market products in the utility portfolio, including supply excess and, as proposed in Chapter 4, a Staggered Portfolio Auction of GHG-free Utility Owned Generation and RPS PPAs.
- Recognize and respond to opportunities to modify existing contracts to reduce cost exposure for all customers and address the vintaging of those contracts when procurement decisions are renewed.

Implementing these and other portfolio management objectives identified in this proceeding will reduce costs for all customers.

A. Require Risk Mitigation in Departing Load Forecasting

Reasonably forecasting departing load can play a foundational role in avoiding unnecessary procurement and inappropriate attribution of the costs resulting from that procurement. If the utility anticipates that load will be departing and responds reasonably, it will mitigate the risk of excess long-term procurement in its portfolio, which in turn will minimize stranded assets and above-market costs. Failure to sufficiently recognize the departing load risk directionally results in over-procurement.

Yet, despite AB 117's enactment in 2002, the Commission's 2005 decision emphasizing the utilities' obligations relating to departing load forecasting[4] and CCAs

---

[3] Scoping Memo at 19 (The scope does not "include revisiting prior Commission determinations regarding the reasonableness of the IOUs' past procurement actions.").

[4] D.05-12-041 at 31-32 states: "In all cases, the utility must reasonably manage procurement consistent with Section 366.2, which provides that CCAs must assume only the

first serving customers as far back as 2010, the utilities appear to have only very recently started to take a more proactive approach to incorporating uncertainty and risk mitigation when forecasting departed load.

Did the decisions that resulted from this load forecasting approach result in procurement commitments and associated costs that are reasonably attributable to departing load? Could these costs have been avoided by better forecasting and more prudent portfolio management? Are there efforts the utilities could or should have made to mitigate any identified risk of over-procurement, or did relying on backward looking load migration estimates serve to realize the risk? CalCCA did not undertake an assessment of the impact of prior forecasting methodologies in this proceeding in light of Scoping Memo limitations on revisiting prior decisions. Going forward, however, the Commission should provide a forum for a more expansive and meaningful annual review of portfolio cost mitigation measures where affected stakeholders engage to hold the utilities accountable for their portfolio management decisions.

A good starting point for considering these issues from a more current posture is SCE's description of its approach to departing load forecasting:[5]

- Before 2016, a specific CCA was excluded from SCE's bundled service forecast only upon the occurrence of: 1) start of CCA service or 2) filing of a binding notice of intent, based on CPUC decisions issued in 2005 and 2008.
- In 2016, SCE added a third criterion for excluding a specific potential CCA from SCE's bundled service forecast: participation in the CPUC's RA proceeding.

"net unavoidable costs" of utility power procurement. While we recognize the uncertainties the utilities face in trying to forecast load loss prior to receiving a CCA's binding commitment, we also believe the utility should take reasonable steps to plan for that contingency, for example, by reducing long-term commitments until a CCA's plans are assured."

[5] Non-confidential version of R.17-06-026 SCE Load Forecast (retail at ISO), March 2, 2018.

SCE relies solely on that three-point criteria for forecasting CCA departing load in the first two years of the forecast period.

- Beyond the first two years, SCE runs a Monte Carlo simulation of expected CCA load departure to forecast its remaining bundled service load. Each city in SCE's service territory is assigned a probability of departure based on its level of interaction with SCE's Customer Choice Services organization, including a request for historical load data, the passing of a municipal ordinance, and the execution of an SCE application package. SCE uses the Monte Carlo Simulation to generate a range of potential outcomes. The Monte Carlo simulation runs iteratively for 10,000 times and performs random draws among all cities (except for cities who already departed) for each year based on the probability distribution. Based on the 10,000 run outcomes, SCE then selects the 50th percentile (Expected Value) outcome for each year to represent SCE's forecast of total departing load. The simulation currently assumes the independence of each city's departure.

PG&E likewise has more recently adopted a stochastic modeling approach to forecasting departing load.[6]

While these changes are a step in the right direction, a more aggressive approach to forecasting should be pursued in light of the current risk of load departures resulting from CCA formation. At a minimum, rather than relying on Expected Value from stochastic models, departing load should be forecast looking at the "tail" risk in the probability distribution.[7] Forecasting departing load more aggressively presents little risk to the portfolio, particularly under today's circumstances where the utilities hold RPS resources in excess of their bundled load needs.

B. Actively Market Portfolio Resources Under Reasonable Terms and Conditions to Reduce Uneconomic Costs

A readily available means of mitigating uneconomic costs is to more actively monetize the PCIA portfolio. CalCCA's review indicates that the utilities have

---

[6] *See* Confidential Exhibit 3-F.

[7] With significant likelihood of more CCA departure, portfolio flexibility should be a key element of IOU resource planning to avoid unnecessary costs resulting from over-procurement.

periodically offered and sold products into the market at limited levels and primarily for short periods into the future. However, the data contained in Confidential Exhibit 3-G, indicate that the utilities have recently begun to engage in more forward sales of products in the market. Moreover, that same data indicates that these more recent forward sales, often for longer periods into the future, have attracted higher prices than the earlier, shorter-term sales. Our proposal in Chapter 4 for a Staggered Portfolio Auction takes this notion much further, monetizing a significant portion of the PCIA-eligible portfolio.

Regardless of the means by which the resources are offered, the terms and conditions of the offers must be developed in a way that is most likely to maximize the interest of the market (including CCAs) and thereby maximize the value of the offering. Interest in the auction will be influenced by the way in which products are offered, including:

- ✓ The number of projects/contracts and type of resources being offered.
- ✓ Timing of RFO issuance and bid due dates relative to ongoing procurement schedules.
- ✓ Product structure, *e.g.*, allowing for fixed price contracts with specified or preferred hourly delivery profiles to allow participants to capture the energy value for load hedging.
- ✓ Scope of information provided to develop detailed analysis of specific projects, *e.g.*, information on P-Node locations to garner premiums based on geographic preferences, congestions issues, etc.

The utilities should solicit input from potential market participants to ensure ratepayers receive the highest price for the products offered to the market.

C. Recognize and Address Evolving Contract Opportunities

Procurement costs do not become unavoidable forever simply because a project has been approved by the Commission. Rather, questions must be answered as to whether the utility acted reasonably in maintaining or extending the contractual commitment over the life of the project, in keeping the resource, and whether it has done so to address future bundled load needs. Without such evidence, such costs cannot be deemed unavoidable and attributable to departing CCA load, or properly assigned to any particular vintage of departing load.

Changing conditions and excess procurement highlight the importance of continual review of existing contracts. The history of PG&E's PPA with the Topaz solar facility illustrates one such opportunity that is instructive for evaluating the impact of departing load on procurement decisions and cost attribution.

- PG&E originally signed a contract with Topaz in July of 2008 for a 550 MW solar facility with a 20-year term.
- The same year in which this contract was originally signed, Marin Energy Authority (now Marin Clean Energy) formed.
- According to PG&E Advice Letter 3514-E, in the spring of 2009, First Solar notified PG&E that Topaz, its wholly-owned subsidiary, would not be able to perform under the PPA due to project cost increases.
- In 2009, CCA measures were being considered in several areas inside PG&E's service region, but PG&E did not appear to reduce its sales forecast for potential departing CCA load.
- In 2009, despite the imminent formation of Marin Clean Energy and other burgeoning CCA activity, PG&E opted to negotiate new terms with Topaz, including an extension of the term and a substantial cost increase. The negotiated amendment price was above the relevant Market Price Referent.
- Meanwhile, by December of 2009, Marin Clean Energy had submitted its Community Choice Aggregation Implementation Plan and Statement of Intent to the Commission.

- The decision by PG&E to renegotiate and continue with the Topaz contract at a minimum should have triggered a new date for vintaging the Topaz plant. Load that had departed or served notice of departure should not have been tied to the decision to continue with the construction of this above market price facility.

CalCCA acknowledges that this contract and its amendment were approved by both PG&E and the Commission. CalCCA also acknowledges that the increased costs agreed to in the amendment may have appeared reasonable at the time in light of PG&E's unrevised forecasted RPS need and RFO pricing. Nonetheless, this scenario illustrates an example of an opportunity for PG&E to reevaluate or exit a contract due to changing circumstances, the result of which would have been to: (1) exclude that resource from the PCIA; (2) obviate the need to deal with excess long-term RPS procurement; and (3) reduce costs for PG&E's own customers.

Under conditions like this, departing load vintages require modification. If the utility is presented with an opportunity to end an existing contract obligation, that opportunity should mark a new procurement date because that procurement decision would not have been made on behalf of previously departed or imminently departing customers. Continuing to rely on the initial execution date to vintage the contract fails to acknowledge when an irrevocable decision has been made on behalf of a customer and the costs become "unavoidable."

VI. CONSISTENCY WITH OVERALL GOAL AND GUIDING PRINCIPLES

CalCCA's recommendations to reduce costs through PPA buydown, securitization and portfolio management are consistent with the Scoping Memo's guiding principles.

Prevent Cost Shifts. Improvements in departing load forecasting and contract administration processes are specifically focused to ensure that the utilities' actions result in the elimination of avoidable costs, inappropriate attribution of costs and the cost shifts that result from such errors.

Transparent and Verifiable. Developing expressly stated and Commission-approved portfolio optimization policies and guidelines provides increased transparency and validation in an area which has been difficult for CCAs and other parties to penetrate.

Reasonably Predictable Outcomes. The implementation of a greater structure to portfolio optimization expectations will help provide greater understanding and predictability of future outcomes for the utilities, for the Commission, and for CCAs and other stakeholders.

Preserve all Short, Medium and Long-Term Value. We envision portfolio optimization improvements that will not just preserve, but will enhance, value for utilities and their customers.

Complement CCAs' Procurement, Goals and Needs. Improvements in utility portfolio optimization will increase CCAs' discretion and flexibility in exercising their procurement responsibilities.

Unreasonable Obstacles Avoided. There are no unreasonable outcomes created with CalCCA's proposals to enhance the utilities' portfolio optimization processes.

Include Only Legitimately Unavoidable Costs and Reflect the Value Benefits of Departing Customers. CalCCA's recommendations focus squarely on addressing a gap in existing policies and guidelines which exacerbate departing customers' current and prospective exposure to costs that can be avoided and may not be properly attributable to them.

Respect the Terms of Existing PPAs. The CalCCA proposal expressly preserves the terms and conditions of existing PPAs but should provide more direction around expectations for how the utilities will enter into and administer those agreements, including incentivizing the utilities to exercise their contractual rights when appropriate to minimize costs for all customers.

EXHIBIT 3-A

EXHIBIT 3-B

EXHIBIT 3-C

EXHIBIT 3-D

EXHIBIT 3-E

CONFIDENTIAL

EXHIBIT 3-F

CONFIDENTIAL

EXHIBIT 3-G

CONFIDENTIAL

Rulemaking 17-06-026
Exhibit ____________________
Date April 2, 2018
Witnesses Various

PREPARED DIRECT TESTIMONY OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

VOLUME 3
Chapters 4-7

PCIA Alternatives
PCIA "Caps" and "Sunset"
Forecasting Cost Responsibility for Future Periods
Other Issues
(Common Outline §IV, §V, §VI, §VII)

and
Qualifications

CalCCA
California Community Choice Association

ORDER INSTITUTING RULEMAKING TO REVIEW, REVISE, AND CONSIDER ALTERNATIVES TO THE POWER CHARGE INDIFFERENCE ADJUSTMENT

R.17-06-026

PREPARED OPENING TESTIMONY OF THE CALIFORNIA COMMUNITY CHOICE ASSOCIATION

Table of Contents

Volume 3

Chapter		Witness	Page
4	**PCIA ALTERNATIVES – AUCTION OF UTILITIES' RPS-ELIGIBLE AND GHG-FREE RESOURCES** (Common Outline §IV)	A. Hoekstra T. Merrinan	
	I. Auctioning Utility RPS-Eligible and GHG-Free Resources Allows for Product Redistribution and Creates a Transparent and Reliable Benchmark to Determine Above-Market Costs		4-1
	II. Proposed Auction Structure		4-2
	A. Auction Scope and Characteristics		4-2
	B. Auction Participants		4-6
	C. Auction Administration		4-6
	D. Auction Operation		4-7
	E. Unintended Consequences and Market Monitoring		4-8
	F. Residual Portfolio		4-8
	G. Precedent in the California Cap and Trade Auction Model		4-9
	III. Consistency with Overall Goal and Guiding Principles		4-11
5	**PCIA "CAPS" AND "SUNSET"** (Common Outline §V)	A. Hoekstra	

Chapter		Witness	Page
	I. PCIA Rate Caps		5-1
	II. Sunset of Stranded Procurement Cost Responsibility		5-2
6	**FORECASTING COST RESPONSIBILITY FOR FUTURE PERIODS** (Common Outline §VI)	A. Hoekstra	6-1
7	**OTHER ISSUES** (Common Outline §VII)		
	I. Permit CCA and DA Customers to Prepay All or a Portion of Their Future PCIA Obligations to Further the Goals of Stability and Predictability	R. McCann	7-1
	A. Prepayment Has Been Used in Other Similar Settings		7-1
	1. California Publicly Owned Utilities Have Prepaid Departing Load Obligations		7-2
	2. Commercial Customers Have Prepaid Bundled Service Obligations When Departing Utility Services		7-3
	B. The Prepayment Calculation Should Rely on Values from the Staggered Portfolio Auction or as a Result of Bilateral Negotiation Subject to Commission Approval		7-4
	C. Prepayment Would Not Shift Costs Among Bundled and Departing Load Customers		7-6
	II. Require Identification of the PCIA Rate as a Separate Line Item on All Customer Bills to Promote Fair Competition and Reduce the Complexity of Customer Choice	R. Kinosian	7-7
	III. Adopt Guiding Principles for Allocation of Costs Related to the Utilities' Regulatory Activities to Avoid Cross Subsidies	A, Hoekstra	7-8

Chapter		Witness	Page
IV.	Reexamine the Utility's Provider of Last Resort Obligation to Further a Long-Term Durable Solution to Reduce Stranded Costs	A. Hoekstra	7-11

WITNESS QUALIFICATIONS

Aldyn Hoekstra
Robert Kinosian
Teresa Marrinan
Richard McCann

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

CHAPTER 4

PCIA ALTERNATIVES
AUCTION OF UTILITIES' RPS-ELIGIBLE AND GHG-FREE RESOURCES

(Common Outline §IV)

I. AUCTIONING UTILITY RPS-ELIGIBLE AND GHG-FREE RESOURCES ALLOWS FOR PRODUCT REDISTRIBUTION AND CREATES A TRANSPARENT AND RELIABLE BENCHMARK TO DETERMINE ABOVE-MARKET COSTS

In Chapter 3, CalCCA introduced the concept of an auction as a potential approach for optimizing the utilities' PCIA-eligible portfolios and mitigating the excess costs in those portfolios. The utilities have recently begun to sell off excess supply on an *ad hoc* basis, but CalCCA proposes a more comprehensive approach to more efficiently and effectively redistribute excess supply. In a "Staggered Portfolio Auction," the utilities would offer 100% of the PCIA-eligible output of their RPS-eligible PPAs, GHG-free resources and energy storage (Auction Resources) in multiple tranches over time. Buyers would include the utilities, CCAs and ESPs who need resources to build out their load-serving portfolios and other market participants. The SPA would accomplish several beneficial goals:

1. It would rectify the existing inequity in which departing load customers are obligated to pay the costs of these resources in the PCIA, but denied meaningful access to use of these resources.
2. It would redistribute Auction Resources to LSEs that value them most, with the likely additional benefit of reducing or eliminating wasteful and duplicative procurement.
3. It would mitigate the risk of future cost shifts in either direction because all LSEs (IOUs, CCA, DA providers) would voluntarily bid to procure resources, based on the value they and their customers place on these resources and their alternatives, to best serve their respective customer classes.
4. It would explicitly reveal a current market price for the Auction Resources, which could be used as the market price benchmark to determine PCIA cost responsibility for any remaining resources in the utilities' PCIA-eligible portfolios. This would reflect a more accurate value of those resources because the value would be derived from an actual, verifiable, long-term market transaction.

A structured auction, like the SPA, is a superior approach to the long-term market-based redistribution of supply and valuation of RPS-eligible Energy, GHG-free Energy and energy storage. CalCCA's auction proposal and benefits are described in greater detail below.

II. PROPOSED AUCTION STRUCTURE

While recognizing that the precise design of the auction requires more evaluation and analysis than is possible within this phase of the proceeding, CalCCA proposes implementation details for the SPA as follows. The intent of this testimony is to provide a broad structural and conceptual framework for an auction process that can be further developed in a subsequent phase of this proceeding.

A. Auction Scope and Characteristics

The SPA would include 100% of the Auction Resources. An illustration of the projected volumes for the 12-year period from 2019-2030 period in each category for PG&E and SCE would be as follows[1]:

Table 4-1

	PG&E (GWh)	SCE (GWh)	Combined
RPS-eligible	**198,000**	**276,000**	**473,000**
GHG-free	**228,000**	**102,000**	**329,000**

As shown in Figure 4-2 below, these volumes represent the following during the 12-year period from 2019-2030:

For PG&E:

[1] *See* the detailed annual values in Figure 4-2. The values in both Table 4-1 and Figure 4-2 are illustrative because they assume a fixed annual level of Departing Load of 40% for the entire 12-year period. Although this assumption is likely to be realistic for purposes of the illustration, it does not equal the projected level of Departing Load in any particular period.

- 198,000 GWh of RPS-eligible Energy represents:
    - 21% of the Total Service Territory Load
    - 51% of the RPS obligation for the Total Service Territory Load
    - 35% of the Bundled Load (illustratively assuming 40% departing load)
    - 85% of the RPS obligation for this Bundled Load

- 228,000 GWh of GHG-free Energy represents:
    - 24% of the Total Service Territory Load
    - 40% of the Bundled Load (illustratively assuming 40% departing load)

- 426,000 GWh of combined RPS-eligible and GHG-free Energy represents:
    - 45% of the Total Service Territory Load
    - 75% of the Bundled Load (illustratively assuming 40% departing load)

For SCE:

- 276,000 GWh of RPS-eligible Energy represents:
    - 29% of the Total Service Territory Load
    - 72% of the RPS obligation for the Total Service Territory Load
    - 49% of the Bundled Load (illustratively assuming 40% departing load)
    - 120% of the RPS obligation for this Bundled Load

- 102,000 GWh of GHG-free Energy represents:
    - 11% of the Total Service Territory Load
    - 18% of the Bundled Load (illustratively assuming 40% departing load)

- 378,000 GWh of combined RPS-eligible and GHG-free Energy represents:
    - 40% of the Total Service Territory Load
    - 67% of the Bundled Load (illustratively assuming 40% departing load)

Figure 4-2

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	12-Yr Total
Service Territory Load (GWh, All Customers)													
PG&E	74,392	75,814	76,079	77,118	77,909	78,607	79,842	80,859	81,100	81,748	82,367	83,048	947,880
SCE	73,653	74,547	75,148	76,120	77,342	78,053	78,757	79,278	79,848	80,410	80,942	81,478	935,357
Subtotal	148,045	149,661	151,227	[illegible]	[illegible]	156,760	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	164,526	1,883,237
RPS Target (%)	31.3%	33.0%	34.7%	36.4%	38.1%	39.8%	41.5%	43.2%	44.9%	46.6%	48.3%	50.0%	
RPS Compliance Requirements (GWh, All Customers in Service Territory)													
PG&E	23,265	24,854	26,399	28,071	29,716	31,321	33,051	34,713	36,414	38,096	39,798	41,524	387,238
SCE	23,053	24,535	26,076	27,780	29,467	31,069	32,676	34,245	35,852	37,471	39,095	40,739	381,985
Subtotal	[illegible]	[illegible]	52,474	55,770	59,183	[illegible]	65,727	[illegible]	72,266	75,564	[illegible]	[illegible]	769,223
Departing Load (%)	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	
RPS Compliance Requirements (GWh, Bundled Customers Only)													
PG&E	13,971	14,612	15,840	16,843	17,831	18,793	19,831	20,828	21,848	22,856	23,876	24,914	232,343
SCE	13,832	14,721	15,646	16,625	17,680	18,641	19,606	20,547	21,511	22,483	23,457	24,443	229,191
Subtotal	[illegible]	[illegible]	31,485	33,467	35,511	37,434	[illegible]	41,376	[illegible]	[illegible]	47,336	[illegible]	461,534
RPS-Eligible Volumes (GWh)													
PG&E	19,728	19,576	19,289	16,746	15,808	16,037	15,965	15,881	15,072	15,084	14,544	14,537	198,068
SCE	21,874	23,604	24,652	24,621	24,500	24,429	24,290	23,808	22,189	20,813	20,401	20,290	275,901
Subtotal	[illegible]	[illegible]	[illegible]	41,367	[illegible]	[illegible]	40,350	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	473,969
GHG-Free Volumes (GWh)													
PG&E	24,494	20,313	27,501	27,564	27,919	25,478	15,881	9,567	9,571	8,571	9,571	9,571	227,681
SCE	8,499	8,516	8,439	8,587	8,503	8,430	8,565	8,503	8,436	8,416	8,418	8,436	101,789
Subtotal	[illegible]	[illegible]	36,081	36,472	36,484	33,908	24,446	18,122	[illegible]	[illegible]	[illegible]	[illegible]	329,470

1 RPS-eligible PPAs would generally mirror the original utility contracts with the project owner, including term and the scope of products (*e.g.*, RPS-eligible Energy and RA Capacity), to the extent there is market interest in these products. Contracts over 50 MW could be split into multiple identical contracts to increase the liquidity of the auction for these larger resources by making them feasible for a broader group of bidders. The auction would have the following characteristics:

Minimum Bid. A minimum bid price, *e.g.* based on short-term market prices, broker quotes or other metrics, could be used as values to ensure that market illiquidity or anomalous behavior does not result in an artificially low price. The Commission should consider whether the minimum bid is public or confidential.

Buyer Concentration Limits. If considered necessary by the Commission, maximum participant concentration limits could be set to encourage liquidity and a well-functioning process.

Bid Evaluation. A separate market-clearing price for each auction tranche, representing the highest winning bid in the tranche where bid evaluation is based on an all-in bid price (expressed in $/MWh) for all the products and attributes provided under the PPA.

First Auction Date. January 2020, to allow lead-time to develop the auction details.

Review and Approval. The Commission, after considering stakeholder input, will determine auction structure and criteria and have final approval of agreements arising from the SPA. Details will be determined based on the Commission's preferences, which may involve implementation by an independent auction manager, review by an Independent Evaluator, PRG, and/or other stakeholder process.

The auction of GHG-free UOG resources and RPS-eligible UOG resources (small hydro and energy storage) would differ from the auction of RPS-eligible PPAs. These UOG resources would be auctioned as blocks of GHG-free or RPS-eligible Energy (*e.g.*, 50 MW each) and associated RA Capacity. The auction would have the following characteristics:

Term**:** To be determined, based on market interest and legal constraints (*e.g.*, until the expiration of an existing license).

Products and Attributes Conveyed**.**(recognizing the potential complexity of transacting for resources from very large nuclear and hydro facilities and/or facilities under the coordinated operation within a larger, integrated complex):

- Fixed blocks of firm GHG-free Energy and RA (in the case of nuclear and large hydro)
- Fixed blocks of RPS-eligible Energy and RA (in the case of small hydro facilities)
- Energy Storage Projects

The auction mechanism for the UOG resources would have the following features:

Minimum Bid. A minimum bid price, *e.g.*, based on short-term market prices, broker quotes or other metrics could be used as values to ensure that market illiquidity or anomalous behavior does not result in an artificially low price. The Commission should consider whether the minimum bid is public or confidential.

Bid Evaluation. A separate market-clearing price for each auction tranche, representing the highest winning bid in the tranche where bid evaluation is:

- Based on the bid price (expressed in $/MWh) for RPS-eligible Energy
- Based on the bid price (expressed in $/MWh) for GHG-free Energy
- Based on the bid price (expressed in $/kW-year) for RA Capacity
- Based on valuation criteria to be defined for Energy Storage

***Buyer Concentration Limits*.** If considered necessary by the Commission, maximum participant concentration limits could be set to encourage liquidity and a well-functioning process.

***First Auction*.** January 2020, to allow lead-time to develop the auction details.

***Review and Approval*.** The Commission, after considering stakeholder input, will determine auction structure and criteria and have final approval of agreements arising from the SPA. Details will be determined based on the Commission's preferences, which may involve implementation by an independent auction manager, review by an Independent Evaluator, PRG, and/or other stakeholder process.

B. Auction Participants

Auctions would be open to all market participants on a voluntary basis. Although participation is voluntary for the utilities, the requirement for them to sell 100% of their RPS-eligible Energy and GHG-free Energy in the portfolios should naturally drive them to participate actively and bid aggressively to secure a portion of those resources for bundled customers. This factor, combined with the entry of new CCAs into the market, would tend to drive a significant level of utility demand for the resources being auctioned. Expanding participation on a voluntary basis to all other participants, including non-LSEs, would further expand the number of auction participations and increase the depth, liquidity, and incremental value of the products.

C. Auction Administration

The utilities' dominance on the sale side of the auction and strong presence in the purchase-side presents a potential conflict of interest or self-dealing. It is thus critical that the Commission take a strong role in the design, implementation and administration of the auction. It may elect, as the utilities have done in other procurement processes, to retain a third-party consultant to administer some of the implementation details. The consultant also could be tasked to bring additional experience and expertise to assist the Commission in developing auction mechanics, timing, product specifics and contract terms and conditions. Under no circumstances should the utility be able to see the bidding behavior of potential competitors. Instead, all entities should only see the winning bid. Once bids are accepted, the amount of stranded costs in that contract will be quantitatively defined. Then CCAs should have the option to pre-pay their obligation of the relevant contract on an NPV basis.

D. Auction Operation

Acknowledging a need for more in-depth review by the Commission, CalCCA proposes that the SPAs be held quarterly for two years. Under such an approach, eight separate auction tranches representing one-eighth (12.5%) of the portfolio would be auctioned in each utility portfolio. The auction administrator would offer a diverse group of contracts to the market, with varying sizes, terms, locations, and technologies.

There are several reasons for this recommended structure:

- **Increase participation and liquidity.** Multiple auctions would involve a narrower set of specific contracts and/or smaller volumes than a single comprehensive auction. This structure will likely be more attractive and/or more manageable for a greater number of bidders and thus would lead to greater participation and higher prices.

- **Flexibility to adjust for new events or information.** The quarterly auction approach allows for greater ability to adjust the specific contracts, quantities, and/or products being auctioned to account for new market developments, State policy changes, and/or reliability needs that affect LSEs’ procurement practices.

- **Reduce risks of anomalous bidding behavior.** Multiple auctions over a period of two years would reduce the impacts of strategic bidding, gaming or other unforeseen behaviors by auction participants that would jeopardize the integrity of the auction process.

- **Mitigate effects of anomalous market conditions.** Multiple auctions spread out over time would average out price volatility, and therefore reduce the impacts of unforeseen and temporary price increases or decreases compared to a single comprehensive auction happening once.

Subsequent auctions could be held after two years as needed pursuant to Commission determination.

E. Unintended Consequences and Market Monitoring

Auctions may present a risk of unintended consequences and manipulation, so the Commission may wish to address such potential concerns through further development of auction design details. For example, auction design would need to consider and address the risks arising from utility participation. Rules or processes may be necessary to address complexities or conflicts of interest stemming from the utility's ownership of the auctioned assets and their role in operating those assets. In addition, consideration should be given to preventing the auction from exacerbating excess supply and unnecessarily adding to stranded costs through duplicative procurement outside of the auction. The utility should be required to demonstrate the reasonableness of any decision to procure any new resource outside of the auction process. Finally, rules may be required to prevent market abuse by the utilities, given the relative size of their bundled load and their superior understanding of the Auction Resources.

F. Residual Portfolio

A "residual" portfolio will remain at least until the end of the two-year auction period because not all portfolio products will have been offered into the market. The value of that remaining portfolio will be determined, to the extent possible, using the market prices obtained in the auction process. For products types not monetized in the market (*e.g.*, RA from fossil plants), the benchmark components from the reformed PCIA will be applied. Any costs above the combined benchmark will be treated as uneconomic costs and subject to a Residual PCIA to be paid by all customers: bundled, CCA and DA.

G. Precedent in the California Cap and Trade Auction Model

The auction we propose mimics, to some degree, the auction structure created by the California Air Resources Board's Cap and Trade Regulation. The C&T Regulation allocates a large quantity of free GHG allowances to each utility annually to monetize on behalf of their customers.[2] The utilities are required to offer 100% of their allowances into the auction with other allowance holders,[3] but must purchase from the auction GHG allowances needed to meet their C&T Regulation compliance requirements on behalf of their customers. The auction of California Carbon Credits is instructive because:

- It has been carried out by a California regulatory agency over several years, indicating a critical threshold level of successful implementation and familiarity to many of the key stakeholders in this case that are California power market participants.
- It also involves a situation in which the utilities start with the entire endowment of a specific portfolio of goods with value (California Carbon Credits are analogous to GHG-free/RPS-eligible Energy) and it is necessary and beneficial to make that portfolio available to the broader market through a market-based mechanism where the IOUs may have a significant market presence that is not matched by other market participants.

---

[2] Cal. Code. Regs. tit. 17, §95892(a) (2017).
[3] *Id.* §95892(c).

The auctions have other similarities. CARB holds C&T auctions quarterly,[4] allowing allowance holders and purchasers to determine when best to sell or purchase their allowances.[5] The C&T Regulation provides for a price floor for each auction, escalating over time,[6] and maintains holding limits for each participant.[7] Other markets have arisen outside of the primary auction, as well, including broker-dealer markets.

While it is uncertain what auction-clearing prices for the Auction Resources might be realized in the proposed SPA, CalCCA's analysis indicates that there are significant potential benefits from this type of structured process to reallocate the resources in the utility portfolios. A preliminary sensitivity study suggests that for the 12-year period from 2019-2030:

- We estimate Net Costs[8] of $18.7 billion for PG&E with the illustrative potential to reduce those costs by up to $5 billion or more depending on the auction clearing price.
    - Unit Net Costs[9] of 1.99¢/kWh with the illustrative potential to reduce them by up to 0.50¢/kWh or more depending on auction-clearing prices.
- We estimate Net Costs of $9.4 billion for SCE with the illustrative potential to reduce those costs by up to $5 billion or more depending on the auction clearing price.
    - Unit Net Costs of 0.99¢/kWh with the illustrative potential to reduce them by up to 0.50¢/kWh or more depending on auction-clearing prices.

---

4 *Id.* §95910(a).
5 *Id.* §95910(a). Some limits apply to utility sale of allocated allowances. *See* §95892(c).
6 *Id.* §95911(b).
7 *Id.* §95920.
8 Net Cost is defined here similarly as in previous chapters; the difference between Total Cost and Market Value, where Market Value assumes the current Market Price Benchmark adopted in the 2018 ERRA proceedings.
9 Unit Net Cost is defined as Net Cost divided by Total Service Territory Load (inclusive of all Bundled and Departing Load). This is comparable to the "Indifference Rate" currently used in PCIA proceedings.

We believe the SPA also satisfies the general principles for portfolio optimization proposals articulated at the beginning of this section.

CalCCA recognizes that there are multiple approaches with various advantages and disadvantages to each that should be analyzed and subject to further stakeholder input in either a subsequent phase of this proceeding or subsequent proceeding dedicated to development of specific auction mechanics.

III. CONSISTENCY WITH OVERALL GOAL AND GUIDING PRINCIPLES

SPAs are consistent with the Scoping Memo's guiding principles.

Prevent Cost Shifts. Staggered Portfolio Auctions meet the Commission's overall goal of preventing costs shifts between bundled and departing load customers. Under the current PCIA, the cost responsibility of departing load customers has been rising over the past few years using administrative market price benchmarks. It is impossible to determine when actions taken by the utility have been on behalf of their bundled customers or the portfolio at large. By participating in SPAs, it will be clear that the utility's actions are on behalf of bundled customers only.

Transparent and Verifiable. The SPA provides a transparent mechanism for opportunity to extract greater value for these supplies, mitigate risk of cost shift in either direction, and reduce costs for all customers (both bundled and departing) with improved transparency and certainty. In addition, the SPAs provide for Auction Resources to be reallocated among LSEs that must contribute to their costs in order to satisfy long-term compliance requirements and/or unmet market demand for these products.

Reasonably Predictable Outcomes. The implementation of a structured auction process with a well-defined and Commission-approved format, product coverage and timeline will tend to make processes and outcomes more predictable than the status quo. The utilities and other parties should find it easier to manage under this new approach than under the *ad hoc* approach currently in place.

Preserve all Short, Medium and Long-Term Value. SPAs provide an effective process to optimize IOU portfolio management while allowing CCA/DA providers to meet contract supply needs and reduce overall portfolio costs. A potentially significant share of the Net Costs in the IOUs portfolios that drive departing load cost responsibility would be removed from the IOU portfolios. SPAs provide an on-going process to rationalize the resources held in the portfolios and to reduce the associated Net Costs.

Complement CCAs' Procurement, Goals and Needs. SPAs also provide a transparent and verifiable process for CCAs to identify, bid on, and procure resources needed to supply their customers, maintain control over their own procurement decisions, and receive their fair share of the benefits associated with the overmarket costs they incur.

Flexibility to Maintain Accuracy and Stability. Creating a liquid, long-term market will accurately value the utilities' portfolios. A reasonable market price benchmark derived from actual winning bid prices in the auctions provides a dynamic reflection of prevailing market prices based on closed deals for long-term supplies through an open process with transparent results. In addition, selling long-term products from the portfolios will lead to stable PCIA rates over time.

Unreasonable Obstacles Avoided. SPAs do not create unreasonable obstacles to participation, as they would be designed to allow participation by all interested market participants. SPAs facilitate voluntary CCA access to power supplies and represent a fair trade-off for CCAs — in exchange for continuing responsibility to pay the Net Costs of these resources, CCAs would at least gain access to the products for use in meeting their customers' requirements. This would allow CCAs to plan their own procurement correspondingly.

Consistent with California Energy Policy Goals. Nothing in the SPA changes the State's policy goals or the obligations of all LSEs to meet these goals. It simply creates another market for trading products needed to meet those goals.

Only Legitimately Unavoidable Costs Included. The statute requires that any methodology should only include legitimately unavoidable costs which, in turn, requires the Commission to account for the utilities' responsibility to prudently manage their generation portfolio and take all reasonable steps to minimize above-market costs. By offering excess RPS-eligible and GHG-free supply from utility portfolios as a product that meets CCA or other LSE needs, utility portfolios reduce their excess supplies in a revenue maximizing manner, thus reducing above-market costs for all customers.

Respect the Terms of Existing PPAs. The CalCCA proposal does not propose contract abrogation or even contract assignment, but expressly preserves the terms and conditions of existing PPAs and seeks to implement auctions in which the utilities' existing contractual obligations are taken on by alternative purchasers.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

CHAPTER 5

PCIA "CAPS" AND "SUNSET"

(Common Outline §V)

I. PCIA RATE CAPS

CalCCA members place a high value on predictability and stability in the PCIA rate from year-to-year. One stabilizing tool that can be used and has been utilized by the Commission in the past is a rate cap. A cap provides assurances to both the CCA and its customers that costs outside of the CCA's control – the PCIA rate – will not result in rate shock or otherwise interfere with procurement planning.

The Commission has adopted rate caps both in the context of rate cases and stranded cost responsibility. In SCE's GRC Phase II Rate Case,[1] the Commission adopted a settlement capping rate increases to 3% for distribution revenues and 2% for generation revenues in order to avoid rate shock and to transition more moderately to cost-of-service rates.[2] A fixed rate cap of 2.7¢/kWh on the DA CRS was also adopted by the Commission in response to concerns that the level of CRS imposed on DA risked making DA uneconomic.[3] In both cases, costs above and below the cap were netted in a balancing account to ensure full cost recovery over time.[4]

CalCCA sees the potential value in a rate cap, depending upon the evolution of the PCIA rate but does not propose a cap at this time. It requests, however, that the Commission establish the opportunity for parties to evaluate the need for and to propose a rate cap in each annual Forecast ERRA.

---

[1] A.14-06-014.

[2] D.16-03-030 at 11. The Decision acknowledges that "'Capping'…of allocated revenues to rate groups…promote[s] rate stability while achieving movement towards cost-based rate levels"

[3] D.02-11-022, Ordering Paragraph 19 at 109.

[4] *Id.* at 24-27.

II. SUNSET OF STRANDED PROCUREMENT COST RESPONSIBILITY

Non-utility LSEs share frustration with the continuing presence of stranded procurement costs and the related surcharges. Some ESPs have been dealing with stranded procurement costs – whether the CTC, DWR Power Charge or the PCIA – for two decades. Yet there is no clear end in sight. AB 117 makes clear, for example, that a CCA customer will bear cost responsibility for "net unavoidable costs" of purchase contracts until these contracts expire or are terminated; many of these contracts have terms of up to 25 years or longer.[5] Seemingly every new piece of legislation, most recently SB 350, offers some version of stranded cost responsibility. While the underlying motivation for these provisions is understood – preventing cost shifts – the dynamics surrounding the stranded cost problem must be addressed for stranded costs to fully sunset.

In the near term, it is critical to undertake measures to stop the accumulation of new stranded procurement costs. CalCCA's proposal to improve departing load forecasting, for example, aims in this direction by reducing the risk of excess procurement. More importantly, the Commission must remain aware of the potential for new contracts, contract renewals or investments to exacerbate the stranded cost problem. In evaluating any new resource commitment, the Commission should make three explicit determinations: (1) the expected effect of the commitment on the PCIA rate for all vintages of departing load; (2) whether the utility's forecast of departing load was reasonable at the time the resource commitment was made; and (3) to which vintages of departing load the commitment is attributable.

---

[5] Cal. Pub. Util. Code §366.2.

Additionally, the Commission should make a finding in this case regarding the establishment of a defined sunset date for these stranded costs. Constraints on stranded cost recovery, such as the limitation on CTC recovery pursuant to AB 1890, reflect a legitimate viewpoint that transitions should not be open-ended but should be subject to defined limits around the time, scope and magnitude of above-market cost recovery. A fixed time limit on departing load cost recovery, to the extent permitted by law and consistent with other state policy goals, would provide greater certainty and flexibility to CCAs in building the optimal portfolio to meet their customers' needs.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

CHAPTER 6

FORECASTING COST RESPONSIBILITY FOR FUTURE PERIODS
(Common Outline §VI)

A key objective for CalCCA in this proceeding is the implementation of a reasonable, transparent, and repeatable process for forecasting long-term PCIA rates for use among the various parties. A realistic long-term PCIA rate forecast would be supportive of CCAs' overall business planning, procurement decisionmaking, portfolio risk management, ratesetting and other related operational functions. CalCCA believes there is a workable path for the Commission, building upon the insights gained and work completed in this proceeding, to define a process of maintaining and continually refreshing a long-term forecast of PCIA rates.

Under the CCA proposal, the utilities would leverage the work done in this case to build and maintain a model capable of presenting reasonable projections of PCIA-eligible portfolio cost value metrics. The CCA proposal would:

- Formalize the approach embodied in the "ALJ Data Matrix" to project long-term (10-years or longer) projections of the Generation Volumes (in GWH) and Total Cost (in $) of all resources in their PCIA-Eligible portfolios.
- Require the utilities to provide annual updates of these long-term projections as part of their annual ERRA Forecast filings.
- Provide a section of the model for parties to input forward market price curves of their own choosing, upon which to calculate the Market Value and Net Costs (Total Costs in excess of Market Value).

The availability of this information will allow parties' reviewing representatives to calculate long-term projections of the Indifference Amount and Indifference Rate (differentiated by rate class and vintage). The information should be made available to parties under the Modified NDA developed in this proceeding to cover access and use of this material.

An alternative should be made available for parties who are unable to designate a reviewing representative under the Modified NDA. These parties should be permitted to provide a forward price curve to the utility and have the utility generate the long-term PCIA forecast for their vintage.

CalCCA believes that formalizing this approach, building on work that has been proven workable and highly valuable in this proceeding, provides a reasonable opportunity for all parties to gain the benefit of long-term PCIA forecasting while minimizing the burden on the utilities.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

CHAPTER 7

OTHER ISSUES

(Common Outline §VII)

I. PERMIT CCA AND DA CUSTOMERS TO PREPAY ALL OR A PORTION OF THEIR FUTURE PCIA OBLIGATIONS TO FURTHER THE GOALS OF STABILITY AND PREDICTABILITY

The current PCIA is volatile, difficult to forecast and not calculated in a transparent manner; monitoring the PCIA requires ongoing regulatory intervention. The Commission could address these challenges and bring certainty and predictability to CCA and DA customers by permitting CCA and DA providers to prepay all or a portion of their customers' stranded cost obligation. Prepayment would entail an LSE paying the net present value of its future net obligations to the utility based on the LSE's load and vintage. It would protect both CCAs and utilities from ongoing uncertainty regarding the amount and timing of stranded-asset cost obligations. LSEs considering formation could accurately assess and potentially finance their customer's future obligations to the incumbent utility.

A viable prepayment option requires a clear methodology that can be overseen and audited by the Commission to ensure indifference and transparency. To reduce burden on all customers, however, any reductions in outstanding liabilities should first be pursued. To that end, prepayment should occur only after the Commission and utilities act to reduce outstanding stranded asset costs and/or sell the underlying attributes at maximum value. After reasonable efforts have been made to reduce portfolio costs, the net present value of any future net costs in the CCA's vintage would be used to calculate the prepayment amount.

A. Prepayment Has Been Used in Other Similar Settings

Prepayment of departing load obligations have been successfully used in California in similar circumstances. This approach has also been used outside of the State in support of retail competition. These examples – highlighted below – with the proposed Staggered Portfolio Auction determining the prepayment amount, provide potential frameworks to facilitate prepayment transactions.

1. California Publicly Owned Utilities Have Prepaid Departing Load Obligations

In 2007, Commission Resolution E-3999[1] directed the IOUs to offer bilateral agreements to publicly owned utilities (with departing load customers) as an alternative to the Municipal Departing Load tariff. The Commission rejected the utilities' proposal to collect the full, undiscounted expected value of the CRS and other NBCs, plus an additional 2%, as unfair and inconsistent with Commission precedent. Instead, PG&E and SCE were directed to calculate a lump-sum payment based on the net present value of all future CRS and other NBCs.[2]

Following this Resolution, PG&E and SCE entered into bilateral agreements with eight POUs: Power and Water Resource Pooling Authority, Merced Irrigation District, Modesto Irrigation District, Turlock Irrigation District, and the Cities of Azusa, Rancho Cucamonga, Moreno Valley, and Victorville. Only three of the eight POU agreements have publicly available costs. Those costs a range from a low of $1.5 million under Modesto Irrigation District's agreement to a high of $6.9 million under the Turlock Irrigation District's agreement in 2016. These LSEs each have over 100,000 customer accounts, and a load of 2,503 GWh and 2,000 GWh, respectively.[3] In 2009, D.09-08-

---

[1] Resolution E-3999, available online at: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_RESOLUTION/62648.PDF.

[2] The calculation of a net present value requires use of a discount rate. In this proceeding, the Commission used the IOUs' weighted cost of capital. Use of other discount rates may be appropriate depending upon the type of obligation being paid off. For example, IOUs do not make any profits or return from the purchased power contracts, thus use of the weighted cost of capital may not be the appropriate metric. The ability to securitize these obligations would also affect the appropriate discount rate.

[3] Source, 2016 EIA data. Available at: https://www.eia.gov/electricity/data.php#sales.

015[4] expressly concluded that the PG&E/PWRPA agreement fully satisfied the departing load obligations of PWRPA's customers, and that PG&E had 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 nonbypassable charge obligations through payments of amounts that may differ from tariffed charges.

2. Commercial Customers Have Prepaid Bundled Service Obligations When Departing Utility Service

Like California, Nevada has an RPS requirement (25% by 2025), additional renewable procurement required by legislation, and requires Commission approval for new generation. Recognizing these obligations, MGM resorts in Nevada left bundled service from Nevada Power Company in 2015 for a lump-sum payment of $87 million and Switch, a data center company, departed utility service on payment of a $27 million exit fee.

MGM represented 4.86% of Nevada Power Company's annual sales with 59 accounts at 19 different locations. In the buyout, the PUCN directed Nevada Power Company to perform production cost simulations to show the total costs with, and without, MGM. The Nevada Commission directed Nevada Power Company 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 PUCN directed NPC to include O&M savings resulting from

---

[4] D.09-08-015, available at: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/105902.PDF.

reduced operation due to MGM's departure. The net present value of all costs and savings were calculated based on NPC's weighted average cost of capital.[5]

Switch was initially denied the ability to exit by the Public Utilities Commission of Nevada on the grounds that it violated the principle of indifference by failing to allocate a share of legislated energy policies into the exit-fee calculation. The PUCN later reconsidered this decision, and unanimously voted to grant Switch permission to depart service after paying a $27 million exit fee.[6]

There are other examples of a departing corporate customer and the incumbent utility agreeing to lump-sum buyout terms. In 2016, Puget Sound Energy and Microsoft jointly filed an Advice Letter with the Washington Utilities and Transportation Commission recommending adoption of a tariff which would grant Microsoft the ability to procure its own generation and only take transmission and distribution service from Puget Sound Energy.[7] In that case, the two entities agreed upon an exit-fee of $23.9 million.

B. The Prepayment Calculation Could Rely on Values from the Staggered Portfolio Auction or as a Result of Bilateral Negotiation Subject to Commission Approval

After using a Reverse Auction for voluntary offers by sellers, securitization of a portion of the IOU portfolio, and performing a Staggered Portfolio Auction to reallocate resources and create a benchmark, prepayment could be used to address remaining resources and corresponding stranded-cost liabilities. A prepayment option preserves

---

[5] *See* Public Utility Commission of Nevada docket 15-05017 for MGM Application, testimony, and Staff response.

[6] *See* Public Utility Commission of Nevada docket 16-09023 for documents related to the Switch Application.

[7] *See* Washington Utilities and Transportation Commission docket UE-161123 for the Settlement Agreement and Order approving the Settlement.

indifference and provides a path for LSEs to reduce volatility and protect their customers from rate shock.

To calculate a prepayment value, two inputs must be determined: 1) the NPV of the future stream of costs for resources within the customer's vintage and, 2) the current market value of these resources. To calculate the NPV of future costs, the total amount of remaining obligations over the life of existing contracts should be aggregated by year and discounted at an appropriate rate. This will provide the total obligation – in today's dollars – on a per-customer basis.

The Staggered Portfolio Auction[8] could provide valuable information to determine the current market value; for the full host of attributes contained in various categories of resources with varying terms. Bundled ratepayers and other departing load customers sharing portfolio obligations would be protected from an unreasonably low prepayment price through the use of a floor price in the SPA. Alternatively, direct bilateral negotiation, subject to Commission approval, as the utilities did for the eight POUs mentioned above, could identify the fair value of the remaining obligations. Once a fair value has been established, LSEs would have the option to prepay all or a portion of their vintaged obligation for various resource types using resource categories that match those used in the auction.

The Commission recently recognized prepayments as a method to preserve indifference in the context of Resource Adequacy. Resolution E-4907, which stipulated terms for a transfer of RA from a utility to an LSE found that one of two conditions was necessary to preserve indifference: 1) a bilateral agreement between the utility and

---

[8] As proposed in Chapter 4.

CCA, or 2) a Commission-calculated weighted average capacity cost which the CCA would have to pay. The Commission reasoned that that neither LSE would enter into an agreement that would harm its customers under the first scenario, and that the Commission could calculate the weighted average capacity cost of RA under the second.

C. Prepayment Would Not Shift Costs Among Bundled and Departing Load Customers

The Commission has an obligation to ensure that prepayment, like the calculation of the PCIA, does not shift costs among bundled and unbundled customers. There are two potential types of cost shift: 1) from the prepaying customers to bundled customers, *and* 2) from a prepaying customer to other departing load customers. The availability of actual, contemporaneous sales prices for similar products for a similar term could help calculate the prepayment amount and substantially reduce the risk of cost shifts. The prepayment terms should mirror the payment obligations for PPAs and UOG resources included in the portfolio of resources for which the prepayment is being applied.

Some may argue that prepayment is inherently at odds with the concept of indifference and would place all other customers – bundled and departing load – at risk. Yet every forecast that is made, whether in procurement or ratemaking, risks being too high or too low. A retroactive look at any commercial transaction several years after it has taken place – with access to information not available at the time of transaction – may lead one party to make a different choice if they could travel back in time. But as market participants inherently understand, all transactions are made based on the best available information at the time, not what parties have learned since. Every time an

IOU enters into a long-term contract, its ratepayers are subject to the risk that the IOU may have made a commitment that might turn out to be ill-advised. In every long-term contract the IOU might also realize an unforeseen windfall benefit as it avoids future market spikes.

II. REQUIRE IDENTIFICATION OF THE PCIA RATE AS A SEPARATE LINE ITEM ON ALL CUSTOMER BILLS TO PROMOTE FAIR COMPETITION AND REDUCE THE COMPLEXITY OF CUSTOMER CHOICE

The PCIA rate reflects the uneconomic costs of utility procurement and is charged to bundled, CCA and DA customers. Even though all customers, including the utility's bundled customers, pay for the uneconomic costs reflected in the PCIA, the charge is not separately identified on the Energy Statements provided to bundled customers. In contrast, the PCIA rate is separately identified on the Energy Statement provided by PG&E to CCA or DA customers, allowing a distinction between the CCA or DA supplier's costs and the customer's share of the utility's uneconomic costs.

The current utility bill presentation masks the fact that all customers are shouldering the burden of the utility's uneconomic costs. Today, a customer who performed a side-by-side comparison of billing formats would observe that the CCA bill includes a rate that is not present on the bundled service bill. Without explanation, customers might erroneously conclude that CCA customers are required to pay additional costs not included in bundled service.

The Commission should direct the utilities to modify this practice, requiring separate identification, using the same terminology, of the component of all customers' rates that recovers uneconomic costs. Applying the charge similarly on all bills prevents this charge from becoming a competitive issue when comparing alternatives and makes clear that all customers – bundled, CCA and DA customers – are sharing this cost responsibility. Operationally, this will also reduce confusion in a scenario in which customers can move back and forth between bundled and un-bundled service.

Recognizing that the uneconomic cost portion of the rate is not an "indifference adjustment" when applied to a bundled customer, the PCIA rate and the bundled customer analog should be labeled more descriptively. We recommend labeling the charge the "Electricity Provider Transition Charge."

III. ADOPT GUIDING PRINCIPLES FOR ALLOCATION OF COSTS RELATED TO THE UTILITIES' REGULATORY ACTIVITIES TO AVOID CROSS SUBSIDIES

Sections 365.2 and 366.3 require the Commission to "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." These statutory provisions are not limited to only the direct costs incurred in power procurement, but also to other costs required to support the generation function.

With respect to cost-allocation issues, it is important to recall two complementary legislative declarations. First, the Legislature has declared that the IOUs have "inherent market power" derived from the "potential to cross-subsidize competitive generation services," and therefore the Legislature directed the Commission to establish rules to "protect against cross-subsidization by ratepayers."[9] Second, as stated by the Commission, "[t]he state Legislature has expressed the state's policy to permit *and*

[9] *See, e.g.,* SB 790 (2011); § 2(c) ("Electrical corporations have inherent market power derived from, among other things, *** the potential to cross-subsidize competitive generation services.") *See also* SB 790; § 2(h) ("It is therefore necessary to establish a code of conduct, associated rules, and enforcement procedures, applicable to electrical corporations in order to *** foster fair competition, and to protect against cross-subsidization by ratepayers.").

promote CCAs by enacting AB 117…."[10] Read together, these legislative declarations support the Commission's robust examination of all costs attributable to the IOUs' generation services – "not incurred on behalf of departing load" – that are currently being allocated to CCA customers. This examination should cover all relevant portions of the utilities' accounts and records, including how the utilities recover regulatory advocacy costs that are aimed at or support their generation services. As the Commission has previously stated in the context of another competitive service initiative, the Commissions should "not permit allocations of generation cost to distribution customers. To do so would compromise market efficiency by producing artificially low utility generation rates […] and provide competitive advantages, which would stifle competition to the utilities."[11] Moreover, permitting allocations of generation cost to distribution customers would violate SB 350. In the context of this proceeding, CalCCA is *not* proposing a new or elaborate cost-allocation scheme. Rather, as part of the final order in Track 2, CalCCA asks that the Commission establish certain guiding principles that can be used in cost-recovery proceedings to ensure that generation-related costs are not being allocated through distribution rates.

As noted above, an area that may require closer scrutiny is the allocation of regulatory-related costs to the distribution function, particularly when the principal focus of such activity is on costs the utilities incur to support their procurement services or procurement competition-related matters. Prime examples are the significant regulatory cost associated with the utilities' failed effort to implement the Portfolio Allocation

---

[10] D.04-12-046 at 3 (emphasis added). *See also* D.10-05-050 at 13 (emphasis added) ("Certainly, Section 336.2(c)(9) evidences a substantial governmental interest in *encouraging the development* of CCA programs and allowing customer choice to participate in them.").

[11] D.97-08-56 at 8.

Methodology proposal,[12] and with SCE's current effort to modify the CCA Code of Conduct.[13] The PAM initiative, led by SCE, is an example of a major regulatory effort that had as its primary purpose the reallocation of generation-related costs, clearly something that principally benefits utility generation services, and should be allocated more heavily to the generation function. The CCA Code of Conduct initiative implicates key procurement competition-related issues and should likewise be allocated more heavily to the generation function. In both of these examples, as proposed, SCE distribution customers will be expected to bear approximately 84% of the costs.

In light of this, CalCCA recommends that the following guiding principles be adopted by the Commission in this proceeding:

- SB 350 and SB 790 require that greater scrutiny be given to the allocation of regulatory-related costs by the utilities to the generation and distribution functions in order to avoid cross-subsidization and an allocation of costs that were not incurred on behalf of the departing load.
- A cost is not incurred on behalf of the departing load if it supports the utilities' generation services or is related to an activity that benefits their generation services for their bundled customers.
- The utilities' bundled customers may be benefitted by various activities and initiatives, including transportation electrification or time-of-use rates that allow for better utilization of the utilities' generation services used to serve bundled load.
- In regulatory proceedings in which cost-recovery is an issue, the utilities will bear the burden of showing that their respective cost-allocation methodology is reasonable and otherwise does not result in cross-subsidization.

Adoption of these principles will provide a framework for future review and allocation of regulatory costs incurred by the utilities.

---

12 A.17-04-018.

13 Petition for Modification of Decision 12-12-036 of Pacific Gas and Electric Company (U 39-E), San Diego Gas & Electric Company (U 902-E) and Southern California Edison Company (U 338-E), filed January 30, 2018, in R.12-02-009.

IV. REEXAMINE THE UTILITY'S PROVIDER OF LAST RESORT OBLIGATION TO FURTHER A LONG-TERM DURABLE SOLUTION TO REDUCE STRANDED COSTS

Once a CCA launches in a given territory, the CCA becomes the default energy supplier for the customers within that territory, while the IOU supplies energy to customers who affirmatively opt out of CCA service.[14] CCAs have an obligation to offer service to all residential customers in their community but cannot impose departing load charges on bundled customers for long-term resources that the CCAs have acquired to meet many of the same obligations as the incumbent utility including providing system reliability (Resource Adequacy), meeting environmental goals (RPS requirements) and other activities that benefit bundled customers or the State more broadly. Eight years after the implementation of the first CCA, CCAs have proved to be reliable service providers.[15] Despite performance consistent with these obligations, AB 117 requires that the IOU remain the Provider of Last Resort for energy supply in case of suspension or revocation of the registration of a CCA.[16]

Ultimately, in order to prevent another build-up of IOU above-market resources, the Commission, and potentially the Legislature, will have to address how the respective POLR responsibilities of the IOUs function in harmony with CCA service. To date, the utilities' POLR obligation coupled with the existing PCIA mechanism create the potential

---

[14] Pub. Util. Code 366.2.

[15] However small, there is a non-zero risk of an unplanned, mass return of CCA customers to the utility. To address this, the Commission requires CCAs to post a bond which is intended to cover the administrative costs of the IOU facilitating a rapid increase in customer base in this scenario.

[16] Pub. Util. Code §394.25(c) ("Any suspension or revocation of a registration shall require the electric service provider to cease serving customers within the boundaries of investor-owned electric corporations, and the affected customers shall be served by the electrical corporation until the time when they may select service from another service provider.").

for excess overpriced IOU procurement without adequate accountability for the resulting increased costs to both CCA and bundled customers. CCAs, meanwhile, are simultaneously seeking to procure longer-term supply in a market that is artificially constrained if the IOUs do not fairly offer oversupply for sale to the market. As a result, CCAs see increased costs and the potential for duplicative procurement.

In their May 2017 White Paper on consumer choice, Commission Staff observed:

> Currently, POUs and IOUs are the provider of last resort in their respective service territories. With changes coming to California's retail energy market, the CPUC must consider the implications of the changes for customers and evaluate whether a new 'provider of last resort' (POLR) requirement should be put in place.[17]

While the Commission has declined to broach this subject in this proceeding and has not yet issued a consumer choice rulemaking, the POLR issue materially affects IOU procurement. Moreover, it has a more long-lasting effect to the extent CCAs or ESPs fill their portfolio with long-term commitments, leaving the IOUs no long-term market to sell off their excess procurement. CalCCA encourages the Commission to review this issue in the anticipated Customer Choice rulemaking.

---

[17] Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework, Staff White Paper, May 2017, available at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/Retail%20Choice%20White%20Paper%205%208%2017.pdf.

CALIFORNIA COMMUNITY CHOICE ASSOCIATION

QUALIFICATIONS

ALDYN W. HOEKSTRA

545 Savoy Street
San Diego, CA 92106
AHoekstra@hanoverstrategyadvisors.com
(619) 847-6791

Business Strategy • Financial Planning • Commodities

Senior executive and expert advisor focused on strategy formulation, financial planning, business development and commercial execution in North American electric power and fuels markets. Demonstrated ability to identify business trends and market opportunities, formulate strategic options and implementation plans, and manage operations and initiatives for growth and profitability. Commodity business leader with proven P&L success in utility, wholesale and retail energy markets. Deep experience in financial planning, forecasting, regulatory affairs, valuation of physical and financial assets and portfolios, and portfolio risk management and hedging. Known for innovation, openness, agility, customer focus and driving results.

- Strategy Development
- Competitive Assessment
- Innovation Leadership
- Product Development
- Regulatory Policy
- Financial Objectives
- Market Forecasting
- Asset Valuation
- Project Finance
- Enterprise Valuation
- Risk Management
- Marketing and Trading
- Deal Structuring & Pricing
- Portfolio Valuation
- Processes and Systems

PROFESSIONAL EXPERIENCE

HANOVER STRATEGY ADVISORS • San Diego, CA **October 2014 – Present**
Founding Partner
Hanover Strategy Advisors is a trusted advisor to utilities, generators, marketers, large users and financial institutions on energy strategy, financial, market and regulatory issues. We serve clients in the areas of Business Strategy, Commercial Advisory, Commodity Risk Management and Market Assessment. Our clients are energy infrastructure investors and lenders, utilities and generators, marketing and trading organizations, commercial and industrial energy consumers, and public power, water and community choice aggregation agencies throughout the US. Specific client engagements have included serving as a strategy and commercial advisor in the areas of power sales and portfolio risk management, fuel procurement, ISO/RTO operations, commercial contracting, asset valuation, hedging and forecasting. Provided strategy assistance, market assessment, strategic positioning and product structuring for renewable energy, distributed energy and technology integration initiatives. Example clients include: Diamond Generating, Oregon Clean Energy, Buckeye Power, Transatlantic Power Holdings, San Diego County Water Authority, Sonoma Clean Power, Ellison, Schneider & Harris, Siemens/Pace Global and AES North America Development.

THE AES CORPORATION/DPL INC. • Dayton, OH **2010 – 2014**
Vice President, Merchant Portfolio Strategy (July 2012 to May 2014)
Leader of wholesale merchant business activity with responsibility for the Company's generation asset, power marketing and trading strategies and the successful capture of approximately $135 million in commodity margins.

- Led the creation and implementation of an enhanced Portfolio Management function responsible for asset optimization, hedging and trading activities for all Company merchant generation assets and load-serving portfolios. Established and managed an expanded commercial front office organization responsible for the portfolio management, structuring, pricing and analytics functions for all market-facing AES assets throughout the US.
- Conceptualized and executed commodity portfolio risk management strategies to achieve targeted earnings and cash flow performance by defining risk tolerances, processes, controls and risk-adjusted performance metrics to manage and enhance portfolio performance.

Director, DP&L Origination and Structuring (May 2010 to July 2012)
Managed the wholesale origination, deal structuring and pricing functions for The Dayton Power and Light Company's 3,500 MW generation asset and load-serving portfolio, and the successful capture of approximately $185 million in commodity margins.

- Managed strategy development, marketing, product development, financial assessment and negotiation of wholesale, retail and renewable commodity transactions.
- Oversaw all pricing, portfolio analytics and market assessment for wholesale, retail and intercompany commodity transactions and hedging activities.

PACE GLOBAL ENERGY SERVICES • San Diego, CA **2005 – 2009**
Vice President, Utility and Risk Strategies
Provided consulting services encompassing market assessment, investment advisory, risk management and resource planning to utilities, energy merchants, banks and end-users.

- Managed IRP engagements for California municipal utilities that balanced multiple competing objectives (cost, reliability, risk and greenhouse gas reductions). Led a stakeholder participation process creating community support for the recommended strategy.
- Managed a multi-year engagement with a state water agency to implement a comprehensive electric power and natural gas risk management and dynamic hedging program.

SEMPRA ENERGY • San Diego, CA **2000 – 2004**
Vice President, Strategy & Risk Management (2004)
Vice President, Strategy & Development (2002-2003)
Director, Strategic Planning (2000-2001)

Managed strategy, risk management, development, finance and regulatory functions for a national retail energy marketing business. Drove business success through leadership of insightful strategic planning, tight risk and process controls, and diligent oversight of sales and operations activities to ensure consistency with business strategy, risk tolerance and financial targets.

- Implemented risk-adjusted performance metrics to drive customer targeting, product development and pricing decisions, generating industry-best profit margins and risk profiles.
- Managed development of long-term, unit-contingent wholesale and retail power sales agreements, producing $40 million in margin from a generation asset acquisition in Texas.

- Led customer targeting, deal structuring and negotiations for the closing of retail power sales contracts worth $120 million in gross margin with former Enron customers post-bankruptcy.
- Developed and implemented a retail power sales campaign to capture a fleeting opportunity during the 2001 California power crisis, generating in $60 million in gross margin.
- Managed the integration of 4 business units with 500 employees into a leading US integrated energy services provider. Created comprehensive sales, structuring, portfolio management, operations and back-office capabilities, processes and technologies.

ICF CONSULTING • San Rafael, CA **1999 – 2000**
Vice President/Principal
Founding member of a new practice created to provide strategy consulting to private sector energy clients. Developed and managed a $5 million engagement for a power and gas industry leader, which implemented our recommendations to pursue a transforming business unit reorganization based on a revolutionary integrated strategy and business model for energy marketing. Was hired by client Sempra Energy upon successful completion of the engagement.

CAMBRIDGE ENERGY RESEARCH ASSOCIATES • Oakland, CA **1994 – 1998**
Associate Director
Directed research and consulting for CERA's California Energy retainer advisory service in its West Coast office, providing strategic analysis of Western electric power and natural gas market fundamentals, regulatory initiatives, economic drivers and governmental policy. Served as trusted advisor to a global client base on implications of California energy market developments.

BARAKAT & CHAMBERLIN • Oakland, CA **1991 – 1994**
Senior Associate
Provided economic, financial and regulatory analysis in support of market planning, project financing, business litigation and asset valuation projects. Completed dozens of generation asset valuations and power/fuel contract assessments for M&A and project financing due diligence efforts, as well as property tax, eminent domain, bankruptcy and regulatory proceedings.

MRW & ASSOCIATES • Oakland, CA **1988 – 1991**
Associate
Provided economic and financial analysis of electric power and natural gas markets, capital projects and regulatory matters. Specialized in market assessments, resource planning, avoided cost pricing, competitive bidding, project financings, mergers & acquisitions and litigation support.

EDUCATION

STANFORD UNIVERSITY • Stanford, CA
Master of Science, Engineering-Economic Systems

PURDUE UNIVERSITY • West Lafayette, IN
Bachelor of Science, Industrial Engineering

ROBERT KINOSIAN

EDUCATION

1983	Bachelor of Science degree in mechanical engineering from the University of California Berkeley, graduating with honors.

WORK HISTORY

1984 -2001	Analyst, California Public Utilities Commission's Division of Ratepayer Advocates. Addressed issues including: ratemaking and decommissioning of nuclear facilities; cost and operation of other utility resources (coal, hydroelectric and natural gas); conservation and load management programs; rate design; cost of capital; contracting for renewable generation; resource planning; and issuance of rate reduction bonds. In addition, represented the Commission in proceedings before the California Energy Commission and State legislature.
2001-2003	Advisor to Commission President. Reviewed/modified proposed energy decisions, working with other Commissioner's offices, administrative law judges and staff. Represented the Commission on legislative issues regarding the California energy crisis, the Governor's task force renegotiating Department of Water Resources energy contracts, and the PG&E bankruptcy proceedings.
2004-2007	Division of Ratepayer Advocate Senior Management - Policy Advisor. Provided assistance to the Division Director. Led lobbying efforts with the Commission, State legislature and outside parties. Reviewed division testimony to provide quality control and consistency. Trained division staff on testimony preparation and lobbying.
2007-2010	Advisor to Commissioner John Bohn. Reviewed/modified proposed energy decisions, working with other Commissioner's offices, administrative law judges and staff.
2010	Analyst, Safety and Enforcement Division. Reviewed the San Bruno pipeline explosion and PG&E gas system practices, and addressed utility proposal to modify CPUC treatment of fire related costs.
2011-2014	Analyst, Division of Strategic Planning. Prepared reports on potential improvements to the Commission's residential solar programs and new customer billing techniques.
2015-2018	Consultant to Community Choice Aggregators and municipal agencies regarding CPUC proceedings and processes.

TERESA F. MARRINAN
4818 Corwin Rd.
Waynesville, OH 45068
TMarrinan@hanoverstrategyadvisors.com
(937) 901-4890

Strategic Planning - Portfolio Management - Energy Risk Management

Senior commercial executive experienced in building and leading wholesale and retail electricity businesses in both restructured and traditional markets. Champion of strategic business initiatives that create sustainable value and growth. Proven leader of successful teams able to quickly grow capabilities in retail electricity sales, wholesale trading, fuel procurement, hedging, RTO operations, analytics and risk management. Demonstrated ability to identify and execute strategies to capture the option value of assets. Analyzed and executed business startups, purchases and sales. Officer of DP&L and DPL Inc., 2007 to 2014. Excellent communication skills and Board-level interactions in multiple contexts. Chair of two non-profit Boards. Member of two health insurance Boards and Goodwill Easter Seals Miami Valley Board.

- Strategic Leadership
- Industry Thought Leader
- Agent for Change
- Team Builder
- Superior Communicator
- Board Member/Influencer
- Portfolio Management
- Marketing and Trading
- Deal Structuring and Pricing
- ISO/RTO Affairs
- California CCA
- Renewables and Storage
- Risk Management
- Fuel Procurement
- Generation Operations
- NERC Compliance
- RTO Integration
- Allowances/Capacity/FTR

PROFESSIONAL EXPERIENCE

HANOVER STRATEGY ADVISORS • Dayton, OH **October 2014 – Present**
Founding Partner

Hanover Strategy Advisors is a trusted advisor to utilities, generators, marketers, large users and financial institutions on energy strategy, financial, market and regulatory issues. We serve clients in the areas of Business Strategy, Commercial Advisory, Commodity Risk Management and Market Assessment. Our clients are energy infrastructure investors and lenders, utilities and generators, marketing and trading organizations, commercial and industrial energy consumers, and public power, water and community choice aggregation agencies throughout the US. Specific client engagements have included serving as a strategy and commercial advisor in the areas of power sales and portfolio risk management, fuel procurement, ISO/RTO operations, commercial contracting, asset valuation, hedging and forecasting. Provided strategy assistance for a community college and a venture capital fund. Example clients include: Diamond Generating, Oregon Clean Energy, Buckeye Power, Transatlantic Power Holdings, San Diego County Water Authority, Sonoma Clean Power, Ellison, Schneider & Harris, Sinclair Community College and The Dayton Development Coalition.

THE UNIVERSITY OF DAYTON • Dayton, OH **August 2014 – Present**
Instructor, Department of Economics and Finance
Level 400 Finance course in energy commodity trading.

THE AES CORPORATION • Dayton, OH **2012 – 2014**
Senior Vice President, US SBU Commercial
Managed the commercial functions for all AES assets in the US as well as its retail power marketing businesses in Ohio and IL. This included coal, gas, wind, solar and battery storage assets totaling 13,000 MW. In addition, the two retail businesses consisted of more than 300,000 customers, 2,500 MW of load and $500 million in annual revenue. The annual commercial activity in the entire US portfolio totals roughly $3 billion. Responsible for the 7x24 generation dispatch function; ISO scheduling; fuel procurement and fuel transportation; commodity scheduling; wholesale and retail position reporting and position management; wholesale trading and asset optimization; structured transactions and origination and PJM relationship management.

- Led the first effort to capture and communicate the commercial value of the individual generators and commercial transactions for AES US into a single consolidated portfolio
- Retail and Wholesale margin booked of roughly $210M
- Pricing for AES participation in CAISO Long-Term Procurement Process
- Decision analysis to close ERCOT petcoke-fired plant
- Integration of Tait Battery Storage into PJM ancillary services market
- Built and managed a high performing team of 130 retail and wholesale professionals
- Ohio retail business won the 2013 JD Power customer service award for the state of Ohio
- Grew the retail businesses from roughly 30,000 to more than 300,000 customers through aggressive marketing, strategic participation in the IL aggregation process and expansion of direct sales force
- Led organizational and system changes to support rapid growth in competitive businesses
- Led AES evaluation of options for regulatory rate recovery filings considering implications for margins and risks from load auctions, fixed cost recovery and value of POLR load including assumptions around expected switching levels
- Managed Generation and Commercial reorganization planning for AES US SBU
- Oversaw valuation for proposed DPL generation asset sale in 2014

THE DAYTON POWER AND LIGHT CO. • Dayton, OH
Senior Vice President, Business Planning & Development (September 2010 – December 2011)
Corporate development executive for the purchase of the Company's Illinois retail affiliate MC2, and the sale of DPL to AES for $4.7 billion. Responsible for strategy development and asset valuation, as well as portfolio valuation and position/risk reporting for regulated delivery, generation, wholesale and retail business lines. Responsible for wholesale origination and complex deal structuring.

- Managed corporate development activities
- Sale of DPL to AES in the money by $2.5 billion relative to current market valuations
- Purchase of MC2 made at price equal to its booked transaction value
- MC2 became the engine driving10x growth in the retail customer base over two years
- Led DPL Inc. strategy development and communication to BOD

- Responsible for scenario and risk analysis that demonstrated compelling logic to sell DPL
- Built a full-service pricing desk for pricing and structuring all retail, wholesale and intercompany commodity transactions
- $110M in retail and wholesale margin booked
- Managed DPL generation and commercial integration into AES

Vice President, Commercial Operations (August 2007-August 2010)
Responsible for generation operations, fuel procurement, ISO relations and energy trading. Managed fuel procurement during a period of volatile rapidly increasing commodity prices.

- Recognized and acted on changing market and regulatory dynamics to counteract competitive threats from retail switching by alerting and influencing executive management and Board of Directors on key strategic threats and responses
- Led the transition from a tariff sale-based generation utility to a retail and wholesale portfolio-based, deregulated generator
- Drove the early-mover decision in the DPL territory to market and sign above-market, long-term agreements with retail customers
- Led the expansion of DPL retail marketing outside of the native load service territory
- Launched and managed the Company's first fuel trading activity
- Influenced plant operators to expand fuel quality specifications and significantly increase fuel flexibility
- Exercised optionality around fuel quality, inventory size and commodity substitution to book trading gains of more than $100 million in 2008 and $25 million in 2009
- Successfully led negotiations with a fuel supplier to reduce exposure from contested contract from $90 million to $3 million
- Led the development of a small solar facility to meet Ohio renewable requirements
- Led the selection and implementation of commodity portfolio optimization system

Additional Experience

THE DAYTON POWER AND LIGHT CO. • Dayton, OH
Managing Director, Head Trader, Risk Manager, Trader, Rate Analyst
Held a variety of positions of continually increasing responsibility within DP&L. Responsible for a variety of trading, origination and risk control functions.

- Led a joint venture with a large Houston trading house that co-managed the DPL unregulated generation fleet
- Managed valuation of option buy-in price and negotiations with JV trading partner
- Captured gross margins of up to $90 million per year from active management of unregulated generation portfolio
- Led the integration of DPL generation into the PJM independent system operator
- Founding member of Risk Management Committee and author of DPL's first risk policy
- Negotiated the purchase of option contracts in late 1990's prior to Midwest capacity shortages that netted over $100 million in trading value
- Provided expert witness testimony in various regulatory proceedings
- Served as the Company's lead expert on load research

EDUCATION

XAVIER UNIVERSITY • Cincinnati, OH
Master of Business Administration

THE UNIVERSITY OF DAYTON • Dayton, OH
Bachelor of Science, Business Administration

BOARD MEMBERSHIPS and PROFESSIONAL AFFILIATIONS

THE FOODBANK • Dayton, OH
Past Board Chair, previous Treasurer – Board member since 2011
Significant accomplishments include construction of a new facility to house the Foodbank operations in 2013 and the formation of an endowment of more than $1M.

GOODWILL EASTER SEALS • Dayton, OH
Trustee since 2015

PREMIER HEALTH PLAN • Dayton, OH
PREMIER HEALTH INSURANCE CORPORATION • Dayton, OH
Board Member since 2014

WOMEN IN ENERGY • Dayton, OH
Member 2011 to 2014 – Industry group of female utility company officers

THE COX ARBORETUM FOUNDATION • Dayton, OH
2008 to 2013 – Board President, Past President, Finance Committee and Board Member

M.CUBED
POLICY ANALYSIS FOR THE PUBLIC AND PRIVATE SECTORS

DR. RICHARD MCCANN
PARTNER
426 12th Street
Davis, California 95616
530.757.6363
McCann@MCubed-Econ.Com

Professional Experience

M.Cubed, Partner, 1993-2008, 2014-present
Aspen Environmental Group, Senior Associate, 2008-2013
Foster Associates/Spectrum Economics/QED Research, Senior Economist, 1986-1992
Dames & Moore, Economist, 1985-1986

Academic Background

PhD, Agricultural and Resource Economics, University of California, Berkeley, 1998
MS, Agricultural and Resource Economics, University of California, Berkeley, 1990
MPP, Institute of Public Policy Studies, University of Michigan, 1986
BS, Political Economy of Natural Resources, University of California, Berkeley, 1981

Dr. McCann has analyzed many different aspects of energy utility and market operations in California. He has testified numerous times before the CPUC on impacts of electricity rates on agricultural groundwater pumping, reimbursement to master-metered manufactured housing community customers for utility services, competitive fuel choices, and proposed drought-mitigation policies. He has testified on the appropriate level of exit fees for community choice aggregators, and appropriate protection of solar project investment by customers. He also testified before the Federal Energy Regulatory Commission in the California energy crisis Refund Proceeding. He has worked with the California Energy Commission to estimate the costs for new alternative generating technologies and developing several system modeling tools for local capacity planning and renewable generation integration. For the CEC, he examined the potential consequences of decommissioning the dams on the Klamath River, and for the SWRCB, the changes in greenhouse gas emissions from hydro licensing conditions. He also led the modeling efforts on behalf of the California Public Utilities Commission to assess the environmental impacts of proposed generation plant divestitures.

Projects

Energy, Hydropower and Utilities

Regulatory Analysis and Support, Sonoma Clean Power (2016-present). Testifying at the California Public Utilities Commission (CPUC) in Pacific Gas and Electric's (PG&E) rate proceedings on the power charge indifference adjustment (PCIA) "exit" fee and other issues.

Regulatory Analysis and Support, CalChoice (2017). Testifying at the California Public Utilities Commission (CPUC) in Southern California Edison's (SCE) rate proceedings on the power charge indifference adjustment (PCIA) "exit" fee and other issues.

Agricultural Rate Setting Testimony, Agricultural Energy Consumers Association (1992-present). Testified about agricultural economic issues related to energy use, linkage to California water management policy, and utility rates in numerous proceedings at the California Public Utilities Commission, California Energy Commission, and California State Legislature. Analyzed various aspects of electric industry restructuring; proposed innovative pricing options; examined marginal cost principles and applications, and testified in a large number of energy related hearings. Developed innovative rate allocation methodology that incorporated regional marginal costs and value of service planning based on the Pacific Gas and Electric Co. Area Cost Study.

Testimony on Protecting Solar Project Investment by Customers, County of Santa Clara (2017-present). Testified before the California Public Utilities Commission on

Master-Meter Rate Setting Testimony, Western Manufactured Housing Communities Association (1998-present). Examined issues associated with the structure of and cost associated with providing electric service to master-metered mobile home parks. Testified in Pacific Gas and Electric Co., Southern California Edison Co., Southern California Gas Co. and San Diego Gas and Electric Co. rate proceedings on establishing “master-meter/submeter credits” provided to private mobile home park utility systems.

Master-Metered Utility Systems Transfer Program, Western Manufactured Housing Communities Association (2003-present). Prepared petition that opened a rulemaking to facilitate transfer of master-metered utility systems to serving utilities and testified in that proceeding. Testified before the State Legislature on proposed legislation. Persuaded all electric and gas utilities in California to institute a pilot program to convert 10% of privately-owned MHP systems to utility ownership.

Community Solar Gardens Testimony, Sierra Club (2014). Testified in Pacific Gas and Electric and Southern California Edison Green Tariff applications on changes needed to encourage the development of neighborhood and community-scale renewable distributed generation by allowing direct contracting and removing unnecessary transaction costs.

Time of Use Rates in California Residential Rates Rulemaking, Environmental Defense Fund (2013-2014). Modeled how increased penetration of TOU rates in the residential sector for all three investor-owned utilities would reduce peak and energy demand, reduce residential bills, and reduce utility costs. Changes in revenues and costs were developed from the utilities’ most recent general rate case filings.

Southern California Edison v. State of Nevada Department of Taxation, Nevada Attorney General’s Office (2013-2014). Testified on whether the sales tax imposed on coal delivered to SCE’s Mohave Generating Station created a competitive disadvantage for SCE in the Western power market during the 1998-2000 period.

Professional Affiliations

American Agricultural Economics Association
Association of Environmental and Resource Economists
American Economics Association

Civic Activities

Member, City of Davis Utilities Rate Advisory Commission
Former Member, City of Davis Community Choice Energy Advisory Committee
Co-Chair, Cool Davis Energy Steering Committee
Member, Western Manufactured Housing Communities Association Utilities Task Force
Former Member, City of Davis Citizens Electricity Restructuring Task Force
Former Member, Yolo County Housing Commission
Member, Phi Beta Kappa Honorary Fraternity

Direct Testimony of

Paul Sutherland, Senior Advisor

Saber Partners, LLC

DIRECT TESTIMONY OF PAUL R. SUTHERLAND, CPUC R.17-06-026

Q. Please state your name and business address.

A. Paul R. Sutherland, Saber Partners, LLC (Saber or Saber Partners), 44 Wall Street, New York, New York 10005.

Q. By whom are you employed and what is your position?

A. I am with Saber Partners, LLC, and serve as a Senior Advisor.

Q. Please describe your duties and responsibilities in that position.

A. My responsibilities with Saber include work in data management, financial modeling, financial analysis, issuance cost auditing, deal structuring, pricing analysis with respect to relative value and review of issuance advice letters, all on behalf of public utility commission clients. I have performed these functions while advising the following regulatory bodies regarding utility securitizations: Public Utility Commission of Texas, West Virginia Public Service Commission, New Jersey Board of Public Utilities, Florida Public Service Commission and the Wisconsin Public Service Commission.

Q. Please describe your educational background and professional experience.

A. I have a bachelor's degree in electrical engineering from Cornell University. I also have a master's degree in business administration from the University of Chicago.

I began working with Florida Power & Light Company (FPL) in 1976 doing economic analysis of new energy technologies in the Research and Development (R&D) Department. After several years, I moved to the Finance Department as a Financial Analyst. Over the next 20 years I held various positions, including Coordinator of Financial Systems, Manager of Corporate Finance, Manager of Financial Analysis and Forecasting, and Assistant Treasurer of both the utility and FPL Group Capital. Before leaving FPL in 1998, I was Director of Finance, Accounting & Systems for the FPL Energy Marketing and Trading Division. During my time with FPL, I testified as an expert witness on cost of capital and financial integrity. I have also taught classes on economic decisionmaking and on quality improvement. It was during this time (1989) that FPL became the first non-Japanese company to win the Deming Prize for Total Quality Management.

In 2000, after a year as adjunct professor of mathematics at Palm Beach Atlantic College, I joined Saber Partners, LLC as a Senior Managing Director. I have been associated with Saber Partners since that time in various roles, including my current position as Senior Advisor. I have taken part in 13 investor-owned utility securitization financings that raised over $9.5 billion in capital for 8 different utilities.

Q. Can you provide some of your background and experience with utility financings while you were at FPL?

A. Yes. While at FPL, as Manager of Corporate Finance and Assistant Treasurer, I helped FPL complete over $2 billion of debt and equity financings in the public capital markets. FPL executed both competitive and negotiated securities offering transactions. FPL was also among the first to issue long-term variable rate tax-exempt debt that could be (and was) later converted to a fixed rate. Part of my job was to prepare and, along with the Treasurer and Chief Financial Officer (CFO), deliver rating agency presentations to support the credit ratings from the three major rating agencies.

Q. Are you sponsoring any exhibits in this case?

A. Yes, I am sponsoring:

Exhibit A, Glossary

Exhibit B, Flow diagram of transaction participants and cash flow

Exhibit C, List of securitization transactions to date

Exhibit D, Credit rating chart

Exhibits E. i, SEC view on securitization of regulatory assets

E.ii, Accountants Handbook §4-12 Securitization of Regulatory Assets

E. iii, FASB Accounting Standards Codification Topic 860-10-55-8

E.iv, SEC Letter dated 9/19/2007

Exhibit F.i.a, Duke Energy Florida (DEF) Prospectus cover

F.ii, Prospectus pp. 4-20: Prospectus Summary with highlighted sections showing risk mitigation factors

F.iii, Prospectus pp. 99-102: WAL and Yield Considerations - Sensitivity Analysis

Exhibit G, Various uses for securitization in past transactions

Exhibit H, Securitization 4-tranche structure: PG&E all UOG & ex-fossil, SCE all UOG

Exhibit I, Traditional revenue requirement: PG&E all UOG & ex-fossil, SCE all UOG

Exhibit J, Levelized vs. declining revenue requirements: PG&E all UOG & ex-fossil, SCE all UOG

Exhibit K, Savings dependent upon more than just interest rates: PG&E and SCE

Exhibit L.i and ii, Upfront and Ongoing costs of securitization

Exhibit M, Summary of potential savings with UOG securitization: PG&E and SCE

Exhibit N, VEPP Inc. Article from *The Wall Street Journal*

Exhibit O, PSNH Use of Proceeds

Exhibit P, Hypothetical PPA buydown

Exhibit Q, Sources of Data Used

Q. Whom do you represent in this proceeding?

A. I represent Saber Partners, LLC, who has been hired by the California Community Choice Association (CalCCA) to provide an independent evaluation and opinion as to the benefits, costs, risks, and rewards for PCG and EIX customers and shareholders of using securitization as part of the California Commission's Rulemaking 17-06-026, to "consider alternatives to the Power Charge Indifference Adjustment."

Q. What is the purpose of your testimony?

A. The purpose is to analyze the potential customer savings from using the financing technique known as securitization, should the California State legislature authorize it and Pacific Gas and Electric Company (PG&E) and /or Southern California Edison Company (SCE), together with the California Public Utilities Commission (CPUC or the Commission) and other stakeholders, agree to pursue it.

I will provide an overview of utility securitization financing to explain what it is, how it differs from other types of debt offerings, and why it is advantageous to the ratepayers to use it in applications such as with the financing of utility owned generation (UOG) and possibly also to finance buydowns of high-priced power purchase agreements (PPAs). The main purpose of my testimony is to analyze the utility securitization applications in question and discuss quantitative and qualitative benefits that could be achieved, both for the ratepayer and the utility. Included in this testimony as Exhibit A is a glossary of terms to help in understanding some technical financial terms in the language of the financial markets.

Q. What is securitization?

A. In general, securitization is a process by which a pool of assets which generate a cash flow, such as loans, credit card balances or other receivables, is used as collateral for a bond offering. The pledged asset generates a flow of cash that is used to pay principal and interest on the bonds.

To give buyers of the bonds comfort that only they have a claim on the pledged assets and that they will be repaid, the pledged assets are transferred to a special purpose legal entity which is protected from any credit problems of the utility. This is known as a "bankruptcy remote" or "ring fenced" entity and is often called a special or limited purpose entity (SPE). This means it has a strictly limited purpose i.e., to own the pledged assets and to pay the principal and interest on its bonds. When setting up this "special purpose entity", the entire right, title and interest in the pledged assets is transferred at a "fair market value" to the SPE. The SPE pledges these assets to secure the bonds, and the cash flows from those pledged assets are used to pay principal and interest on the bonds. Thus, the risk to the bondholder is just the risk associated with the cash flows from the pledged assets in the SPE. The pledged assets can be physical (such as plant and equipment) or financial (such as a loan receivable or the right to some other revenue). Exhibit B is a flowchart that shows the flow of funds in a securitization transaction while the bonds are outstanding.

Q. What is securitization in the context of electric utilities?

A. For investor-owned electric utilities, securitization is a specific legislatively enabled and regulatory approved process of issuing highly-rated securities through special purpose, bankruptcy remote/ring fenced entities to raise capital for purposes such as compensating the utility for stranded assets or storm-related expenditures. It is a direct borrowing on the utility's customer rate base in its distribution territory without involving the utility's balance sheet for credit purposes or comingling with the utility's other creditors. Because of this, the bonds have often been called ratepayer-backed bonds or ratepayer obligation charge (ROC) bonds and even rate reduction bonds (RRB), among other terms.

Bond repayment is secured through collection by the utility of a Commission-approved and periodically adjusted dedicated rate component and not a pool of receivables. The SPE and the securities it issues are perceived to carry much less risk than standard utility corporate debt and are therefore attractive to investors at a lower cost to the utility. Mr. Fichera's testimony details the legislative and regulatory framework critical to a successful securitization and one that protects ratepayer interests. Ratepayers benefit because the carrying costs of this debt are much less than the costs that would be incurred using traditional utility financing methods of debt and equity, which is often called the utility's "weighted average cost of capital" (WACC). For the utility, securitization increases cash flow and achieves a lower cost of capital than traditional means of raising capital. Electric utility securitization has been used by investor-owned utilities as a taxable debt financing tool at least 64 times since 1997. Those transactions are listed in my Exhibit C.

Q. What are the benefits of using the type of securitization financing that you have described in the current situation?

A. In the case of PG&E and SCE, securitization offers an opportunity to reduce the costs of resources in the utilities' PCIA (Power Charge Indifference Adjustment) portfolios for all customers responsible for paying the PCIA, including bundled, community choice aggregation (CCA) and direct access (DA) customers. The non-bypassable securitized charge also might improve cost transparency and facilitate collection of PCIA from CCA and DA customers.

This testimony contemplates two possible uses of securitization within the PCIA-Eligible portfolios:

1. Utility-owned generation (UOG); and
2. High-cost power purchase agreements (PPAs).

Securitization would reduce the cost of financing UOG assets by reducing the utility's weighted average cost of capital to a much lower securitized debt-only interest rate. This tool could also be used to provide funding to buy down the prices of high-priced contracts for the purchase of energy, again taking advantage of differences between a project owner's capital costs and securitized debt interest rates.

Securitization offers added benefits beyond the differences in the cost of capital. Because securitization reduces utility income, it also reduces income taxes, including income-based state franchise taxes, as well as revenue-based local franchise fees. In addition, securitization levelizes the debt carrying charges, shifting more costs into later years. This creates a net present value (NPV) benefit.

As discussed below, securitization of UOG assets and possibly of PPA buydown costs would deliver significant value to all PG&E and SCE ratepayers responsible for the PCIA, including CCA and DA customers. Securitization of the PCIA UOG rate base could potentially produce NPV savings to PG&E customers from $1.3 to $1.6 billion, and to SCE customers approximately $589 million. Additional savings may also be achievable through the securitization of PPA buydowns. My testimony provides an illustrative buydown example using an average price reduction of 13 cent per KWH for 2,000 GWH/year of purchased power, which, when netted against a securitization cost of 9.4 cents/KWH results in a net savings of 3.6 cents/KWH in the first year. Such a restructuring could result in NPV savings to bundled, CCA and DA ratepayers of $449 million. Whichever scenario the Commission, utilities and stakeholders elect to pursue, securitization will deliver value to ratepayers, the utility, and the state in reducing procurement costs and, if consistent with state goals, continuing to transition to a more competitive environment.

Q. How are securitization bonds structured to attract private capital?

A. Securitization bonds usually have multiple maturities such as 3, 5, 10, 15 or 20 years. These maturities are also known as “tranches” or a “series,” part of a larger composite issue. Rather than pay bonds all at once at the maturity (as is done in traditional utility finance, known as “bullet” or single maturity bonds), the securitization bonds pay off over time like a home mortgage. They pay a mix of principal and interest over a number of years. The schedule of principal payments is known as the amortization schedule. In the past, many utilities and corporations issued bonds with a form of an amortization schedule in them. They were known as “sinking fund” bonds which paid down over time. State and Local governments use this form of financing in a slightly different way through the issuance of many different bonds maturing sequentially. These are known as serial bonds.

Q. When do ratepayers repay the bonds?

A. With utility securitization financing, each tranche will have its own amortization schedule and interest rate. There will be a specific date when each bond begins to repay principal and interest, and a subsequent date when the next principal payment will be made on that bond. Interest will be paid on those dates as well, and the amount of interest paid will be calculated on the amount that is outstanding i.e., has not already been repaid. These principal dates are known as the “Scheduled Maturities.” When one averages those scheduled dates with the dollar amount of the payments over the time it takes to receive all payments for a specific tranche or series, one gets the "weighted average life" of the tranche (WAL). By "life" we are referring to the time the bonds remain active and outstanding.

Q. Is there another type of maturity associated with these bonds other than the scheduled maturity?

A. Yes. There is a "legal final maturity" associated with tranche. This is the date by which the investor must receive the principal amount that was scheduled to be paid or it will be declared an event of default and investors will be given legal rights to seek recovery of their investment.

Q. Why is there a time difference between a "Scheduled Maturity" and a "Legal Final Maturity"?

A. The only cash available to pay the principal and interest on the bonds comes from the collection of the charge on ratepayer bills based on their consumption of electricity. The timing of the receipt of that cash is uncertain and could be affected by many factors influencing the consumption of electricity. Consequently, there is some time built into the structure of the bond to address any volatility in collections.

Q. How do investors perceive the quality or creditworthiness of utility securitization bonds compared to that of traditional utility debt?

A. Investors generally rely upon nationally recognized independent credit rating agencies, such as Moody's, Standard & Poor's and Fitch to evaluate the financial and legal characteristics of the SPE and the bonds. These agencies give an opinion as to the likelihood of receiving principal and interest on the bonds when it is legally due, not when it is scheduled to be paid. They evaluate or rate this likelihood on a scale from highly likely to be repaid on time to unlikely to be paid on time, on the legal maturity dates.

As a short cut for investors to judge the credit of one bond to another, the rating agencies assign letters to their opinions. This scale is known as a "ratings scale" and is usually denoted by letters such as AAA for the best and strongest credit to CCC for a very weak credit. Exhibit D shows the rating scales for the 3 major credit rating agencies. The likelihood of repayment is also known as "default risk," or what the likelihood is that an issuer will not pay when an amount is legally due, and defaults on its obligation. With one exception, all utility securitization debt since 1997 has been rated AAA by the major rating agencies. This is not the case with other types of securitization debt. Moreover, no investor owned utility securitization bond has ever been downgraded or even placed on a watch list for possible downgrade, even through the bankruptcy of PG&E and Montana Power and the 2008-09 financial crisis.

Q. What is a common name for securities in a securitization?

A. When the pledged assets are fixed and there are limited intangible rights or a specific pool of payment obligations from identified obligors, they are commonly referred to as asset-backed securities (ABS). Common ABS types include those backed by corporate loans, credit card receivables or auto loan receivables. The cash flows are usually fixed or limited to a specific identified pool of assets.

Q. Is this a correct description for utility securitization?

A. No, for the reasons described below, it is not. However, utility securitization bonds compete for investment capital from ABS investors and corporate bond investors. It is important for investors to know the similarities and differences in the bonds to achieve the lowest cost of capital in the market

Q. What rating do most ABS receive?

A. The rating that ABS receive always depends on the quality and amount of the pledged assets (receivables), the legal structure, and a host of other factors. Generally, the higher the rating, the lower the interest rate on the ABS. Issuers borrowing against the pledged assets try to structure the transaction to receive a high rating, such as AAA, to make the most efficient use of the pledged assets as collateral for the ABS.

However, there are also lower rated ABS, and even within a single SPE there might be two or more classes of securities with different rights to the collateral in the pool, and thus different ratings. The market for ABS is very complex, and there are a wide variety of credit issues and concerns with ABS. ABS with AAA ratings and comparable terms to maturity might be valued very differently by investors.

Q. How is utility securitization debt different from ABS?

A. When properly structured, utility securitization bonds are not ABS. They are not backed by a pool of receivables or a finite set of cashflows. While they do have some things in common, there are several important differences that make utility securitization debt more secure than even the best AAA-rated ABS or corporate bonds.

The common feature of a utility securitization with ABS is that both use an SPE to issue bonds based on a cash flow from the pledged assets in the SPE and a separate "servicer" to collect the cash flows from the pledged assets and distribute to investors. Some terminology describing the SPE is also the same.

However, on the critical features relating to the credit-worthiness of the bonds – the payment of principal and interest when due - utility securitizations are decidedly not like what are commonly referred to as "asset-backed securities." For example, as described in Mr. Fichera's testimony in more detail, in each state where utility securitization bonds have been issued, they were issued under specific enabling state legislation. The legislation created a new type of intangible property which consists of the right to impose, adjust, bill and collect amounts from virtually all electric customers in a given service territory.

Thus, securitized utility bonds are backed by an enforceable regulatory right, not by an enforceable contract right or pool of receivables or other assets. Important differences in investors' rights and remedies arise by reason of this difference in the nature of the rights that back securitized utility bonds. For this reason, the Office of Chief Accountant of the U.S. Securities and Exchange Commission (SEC) has directed that the property that is pledged to support securitized utility bonds should <u>not</u> be treated as a "financial asset" and that the securitized utility bonds themselves <u>not</u> be treated as "asset-backed securities" for financial reporting purposes. See Exhibits E.i-iv.

Q. What is SEC Regulation AB?

A. Regulation AB (17 CFR § 229.1100, et. seq.,) is the SEC regulation setting forth general rules for the sale of ABS through public offerings. Any publicly offered securitized utility bonds issued for the benefit of PG&E or SCE would need to comply with Regulation AB if the securitized utility bonds are treated as "asset-backed securities."

Q. Do you expect the SEC to treat securitized utility bonds issued for the benefit of PG&E and/or SCE, as summarized in Mr. Abramson's, Mr. Schoenblum's and Mr. Fichera's testimony, as "asset-backed securities" for purposes of Regulation AB?

A. No. Mr. Abramson, Mr. Schoenblum and Mr. Fichera recommend that financing orders providing for the issuance of securitized utility bonds authorize those bonds to be issued in one or more series over a period of time. The SEC defines the term "asset-backed security" to exclude securities issued by an entity that is authorized to issue more than one series of bonds over time. SPEs formed to issue securitized utility bonds for West Virginia utilities (MP Funding and PE Funding) were authorized to issue more than one series of bonds over time and were treated as corporate bond issuers. This allowed the bonds to appeal to the broadest possible investor base and achieve a lower interest rate.

The SEC's Office of Chief Counsel, Division of Corporation Finance confirmed that these bonds were not asset-backed securities. In an interpretive and "no-action" letter dated September 19, 2007, they stated: "Based on the facts presented, it is the Division's view that MP Funding and PE Funding are not asset-backed issues and the Bonds are not asset-backed securities within the meaning of Item 1101 of Regulation AB." A copy of that September 19, 2007 letter is attached to this testimony as Exhibit E.iv. Saber Partners, as Financial Advisor to the West Virginia Public Service Commission, participated actively in requesting and receiving that September 19, 2007 interpretive and no-action letter. Therefore, I expect the SEC Division of

Corporation Finance will *not* treat securitized utility bonds issued for the benefit of PG&E and/or SCE as "asset-backed securities" for purposes of Regulation AB. Consequently, the bonds will appeal to the broadest possible market and could achieve the lowest possible cost to ratepayers.

Q. How have these principles been applied in the prospectuses of publicly offered securitized utility bonds?

A. The most recent publicly offered securitized utility bonds were $1,294,290,000 of nuclear asset recovery Series A Bonds issued on June 15, 2016 by Duke Energy Florida Project Finance, LLC ("DEF Project Finance") for the benefit of Duke Energy Florida, LLC ("DEF" or "depositor"). Excerpts from the prospectus for those bonds (the "2016 DEF Prospectus") are attached to this testimony as Exhibits F.i, F.ii and F.iii. Consistent with the SEC's September 19, 2007 letter, the cover page of that prospectus stated clearly: "*The Series A Bonds are corporate securities. Neither the depositor nor DEF Project Finance is an asset-backed issuer and the Series A Bonds are not asset-backed securities as defined by the SEC governing regulations Item 1101 of Regulation AB."*[1]

Q. Since investor perceptions of the credit affect the interest rate on the bonds, how do utility securitization bonds compare to ABS or traditional utility securities in terms of creditworthiness?

A. Several characteristics of utility securitization debt make it more creditworthy and less risky than ABS debt and traditional utility debt. If investors are properly educated, this should the bonds to achieve lower interest rates from investors.

[1] *See also* 2016 DEF Prospectus page 4: "We are not an asset-backed issuer, and the Series A Bonds are not asset-backed securities within the meaning of Item 1101(c) of Regulation AB... We may issue additional nuclear asset-recovery bonds, but only as authorized under the financing order or under a new and separate financing order."; 2016 DEF Prospectus page 13: "The bonds are corporate securities and are not asset-backed securities as defined by the SEC in governing regulations Item 1101 of Regulation AB."; 2016 DEF Prospectus page 37: "The nuclear asset-recovery property is not a receivable, and the principal collateral securing the bonds is not a pool of receivables, nor are the bonds asset-backed securities within the meaning of Item 1101 of Regulation AB."

First, the obligation to pay the securitized charge arises from state legislation and regulation, and not by contract. As summarized above, the SEC Office of Chief Accountant has declared this difference to be sufficiently material to give rise to different accounting treatment for ABS than for securitized utility debt.

Second, as explained on page 13 of the 2016 DEF Prospectus Summary in my Exhibit F.ii, the obligation of the ratepayers is joint and several.

Q How are customers responsible for paying securitization charges on a joint and several basis?

A. This is a critical distinguishing factor. If some customers no longer receive electric transmission or distribution service from DEF or its successors or, for whatever reason, fail to pay the nuclear asset-recovery charges, other customers that continue to consume electric transmission or distribution service from DEF or its successors would be responsible for paying nuclear asset-recovery charges. Any delinquencies or under-collections in one customer rate class will be considered in the application of the true-up mechanism to adjust the nuclear asset-recovery charge for all customers of DEF.

This is to be distinguished from a credit card or home mortgage backed ABS where if one customer does not pay his or her credit card bill or home mortgage for whatever reason, the remaining customers in the pool of credit card receivables or home mortgages do not become responsible for the shortfall. Consequently, this means that investors in conventional ABS debt might not receive all their principal and interest. This is a material difference.

Finally, as described in more detail in Mr. Fichera's testimony, the securitized charge is non-bypassable. This means that if the ratepayer takes delivery of electricity by means of wires owned by the utility or its successor, there is no way the ratepayer can avoid the charge. The financing order issued by the regulator is irrevocable and therefore cannot be revisited at any time during the life of the bonds. This makes it very important for the Commission to have a complete understanding of the transaction up front, which is a key reason for the Commission, when making irrevocable decisions, to have available experts and independent and experienced financial advisors to assist the Commission in discharging its duties.

Q. Have issuers tried to quantify the risk of default of securitized utility bonds?

A. Yes. The 2016 DEF Prospectus addresses this issue under the heading "Sensitivity to Credit Risk," on pages 100-102, Exhibit F.iii. Various stress tests were performed on the bond structure using a model of forecasted utility revenues. The conclusion was "For an event of default to occur with respect to any such payment due under the indenture, the forecast variance for the forecast period leading up to such payment would need to be greater than minus 60%, or more than 16 standard deviations from the forecast variance mean."

Q. What do investors look at when evaluating a bond besides the interest rate and the likelihood of repayment?

A. Two investor concerns are related to uncertainty regarding the timing of principal repayment. Investors ask, first, "Will I get my investment back sooner than expected?" and second, "Will I get my investment back later than expected?" These two types of uncertainty are known as "prepayment risk" and "extension risk," respectively.

Usually a bond has a specific schedule of principal and interest payments. Investors are lending money (by buying the bonds), and they want to earn a return over a specific time period. However, bonds could be sold with the issuer's option (referred to as a "call option") to pay back the investor sooner than scheduled. The existence of such a "call" option results in prepayment risk. The bond issuers might want to pay back sooner for a variety of legal or managerial reasons, but usually it is because interest rates are lower, so the issuers can sell a new bond at a lower rate to pay off the older bond at a higher rate. Investors who get their money back sooner might consider it a good thing, but not if they cannot reinvest at the same or better rate compared to what they were previously getting. The capital markets usually extract a premium (higher interest rate) for this "prepayment risk."

Q. Do AAA-rated ABS bonds typically have prepayment risk?

A. Yes. AAA-rated ABS bonds typically have prepayment risk. Many AAA-rated ABS issuers flow through substantially all payments received in respect of the specific collateralized pool of financial assets, such as receivables and home mortgages, even though this might force investors to accept repayment of their principal investment earlier than scheduled and expected when they initially bought the security. Conversely, most utility securitization bonds do <u>not</u> have prepayment risk. For example, page 99 of the 2016 DEF Prospectus in my Exhibit F.iii. states: "No prepayment is permitted."

Q. You also mentioned "extension risk." What is that?

A. Rating agencies' stress-case studies of ABS often show there is significant risk that even AAA-rated ABS will return investors' principal significantly later than scheduled. As I mentioned above, this is commonly called "extension risk." Investors usually require additional yield (higher interest rate) to compensate for any material extension risk. We suggest that the proposed utility owned generation bonds be structured such that any "extension risk" will be insignificant. Indeed, in many stress-case scenarios we have seen that this risk is statistically insignificant. That cannot be said of most ABS bonds because of the nature of the pledged assets and how the ABS bonds are structured.

As I have said, securitized utility bonds represent a joint and several liability of all ratepayers collectively. Securitized bonds are structured with a true-up mechanism contained in the financing order that adjusts the charge on consumers to whatever level is necessary to meet the schedule of principal and interest payments. This mechanism requires the securitized charge to be adjusted periodically pursuant to a pre-approved formula, usually semi-annually or more frequently if desired, to ensure the principal and interest is paid according to schedule. For example, if there were an unexpected decline in energy sales for some period, the charge per KWH could be increased subsequently to make up for the earlier shortfall. Thus, the true up mechanism is very responsive to unforeseen changes in collections. In other words, it is a robust adjustment mechanism to collect from electricity ratepayers whatever is needed to meet the bond's cash flow obligations.

The most important way to capture value from investors is to describe accurately and precisely the characteristics of the utility securitization in the disclosure documents accompanying the sale of the bonds to investors. The SEC registration statements pursuant to which a number of prior securitized utility bonds have been offered have provided detail about the unusual and superior credit quality of the securities. I have highlighted in the DEF Prospectus Summary (Exhibit F.ii) in particular, certain sections discussing aspects that mitigate against risk to the investor and help lower the interest rate on the bonds.

Q. Was extension risk discussed in detail in the 2016 DEF Prospectus?

A. Yes. Page 100 of the 2016 DEF Prospectus stated:

"The weighted average life table below illustrates whether there is risk to bondholders of a material weighted average life extension of each WAL designation.

"The table shows changes from the expected weighted average life of each WAL designation of bonds assuming actual future electricity consumption and related charge collections varies from DEF's forecast of future electricity consumption and related charge collections (the forecast variance) of 5% (1.3 standard deviations from the forecast variance mean) or 15% (4.0 standard deviations from the forecast variance mean) during each payment period.

The weighted average life table below illustrates that the aggregate payment of principal of and interest on the bonds and the timing of such payments are not expected to change materially over the life of the bonds, based on the assumptions we have made."

Series A Bonds	Expected Weighted Average Life (yrs)	Effect on Weighted Average Life (Rounded*) of Change in Forecast Variance: −5% (1.3 Standard Deviations from Forecast Variance Mean) Weighted Average Life (yrs)	Effect on Weighted Average Life (Rounded*) of Change in Forecast Variance: −15% (4.0 Standard Deviations from Forecast Variance Mean) Weighted Average Life (yrs)
Series A 2018	2.0	2.0	2.0
Series A 2021	5.0	5.0	5.1
Series A 2026	10.0	10.0	10.0
Series A 2032	15.2	15.2	15.3
Series A 2035	18.7	18.7	18.8

* Number is rounded to 1/10th of one year

Q. Do you expect it will possible for similar statements about extension risk to be included in the prospectuses pursuant to which the securitized utility bonds proposed to be issued for PG&E and SCE are issued?

A. Yes.

Q. How would California utilities, if they wanted to, issue utility securitization debt?

A. Mr. Fichera's testimony details the steps needed for successfully pursuing securitization in California to achieve the benefits that I will describe below. He describes the type of enabling legislation needed, the irrevocable financing order that would be issued by the Commission as well as other issues need to protect ratepayer interests in the sale of the bonds to private investors.

Q. Would securitization of the unrecovered costs of UOG assets prevent PG&E or SCE from divesting those UOG assets in the future?

A. No. Securitized utility bonds will be secured by a pledge of the intangible property right that represents the right to impose, adjust, bill and collect the securitization charge. That will be entirely separate from the UOG assets themselves. The UOG assets will not be pledged to secure the securitization charge. Consequently, securitization would not impair the ability of PG&E or SCE to divest their UOG assets.

Q. How would cash received upon the future sale of UOG assets be treated so that ratepayers would not be adversely affected by a divestiture?

A. Cash received from any future sale of UOG assets would be tracked in a balancing account and used to adjust other rates and charges imposed on customers, including CCA and DA customers.

Q. Can you give an example of how a balancing account has been used for such purposes in connection with prior California utility securitized bonds?

A. Yes. Mr. Abramson's testimony describes securitized Energy Recovery Bonds issued in 2005 to refinance a bankruptcy-related regulatory asset of PG&E. CPUC Decision No. 03-12-035 initially established that regulatory asset in the amount of $3.0 billion, but provided that the amount of that regulatory asset was to be reduced to the extent PG&E in the future received energy supplier refunds arising in connection with the 2000-2011 energy crisis. In its Financing Order (Decision No. 04-11-015) authorizing the issuance of Energy Recovery Bonds to refinance the unrecovered balance of this PG&E regulatory asset, the CPUC ordered that an Energy Recovery Balancing Account (ERBBA) be established for a variety of purposes, and that amounts credited to the ERBBA were to be returned to customers through a separate ERBBA charge. The ERBBA charge was not pledged to secure the Energy Recovery Bonds. One of those purposes was to track future energy supplier refunds. The Financing Order states: "These energy supplier refunds will be credited to the ERBBA, earn short-term interest while in the ERBBA, and be refunded to consumers via the next annual adjustment to the ERBBA charge." Similarly, amounts received from any future divestiture of UOG assets should be returned to the utility's customers by means of adjustments to other rates and charges.

Q. What are the roles of the different participants in a typical utility securitization?

A. The easiest way to understand the various roles is to look at the flowchart in my Exhibit B. The electric utility sponsors the transaction, sells the intangible asset to the SPE and, at least initially, services the bonds by billing the customer, collecting the charge and remitting the funds to the trustee. The trustee pays the stated interest and principal to the bondholder. The Commission issues the financing order and checks proposed true-up adjustments to the securitization charge for mathematical correctness. The electric retail customer (including CCA and DA customers) pays the charge and bears all the financial burden associated with the debt once the bonds are sold.

The activities of the SPE should be restricted by the financing documents so that it cannot engage in any activities unrelated to this financing without receiving a rating confirmation from the rating agencies. The SPE will be owned by the sponsoring utility and will be capitalized by the utility such that its equity capital is 0.5 percent of the SPE's securitized bonds.

Q. How have utility securitizations been used in the past?

A. Investor owned utilities, together with state legislatures and public utilities commissions, have used utility securitization bonds to fund, among other things, stranded costs from utility deregulation, environmental control costs and, in the case of Florida, in 2006, and most recently, New Orleans in 2015, storm recovery costs. See Exhibit G for more examples.

Q. How are ratepayer benefits achieved with utility securitization?

A. The securitization of unrecovered costs of UOG assets will benefit ratepayers in multiple ways. First, and most importantly, there will be economic benefits to ratepayers. Significant savings occur when securitized bonds are used to replace a combination of conventional utility debt and equity financing. It is effectively off-balance-sheet and non-recourse to the utility. The utility is fully-protected. This means that the utility can finance the asset or expense in question with nearly 100% debt rather than its normal capital mix of about 50% debt and 50% equity, without any impairment of its credit structure. The ratepayer savings are even greater for a utility like PG&E that has a lower credit rating.

There are several reasons why utility securitization saves money. First, the cost of equity is much higher than the cost of debt. A 5% cost of traditional long-term debt and an 11% cost of equity are typical values in today's environment. In addition, savings occur by the avoidance of income taxes that would otherwise have to be paid on the equity return. These savings accrue directly to the ratepayers in the form of lower overall rates than would otherwise be levied.

Another source of savings comes from pricing these securitized ratepayer-backed bonds in the capital markets commensurate with their extremely high credit quality. In general, the better the credit rating, the lower the interest cost. By separating the operating utility from the SPE issuer of the bonds and isolating the cash flow, the credit associated with securitized ratepayer-backed bonds will be evaluated by investors as independent of the sponsoring utility and independent of the traditional debt of the utility. Traditional utility debt has numerous risks associated with its repayment. Those risks will not be present in connection with securitized ratepayer-backed bonds.

The savings commensurate with top-quality credit is not automatic. Not all "AAA" rated bonds are sold or trade at the same interest rate or yield. There are a number of steps that are required at the time the securitized ratepayer-backed bonds are structured, marketed, and priced to achieve the lowest cost available in the market and to capture the full economic value of the unique government guarantees embodied in the legislation and the irrevocable nature of the financing order.

In addition, by using the "best practices" identified in the testimony of Mr. Fichera, the CPUC and the utilities can work to maximize benefits and to improve ratepayer protections.

Additional ratepayer NPV savings occur due to the levelizing of revenue requirements, which I shall discuss shortly.

Q. Why is a "lowest cost" standard important?

A. Since the proceeds of a bond issuance are cash dollars, the appropriate standard in reviewing benefits is the "lowest cost" standard. Issuers want to raise the maximum amount of dollars at the lowest possible cost. Note, however, that underwriters have a vested interest in urging the use of a standard of "reasonable cost" because "reasonable" covers a range of outcomes. For any large, long-term financing, that range might represent millions or tens of millions of dollars in extra costs. One might choose to use a reasonable costs standard to reimburse a doctor, where there are differences in both the type and quality of care. However, one dollar has the same quality as another dollar, and a bond issuer should want the most dollars for the lowest cost. Mr. Fichera's testimony discusses this issue in more detail.

Q. What are the benefits to the utility that you briefly mentioned earlier?

A. As described above, securitization of the unrecovered costs of UOG assets can have several benefits to the utilities. When structured correctly, this financing method will increase cash flow for the utilities and allow for debt to be issued at a superior credit rating. In addition, when state policies promote retail competition and the utility elects to transition out of procurement, it allows the utility to make this transition in a cost-effective manner.

Securitization offers greater potential benefits to PG&E in light of recent downgrades of its debt. The restoration and strengthening of PG&E as an investment grade company may be considered vital to the company's future ability to service its customers. The securitization of unrecovered costs of UOG will provide PG&E access to capital at a lower cost than they might otherwise be able to obtain. PG&E may then use such capital either in response to storm damage or wild fire response or to pay down higher cost debt, thereby potentially causing its credit rating to increase as its debt-to-equity ratio decreases. See the testimony of Mr. Abramson for a more detailed discussion of potential benefits to the utility.

Q. Can you describe the analysis you performed to quantify the potential ratepayer benefits?

A. Yes. As noted previously, if a securitization strategy were undertaken, cash realized by the utility could be used to either pay down other, more expensive, utility debt, or to free up debt and equity capital for other important projects, such as planned capital expenditures, emergency funds or extraordinary expenses. The utility's revenue requirement would decrease, resulting in savings to ratepayers. Significant value could be found in each, or all, of the potential applications of securitization discussed in this testimony.

Securitizing all or a portion of the existing UOG rate base would reduce financing costs to all ratepayers, including bundled customers and CCA/DA customers. As discussed in the overview of Chapter 3, CalCCA proposes securitization of all unrecovered costs of UOG remaining in the PCIA-Eligible portfolio. I performed an analysis that shows that if all of PG&E's unrecovered costs of UOG were securitized, this strategy could remove up to an NPV of $1.6 billion in costs from the PG&E portfolio of generation assets. Exhibit H shows what the structure of such a securitization might look like assuming interest rates as they exist today and assuming the financing as of the end of this year. Exhibit I shows the same assets financed at PG&E's current cost of capital using traditional ratemaking and asset depreciation and debt amortization. While PG&E's weighted average cost of capital is 7.69% (or about 9.75% pre-tax), the cost of the securitization financing has an overall cost rate of just 3.91% (for a WAL of 11.7 years), and there is no gross-up for income taxes since there is no equity financing involved. The difference between these two financing scenarios amounts to about $1.6 billion on an NPV basis.

Page 2 of Exhibit H shows the structure for securitization of PG&E's UOG excluding fossil generation, while page 2 of Exhibit I shows the same assets financed using traditional capital structure. The NPV benefit in this case amounts to $1.3 billion.

I also performed an analysis that shows that if all of SCE's unrecovered costs of non-CAM UOG were securitized, this strategy could remove up to an NPV of $589 million in costs from the

SCE portfolio of generation assets. Page 3 of Exhibit H shows what the structure of such a securitization might look like assuming interest rates as they exist today and assuming the financing as of the end of this year. Page 3 of Exhibit I shows the same assets financed at SCE's current cost of capital using traditional ratemaking and asset depreciation and debt amortization. While SCE's weighted average cost of capital is 7.61% (or about 9.53% pre-tax), the cost of the securitization financing has an overall cost rate of just 4.07% (for a slightly longer WAL of 14.94 years), and there is no gross-up for income taxes since there is no equity financing involved. The difference between these two financing scenarios amounts to about $589 million on an NPV basis.

Q. Does the use of securitization financing affect the timeframe over which the UOG assets are paid for by the ratepayers?

A. Yes, not so much in the number of years over which the ratepayer pays, but rather in the amount the ratepayer pays in the earlier years versus the later years. Exhibit J shows the annual revenue requirements for each of the two different financing approaches. Traditional ratemaking requires the ratepayer to pay much more in the early years of an asset's useful life and much less in the later years. Securitization financing allows the ratepayer to pay a levelized amount throughout the life of the assets in question. By levelizing the payments that are financed with inexpensive debt rather than front-end loading revenue requirements, the NPV savings, when discounted at the utility cost of capital (7.69% and 7.61% for PG&E and SCE, respectively), are increased substantially.

Q. Are all utility securitizations structured in this same way to levelize revenue requirements?

A. Yes, in a general sense, although the details may differ slightly. Some deals are structured to levelize the total dollar revenue requirement. Others are structured to levelize annual payments of principal. Others are structured to levelize the securitization charge in cents per kilowatt hour. This can be done by taking into account a projection of KWH sales growth over the life of the bonds.

Q. Did your analysis attempt to explain which aspects of a utility securitization account for most of the savings that you have projected?

A. Yes. Exhibit K shows how much of the total securitization savings result from different characteristics of the financing structure and the economic environment in which it is used. There are three main sources of savings and several smaller sources. Biggest of all is the difference in cost between utility equity and securitization debt. While PG&E's authorized cost of equity is 10.25%, which accounts for 52% of its capital structure, the securitization debt at current levels would bear an interest rate of only about 3.91%. This difference accounts for about 43% of the overall savings in the case of PG&E. In the case of SCE, the utility's authorized cost of equity is 10.3% and accounts for 48% of the capital structure. SCE also has 9% of its capitalization in preferred stock costing 5.82% (compared to just 1% preferred stock for PG&E). Securitized debt in the SCE 4-tranche securitization structure would cost only about 4.07%, as I mentioned earlier. In the case of SCE, more expensive equity accounts for about 47% of the savings.

The second largest contributor to savings is the difference due to income-based taxes which burden the equity portion of the capital structure. When the Federal tax rate of 21% is combined with the 8.84% rate for California income-based franchise taxes, the effective composite income tax rate is 28%. With securitization financing, there are no income-based taxes. This difference accounts for about 29% of the $1.6 billion savings in the case of PG&E and 33% of the savings in the case of SCE.

The third contributor to savings is the levelization that I discussed previously. Levelizing the revenue requirements when securitizing PG&E's utility owned generation creates about 23% of the $1.6 billion total NPV savings that I have estimated for PG&E ratepayers. For SCE, levelization accounts for just 15% of the $589 million total NPV savings. The reason for the difference between the two utilities is because in PG&E's case, the securitization scenario shifts a greater proportion of the revenue requirements into the future, particularly due to the relatively short remaining useful life of PG&E's nuclear assets.

In addition to these major factors, there are savings from the fact that AAA rated securitization debt is less expensive than A+ or BBB+ rated utility debt (4% of the savings) and the fact that revenue-based fees, such as local franchise fees would be slightly less (1% of the savings).

Q. Are there any transaction fees associated with securitization financing that are greater than in traditional utility financing?

A. Yes, there are, due to the complexity and structured way that these financings work. In Exhibits I.i and ii, I show what upfront and ongoing transaction costs have been in some recent securitization transactions. In my analysis, I have assumed that upfront costs, together with the NPV of ongoing costs, would be about 2% of the principal amount.

This is a conservative estimate for several reasons. First, in the case of the Duke Energy Florida transaction, which had a $1.294 billion principal amount, the NPV of transaction costs was just over 2% of principal. Both upfront and ongoing costs have a variable component that would be less for larger transactions. My example assumes a principal amount of up to $4.65 billion in the case of PG&E and $1.48 billion for SCE, so that even if the securitizations were done in two transactions for PG&E, the transaction costs would probably be 2% or less in each case. Secondly, financing orders generally include a provision that requires the utility to reduce other electric utility rates and charges to reflect the amount by which any of the bond servicing fee paid to the utility is in excess of its marginal or incremental cost to perform the service.

Q. What other cases for using securitization to refinance the unrecovered costs of UOG did you examine?

A. Using the same methodology, I have described, I looked at securitization for PG&E excluding fossil generation. That is how I arrived at a range of possible NPV savings of $1.3 to $1.6 billion for PG&E ratepayers. In the case of SCE, it is my understanding that there is no non-CAM fossil generation, so I only looked at the single UOG case for SCE. I have summarized the results of my analysis in Exhibit M.

Q. Are there any other material differences, besides the amount of potential savings, between the cases you examined for PG&E and those you analyzed for SCE?

A. Yes. The case I looked at for SCE assumed a final expected maturity for the securitization bonds of 25 years rather than the 20 years for PG&E. I extended the final maturities because the remaining lives for the UOG assets were longer in the case of the SCE generation. There is some uncertainty associated with this assumption, since 20 years is the longest securitization that has been done to date. Still, I believe it is achievable with no severe penalty in terms of a significantly higher interest rate or marketability. There is a very strong demand for these types of securities in today's market.

Q. How would costs associated with capital additions be affected by securitization of unrecovered costs of existing UOG plant assets?

A. If securitization is limited to refinancing unrecovered costs of existing UOG assets, the costs of future capital additions would not be affected. That future rate base would be depreciated using traditional ratemaking, subject to the utility rate of return, and recovered in rates from customers, rather than through a dedicated rate component. Chapter 3 addresses ongoing PCIA cost responsibility for uneconomic capital additions.

It is possible that near-term capital additions for which costs are fairly certain at the time of the securitization could be included in the initial UOG securitization. Furthermore, major subsequent capital additions could be financed with a future securitization if amounts were large enough to warrant. For example, Monongahela Power and Potomac Edison (subsidiaries of Allegheny Energy Inc. at the time through MP Funding and PE Funding subsidiaries) financed flue gas desulfurization equipment with a securitization in 2007 and then followed up with securitization of additional costs for that equipment in 2009. Saber Partners oversaw both transactions as Financial Advisor to the West Virginia Public Service Commission.

Q. Are there any other potential uses for securitization in PG&E and SCE that you have examined?

A. Yes, another way to utilize securitization is to finance the buydown of existing PPA contracts. Some of these contracts were set with prices as high as 18 cents/KWH or more at a time when electric rates were expected to escalate sharply. That was before the growth of availability of shale oil and the advent of fracking that has produced an abundance of natural gas. These are generally long-term contracts (some for 20-25 years) at set prices and quantities. The prices of many of these contracts may now exceed current and expected future market prices. While many of these PPAs have supported the state's goal of increasing reliance on renewable resources or increased reliability, they tie the utility to long term, high-cost contracts. There may be circumstances in which some of the generators that are selling power to the utilities under these PPAs may be willing to enter into voluntary and mutually agreeable reductions in the PPA prices in exchange for an up-front cash payment, i.e. a buydown.

Securitization, through the same process described above, could be used to reduce the costs of one or more of these contracts. As discussed in Chapter 3, the utility might conduct a "reverse RFO" seeking voluntary proposals from sellers/generators for a buydown of the contract price. As CalCCA has proposed the process, the price reduction would be the only change, and all other terms of the PPA would remain in effect. The likely delta between a securitized debt interest rate and the counterparties' internal discount rates (likely based principally on their own cost of capital) presents another opportunity for ratepayer savings. In this case, legislation would grant the Commission specific authority to administer a PPA buydown program, potentially with conditions, and to fund the buydowns using a dedicated rate component through a securitization financing.

Q. Has securitized debt been issued for this purpose in the past?

A. Using securitization to fund PPA buydowns was proposed in Vermont in 1999. Exhibit N is an article from *The Wall Street Journal* that discusses the attempt of the Vermont Electric

Power Producers (VEPP Inc.) to buydown PPAs that where priced as high as 17.5 cents/KWH. Saber Partners served as Financial Advisor to VEPP, Inc. and assisted in achieving the enabling state legislation. The state of Vermont passed the enabling legislation to authorize securitization for this purpose. After much study and negotiation, VEPP Inc. was never able to execute the buydowns at prices that created ratepayer savings, and securitized bonds, therefore, were not issued.

However, in April 2001 and again in January 2002, Public Service Company of New Hampshire issued Rate Reduction Bonds (another term for securitization debt) for reducing its capitalization and buying down high-cost PPAs. Exhibit O shows cover information and Use of Proceeds language from those two transactions.

Q. Have you been able to quantify the potential savings that could result from using securitization to buydown high-cost PPAs?

A. While I did not examine the utilities' PPAs to determine how much each utility might be able to save through buydowns, I was able to model a hypothetical case that convinced me that savings may be possible. Exhibit P shows that under certain circumstances, in particular even when the PPA counterparty has a relatively low cost of capital (assumed to be 6.5% in my example) and when a long maturity securitization is used, some savings are possible. However, without examining the PPA portfolios, I would expect the savings to be neither as large nor as certain as they would be in the case of refinancing the unrecovered cost of UOG. As shown in Exhibit P, the NPV savings amount to just 17% of the principal amount of securitized bonds issued to buydown PPAs compared to 34% to 41% in the case of securitized bonds issued to refinance the unrecovered costs of UOG (see Exhibit M). To a large extent, this is because PPAs are already structured to levelize revenue requirements, so there is little or no added benefit from the levelization in the securitization structure. Some of the NPV benefit in my hypothetical case results from extending the term of the securitization debt beyond the term of the PPAs being bought down.

Q. Is there greater uncertainty associated with using securitization to buydown high-cost PPAs as compared to using it to finance UOG?

A. Yes. The uncertainty arises because, unlike utility cost of capital, which is public information, it is not known what the PPA counterparty's cost of capital may be, and that is key to what the cost of a buydown will be. If the PPA counterparty has a high cost of capital, say 10% or so, the NPV of future prices (thus, the buydown lump sum payment demanded by the PPA owner/counterparty) would be smaller, making the buydown savings greater for the ratepayer. However, PPA projects are usually highly leveraged so that, while the cost of equity may be relatively high, it is a very small component of the PPA counterparty's cost of capital.

In addition, there are certain risks and/or circumstances that could make this type of securitization unattractive. For example, partial buydown or prepayment may not be a practical option under the terms of a power purchase agreement or could come with breakage costs and make-whole or prepayment penalties that may make a buy-down economically unsuitable for a particular contract. Also, there is some risk that the utility's relationships with its counterparty/generators could be damaged by the authorization of a potential buy-down. It is conceivable that the counterparty/generators are not cooperative and find the legislation oppressive in that it attempts to force their hand. However, a completely voluntary buydown program through, for example, something like a reverse auction, may mitigate some of that risk. Finally, the "opening up" of the transaction to renegotiation may not work in the utility's favor, as counterparties may attempt to renegotiate terms besides price to the detriment of the utility.

On the other hand, some counterparties might welcome a large cash buydown as an opportunity to raise significant amounts of cash without the need to resort to the capital markets. Therefore, securitized bonds issued to finance the buydown of high-priced PPAs might be a significant benefit to both ratepayers and PPA counterparties even if only counterparties to a few of the largest high cost PPAs opt into the program.

Q. Would PG&E and SCE benefit from the use of securitization to buydown existing high-priced PPAs?

A. Yes. In recent years, credit rating agencies have begun to analyze long-term PPAs as though they were, in part, debt of the purchasing utility. This exposes PCG/PG&E and EIX/SCE to risk that the credit ratings on their other debt and equity securities will be reduced. This "debt equivalence" concern should be mitigated if PG&E's and SCE's annual payment obligations pursuant to their PPAs is materially reduced.

Q. Do you believe that the benefits you have quantified in your analyses are highly sensitive to potential changes in interest rates and might largely disappear if interest rates were to rise before a securitization financing could be brought to market?

A. No. My analysis indicates that the savings are not especially sensitive to the absolute level of interest rates. As my Exhibit K shows, the vast majority of benefits are due to

(1) levelization of revenue requirements,

(2) income-based taxes (Federal and state), and

(3) the spread between the cost of equity and the cost of securitization debt.

Consequently, if the cost of all types of capital rises in proportion, savings would not be significantly affected.

The greater risk is if the rates for securitization debt rise out of proportion to other rates. My calculations show that a 100 basis point (1%) increase in securitization interest rates with no change in the rest of the market (ceteris paribus) would decrease the $1.6 billion savings to PG&E ratepayers to a still significant $1.3 billion. Such a large distortion in the market for pricing securitization debt has only occurred once since such debt was first issued in 1997, and that happened during the financial crisis of 2008. I do not believe such a crisis is likely to happen again before PG&E and/or SCE have the chance to take advantage of this opportunity.

Q. Can you summarize your recommendations?

A. Yes. I recommend that the parties to this proceeding seek State of California legislation authorizing the issuance of securitized utility bonds as described in my testimony and in the testimony of Mr. Fichera, Mr. Abramson and Mr. Schoenblum.

SABER PARTNERS, LLC

EXHIBITS FOR

TESTIMONY OF PAUL SUTHERLAND

SABER PARTNERS, LLC

3/31/2018

SABER PARTNERS, LLC

EXHIBIT A

Glossary

Asset-backed security (ABS) - A debt security issued by a special purpose entity, the payment of which is backed by a physical asset (e.g., rail cars or airplanes) or a financial asset (e.g., a mortgage or the value of a portfolio of credit card receivables). At least for some purposes, utility securitization bonds are not technically asset-backed securities but often have been treated as such to the detriment of ratepayers.

Bankruptcy remote - An entity designed in such a way that (i) the likelihood of it going into bankruptcy is extremely small, and (ii) it would experience as little economic impact as possible in the event of a bankruptcy of other related legal entities.

Basis point (bp) - One one-hundredth of a percentage point. Often referred to in writing as "bp" (or "bps" in the plural).

Benchmark – When pricing a bond, the benchmark is a security with high price transparency that is agreed upon by all parties so that the yield on the new issue can be set relative to the yield on the benchmark. In that way, if yields in the market move after agreeing on the spread to benchmark but before final pricing, the parties do not have to renegotiate the final price/yield. A benchmark can also be a similar security used to determine relative value when talking to investors.

Maturity - The length of time until the issuer of a bond has to repay specified amounts to the lender / investor.

Final scheduled maturity date– The date by which it is expected that the final principal payment on a bond or on a group of substantially identical bonds will be made.

Final legal maturity date – The date by which, if the principal is not fully paid, the bonds will be considered to be in default. Usually, the final legal maturity date is one to two years after the final scheduled maturity date.

Irrevocable financing order - A finance order issued by state regulators that cannot be changed or revoked at a later date as long as the securitization bonds are outstanding, and which (i) segregates a specific component of the retail rate charge through the service territory, (ii) causes the right to receive this component to be treated as an interest in property that can be bought, sold or pledged (i.e. a receivable), (iii) authorizes the utility to sell such property to an SPE, (iv) authorizes the SPE to issue debt secured by such property, and (v) requires the utility which sold the property to use the proceeds of the sale for a specific purpose.

Relative value - The relationship between two securities. In pricing a new bond issue, for example, it is useful to compare the spread over swaps of the proposed bond yield to the spread over swaps of a AAA-rated US agency bond. If the two securities were judged equal in risk with identical terms (not callable, same WAL, etc.) but one had a higher spread, it would be said to have greater relative value.

Road show - A formal presentation to potential purchasers of a security, typically organized by underwriters with the involvement of the issuer and the financial advisor. A team sometimes travels around the U.S. to discuss the features of the security, resulting in the term "Road Show." Sometimes the team travels to foreign financial centers to make these presentations. In recent years, most Road Shows have been conducted using electronic media over the Internet, reducing or eliminating the need for travel.

Secondary market – The market in which stocks or bonds are traded after their initial issuance. When a bond trades at a substantially higher price (lower yield) in the secondary market immediately following its issuance, this is an indication that it was mispriced (priced too low) by the underwriters.

Securitization - The process by which a pool of assets, such as loan receivables, is used as a basis for issuing highly rated (often AAA) bonds. The pool of assets is created and transferred to a trust or, in a utility securitization, to a bankruptcy remote entity, known as a special purpose entity (SPE). The entire right, title and interest in the assets are transferred at a fair market value to the SPE. The SPE pledges the assets to secure the bonds and the cash flows from those assets are used to pay principal and interest on the bonds. Thus, the risk to the bondholder is just the risk associated with the cash flows from the assets in the SPE. The assets can be physical (such as plant and equipment) or intangible (such as a loan receivable or the right to some other revenue stream).

Special purpose entity (SPE) – A bankruptcy remote (see **bankruptcy remote** definition, above) legal entity set up for the express purpose of owning the right, title and interest in the assets used to secure the bonds and provide the cash flows to pay interest and principal on the bonds.

Spread – The difference between the market yields of different fixed income securities of similar maturities, expressed in basis points. If a Treasury bond maturing in seven years is trading to yield 3.87%, and a AAA-rated corporate bond is trading to yield 4.25%, the corporate bond is said to trade at a 38 basis point spread to the Treasury bond (4.25 – 3.87 = .38).

Spread is the easiest way to compare the cost of funds represented by different debt securities. Participants will refer to the spread "relative to Treasuries" or "relative to swaps" as the most meaningful measure used to compare a given debt security to the most liquid, most secure, and most easily available benchmark for a given maturity. Spreads are often referred to as either "tight" or "wide" to the benchmark. (See **Tight Spread/Wide Spread** definition below.)

SABER PARTNERS, LLC

Exhibit B

Participants in Electric Utility UOG/PPA Securitization Transaction

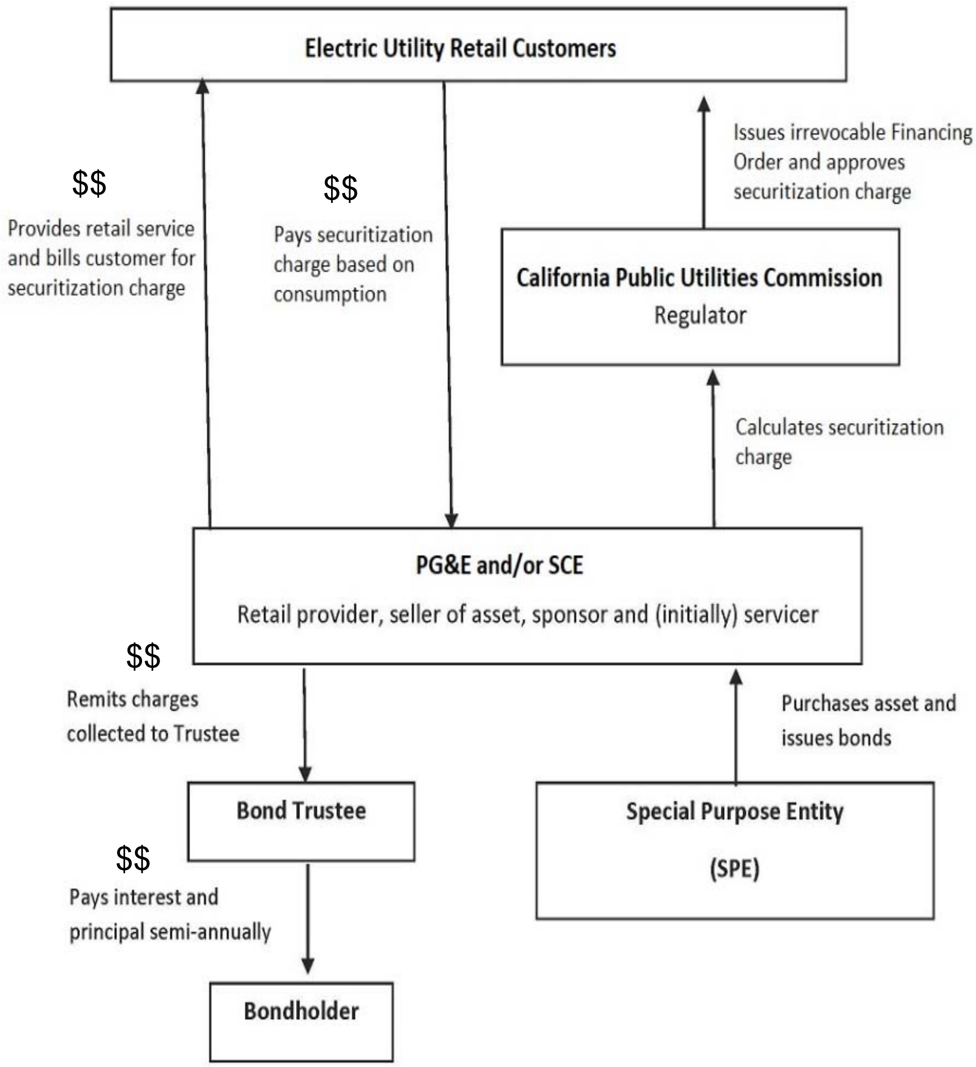


Exhibit C

Deal #	Issuer	Utility Beneficiary	Tranche	Amount	Weighted Average Life (years)
64	Duke Energy Florida Project Finance, LLC (6/15/2016)	Duke Energy Florida	A-1	$ 183,000,000	2.00
			A-2	$ 150,000,000	5.00
			A-3	$ 436,000,000	10.00
			A-4	$ 250,000,000	15.20
			A-5	$ 275,290,000	18.70
			Total	$ 1,294,290,000	11.14
63	Entergy New Orleans Storm Recovery Funding I, LLC (7/14/15)	Entergy New Orleans	A-1	$ 98,730,000	4.98
62	Department of Business, Economic Development, and Tourism (Hawaii) (11/04/2014)	Hawaiian Electric Co., Hawaii Electric Light Co., Maui Electric Co	A-1	$ 50,000,000	3.05
			A-2	$ 100,000,000	10.21
			Total	$ 150,000,000	7.82
61	Louisiana Local Government Environmental Facilities and Community Development Authority Taxable municipal securities) (7/29/2014)	Louisiana Utilities Restoration Corporation Project/ELL	A-1	$ 91,700,000	3.00
			A-2	$ 152,150,000	8.90
			Total	$ 243,850,000	6.68
60	Louisiana Local Governments Environmental Facilities Authority (Taxable municipal securities) (7/29/2014)	Louisiana Utilities Restoration Corporation Project/EGSL	A-1	$ 71,000,000	6.72
59	Consumers 2014 Securitization Funding, LLC (7/14/2014)	Consumers Energy	A-1	$ 124,500,000	3.00
			A-2	$ 139,000,000	8.00
			A-3	$ 114,500,000	12.26
			Total	$ 378,000,000	7.64
58	Appalachian Consumer Rate Relief Funding LLC (11/6/2013)	Appalachian Power Company	A-1	$ 215,800,000	5.00
			A-2	$ 164,500,000	12.24
			Total	$ 380,300,000	8.13
57	Ohio Phase-In-Recovery Funding, LLC (7/23/2013)	Ohio Power Company	A-1	$ 164,900,000	2.25
			A-2	$ 102,508,000	5.08
			Total	$ 267,408,000	3.33
56	FirstEnergy Ohio PIRB Special Purpose Trust 2013 (Issued as pass-through certificates, backed by bonds issued by CEI, OE and TE) (6/12/2013)	The Cleveland Electric Illuminating Company (CEL), Ohio Edison Company (OE), The Toledo Edison Company (TE)	A-1	$ 111,971,000	1.60
			A-2	$ 70,468,000	5.07
			A-3	$ 262,483,000	13.70
			Total	$ 444,922,000	9.29
55	AEP Texas Central Transition Funding III LLC (3/7/2012)	AEP Texas Central Company	A-1	$ 307,900,000	3.00
			A-2	$ 180,200,000	7.00
			A-3	$ 311,900,000	10.76
			Total	$ 800,000,000	6.93
54	CenterPoint Energy Transition Bond Company IV, LLC (1/11/2012)	CenterPoint Energy Houston Electric, LLC	A-1	$ 606,222,000	3.00
			A-2	$ 407,516,000	7.00
			A-3	$ 681,262,000	10.82
			Total	$ 1,695,000,000	7.10
53	Entergy Louisiana Investment Recovery Funding I, LLC (9/15/2011)	Entergy Louisiana, LLC	A-1	$ 207,156,000	5.27
			Total	$ 207,156,000	5.27
52	Entergy Arkansas Energy Restoration Funding, LLC (8/11/2010)	Entergy Arkansas, Inc.	A-1	$ 124,100,000	5.44
			Total	$ 124,100,000	5.44
51	Louisiana Local Government Environmental Facilities and Community Development Authority (Taxable municipal securities) (7/15/2010)	Louisiana Utilities Restoration Corporation Project/ELL	A-1	$ 112,000,000	2.00
			A-2	$ 111,000,000	5.00
			A-3	$ 121,000,000	8.00
			A-4	$ 124,900,000	10.90
			Total	$ 468,900,000	6.63
50	Louisiana Local Government Environmental Facilities and Community Development Authority (Taxable municipal securities) (7/15/2010)	Louisiana Utilities Restoration Corporation Project/EGSL	A-1	$ 97,000,000	3.00
			A-2	$ 60,000,000	7.00
			A-3	$ 87,100,000	10.40
			Total	$ 244,100,000	6.62
49	MP Environmental Funding LLC (12/16/2009)	Monongahela Power	A-1	$ 64,380,000	19.02
			Total	$ 64,380,000	19.02
48	PE Environmental Funding LLC (12/16/2009)	Potomac Edison	A-1	$ 21,510,000	19.02
			Total	$ 21,510,000	19.02

Deal #	Issuer	Utility Beneficiary	Tranche	Amount	Weighted Average Life (years)
47	CenterPoint Energy Restoration Bond Company, LLC	CenterPoint Energy Houston Electric, LLC	A-1	$ 224,788,000	3.00
	(11/18/2009)		A-2	$ 160,152,000	7.00
			A-3	$ 279,919,000	10.82
			Total	$ 664,859,000	7.26
46	Entergy Texas Restoration Funding, LLC	Entergy Texas, Inc.	A-1	$ 182,500,000	3.00
	(10/29/09)		A-2	$ 144,800,000	7.00
			A-3	$ 218,600,000	10.86
			Total	$ 545,900,000	7.21
45	Louisiana Public Facilities Authority	Louisiana Utilities Restoration Corporation/EGSL	A-1	$ 103,000,000	2.66
	(Taxable municipal securities)		A-2	$ 90,000,000	6.24
	(8/20/2008)		A-3	$ 85,400,000	8.97
			Total	$ 278,400,000	5.75
44	Louisiana Public Facilities Authority	Louisiana Utilities Restoration Corporation/ELL	A-1	$ 160,000,000	1.99
	(Taxable municipal securities)		A-2	$ 367,000,000	5.97
	(7/22/2008)		A-3	$ 160,700,000	9.32
			Total	$ 687,700,000	5.83
43	Cleco Katrina/Rita Hurricane Recovery Funding LLC	Cleco Power LLC	A-1	$ 113,000,000	5.00
	(2/28/2008)		A-2	$ 67,600,000	10.58
			Total	$ 180,600,000	7.09
42	CenterPoint Energy Transition Bond III, LLC	CenterPoint Energy Houston Electric, LLC	A-1	$ 301,427,000	5.00
	(1/29/2008)		A-2	$ 187,045,000	10.52
			Total	$ 488,472,000	7.11
41	Entergy Gulf States Reconstruction Funding I, LLC	Entergy Gulf States, Inc.	A-1	$ 93,500,000	2.99
	(6/22/2007)		A-2	$ 121,600,000	7.99
			A-3	$ 114,400,000	12.24
			Total	$ 329,500,000	8.05
40	RSB BondCo LLC	Baltimore Gas & Electric	A-1	$ 284,000,000	2.99
	(6/22/2007)		A-2	$ 220,000,000	6.99
			A-3	$ 119,200,000	9.27
			Total	$ 623,200,000	5.60
39	FPL Recovery Funding LLC	Florida Power & Light	A-1	$ 124,000,000	1.97
	(5/15/07)		A-2	$ 140,000,000	4.98
			A-3	$ 100,000,000	7.31
			A-4	$ 288,000,000	10.38
			Total	$ 652,000,000	7.15
38	MP Environmental Funding LLC	Monongahela Power	A-1	$ 86,200,000	4.00
	(4/3/2007)		A-2	$ 76,000,000	10.00
			A-3	$ 153,250,000	16.00
			A-4	$ 29,025,000	20.00
			Total	$ 344,475,000	12.01
37	PE Environmental Funding LLC	Potomac Edison	A-1	$ 28,450,000	4.00
	(4/3/2007)		A-2	$ 25,700,000	10.00
			A-3	$ 50,700,000	16.10
			A-4	$ 9,975,000	19.94
			Total	$ 114,825,000	12.07
36	AEP Texas Central Transition Funding II LLC	AEP Texas Central Company	A-1	$ 217,000,000	2.00
	(10/4/2006)		A-2	$ 341,000,000	5.00
			A-3	$ 250,000,000	7.58
			A-4	$ 437,000,000	10.00
			A-5	$ 494,700,000	12.68
			Total	$ 1,739,700,000	8.44
35	JCP&L Transition Funding II LLC	Jersey Central Power & Light	A-1	$ 56,348,000	3.00
	(8/4/2006)		A-2	$ 25,693,000	7.00
			A-3	$ 49,220,000	10.00
			A-4	$ 51,139,000	13.40
			Total	$ 182,400,000	8.37

Deal #	Issuer	Utility Beneficiary	Tranche	Amount	Weighted Average Life (years)
34	CenterPoint Energy Transition Bond Company II, LLC	CenterPoint Houston	A-1	$ 250,000,000	2.02
	(12/9/2005)		A-2	$ 368,000,000	5.00
			A-3	$ 252,000,000	7.47
			A-4	$ 519,000,000	10.01
			A-5	$ 462,000,000	12.71
			Total	$ 1,851,000,000	8.26
33	PG&E Energy Recovery Funding LLC	Pacific Gas & Electric	A-1	$ 351,000,000	2.00
	(11/3/2005)		A-2	$ 372,000,000	5.00
			A-3	$ 121,461,000	6.83
			Total	$ 844,461,000	4.02
32	WPP Funding LLC	West Penn Power	A-1	$ 115,000,000	4.24
	(9/22/2005)		Total	$ 115,000,000	4.24
31	PSE&G Transition Funding II LLC	Public Service Electric & Gas	A-1	$ 25,200,000	2.00
	(9/9/2005)		A-2	$ 35,000,000	5.00
			A-3	$ 20,000,000	7.47
			A-4	$ 22,500,000	9.16
			Total	$ 102,700,000	5.66
30	Massachusetts RRB Special Purpose Trust 2005-1	Boston Edison and Commonwealth Electric	A-1	$ 109,200,000	1.00
	(BEC Funding ll, LLC $265.5M and CEC Funding, LLC $409.0M)		A-2	$ 154,000,000	2.50
	2/15/2005		A-3	$ 266,500,000	5.00
			A-4	$ 144,800,000	7.40
			Total	$ 674,500,000	4.30
29	PG&E Energy Recovery Funding LLC	Pacific Gas & Electric	A-1	$ 268,000,000	1.00
	(2/3/2005)		A-2	$ 647,000,000	3.00
			A-3	$ 320,000,000	5.00
			A-4	$ 468,000,000	6.50
			A-5	$ 184,864,000	7.68
			Total	$ 1,887,864,000	4.38
28	Rockland Electric Company Transition Funding LLC	Rockland Electric	A-1	$ 46,300,000	8.70
	(7/28/04)		Total	$ 46,300,000	8.70
27	TXU Electric Delivery Transition Bond Company LLC	Oncor Electric Delivery Company	A-1	$ 279,000,000	3.00
	(5/28/2004)		A-2	$ 221,000,000	7.00
			A-3	$ 289,777,000	10.43
			Total	$ 789,777,000	6.85
26	Atlantic City Electric Transition Funding LLC	Atlantic City Electric	A-1	$ 46,000,000	2.97
	(12/18/2003)		A-2	$ 52,000,000	8.24
			A-3	$ 54,000,000	12.90
			Total	$ 152,000,000	8.30
25	Oncor Electric Delivery Transition Bond Company LLC	Oncor Electric Delivery Company	A-1	$ 103,000,000	2.00
	(8/14/2003)		A-2	$ 122,000,000	5.00
			A-3	$ 130,000,000	8.00
			A-4	$ 145,000,000	10.83
			Total	$ 500,000,000	6.85
24	Atlantic City Electric Transition Funding LLC	Atlantic City Electric	A-1	$ 109,000,000	3.00
	(12/11/2002)		A-2	$ 66,000,000	7.00
			A-3	$ 118,000,000	10.50
			A-4	$ 147,000,000	15.39
			Total	$ 440,000,000	9.75
23	JCP&L Transition Funding LLC	Jersey Central Power & Light	A-1	$ 91,111,000	3.00
	(6/4/2002)		A-2	$ 52,297,000	7.00
			A-3	$ 77,075,000	10.00
			A-4	$ 99,517,000	13.40
			Total	$ 320,000,000	8.57
22	CPL Transition Funding LLC	Central Power & Light	A-1	$ 128,950,233	1.90
	(1/31/2002)		A-2	$ 154,506,810	4.70
			A-3	$ 107,094,258	7.20
			A-4	$ 214,926,738	10.00
			A-5	$ 191,856,858	13.00
			Total	$ 797,334,897	8.01

SABER PARTNERS, LLC

Deal #	Issuer	Utility Beneficiary	Tranche	Amount	Weighted Average Life (years)
21	PSNH Funding LLC 2	Public Service Company of New Hampshire	A-1	$ 50,000,000	3.50
	(1/16/2002)		Total	$ 50,000,000	3.50
20	Consumers Funding LLC	Consumers Energy	A-1	$ 26,000,000	1.00
	(10/31/2001)		A-2	$ 84,000,000	3.00
			A-3	$ 31,000,000	5.00
			A-4	$ 95,000,000	7.00
			A-5	$ 117,000,000	10.00
			A-6	$ 115,592,000	12.80
			Total	$ 468,592,000	8.00
19	Reliant Energy Transition Bond Company I, LLC	Reliant Energy	A-1	$ 115,000,000	2.71
	(10/17/2001)		A-2	$ 118,000,000	5.19
			A-3	$ 130,000,000	7.19
			A-4	$ 385,987,000	10.29
			Total	$ 748,987,000	7.78
18	Massachusetts RRB Special Purpose Trust WMECO-1	Western Massachusetts Electric	A-1	$ 155,000,000	7.00
	(5/14/2001)		Total	$ 155,000,000	7.00
17	PSNH Funding LLC	Public Service Company of New Hampshire	A-1	$ 75,211,483	1.09
	(4/20/2001)		A-2	$ 214,649,395	5.04
			A-3	$ 235,139,122	9.99
			Total	$ 525,000,000	6.69
16	Connecticut RRB Special Purpose Trust CL&P-1	Connecticut Light and Power	A-1	$ 224,858,822	1.18
	(3/27/2001)		A-2	$ 255,056,333	3.16
			A-3	$ 292,381,624	5.16
			A-4	$ 287,907,878	7.02
			A-5	$ 378,195,343	8.89
			Total	$ 1,438,400,000	5.54
15	The Detroit Edison Securitization Funding LLC	Detroit Edison Company	A-1	$ 124,540,305	1.50
	(3/2/2001)		A-2	$ 179,037,815	3.30
			A-3	$ 322,791,421	5.80
			A-4	$ 406,722,416	8.80
			A-5	$ 326,236,780	11.30
			A-6	$ 390,671,263	13.30
			Total	$ 1,750,000,000	8.64
14	PECO Energy Transition Trust	PECO Energy	A-1	$ 805,500,000	9.25
	(2/15/2001)		Total	$ 805,500,000	9.25
13	PSE&G Transition Funding LLC	Public Service Electric & Gas	A-1	$ 105,249,914	1.00
	(1/25/2001)		A-2	$ 368,980,380	2.90
			A-3	$ 182,621,909	4.88
			A-4	$ 496,606,425	7.02
			A-5	$ 328,032,965	9.38
			A-6	$ 453,559,632	11.39
			A-7	$ 219,688,870	12.99
			A-8	$ 370,259,905	14.27
			Total	$ 2,525,000,000	8.69
12	PECO Energy Transition Trust	PECO Energy	A-1	$ 110,000,000	1.11
	(4/27/2000)		A-2	$ 140,000,000	2.08
			A-3	$ 398,900,000	8.74
			A-4	$ 351,100,000	9.33
			Total	$ 1,000,000,000	7.18
11	West Penn Funding, LLC	West Penn Power	A-1	$ 74,000,000	1.00
	(11/3/1999)		A-2	$ 172,000,000	3.00
			A-3	$ 198,000,000	5.50
			A-4	$ 156,000,000	7.80
			Total	$ 600,000,000	4.83
10	PP&L Transition Bond Company LLC	Pennsylvania Power & Light	A-1	$ 293,000,000	1.00
	(7/29/1999)		A-2	$ 178,000,000	2.00
			A-3	$ 303,000,000	3.00
			A-4	$ 201,000,000	4.00
			A-5	$ 313,000,000	5.00
			A-6	$ 223,000,000	6.00
			A-7	$ 455,000,000	7.22
			A-8	$ 454,000,000	8.75
			Total	$ 2,420,000,000	5.17

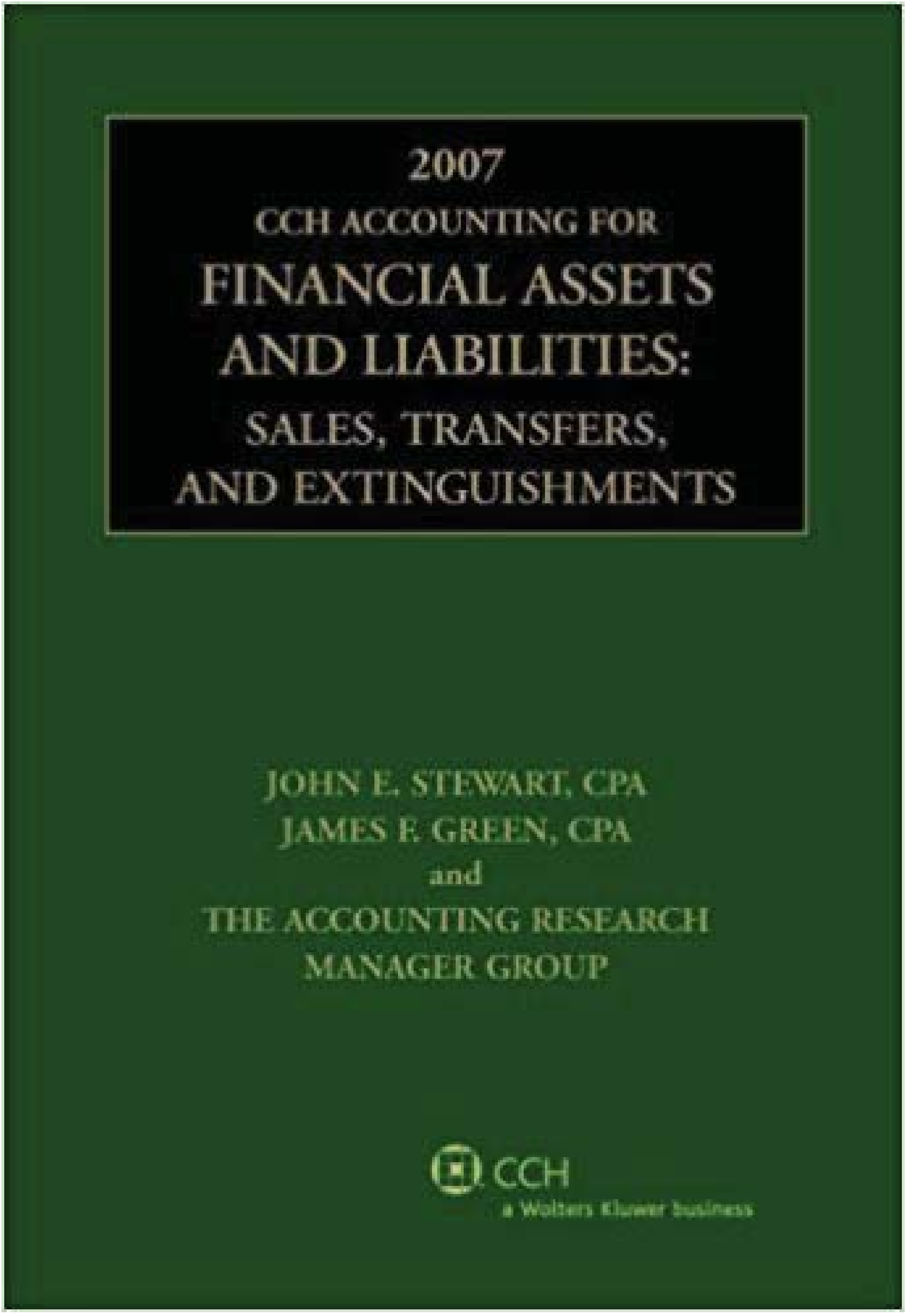
Deal #	Issuer	Utility Beneficiary	Tranche	Amount	Weighted Average Life (years)
9	Massachusetts RRB Special Purpose Trust BEC-1	Boston Edison	A-1	$ 108,500,000	1.09
	(7/27/1999)		A-2	$ 170,600,000	3.13
			A-3	$ 103,400,000	5.13
			A-4	$ 170,900,000	7.13
			A-5	$ 171,600,000	9.63
			Total	$ 725,000,000	5.59
8	Sierra Pacific	Sierra Pacific Power	A-1	$ 24,000,000	
	(4/8/1999)		Total	$ 24,000,000	
7	PECO Energy Transition Trust	PECO Energy	A-1	$ 244,500,000	1.30
	(3/18/1999)		A-2	$ 275,400,000	3.27
			A-3	$ 667,000,000	4.04
			A-4	$ 458,500,000	5.38
			A-5	$ 464,600,000	6.29
			A-6	$ 993,400,000	7.28
			A-7	$ 896,700,000	8.92
			Total	$ 4,000,100,000	6.13
6	MPC Natural Gas Funding Trust 1998-1	Montana Power	A-1	$ 64,000,000	
	(12/22/1998)		Total	$ 64,000,000	
5	Illinois Power Special Purpose Trust	Illinois Power	A-1	$ 110,000,000	0.79
	(12/10/1998)		A-2	$ 100,000,000	1.79
			A-3	$ 80,000,000	2.93
			A-4	$ 85,000,000	3.93
			A-5	$ 175,000,000	5.17
			A-6	$ 175,000,000	7.40
			A-7	$ 139,000,000	9.54
			Total	$ 864,000,000	5.05
4	ComEd Transitional Funding Trust	Commonwealth Edison	A-1	$ 426,600,000	0.88
	(12/7/1998)		A-2	$ 423,400,000	2.04
			A-3	$ 259,300,000	3.04
			A-4	$ 420,700,000	4.04
			A-5	$ 598,700,000	5.54
			A-6	$ 761,300,000	7.54
			A-7	$ 510,000,000	9.41
			Total	$ 3,400,000,000	5.17
3	California Infrastructure and Economic Development	San Diego Gas & Electric	A-1	$ 65,800,000	0.77
	Bank Special Purpose Trust SDG&E,-1		A-2	$ 82,600,000	1.78
	(12/4/1997)		A-3	$ 66,200,000	2.92
			A-4	$ 65,700,000	3.92
			A-5	$ 96,500,000	5.15
			A-6	$ 197,600,000	7.29
			A-7	$ 83,500,000	9.52
			Total	$ 657,900,000	5.14
2	California Infrastructure and Economic Development	Southern California Edison	A-1	$ 246,000,000	0.79
	Bank Special Purpose Trust SCE-1		A-2	$ 307,000,000	1.79
	(12/4/1997)		A-3	$ 248,000,000	2.93
			A-4	$ 246,000,000	3.93
			A-5	$ 361,000,000	5.17
			A-6	$ 740,000,000	7.40
			A-7	$ 315,000,000	9.54
			Total	$ 2,463,000,000	5.19
1	PG&E Funding LLC	Pacific Gas & Electric	A-1	$ 125,000,000	0.56
	(11/25/1997)		A-2	$ 265,000,000	1.09
			A-3	$ 280,000,000	1.99
			A-4	$ 300,000,000	3.01
			A-5	$ 290,000,000	4.02
			A-6	$ 375,000,000	5.17
			A-7	$ 866,000,000	7.31
			A-8	$ 400,000,000	9.48
			Total	$ 2,901,000,000	5.19
	Total of all taxable utility securitizations on behalf of IOU ratepayers			$ 49,892,092,897	

* Excludes two transactions for the benefit of ratepayers of the Long Island Power Authority (a governmental utility) in 2013 and 2015, which were a combination of taxable and tax-exempt debt.

Exhibit D

Moody's		S&P		Fitch		Rating description	
Long-term	Short-term	Long-term	Short-term	Long-term	Short-term		
Aaa	P-1	AAA	A-1+	AAA	F1+	Prime	Investment-grade
Aa1		AA+		AA+		High grade	
Aa2		AA		AA			
Aa3		AA−		AA−			
A1		A+	A-1	A+	F1	Upper medium grade	
A2		A		A			
A3	P-2	A−	A-2	A−	F2		
Baa1		BBB+		BBB+		Lower medium grade	
Baa2	P-3	BBB	A-3	BBB	F3		
Baa3		BBB−		BBB−			
Ba1	Not prime	BB+	B	BB+	B	Non-investment grade speculative	Non-investment grade AKA high-yield bonds AKA junk bonds
Ba2		BB		BB			
Ba3		BB−		BB−			
B1		B+		B+		Highly speculative	
B2		B		B			
B3		B−		B−			
Caa1		CCC+	C	CCC	C	Substantial risks	
Caa2		CCC				Extremely speculative	
Caa3		CCC−				Default imminent with little prospect for recovery	
Ca		CC					
		C					
C		D	/	DDD	/	In default	
/				DD			
				D			

Exhibit E.i


2007
CCH ACCOUNTING FOR
FINANCIAL ASSETS
AND LIABILITIES:
SALES, TRANSFERS,
AND EXTINGUISHMENTS
JOHN E. STEWART, CPA
JAMES F. GREEN, CPA
and
THE ACCOUNTING RESEARCH
MANAGER GROUP
CCH
a Wolters Kluwer business

Question: Is a transfer of trade receivables for which the related goods or services have been provided, but for which the related receivables have not been billed, a transfer of financial assets that is accounted for under Statement 140?

Response: Yes. A common situation that creates unbilled receivables is when a utility company is able to recognize revenue for the service it provides to its customers but, due to its billing cycle, the customers are not invoiced until a later date. Since the utility has provided the service to its customer, it has a contractual right to receive payment for services rendered and generally would have recognized the related sale of electricity as revenue. Thus, unbilled receivables are recorded financial assets, the transfer of which would be accounted for under Statement 140. One possible technique to determine whether the would-be transferor has a contractual right to receive payment equal to the amount of the unbilled receivable would be to confirm the existence of the receivable amount with a sample of customers.

4-12. Securitization of Regulatory Assets

Summary: Regulatory assets (often called stranded costs) are not financial assets and therefore are not covered by Statement 140. The SEC staff believes EITF Issue No. 88-18, "Sales of Future Revenues," covers them.

Question (from FASB Staff Implementation Guide, Question 6):

> The deregulation of utility rates charged for electric power generation has caused electricity-producing companies to identify some of their electric power generation operations as "stranded costs." Prior to deregulation, utilities typically expected to be reimbursed for costs through regulation of rates charged to customers. After deregulation, some of these costs may no longer be recoverable through unregulated rates. Hence, such potentially unrecoverable costs often are referred to as stranded costs. However, some of those stranded costs may be recovered through a surcharge or tariff imposed on rate-regulated goods or services provided by another portion of the entity whose pricing remains regulated.
>
> Some entities have securitized their enforceable rights to impose that tariff (often referred to as "securitized stranded costs"), thereby obtaining cash from investors in exchange for the future cash flows to be realized from collecting surcharges imposed on customers of the rate-regulated goods or services. Are securitized stranded

costs considered to be financial assets, the transfer of which would be within the scope of Statement 140?

Response (from FASB Staff Implementation Guide, Question 6):

No. Paragraph 364 defines *financial asset* as "...a contract that conveys to a second entity a *contractual right* (a) to receive cash or another financial instrument from a first entity or (b) to exchange other financial instruments on potentially favorable terms with the first entity" (emphasis added). Therefore, to be a financial asset, an asset must arise from a contractual agreement between two or more parties, not by an imposition of an obligation by one party on another. This notion in Statement 140 is consistent with the notion discussed in paragraph 39 of FASB Statement No. 105, *Disclosure of Information about Financial Instruments with Off-Balance-Sheet Risk and Financial Instruments with Concentrations of Credit Risk*,[2] which stated:

> Other contingent items that ultimately may require the payment of cash but do not as yet arise from contracts, such as contingent liabilities for tort judgments payable, are not financial instruments. However, when those obligations become enforceable by government or courts of law and are thereby contractually reduced to fixed payment schedules, the items would be financial instruments under the definition.

Securitized stranded costs are not financial assets, and therefore transfers of securitized stranded costs are not within the scope of Statement 140. Securitized stranded costs are not financial assets because they are imposed on ratepayers by a state government or its regulatory commission and, thus, while an enforceable right for the utility, they are not a *contractual* right to receive payments from another party. To elaborate, while a right to collect cash flows exists, *it is not the result of a contract* and, thus, not a financial asset. Refer to Question 7 [Interpretation 2-4].

---

[2] Although Statement 105 was superseded by FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities*, the Board's definition of *financial asset* continues to be based on the definition of a financial instrument found in Statement 105.

Commentary: We discussed this issue with the SEC staff before the issuance of the FASB Staff Implementation Guide on Statement 125 (which preceded the Statement 140 FASB Staff Implementation

Guide). The SEC staff concluded that regulatory assets are not financial assets. The staff believes the legislation that provides for the securitization of regulatory assets simply allows the utility's regulatory authority to impose a tariff on electricity sold in the future. The law, however, does not transform regulatory assets into financial assets since they generally do not qualify to be accounted for as revenue until they are "billable" to the customer. The basis for the SEC staff's conclusion is that the resulting law creates an enforceable right (which is a right imposed on one party by another, such as a property tax), but not a contractual right. The SEC staff, after consulting with the FASB staff, concluded that the FASB specifically limited financial assets to contractual rights to cash or other financial assets, which are essentially a subset of enforceable rights. Thus, such an enforceable right does not meet the definition of a financial asset.

The SEC staff also concluded that the proceeds received by the utility do not represent cash for assets sold, but cash received for future services. This approach effectively precludes accounting for this type of a transaction as a sale outside of Statement 140. The SEC staff believes the proceeds represent debt. EITF Issue No. 88-18, "Sales of Future Revenues," provides the most relevant guidance to make that determination (see Interpretation 4-9).

4-13. Transfers of Minimum Lease Payments Under an Operating Lease

Summary: Transfers of contractual payments receivable under an operating lease are not within the scope of Statement 140.

Question (from FASB Staff Implementation Guide, Question 1):

> If a right to receive the minimum lease payments to be received under an operating lease is transferred, could it be considered a financial asset within the scope of Statement 140?

Response (from FASB Staff Implementation Guide, Question 1):

> No. A right to receive the minimum lease payments to be received under an operating lease is an unrecognized financial asset. As stated in paragraph 4, Statement 140 "does not address... transfers of unrecognized financial assets, for example, minimum lease payments to be received under operating leases."

Exhibit E.ii

TWELFTH EDITION

ACCOUNTANTS' HANDBOOK

VOLUME TWO:
Special Industries and Special Topics

Lynford Graham

D.R. Carmichael

asset's carrying amount and subsequently allocated to expense over that asset's useful life. ASC Topic 410 includes special provisions for entities that apply ASC Topic 980. Differences between amounts collected through rates and amounts recognized in accordance with ASC Topic 410 were recognized as regulatory assets and liabilities if the requirements of ASC Topic 980 were met.

(v) Securitization of Stranded Costs, Including Regulatory Assets. In connection with the electric industry restructuring efforts that occurred in a number of states, regulatory mechanisms were established to mitigate potential stranded costs. The legislative or regulatory framework for moving to a competitive marketplace included provisions when issued for the affected companies to securitize or "monetize" all or a portion of their stranded costs through the issuance of debt securities that would provide the utility with a lower cost of capital than that to which they were previously exposed. Generally, such provisions establish a separate unbundled revenue stream from the current bundled stream, surcharge, or tariff that would be the source of recovery from a company's rate payers for the stranded costs. Companies securitize their rights to impose such revenue stream, surcharge, or tariff by receiving cash flows from investors in exchange for future cash flows to be collected from customers. The utility would issue debt obligations in an amount equal to its stranded costs (or portion thereof). The resulting debt obligations would be nonrecourse since the company would sell the stranded costs to a credit-enhanced, bankruptcy remote special-purpose entity or trust established to finance the purchase through the sale of state-authorized debt. Collections of the tariff by the company would be passed through to holders of the debt as periodic payments of interest and principal.

The potential benefits to a company from securitizing stranded costs include the opportunity to improve credit quality and to use the proceeds to reduce leverage and fixed charges, or fund the termination of uneconomic contracts. The expectation is that monetizing the stranded costs would result in lower rates for consumers since higher cost of capital is effectively replaced by traditional utility debt with lower cost.

In February 1997, the SEC's Office of Chief Accountant provided financial reporting guidance to California's utility registrants for proceeds received in connection with a stranded cost securitization. The SEC Staff concluded that the proceeds received should be classified as either debt or deferred revenue based on the guidance in ASC Topic 470-10-25, *Debt*.

ASC Topic 470-10-25 reached a consensus that the presence of any one of six specifically identified factors independently creates a rebuttable presumption that classification of the proceeds as debt is appropriate. The facts and circumstances of stranded cost securitization transactions will typically result in the presence of one or more of the factors. Thus, securitization proceeds are generally expected to be classified as debt for financial reporting purposes.

ASC Topic 470-10-25 also concluded that amounts recorded as debt should be amortized under the interest method. Generally, this will result in an increasing amount of stranded cost recognition in the income statement during the securitization period. This occurs because the amount recognized will equal the principal portion (on a mortgage basis) of the tariffed debt service cost that is billable to customers and recorded as revenue during each period.

In connection with providing classification guidance, the SEC Staff also concluded that regulatory assets are not financial assets. This is supported by ASC Topic 860-55-8, *Transfers and Servicing*, and SFAS No. 166, *Accounting for Transfers of Financial Assets—an Amendment of FASB No. 140*-FASB Statement Appendix C paragraph 6. Further, the legislation that provides for the securitization of regulatory assets simply allows the utility's regulator to impose a surcharge or tariff on electricity sold in the future. The law, however, does not transpose regulatory assets into financial assets. The basis for the SEC Staff's conclusion is that the resulting law creates an enforceable right (which is a right imposed on one party by another, such as a property tax) and not a contractual right. The SEC Staff, after consulting with the FASB Staff, concluded that the FASB specifically limited financial assets to a contractual right, which is essentially a subset of an enforceable right. Thus, enforceable rights that are not contractual rights do not meet the definition of a financial asset under ASC Topic 860-55-8. However, beneficial interests in a securitization trust that holds nonfinancial assets, such as securitized stranded costs, would be considered financial

Exhibit E.iii

Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 860-10-55-8

Securitized stranded costs are not financial assets, and therefore transfers of securitized stranded costs are not within the scope of this Subtopic. Securitized stranded costs are not financial assets because they are imposed on ratepayers by a state government or its regulatory commission and, thus, while an enforceable right for the utility, they are not a contractual right to receive payments from another party. To elaborate, while a right to collect cash flows exists, it is not the result of a contract and, thus, not a financial asset.

Exhibit E.iv

Regulation AB
Item 1101

September 19, 2007

Response of the Office of Chief Counsel
Division of Corporation Finance

Re: MP Environmental Funding LLC, PE Environmental Funding LLC
Incoming letter dated September 7, 2007

Capitalized terms used in this response have the same meaning as defined in your letter. Based on the facts presented, it is the Division's view that MP Funding and PE Funding are not asset-backed issuers and the Bonds are not asset-backed securities within the meaning of Item 1101 of Regulation AB. Notwithstanding that conclusion, the Division will not recommend enforcement action to the Commission if the Issuers file periodic reports related to the Bonds in compliance with the disclosure and reporting regime established in Regulation AB.

This position is based on the representations made to the Division in your letter. Any different facts or conditions might require the Division to reach a different conclusion. Moreover, with the exception of the position concerning the status of the Issuers and Bonds under Item 1101 of Regulation AB, this response merely expresses the Division's position on enforcement action, and does not purport to express any legal conclusions on the questions presented.

Sincerely,

Jeffrey S. Cohan
Special Counsel

From SEC website https://www.sec.gov/divisions/corpfin/cf-noaction/2007/mpef091907-1101.htm.

THELEN REID BROWN
RAYSMAN & STEINER LLP
ATTORNEYS AT LAW

NEW YORK · SAN FRANCISCO · WASHINGTON, DC · LOS ANGELES
SILICON VALLEY · HARTFORD · NORTHERN NEW JERSEY · SHANGHAI

September 7, 2007

Securities and Exchange Commission
Division of Corporation Finance
Office of Chief Counsel
100 F Street, N. E.
Washington, D.C. 20549

Attention: Paula Dubberly, Associate Director (Legal)

Re: **MP Environmental Funding LLC, PE Environmental Funding LLC Senior Secured Sinking Fund Environmental Control Bonds, Series A**

Dear Ms. Dubberly:

On behalf of MP Environmental Funding LLC ("MP Funding"), Monongahela Power Company ("Mon Power"), PE Environmental Funding LLC ("PE Funding", and together with MP Funding, the "Issuers") and Potomac Edison Company ("Potomac Edison", and together with Mon Power, the "Utilities"), we hereby request from the Staff (the "Staff") of the Securities and Exchange Commission (the "Commission") (a) confirmation that the Issuers are not asset-backed issuers and the bonds described below are not asset-backed securities within the meaning of Item 1101(b) and (c), respectively, of Regulation AB, and (b) assurance that, notwithstanding the fact that the Issuers are not asset-backed issuers and the bonds described below are not asset-backed securities, the Staff will not recommend enforcement action to the Commission if the Issuers file periodic reports in respect of the bonds described below in compliance with the disclosure and reporting regime established in Regulation AB.

Background

MP Funding is an indirectly wholly-owned finance subsidiary of Mon Power. Mon Power is a vertically integrated electric utility that provides electric service to over 375,000 customers in the state of West Virginia at rates regulated by the Public Service Commission of West Virginia (the "PSC") and the Federal Energy Regulatory Commission ("FERC"). MP Funding is indirectly wholly-owned by Mon Power but is bankruptcy remote from Mon Power and its affiliates.

PE Funding is an indirectly wholly-owned finance subsidiary of Potomac Edison. Potomac Edison is an electric utility that provides electric service to over 125,000 customers in the state of West Virginia at rates regulated by the PSC and FERC. PE Funding is indirectly wholly-owned by Potomac Edison but is bankruptcy remote from Potomac Edison and its affiliates.

On April 11, 2007, MP Funding issued $344,475,000 aggregate principal amount of its Senior Secured Sinking Fund Environmental Control Bonds, Series A (the "MP Funding Bonds") and PE Funding issued $114,825,000 aggregate principal amount of its Senior Secured Sinking Fund Environmental Control Bonds, Series A (the "PE Funding Bonds" and, together with the MP Funding Bonds, the "Bonds"). The Bonds were issued pursuant to Section 24-2-4e of the West Virginia Code (the "Financing Act") and a financing order of the PSC issued on April 7, 2006, as amended on June 13, 2006, and January 17, 2007 (the "Financing Order").

The Bonds are the Issuers' senior secured obligations, secured by the Issuers' environmental control property. Environmental control property includes the right, pursuant to the Financing Order, to impose, charge, collect and receive special, irrevocable non-bypassable charges, known as environmental control charges, to be paid by all electric service customers located within the Issuers' respective West Virginia service territories; the right to implement a true-up mechanism to adjust the amount of the environmental control charges at least semi-annually, or more frequently if necessary; the right to receive all revenues and collections resulting from the environmental control charges, and other rights and interests that arise under the Financing Order.

The Financing Order, the organizational documents for MP Funding and for PE Funding, and the transaction documents supporting the Bonds give MP Funding and PE Funding the authority and flexibility to issue additional indebtedness (including additional debt securities that are not environmental control bonds) in future transactions with the approval of the PSC. These documents expressly envision that the PSC may issue additional financing orders authorizing and directing Mon Power to use MP Funding, and/or authorizing and directing Potomac Edison to use PE Funding, to implement other financings for the benefit of West Virginia ratepayers. As a result, MP Funding and PE Funding each may acquire additional separate property (including property other than environmental control property) and may issue one or more additional series of securities that are supported by such additional and separate property or other collateral.

Discussion

SEC Release No. 33-8518 states that securities issued by entities that are organized as "series trusts" with flexibility to issue additional securities in wholly separate and unrelated transactions will not be "asset-backed securities" for purposes of Regulation AB.

The Issuers' organizational documents, as well as the transaction documents supporting the Bonds and the Financing Order, give the Issuers the authority and flexibility to issue additional indebtedness (including additional debt securities that are not environmental control bonds) in wholly separate and unrelated future transactions with the approval of the PSC. The PSC may authorize and direct Mon Power to use MP Funding, and/or authorize and direct Potomac Edison to use PE Funding, to implement other financings for the benefit of West Virginia ratepayers. The Issuers may acquire additional separate property (including property other than environmental control property) and issue one or more additional series of securities that are supported by such additional and separate property or other collateral. By way of example, the Issuers' future financings may include additional series of environmental control bonds to finance costs of other environmental control facilities either at the Ft. Martin generation facility or other facilities. If authorized by future state governmental action, such future financings may also include bonds issued to finance any extraordinary power purchase costs incurred by the Utilities, costs of the Utilities' facilities or contracts that become uneconomic in connection with a future deregulation of the supply of electricity in West Virginia, or any other of the Utilities' costs that might be approved by a future PSC order.

The Issuers' series trust structures place the Issuers outside the definition of "asset-backed issuer" and the Bonds outside the definition of "asset-backed securities" as those terms are defined in Sections 1101(b) and (c) of Regulation AB. As such, the Issuers would ordinarily be required to file quarterly reports on Form 10-Q and annual reports on Form 10-K pursuant to Rules 13a-13(a) and 13(a)-1, respectively, of the Securities Exchange Act of 1934, as amended. However, pursuant to a telephone conference with the Staff on March 5, 2007 and notwithstanding that the Issuers are not asset-backed issuers and the Bonds are not asset-backed securities, the Staff has advised the Issuers that continuing disclosure with respect to the Bonds should be provided in compliance with the applicable provisions of Regulation AB, including filing periodic and annual reports on Forms 10-D and 10-K.[1] These forms will allow the Issuers to convey to investors certain information about the Bonds that is not provided for under the reporting regime applicable to non-asset backed issuers, such as the distribution and servicer-related information described in Items 1121-1123 of Regulation AB. With respect to the requirements of Items 1122 and 1123 of Regulation AB that a servicer compliance statement be signed by an authorized officer of the servicer, Mon Power, as servicer in connection with the MP Funding Bonds, and Potomac Edison, as servicer in connection with the PE Funding Bonds, each confirm that the senior officer in charge of the servicing function will execute such servicer compliance statements in his or her individual capacity as required by Item 601(b)(31)-(35) of Regulation S-K.

Conclusion

On the basis of the facts and representations set forth above, the Issuers respectfully request from the Staff (a) confirmation that MP Funding and PE Funding are not asset-backed issuers and the Bonds are not asset-backed securities within the meaning of Item 1101(b) and (c), respectively, of Regulation AB, and (b) assurance that, notwithstanding the fact that the Issuers are not asset-backed issuers and the Bonds are not asset-backed securities, the Staff will not recommend enforcement action to the Commission if MP Funding and PE Funding file periodic reports in respect of the Bonds in compliance with the disclosure and reporting regime established in Regulation AB.

---

[1] The Issuers note that non-asset-backed issuers are generally subject to the requirements of Section 404 of the Sarbanes-Oxley Act of 2002, which requires the inclusion in Forms 10-Q and 10-K of reports by management as to the issuer's internal control structure. These reports are not required as to filings made on Forms 10-D or 10-K in compliance with Regulation AB, and therefore the Issuers would not include any such reports in their proposed filings on Forms 10-D and 10-K.

Seven additional copies of this letter are enclosed pursuant to Securities Act Release No. 33-6269. Please feel free to contact Robert J. Reger, Jr. at (212) 603-2526 or Mahendra Churaman at (212) 603-8971 with any questions or requests for additional information.

Very truly yours,

THELEN REID BROWN RAYSMAN & STEINER LLP,
counsel to MP Environmental Funding LLC, Monongahela Power Company, PE Environmental Funding LLC, and The Potomac Edison Company

By: Robert J. Reger, Jr.

Robert J. Reger, Jr.

Filed Pursuant to Rule 424(b)(1)
File No. 333-209196 and 333-209196-01

PROSPECTUS

$1,294,290,000 SERIES A SENIOR SECURED BONDS,

DUKE ENERGY FLORIDA, LLC

Sponsor, Depositor and Initial Servicer
Central Index Key Number: 0000037637

DUKE ENERGY FLORIDA PROJECT FINANCE, LLC

Issuing Entity
Central Index Key Number: 0001669374

Series A Bonds	Expected Weighted Average Life (Years)		Principal Amount Offered	Scheduled Final Payment Date	Final Maturity Date	Interest Rate	Initial Price to Public	Underwriting Discounts and Commissions		Proceeds to Issuer (Before Expenses)
Series A 2018	2.0	$	183,000,000	03/01/2020	03/01/2022	1.196%	99.999%	0.25%	$	182,540,670
Series A 2021	5.0	$	150,000,000	09/01/2022	09/01/2024	1.731%	99.998%	0.40%	$	149,397,000
Series A 2026	10.0	$	436,000,000	09/01/2029	09/01/2031	2.538%	99.996%	0.50%	$	433,802,560
Series A 2032	15.2	$	250,000,000	03/01/2033	03/01/2035	2.858%	99.995%	0.65%	$	248,362,500
Series A 2035	18.7	$	275,290,000	09/01/2036	09/01/2038	3.112%	99.994%	0.70%	$	273,346,453

The total price to the public is $1,294,238,713. The total amount of the underwriting discounts and commissions is $6,789,530. The total amount of proceeds to Duke Energy Florida Project Finance, LLC before deduction of expenses (estimated to be $9,163,470) is $1,287,449,183.

Duke Energy Florida, LLC, as **depositor**, is offering $1,294,290,000 aggregate principal amount of Series A Senior Secured Bonds listed above (each weighted average life designation a "WAL" and the five WALs collectively, the **Series A Bonds** or the **bonds)**, to be issued by Duke Energy Florida Project Finance, LLC, referred to herein as **DEF Project Finance**, as **issuing entity**.

The Series A Bonds are senior secured obligations of DEF Project Finance, and are its obligations only. The Series A Bonds are supported by **nuclear asset-recovery property**, which consists of all rights and interest of DEF Project Finance under the financing order, including the right to impose, bill, collect and receive irrevocable, binding, nonbypassable charges based on the usage of electricity. These charges pay principal, interest and expenses of the Series A Bonds and are known as **nuclear asset-recovery charges,** or as **ratepayer obligation charges** or **ROCs** and upon the issuance of the bonds may not be reduced, impaired, postponed, terminated or otherwise adjusted by the Florida Commission except as adjusted pursuant to the true-up mechanism described herein. These charges will be paid on a joint and several basis by all existing or future customers (individuals, corporations, other business entities, the State of Florida and other federal, state and local government entities) receiving transmission or distribution service from Duke Energy Florida, LLC, or **DEF**, or its successors or assignees under rate schedules approved by the Florida Commission or under special contracts. Nuclear asset-recovery charges are payable by customers even if the customers elect to purchase electricity from an alternative electricity supplier following a fundamental change in regulation of public utilities in Florida. Nuclear asset-recovery property includes the right to a mandatory true-up mechanism for making any adjustments that are necessary to correct for any overcollection or undercollection of nuclear asset-recovery charges or to otherwise ensure the timely payment of principal of and interest on the bonds when due and other financing costs and other required amounts and charges payable in connection with the bonds. With respect to the foregoing, interest is due on each payment date and principal is due upon the final maturity date for each WAL.

The Series A Bonds do not constitute a debt, liability or other obligation of, or interest in, DEF or any of its other affiliates (other than us). The bonds will not be insured or guaranteed by DEF, including in its capacity as sponsor, depositor, seller or servicer, or by its parent, Duke Energy Corporation, any of their respective affiliates, the indenture trustee or any other person or entity. The Series A Bonds will be nonrecourse obligations, secured only by the collateral. The Series A Bonds are not a debt or general obligation of the Florida Commission, the State of Florida or any of its political subdivisions, agencies, or instrumentalities. However, in so far as the State of Florida or any such political subdivision, agency or instrumentality is receiving transmission or distribution service from DEF or its successor or assignee, such governmental entity will be obligated, in its capacity as a customer, to pay nuclear asset-recovery charges.

The Series A Bonds are a type of ratepayer obligation charge or **ROC bonds**, to be issued pursuant to a special Florida statute, or the **Financing Act**, and an irrevocable **financing order** of the Florida Public Service Commission, or the **FPSC** or the **Florida Commission**. Under the irrevocable financing order, the Florida Commission guarantees it will act, as directed by the Financing Act, to implement the true-up mechanism for making any adjustments that are necessary to correct for any overcollection or undercollection of nuclear asset-recovery charges or to otherwise ensure the timely payment of principal of and interest on the bonds when due and other financing costs and other required amounts and charges payable in connection with the bonds. The Florida Commission's obligations under the Financing Act and the financing order are direct, explicit, irrevocable and unconditional upon issuance of the bonds. Those obligations are legally enforceable against the Florida Commission, a United States public sector entity.

All matters relating to the structuring, marketing and pricing of the Series A Bonds have been considered jointly by DEF, by designated personnel of the Florida Commission and by the Florida Commission's financial advisor. The financial advisor to the Florida Commission is:

Saber Partners, LLC

The bonds will accrue interest from the date of issuance. The bonds are scheduled to pay principal and interest semi-annually and sequentially as described herein. We will pay interest and principal on the bonds on March 1 and September 1 of each year, beginning on March 1, 2017. The Series A Bonds are not subject to optional redemption prior to maturity.

[illegible]3. The Series A Bonds will be payable only from revenues received by us under the indenture for the bonds and funds on deposit in trust accounts relating to the bonds. These amounts, together with the nuclear asset-recovery property, including the Florida Commission guaranteed true-up mechanism, are the source of funds for the payment of principal of and interest on the Series A Bonds. A capital subaccount will hold the depositor's capital contribution to us. An excess funds subaccount will hold revenues that are collected but not needed to meet current obligations associated with the Series A Bonds. Credit enhancement for the bonds will be provided by the true-up mechanism, as well as the capital subaccount. The primary purpose of the excess funds subaccount is not to provide credit enhancement for the bonds. However, amounts in the excess funds subaccount may be used to make debt service payments on the bonds when needed.

DEF is the depositor, sponsor, seller and initial servicer with regard to the bonds. DEF is the sole member and owner of our equity interest. Our Central Index Key number is 0001669374. DEF's Central Index Key number is 0000037637.

Investing in the Series A Bonds involves risks. See "<u>Risk Factors</u>" beginning on page 21 to read about factors you should consider before buying the Series A Bonds.

NEITHER THE SECURITIES AND EXCHANGE COMMISSION NOR ANY STATE SECURITIES COMMISSION HAS APPROVED OR DISAPPROVED OF THESE SECURITIES OR PASSED UPON THE ACCURACY OR ADEQUACY OF THIS PROSPECTUS. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

The Series A Bonds will be ready for delivery in book-entry form through the facilities of The Depository Trust Company against payment in New York, New York on or about June 22, 2016.

RBC Capital Markets **GUGGENHEIM SECURITIES**

Joint Book-Running Managers

Drexel Hamilton Ramirez & Co., Inc. **Jefferies SMBC Nikko** **MUFG The Williams Capital Group, L.P.**

Senior Co-Managers

The date of this prospectus is June 15, 2016

Exhibit F.ii

PROSPECTUS SUMMARY

This summary highlights some information from this prospectus. Because this is a summary, it does not contain all of the information that may be important to you. You should read this prospectus in its entirety before you buy the bonds.

You should carefully consider the Risk Factors beginning on page 21 of this prospectus before you invest in the bonds

Securities offered:	Series A Senior Secured Bonds of Duke Energy Florida Project Finance, LLC, as listed on the cover page of this prospectus (collectively, the "Series A Bonds"), scheduled to pay interest semi-annually and principal semi-annually and sequentially in accordance with the sinking fund schedule described in this prospectus.
Issuing entity (a corporate issuer):	Duke Energy Florida Project Finance, LLC is a special purpose project finance subsidiary of DEF, organized as a Delaware limited liability company. DEF is our sole member and owns all of our equity interests. We are not a municipal issuer. We are not an asset-backed issuer, and the Series A Bonds are not asset-backed securities within the meaning of Item 1101(c) of Regulation AB. We were formed for the limited purpose of purchasing, owning and administering nuclear asset-recovery property, issuing nuclear asset-recovery bonds from time to time (including the Series A Bonds) and performing activities incidental thereto to finance certain activities of DEF related to the retirement of the Crystal River 3 nuclear plant. These are the first nuclear asset-recovery bonds which DEF Project Finance has issued. We may issue additional nuclear asset-recovery bonds, but only as authorized under the financing order or under a new and separate financing order. We are responsible to the State of Florida and the Florida Commission on an ongoing basis as provided in its organizational documents, the transaction documents and the financing order. Please read "The Issuing Entity" in this prospectus. Our address and phone number are as follows: 299 First Avenue North, St. Petersburg, Florida 33701, 704-382-3853.
Corporate financial reporting:	As required by the Financial Accounting Standards Board and the SEC Office of Chief Accountant governing corporate financial reporting for investor-owned utilities, nuclear asset-recovery charges will be reported as revenue on the consolidated income statement of our parent, DEF, a regulated public utility as future electricity transmission and distribution services are billable to customers.
Corporate tax treatment:	The bonds will be treated as debt of DEF for U.S. federal income tax purposes. See "Material U.S. Federal Income Tax Consequences" in this prospectus. For federal income tax purposes, DEF will not recognize gross income unless and until DEF bills customers for the nuclear asset-recovery charges and only in connection with such billing of customers for such nuclear asset-recovery charges.

The depositor, sponsor, seller and initial servicer of the bonds:	DEF is a regulated public utility primarily engaged in the generation, transmission, distribution, and sale of electricity in portions of Florida, including the greater Gainesville, Orlando, St. Petersburg, and Tallahassee areas. DEF's service area covers approximately 13,000 square miles and supplies electric service to approximately 1.7 million residential, commercial and industrial customers. During the twelve months ended December 31, 2015, DEF billed approximately 38.6 billion kilowatt hours of electricity to its covered electric customers in Florida, resulting in revenues of approximately $4.4 billion.

The address and phone number of DEF are as follows: 299 First Avenue North, St. Petersburg, Florida 33701. DEF's telephone number is 704-382-3853.

DEF is an indirect, wholly owned subsidiary of Duke Energy Corporation. DEF, as initial servicer, will bill and collect nuclear asset-recovery charges and will remit nuclear asset-recovery charge collections daily to the indenture trustee according to the terms of the servicing agreement. Neither DEF nor Duke Energy Corporation nor any other affiliate (other than us) is an obligor of the bonds. The bonds will not be insured or guaranteed by DEF, including in its capacity as sponsor, depositor, seller or servicer, or by its parent, Duke Energy Corporation, any of their respective affiliates, the indenture trustee or any other person or entity. There are currently no other retail electric providers operating in DEF's Florida service territory. See "The Servicing Agreement" in this prospectus.

DEF, as initial servicer, will be entitled to receive an annual servicing fee in an amount equal to 0.05% of the aggregate initial principal amount of the bonds. This servicing fee will be payable in equal installments on each semi-annual payment date, in arrears. The indenture trustee will pay the servicing fee (together with any portion of the servicing fee that remains unpaid from prior payment dates) to the extent of available funds prior to the distribution of any interest on and principal of the bonds.

DEF, as administrator, will be entitled to receive an annual administration fee of $50,000. This annual administration fee will be payable annually, in arrears. The indenture trustee will pay the administration fee (together with any portion of the administration fee that remains unpaid from prior payment dates) to the extent of available funds prior to the distribution of any interest on and principal of the bonds.

Our relationship with DEF:	On the issue date for the Series A Bonds, DEF will sell nuclear asset-recovery property to us pursuant to a sale agreement between us and DEF. DEF will service the nuclear asset-recovery property pursuant to a servicing agreement between us and DEF. See "The Sale Agreement" and "The Servicing Agreement" in this prospectus. Neither the bonds nor the property securing the bonds is an obligation of DEF or any of its affiliates, except for us.
Our relationship with the Florida Commission:	We are responsible to the Florida Commission, as provided in its organizational documents, the basic documents and the financing order. Please read "The Issuing Entity" in this prospectus.
Our managers:	The following is a list of our managers as of the date of this prospectus:

Name	Age	Title	Background
Stephen G. De May	53	Manager	Stephen G. De May has been Treasurer and Senior Vice President, Tax of Duke Energy Corporation since February 2016. Mr. De May was Senior Vice President and Treasurer of Duke Energy Corporation from 2012 to 2016 and Senior Vice President, Investor Relations and Treasurer of Duke Energy Corporation from 2009 to 2012.
William E. Currens Jr.	47	Manager	William E. Currens Jr. was appointed as Senior Vice President, Chief Accounting Officer and Controller of Duke Energy Corporation, effective May 2016. Prior to that, Mr. Currens served as Vice President, Investor Relations of Duke Energy Corporation since September 2013 and served as General Manager, Investor Relations of Duke Energy Corporation from April 2008 until September 2013.

Name	Age	Title	Background
Bernard J. Angelo	46	Independent Manager	Bernard J. Angelo joined Global Securitization Service, LLC ("GSS") in April 1997. Mr. Angelo actively assists clients and their legal counsel during the structuring phase of their transactions and assimilates bank sponsored commercial paper programs into the operating matrix at GSS. Mr. Angelo has extensive experience in managing commercial paper and medium term note programs, as well as both the business and legal side of structured finance. Fortune 1000 companies have selected Mr. Angelo to serve as independent director for their SPV subsidiaries established to finance commercial real estate, energy infrastructure and many classes of financial assets. Mr. Angelo serves as an independent director for our affiliates, Duke Energy Florida Project Finance, LLC, Duke Energy Receivables Finance Company, LLC, Duke Energy Florida Receivables LLC and Duke Energy Progress Receivables LLC.

Financial advisor to the Florida Commission:	Saber Partners, LLC
Credit ratings:	The bonds are expected to receive credit ratings from at least two nationally recognized statistical rating organizations. Please read "Ratings" in this prospectus.

Bond structure:	Sinking fund bonds: Series A 2018 Bonds, expected weighted average life 2.0 years, Series A 2021 Bonds, expected weighted average life 5.0 years, Series A 2026 Bonds, expected weighted average life 10.0 years, Series A 2032 Bonds, expected weighted average life 15.2 years and Series A 2035, expected weighted average life 18.7 years. The bonds are scheduled to pay principal semi-annually and sequentially. See "Weighted Average Life and Yield Considerations for the Bonds" in this prospectus.
Average life profile:	Stable, meaning prepayment is not permitted and the aggregate payments of principal of and interest on the bonds and the timing of such payments are not expected to change materially over the life of the bonds under the stress cases analyzed under the heading "Weighted Average Life and Yield Considerations for the Bonds—Sensitivity Analysis—Weighted Average Life" in this prospectus.
Optional redemption:	No optional redemption. Non-callable for the life of the bonds.
Payment dates and interest accrual:	Semi-annually, March 1 and September 1. Interest will be calculated on a 30/360 basis. The first scheduled payment date is March 1, 2017. Interest is due on each payment date for the Series A Bonds, and principal for each weighted average life designation or **WAL** is due upon the final maturity date for that WAL. Failure to pay the entire outstanding principal amount of a WAL by the final maturity date for such WAL will result in an event of default. See "Description of the Series A Bonds—Interest Payments Generally", "—Principal" and "—Events of Default; Rights Upon Event of Default" in this prospectus.

	Scheduled Final Payment Dates	Final Maturity Dates
Series A 2018	03/01/2020	03/01/2022
Series A 2021	09/01/2022	09/01/2024
Series A 2026	09/01/2029	09/01/2031
Series A 2032	03/01/2033	03/01/2035
Series A 2035	09/01/2036	09/01/2038

Indenture trustee:	The Bank of New York Mellon Trust Company, National Association will act as indenture trustee under the indenture pursuant to which the bonds will be issued.
Minimum denominations of the bonds:	$2,000 and integral multiples of $1,000 in excess thereof, except for one bond, which may be of a smaller denomination.

Use of proceeds:	We will use the proceeds of the offering to (i) purchase the nuclear asset-recovery property relating to the bonds from DEF, owner of the retired Crystal River 3 nuclear power plant project, or CR3, who in turn will use the proceeds it receives from the sale of the nuclear asset-recovery property to pay down a portion of its outstanding short-term debt and/or to make an equity distribution to DEF's parent, Duke Energy Corporation, and (ii) pay upfront bond issuance costs.
Background of transaction and the enabling legislation, the Financing Act:	In 2015, the Florida legislature enacted the **Financing Act**, codified as Section 366.95, Florida Statutes. The Financing Act allows electric utilities to access lower-cost funds through nuclear asset-recovery bonds pursuant to financing orders issued by the Florida Commission. One purpose of the Financing Act is to lower the cost to customers associated with the long-term financing of costs incurred in connection with the early retirement or abandonment of a nuclear generating asset unit where such early retirement or abandonment is deemed reasonable and prudent by the Florida Commission through a final order approving a settlement or other final order issued by the Florida Commission before July 1, 2017, and where pretax costs to be financed exceeded $750 million. The Florida Commission issued an irrevocable financing order to DEF on November 19, 2015. Pursuant to that financing order, DEF established DEF Project Finance to be a bankruptcy-remote special purpose subsidiary to issue the nuclear asset-recovery bonds (including the Series A Bonds). In the financing order, the Florida Commission authorized the imposition and collection of nuclear asset-recovery charges on all DEF transmission and distribution customers. DEF, as initial servicer, will collect nuclear asset-recovery charges on our behalf and will remit the nuclear asset-recovery charges to an indenture trustee as described in the "Servicing Agreement—Remittances to Collection Account". Please read "The Nuclear Asset-Recovery Property and the Financing Act" in this prospectus. The Financing Act permits the Florida Commission to impose irrevocable, binding, nonbypassable nuclear asset-recovery charges on all future and existing customers receiving transmission or distribution service from DEF or its successors or assignees under FPSC-approved rate schedules or under special contracts sufficient to pay principal of and interest on the bonds and other administrative expenses of the offering. The Florida Commission governs the amount and terms for collections of these nuclear asset-recovery charges through one or more financing orders issued to DEF and upon the issuance of the bonds these nuclear asset-recovery charges may not be reduced, impaired, postponed, terminated or otherwise adjusted by the Florida Commission except as adjusted pursuant to the true-up mechanism described herein.

Nuclear asset-recovery charges are nonbypassable by customers:	The nuclear asset-recovery charges are *nonbypassable,* consumption-based charges separate and apart from DEF's base rates; the nuclear asset-recovery charges are to be paid by all existing and future customers receiving transmission or distribution service from DEF or its successors or assignees under FPSC-approved rate schedules or under special contracts. Such customers must pay nuclear asset-recovery charges even if DEF goes out of business and its transmission and distribution services are taken over by another utility or if a customer elects to purchase electricity from an alternative electric supplier following a fundamental change in regulation of public utilities in Florida. No customer receiving transmission or distribution service from DEF can avoid the charge. ROCs may not be avoided by DEF's customers and must be paid by such customers until the bonds are paid in full. The only way to avoid the ROCs is to disconnect from DEF's electric grid. See "DEF's Financing Order—Nuclear Asset-Recovery Charges" in this prospectus.
Small initial nuclear asset-recovery charge as a percentage of customer's total electricity bill:	The initial nuclear asset-recovery charge is expected to represent approximately 2.7% of the total bill, as of April 2016, received by 1,000 kWh residential customer of DEF.
Florida state pledge to protect bondholder rights:	The State of Florida has pledged to the bondholders that it will not: • alter the provisions of the Financing Act that make the nuclear asset-recovery charges imposed by the financing order irrevocable, binding, and nonbypassable charges; • take or permit any action that impairs or would impair the value of nuclear asset-recovery property or revises the nuclear asset-recovery costs for which recovery is authorized; or, • except as authorized under the Financing Act with respect to the true-up mechanism, reduce, alter, or impair nuclear asset-recovery charges that are to be imposed, collected, and remitted for the benefit of the bondholders and other financing parties until any and all principal, interest, premium, financing costs and other fees, expenses, or charges incurred, and any contracts to be performed, in connection with the nuclear asset-recovery bonds have been paid and performed in full.

Nothing in this pledge will preclude limitation or alteration if full compensation is made by law for the full protection of the nuclear asset-recovery charges collected pursuant to a financing order and of the bondholders and any assignee or financing party entering into a contract with the electric utility. Please read "Risk Factors—Risks Associated with Potential Judicial, Legislative or Regulatory Actions—Future Florida Legislative Action Might Attempt to Invalidate the Bonds or the Nuclear Asset-Recovery Property" in this prospectus.

This agreement is referred to as the **state pledge**.

The bonds will not be a debt or general obligation of the Florida Commission, the State of Florida, or any of its political subdivisions, agencies, or instrumentalities, and are not a charge on the full faith and credit or taxing power of the State of Florida or any other governmental agency or instrumentality. However, the State of Florida and other governmental entities, to the extent that they are customers, will be obligated to pay nuclear asset-recovery charges securing the bonds.

Florida Commission mandates statutory true-up adjustments to the nuclear asset-recovery charges:

The Financing Act and the financing order require that we, or DEF, file with the Florida Commission at least semi-annually (and quarterly after the scheduled final payment date for the latest maturing bond) a letter applying the true-up mechanism to be reviewed by the Florida Commission for any mathematical errors to correct for any overcollection or undercollection of the nuclear asset-recovery charges and make any adjustments to ensure the recovery of revenues sufficient to provide for the timely payment of scheduled principal of and interest on the bonds and other required amounts and charges payable in connection with the bonds (such amounts, the **periodic payment requirement**). Under the servicing agreement, the servicer will make adjustments to the nuclear asset-recovery charges at least semi-annually. In addition to the semi-annual true-up adjustment, the servicer is authorized to make interim adjustments at any time for any reason to ensure the timely payment of the periodic payment requirement.

In addition, the servicer will make a non-standard true-up adjustment to be effective simultaneously with a base rate change that includes any change in the rate allocation among customers used to determine the nuclear asset-recovery charges.

These adjustments are sometimes referred to as the Florida Commission guaranteed true-up mechanism or the true-up mechanism. Please read "DEF's Financing Order—FPSC Guaranteed True-Up Mechanism" in this prospectus.

Guarantee of Regulatory Action:	The state pledge and the irrevocability of the financing order, in conjunction with the true-up adjustment, constitute a guarantee of regulatory action for the benefit of bondholders. This performance guarantee is pursuant to the irrevocable financing order as authorized by the Financing Act. Please read "DEF's Financing Order—FPSC Guaranteed True-Up Mechanism" in this prospectus. The financing order provides that the true-up mechanism and all other obligations of the Florida Commission pursuant to its irrevocable financing order are direct, explicit, irrevocable and unconditional upon issuance of the bonds and are legally enforceable against the Florida Commission, a United States public sector entity. See "DEF's Financing Order—FPSC Guaranteed True-Up Mechanism—FPSC-Guaranteed True-Up Mechanism as Regulatory Guaranty" in this prospectus.
There is no limit or cap on level of nuclear asset-recovery charges:	Under the irrevocable financing order, the Florida Commission guarantees it will act, as directed by the Financing Act, to implement the true-up mechanism for making any adjustments that are necessary to correct for any overcollection or undercollection of the nuclear asset-recovery charges or to otherwise ensure the timely payment of principal of and interest on the bonds when due and other financing costs and other required amounts and charges payable in connection with the bonds. See "Description of the Series A Bonds—Events of Default; Rights Upon Event of Default" in this prospectus.
Credit/security for the bonds:	The bonds are secured by nuclear asset-recovery property, by funds on deposit in the collection account, including the general subaccount, the capital subaccount and the excess funds subaccount, by our rights under the various transaction documents, by our right to compel the servicer to file for and obtain true-up adjustments, and by all payments on or under the pledged collateral and by all proceeds in respect to the pledged collateral. See "Security for the Series A Bonds" in this prospectus. Nuclear Asset-Recovery property is a present property right created by the Financing Act and the financing order and is protected by the state pledge described in this prospectus. See "The Nuclear Asset-Recovery Property and the Financing Act" in this prospectus.

In general, nuclear asset-recovery property permits a nuclear asset-recovery charge, also known as a **ratepayer obligation charge** or **ROC**, to be:

1. paid on a joint and several basis by all existing and future customers (individuals, corporations, other business entities, the State of Florida and other federal, state and local governmental entities) receiving transmission or distribution service from DEF or its successors or assignees under FPSC-approved rate schedules or under special contracts, even if a customer elects to purchase electricity from an alternative electric supplier following a fundamental change in regulation of public utilities in Florida;

2. collected by DEF, as servicer, and remitted to the indenture trustee daily to provide for payments in respect of the bonds; and

3. adjusted at least semi-annually (and quarterly after the scheduled final payment date for the latest maturing bond), and more frequently as needed to ensure recovery of revenues sufficient to pay principal of and interest on the bonds when due and other financing costs and other required amounts and charges payable in connection with the bonds.

The nuclear asset-recovery property securing the bonds consists of all rights and interests of DEF under the financing order. The nuclear asset-recovery property is being sold to us by DEF in connection with the issuance of the bonds.

- Nuclear asset-recovery property is not a receivable, and the bonds are not secured by a pool of receivables.

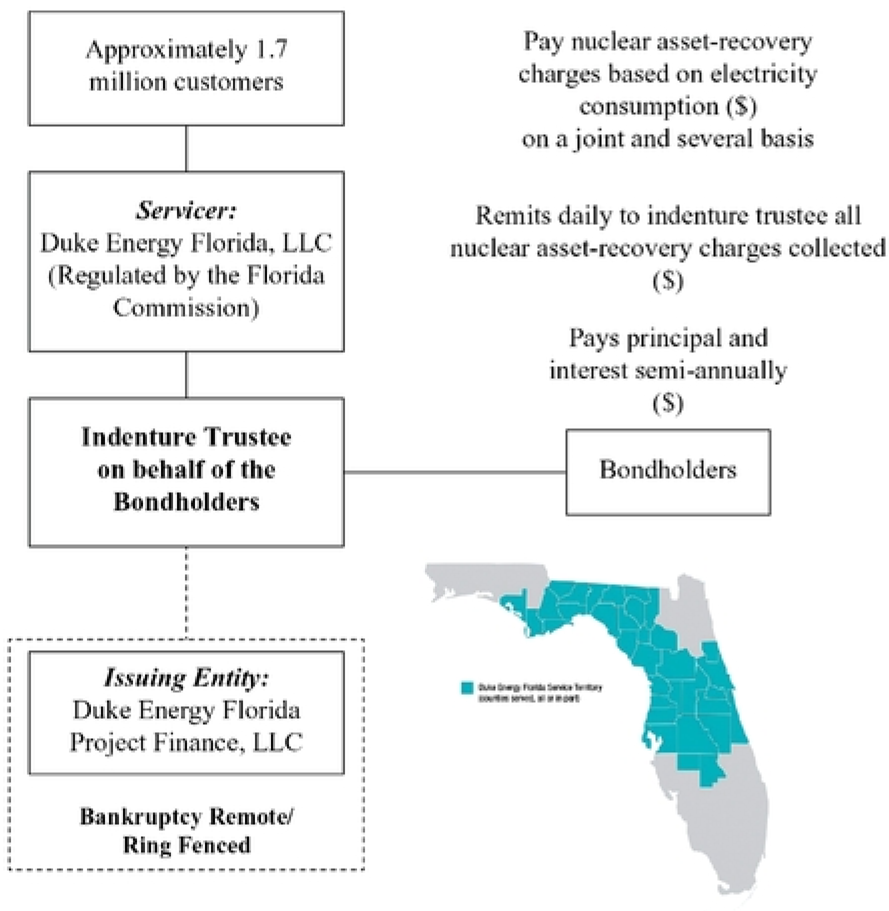
- The bonds are corporate securities and are not asset-backed securities as defined by the SEC in governing regulations Item 1101 of Regulation AB.

Nuclear asset-recovery property includes the right to impose, bill, collect and receive nuclear asset-recovery charges from all existing and future customers receiving transmission or distribution service from DEF or its successors or assignees under FPSC-approved rate schedules or under special contracts to be paid on a joint and several basis. Nuclear asset-recovery property includes the right to a mandatory true-up mechanism that at least semi-annually, and more frequently as needed, adjusts the nuclear asset-recovery charges to levels necessary to ensure recovery of revenues sufficient to timely pay principal of and interest on the bonds when due and other financing costs and other required amounts and charges payable in connection with the bonds. With respect to the foregoing, interest is due on each payment date and principal is due upon the final maturity date for each WAL. It also includes the right to receive all revenues, collections, claims, rights to payments, payments, money, or proceeds arising from DEF's rights and interests under the financing order.

Under the irrevocable financing order, the Florida Commission guarantees it will act, as directed by the Financing Act, to implement the true-up mechanism for making any adjustments that are necessary to correct for any overcollection or undercollection of the nuclear asset-recovery charges or to otherwise ensure the timely payment of principal of and interest on the bonds when due and other financing costs and other required amounts and charges payable in connection with the bonds.

Credit enhancement for the bonds will be provided by the true-up mechanism, as well as by the capital subaccount. The primary purpose of the excess funds subaccount is not to provide credit enhancement for the bonds but to hold funds collected in amounts that were more than necessary to pay current debt service. However, amounts in the excess funds subaccount may be used to make debt service payments on the bonds when needed.

Allocation and flow of funds: The following chart represents a general summary of the flow of funds.



DEF service area: Approximately 1.7 million customers, 13,000 square miles, operating in all or part of 35 Florida counties

Generally, DEF's transmission and distribution customers will pay nuclear asset-recovery charges and all other components of their monthly electricity bills to DEF.

On each payment date, the indenture trustee will pay all amounts on deposit in the general subaccount of the collection account in the following order of priority:

1. payment of the indenture trustee's fees, expenses and outstanding indemnity amounts in an amount not to exceed annually $500,000 in the then current calendar year;

2. payment of the servicing fee plus any unpaid servicing fees from prior payment dates;

3. payment of the administration fee to the extent due on that payment date and of the fees of our independent manager plus any unpaid administration or management fees from prior payment dates;

4. payment of all of our other ordinary periodic operating expenses;

5. payment of the interest then due, including any past-due interest;

6. payment of the principal required to be paid on the final maturity date for each WAL or as a result of acceleration upon an event of default;

7. payment of the principal then scheduled to be paid in accordance with the expected sinking fund schedule, including any previously unpaid scheduled principal, paid pro rata among the bonds if there is a deficiency;

8. payment of any of our remaining unpaid operating expenses and any remaining amounts owed pursuant to the basic documents;

9. replenishment of any amounts drawn from the capital subaccount;

10. release to DEF of an amount equal to the rate of return on the amount contributed to the capital subaccount, including any portion of such rate of return for any prior payment date that has not yet been paid, so long as no event of default has occurred and is continuing; and

11. allocation of the remainder collected, if any, to the excess funds subaccount for future payments.

See "Security for the Series A Bonds—How Funds in the Collection Account Will Be Allocated" in this prospectus. The servicing fee referred to in clause (2) is described in "The Servicing Agreement", and the amount of the administrative fee referred to in clause (3) above is described in "Issuing Entity—The Administrative Agreement" below.

Issuance of additional nuclear asset-recovery bonds by us:

We have been organized to serve as a special purpose project finance subsidiary of DEF. As authorized by the financing order, our organizational documents as well as the transaction documents supporting the bonds give us the authority and flexibility to issue additional nuclear asset-recovery bonds in future transactions, with the approval of the Florida Commission. As a result, we may acquire additional nuclear asset-recovery property and issue one or more additional series of nuclear asset-recovery bonds that are supported by such additional and separate nuclear asset-recovery property or other collateral. For example, such future financings may include additional series of nuclear asset-recovery bonds to finance additional nuclear asset-recovery costs at CR3. If authorized by the Florida Commission, such future financings may include nuclear asset-recovery bonds issued to finance costs, if any, which result from (1) capital costs of dry cask storage facilities at CR3, (2) additional funds needed to fund the CR3 Nuclear Decommissioning Trust in support of decommissioning CR3 or (3) costs which result from a new requirement adopted after October 14, 2015, by the United States Nuclear Regulatory Commission, Federal Energy Commission, or North American Electric Reliability Corporation that are applicable industry wide or generally applicable to shut down nuclear plants or (4) any other CR3 Force Majeure event, as defined in the "Glossary" of this prospectus.

Each series of nuclear asset-recovery bonds that may be issued will be backed by separate nuclear asset-recovery property we acquire for the separate purpose of repaying that series. Any new series of such securities may include terms and provisions that would be unique to that particular series of nuclear asset-recovery bonds. Each series that we may issue will have the benefit of a true-up mechanism.

However, we may not issue additional nuclear asset-recovery bonds unless the rating agency condition for the bonds, as defined in the "Glossary", has been satisfied. It will be a condition of issuance for each series of nuclear asset-recovery bonds that the new series receive a rating or ratings as required by the applicable financing order. In addition, we may not issue additional nuclear asset-recovery bonds (other than additional nuclear asset-recovery bonds under the financing order) unless each of the following conditions is satisfied:

- except for additional nuclear asset-recovery bonds authorized under the financing order, DEF requests and receives another financing order from the Florida Commission;

- each series has recourse only to the nuclear asset-recovery property and funds on deposit in the trust accounts held by the indenture trustee with respect to that series, is nonrecourse to our other assets and does not constitute a claim against us if revenue from the ROCs and funds on deposit in the trust accounts with respect to that series are insufficient to pay such other series in full;

- the indenture trustee and the rating agencies then rating any series of our outstanding nuclear asset-recovery bonds are provided an opinion of a nationally recognized law firm experienced in such matters to the effect that such issuance would not result in our substantive consolidation with DEF and that there has been a true sale of the nuclear asset-recovery property with respect to such series, subject to the customary exceptions, qualifications and assumptions contained therein;

- transaction documentation for the other series provides that holders of the nuclear asset-recovery bonds of the other series will not file or join in filing of any bankruptcy petition against us;

- if holders of such other series are deemed to have any interest in any of our assets that are dedicated to the bonds, holders of such other nuclear asset-recovery bonds must agree that their interest in the assets that are dedicated to the bonds is subordinate to claims or rights of holders of the bonds;

- each series will have its own bank accounts or trust accounts; and

- each series will bear its own indenture trustee fees, servicer fees and pro rata portion administration fees due under the administration agreement.

Allocation among series:	The bonds will not be subordinated in right of payment to any other series of nuclear asset-recovery bonds. Each series of nuclear asset-recovery bonds will be secured by its own nuclear asset-recovery property, which will include the right to impose, bill, collect and receive nuclear asset-recovery charges calculated in respect of that series, and the right to impose interim and annual true-up adjustments to correct overcollections or undercollections in respect of that series. Each series will also have its own collection account, including any related subaccounts, into which revenue from the nuclear asset-recovery charges relating to that series will be deposited and from which amounts will be withdrawn to pay the related series of nuclear asset-recovery bonds. Holders of one series of nuclear asset-recovery bonds will have no recourse to collateral for a different series. Each series that we may issue will also have the benefit of a true-up mechanism. The administration fees, independent manager fees and other operating expenses payable by us on a payment date will be assessed to each series of nuclear asset-recovery bonds on a pro rata basis, based upon the respective outstanding principal amounts of each series. See "Security for the Series A Bonds—Description of Indenture Accounts" and "—How Funds in the Collection Account Will Be Allocated" in this prospectus. Although each series of nuclear asset-recovery bonds will have its own nuclear asset-recovery property, nuclear asset-recovery charges relating to the bonds and nuclear asset-recovery charges relating to any other series of nuclear asset-recovery bonds will be collected through single electricity bills to each electric service customer. The nuclear asset-recovery charges for each series will not be separately identified on customer electricity bills, although customer electricity bills will state that a portion of the electricity bill consists of the rights to the nuclear asset-recovery charges that have been sold to us. In the event a customer does not pay in full all amounts owed under any bill including nuclear asset-recovery charges, each servicer is required to allocate any resulting shortfalls in nuclear asset-recovery charges ratably based on the amounts of nuclear asset-recovery charges owing in respect of the bonds, any amounts owing to any other series and amounts owing to any other subsequently created special-purpose subsidiaries of the utilities which issue nuclear asset-recovery bonds. See "The Servicing Agreement—Remittances to Collection Account" in this prospectus.
ERISA eligible:	Yes; please read "ERISA Considerations" in this prospectus.
Credit risk retention requirements:	The bonds are not subject to the 5% risk retention requirements imposed by Section 15G of the Exchange Act (added by Section 941 of the Dodd-Frank Wall Street Reform and Consumer Protection Act).

	In addition, we and DEF believe that the bonds will not be subject to the 5% risk retention requirement imposed by the European Union Capital Requirements Regulation (Regulation (EU) No 575/2013). For the purposes of the European Union's risk retention rules, we and DEF believe the issue of the bonds does not fall within the definition of a "securitisation" as the credit risk associated with exposure is not tranched. We and DEF believe, therefore, that the EU risk retention rules do not apply to the issue of the bonds.
International Risk Weighting	**We cannot assure you of the risk weighting or other treatment of the bonds under any national law, regulation or policy implementing the international regulatory framework for banking institutions known as Basel III. You should consult your own professional advisors and, as you see fit, supervisory regulators before making any investment in the bonds.** There are certain factors that may be considered by banks in their risk weighting analysis for regulatory capital purposes, including in certain countries other than the United States the rating category of the bonds determined by major credit rating agency. See "Risk Weighting Under Certain International Capital Guidelines" in this prospectus.
Our legal and covenant defeasance options:	We may, by making certain deposits in trust and meeting specified conditions, at any time, terminate all of its obligations under the indenture and the series supplement with respect to the bonds or its obligations to comply with some of the covenants in the indenture and the series supplement, including some of the covenants described under "Description of the Series A Bonds—Covenants of DEF Project Finance" in this prospectus. See "Description of the Series A Bonds—DEF Project Finance's Legal and Covenant Defeasance Options" in this prospectus.
Expected settlement date:	Settling flat. DTC, Clearstream and Euroclear. June 22, 2016.
Continuing disclosure: surveillance/internet-based information post issuance/dedicated Web address:	Duke Energy Corporation, the parent of DEF, will establish a dedicated web address for the life of the bonds. The principal transaction documents and other information concerning the nuclear asset-recovery charges and security relating to the bonds will be posted at such web address, which is currently located at www.duke-energy.com.

The bonds are not asset-backed securities as defined by the SEC in governing regulations Item 1101 of Regulation AB, and neither we nor the depositor is an asset-backed issuer. However, we plan to file with the SEC required periodic and current reports related to the bonds consistent with the disclosure and reporting regime established in Regulation AB and will also post those periodic and current reports at a website associated with DEF or DEF's affiliates.

Risk factors: **You should consider carefully the risk factors beginning on page 21 of this prospectus before you invest in the bonds.**

through (4) above) will become due and payable prior to the next payment date, and setting forth the amount and nature of such operating expense, as well as any supporting documentation that the indenture trustee may reasonably request, the indenture trustee, upon receipt of such information will make payment of such operating expenses on or before the date such payment is due from amounts on deposit in the general subaccount, the excess funds subaccount and the capital subaccount in that order and only to the extent required to make such payment.

Right of Foreclosure

Section 366.95(5)(b)6. of the Financing Act provides that if an event of default or termination occurs under the bonds, the bondholders or their representatives, as secured parties, may foreclose or otherwise enforce the lien on the nuclear asset-recovery property securing such bonds as if they were a secured party under Article 9 of the UCC, and that a court may order that amounts arising from that nuclear asset-recovery property be transferred to a separate account for the holder's benefit, to which their lien and security interest will apply. Upon application by or on behalf of an indenture trustee to a circuit court in Florida, such court shall order sequestration and payment to the indenture trustee of revenues arising from the related nuclear asset-recovery property.

State Pledge

The state pledge in the Financing Act is described under "The Nuclear Asset-Recovery Property and the Financing Act—The Financing Act Provides for the Recovery of Nuclear Asset-Recovery Costs and the Issuance of Nuclear Asset-Recovery Bonds—The Financing Act Contains a State Pledge" in this prospectus. The bondholders and the indenture trustee will be entitled to the benefit of the state pledge and we are authorized to and will include the state pledge on the bonds. We acknowledge that any purchase by a bondholder of a nuclear asset-recovery bond is made in reliance on the state pledge.

WEIGHTED AVERAGE LIFE AND YIELD CONSIDERATIONS FOR THE BONDS

The actual amount of principal and interest payments in respect of the bonds on each semi-annual payment date of each WAL designation of the bonds and the weighted average life thereof will depend on the timing of receipt of nuclear asset-recovery charges and the implementation of the true-up mechanism. The aggregate amount of nuclear asset-recovery charges collected and the rate of principal amortization depends, in part, on energy consumption and the rate of delinquencies and write-offs. The nuclear asset-recovery charges are required to be adjusted at least every six months based in part on the actual rate of collected nuclear asset-recovery charges. However, we can give no assurance that the servicer will forecast accurately actual electricity consumption and the rate of delinquencies and write-offs or implement adjustments to the nuclear asset-recovery charges so as to cause nuclear asset-recovery charges to be collected at any particular rate. Please read "Risk Factors—Servicing Risks—Inaccurate forecasting of electric consumption or collections might reduce scheduled payments on the bonds" and "DEF's Financing Order—FPSC-Guaranteed True-Up Mechanism".

If the servicer collects nuclear asset-recovery charges at a slower rate than forecast during the period of time between mandatory semi-annual true-up adjustments and does not implement an interim true-up adjustment, the bonds may be retired later than scheduled. The servicer, however, may implement a true-up at any time it believes the slower collections may affect the timely payment of principal of and interest on the bonds on a scheduled payment date prior to the mandatory semi-annual true-up adjustment.

No prepayment is permitted. Except in the event of an acceleration of the final payment date of the bonds after an event of default, the bonds will not be paid at a rate faster than that contemplated in the expected sinking fund schedule for each WAL of the bonds even if the receipt of collected nuclear asset-recovery charges is greater than anticipated. Instead, receipts in excess of the amounts necessary to pay debt service on the bonds in accordance with the applicable expected sinking fund schedules, to pay related fees and expenses and to fund subaccounts of the related collection account will be allocated to the excess funds subaccount. Amounts on deposit in the excess funds subaccount will be taken into consideration in calculating the next true-up adjustment.

Upon an acceleration, due to the nature of our business, payment of principal of the bonds will only be made as funds become available. Please read "Risk Factors—Risk Associated with the Unusual Nature of the Nuclear Asset-Recovery Property—Foreclosure of the indenture trustee's lien on the nuclear asset-recovery property for the bonds might not be practical, and acceleration of the bonds before maturity might result in your investment being repaid either earlier or later than expected" and "Risk Factors—You may experience payment delays as a result of limited sources of payment for the bonds and limited credit enhancement".

Sensitivity Analysis

Weighted Average Life

Weighted average life refers to the average amount of time from the date of issuance of a WAL designation of bonds that such bonds will remain outstanding. The timing of principal and interest payments on the bonds will depend on the timing of the servicer's receipt of nuclear asset-recovery charges from customers.

The weighted average life table below illustrates whether there is risk to bondholders of a material weighted average life extension of each WAL designation.

The table shows changes from the expected weighted average life of each WAL designation of bonds assuming actual future electricity consumption and related charge collections varies from DEF's forecast of future electricity consumption and related charge collections (the forecast variance) of 5% (1.3 standard deviations from the forecast variance mean) or 15% (4.0 standard deviations from the forecast variance mean) during each payment period.

The weighted average life table below illustrates that the aggregate payment of principal of and interest on the bonds and the timing of such payments are not expected to change materially over the life of the bonds, based on the assumptions we have made.

		Effect on Weighted Average Life (Rounded*) of Change in Forecast Variance	
		–5% (1.3 Standard Deviations from Forecast Variance Mean)	–15% (4.0 Standard Deviations from Forecast Variance Mean)
Series A Bonds	Expected Weighted Average Life (yrs)	Weighted Average Life (yrs)	Weighted Average Life (yrs)
Series A 2018	2.0	2.0	2.0
Series A 2021	5.0	5.0	5.1
Series A 2026	10.0	10.0	10.0
Series A 2032	15.2	15.2	15.3
Series A 2035	18.7	18.7	18.8

* Number is rounded to 1/10th of one year

Sensitivity to Credit Risk

A stress case analysis examined the maximum amount of forecast variance that could occur without causing an event of default due to insufficient funds available to pay all principal at final maturity for each WAL designation or insufficient funds available to pay interest on each payment date and expense obligations when due.

For an event of default to occur with respect to any such payment due under the indenture, the forecast variance for the forecast period leading up to such payment would need to be greater than minus 60%, or more than 16 standard deviations from the forecast variance mean.

For there not to be enough funds available to pay principal at final maturity for each WAL designation, interest on each payment date and expense obligations when due, our stress case analysis demonstrated that there would need to be unexpected, extensive and persistent drops in electricity consumption or increases in defaults or write offs among electricity consumers that occur in each forecast period prior to the relevant payment date.

We are not aware of any practical circumstance where such unexpected, extensive and persistent drops in the consumption of electricity or increases in defaults and write offs of that magnitude could occur in the DEF service territory. For comparison, during the most recent 10 years, DEF's mean annual forecast variance was minus 0.16% and the largest unfavorable annual forecast variance was minus 6.53%. See "Risk Factors", in particular "—Servicing Risks—Inaccurate forecasting of electric consumption or collections might reduce scheduled payments on the bonds", and "Cautionary Statement Regarding Forward-Looking Statements" in this prospectus.

Figure 2. DEF service area: Approximately 1.7 million customers, 13,000 square miles, operating in all or part of 35 Florida counties

Assumptions

In preparing the analysis above, the following assumptions, among others, have been made:

(i)
the unfavorable forecast variance stays constant over the life of the bonds;

(ii)
the servicer makes timely and accurate semi-annual true-up adjustments (and quarterly following the last scheduled final payment date), but makes no interim true-up adjustments;

(iii)
for purposes of setting initial nuclear asset-recovery charges, the net charge-off rate as a percentage of billed revenue and average days sales outstanding per customer bill is each assumed to equal DEF's average (mean) for the most recent 10 years;

(iv)
for purposes of setting subsequent nuclear asset-recovery charges, and for purposes of calculating actual nuclear asset-recovery charge collections, net charge-off rate as a percentage of billed revenue and the average days sales outstanding per customer bill are both held constant at DEF's maximum (most unfavorable) for the most recent 10 years;

(v)
during the first payment period, interest will accrue for approximately 9 months and the nuclear asset-recovery charges will be collected for approximately 8 months;

(vi)
there is no acceleration of the final maturity date of the bonds; and

(vi)
the principal amounts and interest rates of the bonds of each WAL designation represent estimates based on current market conditions. Other than as discussed above, there can be no assurance that the weighted average lives of or the events of default with respect to the bonds will be as shown.

Concerning the true-up mechanism through which any delinquencies or under-collections in one customer rate class—for any reason—will be taken into account in the application of the true-up mechanism to adjust the nuclear asset-recovery charges for all customers of DEF, for additional information see "DEF's Financing Order—FPSC-Guaranteed True-Up Mechanism" in this prospectus.

Concerning the broad-based nature of the nuclear asset-recovery charge on a basic and essential commodity, electricity, for additional information see "DEF's Financing Order—Nuclear Asset-Recovery Charges" in this prospectus.

Concerning the non-bypassability of the charges, for additional information see "The Nuclear Asset-Recovery Property and the Financing Act—The Financing Act Provides for the Recovery of Nuclear Asset-Recovery Costs and the Issuance of the Bonds—Transmission and Distribution Customers Cannot Avoid Nuclear Asset-Recovery Charges-Nonbypassable" in this prospectus.

Concerning the State Pledge, for additional information see "Security for the Series A Bonds—State Pledge" and "DEF's Financing Order—FPSC-Guaranteed True-Up Mechanism—FPSC-Guaranteed True-Up Mechanism and State Pledge" in this prospectus.

SABER PARTNERS, LLC

Exhibit G

Purpose	State(s)
Unrecovered costs of nuclear plant retired early	Florida
Buydown of high-cost PPAs	New Hampshire
Deferred balances (regulatory assets)	New Jersey Maryland Ohio West Virginia
Stranded costs in connection with electric industry deregulation	Pennsylvania Texas New Hampshire Illinois Montana Massachusetts New Jersey Michigan Connecticut Louisiana
Storm recovery costs	Florida Louisiana Texas Arkansas
Costs of new pollution control equipment at existing electric generating facilities	West Virginia Wisconsin
Costs of new renewable distributed generation	Hawaii

SABER PARTNERS, LLC

Exhibit H

Securitization of PG&E UOG with typical 4-Tranche structure

($000)

	Int. Rate (%):		3.91			3.15			3.75			4.02			4.17	
	WAL (yrs.):	11.70			4.00			10.00			15.00			18.87		
Payment Date	Aggregate Bond Balance	Total Principal Payment	Total Interest Payment	A-1 Principal Balance	Princ. Pmt.	Interest Pmt.	A-2 Principal Balance	Princ. Pmt.	Interest Pmt.	A-3 Principal Balance	Princ. Pmt.	Interest Pmt.	A-4 Principal Balance	Princ. Pmt.	Interest Pmt.	Total Revenue Requirement(1)
12/15/2018	4,649,222	-		1,218,000	-		1,181,000	-		1,235,000	-		1,015,222	-		
12/15/2019	4,484,344	164,878	174,557	1,053,122	164,878	38,334	1,181,000	-	44,291	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2020	4,314,277	170,067	169,368	883,056	170,067	33,145	1,181,000	-	44,291	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2021	4,138,858	175,419	164,016	707,636	175,419	27,792	1,181,000	-	44,291	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2022	3,957,918	180,940	158,495	526,696	180,940	22,271	1,181,000	-	44,291	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2023	3,771,283	186,635	152,800	340,061	186,635	16,577	1,181,000	-	44,291	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2024	3,578,774	192,509	146,926	147,553	192,509	10,703	1,181,000	-	44,291	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2025	3,380,207	198,568	140,867	-	147,553	4,644	1,129,985	51,015	44,291	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2026	3,175,082	205,125	134,310	-	-	-	924,860	205,125	42,377	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2027	2,962,265	212,817	126,617	-	-	-	712,043	212,817	34,685	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2028	2,741,466	220,799	118,636	-	-	-	491,244	220,799	26,704	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2029	2,512,387	229,079	110,356	-	-	-	262,165	229,079	18,423	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2030	2,274,716	237,670	101,765	-	-	-	24,495	237,670	9,832	1,235,000	-	49,613	1,015,222	-	42,320	**339,435**
12/15/2031	2,028,133	246,584	92,851	-	-	-	-	24,495	919	1,012,911	222,089	49,613	1,015,222	-	42,320	**339,435**
12/15/2032	1,771,709	256,424	83,011	-	-	-	-	-	-	756,487	256,424	40,691	1,015,222	-	42,320	**339,435**
12/15/2033	1,504,984	266,725	72,710	-	-	-	-	-	-	489,762	266,725	30,390	1,015,222	-	42,320	**339,435**
12/15/2034	1,227,544	277,440	61,995	-	-	-	-	-	-	212,322	277,440	19,675	1,015,222	-	42,320	**339,435**
12/15/2035	938,958	288,586	50,849	-	-	-	-	-	-	-	212,322	8,530	938,958	76,264	42,320	**339,435**
12/15/2036	638,664	300,294	39,141	-	-	-	-	-	-	-	-	-	638,664	300,294	39,141	**339,435**
12/15/2037	325,852	312,812	26,623	-	-	-	-	-	-	-	-	-	325,852	312,812	26,623	**339,435**
12/15/2038	-	325,852	13,583	-	-	-	-	-	-	-	-	-	-	325,852	13,583	**339,435**
	Total Principal	4,649,222	1,607,903		1,218,000	153,466		1,181,000	442,974		1,235,000	744,255		1,015,222	798,782	**6,788,698**
	less Xaction Cost	(92,984)														
	Asset	4,556,237														

(1) Excluding franchise fees of $75,506 which are assumed paid by the utility on bond-related revenues.

Proprietary

SABER PARTNERS, LLC

Securitization of PG&E UOG excluding fossil with typical 4-Tranche structure

($000)

Payment Date	Aggregate Bond Balance	Total Principal Payment	Total Interest Payment	A-1 Principal Balance	A-1 Princ. Pmt.	A-1 Interest Pmt.	A-2 Principal Balance	A-2 Princ. Pmt.	A-2 Interest Pmt.	A-3 Principal Balance	A-3 Princ. Pmt.	A-3 Interest Pmt.	A-4 Principal Balance	A-4 Princ. Pmt.	A-4 Interest Pmt.	Total Revenue Requirement[1]
Int. Rate (%):			3.91			3.15			3.75			4.02			4.17	
WAL (yrs.):		11.70			4.00			10.00			15.00			18.87		
12/15/2018	3,883,780	-		1,017,000	-		986,000	-		1,032,000	-		848,780	-		
12/15/2019	3,746,047	137,733	145,818	879,267	137,733	32,006	986,000	-	36,975	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2020	3,603,979	142,068	141,483	737,199	142,068	27,671	986,000	-	36,975	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2021	3,457,440	146,539	137,012	590,661	146,539	23,200	986,000	-	36,975	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2022	3,306,290	151,150	132,401	439,510	151,150	18,588	986,000	-	36,975	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2023	3,150,383	155,907	127,644	283,603	155,907	13,832	986,000	-	36,975	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2024	2,989,569	160,814	122,737	122,790	160,814	8,925	986,000	-	36,975	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2025	2,823,695	165,874	117,677	-	122,790	3,864	942,915	43,085	36,975	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2026	2,652,341	171,354	112,197	-	-	-	771,561	171,354	35,359	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2027	2,474,561	177,780	105,771	-	-	-	593,781	177,780	28,933	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2028	2,290,114	184,447	99,104	-	-	-	409,334	184,447	22,267	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2029	2,098,750	191,363	92,187	-	-	-	217,971	191,363	15,350	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2030	1,900,211	198,540	85,011	-	-	-	19,431	198,540	8,174	1,032,000	-	41,456	848,780	-	35,381	**283,551**
12/15/2031	1,694,226	205,985	77,566	-	-	-	-	19,431	729	845,446	186,554	41,456	848,780	-	35,381	**283,551**
12/15/2032	1,480,019	214,207	69,344	-	-	-	-	-	-	631,239	214,207	33,962	848,780	-	35,381	**283,551**
12/15/2033	1,257,206	222,812	60,739	-	-	-	-	-	-	408,427	222,812	25,358	848,780	-	35,381	**283,551**
12/15/2034	1,025,443	231,763	51,788	-	-	-	-	-	-	176,664	231,763	16,407	848,780	-	35,381	**283,551**
12/15/2035	784,370	241,073	42,478	-	-	-	-	-	-	-	176,664	7,097	784,370	64,409	35,381	**283,551**
12/15/2036	533,516	250,855	32,696	-	-	-	-	-	-	-	-	-	533,516	250,855	32,696	**283,551**
12/15/2037	272,204	261,312	22,239	-	-	-	-	-	-	-	-	-	272,204	261,312	22,239	**283,551**
12/15/2038	0	272,204	11,347	-	-	-	-	-	-	-	-	-	-	272,204	11,347	**283,551**
Total Principal	3,883,780	1,787,239			1,017,000	128,086		986,000	369,634		1,032,000	621,758		848,780	667,761	**5,671,019**
less Xaction Cost	(77,676)															
Asset	3,806,104															

(1) Excluding franchise fees of $63,075 which are assumed paid by the utility on bond-related revenues.

SABER PARTNERS, LLC

Securitization of SCE UOG with typical 4-Tranche structure

($000)

	Int. Rate (%):		4.07			3.15			3.81			4.14			4.31	
	WAL (yrs.):	14.94			4.00			11.00			18.00			23.40		
Payment Date	Aggregate Bond Balance	Total Principal Payment	Total Interest Payment	A-1 Principal Balance	Princ. Pmt.	Interest Pmt.	A-2 Principal Balance	Princ. Pmt.	Interest Pmt.	A-3 Principal Balance	Princ. Pmt.	Interest Pmt.	A-4 Principal Balance	Princ. Pmt.	Interest Pmt.	Total Revenue Requirement(1)
12/15/2018	1,476,426	-		276,000	-		375,000	-		460,000	-		365,426	-		
12/15/2019	1,439,012	37,414	57,764	238,586	37,414	8,685	375,000	-	14,298	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2020	1,400,420	38,591	56,586	199,994	38,591	7,507	375,000	-	14,298	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2021	1,360,615	39,806	55,372	160,189	39,806	6,293	375,000	-	14,298	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2022	1,319,556	41,058	54,120	119,130	41,058	5,040	375,000	-	14,298	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2023	1,277,206	42,350	52,828	76,780	42,350	3,749	375,000	-	14,298	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2024	1,233,523	43,683	51,495	33,097	43,683	2,416	375,000	-	14,298	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2025	1,188,466	45,057	50,120	-	33,097	1,041	363,040	11,960	14,298	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2026	1,141,911	46,555	48,623	-	-	-	316,485	46,555	13,842	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2027	1,093,582	48,330	46,848	-	-	-	268,156	48,330	12,067	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2028	1,043,409	50,172	45,005	-	-	-	217,983	50,172	10,224	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2029	991,324	52,085	43,092	-	-	-	165,898	52,085	8,311	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2030	937,252	54,071	41,106	-	-	-	111,826	54,071	6,325	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2031	881,119	56,133	39,045	-	-	-	55,693	56,133	4,264	460,000	-	19,031	365,426	-	15,750	**95,178**
12/15/2032	822,846	58,273	36,905	-	-	-	-	55,693	2,123	457,420	2,580	19,031	365,426	-	15,750	**95,178**
12/15/2033	762,343	60,503	34,674	-	-	-	-	-	-	396,917	60,503	18,925	365,426	-	15,750	**95,178**
12/15/2034	699,336	63,007	32,171	-	-	-	-	-	-	333,910	63,007	16,422	365,426	-	15,750	**95,178**
12/15/2035	633,723	65,613	29,564	-	-	-	-	-	-	268,297	65,613	13,815	365,426	-	15,750	**95,178**
12/15/2036	565,395	68,328	26,850	-	-	-	-	-	-	199,969	68,328	11,100	365,426	-	15,750	**95,178**
12/15/2037	494,240	71,155	24,023	-	-	-	-	-	-	128,814	71,155	8,273	365,426	-	15,750	**95,178**
12/15/2038	420,141	74,099	21,079	-	-	-	-	-	-	54,715	74,099	5,329	365,426	-	15,750	**95,178**
12/15/2039	342,977	77,164	18,013	-	-	-	-	-	-	-	54,715	2,264	342,977	22,449	15,750	**95,178**
12/15/2040	262,581	80,396	14,782	-	-	-	-	-	-	-	-	-	262,581	80,396	14,782	**95,178**
12/15/2041	178,720	83,861	11,317	-	-	-	-	-	-	-	-	-	178,720	83,861	11,317	**95,178**
12/15/2042	91,245	87,475	7,703	-	-	-	-	-	-	-	-	-	91,245	87,475	7,703	**95,178**
12/15/2043	-	91,245	3,933	-	-	-	-	-	-	-	-	-	-	91,245	3,933	**95,178**
	Total Principal	1,476,426	903,018		276,000	34,731		375,000	157,243		460,000	342,568		365,426	368,477	**2,379,444**
	less Xaction Cost	(29,529)														
	Asset	1,446,897														

(1) Excluding franchise fees of $21,609 which are assumed paid by the utility on bond-related revenues.

SABER PARTNERS, LLC

Exhibit I

Expected revenue requirements for PG&E UOG with existing capitalization

($000)

WAL (yrs.)	7.34							
	(a)	(b)	(c)		(d)	(e)	(f)	(g)
Year	Beginning Rate Base	Return	Return on Equity	After Tax Income	Income-Based Taxes	Annual Amortization	Revenue-Based Fees	Total Revenue Requirement
		(a) * WACC	(a) * WCE	(e) + (f) + (g)	(c) * Tax Factor [1]			(b)+(d)+(e)+(f)
2019	4,556,237	350,115	245,399	245,399	95,355	437,763	9,824	893,057
2020	4,118,474	316,476	221,821	221,821	86,194	437,763	9,348	849,780
2021	3,680,711	282,837	198,243	198,243	77,032	437,763	8,872	806,503
2022	3,242,948	249,198	174,665	174,665	67,870	437,763	8,395	763,226
2023	2,805,185	215,559	151,087	151,087	58,708	437,763	7,919	719,950
2024	2,367,422	181,920	127,509	127,509	49,547	437,763	7,443	676,673
2025	1,929,660	148,281	103,931	103,931	40,385	236,681	4,731	430,077
2026	1,692,979	130,094	91,184	91,184	35,432	150,503	3,515	319,543
2027	1,542,476	118,528	83,078	83,078	32,282	150,503	3,351	304,664
2028	1,391,974	106,963	74,972	74,972	29,132	150,503	3,188	289,786
2029	1,241,471	95,398	66,866	66,866	25,982	150,503	3,024	274,907
2030	1,090,968	83,833	58,760	58,760	22,832	150,503	2,860	260,029
2031	940,466	72,268	50,653	50,653	19,683	150,503	2,697	245,150
2032	789,963	60,703	42,547	42,547	16,533	150,503	2,533	230,272
2033	639,460	49,138	34,441	34,441	13,383	150,503	2,369	215,393
2034	488,958	37,573	26,335	26,335	10,233	150,503	2,206	200,514
2035	338,455	26,008	18,229	18,229	7,083	150,503	2,042	185,636
2036	187,952	14,443	10,123	10,123	3,934	137,425	1,733	157,535
2037	50,527	3,883	2,721	2,721	1,057	38,867	487	44,294
2038	11,660	896	628	628	244	11,660	142	12,942
Total	33,107,947	2,544,114	1,783,194	1,783,194	692,900	4,556,237	86,679	7,879,931

[1] Tax factor = Composite tax rate/(1-Composite tax rate)

SABER PARTNERS, LLC

Expected revenue requirements for PG&E UOG excluding fossil with existing capitalization
($000)

WAL (yrs.): 6.81

Year	(a) Beginning Rate Base	(b) Return (a) * WACC	(c) Return on Equity (a) * WCE	After Tax Income (e) + (f) + (g)	(d) Income-Based Taxes (c) * Tax Factor (1)	(e) Annual Amortization	(f) Revenue-Based Fees	(g) Total Revenue Requirement (b)+(d)+(e)+(f)
2019	3,806,104	292,472	204,997	204,997	79,656	398,896	8,576	**779,600**
2020	3,407,208	261,820	183,512	183,512	71,308	398,896	8,142	**740,166**
2021	3,008,312	231,168	162,028	162,028	62,960	398,896	7,708	**700,731**
2022	2,609,416	200,515	140,543	140,543	54,611	398,896	7,274	**661,297**
2023	2,210,520	169,863	119,059	119,059	46,263	398,896	6,840	**621,862**
2024	1,811,624	139,211	97,574	97,574	37,915	398,896	6,407	**582,428**
2025	1,412,729	108,558	76,090	76,090	29,566	197,814	3,736	**339,675**
2026	1,214,915	93,358	65,435	65,435	25,426	111,636	2,563	**232,983**
2027	1,103,279	84,779	59,423	59,423	23,090	111,636	2,441	**221,946**
2028	991,644	76,201	53,410	53,410	20,754	111,636	2,320	**210,910**
2029	880,008	67,622	47,397	47,397	18,417	111,636	2,199	**199,874**
2030	768,372	59,044	41,385	41,385	16,081	111,636	2,077	**188,838**
2031	656,737	50,466	35,372	35,372	13,745	111,636	1,956	**177,802**
2032	545,101	41,887	29,359	29,359	11,408	111,636	1,834	**166,765**
2033	433,465	33,309	23,346	23,346	9,072	111,636	1,713	**155,729**
2034	321,830	24,730	17,334	17,334	6,735	111,636	1,592	**144,693**
2035	210,194	16,152	11,321	11,321	4,399	111,636	1,470	**133,657**
2036	98,558	7,574	5,308	5,308	2,063	98,558	1,203	**109,398**
Total	25,490,016	1,958,729	1,372,892	1,372,892	533,468	3,806,104	70,052	**6,368,354**

(1) Tax factor = Composite tax rate/(1-Composite tax rate)

Proprietary

SABER PARTNERS, LLC

Expected revenue requirements for SCE UOG with existing capitalization
($000)

WAL (yrs.): 9.74

Year	(a) Beginning Rate Base	(b) Return (a) * WACC	(c) Return on Equity (a) * WCE	After Tax Income (e) + (f) + (g)	(d) Income-based Taxes (c) * Tax Factor [1]	(e) Annual Amortization	(f) Revenue-based Fees	(g) Total Revenue Requirement (b)+(d)+(e)+(f)
2019	1,446,897	110,097	79,113	79,113	30,741	83,103	2,034	**225,975**
2020	1,363,795	103,774	74,570	74,570	28,976	83,103	1,960	**217,812**
2021	1,280,692	97,450	70,026	70,026	27,210	83,103	1,887	**209,650**
2022	1,197,590	91,127	65,482	65,482	25,444	83,103	1,813	**201,487**
2023	1,114,487	84,804	60,938	60,938	23,679	83,103	1,740	**193,325**
2024	1,031,385	78,480	56,394	56,394	21,913	83,103	1,666	**185,162**
2025	948,282	72,157	51,850	51,850	20,148	83,103	1,593	**177,000**
2026	865,180	65,833	47,306	47,306	18,382	83,103	1,520	**168,837**
2027	782,077	59,510	42,762	42,762	16,616	83,103	1,446	**160,675**
2028	698,975	53,186	38,219	38,219	14,851	83,103	1,373	**152,512**
2029	615,872	46,863	33,675	33,675	13,085	83,103	1,299	**144,350**
2030	532,770	40,540	29,131	29,131	11,319	83,103	1,226	**136,187**
2031	449,667	34,216	24,587	24,587	9,554	77,803	1,104	**122,677**
2032	371,864	28,296	20,333	20,333	7,901	65,438	923	**102,558**
2033	306,426	23,317	16,755	16,755	6,510	65,438	865	**96,130**
2034	240,987	18,337	13,177	13,177	5,120	65,438	807	**89,703**
2035	175,549	13,358	9,599	9,599	3,730	27,857	408	**45,353**
2036	147,692	11,238	8,076	8,076	3,138	18,462	298	**33,136**
2037	129,231	9,833	7,066	7,066	2,746	18,462	282	**31,323**
2038	110,769	8,429	6,057	6,057	2,353	18,462	266	**29,509**
2039	92,308	7,024	5,047	5,047	1,961	18,462	249	**27,696**
2040	73,846	5,619	4,038	4,038	1,569	18,462	233	**25,883**
2041	55,385	4,214	3,028	3,028	1,177	18,462	217	**24,069**
2042	36,923	2,810	2,019	2,019	784	18,462	200	**22,256**
2043	18,462	1,405	1,009	1,009	392	18,462	184	**20,443**
Total	14,087,113	1,071,917	770,255	770,255	299,300	1,446,897	25,593	**2,843,707**

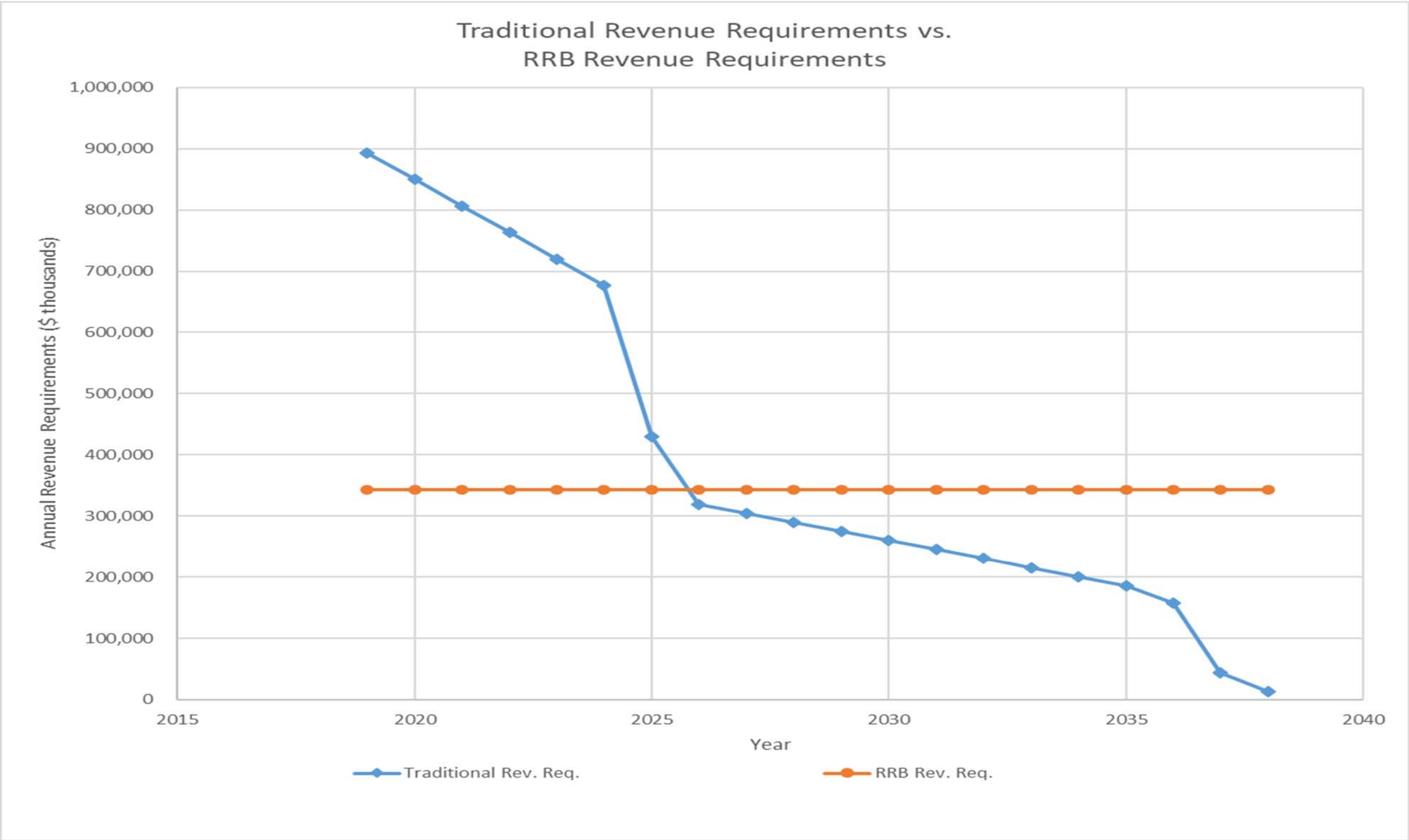
(1) Tax Factor = Composite tax rate/(1-Composite tax rate)

Proprietary

Exhibit J

SABER PARTNERS, LLC

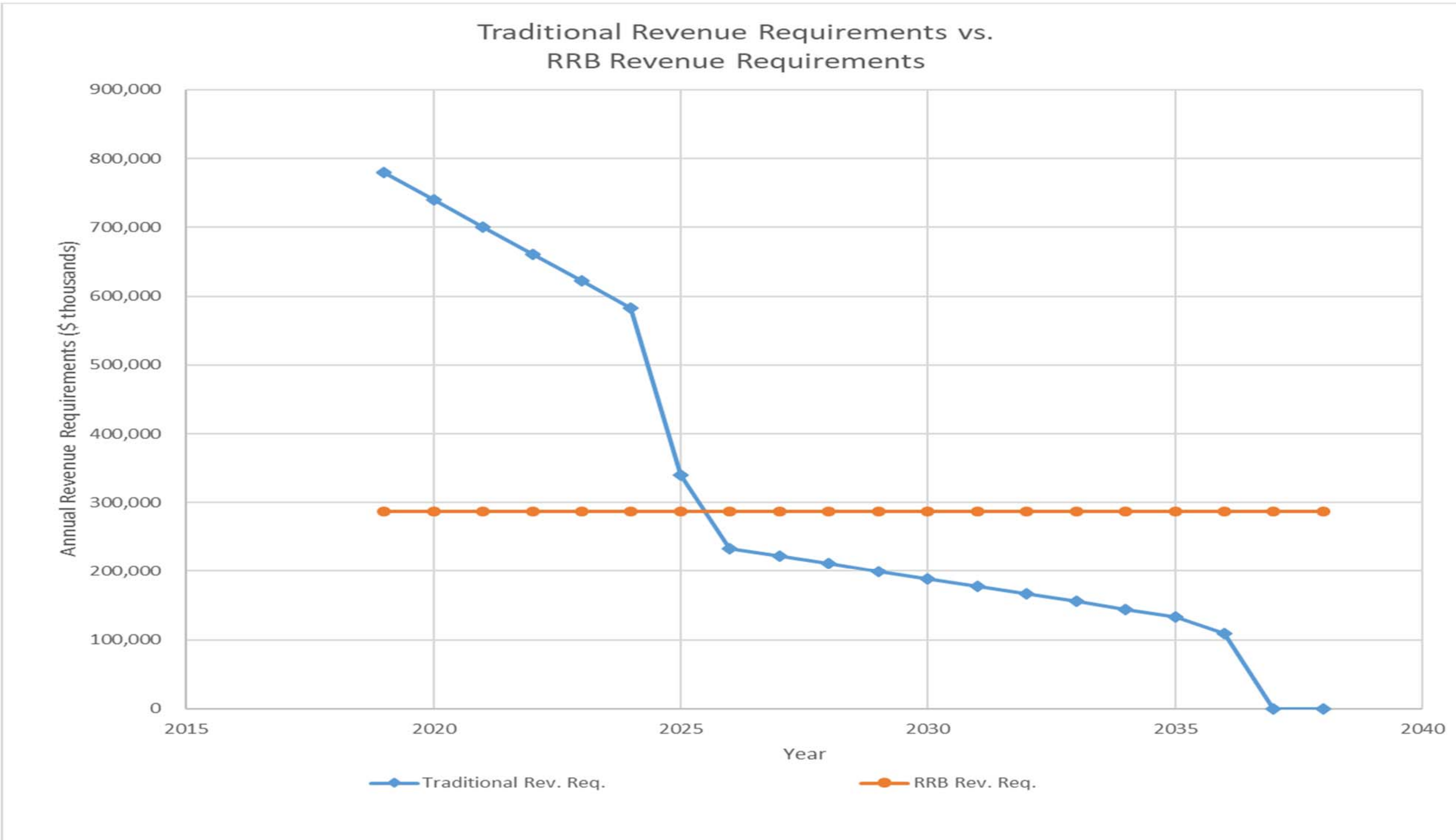
PG&E UOG levelized securitization vs declining traditional annual revenue requirements



Proprietary

SABER PARTNERS, LLC

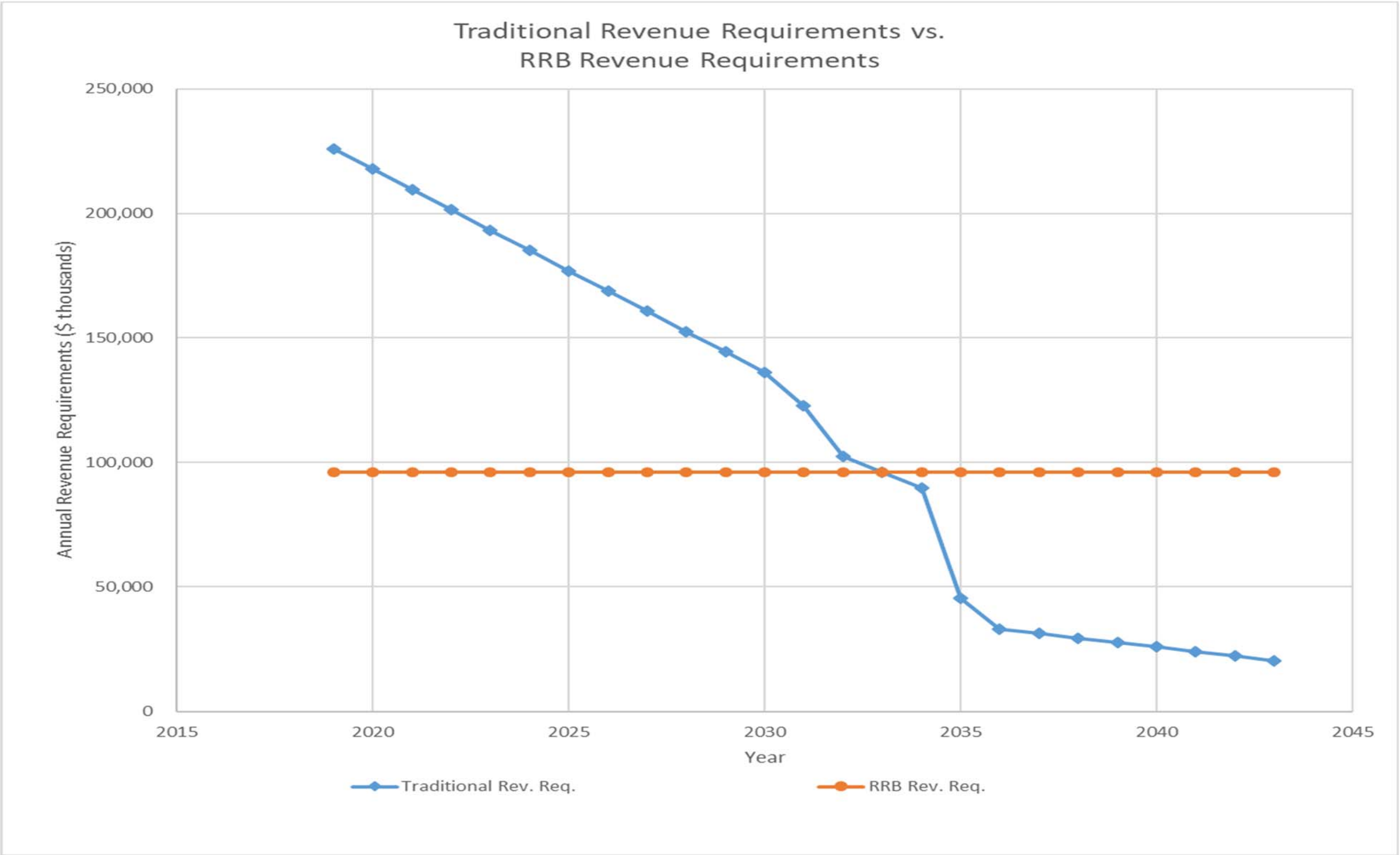
PG&E UOG excluding fossil levelized securitization vs declining traditional annual revenue requirements



Proprietary

SABER PARTNERS, LLC

SCE UOG levelized securitization vs declining traditional annual revenue requirements

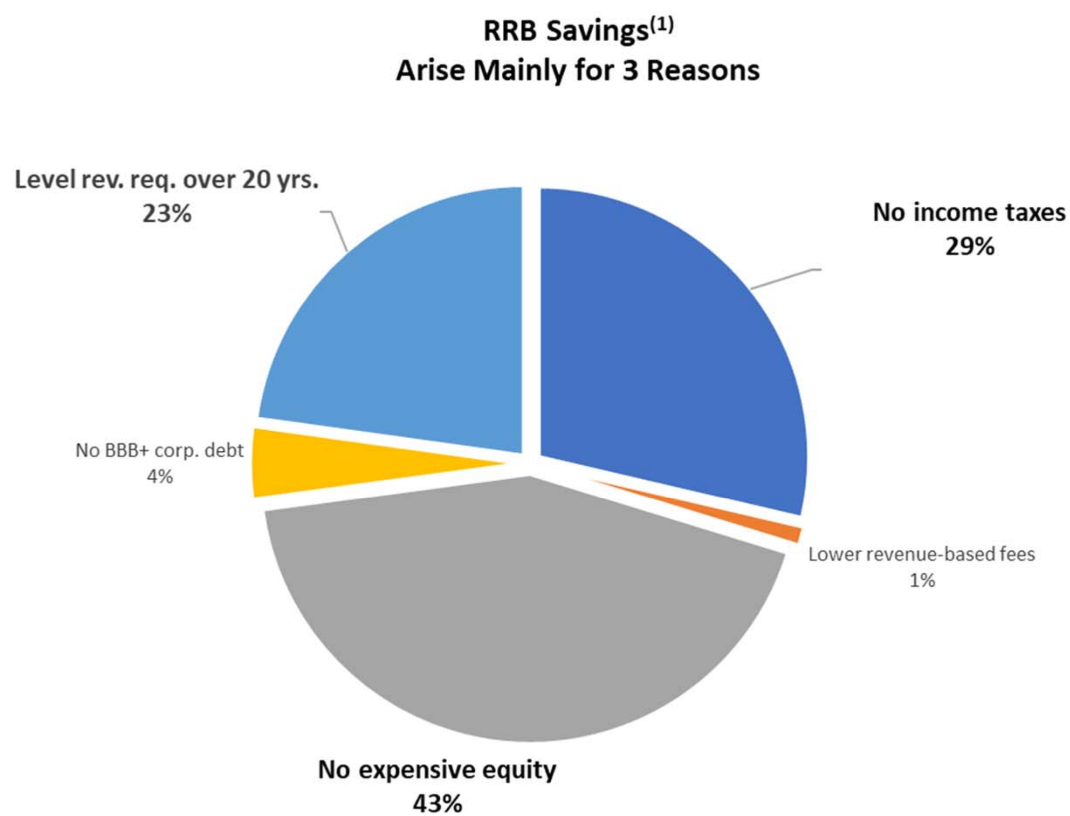


Proprietary

Exhibit K

SABER PARTNERS, LLC

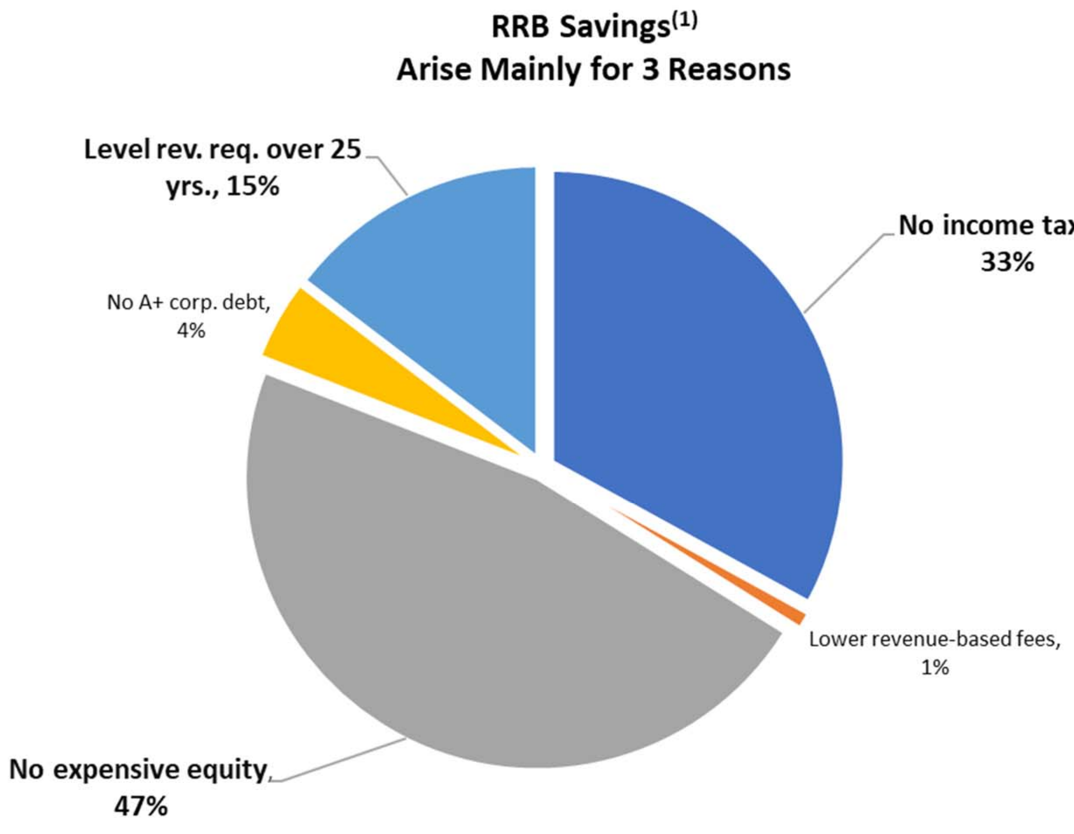
Securitization NPV savings are dependent on factors besides just interest rates – PG&E



(1) Savings net of issuance costs

SABER PARTNERS, LLC

Securitization NPV savings are dependent on factors besides just interest rates – SCE



(1) Savings net of issuance costs

Exhibit L.i

SABER PARTNERS, LLC

RRB upfront issuance cost as a % of principal amount estimated to be ~1.2% for large deals

Up-Front Costs COMPARISON

Of Recent Investor-Owned Utility Securitization Bonds

Issuer:	New Orleans		Consumers		DEF	
	(estimated)		(estimated)		(final)	
Date	7/14/2015		7/14/2014		6/15/2016	
Principal Amount:	$98,730,000		$378,000,000		$1,294,290,000	
Itemized Costs						
Variable Costs (based on principa	Amount	% of PA	Amount	% of PA	Amount	% of PA
Rating Agency Fees	315,000	0.33%	373,550	0.32%	1,601,288	0.12%
Underwriters' Fee	350,555	0.36%	1,687,000	0.45%	6,789,530	0.52%
SEC Registration Fee	11,472	0.01%	50,180	0.01%	130,335	0.01%
Variable Cost Subtotal	**$677,027**		**$2,110,730**		**$8,521,153**	
Fixed Costs (independent of principal amount)						
Accountant Fees	225,000		220,000		72,159	
BondCo Set-up Cost	6,000		150,000		3,500	
Company's Financial Advisor/Str	550,000				290,273	
Commissions's Financial Advisor Fees & Expenses					1,600,000	
Commission's Legal Fees & Expenses			95,544		1,171,000	
Legal Fees, incl. Issuer's Counse	1,355,000		3,316,104		3,376,504	
Company's Non-Legal Securitiza	10,000					
Marketing and Miscellaneous Fe	(1,235)		519,860		36,725	
Original Issue Discount	24,090		100,000		51,287	
Printing / Edgarizing Expenses	30,000		30,000		78,033	
Servicer's Set-up Cost	50,000				382,833	
Trustees Counsel Fees and Expe	47,500		20,000		42,900	
Fixed Cost Subtotal	**$2,296,355**		**4,451,508**		**$7,105,214**	
TOTAL UP-FRONT COSTS (1)	**2,973,382**	**3.01%**	**6,562,238**	**1.74%**	**15,626,367** (2)	**1.21%**

(1) Source: Respective transactions FINAL Issuance Advice Letters (IAL), excluding OID

(2) Amount from Appendix A to DEF's IAL updated 8/18/2016

SABER PARTNERS, LLC

Exhibit L.ii

RRB ongoing costs add about 0.8% NPV

From DEF Attachment 4 Combined Issuance Advice Letter and True Up Adjustment Letter dated 6/16/2016

Duke Energy Florida Principal Amount = $1,294,290,000		
DEF ESTIMATED ANNUAL ONGOING FINANCING COSTS		
Description	**Annual Amount**	
Servicing Fee [1]	$ 647,145	
Return on Invested Capital	201,392	
Subtotal Variable		$ 848,537
Administration Fee	50,000	
Auditor Fees	50,000	
Regulatory Assessment Fees	62,500	
Legal Fees	30,000	
Rating Agency Surveillance Fees	50,000	
Trustee Fees	10,000	
Independent Manager Fees	5,000	
Miscellaneous Fees and Expenses	1,700	
Subtotal Fixed		259,200
TOTAL ESTIMATED ANNUAL ONGOING FINANCING COSTS	**$ 1,107,737**	**$ 1,107,737**

(1) Low end of the range assumes DEF is the servicer (0.05%). However, in most RRB transactions, servicing fees in excess of incremental costto the utility are credited back to ratepayers, so actual cost may be substantially less than assumed.

NPV	**$10,339,435**
NPV as % of Principal	**0.80%**

SABER PARTNERS, LLC

Exhibit M

Substantial savings are possible from securitization of utility owned generation

	Asset Amt.[1] ($000)	Scheduled Final Maturity (yrs.)	WAL [2] (yrs.)	NPV Savings[3] ($000)	NPV Savings[3] (% of P.A.)
PG&E Utility Owned Generation Securitization					
All Non-CAM[4] Utility Owned Generation (UOG)	4,556,237	20	11.7	1,628,508	35%
All Non-CAM[4] UOG Except Fossil	3,806,104	20	11.7	1,337,475	34%
SCE Utility Owned Generation Securitization					
All Non-CAM[4] Utility Owned Generation (UOG) [5]	1,530,000	25	14.9	589,349	41%
					41%

(1) Assuming year end 2018 balances

(2) WAL = weighted average life

(3) Discounted at WACC of 7.69% for PG&E and 7.61% for SCE

(4) Cost Allocation Mechanism

(5) SCE has no fossil Non-CAM generation

Reprinted from THE WALL STREET JOURNAL.

WEDNESDAY, NOVEMBER 10, 1999

THE WALL STREET JOURNAL

NEW ENGLAND

ECONOMIC FOCUS

Contract Deal Is Proposed To Aid Vermont Utilities

By ANDREW CAFFREY
Staff Reporter of THE WALL STREET JOURNAL

The Vermont utility industry's efforts to resolve one of its expensive and thorny electricity issues may be back on track.

A private nonprofit corporation that facilitates the buying and selling of alternative power says it's beginning to work on a deal to either refinance or buy out altogether the high-priced electricity contracts it has with the Vermont-based independent producers that own those generation facilities.

The company, **Vepp** Inc., which stands for Vermont Electric Power Producers, two weeks ago hired Wall Street investment firm Prudential Securities Inc. to draw up proposals to float $150 million to $200 million in bonds. As proposed, the bonds would be repaid with special surcharges on Vermont utility bills.

Proceeds would be used to either buy out all or a portion of the long-term contracts the producers have with the utilities, or to refinance the producers' debt at lower rates, allowing them to cut prices as well.

"There is progress," says John Spencer, Vepp's executive director. "Everyone involved has come to the realization that this type of method is in everyone's best interest."

The 20 small power plants, mostly hydroelectric projects, are a vestige of the 1980s, when the Carter Administration promoted cheaper home-grown alternative energy sources in the face of oil shortages and rising prices from abroad. In 1983, Vermont regulators began requiring utilities to buy a portion of their power from in-state-based renewable energy sources. At the time, traditional energy prices were projected to be much higher, so the prices from these alternative power plants — at anywhere between 9.6 cents and 17.5 cents a kilowatt/hour — seemed like a good deal.

Power Surge

The power prices of selected Vermont independent power plants

Nantana Mill	17.5
Comtu Falls	16.9
Newbury Hydro	14.7
Winooski One	13.0
Martinsville Hydro	12.0
Woodside Hydro	12.0
Dodge Falls	11.9
Killington Hydro	11.7
Barnet Hydro	11.5
Ryegate	10.5
New England average	3.5

NOTE: prices in cents per kilowatt/hour
Sources: Central Vermont Public Service, industry data

But as deregulation has swept the industry nationally, and new technologies made electricity from, say, natural gas cheaper to produce, the energy from the small Vermont plants became an expensive lesson in environmental altruism.

For example, Vermont utilities separately buy about 38% of their power supply from **Hydro-Quebec**, which at around 6.5 cents a kilowatt/hour is considerably cheaper than the electricity from the independent producers. Officials say that nationally the average wholesale price for electricity is 3.5 cents.

Complicating the situation is that unlike states like Massachusetts and Rhode Island — which have deregulated the electric industry and ordered the break-up of the old monopolies — Vermont has pressured its utilities to find ways to cut costs and restructure on their own. Utilities say they have no choice but to restructure, since they're locked into long-term contracts for power at such high prices that they face the prospect of bankruptcy.

By far, the biggest controversy for Vermont utilities is their contract with Hydro-Quebec, which runs to 2020. The utilities say that at current prices, power from Hydro-Quebec will cost Vermont $450 million more than energy at prevailing market rates. And so they're involved in a nasty fight with the Canadian power company to get out of the contract. Separately, they're selling off interests in the Vermont Yankee nuclear plant. (That sale still needs approval from state and federal regulators.)

Meantime, efforts are again under way to try to resolve the issues regarding the Vepp contracts, which generate about 74 megawatts of electricity and supply about 6% of the state's power.

The utilities and independent power producers tried to renegotiate the contracts last summer; the power producers offered to refinance their contracts in such a way that Vermont consumers would save "tens of millions" of dollars off electricity bills, says John Warshow, a partner in three hydro projects.

But the utilities say the power companies' offer was insufficient, and in August they abruptly broke off talks, and instead petitioned state regulators to consider various mechanisms to ease the burden of the contracts.

Mr. Spencer of Vepp hopes that the financial proposals Prudential is expected to develop over the next few weeks will serve as a catalyst to restart the stalled negotiations.

The ultimate goal, officials say, is a net reduction in electricity prices for Vermont consumers.

"This deal will only go forward if we

(over please)

were to lower rates for the retail customer, while meeting the contractual obligations with the independent "producers," says Joseph Fichera, a managing director and head of Prudential's power group. "We think we can show savings."

Though still saving some strong words for each other, both utilities and the power producers cautiously welcomed the attempt by Vepp to forge a middle ground.

"As soon as they have something concrete to discuss with us," says Mr. Warshow, "I am open" to considering it, so long as it "does not adversely impact the producers and is of benefit to the rate payers." The power producers say it was they, not the utilities, who have kept the settlement process alive by pushing to have Prudential hired and a proposed financial package developed.

Meanwhile, says Robert Rogan, a vice president of Central Vermont Public Service Corp. in Rutland, who serves as a spokesman for the state's utilities in restructuring issues: "We welcome any progress. The true test will be when the negotiators come back to the table."

A settlement would need the approval of Vermont regulators, who are concerned about the level of animosity between the utilities and power producers.

Richard Sedano, commissioner of the Vermont Department of Public Service, suggests independent power producers would be wise to accept a less-than-ideal settlement. He says the high price of their electricity makes them a political target, either for regulators who are trying to lower prices in Vermont, or for state legislators who have so far held off mandating deregulation of the industry.

"A safe harbor is a nice thing to have in these times," says Mr. Sedano, "even if it costs you a little."

Exhibit O

PROSPECTUS SUPPLEMENT TO PROSPECTUS DATED APRIL 20, 2001

$525,000,000 RATE REDUCTION BONDS, SERIES 2001-1

PSNH FUNDING LLC

Issuer

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Seller and Servicer

	Interest Rate	Initial Principal Amount	Price (%)	Price ($)	Underwriting Discounts and Commissions (%)	Proceeds to Issuer (%)(1)(2)	Scheduled Maturity Date	Final Maturity Date
Class A-1	4.57%	$ 75,211,483	99.97979%	$ 75,196,284	0.207573%	99.77222%	5/1/2003	5/1/2005
Class A-2	5.73%	$214,649,395	99.93578%	$214,511,547	0.375000%	99.56078%	11/1/2008	11/1/2010
Class A-3	6.48%	$235,139,122	99.96116%	$235,047,798	0.500000%	99.46116%	5/1/2013	5/1/2015

…………………………

USE OF PROCEEDS

The issuer will use the net proceeds from the sale of the bonds to purchase the RRB property from the seller and to pay the costs of issuing the bonds, including the initial funding of the interest reserve subaccount. The seller may apply the net proceeds from the sale of the RRB property in accordance with the finance order to reduce its capitalization and to buy down purchased power obligations.

Filed pursuant to Rule 424(b)(2)

Registration No. 333-76040

PROSPECTUS SUPPLEMENT
To Prospectus Dated January 16, 2002

$50,000,000 Rate Reduction Bonds, Series 2002-1

PSNH Funding LLC 2
Issuer

Public Service Company of New Hampshire
Seller and Servicer

Interest Rate	Initial Principal Amount	Price (%)	Price ($)	Underwriting Discounts and Commissions(%)	Proceeds to Issuer (%)(1)(2)	Scheduled Maturity Date	Final Maturity Date
4.58%	$50,000,000	99.972162%	$49,986,081	0.407%	99.565162%	February 1, 2008	February 1, 2010

(1) Before payment of fees and expenses.
(2) The total price to the public is $49,986,081 and the total amount of the underwriting discounts, commissions and other fees is $353,500. The total amount of proceeds before deduction of expenses (estimated to be $1,480,000) is $49,632,581.

……………………………………………………………….

USE OF PROCEEDS

The issuer will use the net proceeds from the sale of the bonds to purchase the RRB property from the seller and to pay the costs of issuing the bonds, including the initial funding of the interest reserve subaccount. The seller may apply the net proceeds from the sale of the RRB property in accordance with the finance order to buy down purchased power obligations.

SABER PARTNERS, LLC

Exhibit P

Potential savings from PPA buydown

Buydown Assumptions

	Escalation rates	Prices Year 1	Prices Year 2	
Market Price- $/MWH	1.80%	50	50.9	…..
Old Contract Price- $/MWH	0.90%	185	186.7	…..
		Sales		
Annual Sales (GWH)		2,000	2,000	…..
Cost of Capital				
Securitization (20 yr. final maturity)	3.91%			
PPA Investor	6.50%			
Ratepayer	7.69%			

PPA owner cost of capital (hypothetical):

Source of Capital	Capital Structure	Annualized Cost	Wtd. Avg. Cost of Capital (WACC)	Pre-Tax Cost of Capital
Common Equity	5.00%	25.00%	1.25%	1.74%
Long-Term Debt	95.00%	5.53%	5.25%	5.25%
Total Capitalization	100.00%		6.50%	6.99%

Buydown Potential Savings
($ millions)

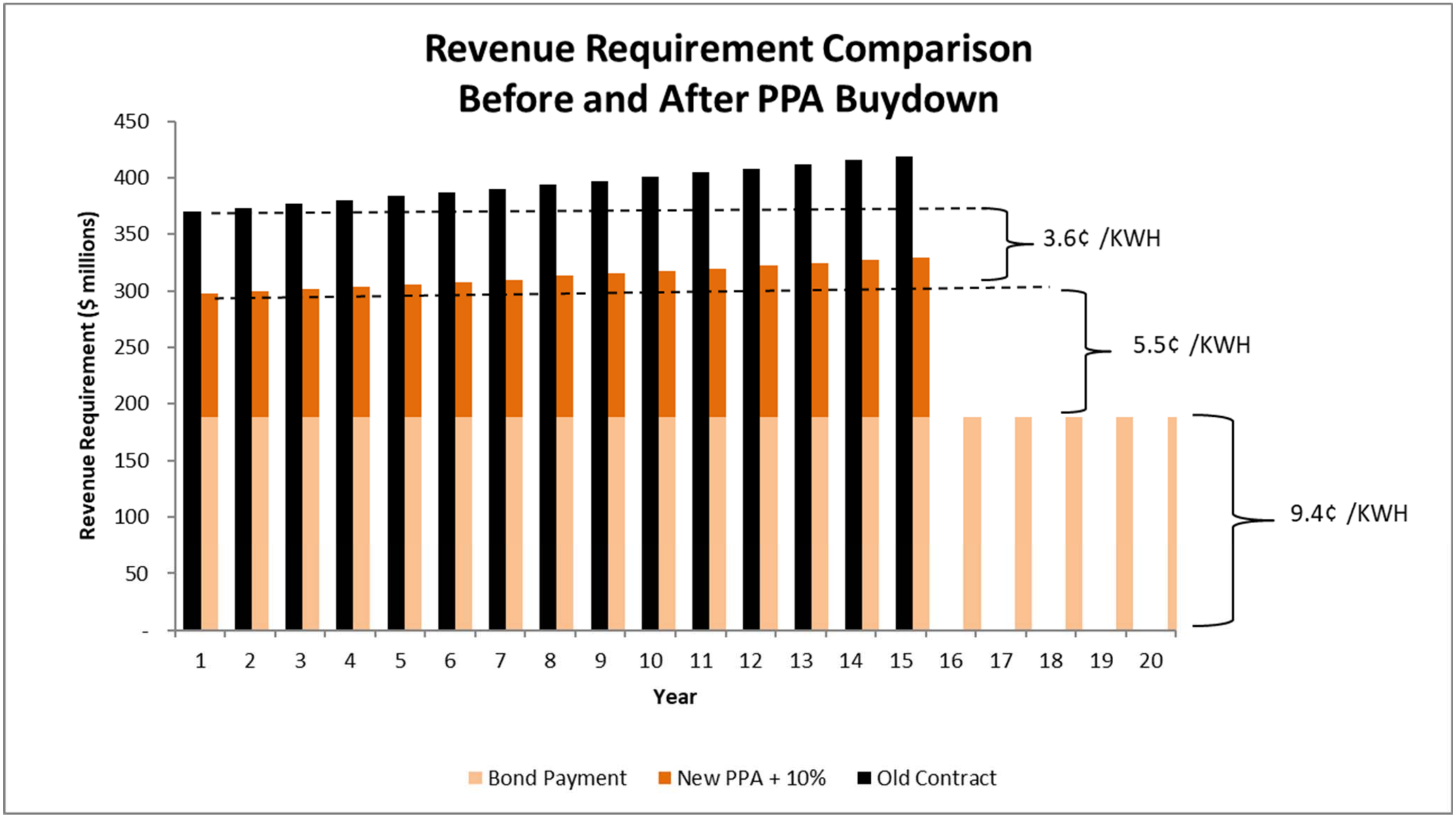
	Year 1	Year 2		Nominal Total	NPV @7.69%	NPV @ 6.5%
Old PPA Rev. Req.	**370.0**	**373.3**	**….**	**5,914**	**3,398**	**3,669**
Market PPA	100.0	101.8	….	1,705	968	1,047
Mkt PPA +10.%	110.0	112.0	….	1,875	1,064	**1,151**
20 Year Levelized bond pmt	187.6	187.6	….	3,751	1,885	2,067
Total New Rev Req.	**297.6**	**299.5**	**….**	**5,626**	**2,949**	**3,218**
Savings				287	449	
Savings as % of principal				11%	**17%**	

2,517	Buydown Cost
51	2% NPV upfront & ongoing costs
2,569	Principal Amount

Proprietary

SABER PARTNERS, LLC

NPV savings from PPA buydown may be achieved by stretching out securitization



Proprietary

SABER PARTNERS, LLC

Exhibit Q

Source of Data Used* in Financial Model Of PG&E and SCE Securitization of UOG

PG&E Inputs

Input	Source
Capital structure	PG&E Advice Letter 3887
Cost of capital	PG&E Advice Letter 3887
2017 Y/E Rate base amounts for Diablo Canyon, hydro, and fossil generation	PG&E's response to CCSF Data Request #2, questions 5-7
2017 Y/E Rate base for solar generation	PG&E's 2017 GRC workpapers for Exhibit PG&E-10, page 14-2
Remaining useful lives	PG&E's 2017 GRC workpapers (same as above), Table 11-1, beginning on page 11-3
Franchise fee factor	PG&E Advice Letter 3894

SCE Inputs

Input	Source
Capital structure	SCE Advice Letter 3665
Cost of capital	SCE Advice Letter 3665
2017 Y/E Rate base amounts and remaining useful lives	SCE workpapers in A. 16-09-001, SCE workpapers for SCE 9 Volume 2, Chapters I and II, pages 133-146

*Provided to Saber Partners, LLC by California Community Choice Association

PENINSULA CLEAN ENERGY AUTHORITY
Board Correspondence

DATE: April 18, 2018
BOARD MEETING DATE: April 26, 2018
SPECIAL NOTICE/HEARING: None
VOTE REQUIRED: None

TO: Honorable Peninsula Clean Energy Authority Board of Directors

FROM: Leslie Brown, Director of Customer Care

SUBJECT: Update on EPA Green Power Partnership and Community Programs for PCE and ECO100 cities

BACKGROUND:

One of PCE's Strategic Goals is to achieve recognition from the EPA's "Green Power Partnership for Green Power Communities" for all cities with municipal accounts enrolled in ECO100. PCE staff reached out to the EPA Green Power Partnership (GPP) team earlier in the year to start the process. PCE staff learned that the GPP team had recently proposed some significant changes to the Partnership requirements that would, if adopted, impact the ability of several individual cities to receive Green Power Partner status due to a significant increase in the minimum kWh purchase requirement. A decision on the changes and updated requirements were initially expected to come at the end of March or early April, but we have not yet received an update.

While we continue to wait for the new Green Power Partnership requirements, PCE staff will pursue obtaining Green Power Community recognition under the program's CCA guidelines. Once the new Partnership requirements are known, PCE staff will coordinate with qualifying cities to enroll in the Green Power Partnership program.

REGULAR MEETING of the Board of Directors of the Peninsula Clean Energy Authority (PCEA)
Thursday, March 22, 2018
MINUTES

Peninsula Clean Energy
2075 Woodside Road, Redwood City, CA 94061
6:30 p.m.

CALL TO ORDER

Meeting was called to order at 6:38 p.m.

ROLL CALL

Present: Dave Pine, County of San Mateo
Carole Groom, County of San Mateo
Jeff Aalfs, Town of Portola Valley, *Chair*
Rick DeGolia, Town of Atherton, *Vice Chair*
Julia Mates, City of Belmont
Donna Colson, City of Burlingame
Rae P. Gonzalez, Town of Colma
Raymond Buenaventura, City of Daly City
Carlos Romero, City of East Palo Alto
Catherine Mahanpour, City of Foster City
Harvey Rarback, City of Half Moon Bay
Elizabeth Cullinan, Town of Hillsborough
Catherine Carlton, City of Menlo Park
Wayne Lee, City of Millbrae
John Keener, City of Pacifica
Cameron Johnson, City of San Carlos
Rick Bonilla, City of San Mateo
Pradeep Gupta, City of South San Francisco
Daniel Yost, Town of Woodside

Absent: City of Brisbane
City of Redwood City
City of San Bruno

Staff: Jan Pepper, Chief Executive Officer
Jay Modi, Director of Finance and Administration
Leslie Brown, Director of Customer Care

Joseph Wiedman, Director of Legislative and Regulatory Affairs
Jeremy Waen, Senior Regulatory Analyst
Kirsten Andews-Schwind, Communications and Outreach Manager
TJ Carter, Marketing Associate
Nirit Eriksson, Associate General Counsel
Anne Bartoletti, Board Clerk/Executive Assistant to the CEO

A quorum was established.

PUBLIC COMMENT:

No public comment.

ACTION TO SET THE AGENDA AND APPROVE CONSENT AGENDA ITEMS

<u>Motion Made / Seconded, as modified:</u> Lee / Romero

Motion passed 17-0 (Absent: Brisbane, Menlo Park, Redwood City, San Bruno. Abstain: Hillsborough)

REGULAR AGENDA

1. **CHAIR REPORT**

Jeff Aalfs–Chair–reported that he appointed an ad hoc committee to review applications to fill vacancies on Peninsula Clean Energy's (PCE) Citizens Advisory Committee. He also reported that he attended the Yosemite Policymakers Conference on Building Livable Communities.

2. **CEO REPORT**

Jan Pepper–Chief Executive Officer–announced that two new employees have been hired. She announced that Chelsea Keyes will start on March 26, 2018 as Power Resources Manager, and Rafael Reyes will start on April 9, 2018 as Energy Programs Director. Jan reported that she is progressing with a search for a Chief Financial Officer (CFO), and that she is currently interviewing candidates for Interim CFO.

Jan announced that PCE's ECO100 product is now Green-e certified, and that PCE's ECOplus rates were adjusted on March 15, 2018 to maintain a 5% savings compared to PG&E rate adjustment that went into effect on March 1.

3. **CITIZENS ADVISORY COMMITTEE REPORT**

Ted Howard–Vice Chair of the Citizens Advisory Committee (CAC)–reported on discussions that took place at the last CAC meeting.

PUBLIC COMMENT:

James Tuleya

4. MARKETING AND OUTREACH REPORT

Kirsten Andrews-Schwind—Communications and Outreach Manager—reported on recent community outreach efforts, and activities planned for Earth Month in April. She announced that applications are being accepted for new CAC members, and applications are being accepted for PCE's Community Outreach Small Grant Pilot that will provide grants for a six-month outreach collaboration. Kirsten also announced that PCE partnered with the County of San Mateo STEM Fair and gave out 2 awards to 7th grade students for projects that focused on clean energy.

PUBLIC COMMENT:

James Tuleya

5. REGULATORY AND LEGISLATIVE REPORT

Joe Wiedman—Director of Legislative and Regulatory Affairs—reported on recent filings, including comments relating to the CPUC's (California Public Utility Commission) NEM 2.0 docket (Net Energy Metering), and responding to a petition for modification of the commission's Code of Conduct. Joe reviewed several bills in the California legislature, and reported on meetings with CPUC Commissioner Guzman-Aceves, and the advisors of Commissioners Randolph, Rechtschaffen, and Peterman, regarding Commission decisions authorizing programs to serve disadvantaged communities.

6. APPOINTMENTS TO THE EXECUTIVE COMMITTEE AND OTHER STANDING BOARD COMMITTEES

Jeff Aalfs reported that, at the January Board meeting, the Board of Directors adopted a policy outlining the process for making appointments to Committees. Jeff presented a slate of names for the Executive Committee, which he proposed to expand to nine seats, and a slate of names for the Audit and Finance Committee.

Motion Made / Seconded: Romero / Gupta

Motion passed 19-0 (Absent: Brisbane, Redwood City, San Bruno.)

Board members expressed interest in creating a standing committee on legislative and regulatory matters that require deeper discussion.

7. PRESENTATION ON CAM (COST-ALLOCATION MECHANISM) AND RA (RESOURCE ADEQUACY)

Jeremy Waen—Senior Regulatory Analyst—presented information on CAM (Cost Allocation Mechanism) and RA (Resource Adequacy). His discussion included the meaning and impacts of RA and CAM, CCAs (Community Choice Aggregator) and grid reliability, the locations and timing of supply versus demand across California, and emerging trends.

8. BOARD MEMBERS' REPORTS

None.

ADJOURNMENT

Meeting was adjourned at 8:41 p.m.

PENINSULA CLEAN ENERGY
JPA Board Correspondence

DATE: April 17, 2018
BOARD MEETING DATE: April 26, 2018
SPECIAL NOTICE/HEARING: None
VOTE REQUIRED: None

TO: Honorable Peninsula Clean Energy Authority Board of Directors

FROM: Jan Pepper, Chief Executive Officer

SUBJECT: Energy Supply Procurement Report – April 2018

BACKGROUND:
This memo summarizes agreements entered into by the Chief Executive Officer since the last regular Board meeting in March. This summary is provided to the Board for information purposes only.

DISCUSSION:
The table below summarizes the contracts that have been entered into by the CEO in accordance with the following policy since the last board meeting.

Execution Month	Purpose	Counterparty	Term	Delivery Period
April 2018	Purchase of PCC1	PG&E	1 year	CY 2019

In December 2017, the Board approved the following Policy Number 15 – Energy Supply Procurement Authority.

Policy: "Energy Procurement" shall mean all contracting for energy and energy-related products for PCE, including but not limited to products related to electricity, capacity, energy efficiency, distributed energy resources, demand response, and storage. In Energy Procurement, Peninsula Clean Energy Authority will procure according to the following guidelines:

1) **Short-Term Agreements:** Chief Executive Officer has authority to approve energy procurement contracts with terms of twelve (12) months or less. The CEO shall report all such agreements to the PCE board monthly.

2) **Medium-Term Agreements:** Chief Executive Officer, in consultation with the General Counsel, has the authority to approve energy procurement contracts with terms greater than twelve (12) months but not more than five (5) years. The CEO shall report all such agreements to the PCE board monthly.

3) **Intermediate and Long-Term Agreements:** Approval by the PCE Board is required before the CEO enters into energy procurement contracts with terms greater than five (5) years.