FINANCIAL STRATEGY

Modeling Results, Risk Analysis & Contingency Plan

July 2017

COMMUNITY CHOICE PARTNERS

SECURING YOUR COMMUNITY'S ENERGY FUTURE

FOREWORD

This Financial Strategy is predicated upon the risk management best practices built into the February 2017 South Bay Clean Power draft Business Plan's recommended RFP design, contracting process and subsequent implementation of South Bay Clean Power (SBCP) CCA.

Since the publication of that report, the two Community Choice agencies which we based many of our design recommendations upon — Silicon Valley Clean Energy and Redwood Coast Energy Authority — have launched successfully. They have each exceeded expectations. Both have produced impressive and comprehensive Energy Risk Management (ERM) policies and real-world capabilities.

Their energy operations are provided by portfolio managers. These are companies and nonprofits (the latter typically owned by other public power entities) that provide an integrated suite of power sector services: planning, origination, contract management, active power market operations and settlements. Contracting with these companies allows CCAs to diversify their energy portfolios by subsequently contracting with multiple suppliers, and generally to fast-track their understanding of how to apply industry-standard energy risk management analytics and practices.

Superior energy risk management impresses lenders as well — which is why Silicon Valley was able to achieve an industry-first in negotiating an $18MM line of credit prior to launch and requiring no municipal guarantees. <u>Truly</u> impressive, and a worthy example for SBCP to leverage.

The proof of concept results are in — and confirm our recommendations for SBCP. In addition to Redwood Coast and Silicon Valley, MCE Clean Energy hired a portfolio manager, and the Inland Choice initiative is currently in contract negotiations with one as well.

To further assist SBCP municipalities, we are releasing a series of "Question and Answers" with five leading portfolio managers. These showcase their services, philosophies, and value-add for Community Choice programs, and provide expert insights into critical issues facing our industry like the Portfolio Allocation Methodology (PAM) proposal by the utilities.

As we detail in our "Regulatory Risk" appendix, we believe PAM will significantly diminish the margins for Community Choice programs in California, starting most likely around 2020. We also believe this is likely <u>unavoidable</u> — and if not, should be planned for as though it is.

To that end, this Financial Strategy incorporates the PAM 'market transformation' into our concluding 'Risk Analysis' section, and proposes a 'Contingency Plan' to help SBCP manage financial risk through this period.

Going into this critical period of uncertainty, we believe the key to stability for SBCP, and the industry as a whole, is to form a Regional JPA of CCAs and to deploy advanced energy risk management capabilities — at scale, and relatively rapidly. (Details in appendix <u>***here***</u> & <u>***here.***</u>)

And that's why we wrote the South Bay Clean Power Business Plan.

However, realizing that the establishment of a Regional JPA of CCAs may not come to pass, or not in time, or not at the right scale, or not actually be sufficient in practice — we have produced this report solely for South Bay Clean Power, were it to launch as a standalone CCA.

The model results are promising:

- If cities move forward relatively quickly, we're confident that a launch date of June or July 2018 is achievable.
- Net revenues of $40MM by the end of 2019 are projected for scenarios considered indicative for SBCP, putting the CCA in a strong position going into the market transformation period; $2.5MM will have been devoted to Distributed Energy staff and programs by that point as well.
- This assumes 0.5% to 1% rate decreases and 60% carbon-free supply, of which 37-39% would be renewable. (We estimate SCE as ~45% carbon-free and ~36% renewable during that time.)
- All startup debt would be repaid by September or October of 2019, absolving municipalities of any guarantees required to raise initial financing. (We have assumed ~$5MM in guarantees to raise $7.5MM in term debt and a $20MM line of credit that requires no guarantee, as based off of Silicon Valley's recent success in negotiating a similar financial package.

To assist SBCP in meeting this timeline, we've achieved three 'industry firsts' with this round of deliverables:

1. Fully transparent model results, with both annual tables and detailed monthly energy, financial and cash-flow outputs that allow full verification of the results;
2. A detailed description of the modeling methodology (which is fairly complex, a lot of which centers around how to accurately model the utility's portfolio and the impacts this has on CCA finances — in four inter-dependent ways.)
3. A 200+ process step Gantt chart, delineating the inter-dependent launch steps for SBCP member governments, key staff, committees, regulators, SCE and key CCA contractors to launch the program — to our knowledge, this is something that no one else has produced or possesses. It allows the identification of the "critical path specifically which tasks have to be executed on time so as not to delay the overall launch date.

Lastly, and in due deference to the unknown regulatory impact we face, our 'Contingency Plan' conclusion provides specific instructions for how SBCP can "*plan for failure, work for success.*" In other words, by understanding and anticipating the timing of this risk, equipping the CCA with the right energy risk management tools for the job, and taking a generally fiscally-conservative approach, we believe SBCP will be able to launch a best in class CCA that achieves your local energy policy goals while effectively managing the inherent risks and liabilities for your JPA, customers and municipalities.

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COMMUNITY CHOICE PARTNERS
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SOUTH BAY CLEAN POWER

TABLE OF CONTENTS

APPENDICES

SOUTH BAY CLEAN POWER

INTRODUCTION

In brief, the structure of this report progresses sequentially through:

1. The initial financing requirements for South Bay Clean Power (SBCP), and a 'walk through' of key graphs to analyze scenario results.
2. An overview of all scenario results, and a series of graphs and tables to facilitate comparisons of trade-offs across the scenarios (which vary renewable and carbon content and rate decreases, while keeping all else the same, and compare SCE and CCA rates and customer savings).
3. A brief tutorial on how the customer phase-in schedule was constructed, which is a make-or-break risk factor for a CCA in the real-world (and analytically challenging).
4. A discussion of the risk & mitigating action assumptions underlying the financial strategy, and summary of residual risk factors (outside of SBCP's control).
5. The 'Contingency Plan' proposed to implement the CCA while minimizing financial risk, which serves as the conclusion of the report body.
6. A series of technical appendices analyzing various sources of risk (regulatory risk, in particular), disclosing the methodology and inputs used in the construction of the model, a disposition of reference material and subject matter experts, and supporting datasets and tables from the model.
7. Lastly, a start-up funding requirement table prepared for South Bay Clean Power. This may be provided for with direct member contributions to be repaid by the CCA JPA, or sourced through a start-up loan (likely backed by a full guarantee from municipalities).

At a high-level, this financial strategy and model forecast has a five-year term and is focused on the startup, launch and early operational phases of South Bay Clean Power. Its primary purpose is to explain and quantitatively demonstrate the feasibility and effectiveness of the CCA's financial strategy during the period when debt is 1) used to collateralize and launch the program and 2) subsequently paid off with net revenues generated over the initial years of operations.

We do so using a series of monthly cash-flow analyses, discussions and visualizations of critical dynamics and risk factors inherent in the modeling analysis, disclosure of the underlying methodology and input assumptions (as well as subject matter experts & key reference documents relied upon), and analyses of various sources of risks and the mitigating strategies (or else contingency plans) recommended for SBCP.

The initial five-year period covered holds the greatest risk for the CCA, as well as any municipalities that have provided contributions or guaranteed loans, and for the CCA's financiers. The forecast horizon and level of specificity in our report is specifically designed to engage lenders, and to support financial negotiations for a startup loan to launch the SBCP CCA.

However, understanding financial risk to CCAs is not a purely mathematical exercise. How the CCA is implemented and operated in practice, and real-world events that are outside of the CCA's direct control will impact the accuracy of the financial forecasts presented in this report.

Consequently, it should be understood that the model relied upon in the production of this report is designed to assess financial risk and the optimal financing strategy for the CCA:

1. In accordance with the ***intended use*** and ***model error risk*** disclaimers in the appendix;
2. Over the initial period when the CCA launches and repays its startup debts;

3. Under extant regulatory and market rules;
4. Assuming that the CCA is launched and operated in accordance with the best practices detailed in the South Bay Clean Power Business Plan (which are industry-proven risk mitigations)[1].

Given the various regulatory changes under discussion that we analyze in this report, conducting modeling that goes beyond the initial (five-year) forecast horizon in this report would be effectively meaningless, and worse — would serve to mislead elected officials on this decision.

Managing and/or mitigating risks of this nature requires more holistic discussions on governance, contracting, operations and politics, and subsequent 'real world' recommendations for the implementation and launch of the CCA — which we reference in the report body, detail in some regards in the appendices, and more broadly discuss these issues in the SBCP Business Plan.

Note that:

1. Key assumptions underpinning the financial model are primarily explained in the methodological appendices in this report, and supported by the CCA Implementation Gantt chart (critical path methodology of 200+ process steps) deliverable.
    a. A workbook of model outputs also accompanies this report. It includes the energy, financial and cash-flow outputs used in preparation of this report, disclosed on a monthly basis.
        i. This granularity allows verification of the cash-flow analysis, and therefore the analytical validity of the customer phase-in and financing strategy.
    b. Note that forecasting the financial performance of the CCA has as much to do with modeling the utility as it does the new CCA.
        i. There are four primary ways in which the utility portfolio and cost structure directly or indirectly impacts a CCA's financial performance; appropriately capturing these relationships and the manner in which both forecasts interact to produce results is of first-order importance.
        ii. Due to the complex nature of the utility's structure and portfolio — and the confidential treatment applied to certain data — *this is more challenging (and uncertain) than predicting the CCA's cost of service independently.* SCE has assisted us (where they can), and we continue to engage with them routinely for clarifications and confirmations.
        iii. For further details, refer to appendix "***Model Methodology and Assumptions***."
2. Key assumptions that underpin the financing strategy — regarding sources of risk and anticipated mitigations — are summarized in this report and analyzed in detail in the various appendices that delineate each category of risk;
    a. The financial strategy necessarily assumes that the recommendations in the SBCP Business Plan will be implemented.

[1] [https://southbaycleanpower.files.wordpress.com/2017/02/sbcp_draft-business-plan_feb15_2017.pdf]

b. Note that the 'best practices' in that plan are primarily risk management and mitigation measures intended to limit direct financial risk to the CCA, its financiers, and customers — as well as financial liabilities to SBCP member municipalities.

Additionally, to provide a measure of 'real world' context to accompany this report, we have provided by a series of "Question and Answer" interviews with five leading power portfolio managers who have reviewed the SBCP Business Plan:

1. Ascend Analytics;
2. Alliance for Cooperative Energy Services Power Marketing (ACES);
3. Customized Energy Solutions, Ltd. (CES);
4. The Energy Authority (TEA);
5. ZGlobal, Inc.

These interviews provide substantial context on the energy risk management practices anticipated for SBCP, as well as expert opinions on key emerging regulatory threats to CCAs, and how best to manage or mitigate the risks posed.

Similarly, we provide supporting documentation from the two CCAs most similar in structure to our recommended design for SBCP: Redwood Coast Energy Authority and Silicon Valley Clean Energy. We include:

1. Both Redwood Coast and Silicon Valley Energy Risk Management (ERM) policies;
2. The contracts these CCAs executed with portfolio managers (The Energy Authority and ZGlobal, respectively) that enable the CCA to exercise effective risk management in practice; and
3. The financing package from Silicon Valley Clean Energy (River City Bank terms and conditions, and board memo from CEO Tom Habashi) — since the financial strategy used in this model and the SBCP Business Plan are based primarily upon their example.

In total, the following documents support this Financial Plan, should be understood as integral to its applicability for SBCP, and will be made available on the SBCP website:

1. Workbook of financial model results for SBCP;
2. SBCP Implementation Gantt chart & Critical Path;
3. Q&A with Portfolio Managers for SBCP;
4. Energy Risk Management policies and portfolio manager service contracts from RCEA and SVCE CCAs;
5. SVCE financial packet; and
6. SBCP Business Plan.

DISCLAIMER: INTERPRETING RESULTS & RECOMMENDATIONS

The forecasts presented in this report are of a preliminary and indicative nature. The appendices provide substantial context for select, key risks that could materially impact the accuracy of the forecasts presented, and the actions we have consequently taken or recommended for SBCP to anticipate, manage or mitigate these risks. Regardless, this report should not be considered as providing a comprehensive disposition of the sources of model error or forecast inaccuracy.

In brief, there are real-world events (e.g. regulatory and other risks) that may impact the validity of the results presented, and there is an inherent risk of model error regardless. The most systemic risks in this regard are listed in the "***Regulatory Risk***" appendix, and include:

1. The risk that utility non-bypassable charge calculations are revised (and increased, likely beginning around 2020). The current charge is the "Power Charge Indifference Adjustment" (PCIA), which the IOUs have proposed replacing with the "Portfolio Allocation Methodology" (PAM).
2. The risk that Direct Access is re-opened in California (an uncertain risk, and may impact the latter part of the forecast period presented here, though this is uncertain).
3. The risk that errors in methodology, calculation steps and input assumptions for the model undermine the validity of the forecasts.

The regulatory risk factors highlighted serve as reminders that models are inherently abstractions of reality, and therefore should not be solely relied upon to inform policy decisions at the Board level — absent an understanding of the broader strategic context, how it could change, and how any inherent risk may best be managed or mitigated.

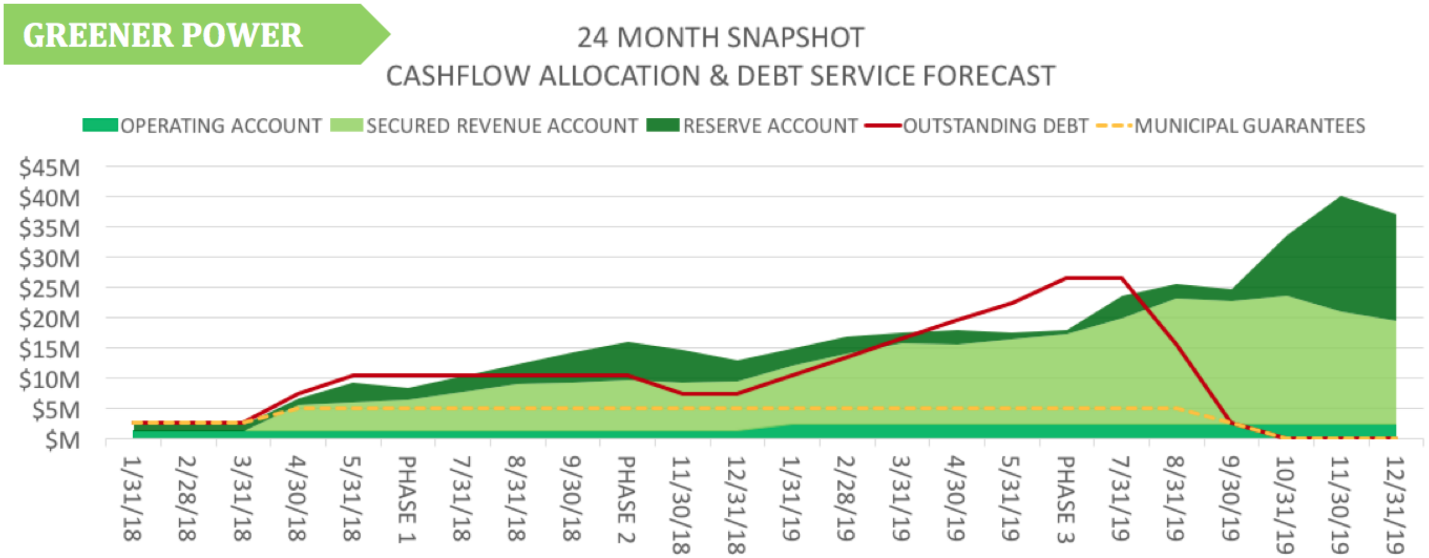
Risk for CCAs is fluid, and the industry is broadly entering into a period of heightened regulatory risk after evolving to date in a relatively supportive market environment. Many of these risks have been anticipated, and various mitigating strategies incorporated into the design of SBCP.

INITIAL FINANCING REQUIREMENTS

The financial strategy for South Bay Clean Power is predicated on our recommendations in the SBCP Business Plan (Feb 2017), with applied best practices based upon Silicon Valley Clean Energy (SVCE)'s recent success. In the model results presented, we assume:

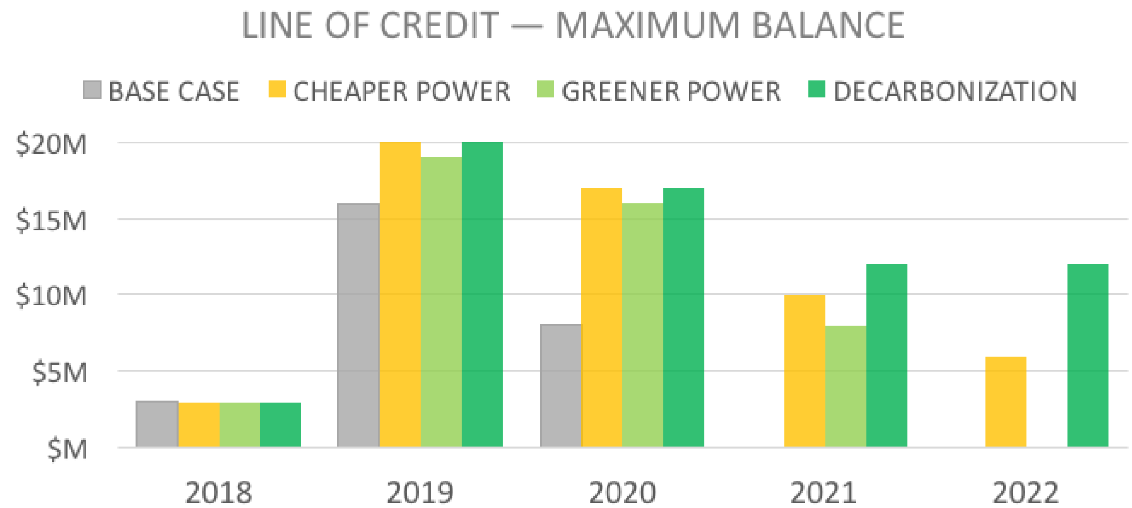
- **$2.5MM start-up loan**: to be executed by October '17, and used primarily as collateral deposits by SCE and regulatory authorities (this allows the formal implementation process to commence) and secondarily, to fund a nominal staff expense. Refer to appendix "***Start-Up Loan Table***" for a detailed disposition of monthly events, expense line items and contingencies.
  - Municipal guarantee: 100% ($2.5MM)
  - CCA guarantee (JPA): secondary lien on revenues
- **$5MM term loan to** support Phase 1 power collateral requirements, executed March '18.
  - Municipal guarantee: 50% ($2.5MM)
  - CCA guarantee (JPA): secondary lien on revenues
- **$20MM line of credit (LOC)** for working capital requirements, also executed March '18.
  - Municipal guarantee: 0%
  - CCA guarantee (JPA): secondary lien on revenues

In all scenarios, the CCA launches in June 2018 and pays off all debts by September/ October 2019 (we use the 'GREENER POWER' scenario as illustrative here, defined under "***Model Results***", p.7):



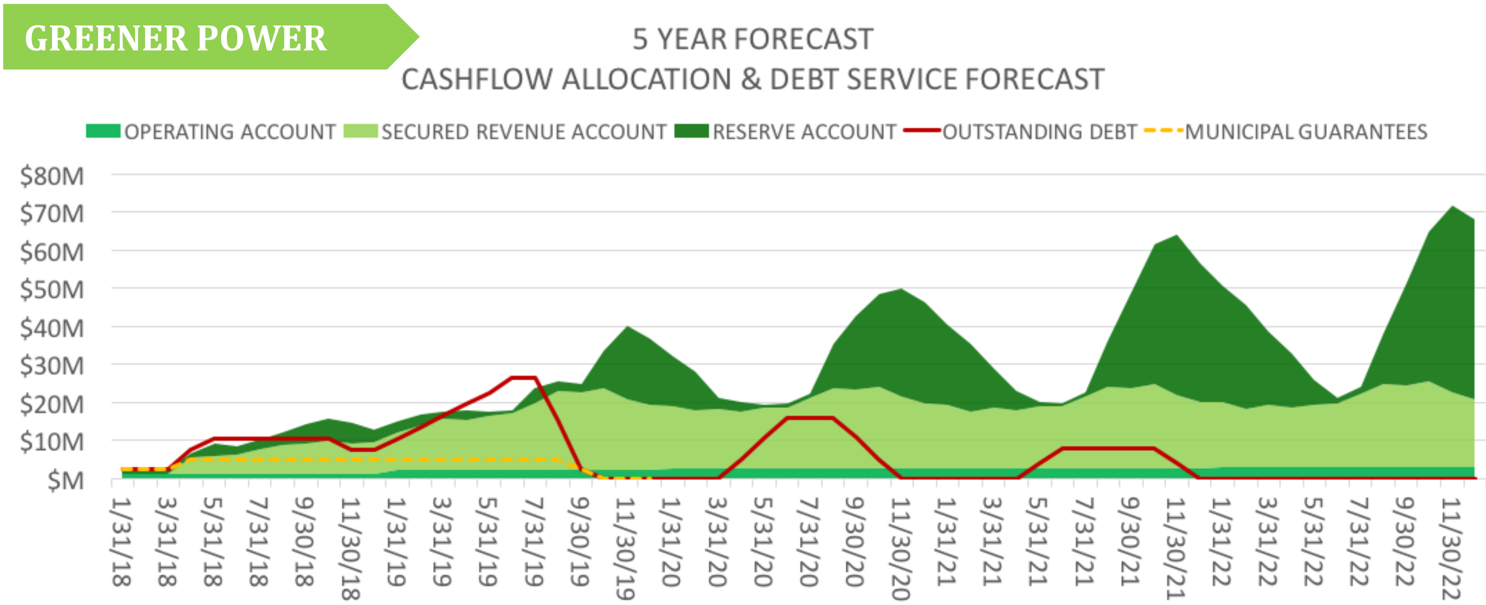
The allocation in the graph above between the operating account, secured revenue account and reserve account reflects the accounting structures, contract payment terms, credit and collateral requirements and other 'real world' financial, regulatory and business process requirements of CCAs. (For further details, refer to appendix "***Cash Flow Analysis***" and to the workbook provided for detailed line item comments and explanatory descriptions.)

The four scenarios presented then vary by their reliance on the annual line of credit to manage seasonal cash-flow imbalances:



The alternative is to self-fund these requirements if the CCA has accrued sufficient cash reserves to do so. This is presented month over month for each scenario, extending out five years:

GREENER POWER



Lastly, a variety of useful metrics are provided to yield insight into trade-offs between the scenarios, and to confirm the validity of financial metrics such as the Debt Service Capacity Ratio (which may also be confirmed bottom up on a monthly basis, based upon the workbook that accompanies this report):

GREENER POWER

	SOUTH BAY CLEAN POWER PERFORMANCE METRICS	2018	2019	2020	2021	2022
Financial Metrics	YE Municipal Guarantees (liability)	5,000,000.00	-	-	-	-
	DSCR (Debt Service Capacity Ratio)	4.26	3.79	1.67	3.05	11.86
	Maximum Debt	$10,500,000	$26,500,000	$16,000,000	$8,000,000	$0
	YE Outstanding Debt	$7,500,000	$0	$0	$0	$0
	YE cash reserves (cumulative)	$6,881,764	$39,069,017	$48,242,484	$58,495,437	$70,177,145
	Annual, as a % of revenue	9%	12%	4%	5%	5%
	Cumulative, as % of annual OpEx	**10%**	**17%**	**17%**	**20%**	**24%**
Portfolio Metrics	Renewable content of CCA portfolio	35%	37%	40%	42%	45%
	Carbon Free (hydro & renewable content)	60%	60%	60%	60%	60%
	Staff & Program Funding for DER	$657,500	$1,895,000	$2,408,750	$2,923,188	$4,438,347
Rate Savings	Rate decrease vs. SCE	1.0%	1.0%	1.0%	1.0%	1.0%
	Community savings from rate decreases (annual)	$0	$0	$0	$0	$0
	Community savings from rate decreases (cumulative)	$963,990	$4,303,149	$8,223,345	$12,252,748	$16,379,093
PCIA Charges	Power Charge Indifference Adjustment (PCIA) payments	$19,450,527	$75,055,887	$93,400,560	$98,525,278	$100,235,079
	PCIA as % of CCA rates	26%	29%	32%	33%	33%
	PCIA as % of SCE's rates	20%	22%	24%	24%	24%
Uses of Revenue	Energy expenses as a % of revenue	82%	83%	91%	90%	89%
	Reserve collection as a % of revenues	9%	12%	4%	5%	5%
	Overhead as a % of revenues	9%	5%	5%	5%	5%

MODEL RESULTS

We have prepared four scenarios to provide SBCP cities with a range of insights into how varying power costs and rate decreases are forecasted to impact the financial performance of the CCA:

SCENARIOS FOR COMPARISON

BASE CASE

The 'Base Case' scenario provides an initial point of comparison with SCE. The CCA matches SCE's estimated renewable and carbon content, and sets rates such that customers would pay the same under either CCA or SCE bundled service.

CHEAPER POWER

The 'Cheaper Power' scenario holds the Base Case assumptions steady but decreases generation rates by 2% in all years as compared to SCE. It is included to provide insight into the impact of rate decreases on the CCA. (And does not reflect policy goals.)

SOUTH BAY CLEAN POWER SCENARIOS

GREENER POWER

'Greener Power' launches and maintains a 60% carbon-free supply through year five, with renewable supply growing from 35% to 45%, and a 1% generation rate decrease relative to SCE. (Between 2018-2022, we estimate SCE at 44% → 50% carbon free, with 34% → 39% renewable content.)

DECARBONIZATION

'Decarbonization' launches at 60% carbon-free with 35% renewable, and grows to 100% carbon-free with 50% renewable by 2022 — with a 0.5% rate decrease compared to SCE.

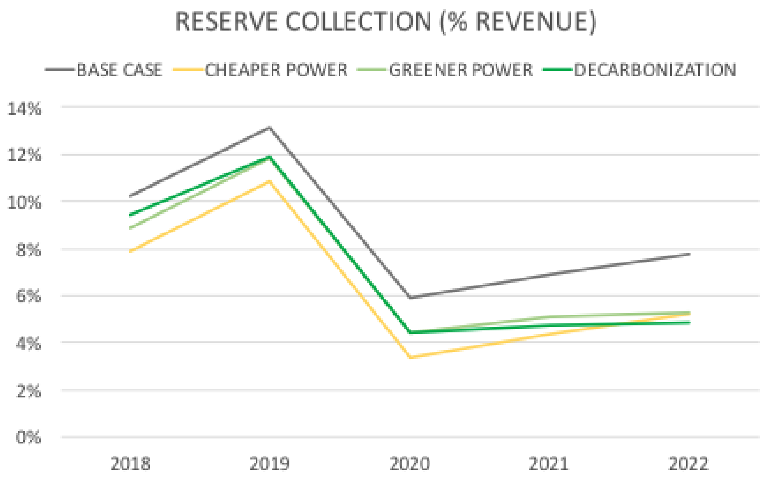
Note that because CCA customers pay a non-bypassable charge to the utility to compensate for the above-market costs of certain power contracts SCE entered into on behalf of all customers, we include those charges in all scenarios. When 'matching' or providing a 'discount' against SCE's rates, the CCA's rate is first set so that the total cost to customers — after adding the non-bypassable charges — does not exceed the what the customer would have paid taking service from SCE. (So CCA rates are still 'lower' than SCE rates regardless.)

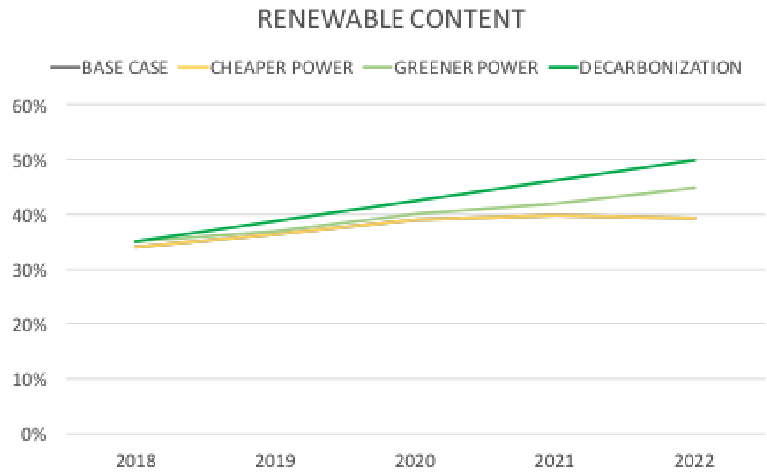
Across all four scenarios, the SBCP CCA maintains the same customer phase-in schedule. Consequently, the financing strategy is also the same, as are the term loan amounts; additional credit support via a line of credit varies in response to the differences in revenue and power costs across scenarios.

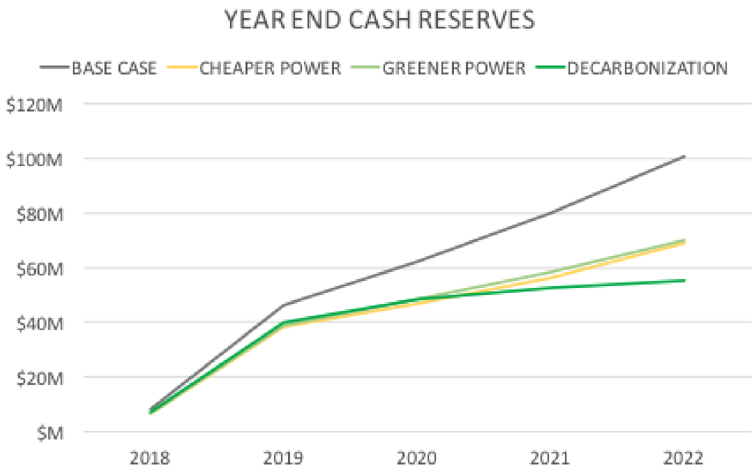
- In every scenario, the CCA pays off its initial startup debt by September or October of 2019 — thereby absolving any municipalities of any guarantees issued to back this financing.
- Thereafter, and reflecting industry best practices, the CCA's short-term credit requirements are managed entirely through a revolving line of credit or the CCA's accrued cash reserves.

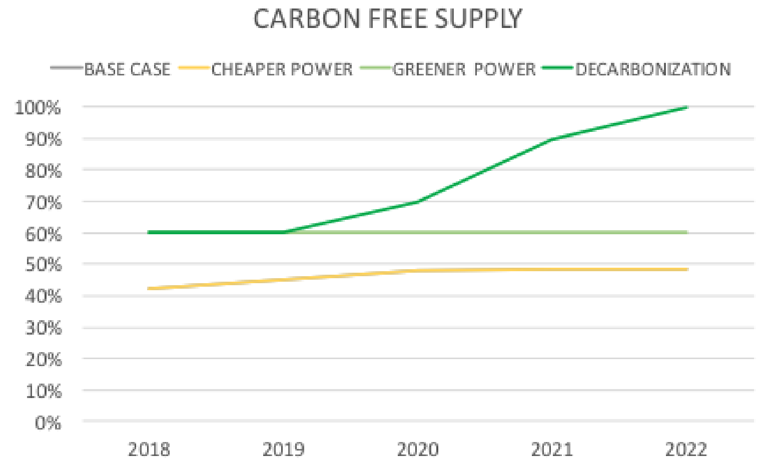
Reflecting SBCP local policy goals, overhead costs support an empowered agency that grows in expert staff capacity from 12 FTE at the end of 2018 to 27 staff by 2020. A range of contractors provide various key and support services, and at-risk contracting is used to lower upfront implementation costs by an estimated $400,000. Lastly, staff positions and program funding for Distributed Energy Resources (DER) remain unchanged across all scenarios, and total $12.3MM in expenses over the five-year forecast horizon. (Staffing and budget tables are included below.)

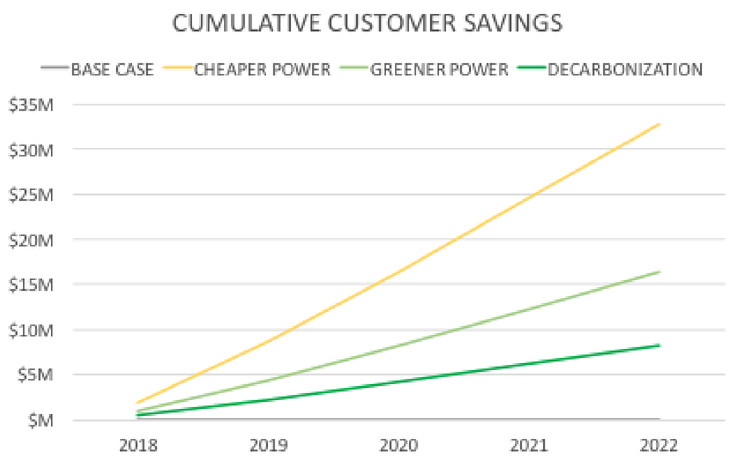
Scenario Comparisons: Key Metrics

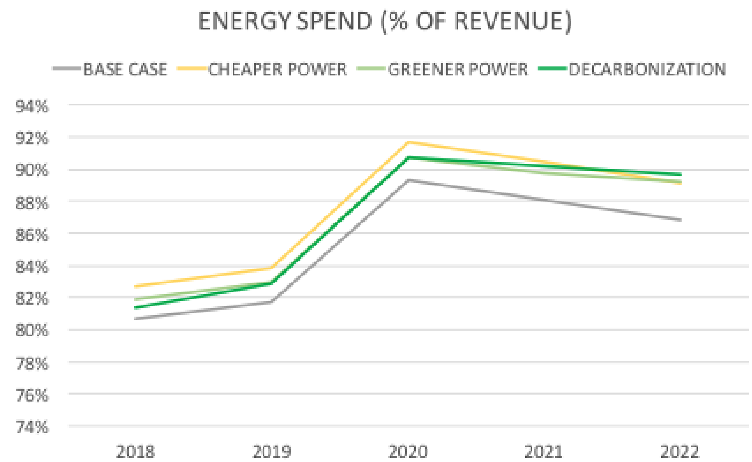




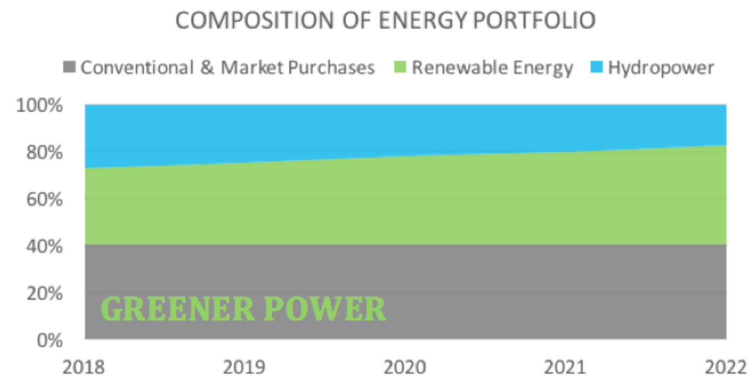


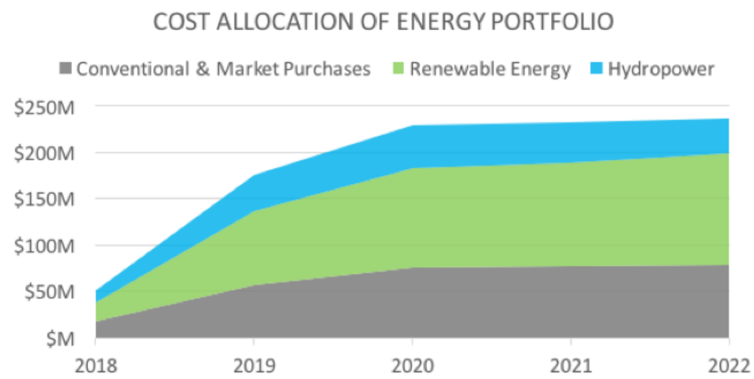


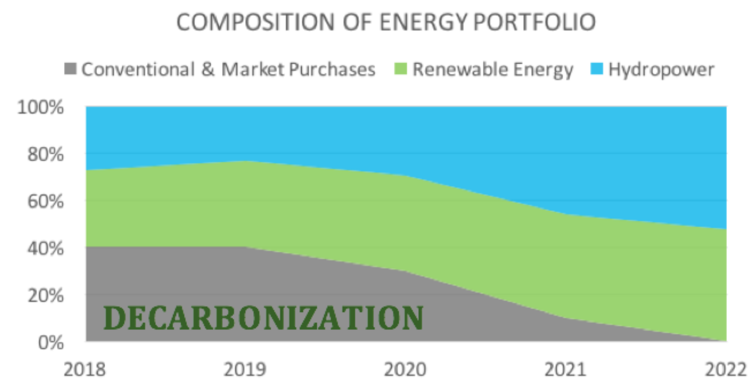


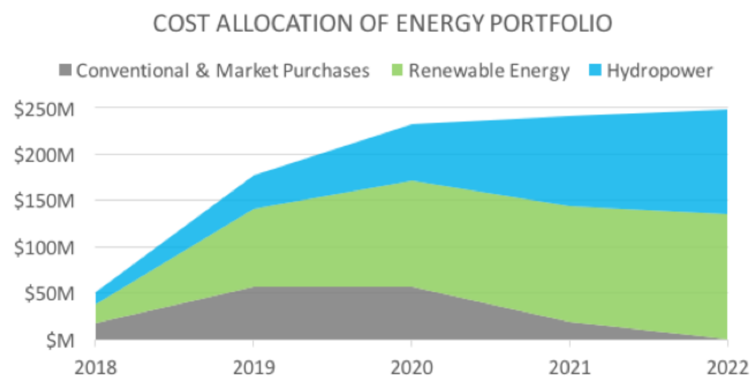


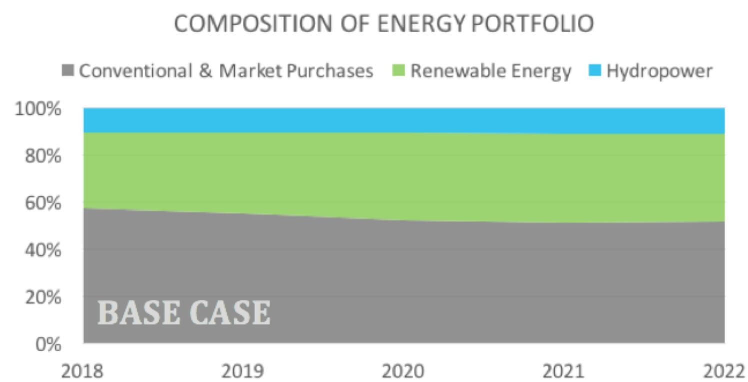
Portfolio Composition & Cost Allocation

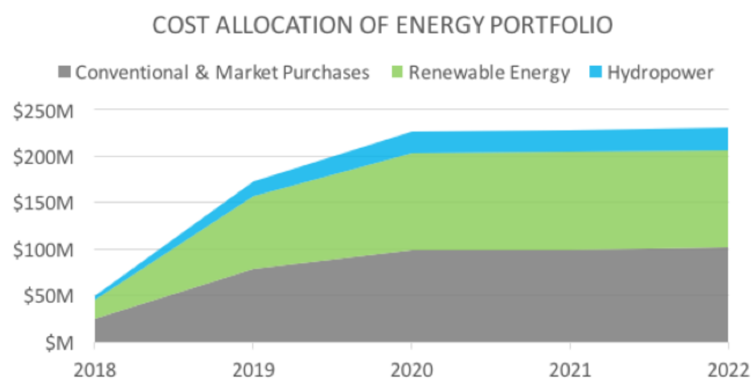


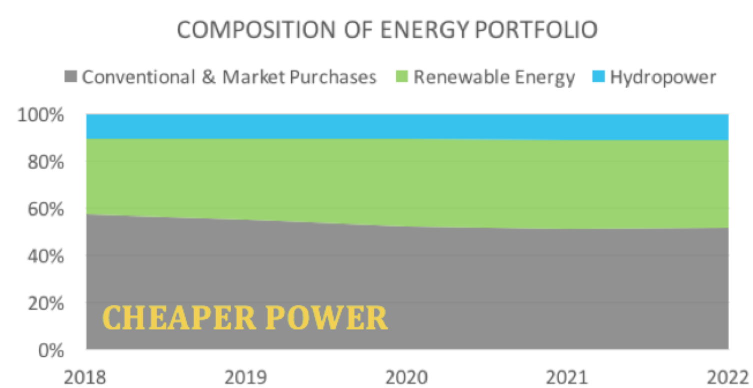


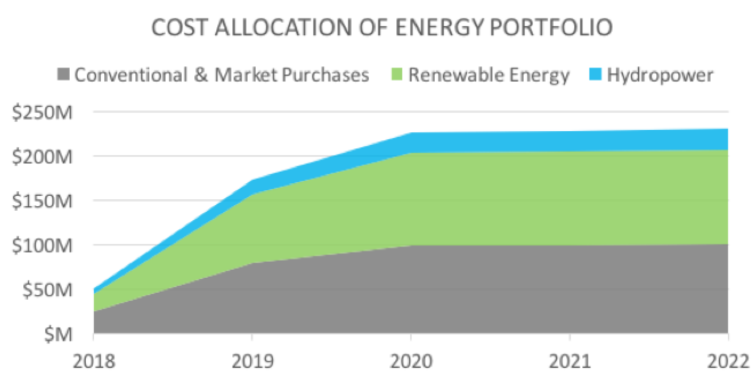






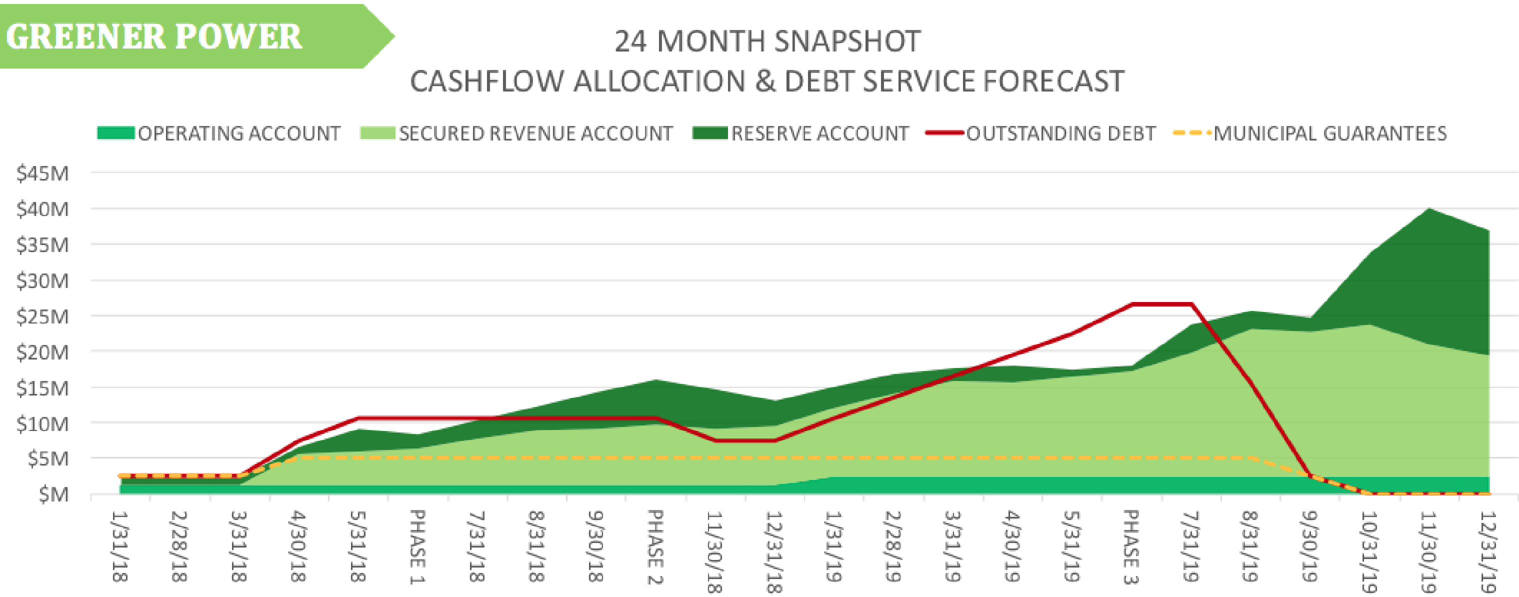




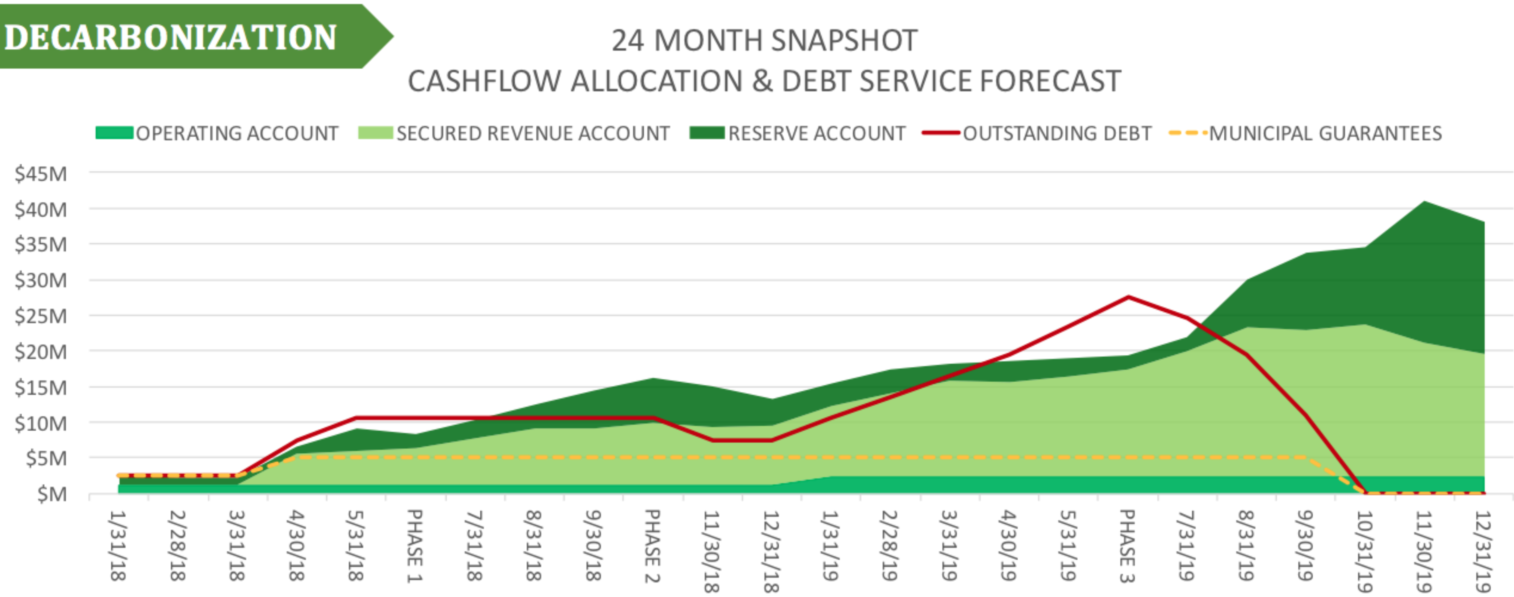


Start-Up Cash-Flow & Debt Repayment Scenarios

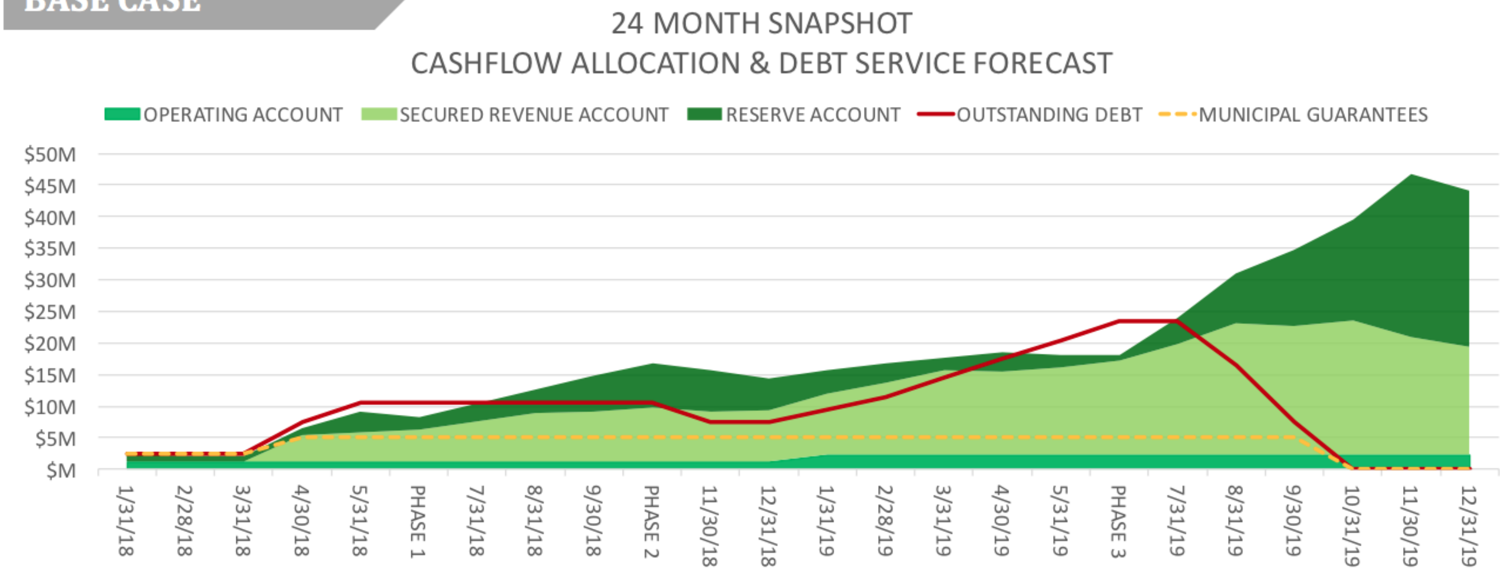
GREENER POWER



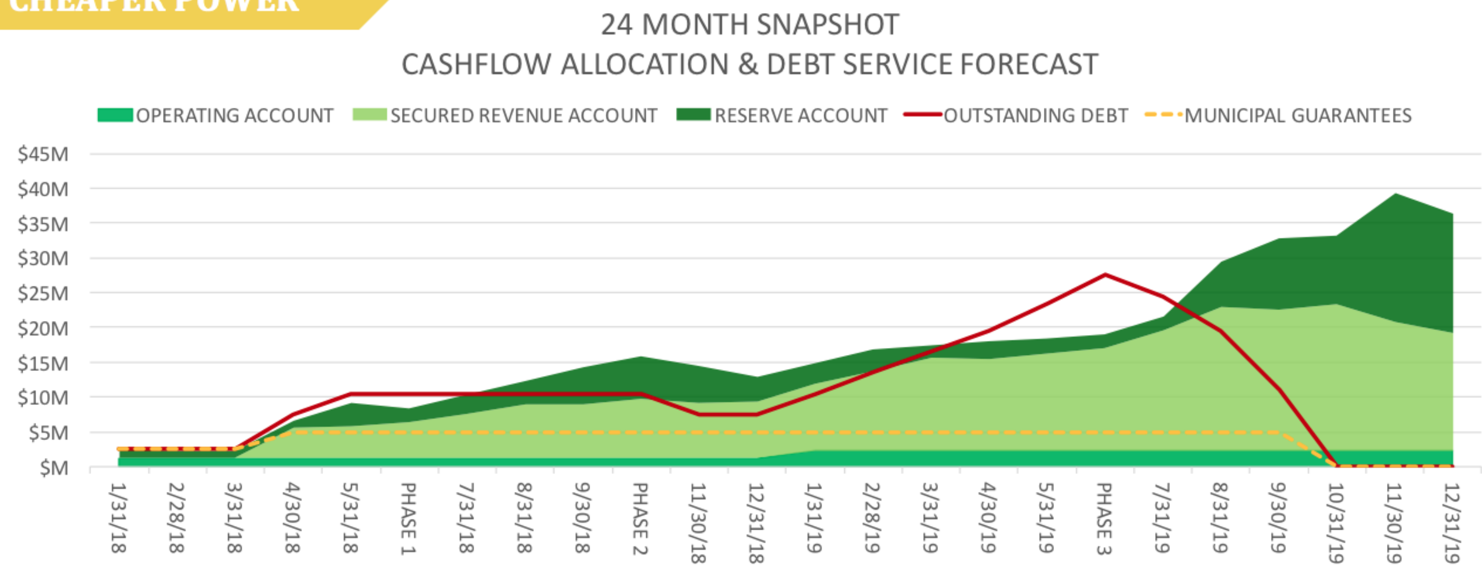
DECARBONIZATION



BASE CASE

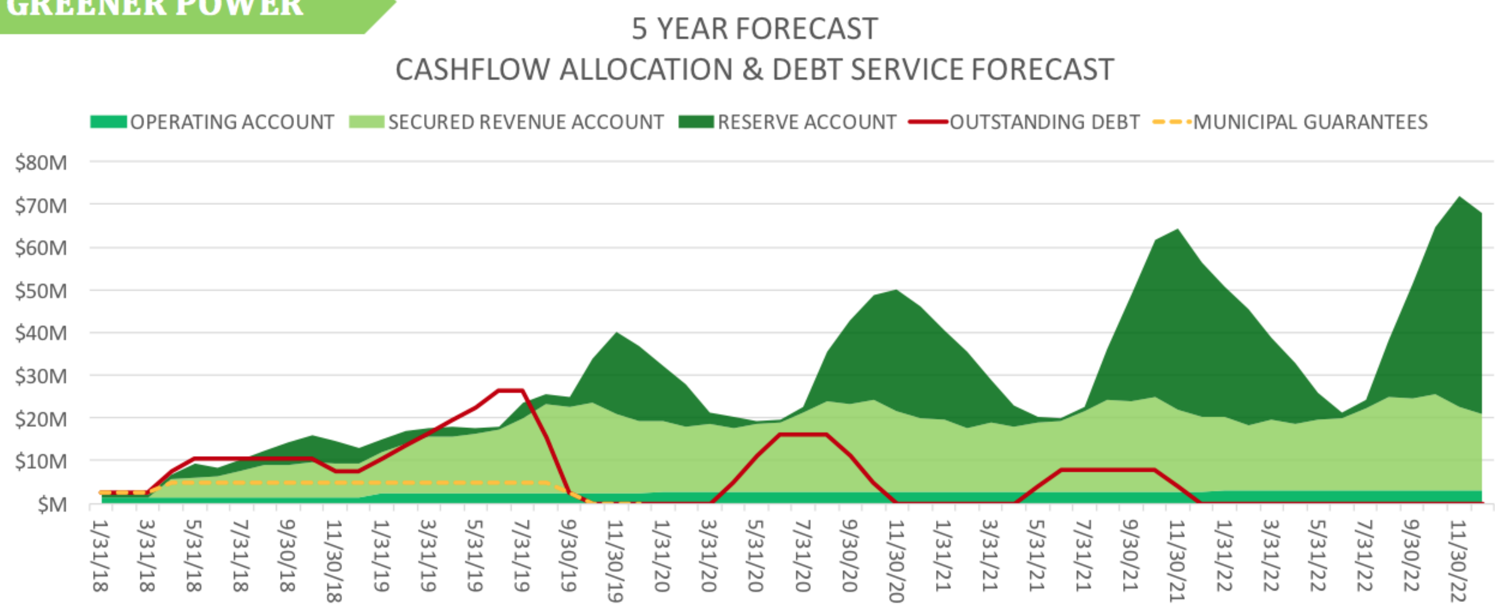


CHEAPER POWER

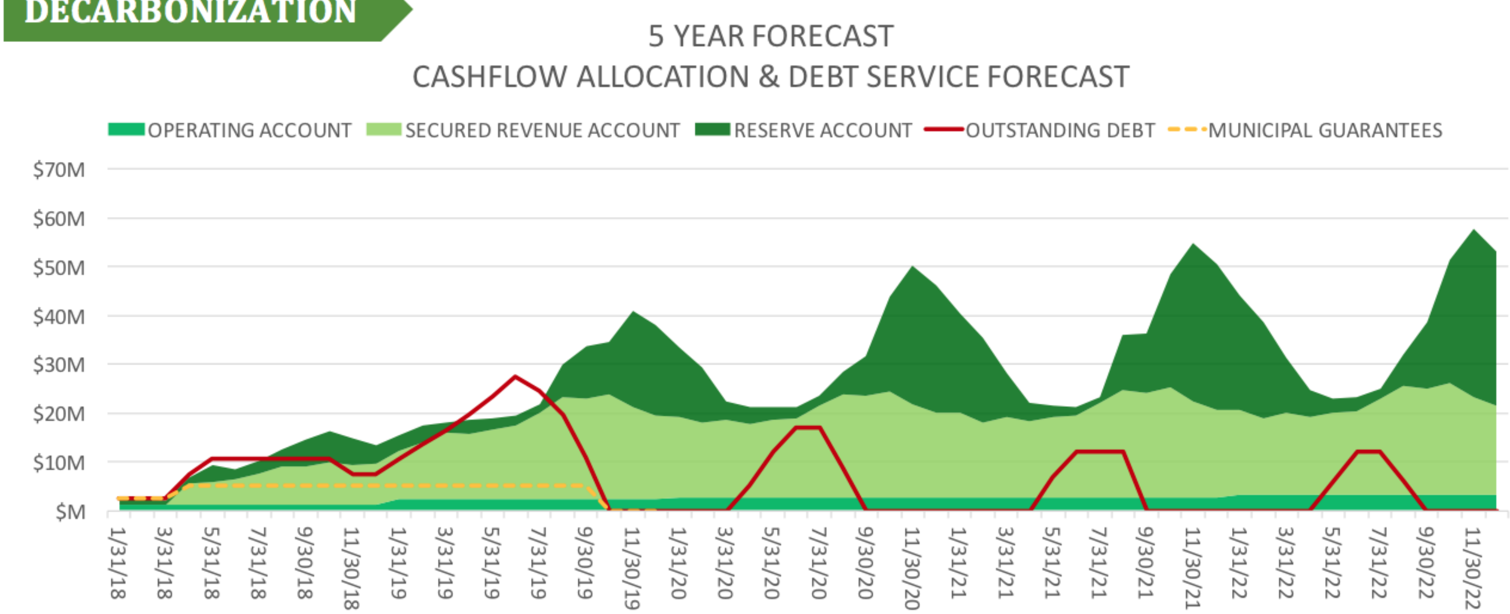


5 Year Cash-Flow & Debt Repayment Scenarios

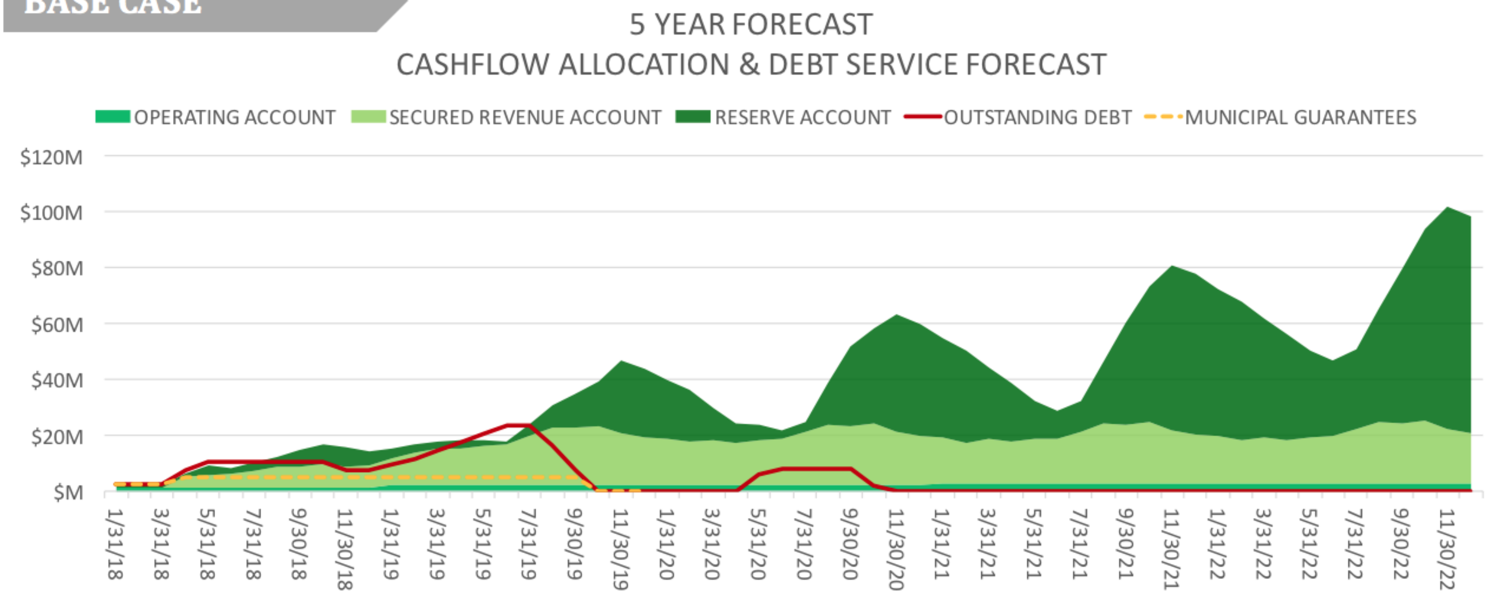
GREENER POWER



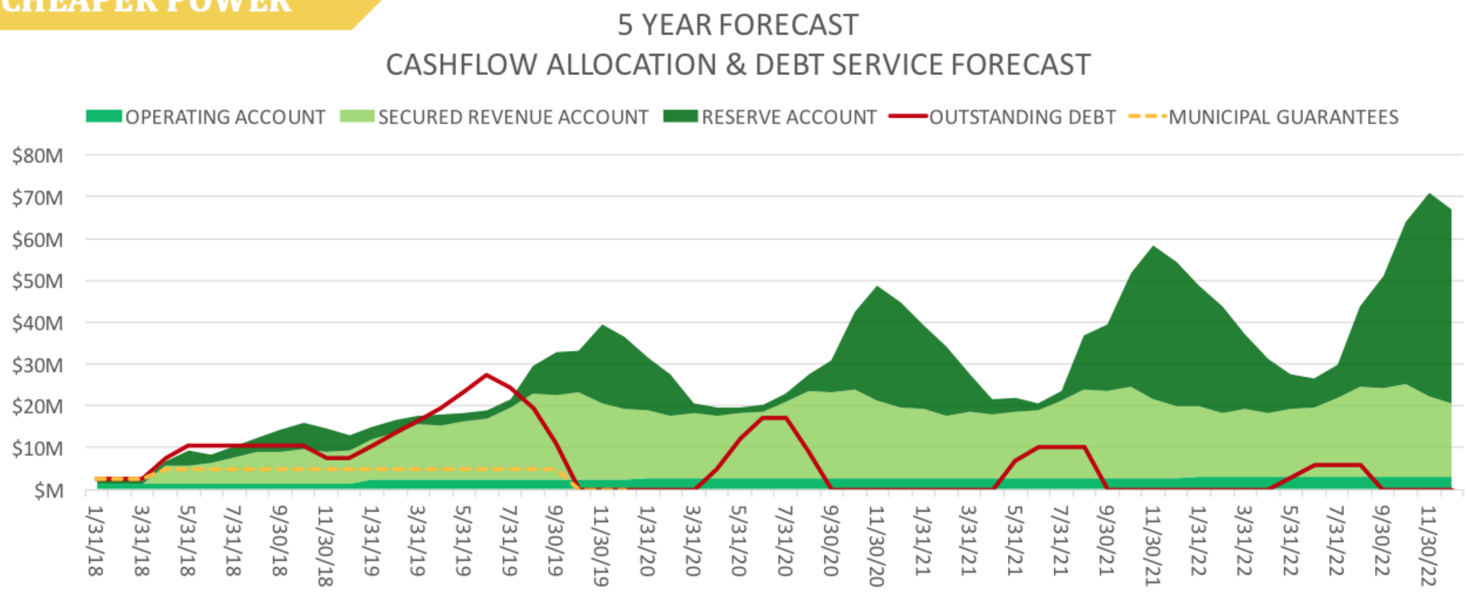
DECARBONIZATION



BASE CASE

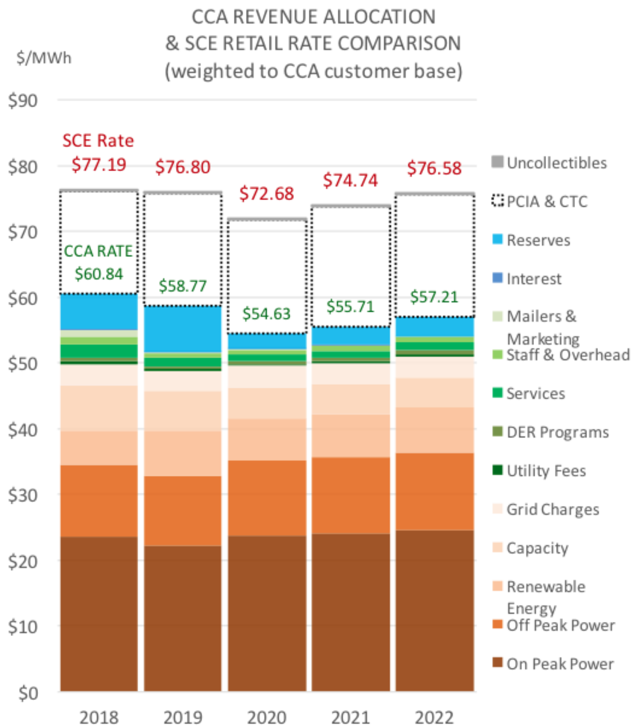


CHEAPER POWER

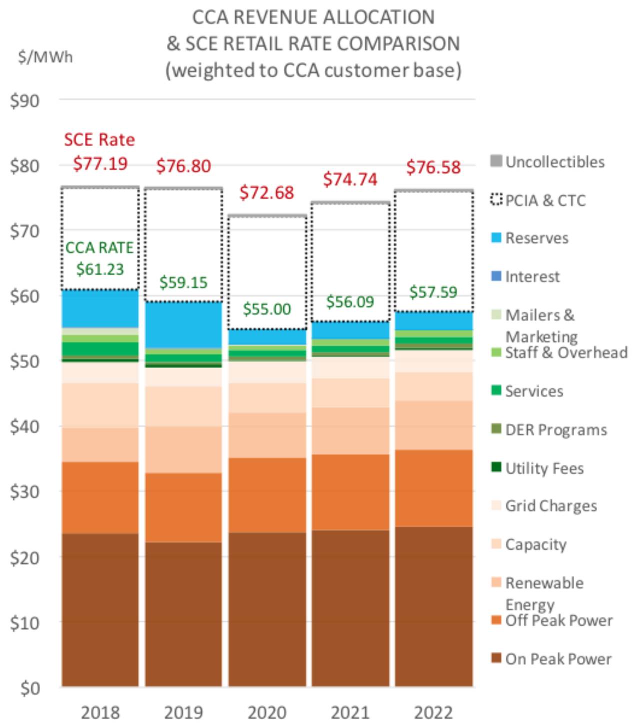


Revenue Allocation & SCE Rate Comparison

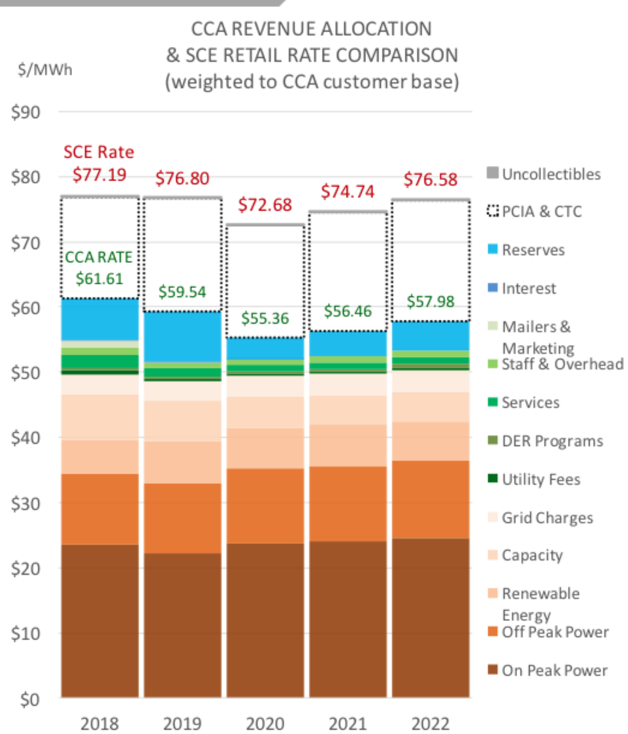
GREENER POWER



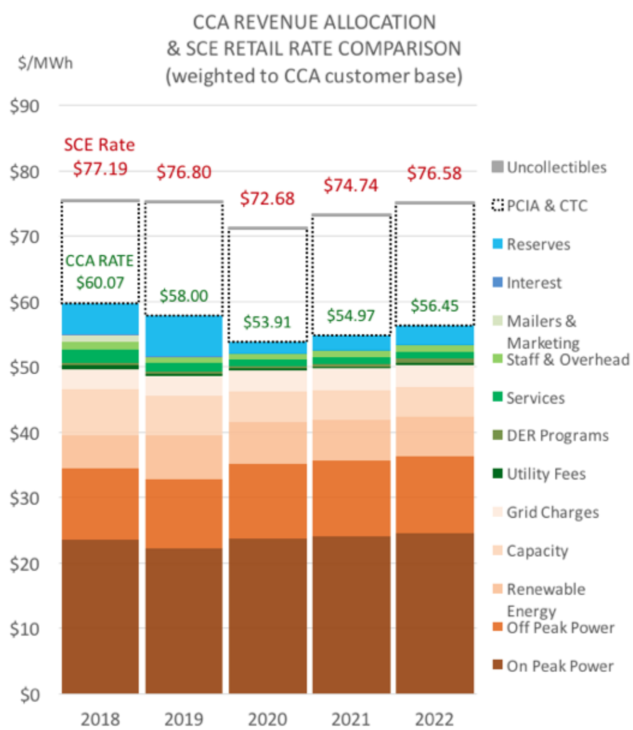
DECARBONIZATION



BASE CASE



CHEAPER POWER



SOUTH BAY CLEAN POWER

Key Performance Metrics

GREENER POWER

SOUTH BAY CLEAN POWER PERFORMANCE METRICS		2018	2019	2020	2021	2022
Financial Metrics	YE Municipal Guarantees (liability)	5,000,000.00	-	-	-	-
	DSCR (Debt Service Capacity Ratio)	4.26	3.79	1.67	3.05	11.86
	Maximum Debt	$10,500,000	$26,500,000	$16,000,000	$8,000,000	$0
	YE Outstanding Debt	$7,500,000	$0	$0	$0	$0
	YE cash reserves (cumulative)	$6,881,764	$39,069,017	$48,242,484	$58,495,437	$70,177,145
	Annual, as a % of revenue	9%	12%	4%	5%	5%
	Cumulative, as % of annual OpEx	10%	17%	17%	20%	24%
Portfolio Metrics	Renewable content of CCA portfolio	35%	37%	40%	42%	45%
	Carbon Free (hydro & renewable content)	60%	60%	60%	60%	60%
	Staff & Program Funding for DER	$657,500	$1,895,000	$2,408,750	$2,923,188	$4,438,347
Rate Savings	Rate decrease vs. SCE	1.0%	1.0%	1.0%	1.0%	1.0%
	Community savings from rate decreases (annual)	$0	$0	$0	$0	$0
	Community savings from rate decreases (cumulative)	$963,990	$4,303,149	$8,223,345	$12,252,748	$16,379,093
PCIA Charges	Power Charge Indifference Adjustment (PCIA) payments	$19,450,527	$75,055,887	$93,400,560	$98,525,278	$100,235,079
	PCIA as % of CCA rates	26%	29%	32%	33%	33%
	PCIA as % of SCE's rates	20%	22%	24%	24%	24%
Uses of Revenue	Energy expenses as a % of revenue	82%	83%	91%	90%	89%
	Reserve collection as a % of revenues	9%	12%	4%	5%	5%
	Overhead as a % of revenues	9%	5%	5%	5%	5%

DECARBONIZATION

SOUTH BAY CLEAN POWER PERFORMANCE METRICS		2018	2019	2020	2021	2022
Financial Metrics	YE Municipal Guarantees (liability)	5,000,000.00	-	-	-	-
	DSCR (Debt Service Capacity Ratio)	4.39	3.60	1.91	1.39	1.10
	Maximum Debt	$10,500,000	$27,500,000	$17,000,000	$12,000,000	$12,000,000
	YE Outstanding Debt	$7,500,000	$0	$0	$0	$0
	YE cash reserves (cumulative)	$7,241,171	$40,132,039	$48,236,504	$52,591,146	$55,348,456
	Annual, as a % of revenue	9%	12%	4%	5%	5%
	Cumulative, as % of annual OpEx	10%	17%	17%	18%	18%
Portfolio Metrics	Renewable content of CCA portfolio	35%	39%	43%	46%	50%
	Carbon Free (hydro & renewable content)	60%	60%	70%	90%	100%
	Staff & Program Funding for DER	$657,500	$1,895,000	$2,408,750	$2,923,188	$4,438,347
Rate Savings	Rate decrease vs. SCE	0.5%	0.5%	0.5%	0.5%	0.5%
	Community savings from rate decreases (annual)	$0	$0	$0	$0	$0
	Community savings from rate decreases (cumulative)	$481,995	$2,151,574	$4,111,673	$6,126,374	$8,189,547
PCIA Charges	Power Charge Indifference Adjustment (PCIA) payments	$19,450,527	$75,055,887	$93,400,560	$98,525,278	$100,235,079
	PCIA as % of CCA rates	25%	29%	31%	33%	32%
	PCIA as % of SCE's rates	20%	22%	24%	24%	24%
Uses of Revenue	Energy expenses as a % of revenue	81%	83%	91%	90%	90%
	Reserve collection as a % of revenues	9%	12%	4%	5%	5%
	Overhead as a % of revenues	9%	5%	5%	5%	5%

BASE CASE

SOUTH BAY CLEAN POWER PERFORMANCE METRICS		2018	2019	2020	2021	2022
Financial Metrics	YE Municipal Guarantees (liability)	5,000,000.00	-	-	-	-
	DSCR (Debt Service Capacity Ratio)	4.72	4.93	5.41	105.86	-
	Maximum Debt	$10,500,000	$23,500,000	$8,000,000	$0	$0
	YE Outstanding Debt	$7,500,000	$0	$0	$0	$0
	YE cash reserves (cumulative)	$8,240,437	$46,217,495	$62,163,407	$79,856,866	$100,620,385
	Annual, as a % of revenue	10%	13%	6%	7%	8%
	Cumulative, as % of annual OpEx	12%	20%	22%	28%	35%
Portfolio Metrics	Renewable content of CCA portfolio	34%	36%	39%	40%	39%
	Carbon Free (hydro & renewable content)	42%	45%	48%	49%	48%
	Staff & Program Funding for DER	$657,500	$1,895,000	$2,408,750	$2,923,188	$4,438,347
Rate Savings	Rate decrease vs. SCE	0.0%	0.0%	0.0%	0.0%	0.0%
	Community savings from rate decreases (annual)	$0	$0	$0	$0	$0
	Community savings from rate decreases (cumulative)	$0	$0	$0	$0	$0
PCIA Charges	Power Charge Indifference Adjustment (PCIA) payments	$19,450,527	$75,055,887	$93,400,560	$98,525,278	$100,235,079
	PCIA as % of CCA rates	25%	29%	31%	32%	32%
	PCIA as % of SCE's rates	20%	22%	24%	24%	24%
Uses of Revenue	Energy expenses as a % of revenue	81%	82%	89%	88%	87%
	Reserve collection as a % of revenues	10%	13%	6%	7%	8%
	Overhead as a % of revenues	9%	5%	5%	5%	5%

CHEAPER POWER

SOUTH BAY CLEAN POWER PERFORMANCE METRICS		2018	2019	2020	2021	2022
Financial Metrics	YE Municipal Guarantees (liability)	5,000,000.00	-	-	-	-
	DSCR (Debt Service Capacity Ratio)	4.23	3.48	1.93	3.23	7.23
	Maximum Debt	$10,500,000	$27,500,000	$17,000,000	$10,000,000	$6,000,000
	YE Outstanding Debt	$7,500,000	$0	$0	$0	$0
	YE cash reserves (cumulative)	$6,802,806	$38,446,022	$46,830,936	$56,645,829	$69,164,081
	Annual, as a % of revenue	8%	11%	3%	4%	5%
	Cumulative, as % of annual OpEx	10%	17%	17%	20%	24%
Portfolio Metrics	Renewable content of CCA portfolio	34%	36%	39%	40%	39%
	Carbon Free (hydro & renewable content)	42%	45%	48%	49%	48%
	Staff & Program Funding for DER	$657,500	$1,895,000	$2,408,750	$2,923,188	$4,438,347
Rate Savings	Rate decrease vs. SCE	2.0%	2.0%	2.0%	2.0%	2.0%
	Community savings from rate decreases (annual)	$0	$0	$0	$0	$0
	Community savings from rate decreases (cumulative)	$1,927,979	$8,606,298	$16,446,691	$24,505,495	$32,758,187
PCIA Charges	Power Charge Indifference Adjustment (PCIA) payments	$19,450,527	$75,055,887	$93,400,560	$98,525,278	$100,235,079
	PCIA as % of CCA rates	26%	30%	32%	33%	33%
	PCIA as % of SCE's rates	20%	22%	24%	24%	24%
Uses of Revenue	Energy expenses as a % of revenue	83%	84%	92%	90%	89%
	Reserve collection as a % of revenues	8%	11%	3%	4%	5%
	Overhead as a % of revenues	9%	5%	5%	5%	5%

SBCP Agency Staffing

These staffing levels are maintained across all four scenarios presented:

SOUTH BAY CLEAN POWER STAFF	2018	2019	2020	2021	2022
GENERAL MANAGER	$325,000	$325,000	$341,250	$358,313	$376,228
Executive Assistant	$63,750	$85,000	$89,250	$93,713	$98,398
AGM POLICY & REGULATORY AFFAIRS	$0	$225,000	$236,250	$248,063	$260,466
Legal Counsel	$0	$175,000	$183,750	$192,938	$202,584
Regulatory & Legislative Analyst	$20,000	$120,000	$126,000	$132,300	$138,915
Regulatory & Legislative Analyst	$0	$0	$0	$132,300	$138,915
AGM ADMINISTRATION	$30,833	$185,000	$194,250	$203,963	$214,161
IT Manager	$0	$0	$99,750	$104,738	$109,974
Controls Specialist	$0	$0	$0	$137,813	$144,703
AGM FINANCE	$168,750	$225,000	$236,250	$248,063	$260,466
Financial Analyst	$0	$0	$157,500	$165,375	$173,644
Rate Analyst	$0	$125,000	$131,250	$137,813	$144,703
AGM ENERGY	$137,500	$275,000	$288,750	$303,188	$318,347
Senior Resource Planner	$0	$200,000	$210,000	$220,500	$231,525
DER Program Manager	$87,500	$150,000	$157,500	$165,375	$173,644
Procurement Manager	$0	$0	$183,750	$192,938	$202,584
Contracts Manager	$0	$0	$131,250	$137,813	$144,703
Compliance Specialist	$0	$125,000	$131,250	$137,813	$144,703
DER Program Analyst	$0	$125,000	$131,250	$137,813	$144,703
AGM EXTERNAL AFFAIRS	$150,000	$200,000	$210,000	$220,500	$231,525
Community Affairs Coordinator	$41,667	$125,000	$131,250	$137,813	$144,703
Marketing Associate	$0	$0	$131,250	$137,813	$144,703
AGM CUSTOMER SERVICE	$161,250	$215,000	$225,750	$237,038	$248,889
Key Account Manager	$83,333	$125,000	$131,250	$137,813	$144,703
Key Account Manager	$0	$125,000	$131,250	$137,813	$144,703
Account Representative	$63,333	$95,000	$99,750	$104,738	$109,974
TOTAL BUDGET FOR STAFF	**$1,332,917**	**$3,225,000**	**$4,089,750**	**$4,564,350**	**$4,792,568**
TOTAL FTE	**13**	**20**	**25**	**27**	**27**

SBCP Agency Operating Budget (non-energy)

These non-energy operating budgets are maintained across all four scenarios presented:

SOUTH BAY CLEAN POWER NON-ENERGY OPERATING BUDGET	2018	2019	2020	2021	2022
Staffing & Overhead	$2,051,250	$5,015,000	$6,389,750	$7,378,350	$9,106,568
Personnel	**$1,332,917**	**$3,225,000**	**$4,089,750**	**$4,564,350**	**$4,792,568**
Office & Equipment	$193,333	$265,000	$275,000	$289,000	$289,000
Misc. Overhead	$25,000	$25,000	$25,000	$25,000	$25,000
Local DER Programs	$500,000	$1,500,000	$2,000,000	$2,500,000	$4,000,000
Outreach & Communications Materials	$1,203,321	$241,209	$109,823	$109,828	$109,828
Enrollment Mailers (enrollments & churn)	$1,053,321	$41,209	$9,823	$9,828	$9,828
Events and Marketing	$150,000	$200,000	$100,000	$100,000	$100,000
Core Services	$1,967,290	$4,725,833	$4,840,646	$4,904,449	$4,969,341
Portfolio Management & Power Market Operations	$437,500	$750,000	$772,500	$795,675	$819,545
Planning & Strategy	$100,625	$172,500	$177,675	$183,005	$188,495
Origination	$70,000	$120,000	$123,600	$127,308	$131,127
Contract Management	$43,750	$75,000	$77,250	$79,568	$81,955
Market Operations (scheduling & active risk management)	$196,875	$337,500	$347,625	$358,054	$368,795
Market Settlements	$26,250	$45,000	$46,350	$47,741	$49,173
Utility Data and Retail Billing	$947,013	$2,461,230	$2,518,376	$2,543,527	$2,568,921
Customer Care & Call Center Operations	$582,777	$1,514,603	$1,549,770	$1,565,247	$1,580,875
Support Services	$449,167	$770,000	$520,000	$495,000	$470,000
Accounting and audits	$72,917	$125,000	$75,000	$50,000	$25,000
Marketing and Branding	$87,500	$150,000	$50,000	$50,000	$50,000
OpenEE Meter (DER backoffice component)	$70,000	$120,000	$120,000	$120,000	$120,000
Integrated Resource Planning	$72,917	$125,000	$75,000	$75,000	$75,000
Regulatory and Legislative Intelligence	$43,750	$75,000	$75,000	$75,000	$75,000
Legal Advice and Regulatory Engagement	$58,333	$100,000	$50,000	$50,000	$50,000
Lobbying	$43,750	$75,000	$75,000	$75,000	$75,000
SCE Fees	$667,793	$1,500,565	$1,529,759	$1,544,917	$1,560,217
Enrollment, Opt-Out & Misc Reports/ Services	$98,186	$17,405	$12,653	$12,658	$12,658
Bill-Ready (mail)	$291,849	$761,141	$778,347	$786,123	$793,974
Bill-Ready (web)	$15,509	$40,447	$41,361	$41,775	$42,192
MDMA Posting	$262,250	$681,571	$697,396	$704,361	$711,394
TOTAL NON-ENERGY EXPENSES	$6,338,821	$12,252,607	$13,389,978	$14,432,544	$16,215,954

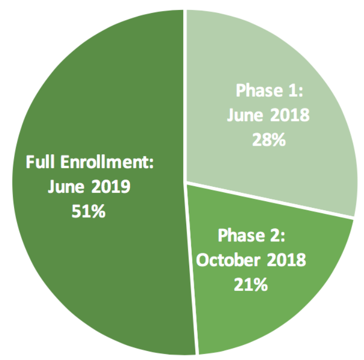
CUSTOMER PHASE-IN STRATEGY: OVERVIEW & KEY DYNAMICS

A make-or-break risk factor in any CCA's startup financing strategy is the customer phase-in schedule. Structuring it well is actually a primary purpose of the entire modeling exercise. Doing so requires forecasting and analyzing cash-flows on a monthly basis during the critical period over which debt is repaid. This is not a simple analysis to perform, owing to the variety of factors we explain in this report (disclosed mainly in the appendix, "***Model Methodology and Assumptions***.")

The highest-level dynamic — which is primarily the result of SCE's rate structures and the PCIA charge — is that revenues from customers fluctuate widely over the course of the year in aggregate. The different rate structures mean these patterns also vary between different groups of customers:

1. On average, nonresidential customers actually cause losses for the CCA out of eight months out of the year — but then bring in substantial net revenues in June through September (primarily because of high demand charges in the summer).
2. In contrast, while some residential ("domestic") customers are on more variable rates, most are not — and on average, generate nominal (but more stable) net revenues year-round. However, this is the most expensive customer class to serve in terms of both power and overhead requirements.

Customer Phase-In Allocation by Load



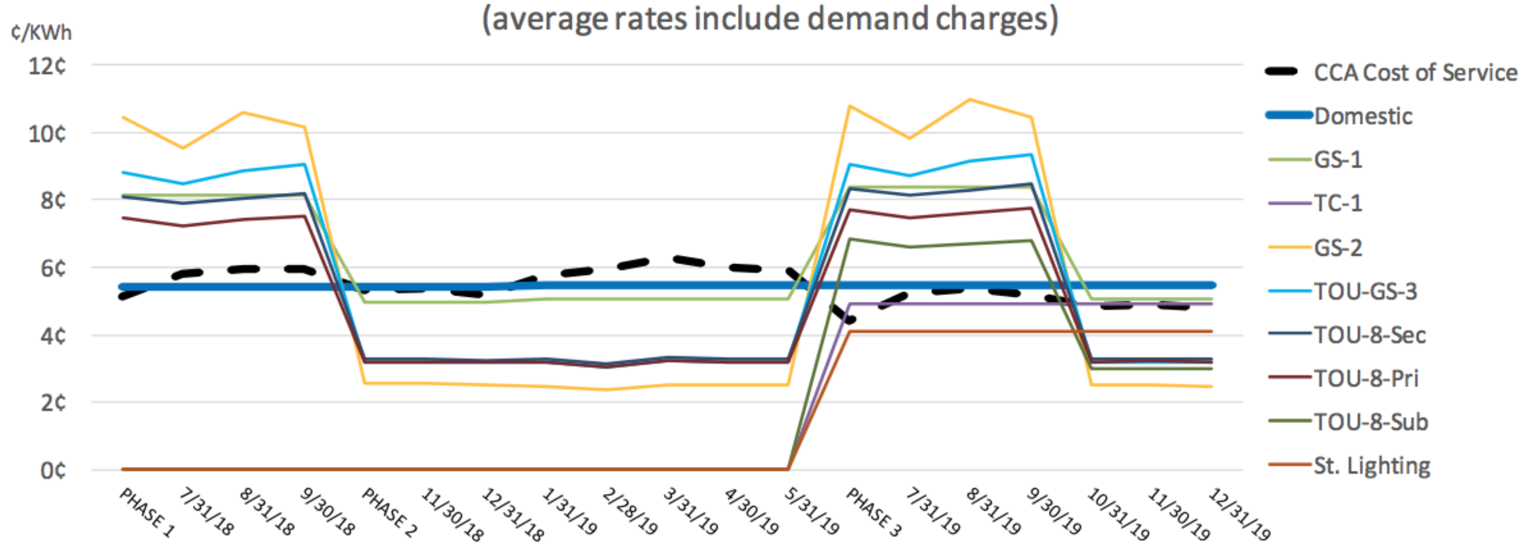
Consequently, the phase-in strategy in these model runs:

1. Enrolls primarily nonresidential customers in June 2018 to maximize initial net revenues;
2. Balances the winter decline in revenues by enrolling remaining residential customer base in October 2018;
3. Adds all remaining nonresidential customers in June 2019 to achieve full enrollment and net revenues.

The three charts which follow visualize these dynamics and their impact on the CCA over the three phase-in periods.

First, we can see when certain customer class rates are above or below the CCA's cost of service:

PHASE-IN PERIOD 'BREAK EVEN': CCA COST OF SERVICE vs. CUSTOMER CLASS RATES (average rates include demand charges)

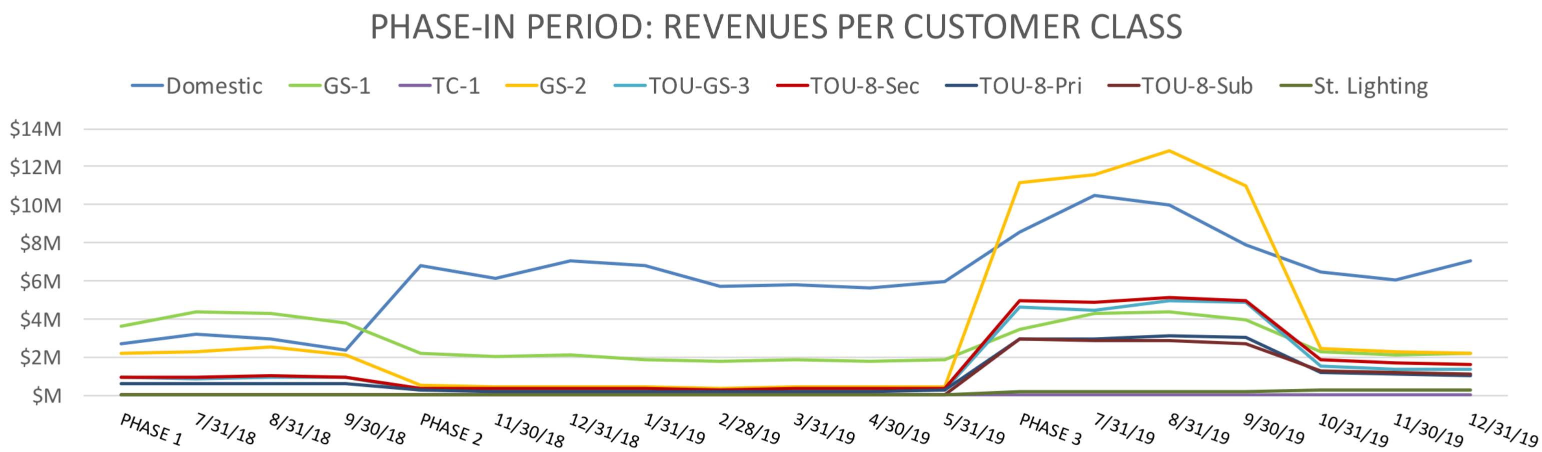


SOUTH BAY CLEAN POWER

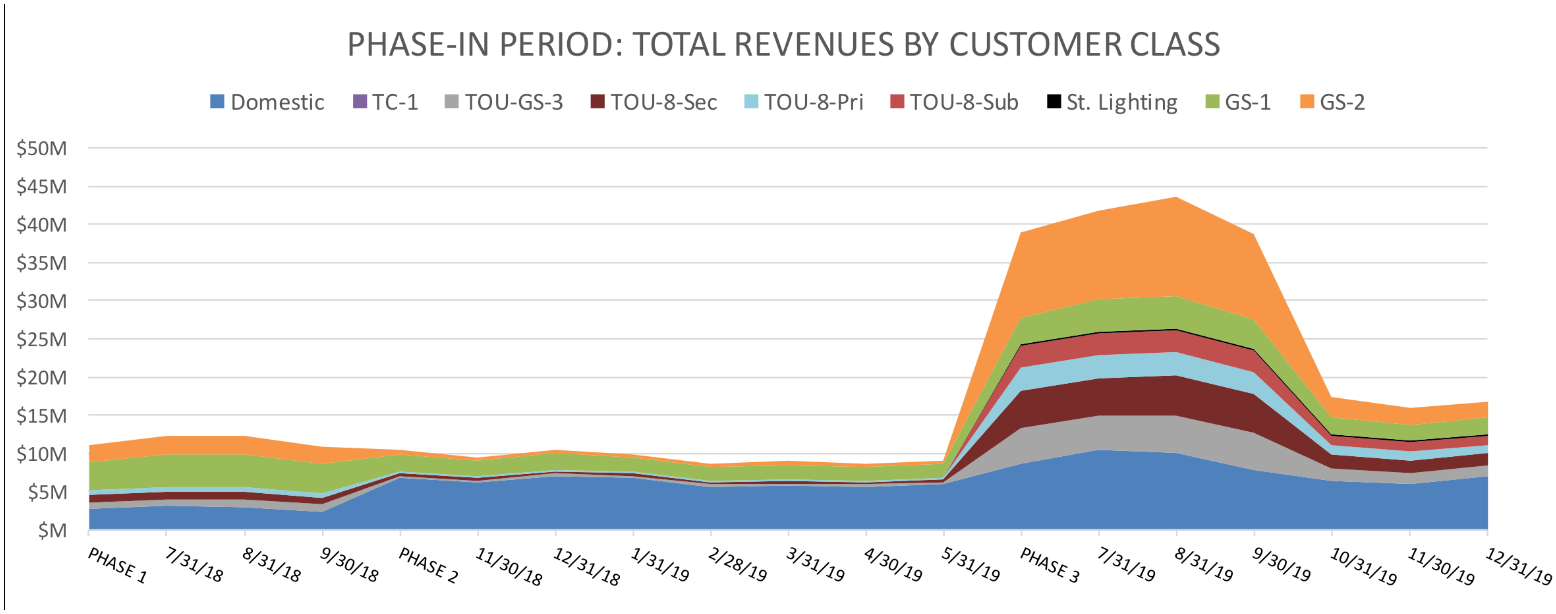
__This phase-in strategy should be considered as illustrative rather than recommended__, and is intended to be refined and revised during the implementation process.

All charts in this section are based on the 'Base Case' scenario, i.e. matching SCE's estimated renewable and carbon content, and maintaining CCA rates at a level that is cost-neutral for customers regardless of whether they're served by the utility or the CCA. This is done by subtracting the PCIA from the average effective rates in each month that customers would have otherwise paid taking service from SCE. "Average effective rates" means all-in revenues from customers in each class, normalized on a volumetric or total revenue basis (i.e. $s or $/KWh, but including revenues from demand charges, etc.)

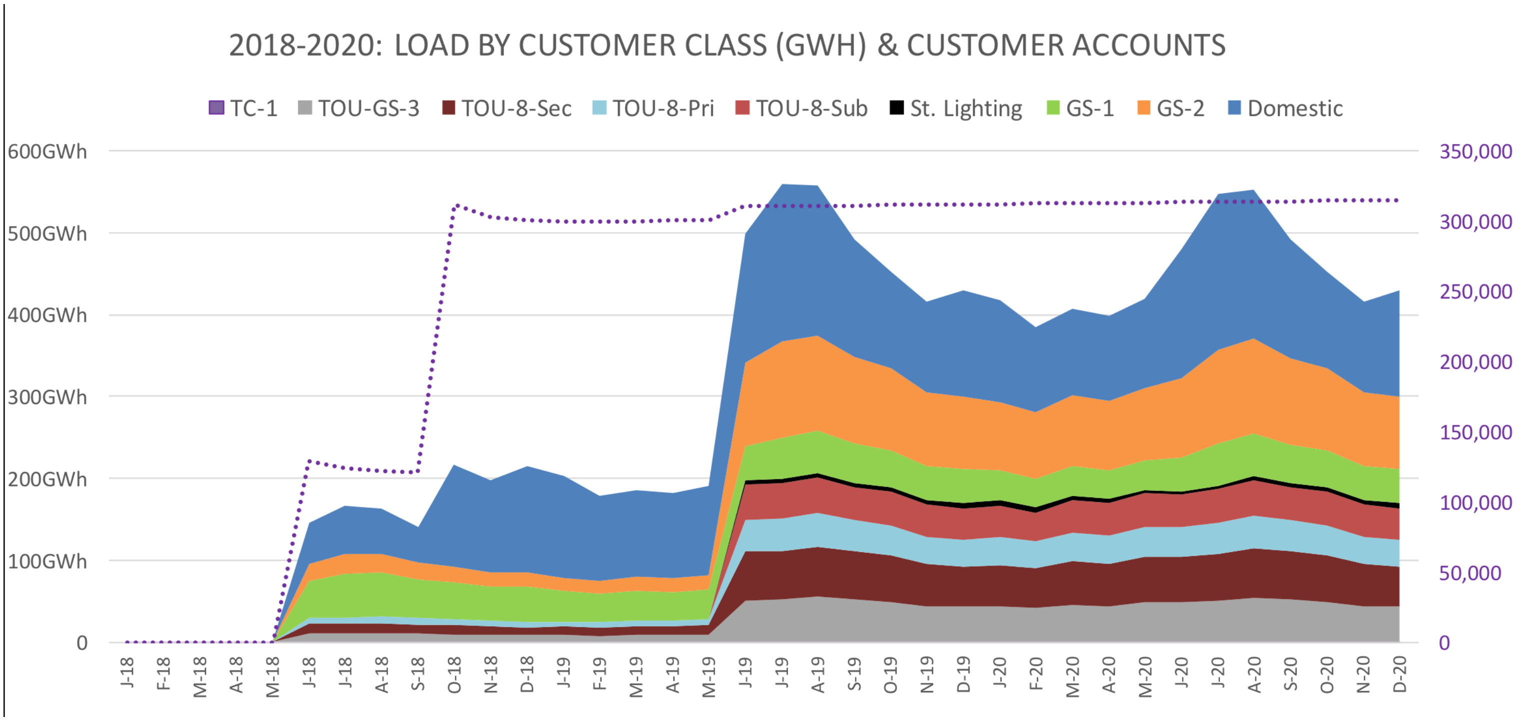
Note how the enrolling residential customers ("domestic", in blue) in the charts below provides substantial revenues as the other classes drop going into the off-season, and continue to do so the next year as well after the CCA is at full enrollment:



Consequently, total revenues for the CCA do not decline significantly during the Phase 2 enrollment period, stabilizing the enterprise until full enrollment is achived the next Summer



In terms of customer accounts and load volumes, the chart below captures the three intial phase in periods and extends beyond for a full year:



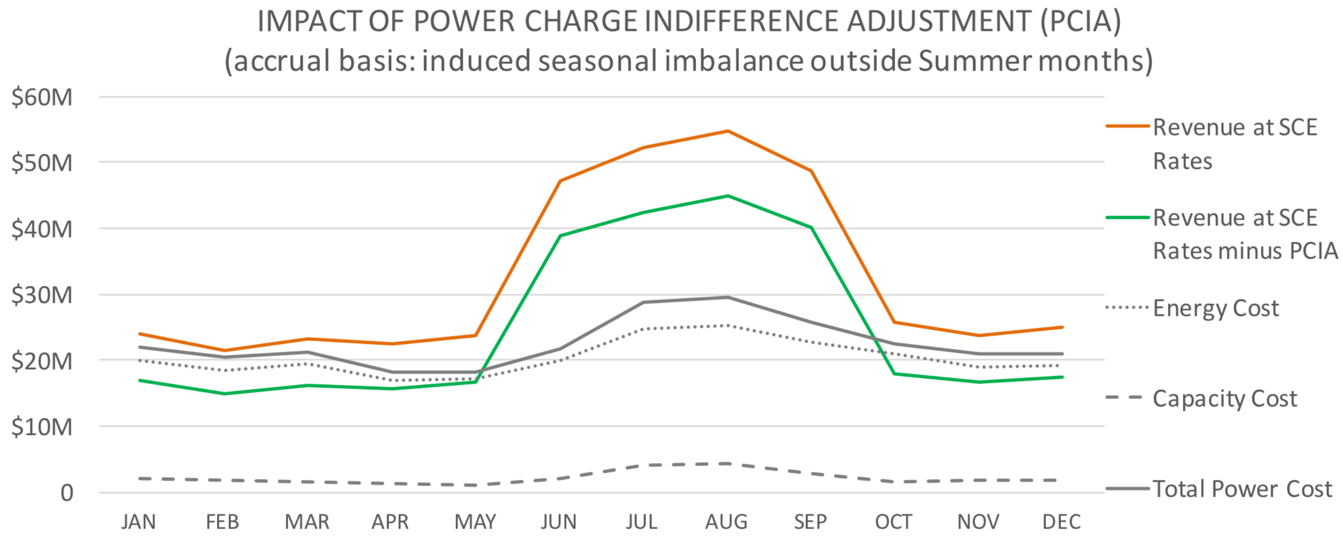
CCAs are free to set their own rate structures that differ from the ones used by SCE and may attempt to mitigate this seasonal liquidity crunch in so doing; however, this may cause confusion, and may potentially cause a subset of customers to experience costs above SCE's rates at launch — and thus risks increasing opt-outs or customer dissatisfaction.

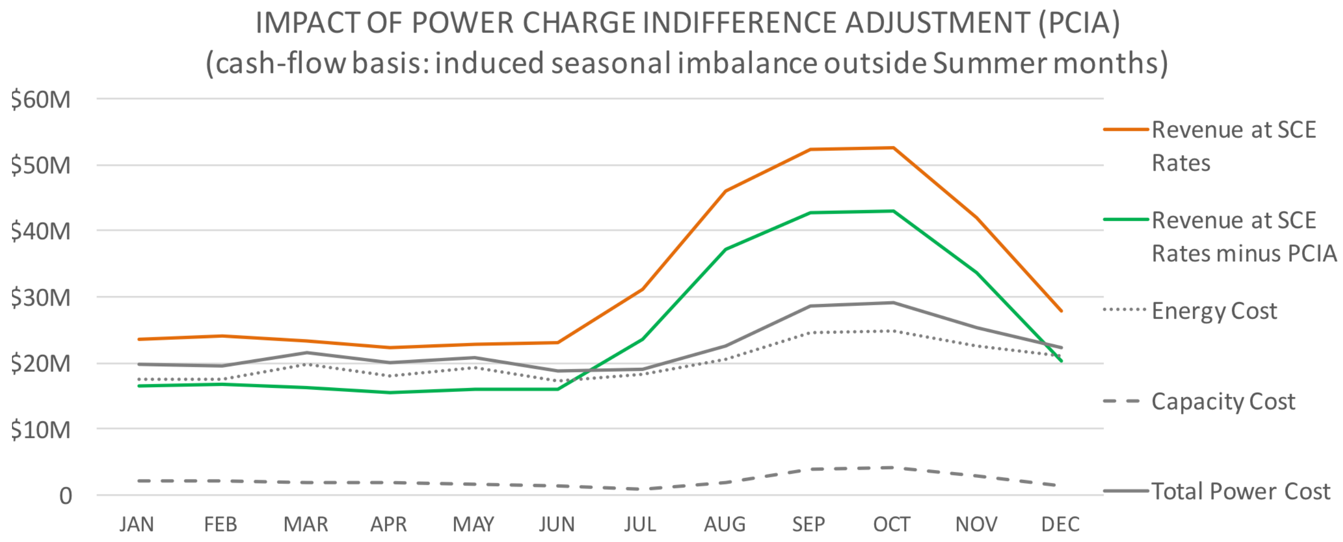
In part, and as mentioned at the beginning of this chapter, this is due to the second key dynamic that compounds the liquidity hurdle imposed by SCE's rate structures — the PCIA. As context, customers that are served by CCAs are charged, on a non-bypassable (i.e. unavoidable) basis, for the net costs of certain contracts that the utility has entered into on behalf of all bundled service customers. For further details, refer to "***Cost Responsibility Surcharge Forecasts (PCIA and CTC charges)"*** in the methodology appendix.

How the PCIA-eligible power contract costs are *functionalized* into rates — i.e. how power costs in aggregate are apportioned into rates for application to customers through rate structures — deeply exacerbates the seasonal liquidity issue for CCAs and complicates rate-setting exercises:

- For customers that remain with SCE, these contract costs are functionalized into the utility's normal rate schedules, which allocate costs across various metrics in rate schedules (i.e. by time of day energy usage, demand charges, et cetera).
- However, once the customer is served by a CCA, these costs are recouped through a fixed volumetric fee (i.e. on a flat $/KWh basis). There is some fluctuation month over month with load volumes, but not nearly as much as through SCE's otherwise-applicable rate schedules.

- Consequently, the CCA is forced to lower its rates to compensate on an equal basis throughout the year; this has the practical effect of lowering the CCA's rates below its cost of power for most months of the year (except for summer).
- The charts below illustrate this impact. Note how if the PCIA costs were functionalized to be recovered more during the summer, the CCA's revenues could be maintained above (or closer to) the cost of power. Doing so would significantly lower credit support requirements and remove a source of financial risk for startup CCAs.





To be clear, this benefits no one — it is purely a product of regulatory artefact. This makes it more challenging (and risky) to structure the financing for startup CCA programs. Also, by incentivizing (requiring) CCAs to launch and phase-in successive tranches of customers close to or entering into the season when SCE is likely recovering above-average volumes of power costs, this dynamic may actually result in a cost-shift.

More broadly, California has long practiced targeted power cost functionalization to induce behavioral change, as charging more for power or demand at specific times of year can have a powerful load-shifting effect that serves to offset peak loads — territory wide. This lowers the need to expand distribution grid capacity, or even the construction of new power plants and transmission lines. It may be that the PCIA serves to lessen these price signals in CCA territories — which will become more pronounced as the non-bypassable charge increases year over year.

We expect this issue to be discussed and ultimately resolved in the PCIA proceeding that has just opened. In the meantime, SBCP must understand the revenue pattern dynamics that have been incorporate into its customer phase-in and financing strategy.

These provide two of the many key dynamics that interact and vary over time to complicate CCA financial modeling exercises. Detailed descriptions of other key dynamics— that were therefore necessary to assess the phase-in and financing strategies for SBCP — are provided in the appendix "***Model Methodology and Assumptions".***

RISK ANALYSIS & CONTINGENCY PLAN

A financial strategy for a CCA analyzes how the agency will finance its operations to meet its strategic objectives — for launch but also continuing into the foreseeable future. It captures the initial startup phase of the agency, and extends typically three to five years beyond that point as well. Generally, the strategy is primarily supported by quantitative analytics in the initial term, ceding to expert judgement further out on the timeline (as future conditions become less certain).

In this manner, no financing strategy would be complete absent a discussion in regards to:

1. How risk is anticipated to be managed, and how this impacts the availability and terms of debt and credit;
2. What the 'residual' risk is (i.e. sources of risk that cannot be mitigated by the CCA itself), and what the contingency plan should be in the event these events come to pass.

This is necessarily a more contextual discussion than the 'hard numbers' in the above sections, and relies upon our own expert judgement — including regarding highly politicized issues that are difficult to assess. As a general rule, we adopt a precautionary approach to risk management in these matters.

Launch Stage

Advantageous access to credit prior to launch hinges upon implementing best practices:

- Regarding the initial term debt and line of credit assumptions (the latter of which is substantial yet requires no municipal guarantee): this is entirely predicated upon SBCP carrying out the best practices in the SBCP Business Plan. By and large, the "best practices" are in fact proven risk-management techniques designed to:
  - Manage the risk of municipal liabilities (as having guaranteed a portion of the startup debt) during this period;
  - Assuage lenders that the CCA will execute well in practice, and launch as planned (thus lowering the aforementioned municipal guarantees).
- As context, the SBCP plan relied heavily upon the 2016-2017 experience and success of Redwood Coast and Silicon Valley Clean Energy. Those two CCAs established the most comprehensive energy risk management policies and real-world capabilities in the industry to date, and were extended financing terms that were the more generous than any CCA had been offered. (That is no coincidence: the latter was predicated upon the former.)

Near-Term Operations (post ~2020):

Regarding model results after 2020: these are predicated upon extant regulations which we expect will change in the near-term; net margins for all CCAs is expected to decline with the imposition of a new methodology to apportion certain power contract and utility overhead costs between utility and CCA customers. (This refers to the PCIA → PAM 'market transformation': review appendix "***Risk of Revision of Non-Bypassable Charges for CCA Customers***" for details.)

- Many CCA advocates consider this to be an issue that may be politically fought. We do not concur, and view it as a mathematical necessity to avoid the risk of systemic and widespread cost-shifts (in violation of the law).
    - Consequently, we are assuming that regulators will impose this change (or a similar fix).
    - Regardless of how this plays out, it is prudent to plan conservatively.
- If the Regional JPA of CCAs is not formed in a timely fashion, it calls into question whether seasonal credit would be extended to SBCP without requiring municipal guarantees (post-2020). As context:
    - The Regional JPA of CCAs was designed as a specific risk mitigation to this market transformation (which we identified as a risk to CCA in 2014).
    - It conceivably allows CCAs to compete against utilities on a level playing field, i.e. once the cost shift is removed through the forthcoming regulatory change.
    - For further details, refer to the appendices, in the "*Risks & Mitigations*" subsections that conclude the discussions of the ***PCIA -> PAM Risk*** and ***JPA Liability issues***.
- Contracting with a portfolio manager to provide energy risk management services is similarly of critical necessity. It is in practice impossible for CCAs to manage this risk absent the capabilities this class of companies (and nonprofits) provides.

Residual Risk

We have not yet analyzed whether the Regional JPA of CCAs, and at what scale, would ensure that CCA remains financially viable after this market transformation. (Though we have recently received data from SCE that will assist in performing indicative calculations.)

Additionally, there are further regulatory risk factors which cannot be mitigated by actions of SBCP and which pose grave threats to CCAs. This includes the re-opening of Direct Access.

- The PCIA → PAM should be assumed to be a near-term reality for planning purposes (i.e. the 'Contingency Plan' below).
- If Direct Access is re-opened around the same time as the PCIA → PAM market transformation, it is conceivable that the creditworthiness of CCAs will be called into question by regulators, to the extent that the CPUC will suspend CCA operations if the members of CCA JPAs do not directly assume liability for the JPA's obligations.
    - The CPUC was granted that specific authority by the California Legislature in 2011;
    - We are still researching the practical mechanisms by which it would applied. (We expect it would be an orderly process that provides sufficient lead time for financial planning.)
- We have anticipated these risks to varying extents, and the SBCP Business Plan recommended mitigating strategies (i.e. design features to enhance the competiveness of the SBCP CCA and the Regional JPA of CCAs, and to specifically respond to concerns we have observed the CPUC has in regard to CCAs);
- Refer to the appendix "***Regulatory Risk***" for an analysis of these risks and mitigations.

Contingency Plan

While it may sound generic, "*Plan for failure, work for success*" is likely the most prudent approach to adopt at the Board level given the current outlook on regulatory risk for CCAs.

This also helps to define the series of actions to take, and red-lines to not cross, for SBCP as it implements and governs a CCA. In brief:

1. Implement SBCP as quickly as possible, to maximize net revenues prior to the market transformation in ~2020;
2. Minimize upfront municipal expenses and overall liabilities during implementation;
3. Follow the procedures and designs of the SBCP Business Plan (including hiring a portfolio manager under the 'single RFP for all services' process);
4. Actively engage other CCA initiatives and municipalities to form the Regional JPA of CCAs;
5. Refine the financial forecasts during the implementation process to ensure the CCA will be able to repay startup debts prior to the PCIA → PAM market transformation;
6. Once launched, do <u>not</u> engage in long-term contracts <u>prior t</u>o the resolution of the PCIA → PAM market transformation and further clarity on the risk Direct Access poses.
7. As a 'book-end' contingency plan, maintain financial reserves and power contract obligations in a manner that affords notifying the CPUC and SCE of the intent to suspend CCA operations one (1) year ahead of time (in accordance with SCE Rule 23, section S) — and then to do so without having to raise rates, otherwise cause losses, fail to meet any extant debt service obligations, or breach any power contracts.

In this manner, a good portion of the 'Contingency Plan' is actually the structure of the enterprise itself (by design).

APPENDICES

MODEL ERROR RISK

The forecasts presented in this report are of a preliminary and indicative nature.

All forecasting exercises are subject to a degree of inherent inaccuracy; CCA financial projections are particularly complex, rely upon customized (i.e. non-standard) spreadsheets and expert judgement to a large extent, and municipalities are generally unaware of power industry best practices to apply when conducting forecasting exercises.

This heightens the risk of both 1) errors in methodology, calculation steps and input assumptions and 2) municipal liability for failing to exercise an acceptable level of diligence — particularly in the event that this compromises the financial performance of the CCA.

This type of error may pose several risks, which depend upon on how the model results are used and whether appropriate qualifiers are included.

Intended Use of Model Results

Along with the SBCP Business Plan and our other deliverables, this report and the current model results are intended to:

1. Provide an indicative forecast to support municipal public policy decisions regarding whether or not to pursue CCA. Doing so would entail:
    a. Devoting a nominal amount of staff resources;
    b. Hiring an Executive Director;
    c. Soliciting the services necessary to implement the program in a transparent and competitive fashion, and hiring companies primarily on an at-risk basis.
2. Provide a basis to negotiate $2.5MM in <u>initial</u> startup funding (which will likely require a full guarantee by participating municipalities), or else justify municipal contributions in this amount.
    a. Most of these funds will be held as collateral by third-parties in order for the implementation process to proceed;
    b. Consequently, these funds are not at-risk under closer to program launch when power contracts must be signed.

This report and the current model results are <u>not</u> intended to support and should not be used for:

1. Negotiating financing products to provide power collateral and working capital requirements;
2. Entering into power purchase agreements;

These process steps are explicitly intended to be supported by more advanced and commercially-standard customer data and revenue forecasting analytics and energy modeling — as well as operational power market expertise. Consequently, this is included in the anticipated scope of work for the CCA's portfolio manager and data manager, and occurs later in the implementation process.

The primary reason for the above disclaimer is because of the PCIA→PAM risk we analyze under the appendix "***<u>Regulatory Risk</u>***".

The model we have prepared for this report is comparable, and may be superior in some regards, to the models that have supported the launch of CCAs to date. It may also be used to provide a reasonably-accurate "snapshot" of the impact of the PAM.

However, in recognition of the fact that prior CCAs may have launched in an artificially-subsidized cost environment, our recommended implementation process anticipates that more advanced customer data analytics, energy risk management practices, market intelligence and power modeling software be used by SBCP prior to engaging in these later-stage financial negotiations and subsequent power contracting. This may be supported by the model presented in this report — as it contains important calculation steps that no commercially-available model provides (owing to the unique nature of the California CCA industry) — or a similar model may be provided by contractors alternatively during implementation. Regardless, the customer data, retail rate projections and energy components of the cost comparison must be updated in the manner we have described.

We have planned for this in our recommended implementation process timeline and RFP design.

Sources of Model Error

In the final analysis, given the reliance on quantitative analytics and qualitative expert judgement necessary to forecast CCA finances, model error poses an inherent risk at this stage of CCA exploration — and through the launch and operation of the program.

The inherent complexity involved effectively means that this risk cannot be fully mitigated on a reasonable timeline or without requiring significant upfront cost to employ a qualified team with strong industry experience.

The current model is intended to be refined and updated in various regards as the implementation process proceeds:

1. The current results are based upon estimated electricity usage data for SBCP; with permission from cities, the model may be updated upon receipt of data from Southern California Edison (SCE). This is also planned for in the implementation process timeline. Data from additional CCAs and groups of cities may also be incorporated, to demonstrate the financial advantages of the Regional JPA of CCAs structure recommended by the SBCP Business Plan.
2. We are continuing to work with Southern California Edison to confirm the accuracy of model input assumptions, as appropriate. Broadly, their staff has been proactive and very helpful.

To lessen the risk of calculation step errors, we have employed several best practices in the construction of the model:

1. We have visualized the results and underlying datasets in a variety of charts and tables that highlight key patterns and inter-dependent relationships (many of which are in this report):
    a. Effective visualization of complex systems and large datasets is one of the most powerful ways to both understand and error check a model (errors tend to be apparent as shifts in patterns or outlier data points — and may be impossible to identify otherwise).
    b. Consequently, this is also an effective technique to communicate the model results, key dynamics and risk factors to other experts or a non-expert audience.

2. Structurally, we have segmented and performed calculations in a bottom-up manner wherever possible in order to facilitate the use of cross-checking calculations, both on the summary output dataset and throughout the various calculations steps underlying the model. To take one example:
    a. Energy usage and cost data is based upon hourly load profiles;
    b. In the workbook accompanying this report, this data is rolled up into monthly totals for:
        i. Onsite load in total and for each type of customer (i.e. usage "at the meter");
        ii. "Loss adjusted load" — i.e. after applying distribution losses, which vary by the type of customer, to estimate the volumes of energy the CCA must purchase at the wholesale level — both in total and by on-peak and off-peak periods.
    c. The loss adjusted profile is then used to calculate the cost of energy on an hourly basis, which is subsequently split into on-peak and off-peak costs and also average prices on a volumetric (i.e. $/MWh) basis — and this is rolled up into monthly totals for the summary workbook.
    d. This allows an error cross-check calculation to be applied to the monthly totals:
        i. The usage figures that came directly out of the load calculations are multiplied by the volumetric power prices in each period for comparison to the total power cost figures (which came from the energy calculation steps).
        ii. If the totals are different, the model flags the error — which indicates that the load data was not handled appropriately in one or both of the separate calculation sequences.
            1. This would not be possible if, for example, the average volumetric power prices were calculated and then applied directly to the load data in each month to calculate total power costs.
            2. Keeping these, and other calculation steps, structurally separate permits a broad range of error checking to guard against internal model errors.
            3. Note that cash-flow errors are particularly hard to diagnose; we describe the methodology employed to do so in the body of this report.

To help mitigate the risk of errors in methodological and input assumptions, and as a general best practice for transparency and community involvement:

1. This report and the accompanying datasets fully disclose the energy, financial and cash-flow model results on a monthly basis, as well as our model methodology, and provide substantial discussions and visualizations of key dynamics that could introduce errors if not handled appropriately.
    a. This level of transparency in model assumptions and results is unprecedented in the CCA industry — which strengthens SBCP's public record of disclosure and serves to limit legal liability stemming from any future allegations of negligence;

b. This could facilitate reviews by interested members of the public and industry, would facilitate a formal peer review process, and we plan to solicit the opinions of industry experts by disseminating this report widely regardless.

2. This report, our model results and all other supporting deliverables will be sent directly to the members of the SBCP Advisory Committee, key electeds and staff involved with the CCA initiative, and posted on the SBCP website for the broader public.

Ultimately, the largest sources of error in methodology and input assumptions pertain to the energy and revenue forecasts. This will be mitigated to a great extent during the implementation process of the CCA through the reliance on expert contractors that use industry-standard software in an operational capacity (as previously described).

REGULATORY RISK

The CCA industry has recently entered into a period of unprecedented and multi-faceted regulatory risk in this regard. In our opinion, these are the primary sources of risk that most complicate any standard or proven approach used to date to design and launch a CCA:

1. Regulators are entertaining proposals to revise how power contract costs and benefits are allocated between utilities and CCAs;
    a. We believe this is tantamount to a market transformation that may significantly lower the net revenues experienced by CCAs to date in the California market;
2. Furthermore, regulators have pro-actively generated discussion of reopening Direct Access, which could also compromise the financial performance of CCAs in various ways (if it leads to an approval to expand Direct Access from the California Legislature);
3. Lastly, in the event that the CPUC determines that:
    a. The credit-worthiness of CCAs is called into question, either by the CCA's internal practices or because of changing conditions (such as those induced by the aforementioned regulatory decisions); and
    b. That this could shift financial liabilities to utility customers in ways other CPUC mechanisms cannot fully protect against;

   Then the CPUC has the statutory authority to request the members of CCA JPAs assume financial liability for the JPA itself — or otherwise may be able to force the suspension of CCA operations. (We are still researching this.)

None of these risks can be mitigated. To help <u>manage</u> these risks, we recommend that SBCP rely upon a portfolio manager for energy risk management services, including active market operations, implement the operational model and generally follow the best practices in the SBCP Business Plan, and proactively form the Regional JPA of CCAs as structured in therein. The sections below analyze these risks and explain in context how these recommendations serve to manage or mitigate the risks identified.

Risk of Revision of Non-Bypassable Charges for CCA customers

The utilities' recent joint proposal to implement the Portfolio Allocation Mechanism (PAM) to replace the Power Charge Indifference Adjustment (PCIA) would, if approved as proposed or in a similar fashion, materially impact these forecasts. **The new proposal would likely diminish the financial performance of all CCAs, likely starting around 2020.**

As context, customers that are served by CCAs are charged, on a non-bypassable (i.e. unavoidable) basis, for the net costs of certain contracts that the utility has entered into on behalf of all bundled service customers.

The legal origin of this charge is the California Public Utilities Commission's (CPUC) statutory responsibility to ensure that customers who depart to CCA service do not unfairly cause customers that remain with the utility to pay more than they otherwise should. Certain contracts and generation facilities owned by the utilities are therefore eligible for cost recovery — from all customers, including those served by CCAs — in this manner under extant statute and regulation.

The current cost-recovery mechanism is referred to as the "Customer Responsibility Surcharge" (CRS), and consists of two charges:

1. Contracts prior to 2002 are recovered via the Competition Transition Charge (CTC), and are relatively nominal;
2. Subsequent contracts are recovered via the Power Charge Indifferent Adjustment (PCIA) mechanism. Primarily, these costs are driven by long-term renewable contracts, but also include certain utility owned generation and shorter-term conventional contract components.

The PCIA has increased in recent years, generating concern and protests from CCAs. Simultaneously, the IOUs have asserted that the methodology underlying the PCIA calculation is inaccurate and must be revised.

Under the current methodology, key calculation inputs are based on estimates provided by regulators and various official surveys and studies. In other words, the calculation — used to apportion large amounts of money between CCA and utility customers each year — is subject to error in human judgement, and may or may not reflect reality. The IOUs assert that it unrealistic. Consequently, the IOUs also assert that there is an unfair cost-subsidy that benefits CCA customers at the expense of utility customers.

With so many, and such large, CCAs launching in the near future, the issue must be fully investigated and resolved in an expedited fashion. Otherwise, if the utilities assertions prove true, the rates of utility customers will begin to increase year over year in direct proportion to the load departing to newly-formed CCAs.

This would, naturally, generate significant political ramifications and almost certainly present legal and financial liabilities for all parties involved.

After a series of six workshops between CCAs and IOUs (in which SBCP actively participated), the IOUs submitted an application to the CPUC to implement an alternate mechanism — the PAM — which they assert will fairly and transparently apportion costs going forward. CCAs have objected, and intend to propose alternative methodologies in future.

Consequently, on 10 July 2017, the CPUC has opened Rulemaking 17-06-026 to fully investigate and decide upon cost allocation issues between CCAs and Investor Owned Utilities (IOUs).

If the utilities' assertions are correct, the resulting price adjustment will be structural and long-lasting — it represents a potential market transformation over the near-term. Consequently, this is the single largest risk of uncertainty to consider when interpreting these model results, and the largest source of regulatory risk for SBCP and all CCAs in the real-world.

Risk Management and Mitigations

Risks which are not acknowledged or understood cannot be planned for and managed; consequently, it is critical that SBCP track the PCIA/PAM issue closely, in order to take it fully under consideration in the event that municipalities proceed with CCA implementation.

We have been aware of this potential market transformation since 2014, and in February of 2017 submitted a CPUC filing that identified and detailed the risks to CCAs. We also proposed a number of CCA design innovations as potential risk mitigation in that filing, participated in the joint CCA and

IOU workshops in late 2016/ early 2017, and we continue to track and be engaged with the regulatory discussions.

Consequently, the utilities PAM proposal was detailed in an appendix to the SBCP draft Business Plan, and our design recommendations for SBCP have been structured primarily around how to best manage this risk. We have presented numerous recommendations in this regard; the three most consequential are to:

1. Hire a portfolio manager to ensure that the CCA implements industry-standard energy risk management practices (one of which is to plan the CCA's portfolio and strategy around the PCIA/ PAM risk);
2. Implement the Regional JPA of CCAs with other interested CCA initiatives and programs; this provides an economy of scale that will spread overhead costs over an increasingly-large territory and will facilitate regional planning and procurement to minimize energy portfolio costs. (Thereby keeping power costs optimized and as low as possible.)
    a. For further details on this, refer to ***the appendix, concluding "Risks & Mitigations" subsection of this "Regulatory Risk" chapter***.
3. Implement a financial strategy and contracting strategy for CCA implementation that takes this risk into account, to lower direct municipal liabilities to the greatest extent possible;
    a. Note that the at-risk contracting component of our recommendations *is designed primarily to accelerate program launch* without requiring substantial staff oversight costs (it automatically financially motivates key contractors to do so), and secondarily to lower upfront direct costs for SBCP member municipalities.
4. Once launched, avoid long-term contracting and prioritize the collection of reserve funds until the PCIA/PAM issue is resolved, in order to mitigate long-term contract risk and simultaneously insulate CCA customers to the greatest extent possible.

Lastly, as this proceeding progresses over the coming months, we plan to conduct scenario forecasts to assess the impact of the proposed changes.

To assist our efforts, staff at SCE directed us to a recently-disclosed dataset of 350+ power contracts (2016 portfolio) that SCE is seeking cost recovery for under the PAM.

Risk of Retail Direct Access Re-Opening

Retail Direct Access, under which individual customers may contract with an Energy Service Provider (ESP) for generation service, has been largely capped in California since the Energy Crisis (albeit with a nominal expansion in 2013). **Recent initiatives have heightened the possibility that Direct Access could be re-opened in the near-future, which poses distinct risks to the financial performance of CCA programs and their ability to achieve local policy goals in practice.**

Over the course of 2017, California Public Utilities Commissioner Michael Picker appeared to unilaterally generate widespread industry discussion on the possibility that these caps could be lifted in the near future, and speculated that the utilities may be allowed to form their own affiliate power marketing companies as well.

In media interviews, he appeared to conflate the expansion of distributed generation and community-led CCA initiatives with widespread support for Direct Access (the explanation for this position in response to a direct question from an interviewer did not offer an understandable rationale). To generate further discussion, the CPUC organized two all-day 'En Banc' meeting in 2017 that drew hundreds of power industry stakeholders, first to a CCA summit in San Francisco and then a Direct Access and distributed generation summit in Sacramento to discuss the matter. At the conclusion of the Direct Access hearing, Commissioner Picker asserted that a proceeding would be opened to re-consider many aspects of how the California power sector were structured, and to further discuss his proposal to explore re-opening Direct Access.

Doing so would likely compromise CCA programs in numerous ways. Ultimately, it risks rendering the uniquely-stable version of CCA that has evolved in California non-viable. Such a change would undermine the ability of new CCA initiatives to launch, and would jeopardize the ability of all CCA programs to engage in long-term planning and contracting — which is a prerequisite to meaningful control of their community's energy future.

This would effectively shift some portion of — and perhaps ultimately all —responsibilities for long-term planning and contracting back to the IOUs under the CPUC's oversight. Consideration must be given that this is the CPUC's underlying strategy in play.

Strategic Direction of the CPUC on Re-Opening Direct Access

More broadly, and in our professional opinion, the CPUC has become increasingly activist in its role and has expanded its effective purview into matters of policy that are rightly left to the California State Legislature. In this particular case, in permitting the most recent expansion of Direct Access, SB 695 (2009) stated clearly that:

> *Except as expressly authorized by this section… the right of retail end-use customers pursuant to this chapter to acquire service from other providers is suspended until the Legislature, by statute, lifts the suspension or otherwise authorizes direct transactions.*

While the CPUC cannot expand Direct Access by fiat, by stimulating the widespread and rapid speculation that Direct Access could be re-opened, it is effectively using its stature and resources to publicize and convene forums in which to discuss and consider the matter. This crossover from regulations into politics has caught many industry observers <u>entirely</u> by surprise.

This is likely directly related to the rapid expansion of CCA programs in California. The tension between local control and CPUC oversight has become increasingly apparent across multiple regulatory proceedings over the past year — particularly in the Integrated Resource Plan proceeding (R.16-02-007), and in regard to the creditworthiness of CCAs, their energy risk management practices, and the corresponding 'CCA Bond' that the Commission requires prior to launch (R.03-10-003).

In all fairness, there are various grey areas in the laws governing CCAs, and it is not entirely clear how the CPUC should reconcile the current processes used to govern the power sector with the rapid expansion of CCA. It is a challenging undertaking, and inherently poses a loss of regulatory authority for the Commission.

The Commission exercises strong regulatory authorities to ensure the physical stability of the power grid, and is empowered to allocate costs equitably through various mechanisms. However, the Commission lacks meaningful control over the long-term planning practices of CCAs and has expressed concern that CCAs may fragment regional planning efforts as a consequence (thus leading to suboptimal investment decisions). They have also voiced concerns that CCAs may not be engaging in prudent risk management practices — the Commission only exercises indirect oversight over CCAs in this manner: they cannot specify how CCAs are to conduct their procurement, portfolio strategy or market operations, but can assess the creditworthiness of CCAs and determine the methodology used to set credit requirements prior to the launch of a CCA (hence, the sudden re-opening of the CCA Bond issue this year).

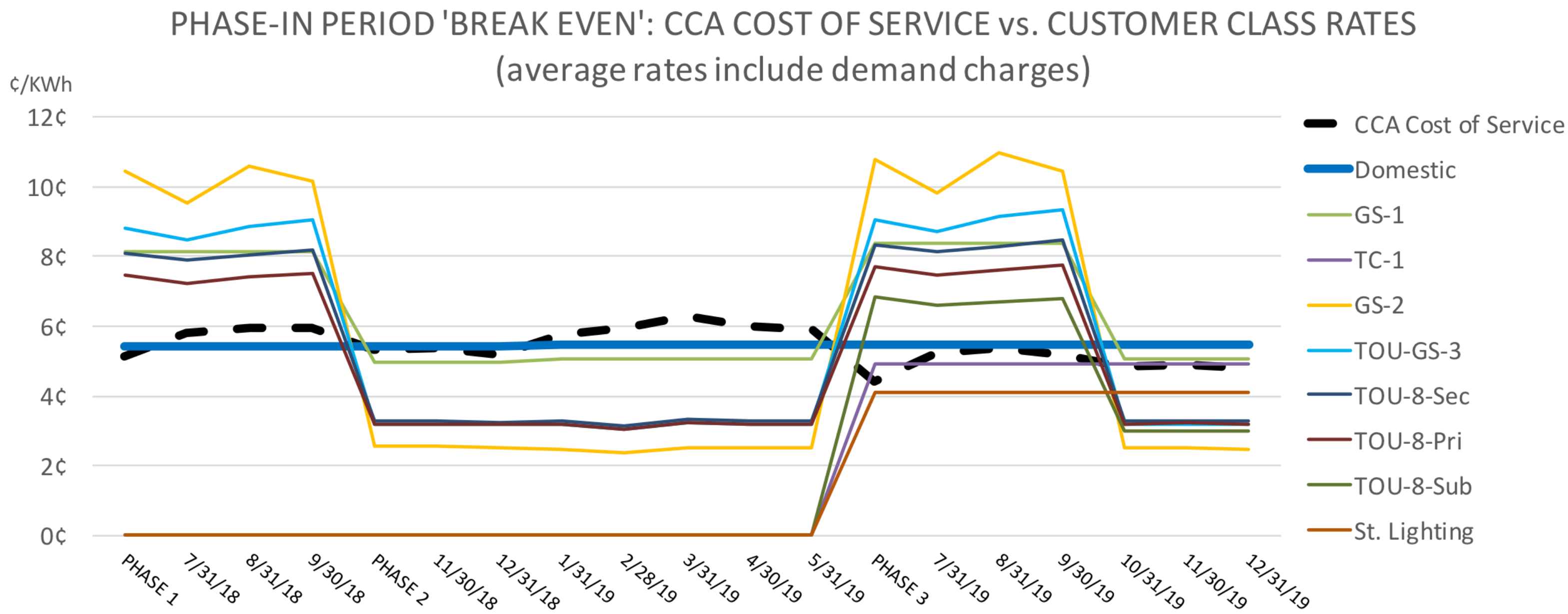
Re-opening Direct Access may well absolve the Commissions concerns indirectly, by first shifting a significant portion of planning responsibilities back to the IOUs, and ultimately undermining the financial viability of CCA's entirely. This requires some explanation, which is provided in the section below.

Financial Impact of Direct Access on CCA

While we have not yet explicitly analyzed the potential impact of Direct Access on SBCP, this report does provide numerous quantitative insights into why a stable base of nonresidential customers is important for the financial viability of the CCA — certainly in SCE's territory and likely in all IOU territories.

1. Specifically, nonresidential customers:
    a. Have the lowest overhead cost to serve, as they consume more power on average but require less data management, billing and call center resources;
    b. Are <u>critical</u> during startup phases to maximize cash-flow and repay startup debts. This is because they typically have much higher rates during the summer months, whereas residential customer rates are fairly stable throughout the year. (Most CCAs to date have launched with a first phase of mostly nonresidential customers, and this is in fact recommended for SBCP.)
    c. Help balance and diversify the load profile of the program to minimize wholesale rates.
2. Residential customers are the most volatile and least cost-effective to serve, and bring in fairly nominal net revenues over the course of the year.
    a. Consequently, it is unclear whether a CCA could survive with an unstable nonresidential customer base.
    b. It is even less clear that new CCAs would be able to secure the requisite financing necessary to launch under these conditions.

As initial quantitative insights, the chart below shows when certain customer class rates are above or below the CCA's cost of service during the phase-in period and after full enrollment (residential is "Domestic" in blue and doesn't generate substantial net revenues like the nonresidential customers do:



For further context and analysis, refer to the chapter "**Customer Phase-In Strategy: Overview & Key Dynamics**".

3. Nonresidential customers are strategically important, from a financial perspective, to provide the initial positive business case that allows for targeted deployments of DER (which SBCP anticipates prioritizing):
   a. Two examples — both of which would help the CCA lower wholesale costs and likely provide a positive business case to accelerate the CCA's DER capabilities — are:
      i. Demand response programs, which are typically very dependent on nonresidential customers;
      ii. Onsite installations of battery storage, which are predominantly cost-effective only for nonresidential customers exposed to rates with high demand charges.
   b. If SBCP's nonresidential customer base were to shrink dramatically, the CCA may find it difficult to justify deploying DER services.
   c. Conversely, if these customers were a stable part of the program's customer base, they would provide the initial foundation upon which to deploy and grow DER services.

Strategic Impact of Direct Access on CCA

Some industry participants have suggested that the CPUC look to how "other states" have markets in which CCA and Direct Access "co-exist". However, the five states that allow both (Illinois, Ohio, Massachusetts, New York, New Jersey) effectively preclude the empowered and stable version of CCA that has evolved in California. In our experience, industry observers that compare California to other states when discussing CCA invariably do not understand the distinctions — which are very important.

1. Out of the 1,000+ CCAs in restructured states around the country, there is one stable government agency model of CCA outside of California:
    a. It is in Massachusetts, and was the first CCA in the country: Cape Light Compact (founded in 1997). This agency has a dedicated staff, engages in regulatory affairs and runs energy efficiency programs.
    b. However, the Cape Light Compact is unable to accrue a significant balance sheet, and thus cannot engage in long-term planning and contracting; they have constructed one or two relatively small solar arrays and supported a number of distributed rooftop installations (by leveraging connections through school districts, etc.).
    c. Although they continue to explore avenues to expand their activities in this regard, it is not comparable to the statutory authorities California CCAs enjoy in California regarding their formal role in long-term planning and the expansive expertise this requires our CCAs to employ.
2. The other 999+ CCAs are essentially short-term franchise agreements for ESPs to sell power to a community on a short-term basis, typically one to three years.
    a. This includes other large aggregations, which some industry observers may consider to be comparable to California CCAs — such as NOPEC and SOPEC in Ohio. They are not comparable.
        i. These are multi-jurisdictional Councils of Governments, and have run CCA programs for almost 20 years. They offer certain efficiency or PACE options for customers.
        ii. However, they still rely on a single power marketer to offer CCA service. They have not built up staff capacity or expanded control over energy operations and planning — and NOPEC has nearly been suspended twice when the ESP exited the contract unexpectedly.
        iii. In fact, these CCAs exist primarily to seek cheaper power under short-term contracts.
    b. Chicago was an extremely high-profile CCA that provides a good case study:
        i. The city launched a CCA that prioritized the exclusion of coal from its power supply.
        ii. This generated a substantial amount of positive press coverage.
        iii. Within a couple of years, the CCA was charging rates above the cost of the utility and competing suppliers; it was suspended and returned its customer base back to the utility.

Thus, the all other CCA states provide compelling case studies in how markets that allow Direct Access effectively preclude CCAs from meaningful control over their energy future. Following their example would, in point of fact, re-centralize control of long-term planning in the IOUs under CPUC oversight:

1. As context, ESPs have historically professed a lack of interest in long-term contracting, preferring to engage in shorter-term market activities (as befits their business model and cost structure);
    a. In the PCIA/PAM workshops earlier in the year, ESP representatives stated that they would prefer if the IOUs continue to engage in planning and long-term contracting, and assign Direct Access customers nonbypassable charges to cover the costs.
2. The practical result of this would be that any customers departing a CCA for ESP service under Direct Access would shift planning authority back to the IOUs and CPUC and away from CCAs.
    a. CCAs do not have nonbypassable charge cost recovery authorities under extant statute, while IOUs do — this would provide a distinct advantage to position the IOUs as the 'natural' planning and contracting agent in a market wherein substantial portions of the customer base were free to change switch their generation provider.
    b. CCAs, on the other hand, and especially early-stage CCAs that lack financial reserves, will likely find it increasingly difficult to convince project developers and financiers that they are sufficiently stable to be considered a credit-worthy counterparty for the long-term (10 to 20 year) contracts required to construct new renewables.
        i. This will diminish the pool of counterparties willing to contract with CCAs, diminishing competition and driving up risk premiums layered into pricing offer to CCAs.
    c. The two dynamics above re-inforce one another, in that IOUs will have a strong and increasing advantage in maintaining the lowest cost contracting advantage over CCAs.

Lastly, this erosion of CCAs' customer base will happen much more rapidly than most industry observers might realize:

1. Commissioner Picker's initial comments on re-opening Direct Access included speculating that IOUs may be allowed to form affiliate companies to compete as ESPs.
    a. This would provide an avenue for the IOUs to pro-actively target, market and win back customers from existing and new CCAs — <u>starting with customer classes that are financially necessary to launch new CCAs.</u>
2. Any expansion of Direct Access, when it opens, will likely produce a rapid outflow of key customers for CCAs:
    a. There is a substantial waiting list for Direct Access service already, and ESPs will additionally fund active targeting and engagement with key customers in <u>advance</u> of any re-opening;
    b. Nonresidential customers have typically moved to secure their right to ESP service quickly when allowed, as a general precaution against the unplanned closing of Direct Access in future (i.e. again, as when it was closed during the Energy Crisis).

Even more broadly, it is important to note that "power planning" is broadly separate into two domains: energy planning and capacity planning:

1. Energy planning is what CCAs currently do — they assess how much electricity their customer base will need in future, contract for adequate supplies to hedge against market volatility, and engage in some amount of long-term planning and contracting to build new renewables.
2. Capacity planning ensures the stability of the power grid by matching peak load for all customers against instantaneous output from power plants. This is planned for overall and in specific sub-regions of the grid that are transmission constrained. This planning is holistic, and takes into account all customers instead of the requirements of specific groups of customers served by ESPs, CCAs and IOUs.

CCAs only procure capacity for one or several years out, contracting with existing power plants to do so. Long-term capacity planning and contracting is conducted by the utilities, with contract costs charged to all customers — including CCAs.

CCAs have limited authority to engage in long-term capacity planning. This is one of the 'grey areas' that the Legislature has not fully resolved for the Commission, and which is being debated at the CPUC in the Integrated Resources Plan proceeding. CCAs may self-provide capacity resources to a limited extent, authorized under SB350 to do so for the sake of integrating renewables only, with the consequence that CCA customers would not be charged by the IOUs for that portion of long-term capacity. But CCAs do not have cost-recovery authorities for these contracts, and the utilities do — and long-term capacity contracts by their very nature typically require non-bypassable charge cost recovery to be financially justified.

This is important because long-term capacity planning is a powerful procurement tool that determines significant investments in the power sector — and is actually the venue in which new fossil fuel power plants are often justified and constructed on behalf of CCAs. It is a significant omission in the authorities of CCAs, and until they gain control over it, no CCA will totally control its community's energy future. Conversely, it CCAs were to gain control of this authority, it could become a significant source of funding for accelerating Distributed Energy Resources.

It has been our hope that — as more CCAs launched, employed increasing sophistication in power planning, and began to collaborate and create formal structures to coordinate planning (as our Regional JPA of CCAs model would provide) — CCAs would be able to marshal the necessary political influence and technical capability needed to assume responsibility for <u>all</u> planning and contracting (both energy and capacity). In other words, to assert local control over all power supplies.

Re-opening Direct Access, in addition to compromising current CCA authorities and financial stability, would entirely preclude this from being a realistic objective for California CCAs.

Risk Management and Mitigations

From the outset, CCAs and all of their supporters as a group should be vigorously opposing this initiative — not just at the CPUC but also with proactive engagement with the Legislature and the Governor.

Ultimately, we believe the CPUC's concerns regarding CCA are motivating this initiative, and can be defined as the need to 1) employ more industry-standard energy risk management practices and 2) provide for coordinated planning on a regional level.

These are, not coincidentally, the principal design features recommended for SBCP and the Regional JPA of CCAs. With deliberate intention, the design of the entire CCA serves to mitigate the threat of various regulatory risks (by proactively addressing the concerns expressed by regulators, and by providing the economy of scale that appears likely necessary to compete on a level playing field).

We discuss these risk management and mitigation techniques more fully in one of the sections below, as responses to "***Risk that the CPUC Pierces the Pierces the Veil of CCA JPA Liability Protection***".

In the final analysis, the issue of whether and to what extent Direct Access should be re-opened is a statutory matter for the Legislature to decide. The expansion of CCA programs, with the number of municipal governments and citizen committees that entails throughout the State, may provide adequate political influence to ensure Direct Access does not undermine CCA.

Regardless, SBCP should monitor the evolution of the Direct Access debate at the CPUC and at the Legislature. The potential risks posed to SBCP and the timeline on which this would occur should be quantitatively assessed, and factored in to the program's financial and portfolio strategy.

In terms of impacting the results presented in this report, this is unlikely to occur within the timeframe forecasted to repay initial startup debts, thus removing direct financial liability for municipalities that have guaranteed a portion of the loans. However, it may undermine the projections in the outer years of the forecast period, which will be examined through sensitivity analyses if SBCP proceeds with CCA implementation.

In the event Direct Access were to be re-opened, the CCA should be prepared to offer services that compete with ESPs for these customers. This has been anticipated in the SBCP Business Plan, which specifies the services required to do so and intends to deploy these capabilities at launch.

As context, CCAs have broad rate-setting authority and are able to offer individual customers customized, and flexible, rate structures. The SBCP Business Plan anticipates this type of customer service and provides a corresponding list of functions that the CCA would deploy: below is an excerpt from the "Customer Care: Key Account Relationship Management" function as specified in the operational model (appendix):

> *Establish and maintain relationships with key accounts, and work with other management functions to offer customized services and rate structures. Note that in any CCA territory, there will be a number of very large, sophisticated commercial and industrial customers which will employ energy managers who are tasked with monitoring and minimizing or stabilizing energy costs. These customers should be assigned an account manager by the CCA, and may request specialized rate structures, such as real-time pricing or customized hedging, and/or installation of distributed energy resources that could be supported by or integrated with the CCA's activities.*

It's important to note that the ability to offer these services requires the portfolio manager services as well. Absent the services of a portfolio manager, the CCA only purchases power in large volumes at certain times of the year —conducting power procurement in this manner makes it both difficult to structure customized rate schedules and hedges for large customers, and difficult to modify the CCA's portfolio strategy and power purchases to account for a new large customer's requirements outside of the CCA's purchasing schedule. A portfolio manager provides this flexibility. Similarly, the customer relationship management database and utility data and billing processes need to provide certain functionality here, which is anticipated for SBCP.

Another aspect of offering these services is that large customers may actually pose unique risks to a CCA (or ESP), particularly if their operating schedules (and thus pattern of power usage) are unpredictable, or if there is a risk they could suspend operations entirely. This is a form of counterparty default risk, and is also mitigated, in part, through the reliance on a portfolio manager and the more flexible and active power procurement their services allow CCAs. Additionally, credit concerns for large customers are also managed by negotiating customized financial requirements (i.e. deposits with the CCA or ESP, as cash or a letter of credit, etc.) with the level set according to the level of financial risk that either the customer or the CCA (or ESP) is taking on in the provision of power.

These are all important capabilities that the SBCP has been designed to deploy regardless of whether Direct Access is eventually re-opened in California — but in that event, these capabilities would become critical for the CCA to remain competitive.

RISK THAT THE CPUC PIERCES THE VEIL OF CCA JPA LIABILITY PROTECTION

A law passed by the Legislature in 2011 gave the CPUC specific statutory authority to impose the liabilities of a CCA JPA on its members, or else preclude the operation of the CCA. (Ironically, this law is referred to as the "CCA Bill of Rights".)

This is not, strictly speaking, necessary to understand in order to interpret the model results presented in this report. However, it is critical for SBCP municipalities to understand this risk in the broader context of how the CCA should be planned and operated — especially in light of the regulatory risk factors in play that we have analyzed above — and therefore in how the SBCP Business Plan has been designed to manage if not mitigate this ultimate risk in practice.

This extraordinary and targeted expansion of authority has not been discussed at all within the CCA industry, to our knowledge, and further supports our general view that effective risk mitigation ultimately depends upon the real-world practices of the CCA.

Evolution of the CPUC's Authority Over CCA JPAs

As context, the IOUs previously sought to pierce the JPA liability "firewall" protections of Section 6508.1 by requiring CCA JPAs to execute a CCA Service Agreement contract prior to launch that stipulated joint and severable liability on the members of the CCA JPA.

At the time, they were prohibited from doing so by the CPUC in Decision 08-04-056 (2008).[2] The CPUC ruled that:

> *Section 20 of the utilities' tariffs would effectively remove this exercise of discretion by requiring joint and several liabilities unless otherwise agreed by the local government members and the utility. Section 20 of the utilities' CCA service agreements is therefore in conflict with Government Code Section 6508.1 and impedes the authority and rights of local government agencies.*

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[2] Available online at: [http://www.cityoflarkspur.org/DocumentCenter/View/437]

We are not convinced that Section 20 is necessary to protect utility customers. While the utilities have provided a list of consequences that could occur in the event that a joint powers agency with insufficient assets were to fail, they have provided no persuasive arguments that Section 20 is necessary or why joint power agency CCAs, which are comprised of public, governmental entities, should be considered inherently uncreditworthy. Additionally, we agree with SJVPA that the issue of whether a CCA joint power agency should be required to assume joint and several liabilities should be considered as part of the CCA's creditworthiness review.

Moreover, AB 117 and this Commission's implementation of it mitigate these risks to utility customers by, for example, specifying that bundled utility customers shall not pay higher fuel costs as a result of CCA operations, requiring a CCA to demonstrate a showing of creditworthiness, permitting the utilities to withhold payments to CCAs under certain circumstances, and requiring CCAs to post security bonds or security deposits.

… No provision of law circumscribes the rights of local agencies to create CCA joint powers agencies under agreements that exempt the members of the joint powers agency from joint and several liability for the debts, liabilities, and obligations of the joint powers agency.

Subsequent to this decision, SB 790 (2011) gave the CPUC the authority to impose CCA JPA liabilities directly on its members. This was codified in Public Utilities Code Section 366.2: [3]

Pursuant to Section 6508.1 of the Government Code, members of a joint powers agency that is a community choice aggregator may specify in their joint powers agreement that, unless otherwise agreed by the members of the agency, the debts, liabilities, and obligations of the agency shall not be the debts, liabilities, and obligations, either jointly or severally, of the members of the agency. The [California Public Utilities] commission shall not, as a condition of registration or otherwise, require an agency's members to voluntarily assume the debts, liabilities, and obligations of the agency to the electrical corporation unless the commission finds that the agreement by the agency's members is the only reasonable means by which the agency may establish its creditworthiness under the electrical corporation's tariff to pay charges to the electrical corporation under the tariff.

Applicability of the CPUC's Authority In Practice

The CPUC has not required members of CCA JPAs to assume liability in this manner. In the event that they do in future, the language of Section 366.2 appears to be somewhat limited in that the CPUC has the authority to require a JPA's members to "voluntarily" assume the JPA's liabilities. In other words, the CPUC apparently cannot <u>assign</u> these liabilities to the members by fiat without their consent.

In practice, the CPUC has the authority to prohibit the launch of a JPA during the registration process if the CCA has not met the required creditworthiness requirements, per Public Utilities Code Section 366.2(c)(7) and (8). This would present an opportunity to first require such an action as a precondition for launch. This process is repeated whenever the JPA Agreement is modified, including when a new member joins or an existing member departs.

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[3] Available online at:

[http://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?lawCode=PUC&sectionNum=366.2]

Furthermore, the CPUC has broad authority to ensure creditworthiness requirements through various other mechanisms; we are still researching whether these other authorities could be practically used by the CPUC on a discretionary basis to de-facto require JPA members to assume the JPA's liabilities or else force the suspension of the CCA at some point in the future. Our working assumption for the sake of prudence is that the CPUC can exert its authority in this manner on a discretionary basis.

CCA "Creditworthiness" & Energy Risk Management Concerns

The CPUC's reasoning in Decision 08-04-056 stated that the commission had a variety of extant mechanisms to ensure the creditworthiness of CCAs, and this still holds true.

However, the possibility that this authority will be used in future cannot be ruled out — especially since the IOUs are alleging that one of the primary mechanisms, namely the manner in which the CPUC ensures that the utilities' customers do not pay more because of CCAs (PCIA/PAM), is broken. Simultaneously, and in our opinion not by coincidence, the CCA Bond and creditworthiness evaluation has recently been re-opened for discussion and possible revision in Rulemaking 03-10-003. As context:

- Creditworthiness is currently satisfied by a financial security requirement under which the CCA provides the CPUC with a bond, letter of credit or deposit This is designed to satisfy the cost of customer re-entry back to the IOUs in the event a CCA fails.
- For a number of years, it has been set at a nominal $100,000 ("interim CCA bond") with the CPUC reasoning that CCAs are being prudent and the bond should cover the IOUs' prospective administrative cost for processing customer re-entry.
- The IOUs have long argued that the bond posted by CCAs should cover potential incremental <u>energy procurement</u> costs that would be incurred in the event that the CCA fails, and returns all its customers to utility service en mass. They proposed that this amount should further be updated on a regular basis, to reflect market conditions (similar to a mark-to-market calculation, measuring the financial performance of a power portfolio against market prices to assess the efficacy of its risk management strategy and forecast the financial risk it represents). That would result in an extremely large bond amount that fluctuates widely as market price forecasts do. It would be tens to hundreds of millions of dollars for a CCA the size of SBCP under the IOU's proposed methodology.
- The CPUC has previously dismissed this argument, but has recently held a workshop and re-opened discussion in the proceeding as so many CCAs prepare to launch. The utilities are again posing the same argument described above.

At the center of this debate is what constitutes "creditworthiness" and whether a CCA should be financially liable for the adverse impacts it's actions could have on both its customers and the utilities' customers, in the specific event that the agency failed to exercise appropriate power planning and energy risk management practices.

While the CPUC has no statutory authority to directly regulate these affairs (the Board of the CCA has that authority), it does have strong authority to impose various financial liabilities on CCAs to act as a form of insurance against such poor practices. **Furthermore, we have been given strong indications that key members of the CPUC, including the CPUC President (Michael Picker) are concerned to date that:**

1. **CCAs employ a variety of approaches to energy risk management, which may fail to meet acceptable, industry-standard practices;**
2. **CCAs do not coordinate in a sufficient fashion to ensure that power planning exercises are conducted in a regional manner, which is necessary to optimize investment decisions and meet the State's carbon reduction goals in a least-cost fashion.**
3. **Lack of coordination between IOUs and CCAs on rate setting and distributed resources will fragment the ability to optimize the acceleration of DER throughout the state (regardless of CCA intentions).**

We believe that it these concerns are the underlying motivation behind the variety of regulatory threats that CCAs now face.

Risk Management and Mitigations

Addressing the CPUC's underlying concerns, not coincidentally, ultimately requires the advantages that the Regional JPA of CCAs in the SBCP Business Plan possesses over the standard CCA model:

- Superior energy risk management services are specified to be contracted for under the RFP as part of the Regional JPA's operational model and provided in a standardized fashion to all CCAs to ensure high quality of services.
- Coordinated planning is expressly intended and provided for as a service;
- Distributed energy services and sophisticated rate setting analytics are to be contracted for at the outset as services — and close coordination between SCE and the CCA is anticipated and emphasized throughout the SBCP plan.
- Expert staff capabilities are expanded over time to bring critical services impacting energy risk management decisions in-house — the Regional JPA provides the economy of scale to afford this.

In other words, the SBCP CCA and Regional JPA of CCAs has been designed to mitigate the concerns expressed the CPUC — which appears to possess ample authority to effectively preclude CCA program formation and operation if their concerns are not addressed.

The additional advantage is that doing so provides the economy of scale and expertise in energy risk management that CCAs may soon require to remain financially stable through the PCIA → PAM market transformation.

Furthermore, in recognition that the point of Community Choice is to enable local self-determination, and that governance models that preclude this will not scale in practice as a result, we have taken care to structurally ensure this does not happen:

1. The Regional JPA Board is controlled by the member CCAs to ensure accountability, so that the quality of services does not fail to meet expectations and that full transparency in operations is assured.
    a. All member CCAs control their own power portfolio choices, financial reserves and rate setting.
    b. This structurally ensures local control is never taken away from municipalities and that policy decisions are made at the local level, not by the Regional JPA.

2. Only services and planning coordination are expressly standardized across CCAs; pooled power purchases, and credit risk for project development and public revenue bond issuances can be spread amongst member CCAs at their discretion (i.e. if doing so is the best option).

These core program design elements — the Regional JPA of CCAs and the enhanced approach to energy risk management — were in fact first proposed in the regulatory filing that SBCP's consultants submitted in February 2016. The filing detailed the PCIA risks to CCAs, and proposed as mitigating strategies for CCAs the design recommendations later formalized in the SBCP Business Plan.

However, actual risk management in the real-world depends upon execution — not just design. Effective execution is critical, and not simply because the CPUC possesses the unique authority to impose JPA liabilities on its members (or else suspend operations).

That is why the SBCP Business Plan devoted substantial effort to not only design the CCA's governance structure and operational model, but to specify the RFP design & contracting process and financing strategy in a manner that provides a high degree of risk management in practice.

The PCIA/ PAM issue actually represents an industry restructuring that will most likely lower the net margins CCAs currently enjoy, and CCAs must plan around it for the sake of prudency. The SBCP CCA has been designed in response to this specific and significant risk factor, and the other regulatory threats we have detailed in this appendix.

Consequently, most of the recommendations herein and in the SBCP Business Plan are actually written from an operational and process risk management perspective. These also serve to assuage lenders, thereby enhancing the negotiating position of SBCP for startup funding. To formulate our recommendations, we have leaned heavily on various best practices from the broader public power sector — which is much more experienced than the CCA industry to date in these and other matters.

As a general overview:

1. The first step is to hire an Executive Director with operational experience, to help guide municipalities and ensure that the right companies are hired to provide the necessary services;
    a. Citizen Committees are involved in the RFP design and interviewing process to ensure transparency;
2. RFP design and contracting should follow best practices and be run in a transparent fashion.
    a. This precludes any claim of negligence at the outset of the agency and removes a source of uncertainty for regulators in assessing the credibility of a CCA.
    b. Again, Citizen Committees are involved in the RFP design and interviewing process to ensure transparency;
    c. As context, there are at least two CCA initiatives that we believe have likely violated California Conflict of Interest laws in their hiring processes, and a number of other initiatives attracting heightened scrutiny (including Freedom of Information requests targeting communications between staff and certain bid respondents);
        i. Poor contracting practices make regulators extremely nervous.
3. The RFP for services should be issued through the Regional JPA — or prior to its formation by a leading CCA (like SBCP) with substantial engagement with other interested CCAs;

a. This prevents the market from fragmenting as it would if many CCA initiatives contracted for services, and later tried to somehow join together (current CCAs will invariably have to wait until service contracts expire to join — likely several years).

4. The CCA should contract early on in the implementation process with a portfolio manager for power planning, contracting and energy risk management.

   a. These are companies and nonprofits that have a proven track record in running energy risk management operations for comparably-sized power agencies and utilities.

   b. The reliance on such accredited agents, and the use of industry-standard risk management policies, practices and techniques, provides a measure of protection against any future claims of mismanagement or negligence on the part of the JPA that could otherwise be used to pierce the disclaimer of liability that protects its members.

   c. It also provides the strongest assurance that the CCA's power portfolio is actually being competently managed in a transparent fashion, and in accordance with adopted risk management policies, and employs industry-standard software and proven expertise to do so.

   d. Proper planning and forecasting techniques will also provide the strongest protections to the CCA against financial insolvency owing to unanticipated adverse market conditions and insufficient reserves. (There are defined methodologies and techniques for price and revenue forecasting that should be employed here, which portfolio managers are experts in.)

   e. The PCIA/PAM nonbypassable charge risk can actually be estimated, tracked and incorporated into a CCA's energy portfolio strategy by portfolio managers, which possess the modeling expertise and market intelligence to do so in a prudent and transparent fashion.

   f. Energy risk from the erosion of a CCA's customer base can also be analyzed and incorporated into a CCA's portfolio strategy, rate setting and reserve fund planning in a similar fashion (i.e. quantitatively, by relying on the analytics that portfolio managers provide).

   g. Broadly, liability and risk can be mitigated through appropriate planning, policies and portfolio management services. In the worst-case scenario, the CCA should seek to suspend operations in a planned and coordinated fashion. Notifying the CPUC and SCE of the intent to suspend service one year ahead of time, and alerting customers six months ahead of time, will avoid forcing CCA customers to assume the financial liability of market price exposure (in accordance with SCE Rule 23, section S)[4].

   In other words, "plan for failure, work for success" is the most prudent philosophy at the Board level, and doing so in practice requires a portfolio manager's skillset.

5. The formation of the Regional JPA of CCAs should be prioritized and discussed with other interested CCA initiatives:

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[4] Available online at: [https://www.sce.com/NR/sc3/tm2/pdf/Rule23.pdf]

a. There are 27 public power joint agencies around the country that operate in a similar fashion, by providing shared services to members that retain control over their power choices, finances and rate setting authorities.

b. This allows the expansion of the program without regard to whether or not all the CCAs that join share the same political preferences and policy goals — it doesn't matter, since they all require a similar set of services regardless of their objectives. Because it doesn't matter, the governance model can (and should) separate the operations of the Regional JPA from local control over matters of policy and finance — which is what our proposed model does in practice.

c. This provides an increasing — essentially unlimited — economy of scale for SBCP and all CCAs that join in future, which will lower overhead rates charged for shared operational and planning services. Doing so is a precondition for effectively competing against the utilities in the event the PAM cost recovery mechanism is implemented.

   i. Note that in contrast, a "regional" JPA model that is confined to a specific territory and/or insists on pooling all municipalities into a single CCA (under the statutory definition) cannot actually scale sufficiently in practice, as it will quickly be limited by political factionalism over policy decisions — this will actually drive municipalities to form their own CCA initiatives, thus undermining the entire point of forming the Regional JPA in the first place.

d. Since the Board of the Regional JPA is composed of the Executive Directors of each member CCA, the operations of the agency are partially insulated from political pressures (which otherwise pose a risk, in the CCA and broader public power industry, of inappropriately steering planning decisions in a sub-optimal fashion).

6. Process controls, citizen committees and independent operational audits are required.

   a. These are necessary oversight practices to ensure that day to day operations adhere to policy and direction from the Board, for energy risk management and all other activities that pose liabilities for the JPA and its members.

Related to the last design recommendation above, the draft SBCP JPA — recommended as a template for other interested CCA initiatives — is built around a "strong board" model instead of a "strong Executive Director" model. This means that the SBCP Board would have broad authority in specifying how the agency would be run, in accordance with Operating Rules and Regulations adopted by the Board (including an Energy Risk Management Policy). The Board is vested with the authority to delegate specific responsibilities to the Executive Director therein, and to revise this over time.

The reason why we included an Operational Audit (section 3.4 in the draft JPA) to be carried out by a third-party at least once every two years is primarily to protect this mechanism — i.e. to verify that the agency is actually being operated in accordance with these rules and regulations.

We did this for a specific reason: because we have directly observed the Executive Directors of other CCAs, and the staff and consultants they employ, deviate from policies adopted by their Boards for extended periods of time (without the Board's knowledge or consent, and in some cases, almost certainly with the knowledge of the Executive Director). The deviations we've observed between policy and practice have been on issues of consequence.

This is actually a fairly common problem between management and governance, especially where the Board knows less about what is going on because the subject matter and day to day activities are very complex. CCAs fall squarely into that category.

The way to mitigate this risk is through the application of process controls, independent oversight functions, and judgement in hiring key staff with operational risk management expertise — all of which we have incorporated into the SBCP design recommendations.

There are additional mechanisms the SBCP Board could employ here to provide further assurances. For example, it is not uncommon in the public power industry to require key staff (such as the Executive Director or Power Director) to assume some measure of financial liability, such as by requiring a performance bond. Doing so provides a clear and compelling financial incentive to operate the CCA in accordance with Board policy and established industry practices, and ready recourse in the event this is not done.

To provide a measure of 'real world' proof to support the validity of our recommendations, we are also releasing a number of supporting deliverables with this report:

1. "Question and Answer" interviews with five leading portfolio managers,
    a. This allows these companies and nonprofits to communicate their perspectives and capabilities to prospective SBCP cities
    b. Questions answered include how to best manage regulatory risks such as PCIA/PAM.
2. The financing packet of Silicon Valley Clean Energy (that SBCP's financing strategy is based upon).
3. The Energy Risk Management board policies and contracts with portfolio managers from two most recent CCAs to launch, the Redwood Coast Energy Authority and Silicon Valley Clean Energy.
    a. Both CCAs have adopted the portfolio manager model of CCAs and employed these companies to successfully launch on accelerated timelines.
    b. The immediate benefits to the agencies in doing so has been apparent.
        i. The risk management policies are undeniably more comprehensive as compared to any CCA risk management policy created previously.
        ii. They reflect an industry-standard approach to systematically monitoring, analyzing and mitigating risk in practice, and delegate the responsibilities and authorities required to do so between Board, key staff (such as the Executive Director) and the portfolio manager for the CCA.

Lastly, we re-direct SBCP municipalities to the letter of endorsement we received from W. Kent Palmerton.[5] He is a 40-year veteran of the public power industry, who has actually managed two "regional" JPAs to provide energy services to member municipal utilities and water districts. It is a strong and expert endorsement, in which he calls the Regional JPA of CCAs "long overdue" for the CCA industry, and emphasizes that the SBCP plan should result in "industry-leading energy risk management".

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[5] [https://southbaycleanpower.files.wordpress.com/2017/05/sbcp-endorsement-kent-palmerton-16may2017.pdf]

In total, we believe that our work products and recommendations give SBCP municipalities the ability to successfully launch a CCA, work with other initiatives to form the Regional JPA of CCAs, to execute the implementation of these agencies in an expert and expedited fashion, and ultimately to absolve the CPUC of its concerns — thus managing (and potentially, mitigating) a significant source of regulatory risk that would otherwise jeopardize the long-term viability of the SBCP CCA.

MODEL METHODOLOGY AND ASSUMPTIONS

The sections which follow provide an overview of key calculations, methodologies and input assumptions used to prepare the forecasts in this report and monthly energy, financial and cash-flow results in the accompanying workbook. Additionally, broader industry context is provided where appropriate or necessary to assist with interpreting model results or best practices.

Overview of Methodology and Key Relationships

Forecasting the financial performance of the CCA has as much to do with modeling the utility as it does the new CCA. This is — due to the complex nature of the utility's structure and portfolio, the confidential treatment applied to certain data, and the complexity of the regulations governing how this impacts CCAs and their customers — actually much more challenging than predicting the CCA's cost of service. Consequently, it is also the greatest source of model error.

The CCA and IOU forecasts are highly inter-dependent because of the following four relationships:

1. The utility's generation rates are the "price to beat" that sets the upper limit on revenues for the CCA, and thereby establishes a ceiling on the financial performance of the CCA.
    a. The difference between the CCA's costs and the utility's rates effectively determines the revenues available for purchases of additional renewable power, the accumulation of a reserve fund, rate decreases or to satisfy other energy policy goals.
    b. If the utility's rates are not correctly forecasted, the analysis will show what it costs to run the CCA but not the net revenues available for these purposes (and will not be able to accurately predict if the CCA can meet its financial obligations or policy goals without raising rates above the utility).
2. The utility's generation rate structures are also important to model accurately, particularly for the cashflow analysis, as most CCAs mimic the utility's rate schedules and billing determinates (i.e. the metrics by which electricity usage is translated into bill charges). This analysis establishes the pattern of expected revenue inflows to the CCA.
    a. In SCE's territory, most non-residential customer accounts are charged both for energy consumed during a billing period, and by some measure of onsite peak demand (i.e. the largest draw of electricity over a short time period, typically 5 or 15 minutes).
    b. This means that the pattern of electricity usage, and not just the overall volume consumed, directly impacts billing charges.
    c. These patterns change over time, and are usually highly dependent on weather patterns month over month for many types of customers.
    d. Additionally, nonresidential rate schedules change seasonally, and summer rates (in June through September) are higher — particularly for demand charges.
    e. Thus, a CCA's cashflow analysis has to account for how the specific usage patterns of different types of customers change month to month, and derive bill charges based on rate schedules that change seasonally as well.
3. Certain power contracts entered into by the utility, as well as a portion of the utility's generation assets and accompanying overhead and capital revenue requirements (cost and rate of return), continue to be recouped directly from customers enrolled into CCA programs. This also limits,

and lowers, the rates that CCA may charge without causing customers to pay more than they would by opting-out of the CCA and returning to utility bundled service.

   a. The charge is referred to as the Customer Responsibility Surcharge, and consists of both the Competition Transition Charge (CTC, pre-2002 power contracts) and the Power Charge Indifference Adjustment (PCIA, 2002 through present day contracts).
   b. The PCIA charge component is significant and growing; inaccurate forecasting of the PCIA may compromise a CCA's financial performance during the debt repayment period.
   c. The PCIA also shifts a significant portion of power costs out of customer rate schedules (which are higher in summer for most nonresidential customers) and into a flat, volumetric fee.
      i. This has the practical effect of raising the CCA's cost of service above customer rates for 8 months out of the year (the higher summer rates in June through September rise above the CCA's cost of services).
      ii. A corollary impact is that this causes a cyclical 'cash crunch' that requires additional liquidity for the CCA to manage (i.e. this directly impacts financing requirements for new CCAs, and reserve fund requirements subsequently).

4. Certain power plants the utility has built as well as contracts that the utility has entered into <u>indirectly offset</u> the procurement obligations for CCA programs, thereby lowering program costs.
   a. Specifically, these are capacity contracts entered into by SCE on behalf of all customers (not just bundled service customers), for which CCA customers continue to pay the net capacity costs — and for which the CCA receives a proportional credit under the CAM (cost allocation mechanism).
   b. The utility continues to engage in this contracting and charge CCA customers for new contracts through the CAM; in other words, it is not like the

Given the tight integration of utility and CCA financial forecasts, methodological consistency is critical between the various required analyses, so that the model remains internally coherent and does not disregard any key interconnected relationships, particularly across:

1. The utility's generation rate forecast;
2. The non-bypassable charge forecasts (PCIA and CRS under the CTC, and CAM);
3. The CCA's power portfolio forecast (which must incorporate any credits received from the utility's CAM capacity contracts that serve to offset the CCA's procurement obligations).

Effectively carrying out this analysis while ensuring harmony between the forecasts requires:

1. First: disaggregating the utility's overhead cost structure and power portfolio to a sufficient degree. Certain components of SCE's portfolio — such as nuclear power or hydroelectric generation — are relatively fixed costs. Other slices fluctuate directly or indirectly in response to market prices — such as short term and market purchases, and qualifying facility contracts.
2. Second: further disaggregating the utility's cost structure and power portfolio to separate out the contracts and costs that are allowed to be recouped from CCA customers via non-bypassable charges, and to capture the costs that are actually included in SCE's generation rate.

More broadly, CCA financial modeling must additionally incorporate several distinct categories of dynamics, some of which require significant regulatory intelligence and expert judgement:

1. Regulatory requirements and frameworks for CCAs and IOUs, such as RPS obligations and the methodology by which capacity (resource adequacy) obligations and credits and assigned. The timing of regulatory decisions can be important, as costs and requirements can be impacted in a manner that is not intuitive from a purely technical perspective. The element of regulatory fiat often reflects political artefact or simply the burden of regulating such a complex industry — but this does impact real-world cash-flow for the CCA.
2. Market dynamics and business process considerations that impact cash-flow and financing requirements, such as accurate overhead costs for services and staff, utility fees, the delay between when power must be paid for versus when revenues are received from customers (a delay due to the utility billing cycle), the seasonal variation in rate structures and resulting impact on revenues for the CCA (summer rates are higher than winter rates for certain customer classes), collateral obligations for power purchases, and funds to cover residual market power purchases.
3. Load and price forecasting, and the electricity requirements and costs for various products, such as on- or off-peak forward and market power, renewable power, and local and system capacity.

The most important driver is the cost of electricity, which is also the most difficult to predict. Forecasting and comparing power costs for CCAs and utilities is inherently a "moving target" exercise, driven primarily by the variable nature of electricity and natural gas markets. To be a credible estimation, care must be taken to apply the same underlying forward pricing assumptions to both the CCA and utility portfolios. **Doing so provides an "apples to apples" foundation for the analysis. It is far more important to do this accurately, rather than to layer on scenario after scenario analysis if this underlying relationship has not been captured appropriately**.

Lastly, different methodologies must be used to correctly reflect the power procurement practices of the utilities and new CCA programs, and appropriately capture their relative positions in the market:

1. Utilities maintain complex portfolios of utility-owned power plants, fuel contracts, short- and long-term power contracts, and confidential hedging strategies enabled by their existing staff, infrastructure, established business processes, and access to credit (due to their substantial balance sheets, balancing accounts and cost-recovery authorities).
2. New CCAs launch with limited credit and financial reserves, and rely on contractors to execute short-term (1-3 year) contracts for power, and have more flexibility in contracting choices by virtue of their small size relation to the utility and market but less room for error due to their constrained finances.

Over time, CCAs build up reserve funds and expand access to credit, diversify their portfolios and execute long-term contracts, and build internal staff capacity. (Note that we recommend refraining from long-term contracting until the PCIA/PAM cost allocation is clarified.) Consequently, CCAs are in a very different position than the incumbent utility, and the financial modeling that supports the launch of the CCA must reflect this.

Capacity Planning: Overview & CPUC Induced Changes in Valuation Methodology

One of the most complex and inter-related components of the analysis relates to how capacity requirements, necessary to ensure the stability of the power grid moment to moment and year over year, are determined and allocated to load serving entities. As high-level context:

- Load serving entities (including SCE and CCAs) must contract for capacity sufficient to ensure the stability of the power grid, under Resource Adequacy regulations overseen by the CPUC.
    - CCAs must contract for sufficient capacity on a year-ahead basis, and in practice do so by sourcing capacity from existing facilities at relatively low cost.
    - SCE must do this as well for its own customer base, but is in addition the default contracting agent for new generation built to provide grid stability. Constructing new power plants requires a multi-year lead time, and involves detailed planning studies with long-term horizons. These capacity requirements are studied and determined by the CAISO, deliberated in CPUC proceedings, and contracted for in competitive solicitations run by the IOUs. The net capacity costs of these contracts are recovered from all ratepayers that benefit — not just SCE bundled service customers — on a fully nonbypassable basis under the Capacity Allocation Mechanism (CAM).
        - Power plants built for reliability purposes (i.e. to provide capacity) typically require strong assurance of repayment.
            - This is because the plants may only be economical to run for a small number of hours in the year (i.e. when load is highest), and would otherwise be unable to recover their costs from power market sales competing against other power plants throughout the year.
        - This is why the CAM was implemented. It is a mechanism by which the CPUC:
            - Ensures that new power plants required to ensure the grid stability in future are built in a timely fashion;
            - Apportions the costs for doing to all ratepayers (and ensures that power sales from these plants appropriately lower the resulting net capacity cost passed through to ratepayers);
            - Lowers the capacity obligations of the load-serving entity responsible for those customers (to reflect the fact that those contracts are providing a portion of the total capacity obligations that would otherwise be required, and thereby avoid double-procurement).
- The manner in which capacity requirements are assessed evolves over time. The evolution in California, in recent years, has been driven by the technical challenges the industry collectively faces in how best to integrate increasing volumes of intermittent, renewable resources (primarily, wind and solar):
    - The power grid must have sufficient capacity to be stable system-wide. California also has several sub-regions of the power grid that have constrained transmission capacity, and must therefore have a minimum amount of generation capacity located within those regions specifically.

    - Current obligations therefore differentiate between geographic locations, requiring both system ("generic") and local capacity.
    - The local regions for SBCP are the LA Basin and Big Creek-Ventura.
  - Reflecting the need for the power grid to accommodate increasing volumes of wind and solar — which can vary in output relatively quickly and need to be "balanced" by other power plants to maintain grid stability — capacity obligations also stipulate certain amounts of "flexible capacity requirements" (FCR).
    - There are three different categories of flexible capacity obligations, and this requirement is evolving.
    - At this time, it primarily reflects the near-term need to accommodate the daily ramp in solar production.
  - The underlying methodology by which different types of generation facilities count towards these different capacity requirements is also evolving.
    - The most notable change in this regard, which directly impacts capacity valuations during this forecast period, is how wind and solar is valued.
    - Capacity needs to be supplied, traditionally, primarily to meet loads at times of peak demand. Thus, the methodology until recently has approximated the output of these facilities at the times when load is highest, with some recognition of the uncertainty involved; for a number of years, the capacity contribution of wind and solar has been valued as a relatively static percentage of the facility's nameplate capacity (i.e. the maximum volume of power it is capable of producing under ideal conditions) that varies by month (reflecting seasonality in both output and coincidence of output to peak load).
    - This is moving towards a more dynamic methodology, referred to as "Effective Load Carrying Capacity" (ELCC). This methodology is holistic, and based on power system reliability theory as applied in rigorous quantitative models. As a methodology, it recognizes that as more volumes of a particular type of intermittent resource comes online, the contribution to system capacity of that particular resource decreases somewhat.
    - The change has the practical effect of lowering the capacity valuation of wind and solar resources. This is not trivial, considering the large volumes of wind and solar under contract to both IOUs and CCAs.
      - Note that this impacts utility, PCIA and CCA rate forecasts but not CAM allocations therein, as the latter is predominantly composed of non-intermittent, dispatchable resources.

Capacity Requirements & CAM Allocations

SCE has constructed peaker plants and entered into certain contracts for capacity that are eligible for ongoing cost recovery from all customers (including CCA customers) under the CAM mechanism. The mechanism of cost recovery charges all customers who benefit from the stability ensured by these resources for the net costs of capacity (i.e. any sales of energy and ancillary services from these facilities serve to offset the net costs charged to ratepayers for these facilities). Both in SCE's territory and system-wide, contracts eligible for CAM have been steadily growing and comprise a non-trivial portion of capacity requirements:

Figure 10. RA Procurement Credit Allocation, 2006 – 2016 (RMR, DR, and CAM)

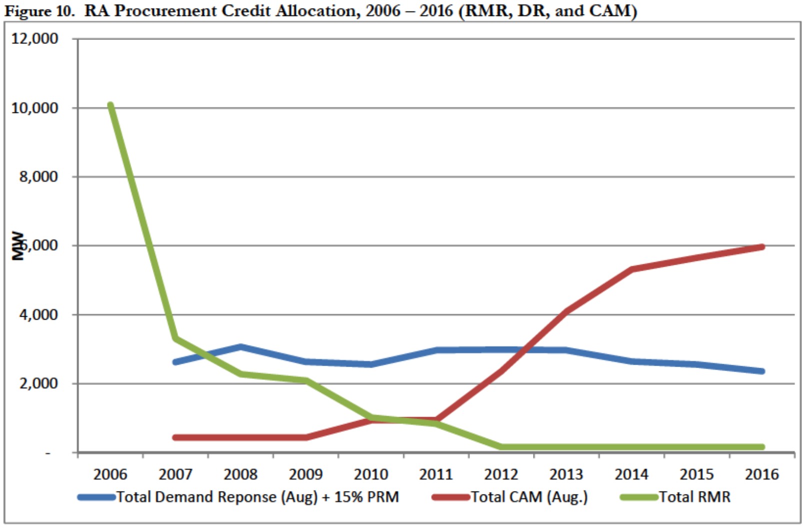


Figure from CAISO

Current eligible contracts are comprised of natural gas fired generation — both combined heat and power and centralized generation, including five UOG peaker plants two of which are enhanced with battery storage — and a nominal amount of demand response. However, SCE has increasingly contracted for a non-trivial portion of future year requirements from preferred resources — i.e. distributed renewable, thermal and battery storage, energy efficiency and demand response. The need for these contracts arose primarily due to the unplanned retirement of the SONGS nuclear generating plant as well as the Aliso Canyon nature gas storage facility. These contracts are coming online within the model's forecast horizon.

These net capacity costs are <u>not</u> included in SCE's generation rates, and the capacity benefits are proportionally allocated to CCAs — this allocation serves to offset the CCA's capacity procurement obligations. This must be taken into account when forecasting both utility rates and the CCA's cost of service. Additionally, the capacity contract allocations have both geographic and performance attributes that must be taken into consideration, and the valuation methodology (under extant regulation) varies in these regards.

- The CPUC's list of CAM-eligible contracts for 2017 discloses the expiration date for each contract currently in service. Monthly capacity attributes, including the system or local geographic designation as well as flexibility attributes, were forecasted forward. The expiration of contracts, including utility-owned generation that had reached the 10-year limit on cost recovery, was taken into account.
- Additional contracts were added to this forecast, reflecting SCE's recent procurement to satisfy local capacity requirements through the forecasted period. Certain attributes of these contracts were estimated, and based on a survey of regulatory filings and advice letters submitted by the utility:

Refer to the two tables in appendix "***Capacity Allocation Mechanism Contract Summary: 2018 & 2022***" - these disclose first and last year key inputs, summaries of eligible contracts by key metrics, local capacity obligations pre- and post-adjustments.

- Under Resource Adequacy regulations, the accounting of system, local and flexible capacity attributes of generators are different. This must be taken into account when assessing how the CAM credits offset CCA obligations.
  - As context, a generation facility located within a local capacity region counts towards both local and system capacity (a resource located outside of these regions is only counted towards meeting system capacity obligations). The flexibility attributes of a resource are assessed and valued regardless of location.
  - The effective capacity ("net qualifying capacity" or NQC) of most resources varies by month. This is used to account for the facility's system capacity contributions.
  - However, for facilities that are located in local capacity areas — for SBCP, within the LA Basin or Big Creek-Ventura region — the August NQC is used to set the capacity credit in each month of the year (provided the resource is still under contract) for local capacity requirements. (The reason is because local capacity requirements are primarily designed to meet the peak loads of this month; the actual monthly NQC is still used to value these resources for system capacity credits.)
  - Flexible capacity valuations are distinct from the Net Qualifying Capacity, and termed "Effective Flexible Capacity" (EFC).
  - The credit allocation regulations correspond with how local capacity obligations are calculated — local capacity requirements are static month over month but change year to year, while system and flexible requirements vary monthly.
  - Most demand response resources under contract with the utility, and Distributed Energy impacts, are incorporated already into the load forecasts prepared by the CEC; however, a nominal volume of DR is included under the CAM mechanism or otherwise "unallocated" from SCE's programs. Note that:
    - These are bifurcated between "load modifying" resources that serve to lower the peak load upon which the CCA's share (and obligations) are based, or "supply side" resources that are counted as credits (akin to traditional supply).
    - DR capacity values should be inflated to account for transmission and distribution losses (+7.6% in SCE's territory) and to reflect the planning reserve margin (+15%). However, care needs to be exercised in not applying these factors to datasets from the utilities or CPUC that already incorporate the assumptions.
    - August NQC values are used for all months of the year when calculating local capacity obligations or credits; system values vary by month.
    - More broadly, non-DR Distributed Energy resources are growing over the forecast period, and handling these calculations appropriately will grow in importance.
- CCAs must provide both system capacity and local capacity, and meet flexible capacity obligations in doing so as well.
  - A CCA's system requirements are set based on monthly peak loads, plus a 15% planning margin. The monthly peak loads are coincident with system demand; to estimate the difference between a CCA's peak load and the CCA's peak load at the time of system

demand, Resource Adequacy compliance filings contain a calibration factor to apply that varies by month. (In practice, this will be calculated by the CEC by analyzing the CCA's specific load profile once the program has been operating for a sufficient period of time.)

- A CCA's local capacity requirements are set based on its share of peak load within its TAC Area (Transmission Access Charge Area) during August of each year (this includes the planning margin).
  - This percentage is applied to the procurement requirements of smaller, constrained geographies within the TAC Area.
    - For SBCP, these are the LA Basin and Big Creek-Ventura local capacity zones.
    - The capacity requirements for each zone is set by CAISO, which publishes studies setting the total requirements for the next year along with a snapshot forecast for what the requirements will be four years in the future. (The difference was assumed to proportionally escalate year over year for forecasting purposes.) Refer to the charts below:

2018 Local Capacity Needs

	Qualifying Capacity			2018 LCR Need Based on Category B			2018 LCR Need Based on Category C with operating procedure		
Local Area Name	QF/ Muni (MW)	Market (MW)	Total (MW)	Existing Capacity Needed	Deficiency	Total (MW)	Existing Capacity Needed**	Deficiency	Total (MW)
Humboldt	14	196	210	121	0	**121**	169	0	**169**
North Coast/ North Bay	118	751	869	634	0	**634**	634	0	**634**
Sierra	1176	949	2125	1215	0	**1215**	1826	287*	**2113**
Stockton	139	466	605	358	0	**358**	398	321*	**719**
Greater Bay	1008	6095	7103	3910	0	**3910**	5160	0	**5160**
Greater Fresno	364	3215	3579	1949	0	**1949**	2081	0	**2081**
Kern	15	551	566	0	0	**0**	453	0	**453**
LA Basin	1556	9179	10735	6873	0	**6873**	7525	0	**7525**
Big Creek/Ventura	430	5227	5657	2023	0	**2023**	2321	0	**2321**
San Diego/ Imperial Valley	202	4713	4915	4032	0	**4032**	4032	0	**4032**
Total	5022	31342	36364	21115	0	**21115**	24599	608	**25207**

Table 5: 2018 Local Capacity Needs vs. Peak Load and Local Area Resources

	2018 Total LCR (MW)	Peak Load (1 in10) (MW)	2018 LCR as % of Peak Load	Total Dependable Local Area Resources (MW)	2018 LCR as % of Total Area Resources
Humboldt	169	187	90%	210	80%
North Coast/North Bay	634	1333	48%	869	73%
Sierra	2113	1818	116%	2125	99%**
Stockton	719	1169	62%	605	119%**
Greater Bay	5160	10247	50%	7103	73%
Greater Fresno	2081	3290	63%	3579	58%
Kern	453	867	52%	566	80%
LA Basin	7525	18466	41%	10735	70%
Big Creek/Ventura	2321	4802	48%	5657	41%
San Diego/Imperial Valley	4032	4924	82%	4915	82%
Total	**25207**	**47103***	**54%***	**36364**	**69%**

2022 Local Capacity Needs

	Qualifying Capacity			2022 LCR Need Based on Category B			2022 LCR Need Based on Category C with operating procedure		
Local Area Name	QF/ Muni (MW)	Market (MW)	Total (MW)	Existing Capacity Needed	Deficiency	Total (MW)	Existing Capacity Needed**	Deficiency	Total (MW)
Humboldt	14	196	210	121	0	**121**	169	0	**169**
North Coast/ North Bay	118	751	869	209	0	**209**	440	0	**440**
Sierra	1176	949	2125	836	0	**836**	1905	62*	**1967**
Stockton	139	466	605	355	0	**355**	406	296*	**702**
Greater Bay	1008	5871	6879	4257	0	**4257**	5153	162*	**5315**
Greater Fresno	364	3215	3579	1479	0	**1479**	1860	0	**1860**
Kern	15	551	566	0	0	**0**	123	0	**123**
LA Basin	1556	6582	8138	5957	0	**5957**	6022	0	**6022**
Big Creek/Ventura	430	3430	3860	2208	0	**2208**	2597	0	**2597**
San Diego/ Imperial Valley	217	4355	4572	4572	71	**4643**	4572	71	**4643**
Total	5037	26366	31403	19994	71	**20065**	23247	591	**23838**

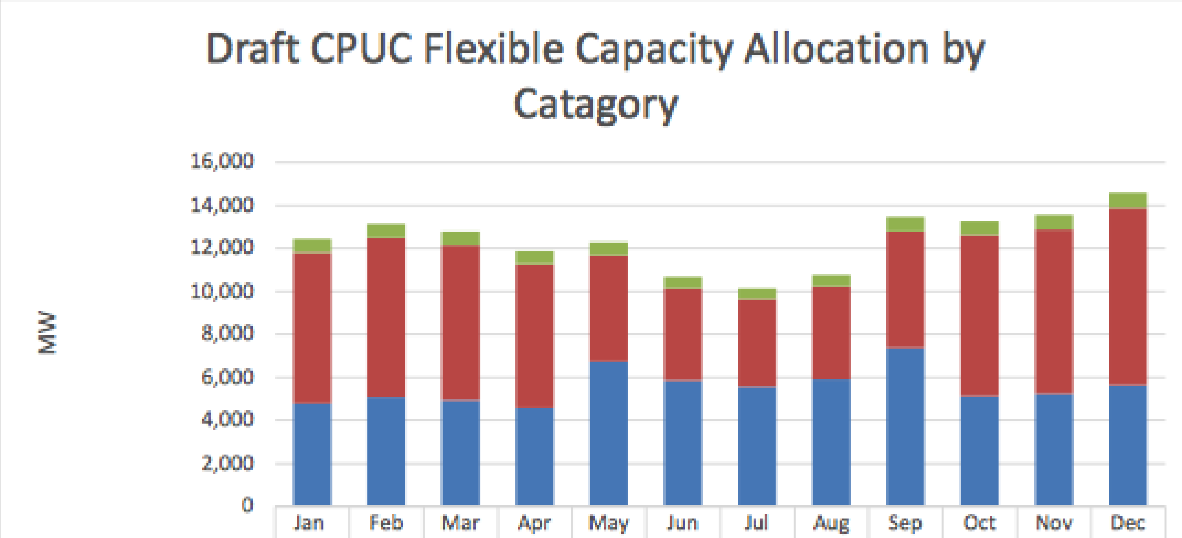
Table 6: 2022 Local Capacity Needs vs. Peak Load and Local Area Resources

	2022 Total LCR (MW)	Peak Load (1 in10) (MW)	2022 LCR as % of Peak Load	Total Dependable Local Area Resources (MW)	2022 LCR as % of Total Area Resources
Humboldt	169	190	89%	210	80%
North Coast/North Bay	440	1249	35%	869	51%
Sierra	1967	1814	108%	2125	93%**
Stockton	702	1035	68%	605	116%**
Greater Bay	5315	10180	52%	6879	77%**
Greater Fresno	1860	3352	55%	3579	52%
Kern	123	885	14%	566	22%
LA Basin	6022	19020	32%	8138	74%
Big Creek/Ventura	2597	5020	52%	3860	67%
San Diego/Imperial Valley	4643	5053	92%	4572	102%
Total	**23838**	**47798***	**50%***	**31403**	**76%**

Tables from CAISO

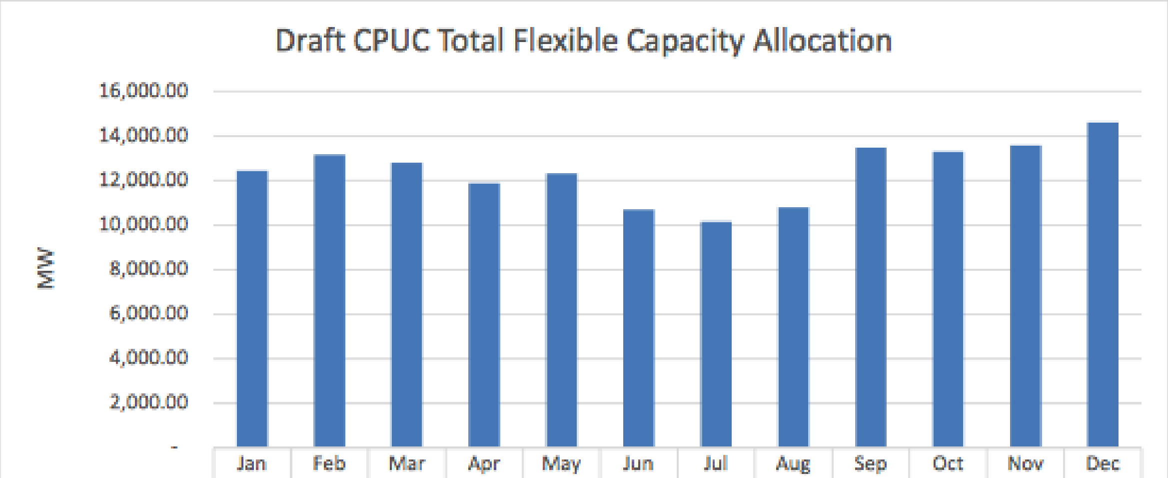
- Flexible requirements are also estimated by the CAISO, vary month over month in total and in type (there are three categories of operational performance requirements), and are allocated based on a CCA's contribution to coincident system peak demand in each month. Refer to the charts below:

Figure 8: CPUC Flexible Capacity Need in Each Category for 2018



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Super-Peak Flexibility	622	658	640	594	615	534	508	539	673	665	678	731
Peak Flexibility	7,010	7,413	7,215	6,694	4,946	4,295	4,081	4,336	5,413	7,491	7,648	8,236
Base Flexiblity	4,806	5,081	4,946	4,589	6,746	5,858	5,567	5,914	7,383	5,135	5,243	5,646

Figure 7: CPUC Jurisdictional LSEs' Contribution to Flexible Capacity Needs

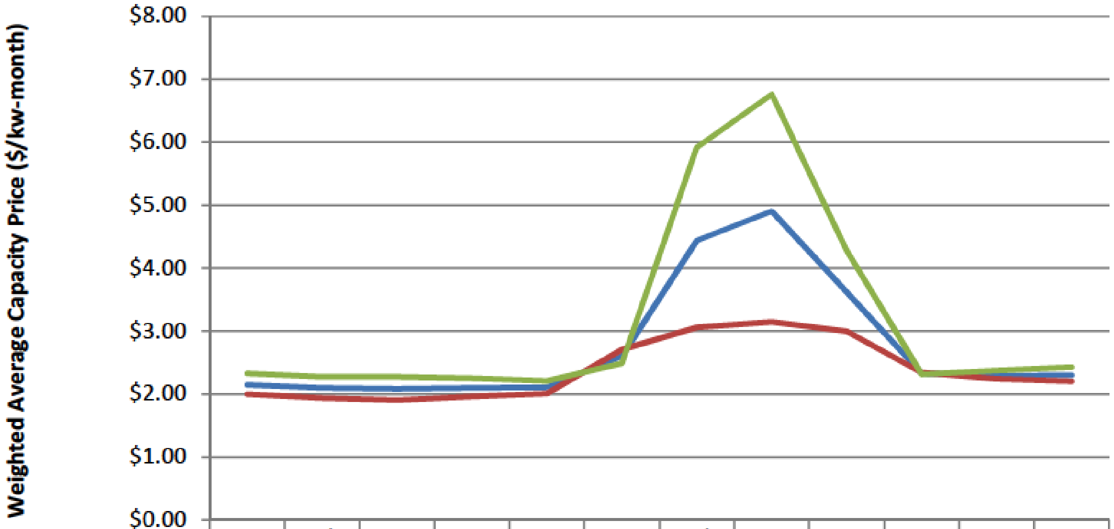


	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Allocation	12,437	13,151	12,801	11,876	12,308	10,688	10,156	10,789	13,468	13,291	13,569	14,611

Figures from CAISO

- The monthly variability in capacity obligations is inherently important to capture, and all the more so since costs for capacity often vary by month as well — particularly in SCE's territory and the local zones therein. This has a non-trivial impact on CCA cashflow projections. Refer to the chart and table below:

Figure 7. Weighted Average RA Capacity Prices by Month and Zone



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
All Prices	$2.14	$2.10	$2.08	$2.10	$2.11	$2.60	$4.44	$4.90	$3.62	$2.33	$2.29	$2.30
NP 26 Prices	$2.00	$1.94	$1.90	$1.96	$2.01	$2.71	$3.06	$3.14	$2.99	$2.34	$2.24	$2.20
SP 26 Prices	$2.33	$2.28	$2.28	$2.25	$2.21	$2.49	$5.92	$6.75	$4.28	$2.31	$2.37	$2.43

Table 8. Capacity Prices by Local Area, 2015-2019

	LA Basin	Big Creek/Ventura	Bay Area	Other PG&E Area	San Diego-IV	CAISO System
Contracted Capacity (MW)	21,644	58,955	49,129	3,459	33,956	96,917
Percentage of Total Capacity in Data Set	8.2%	22.3%	18.6%	1.3%	12.9%	36.7%
Weighted Average Price ($/kW-month)	$3.44	$3.41	$2.30	$2.55	$4.11	$2.45
Average Price ($/kW-month)	$2.99	$3.05	$2.19	$2.67	$3.83	$1.97
Minimum Price ($/kW-month)	$0.15	$0.16	$0.65	$0.65	$0.09	$0.60
Maximum Price ($/kW-month)	$16.12	$15.34	$4.00	$3.50	$26.54	$11.47
85% of MW at or below ($/kW-month)	$5.10	$4.34	$3.00	$3.00	$4.25	$3.00

Figures & table from CAISO

Southern California Edison Rate Forecast

- 2018 SCE generation rates by Rate Group were taken from the most recent 2018 ERRA, and updated to account for the Base Generation Revenue Requirement (2018 GRC filing) and Songs Settlement Revenue Requirement (which will be in effect but are not actually included in the Rate Group average rates SCE discloses in the May 2017 filing).
  - Note that the SONGS Settlement has been re-opened and is being contested; if this is modified or removed in future, it would offset both our estimate of SCE's rates and the PCIA rate forecast calculations (because it is a cost component eligible for recovery from CCA customers through the PCIA). This should be revenue-neutral for the CCA.
- Years 2019-2022 were based upon the CPUC RPS Calculator, which approximates fleet changes as well as SCE's cost structure. Below is a summary slide by the CPUC's consultant (E3), as well two graphs derived from the model that show as the impact on fleet heat rates (fuel efficiency) forecasted from planned retirements over the near-term:

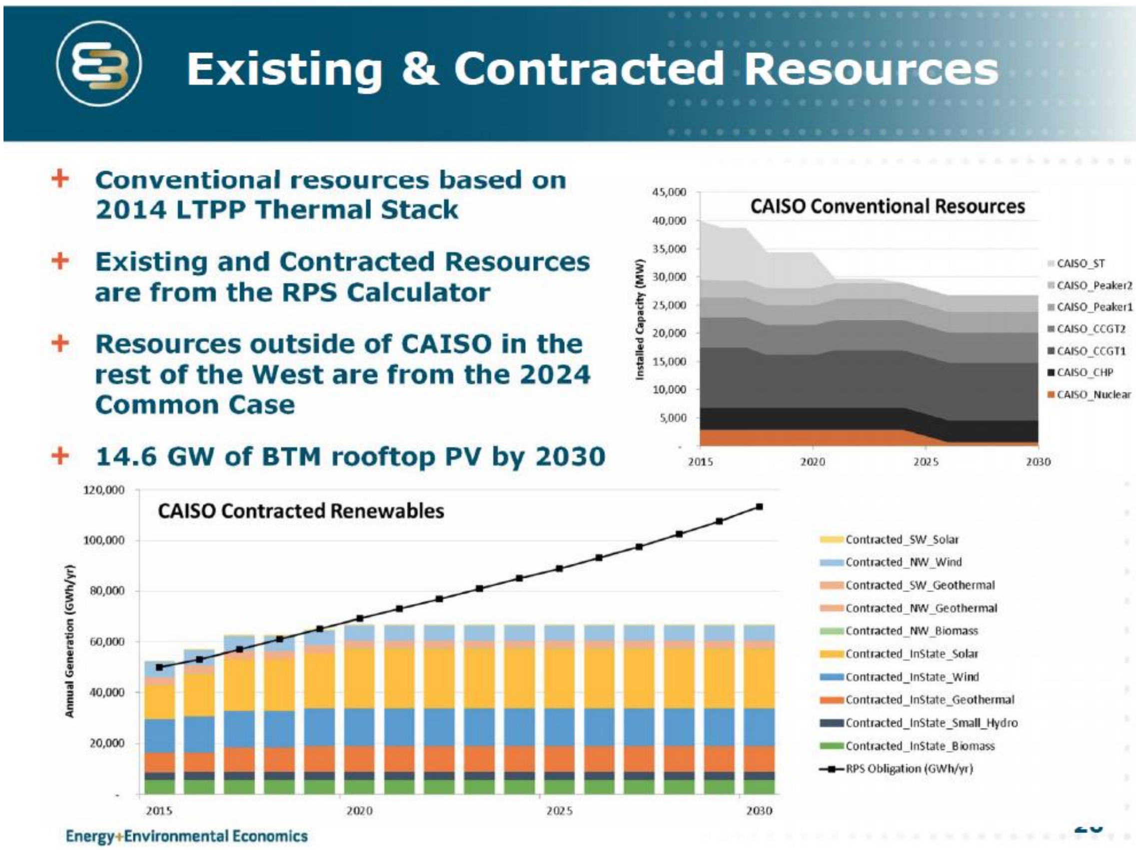
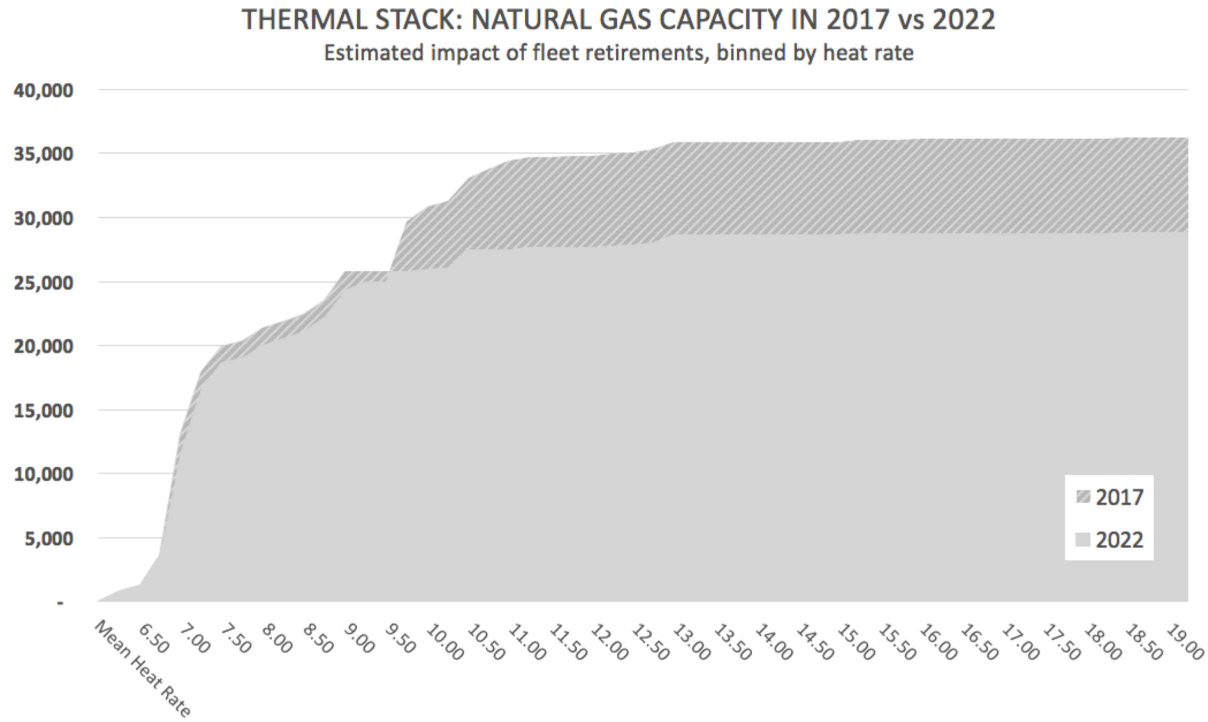
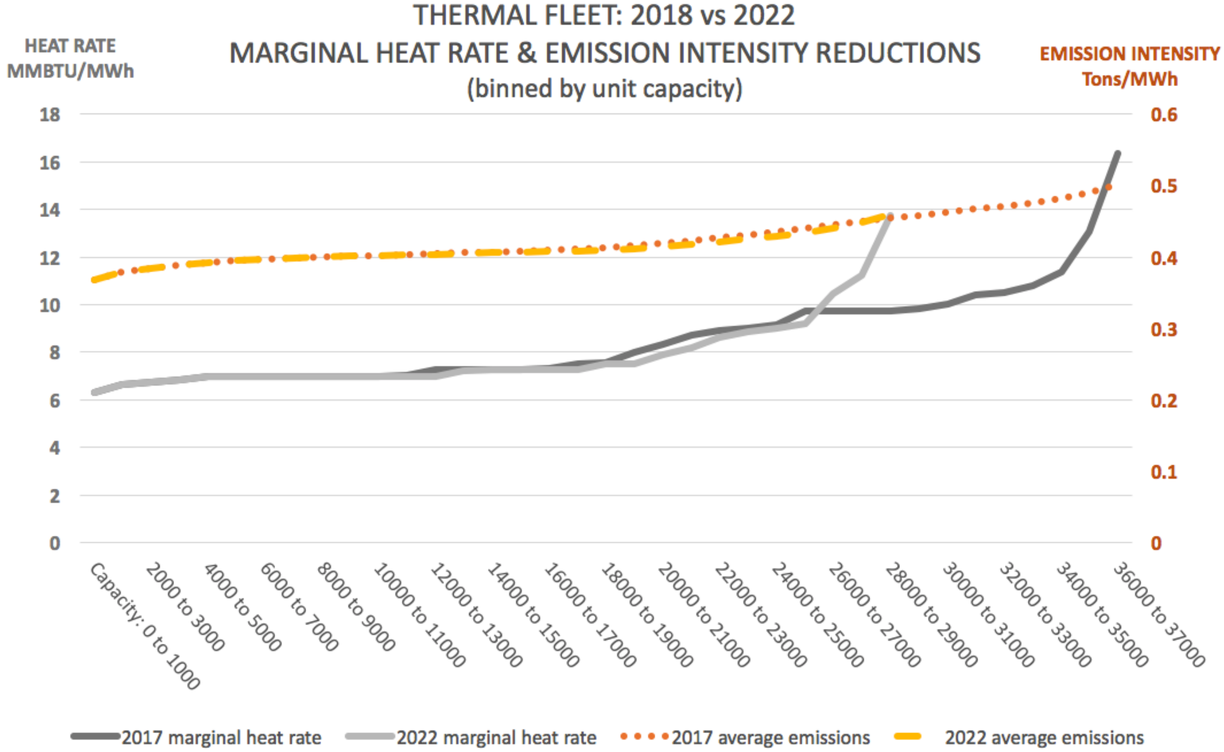


Figure from E3





- This model was updated in various ways to incorporate more recent or exact data and appropriate handling, notably:
    - The CPUC RPS Calculator does <u>not</u> track costs in the same manner as costs are actually functionalized and divided between different rate components in practice. Consequently, when using this model to forecast SCE's generation rates,

it is necessary to separate costs that SCE recoups on its generation rate from costs which are recouped from other components (such as the New System Generation Charge, which recovers the net costs of capacity contracts from all customers — including CCA customers). To this end:

- The model's extant, generic planned capacity additions were removed, and replaced to incorporate an analysis of SCE's actual contracts and authorizations for non-bypassable charge cost recovery.
- These contracts serve to offset SCE's Resource Adequacy requirements (and costs). Note that the same dataset was used to do this for the CCA.
  - CHP generation and capacity in the model were updated to account for the fact that a portion of these resources are actually included in New System Generation (as record in SCE's 2016 ERRA Review of Operations filings).

- Forward natural gas prices for 2018-2020 were updated with prices taken on the same date as the forwards used by SCE in its 2018 ERRA initial filing (which discloses the utility's initial rate forecast for 2018);
  - 2018-2020 natural gas monthly forwards were taken from Henry Hub and adjusted to account for Southern California basis (inter-hub differential based on price forwards) as well as estimated transport tariffs (intra-state) to burner-tip;
  - 2021 to 2022 assume changes in monthly prices as a percentage applied to the prior-year prices based on the IEPR forecast escalation in the RPS Calculator.
- Renewable generation and costs were taken from SCE's recently updated Renewable Plan (BPP).
  - Additionally, any deviation from the original model's inputs were accounted for financially by raising or lowering system power purchases as appropriate;
  - Updated renewable capacity was derived bottom-up, to reflect the CPUC's proposed ELCC methodology for wind and solar projects.
- Retails sales and net energy for load for 2018 was updated per data disclosed in SCE's 2018 ERRA filing.
- Nuclear generation and power costs (note — those not already included in the Base Generation Revenue Requirement) were updated based on the latest ERRA Review of Operations filings.
- SCE's Songs Settlement Revenue Requirement was added, and SCE's Base Generation Revenue Requirement was updated with data disclosed in the 2018 GRC filings. (The latter forecasts through 2020; 2021-2022 are forecasted on the basis of the 2018-2020 trend as in the PCIA calculation).

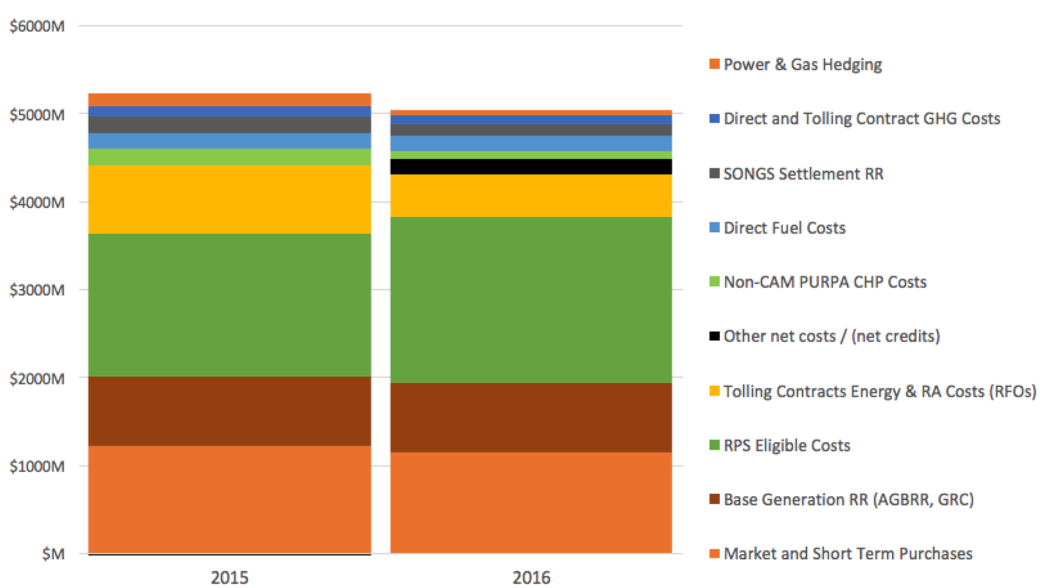
- **This produced forecasted 2018 generation rates within ~2% of those disclosed in SCE's 2018 ERRA, and after calibration, deemed sufficiently accurate to forecast future years.**

Excerpts of various compiled datasets that informed the analysis are below:

SCE ENERGY RESOURCE RECOVERY ACCOUNT (ERRA)

	ACTUAL ($000s)		FORECAST ($000s)	
Primary Regulatory Documentation:	Review of Operations & RPS Plan	Review of Operations & PAM Data Requests	November Forecast & RPS Plan	May Forecast & RPS Plan
	2015	2016	2017	2018
Subtotal Fuel Costs	$181,735	$165,933	$178,706	$90,569
UOG Nuclear	$41,700	$49,000	$38,684	$42,509
Mountainview (natural gas CCCT)	$120,400	$104,767	$132,837	$44,840
UOG Peakers	$4,377	$4,331		
Catalina (Diesel & Propane)	$5,705	$5,018	$5,779	$5,175
Subtotal Purchased Power Costs	$4,066,158	$3,941,470	$3,982,661	$3,888,907
Market and Short Term Purchases	$1,223,212	$1,153,414		
Renewable and PURPA Contracts (non-CAM costs)	*$1,814,620*	$1,976,716		
Non-CAM PURPA CHP Costs		$90,520		
RPS Eligible Costs	$1,630,773	$1,886,196	$2,109,969	$2,203,117
RPS Eligible PURPA		$324,207		
RPS Eligible Other Contracts		$1,561,989		
Tolling Contracts Energy & RA Costs (RFOs)	$772,680	$484,191		
Bilateral — Transmission	$21,619			
Bilateral — RA	$159,586			
Toll - energy	$32,839			
Toll - capacity	$301,036			
Conventional - RA and Toll		$346,977		
Conventional - RA Only		$73,823		
Direct and Tolling Contract GHG Costs	$109,883	$95,513		
Power & Gas Hedging	*$147,767*	*$54,737*		
Other net costs / (net credits)	-$2,005	$267,419		
TOTAL GENERATION COSTS	$4,247,893	$4,107,403	$4,161,367	$3,979,476
NEW SYSTEM GENERATION (net CAM capacity costs)	$457,147	$466,910	$659,168	$574,860

SCE Generation Rate Disaggregation
(Disclosed or derived from 2015 & 2016 actuals)

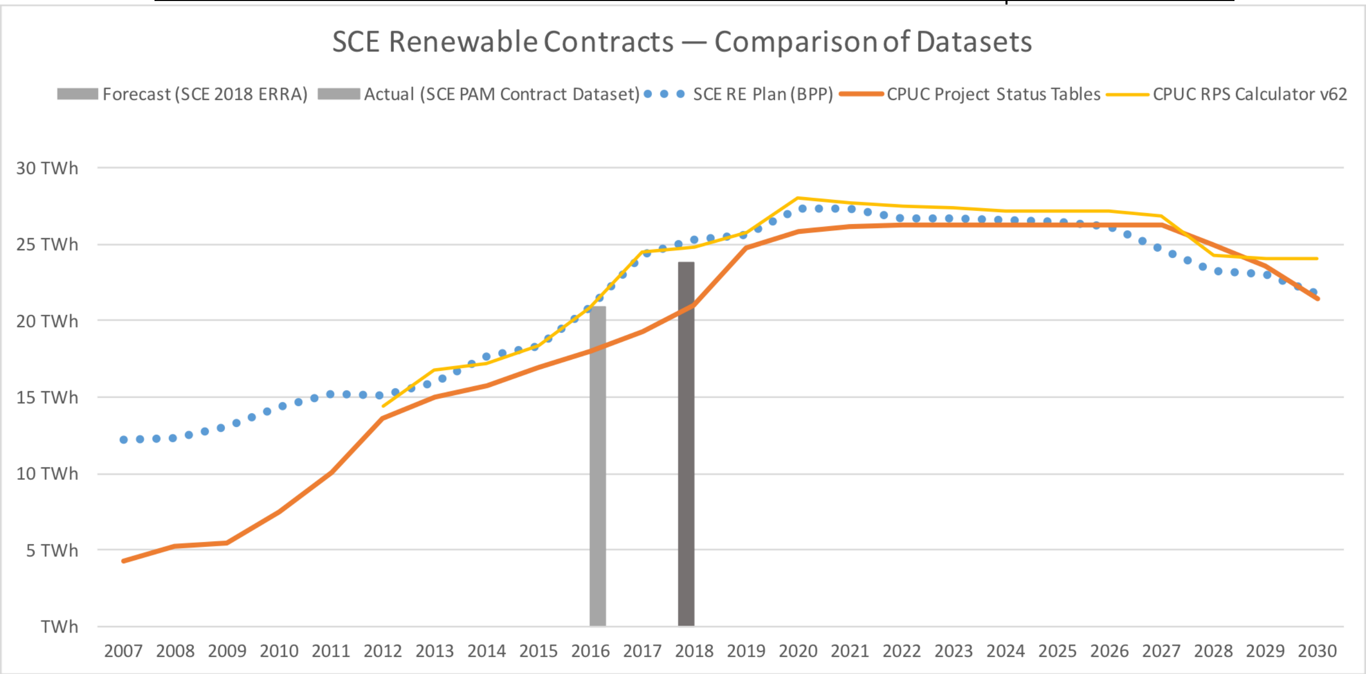


SCE 2018 General Rate Case (GRC Request) ($000s)	Generation ABGRR (Authorized Base Generation Revenue Requirement in SCE Gen & PCIA Rates)			Peakers Revenue Requirement (in New System Generation charge)		
	2018	2019	2020	2018	2019	2020
Procurement Operations	$32,441	$32,441	$32,441	0	0	0
Mountainview (natural gas CCCT)	$23,475	$23,475	$23,475			
Coal (APS Four Corners)	$7,842	$7,842	$7,842	$0	$0	$0
Nuclear (Palo Verde)	$76,747	$76,747	$76,747	$0	$0	$0
Hydro (35 powerhouses, 76 units)	$41,446	$41,446	$41,446	$0	$0	$0
UOG PV	$3,842	$3,842	$3,842	$0	$0	$0
UOG Fuel Cells	$379	$379	$379	$0	$0	$0
Catalina (PBGS diesel, fuel cells & battery)	$4,374	$4,374	$4,374	$0	$0	$0
Mohave Closure (SCE 56% share)	$326	$326	$326	$0	$0	$0
Other	$13,170	$13,170	$13,170	$7,451	$7,451	$7,451
Total UOG Production O&M	$204,042	$204,042	$204,042	$7,451	$7,451	$7,451
Transmission	$0	$0	$0	$0	$0	$0
Distribution	$0	$0	$0	$0	$0	$0
Customer Accounts	$0	$0	$0	$0	$0	$0
Uncollectibles	$1,441	$1,510	$1,585	$118	$117	$118
Customer Service & Information	$1,597	$1,597	$1,597	$0	$0	$0
Administrative & General	$95,370	$99,656	$99,874	$5,074	$5,440	$5,596
Franchise Requirements	$6,521	$6,835	$7,173	$535	$532	$534
Revenue Credits	-$1,830	-$1,903	-$2,026	$0	$0	$0
Total O&M	$307,140	$311,735	$312,245	$13,178	$13,540	$13,699
Escalation	$22,411	$31,649	$40,338	$484	$690	$892
Depreciation	$181,226	$188,005	$202,562	$14,490	$14,750	$15,394
Taxes Other Than On Income						
Property Taxes	$21,511	$21,523	$21,838	$3,569	$3,476	$3,396
Payroll Taxes & Misc	$9,053	$9,367	$9,686	$51	$53	$55
Taxes Based On Income	$13,270	$23,783	$33,268	$7,745	$7,429	$7,424
Total Taxes	$43,834	$54,674	$64,792	$11,366	$10,957	$10,875
Total Operating Expenses	$554,611	$586,063	$619,936	$39,518	$39,937	$40,860
Operating Revenues (at requested profit)	$713,122	$747,473	$784,462	$58,496	$58,153	$58,368
Net Operating Revenue	$158,511	$161,410	$164,526	$18,978	$18,216	$17,508
Rate Base	*$2,015,809*	*$2,052,670*	*$2,092,311*	*$241,344*	*$231,651*	*$222,651*
Rate Of Return	*7.86%*	*7.86%*	*7.86%*	*7.86%*	*7.86%*	*7.86%*

	2018	2019	2020	
	Capital Expenditures in 2018 GRC ($000s, AGBRR & NSG i.e. SCE Peakers)			Primary Drivers
Procurement Overhead	$1,880	$1,980	$1,900	Communications (resiliency)
Mountainview CCGS	$320	$1,391	$13,702	Controls, turbine & building upgrades
Peakers (5 units)	$2,800	$2,700	$100	Building O&M and turbine overhaul
Hydro (35 powerhouses, 76 units)	$55,763	$42,030	$28,685	Gen rewinds, pipe/dam/ waterway,, relicensing & equip
Nuclear (Palo Verde)	$39,500	$37,900	$37,900	
Catalina (PBGS diesel, fuel cells & battery)	$2,450	$2,700	$2,700	Gen stator rewinds (units 1-3)
UOG PV	$200	$200	$200	
UOG Fuel Cells	$0	$0	$0	
Mohave Closure (SCE 56% share)	$0	$0	$0	
Total	$102,913	$88,901	$85,187	

SOUTH BAY CLEAN POWER

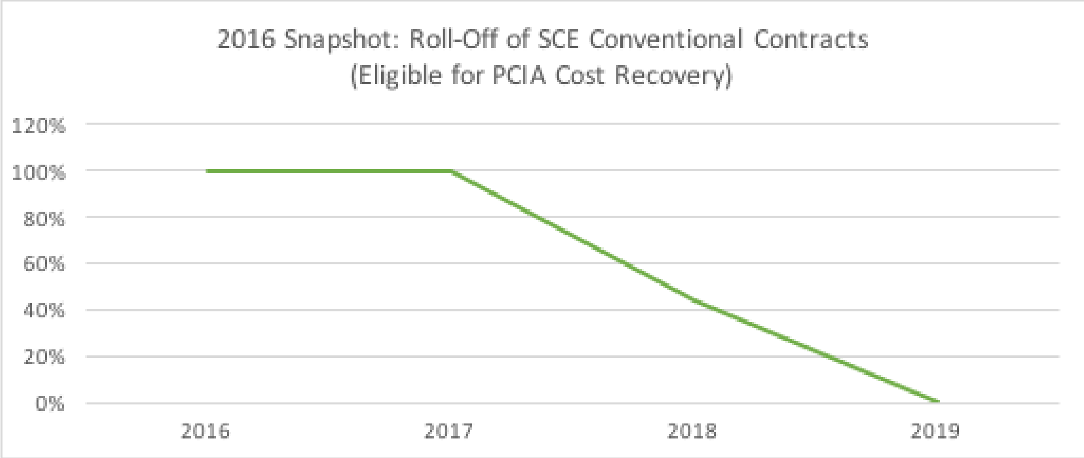
PCIA and PAM Eligible Contract & UOG Cost Comparison for 2016		
	$s	MWH
Total PCIA Eligible (vintage 2016 in year 2016)	**$2,898,955,944**	**33,287,971**
Total PAM Eligible (including Mountainview)	**$3,169,982,735**	**38,188,326**
PCIA Eligible Purchased Fuel & Power (ERRA fuel, GHG and power costs)		
CHP (PURPA, non-CAM)	$90,519,561	1,198,883
PPA Conventional	$420,800,019	2,355,464
Conventional - RA and Toll (RFO & Bilateral)	$336,064,356	1,900,667
Conventional - RA and Toll (PURPA)	$10,912,579	47,159
Conventional - RA Only	$73,823,083	407,638
PPA RPS Eligible	$1,886,196,195	20,782,436
RPS Eligible Other Contracts	$1,561,989,272	15,960,637
RPS-Eligible PURPA Contracts	$324,206,922	4,821,798
GHG Offset	$10,654,414	359,934
Interutility	-$3,555,797	-369,434
Subtotal Non-UOG	**$2,397,515,775**	**24,336,783**
Utility Owned Generation — Fully Loaded Costs (GRC capital & O&M + ERRA fuel and GHG costs)		
UOG RPS Eligible	$55,400,362	115,479
Solar PV & Fuel Cells	$55,400,362	115,479
UOG Conventional	$717,066,598	13,736,064
Mountainview (natural gas CCCT)	$271,026,790	4,900,355
Nuclear (Palo Verde)	$174,148,399	5,094,412
Catalina (PBGS diesel, fuel cells & battery)	$20,519,660	29,475
Hydro	$251,371,749	3,711,822



Cost Responsibility Surcharge Forecasts (PCIA and CTC charges)

- Customers that are served by CCAs and ESPs are charged, on a non-bypassable basis, for the net costs of certain contracts that the utility has entered into on behalf of all bundled service customers (these are distinct from CAM).
    - Contracts prior to 2002 are recovered via the Competition Transition Charge (CTC), and total $310,483,000 in 2018 (for all utility customers).
    - Subsequent contracts are recovered via the Power Charge Indifferent Adjustment (PCIA) mechanism, and total $3,150,828,000 in 2018. Primarily, these costs are driven by long-term renewable contracts, but also include non-trivial utility owned generation and shorter-term conventional contract components.
- 2018 SCE PCIA and CTC charges were estimated using a calculator model disclosed by SCE during the recent PCIA Workshops of 2016/17 and updated with data from with various inputs. Note that this model mimics what is disclosed in SCE's ERRA filings.
    - 2018 forecasts were updated to use the same forward power prices that drive the CCA and SCE generation cost forecasts (as were 2019-2022); note that:
        - The base generation revenue requirement was kept as-disclosed in the May filing, even though this will be increased after SCE's request in the GRC is approved by the CPUC; SCE advised us that they expected this to happen after the 2018 ERRA rates were approved, and so this is a regulatory construct that nominally suppresses the 2018 PCIA rates in practice.
        - The SCE forecast for 2018 cannot simply be taken from the filing and applied to a CCA forecast; in the May filing, SCE uses price forwards from a later date to drive the PCIA forecast as compared to their rate forecast — thus, the calculations have to be performed, and inputs harmonized across the analyses (SCE's PCIA rates are based on 20 April 2017 forwards, while the rates based on 23 February 2017 forwards).
        - SCE's bottom-line average PCIA is incorrectly calculated in the filing — we have notified SCE of this and received confirmation it will be corrected — though this would not affect analyses that more appropriately use rate group average PCIA rates applied to the CCA's actual mix of customers (instead of the bottom-line weighted average, which should not actually be used and is purely informational.)
- Future year forecasts additionally incorporated:
    - SCE's base generation revenue requirement (2018 GRC provides 2018-2020 requests, and trends were applied to forecast 2021-2022);
    - SCE's SONG Settlement Revenue Requirement (2018-2022 disclosed in filings);
    - RPS energy and costs based on SCE's Renewable Plan forecast (2016 BPP, updated 2017); capacity was estimated as derived bottom-up based on renewable contract type, and thereby incorporated the ELCC valuation impact for future years. (Also refer to the chart below previous section showing the discrepancies between various publicly-available datasets.)

- Conventional contracts (Bilateral/ RFO/ IU) rolling off — these contracts are typically less than 5 years in duration and are held confidential; however, SCE disclosed a dataset of PAM-eligible contracts under the PAM Application. To estimate the capacity, energy and cost impacts of 2018 eligible conventional resources, the PAM dataset was analyzed, and the multi-year trend derived was assumed to be comparable for 2018. There was some amount of expert judgement involved with constructing the analysis, as certain contracts allow ranges of capacity (this was discussed with SCE). The only data field not confidential in the PCIA section of the ERRA filing for the 2018 conventional contracts is capacity; it was assumed the cost, energy and capacity relationship derived for 2016 was applicable for 2018. This allowed the trend to be applied and incorporated into future year forecasts:



- Data from the most recent 2018 ERRA and GRC filings, and additional updates and forecasts relying on data from SCE's 2016 Renewable Plan (in the BPP, 2017 update) and the PAM application, were used to update the model and forecast PCIA charges. The same forward power prices that drive the estimates of the CCA's generation costs were used in this model.

- Regarding market price benchmarks:
    - On and off-peak power prices were updated with those used as inputs to the SCE and CCA rate forecasts. SCE's on- and off-peak load weighting applied to these future prices was kept the same (in practice, this fluctuates year to year somewhat).
    - Benchmark prices for the "green" and capacity adders are more difficult to forecast. The capacity adder is based on CEC estimates of the costs of a combustion turbine, and were kept as-is. The "green" benchmark is a weighted average of DOE dataset and SCE renewable prices observed in new and re-confirmed contracts, less forward market power prices (updated as previously mentioned). The DOE adder does not change significantly and was kept as-is. The SCE adder has dropped in recent years, and was trended downwards based on expert judgement.

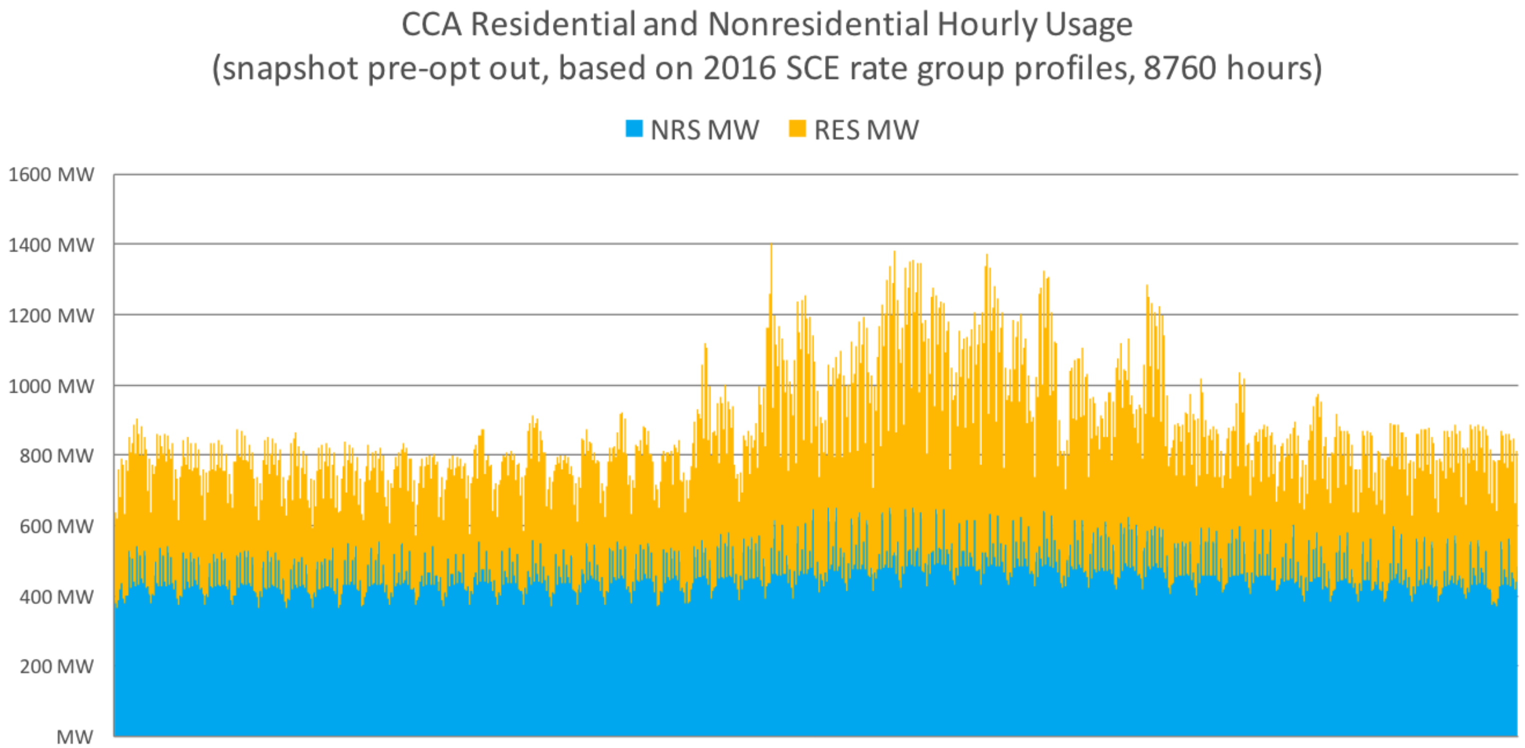
- Note that low-income (CARE) customers are not currently charged the PCIA, but that SCE has recently filed a petition to apply the PCIA to these customers.[6] We are currently assessing what impact this will have on the PCIA calculation.

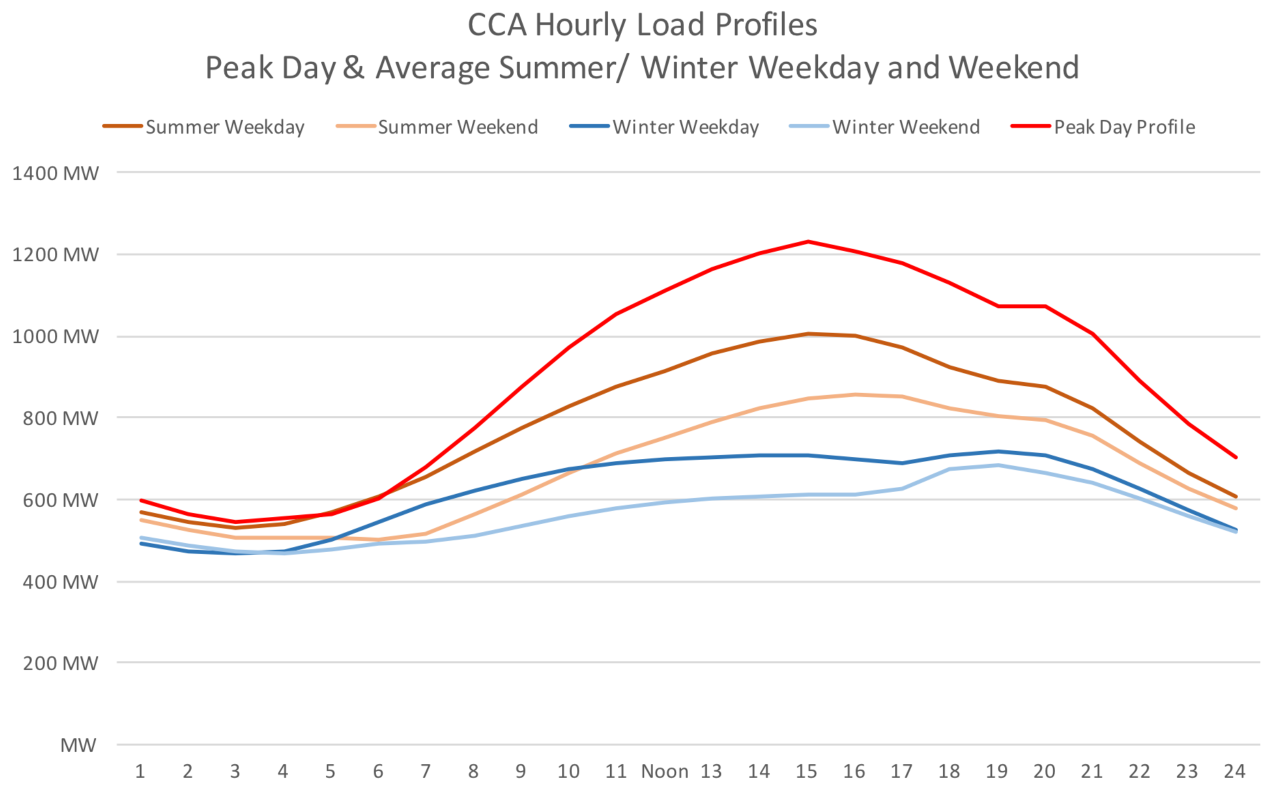
CCA Rate Forecast

- Customer enrollment is staggered in three phase-in periods between June 2018 and June 2019.
    - Opt out curves are estimate customer attrition and stabilization over four months post enrollment (based on observed CCA industry experience).
    - Both in the model and in practice, portion of customers opt-out prior to enrollment; the CCA is still liable for various costs associated with notifying and processing these opt-outs, but does not actually enroll or serve power to these customers.
- We do not possess SBCP customer load data, available under SCE's CCA INFO Tariff (with permission from cities). The model may be updated when this data becomes available during implementation. Current city-level annual usage, net of Direct Access, was disaggregated into customer usage and count by Rate Group based upon Rate Class usage data disclosed in LACCE Business Plan (the dataset based on all CCA-eligible customers within LA County).
    - The LACCE Business Plan only discloses this data by Customer Class, and was subsequently disaggregated into Rate Group as necessary (for the large industrial class) by assuming SCE's allocations within this class were indicative for the CCA as well.
    - The above steps provided the load and customer count data at the level of granularity disclosed in the model run results;
        - Note that agricultural or standby customers were not subsequently included in these model runs (the former because there is not significant load in these classes expected for SBCP cities, and the latter because their usage patterns are particularly unique and so it is very important to use actual data). Thus, the CCA has a somewhat lower load than would be expected at full enrollment.
    - Load growth is based on CEC "California Demand Update 2017-2027 Baseline Forecast" for the "Los Angeles Metro" region.
- CCA loss-adjusted hourly load profiles (and therefore net load requirements) are constructed bottom-up, based upon the aforementioned Rate Groups' hourly profiles and applicable average distribution loss factors (i.e. distribution, primary or secondary — as appropriate for the Rate Group), which are published by SCE online.
    - Note that 2016 temperatures were above-average (though not severely); this likely serves to increase the volatility and peak usage of the CCA —and thus power costs — relatively to SCE's forecast assumptions.
        - It is a therefore source of model error, though one that is conservative.

[6] Available online: [http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M186/K590/186590521.PDF]

- During the SBCP implementation process, a portfolio manager will be relied upon to employ more sophisticated energy and cost forecasts (using a methodology and software platform comparable to that used by SCE); the below are therefore indicative:





SOUTH BAY CLEAN POWER

- CEC monthly coincidence adjustments factors were applied to the aforementioned loss-adjusted load profiles to estimate CCA monthly coincident peak load forecasts.
  - In practice, the CEC will apply generic factors to a CCA until it has been operating for a sufficient period of time to justify constructing customized coincidence adjustment factors based on the actual customer base and load patterns.
    - Additionally, it may be an option to for the CCA to prepare the analysis ahead of time in consultation with the CEC (given how many more CCAs are launching, we expect this will become common practice);
    - This is a unique regulatory artefact that impacts real-world cost allocations between CCA and utility customers that is not widely discussed.
  - The resulting monthly peak loads for compliance purposes take into consideration <u>estimated</u> DR, DER and capacity allocations and residual obligations (as based on CEC Year Ahead template, RPS Calculator and SCE regulatory filings), as well as reserve margin requirements.
    - These are contracts SCE has entered into, the costs of which are recouped directly from all customers, and the CCA receives a credit for this that offsets (i.e. lowers) capacity procurement obligation.
    - CCA capacity (RA) residual requirements (post-allocations, as described above) have costs based upon 2016-2020 SCE and local (i.e. LA Basin and Big Creek—Ventura) prices reported by CEC.
- CCA base power costs distinguish between the SCE_GEN and SCE_DLAP virtual nodes and account for the congestion and basis differentials (wholesale electricity day-ahead market prices for nodes are based on patterns observed in 2016, adjusted to forward market indicators) as well as various CAISO charges (e.g. GMC, AS, RUC, RMR, CPM, BCR charges & RT imbalances).
  - Monthly on and off peak 2018 forward prices, taken on the same day as SCE used to inform its initial 2018 rate forecasts, were applied to 2016 market price patterns observed at the SCE_GEN virtual node (such that the pattern remained the same as 2016 but average prices for the on and off peak periods within each month reflect 2018 future prices). Note that this is identical to the first step performed by SCE to forecast its power rates, as disclosed in the utility's ERRA filings.
    - On-peak hours in WECC are from Monday-Saturday, HE 7:00-HE 22:00, except holidays (and if Christmas, New Year's, or Independence Day fall on a Sunday, then Monday is treated as a holiday). Off-peak hours are all other hours.
    - Note that 2016 was a leap year with 8784 hours (instead of 8760 hours). This was removed from hourly market price and rate group load profiles, which requires care to maintain key relationships (such as the day of the week).
    - Daylight savings times adjustments, similarly, have to be treated with care between hourly datasets from different sources.
  - This treatment maintains the causal relationship between the CCA's generation costs and retail revenues, as both are based on 2016 load and price patterns.

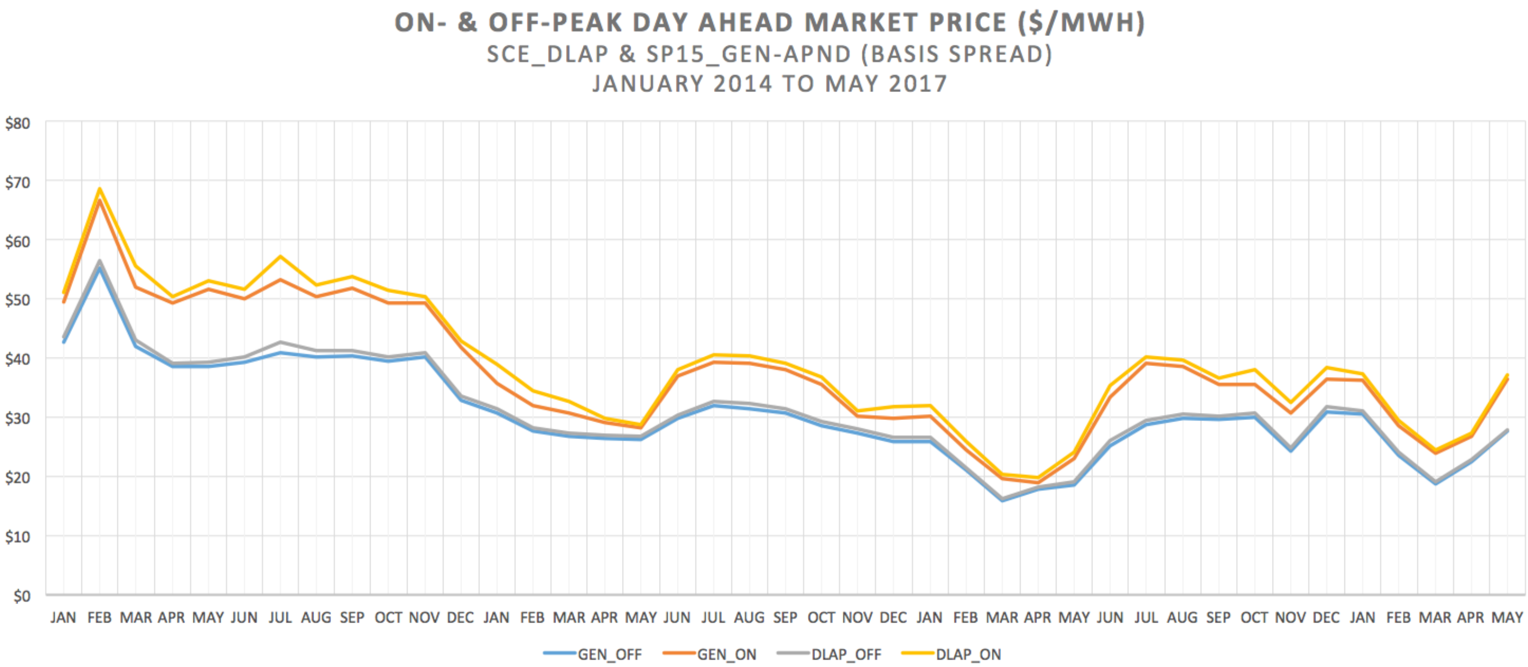
- The SCE portfolio and rate analysis for 2018 was predicated upon natural gas forwards taken on the same day as the power forwards that drive the CCA's 2018 cost of service forecast, providing an 'apples to apples' basis for comparison.
- For 2019-2020, the relationship between revenue and power price patterns for the CCA are maintained, and costs are escalated at the rate outputted from the CPUC RPS Calculator — which captures fleet changes and drives the SCE rate analysis.
- These prices, and other applicable factors, flow into the PCIA calculator as well.

○ Renewable power costs were estimated quantitatively, and then confirmed via market intelligence:

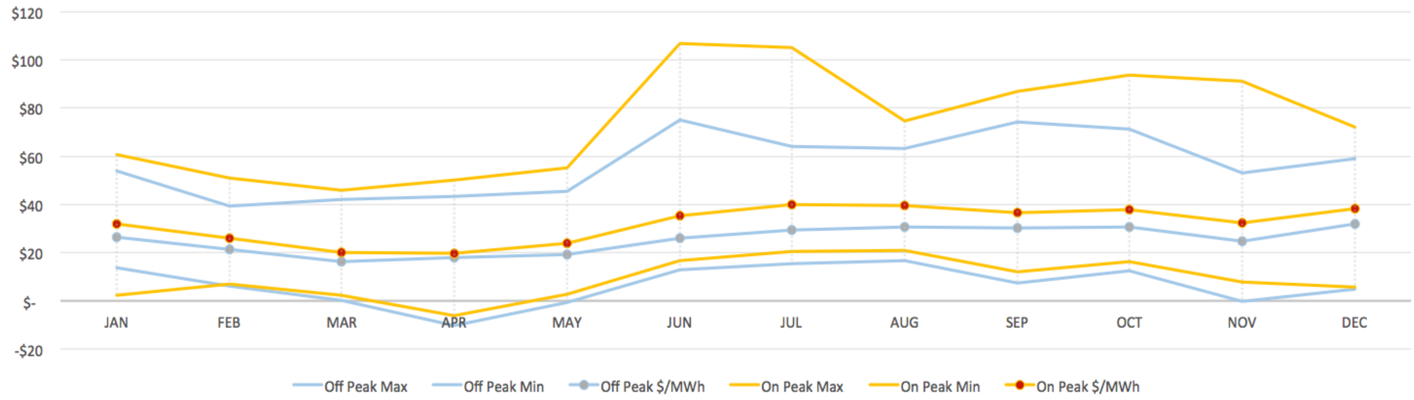
- Hourly solar profiles were matched against market prices, and the difference between 1) the assumed contract price (of $42/MWh) and 2) the market revenues received in each hour from the sale of power was considered to be indicative of a renewable cost adder to apply to base power prices.
  - Note that this is another source of model error if daylight savings time is not appropriately handled across datasets used for the calculations.
- This was confirmed as being reasonable, if on the higher end of the spectrum of observed renewable cost adders in the current market, through discussions with portfolio manager staff actively procuring power for operational CCAs.

○ Carbon-free hydropower adders were similarly estimated and confirmed based on operational market intelligence.

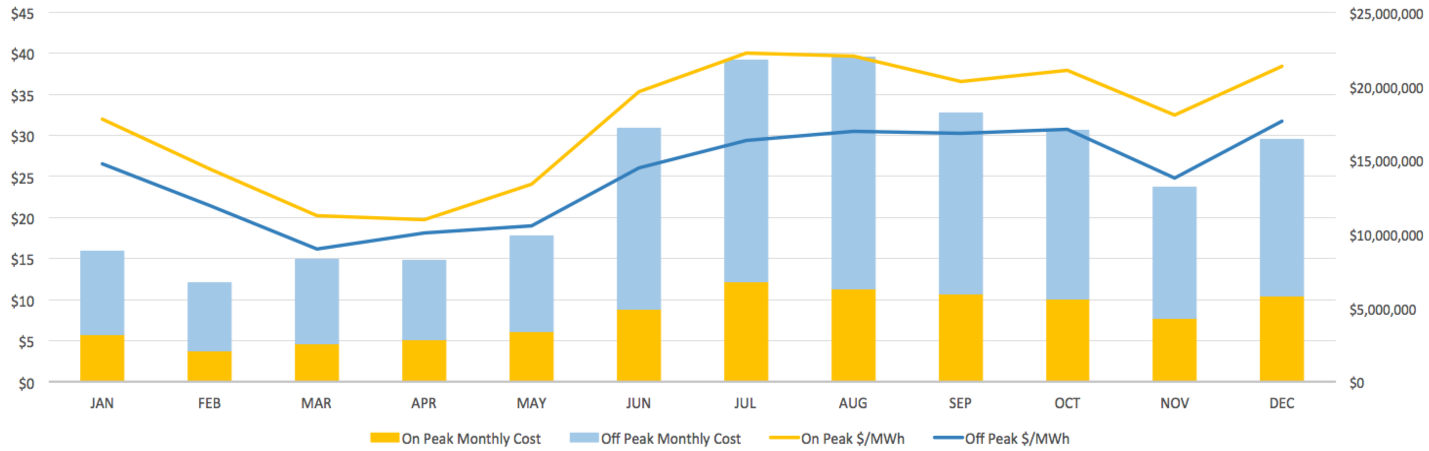
○ The graphs below are provided for the sake of illustrating price patterns (as the last three are based on 2016 prices i.e. not the adjusted prices used for this report) and include the CCA's modeled customer base at full enrollment without accounting for opt-outs:



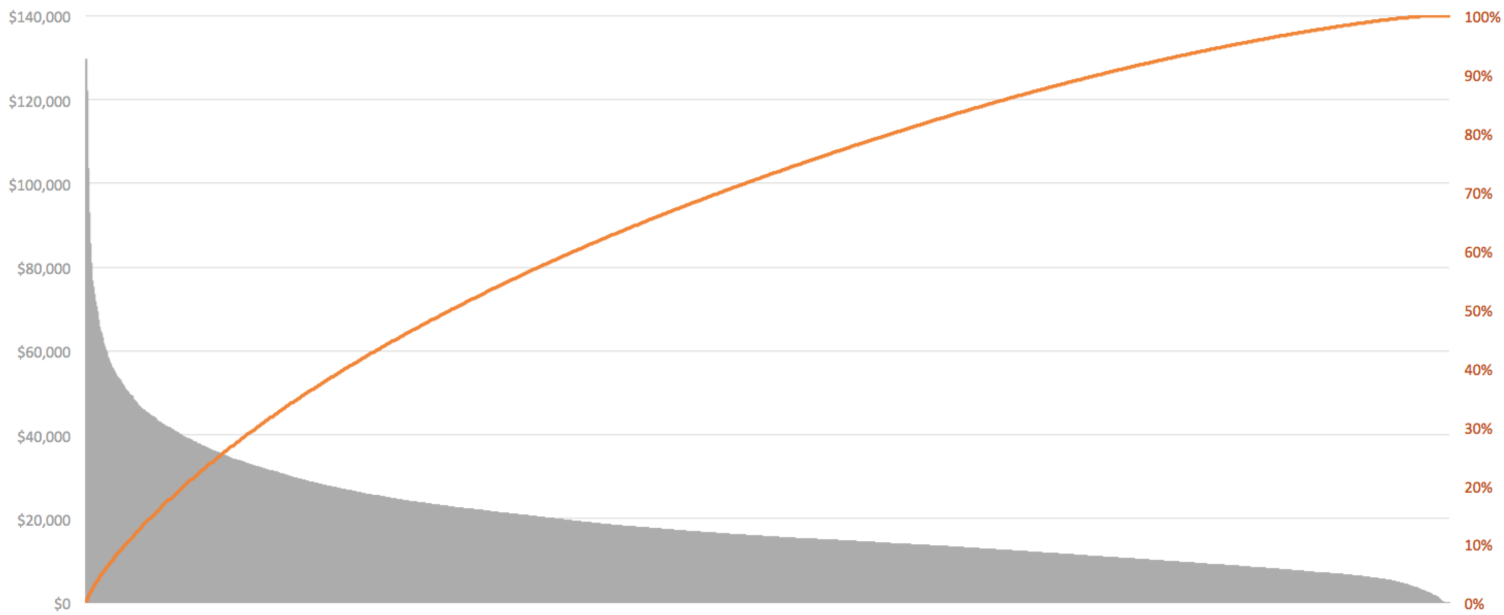
SP15 WEIGHTED DAY AHEAD MARKET MAX, MIN & AVERAGE PRICE ($/MWH)



SP15 ON- & OFF-PEAK MONTHLY COST AND AVERAGE PRICE ($/MWH)



SP15 WEIGHTED HOURLY COST & PERCENT OF ANNUAL COST



SOUTH BAY CLEAN POWER

- CCA overhead, staffing and contractor costs based upon operational CCA experience, recent bid data and market intelligence, and the services and staffing are downscaled but comparable to that disclosed in the SBCP Business Plan (which detailed the Regional JPA of CCAs operational model).
- CCA accounting structure (secured revenue, operations and reserve accounts), the temporal pattern of the cash conversion cycle (i.e. the delay between when power is provided to customers and when revenues are received by the CCA, per the IOU billing cycle, and when certain costs come due) and collateral and financing requirements are based upon operational CCA experience, extant regulations and contracting strategies.
- Net Energy Metering payments were assumed to be an additional 1 cent per kilowatt hour above what SCE currently credits on the generation component of the NEM tariff, with current installations in SBCP member cities estimated based on the CEC's dataset of interconnected PV systems, forecasted forward using SCE's forecast assumptions:

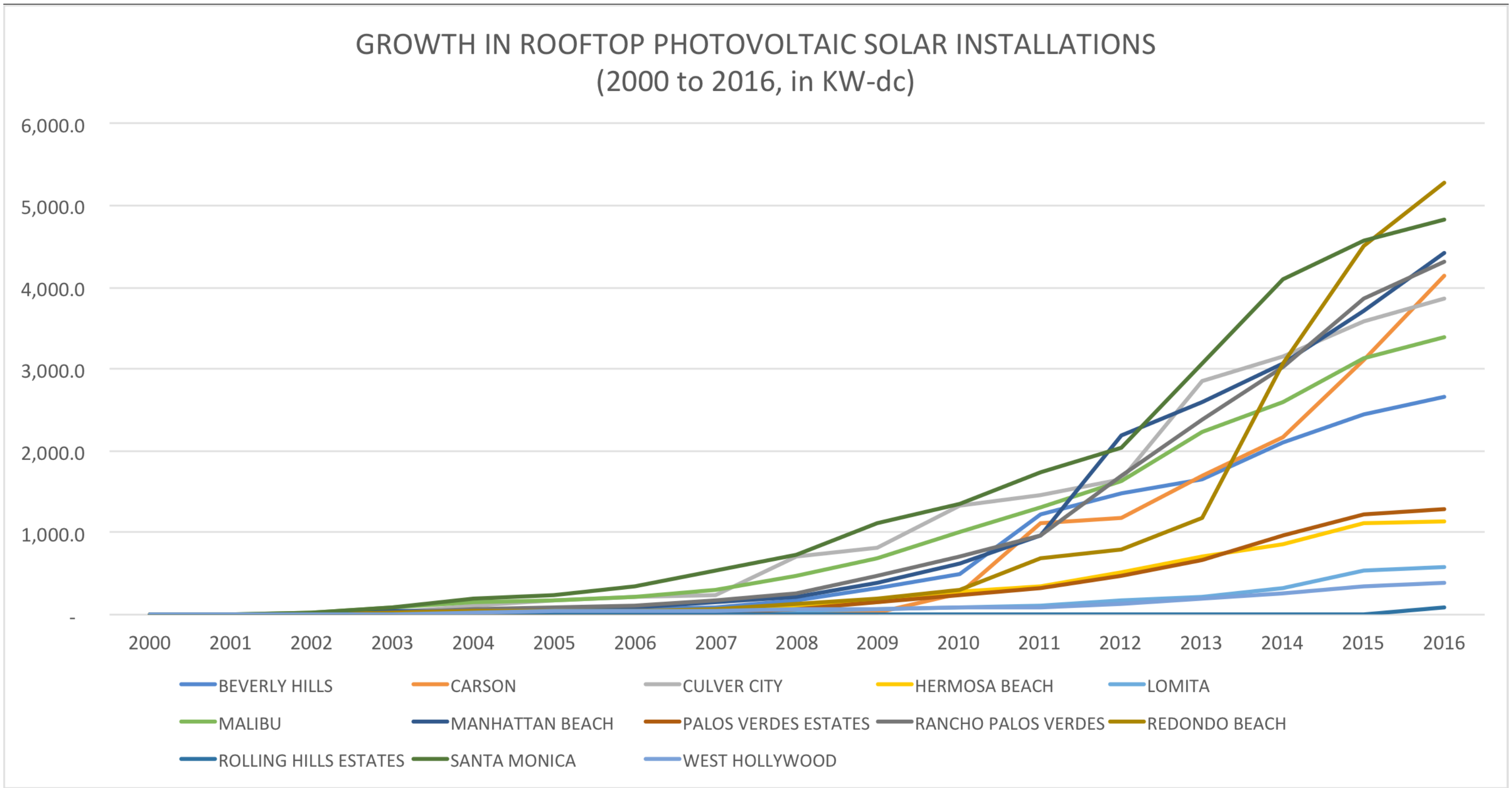


Figure V-8
Residential Solar PV Annual Incremental Installations and Cumulative Installed Capacity; History and Forecast

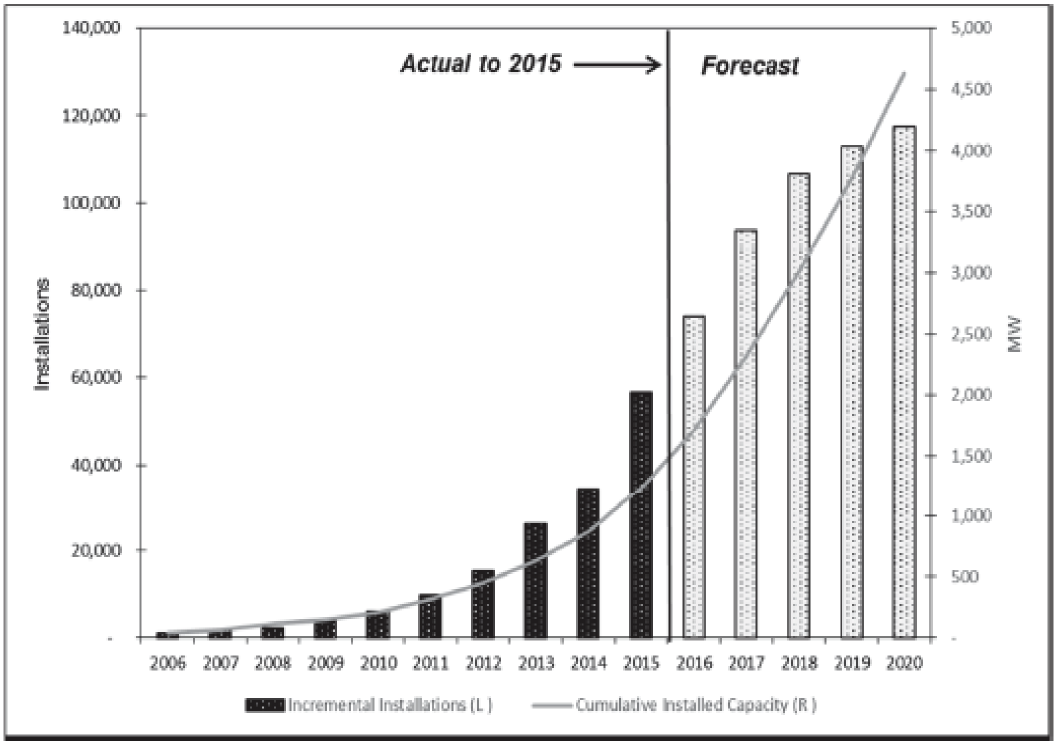


Image from SCE

- Effective rates were estimated based on models of SCE rate structures created by rate group. (SCE's rates are used to set the baseline for the CCA revenue analysis, with program revenues net of PCIA costs, uncollectible expenses and any additional rate discount inputted). Revenue fluctuates month over month depending on the interplay between usage patterns that change month over month and generation rates that change between summer and winter seasons, and is therefore a critical component of the analysis.
    - SCE effective monthly rates by Rate Group were estimated based upon retail rate calculators created for each Rate Group.
        - Note that this is a preliminary analysis; the SBCP Business Plan and our recommended implementation process relies on a data manager to conduct more granular, targeted rate and revenue forecasting exercises to support the launch of the CCA — based on customer specific data and employing operational software platforms to lessen model error risk.
    - SCE's 2016 Static and Dynamic load profiles (as applicable by Rate Group) were applied through these models, and the results compared against SCE ERRA data to confirm revenue calculations and monthly/seasonal patterns.

- Effective monthly rates were increased based on the forecast of SCE's average 2018 rates by Rate Group (as disclosed in SCE's May 2017 ERRA filing and updated as described herein); and inflated for future years on the basis of the SCE rate forecasts.
- Note that demand charge patterns and rate differentials induce a particularly pronounced effect for nonresidential customers in SCE's territory (disregard the usage and revenue figures, as they are indicative; the purpose of the analysis was to establish the <u>pattern</u> of customer bill charges):

Refer to the appendix "***<u>Select SCE Rate Group Calculators</u>***" for screenshots of the calculations.

The chart and heatmaps below show the different patterns between the largest rate classes for various key metrics that drive revenue and costs:

		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Monthly Usage as % of Annual	DOM	8%	6%	7%	7%	7%	10%	12%	12%	9%	8%	7%	8%
	GS-1	7%	7%	7%	7%	7%	8%	10%	10%	9%	9%	8%	9%
	GS-2	7%	7%	8%	8%	8%	9%	10%	10%	9%	9%	8%	8%
	TOU-GS-3	8%	7%	8%	8%	9%	9%	9%	10%	9%	9%	8%	8%
	TOU-8-SEC	8%	7%	8%	8%	9%	9%	9%	9%	9%	9%	8%	8%
	TOU-8-PRI	8%	7%	8%	8%	9%	8%	9%	9%	9%	9%	8%	8%
	TOU-8-SUB	8%	7%	8%	8%	9%	8%	9%	9%	8%	9%	8%	8%
Monthly Bill Revenues as % of Annual (est., SCE rates)	DOM	8%	7%	7%	7%	7%	10%	12%	12%	9%	8%	7%	8%
	GS-1	6%	6%	6%	6%	6%	10%	13%	13%	12%	7%	7%	7%
	GS-2	4%	4%	4%	4%	4%	15%	16%	18%	16%	5%	5%	4%
	TOU-GS-3	5%	5%	6%	5%	6%	13%	13%	15%	15%	6%	5%	5%
	TOU-8-SEC	6%	5%	6%	6%	6%	13%	13%	14%	14%	6%	6%	5%
	TOU-8-PRI	6%	5%	6%	6%	6%	13%	13%	14%	13%	6%	6%	6%
	TOU-8-SUB	6%	6%	6%	6%	7%	12%	12%	13%	12%	7%	6%	6%
Capacity Factor	DOM	62%	58%	62%	58%	60%	40%	50%	49%	46%	49%	60%	65%
	GS-1	67%	64%	66%	59%	63%	52%	57%	59%	56%	59%	58%	74%
	GS-2	69%	60%	63%	58%	61%	57%	61%	61%	57%	58%	56%	68%
	TOU-GS-3	70%	70%	71%	69%	66%	70%	70%	68%	66%	67%	68%	73%
	TOU-8-SEC	75%	76%	78%	76%	74%	78%	76%	77%	76%	75%	74%	77%
	TOU-8-PRI	86%	85%	87%	86%	83%	87%	85%	86%	85%	85%	83%	87%
	TOU-8-SUB	93%	93%	93%	92%	92%	94%	93%	94%	94%	94%	90%	94%
Usage On-Peak (WECC)	DOM	57%	62%	63%	63%	59%	66%	63%	67%	63%	62%	60%	59%
	GS-1	61%	65%	65%	65%	62%	68%	65%	69%	66%	64%	64%	63%
	GS-2	63%	68%	68%	68%	65%	69%	65%	70%	67%	67%	66%	65%
	TOU-GS-3	64%	67%	67%	67%	64%	67%	63%	68%	66%	66%	65%	65%
	TOU-8-SEC	62%	65%	65%	65%	62%	65%	61%	65%	63%	64%	63%	63%
	TOU-8-PRI	58%	61%	62%	61%	58%	61%	57%	62%	60%	60%	60%	60%
	TOU-8-SUB	55%	58%	59%	59%	55%	59%	55%	59%	57%	57%	57%	57%
Monthly Peak as % of Annual Rate-Group Coincident Peak	DOM	50%	48%	42%	46%	45%	100%	96%	93%	81%	60%	47%	49%
	GS-1	61%	65%	61%	70%	65%	91%	100%	98%	96%	84%	82%	64%
	GS-2	62%	75%	71%	79%	75%	93%	98%	99%	100%	90%	88%	67%
	TOU-GS-3	76%	78%	78%	81%	90%	86%	88%	97%	100%	89%	81%	72%
	TOU-8-SEC	84%	85%	86%	88%	94%	93%	95%	99%	100%	94%	89%	81%
	TOU-8-PRI	86%	86%	87%	88%	94%	92%	95%	98%	100%	93%	89%	81%
	TOU-8-SUB	93%	93%	96%	99%	99%	98%	100%	100%	99%	99%	99%	89%

Cash-Flow Analysis

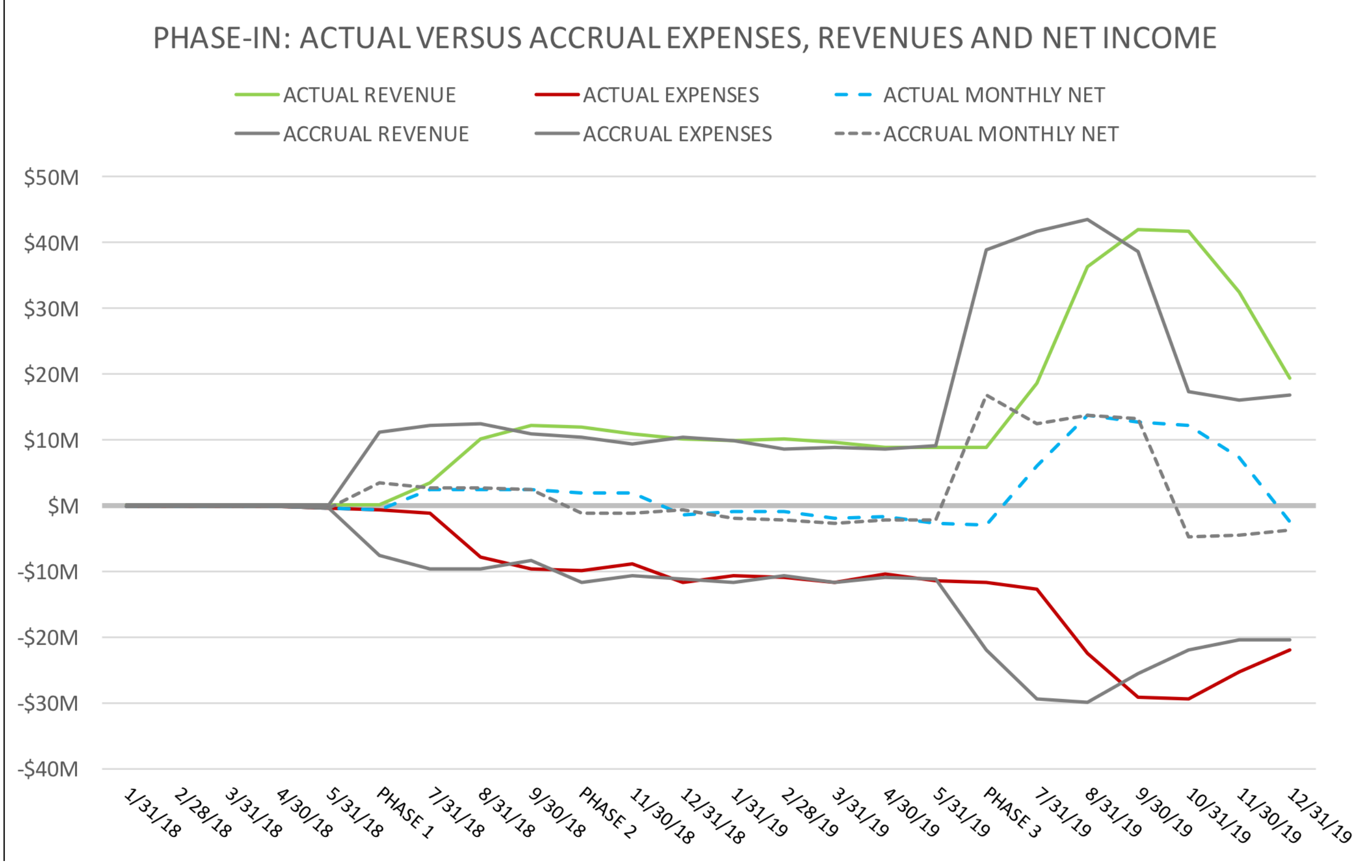
Since revenues and costs vary in terms of when the CCA receives or must pay out funds, the cash-flow analysis reveals the anticipated 'real world' financing requirements of the CCA to manage its initial cash-conversion cycle and ongoing seasonal liquidity crunch (induced by the summer/winter retail rate differential and PCIA, amongst other factors).

To approximate the anticipated schedule of real-world cash-flow for the CCA, the analysis accounts for the difference in timing between:

1. When costs, collateral requirements and revenues are budgeted for on an accrual basis (i.e. $x of power costs in the first month matched based on the load requirements in that same month); versus
2. When the CCA must honor various payment or deposit obligations, and when customer bill receipts are deposited into the CCA's accounts by SCE in the real-world (referred to as the "cash-conversion cycle") on an actual basis i.e. cash-flow.

As can be seen in the chart below, a cash-flow analysis reveals:

- A dynamic that smooths and stretches out both revenues and costs:
  - For revenues, this is the cash-conversion cycle of bill receipts, which flow in every few days (reflecting that customers are on a series of different billing cycles that fall throughout the month).
  - Power costs have been structured to align with this revenue cash-flow cycle, reflecting best practice in the industry and thus minimizing financing requirements.



- This analysis requires an operational perspective of the anticipated, real-world accounting and business processes, credit requirement regulation and calculations, portfolio strategy, counterparties and contractual mechanisms for the CCA in its early phase of operations.

Power costs and collateral requirements are by far the largest use of funds. The timing of real-world expenses varies between contracts for energy or capacity, and for any residual market purchases or sales (resulting from either imbalances between forecasted and actual load or net open — i.e. unhedged — positions for the CCA).

An excerpt of the cash-flow analyses provided is excerpted below:

	2018 JAN	2018 FEB	2018 MAR	2018 APR	2018 MAY	2018 PHASE 1	2018 JUL	2018 AUG
CCA ACCOUNTS								
SECURED REVENUE ACCOUNT								
BOM Revenue Account Balance	$0	$0	$0	$0	$4,308,951	$4,594,169	$5,146,300	$6,363,421
Revenues, pre-disbursement	$0	$0	$0	$0	$0	$0	$2,850,048	$8,141,813
Energy Expenditures	$0	$0	$0	$0	$0	-$371,942	-$536,400	-$7,046,327
Sweep from/(to) Operating Account	$0	$0	$0	$4,308,951	$285,218	$924,072	-$1,780,538	-$1,668,273
Revenues, post-disbursement	$0	$0	$0	$0	$0	$0	$684,011	$1,954,035
EOM Revenue Account Balance	$0	$0	$0	$4,308,951	$4,594,169	$5,146,300	$6,363,421	$7,744,669
OPERATING ACCOUNT								
BOM Operating Account Balance	$0	$1,219,004	$1,219,004	$1,219,004	$1,219,004	$1,219,004	$1,219,004	$1,219,004
Disbursement from/(to) Revenue Account	$0	$0	$0	-$4,308,951	-$285,218	-$924,072	$1,780,538	$1,668,273
Non-Energy Expenses	-$33,333	-$33,333	-$33,333	-$131,898	-$288,789	-$332,488	-$648,409	-$740,671
Sweep from/(to) Reserve Fund	$1,252,337	$33,333	$33,333	$4,440,849	$574,008	$1,256,560	-$1,132,129	-$927,603
EOM Operating Account Balance	$1,219,004	$1,219,004	$1,219,004	$1,219,004	$1,219,004	$1,219,004	$1,219,004	$1,219,004
RESERVE ACCOUNT								
BOM Reserve Account Balance	$0	$1,247,663	$1,002,501	$971,229	$1,088,524	$3,371,730	$2,002,210	$2,767,922
Collateral Requirements	$0	-$211,828	$2,061	-$441,856	-$142,786	-$112,960	-$366,418	-$59,177
Deposits from Financing	$2,500,000	$0	$0	$5,000,000	$3,000,000	$0	$0	$0
Disbursement from/(to) Operating Account	-$1,252,337	-$33,333	-$33,333	-$4,440,849	-$574,008	-$1,256,560	$1,132,129	$927,603
EOM Reserve Account Balance	$1,247,663	$1,002,501	$971,229	$1,088,524	$3,371,730	$2,002,210	$2,767,922	$3,636,347
SECURED REVENUE ACCOUNT REQUIREMENTS								
Waterfall minimum reserve for suppliers	$0	$0	$0	$3,999,000	$4,218,000	$4,295,000	$4,684,000	$4,718,000
Short term settlements (based on EAL + 10% energy)	$0	$0	$0	$309,951	$376,169	$851,300	$995,410	$1,072,634
Total (minimum revenue account requirements)	$0	$0	$0	$4,308,951	$4,594,169	$5,146,300	$5,679,410	$5,790,634
THIRD PARTY ACCOUNTS								
COLLATERAL HELD BY THIRD-PARTIES								
CAISO CRR Auction - monthly	$0	$0	$0	$100,000	$100,000	$100,000	$0	$0
CAISO CRR Auction - annual	$0	$0	$0	$0	$0	$0	$500,000	$500,000
CAISO Estimated Aggregate Liability (EAL) Deposit	$0	$0	$0	$309,951	$376,169	$444,944	$415,425	$485,947
CPUC CCA Bond	$0	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000
SCE Service Deposit	$0	$111,828	$109,767	$141,672	$218,240	$262,425	$258,361	$247,017
Total collateral	$0	$211,828	$209,767	$651,623	$794,409	$907,369	$1,273,787	$1,332,964

In the screenshot above, the program’s cash-flow transfers between three CCA accounts, and outside the accounts to pay expenses or to be held by third-parties to satisfy collateral various credit requirements. In brief:

1. The SECURED REVENUE ACCOUNT is a restricted multi-party account managed by the CCA's collateral trustee (a neutral, third-party financial institution).
    a. During program operations, customer receipts are deposited by the utility directly into this account.
    b. As a credit enhancement, energy suppliers have first rights to revenues in this account. (Lenders have subordinate rights.)

c. The trustee manages the disbursement of funds, and the prioritization of payment, in accordance with agreements between the CCA and its suppliers. This is why it is also referred to as a 'waterfall' mechanism in the financial services industry.

d. The account must maintain a minimum balance for collateral, and may also be structured to pay for anticipated and contingency-based electricity market expenses.

e. To support forward energy purchases prior to program launch, funds from loans or government contributions are deposited by the CCA into this account; post-launch, an additional amount is typically accrued to provide further collateral. Each month thereafter, funds in excess of the required amount are disbursed to the CCA's OPERATING ACCOUNT.

f. Refer to the SBCP draft Business Plan appendix for further details, and a diagram of the recommended waterfall account.

2. The OPERATING ACCOUNT pays for non-energy expenses each month, and typically holds funds to cover 4-6 weeks' worth of these expenses. From there, additional funds are deposited into the RESERVE ACCOUNT.
3. The RESERVE ACCOUNT retains funds for future rate relief, disburses funds to satisfy collateral obligations, and also supplements as necessary the SECURED REVENUE ACCOUNT and OPERATING ACCOUNT.

Model results have been disclosed on a monthly basis, showing each line item of the analysis outputs, including cash-flow. However, note that these are constructed with <u>particular</u> contract structures, regulatory requirements and business process requirements for SBCP, and should be reviewed for applicability and revised if used to inform other CCA analyses.

Note that constructing a cash-flow analysis is particularly complex — and, because the accrual basis data is shuffled according to various calculations, prone to model errors that may go <u>unnoticed</u>. Care to be taken to confirm the results in various ways, for example:

- The primary error check to verify the cash-flow accounts in each month is a wholly-separate sequence of calculations; if the results do not match the aggregate total of the accounts in the cash-flow, an alert is triggered.
- Since no account may be overdrawn in the real-world, an alert is also triggered if it happens in the cash-flow analysis. If the reserve account does go negative for example, this indicates that the CCA is under-capitalized or the debt service schedule requires revision. Note that hard coding a zero into the model logic instead would only compound and hide errors.

REFERENCE MATERIAL & INDUSTRY CONTACTS

Key documents relied upon to conduct this analysis include:

1. SCE 2018 ERRA Forecast (Energy Resource Recovery Account, May 2017 filings)
2. SCE 2017 ERRA Forecast (November 2016 Update)
3. SCE 2016 Renewable Plan (Bundled Procurement Plan filing, updated January 2017 — primarily, "Physical Renewable Net Short Calculation based on SCE assumptions and the actual vs. forecast tables disaggregating volumes and costs by technology type)
4. SCE 2014, 2015 & 2016 ERRA Review of Operations filings & testimony (particularly, Chapters I-IVII and appendices SCE-1 and SCE-2)
5. SCE 2015 & 2018 GRC (General Rate Case) filings and testimony, particularly Volume 5: Power Supply and Volume 9: Results of Operations
6. SCE PAM Eligible Contract Dataset (Portfolio Allocation Methodology Application)
7. SCE SONGS Settlement advice letter 3139-E (10 March 2015).
8. SCE rate schedules and Rate Group dynamic and static hourly load profiles (2016)
9. SCE Schedule CCA-SF (CCA service fees — note that new fees were proposed in 2018 GRC, Additional Testimony in Response to ALJs' Ruling of May 26, 2017, on 28 June 2017 and this should be monitored and incorporated)
10. SCE PCIA Calculator (PCIA workshops, 2016-2017)
11. CPUC 2017 Final CAM Contract list and various SCE advice letters and filings pertaining to authorized and extant procurement eligible for CAM (e.g. LCR RFO & Aliso Canyon)
12. CPUC RPS Calculator, version 62 (produced by E3)
13. CPUC proposed decision on Resource Adequacy (25 May 2017) and the related staff whitepaper on ELCC methodology
14. CEC IEPR demand forecast report and datasets (corrected 2017)
15. CEC Resource Adequacy Cost Report (January 2017)
16. CEC "Currently Interconnected Dataset" of behind-the-meter photovoltaic installations (interconnected and in queue)
17. CAISO OASIS data extracts (notably, 2016 TAC-SCE peak loads and SCE-DLAP and SCE-EZGEN virtual node hourly prices for 2016)
18. CAISO 2017 NQC and technology factor datasets (note CPUC ELCC should be applied instead to wind and solar, not CAISO technology factors)
19. CAISO Local Capacity Requirement planning studies
20. CAISO Market Monitor annual and quarterly update reports
21. LACCE Business Plan (for select LA County specific CCA-eligible load data only)

Additionally, a number of experts provided key insights, market intelligence, advice or datasets used in preparation of the model, including:

1. A helpful team of analysts, business process advisors and regulatory experts at Southern California Edison; the primary point of contact for CCA inquiries is Michelle Stark <michelle.stark@sce.com>
2. Chris Kavalec <Chris.Kavalec@energy.ca.gov> of the California Energy Commission, who supports the Integrated Energy Policy Report and may be contacted for forecast data and clarifications on assumptions (in particular).
3. Various portfolio managers, including:
    a. Alliance for Cooperative Energy Services Power Marketing (ACES). Point of contact is Jeremy Clark <jeremyc@acespower.com>
    b. The Energy Authority (TEA). Point of contact is Jeff Fuller <jfuller@teainc.org>
    c. ZGlobal, Inc. Point of contact is Kevin Coffee <kcoffee@zglobal.biz>
4. Kent Palmerton, 40-year public power veteran with significant operational experience, who has managed two regional Joint Powers Agencies to provide services to member municipal utilities and water districts.

Note that these contacts are included for the sake of transparency and to assist other CCA initiatives, and this does not imply endorsement of or responsibility for any aspect of this work product (which has not been reviewed outside of SBCP prior to publication).

We additionally recommend that CCA initiatives contact the Executive Directors of CCAs that have hired portfolio managers to assist with program implementation:

1. Matthew Marshall, Redwood Coast Energy Authority, <mmarshall@redwoodenergy.org>
2. Tom Habashi, Silicon Valley Clean Energy, <tomh@svcleanenergy.org>

MODEL EXTRACTS

In lieu of summary tables, we have made the full workbook of detailed monthly and annual forecast results in MS EXCEL format available online (on the South Bay Clean Power website).

SELECT SCE RATE GROUP CALCULATORS

SCE RATE GROUP	TOU-8-PRI	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	$/MWH (or MW)	Revenue
ENERGY (MWH)	WINTER-MID	15,962	15,757	18,449	17,017	17,985	-	-	-	-	17,916	16,823	15,726	135,636	$ 45.79	$ 6,210,755
	WINTER-OFF	24,358	20,706	23,021	23,199	25,087	-	-	-	-	25,386	22,754	22,974	187,485	$ 36.45	$ 6,833,833
	SUMMER-ON	-	-	-	-	-	8,658	8,079	9,657	8,955	-	-	-	35,349	$ 70.72	$ 2,499,911
	SUMMER-MID	-	-	-	-	-	15,283	14,308	16,974	15,701	-	-	-	62,266	$ 47.30	$ 2,945,195
	SUMMER-OFF	-	-	-	-	-	18,634	22,206	20,017	20,576	-	-	-	81,433	$ 31.65	$ 2,577,344
	TOTAL MWH	40,320	36,463	41,470	40,216	43,073	42,575	44,593	46,648	45,232	43,302	39,577	38,700	502,169	$ 41.95	$ 21,067,038
CAPACITY (MW)	SUMMER-ON						68	70	73	74				284	$ 18,970	$ 5,389,304
	SUMMER-MID						68	70	73	74				285	$ 3,580	$ 1,020,500
	Peak MW	63	64	64	65	69	68	70	73	74	69	66	60	806		
	Peak/cust. (KW)	833.31	835.72	846.49	857.04	913.83	899.02	923.20	956.97	972.66	905.80	868.90	788.79	10,602	TOTAL:	$ 27,476,841
	Revenue	$1,618,764	$1,476,250	$1,683,873	$1,624,822	$1,737,989	$3,459,999	$3,522,320	$3,756,090	$3,693,845	$1,745,713	$1,599,695	$1,557,482	$27,476,841		

SCE RATE GROUP	TOU-8-SUB	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	$/MWH (or MW)	Revenue
ENERGY (MWH)	WINTER-MID	16,379	16,151	19,228	18,061	18,364	-	-	-	-	18,503	17,912	16,659	141,258	$ 44.82	$ 6,331,178
	WINTER-OFF	29,158	24,624	27,293	28,154	29,602	-	-	-	-	30,477	27,440	27,456	224,203	$ 35.83	$ 8,033,197
	SUMMER-ON	-	-	-	-	-	8,898	8,103	9,416	8,448	-	-	-	34,866	$ 67.45	$ 2,351,702
	SUMMER-MID	-	-	-	-	-	16,053	14,603	17,071	15,402	-	-	-	63,130	$ 45.89	$ 2,897,026
	SUMMER-OFF	-	-	-	-	-	21,965	25,607	23,001	23,267	-	-	-	93,840	$ 31.01	$ 2,909,967
	TOTAL MWH	45,536	40,775	46,521	46,215	47,966	46,916	48,314	49,489	47,117	48,980	45,352	44,115	557,296	$ 40.41	$ 22,523,069
CAPACITY (MW)	SUMMER-ON						69	70	70	70				278	$ 18,700	$ 5,207,585
	SUMMER-MID						69	70	70	69				279	$ 3,450	$ 962,156
	Peak MW	66	65	67	70	70	69	70	70	70	70	70	63	820		
	Peak/cust. (KW)	780.49	778.83	801.10	829.10	832.74	825.24	834.76	837.98	828.09	831.05	830.60	749.41	9,759	TOTAL:	$ 28,692,810
	Revenue	$1,778,812	$1,606,173	$1,839,708	$1,818,259	$1,883,726	$3,553,053	$3,554,529	$3,683,334	$3,537,520	$1,921,304	$1,785,982	$1,730,410	$28,692,810		

SOUTH BAY CLEAN POWER

SCE RATE GROUP	GS-2	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL	$/MWH (or MW)	Revenue
ENERGY (MWH)	WINTER-MID	43,223	45,744	51,059	48,874	49,109	-	-	-	-	55,517	51,710	47,373	392,609	$ 47.57	$ 18,676,416
	WINTER-OFF	52,698	45,666	48,763	50,227	52,754	-	-	-	-	60,745	53,411	54,916	419,180	$ 37.41	$ 15,681,516
	SUMMER-ON	-	-	-	-	-	29,770	31,313	36,257	31,249	-	-	-	128,589	$ 313.35	$ 40,293,339
	SUMMER-MID	-	-	-	-	-	41,683	43,772	49,907	43,611	-	-	-	178,973	$ 87.69	$ 15,694,161
	SUMMER-OFF	-	-	-	-	-	42,242	57,902	49,154	48,575	-	-	-	197,874	$ 30.86	$ 6,106,394
	TOTAL MWH	95,921	91,410	99,822	99,101	101,863	113,695	132,987	135,318	123,436	116,262	105,121	102,289	1,317,225	$ 73.22	$ 96,451,827
CAPACITY (MW)	SUMMER-ON						279	295	297	299				1,169	$ -	$ -
	SUMMER-MID						273	284	282	287				1,126	$ -	$ -
	SUMMER-OFF						184	225	212	199				820	$ -	$ -
	Peak MW	186	226	212	237	224	279	295	297	299	269	262	201	2,986		
	Peak/cust. (KW)	21	26	24	27	25	32	33	34	34	31	30	23	339	TOTAL:	$ 96,451,827
	Revenue	$4,027,557	$3,884,423	$4,253,107	$4,203,928	$4,309,646	$14,287,195	$15,437,031	$17,254,381	$15,115,288	$4,913,398	$4,457,944	$4,307,930	$96,451,827		

SCE RATE GROUP	TOU-GS-3	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	$/MWH (or MW)	Revenue
ENERGY (MWH)	WINTER-MID	22,989	23,043	26,815	25,002	27,221	-	-	-	-	27,258	24,668	23,120	200,114	$ 46.62	$ 9,329,324
	WINTER-OFF	27,638	23,749	26,202	26,584	29,129	-	-	-	-	29,598	26,315	26,877	216,092	$ 37.12	$ 8,021,331
	SUMMER-ON	-	-	-	-	-	13,735	12,778	16,042	14,915	-	-	-	57,469	$ 88.19	$ 5,068,208
	SUMMER-MID	-	-	-	-	-	20,873	19,508	23,870	22,056	-	-	-	86,306	$ 50.95	$ 4,397,287
	SUMMER-OFF	-	-	-	-	-	21,390	25,971	23,284	24,035	-	-	-	94,680	$ 32.26	$ 3,054,373
	TOTAL MWH	50,627	46,792	53,016	51,586	56,350	55,997	58,257	63,195	61,006	56,856	50,983	49,997	654,661	$ 45.63	$ 29,870,523
CAPACITY (MW)	SUMMER-ON						110	113	124	129				476	$ 17,420	$ 8,290,277
	SUMMER-MID						108	110	121	125				463	$ 3,430	$ 1,589,795
	Peak MW	97	100	100	104	115	110	113	124	129	115	104	93	1,304		
	Peak/cust. (KW)	150	153	154	160	177	170	173	191	198	176	161	143	2,006	TOTAL:	$ 39,750,595
	Revenue	$2,097,657	$1,955,811	$2,222,699	$2,152,392	$2,350,307	$5,256,185	$5,297,660	$5,964,927	$5,881,169	$2,369,441	$2,126,833	$2,075,514	$39,750,595		

SCE RATE GROUP	TOU-8-SEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL	$/MWH (or MW)	Revenue
ENERGY (MWH)	WINTER-MID	25,820	25,870	30,112	27,974	29,722	-	-	-	-	29,835	27,694	25,781	222,809	$ 46.74	$ 10,414,092
	WINTER-OFF	33,275	29,037	32,162	32,575	35,361	-	-	-	-	36,122	32,231	32,096	262,859	$ 37.21	$ 9,780,991
	SUMMER-ON	-	-	-	-	-	14,760	13,706	16,464	15,105	-	-	-	60,035	$ 71.79	$ 4,309,923
	SUMMER-MID	-	-	-	-	-	24,407	22,645	26,930	24,651	-	-	-	98,633	$ 48.35	$ 4,768,886
	SUMMER-OFF	-	-	-	-	-	26,476	31,149	28,231	28,766	-	-	-	114,621	$ 32.34	$ 3,706,859
	TOTAL MWH	59,096	54,907	62,274	60,550	65,083	65,642	67,500	71,625	68,522	65,957	59,926	57,877	758,957	$ 43.46	$ 32,980,751
CAPACITY (MW)	SUMMER-ON						116	119	125	126				486	$ 18,920	$ 9,197,364
	SUMMER-MID						116	120	125	126				486	$ 3,630	$ 1,764,336
	Peak MW	106	107	108	111	118	116	120	125	126	119	112	101	1,369		
	Peak/cust. (KW)	924	934	937	964	1,024	1,012	1,039	1,085	1,094	1,031	976	882	11,903	TOTAL:	$ 43,942,451
	Revenue	$2,445,019	$2,289,631	$2,604,168	$2,519,653	$2,704,987	$5,720,459	$5,773,533	$6,209,907	$6,043,469	$2,738,574	$2,493,756	$2,399,296	$43,942,451		

SOUTH BAY CLEAN POWER

CAPACITY ALLOCATION MECHANISM CONTRACT SUMMARY: 2018/22

		1/1/18	2/1/18	3/1/18	4/1/18	5/1/18	6/1/18	7/1/18	8/1/18	9/1/18	10/1/18	11/1/18	12/1/18
Unallocated DR (@meter)	LA Basin	6	6	7	13	26	29	30	32	33	32	8	6
	Big Creek/Ventura	0	0	1	2	2	2	3	3	3	3	1	0
	Outside LCA	1	1	1	2	3	3	3	3	4	4	1	1
Current CAM List (CPUC, 2017)	SCE SYSTEM RA	3,496	3,522	3,467	3,468	3,461	3,527	3,530	3,516	3,535	3,466	3,539	3,586
	DRAM + PRM (assumed)	57	57	59	59	60	62	66	65	65	61	60	62
	LA Basin	2,040	2,079	2,025	2,023	2,030	2,067	2,070	2,061	2,055	1,993	2,063	2,085
	Big Creek-Ventura	427	423	424	417	403	429	429	428	447	435	439	453
	Bay Area	200	200	200	200	195	192	188	188	192	200	200	200
	Fresno	25	17	27	35	31	35	35	35	35	34	34	37
	Flexible 1	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890
	Flexible 2	527	527	527	527	527	527	527	527	527	527	527	527
	Flexible 3	-	-	-	-	-	-	-	-	-	-	-	-
Future CAM Contracts (Aliso Canyon, LCR, etc.)	LA Basin - load modifying	158	160	167	186	183	196	193	192	186	183	161	158
	Big Creek-Ventura - load modifying	6	6	7	10	10	12	11	11	10	10	7	6
	SCE SYSTEM RA	203	203	203	203	203	203	203	203	203	203	203	203
	DRAM + PRM	-	-	-	-	-	-	-	-	-	-	-	-
	LA Basin	202	202	202	202	202	202	202	202	202	202	202	202
	Big Creek-Ventura	1	1	1	1	1	1	1	1	1	1	1	1
	Flexible 1	-	-	-	-	-	-	-	-	-	-	-	-
	Flexible 2	-	-	-	-	-	-	-	-	-	-	-	-
	Flexible 3	203	203	203	203	203	203	203	203	203	203	203	203
Load modifying (T&D+reserve, LCA is Aug NQC & contract by month)	Total (monthly for system)	209	212	223	260	275	296	295	296	288	284	218	209
	LA Basin (Aug NQC for LCR)	275	275	275	275	275	275	275	275	275	275	275	275
	Big Creek (Aug NQC for LCR)	17	17	17	17	17	17	17	17	17	17	17	17
	Outside LCA (Aug NQC, unalloc.)	4	4	4	4	4	4	4	4	4	4	4	4
Supply-Side & CAM-eligible	System	3,698	3,724	3,669	3,671	3,664	3,729	3,732	3,718	3,737	3,669	3,742	3,788
	DRAM + PRM	57	57	59	59	60	62	66	65	65	61	60	62
	LA Basin LCA	2,449	2,449	2,449	2,449	2,449	2,449	2,449	2,449	2,449	2,449	2,449	2,449
	Big Creek-Ventura LCA	429	429	429	429	429	429	429	429	429	429	429	429
	Other Local LCA	222	222	222	222	222	222	222	222	222	222	222	222
	Flexible 1	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890	1,890
	Flexible 2	527	527	527	527	527	527	527	527	527	527	527	527
	Flexible 3	203	203	203	203	203	203	203	203	203	203	203	203
Unadjusted TAC Oblig.	LCR LA Basin	7,525	7,525	7,525	7,525	7,525	7,525	7,525	7,525	7,525	7,525	7,525	7,525
	LCR Big Creek-Ventura	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321	2,321
Net Adj. for TAC Oblig.	LCR LA Basin	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801
	LCR Big Creek-Ventura	1,875	1,875	1,875	1,875	1,875	1,875	1,875	1,875	1,875	1,875	1,875	1,875

	1/1/22	2/1/22	3/1/22	4/1/22	5/1/22	6/1/22	7/1/22	8/1/22	9/1/22	10/1/22	11/1/22	12/1/22
Unallocated DR (@meter)	6	6	7	13	26	29	30	32	33	32	8	6
	0	0	1	2	2	2	3	3	3	3	1	0
	1	1	1	2	3	3	3	3	4	4	1	1
Current CAM List (CPUC, 2017)	2,242	2,271	2,225	2,234	2,245	2,236	1,918	1,907	1,905	1,898	1,897	1,906
	57	57	59	59	60	62	66	65	65	61	60	62
	1,995	2,033	1,988	1,986	1,993	2,026	1,756	1,748	1,745	1,744	1,743	1,747
	108	109	108	109	109	61	61	61	61	59	59	60
	-	-	-	-	-	-	-	-	-	-	-	-
	25	17	27	35	31	35	35	35	35	34	34	37
	1,305	1,305	1,305	1,305	1,305	1,256	1,256	1,256	1,256	1,256	1,256	1,256
	527	527	527	527	527	527	527	527	527	527	527	527
	-	-	-	-	-	-	-	-	-	-	-	-
Future CAM Contracts (Aliso Canyon, LCR, etc.)	153	155	162	181	178	191	188	187	181	178	156	153
	6	6	7	10	10	12	11	11	10	10	7	6
	1,942	1,942	1,942	1,942	1,942	1,942	1,942	1,942	1,942	1,942	1,942	1,942
	-	-	-	-	-	-	-	-	-	-	-	-
	1,679	1,679	1,679	1,679	1,679	1,679	1,679	1,679	1,679	1,679	1,679	1,679
	263	263	263	263	263	263	263	263	263	263	263	263
	1,644	1,644	1,644	1,644	1,644	1,644	1,644	1,644	1,644	1,644	1,644	1,644
	-	-	-	-	-	-	-	-	-	-	-	-
	298	298	298	298	298	298	298	298	298	298	298	298
Load modifying (T&D+reserve, LCA is Aug NQC & contract by month)	203	206	217	254	269	290	288	290	282	277	212	203
	269	269	269	269	269	269	269	269	269	269	269	269
	17	17	17	17	17	17	17	17	17	17	17	17
	4	4	4	4	4	4	4	4	4	4	4	4
Supply-Side & CAM-eligible	4,184	4,213	4,166	4,175	4,187	4,177	3,860	3,849	3,846	3,840	3,839	3,848
	57	57	59	59	60	62	66	65	65	61	60	62
	3,926	3,926	3,926	3,926	3,926	3,926	3,926	3,926	3,926	3,926	3,926	3,926
	691	691	691	691	691	691	691	691	691	691	691	691
	222	222	222	222	222	222	222	222	222	222	222	222
	2,949	2,949	2,949	2,949	2,949	2,900	2,900	2,900	2,900	2,900	2,900	2,900
	527	527	527	527	527	527	527	527	527	527	527	527
	298	298	298	298	298	298	298	298	298	298	298	298
Unadjusted TAC Oblig.	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022	6,022
	2,597	2,597	2,597	2,597	2,597	2,597	2,597	2,597	2,597	2,597	2,597	2,597
Net Adj. for TAC Oblig.	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828
	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889	1,889

SOUTH BAY CLEAN POWER START-UP LOAN TABLE

TOTAL STARTUP LOAN:	$2,219,747
Amounts included in above total for contingencies (explained in "notes" below)	$749,167
Funding in case "Lead City" expenses Aug-Oct (prior to expected loan execution)	$144,167
Funding in case CCA chooses to register as a CAISO Scheduling Coordinator directly	$505,000
Funding in case at-risk contracting for support services is not successful:	$100,000

REFUNDABLE?	ACTIVITIES:	*2018 AUG*	*2018 SEP*	*2018 OCT*	*2018 NOV*	*2018 DEC*	*2018 JAN*	*2018 FEB*	*2018 MAR*	*2018 APR*	*2018 MAY*	*2018 JUN*	TOTAL
		ADVISORY COMMITTEE & LEAD CITY PREPARTIONS	ED RFQ ISSUED & RFP FINALIZED	ED HIRED, LOAN EXECUTED & RFP ISSUED; BIDDER CALL AND Q&A	JPA FORMED & CONTRACTS/LOAN TRANSFERRED; BID EVALUATION, INTERVIEWS, SELECTIONS, NEGOTIATION & EXECUTION OF CONTRACTS		*IMPLEMENTATION PROCESS (REFER TO GANTT)*					CCA LAUNCH	
							TERM LOAN & LOC NEGOTIATION & EXECUTION			<-- POWER COLLATERAL & WORKING CAPITAL			
	DIRECT EXPENSES	$50,000	$52,083	$42,083	$38,183	$52,083	$57,083	$57,083	$82,083	$142,065	$119,815	$119,815	
No, as direct expenses	*City Staff & counsel expenses*	$50,000	$25,000	$15,000	$10,000	$25,000	$5,000	$5,000	$25,000	$0	$0	$0	$160,000
	General Manager	$0	$27,083	$27,083	$27,083	$27,083	$27,083	$27,083	$27,083	$27,083	$27,083	$27,083	$270,833
	Executive Assistant	$0	$0	$0	$0	$0	$0	$0	$0	$7,083	$7,083	$7,083	$21,250
	AGM Finance (Assistant General Manager)	$0	$0	$0	$0	$0	$0	$0	$0	$18,750	$18,750	$18,750	$56,250
	AGM External Affairs	$0	$0	$0	$0	$0	$0	$0	$0	$16,667	$16,667	$16,667	$50,000
	AGM Customer Care	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,417	$10,417	$20,833
	Key Account Manager	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,417	$10,417	$20,833
	Account Representative	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,917	$7,917	$15,833
	Office & Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$21,481	$21,481	$21,481	$64,444
	Utility data request	$0	$0	$0	$1,100	$0	$0	$0	$0	$0	$0	$0	$1,100
	CAISO CRR Registration Fee	$0	$0	$0	$0	$0	$0	$0	$0	$1,000	$0	$0	$1,000
	If applicable: CAISO SC Registration Fee	$0	$0	$0	$0	$0	$0	$0	$5,000	$0	$0	$0	$5,000
	WSPP Registration (Western System Power Pool)	$0	$0	$0	$0	$0	$0	$0	$0	$25,000	$0	$0	$25,000
	At-risk contracting precaution: additional marketing budge	$0	$0	$0	$0	$0	$25,000	$25,000	$25,000	$25,000	$0	$0	$100,000
	COLLATERAL HELD BY THIRD-PARTIES	$0	$0	$0	$0	$0	$0	$211,828	$709,767	$1,151,623	$1,294,409	$1,407,369	
Yes, until power contracts are executed (pre-launch)	*CAISO CRR Auction (Congestion Revenue Rights)*	$0	$0	$0	$0	$0	$0	$0	$0	$100,000	$100,000	$100,000	$100,000
	If applicable: CAISO SC Minimum Participation Agreement	$0	$0	$0	$0	$0	$0	$0	$500,000	$500,000	$500,000	$500,000	$500,000
	CAISO Estimated Aggregate Liability (EAL) Deposit	$0	$0	$0	$0	$0	$0	$0	$0	$309,951	$376,169	$444,944	$444,944
	CPUC CCA Bond	$0	$0	$0	$0	$0	$0	$100,000	$100,000	$100,000	$100,000	$100,000	$100,000
	SCE Service Deposit	$0	$0	$0	$0	$0	$0	$111,828	$109,767	$141,672	$218,240	$262,425	$262,425
	TOTAL	$50,000	$52,083	$42,083	$38,183	$52,083	$57,083	$268,911	$791,850	$1,293,688	$1,414,224	$1,527,184	

	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
COUNTERPARTY / GUARANTOR	Lead City / Lead City (full guarantee)				CCA JPA / member cities (full guarantee) & CCA JPA (secondary lien on revenues)						
REFUNDABLE	$0	$0	$0	$0	$0	$0	$211,828	$709,767	$0	$0	$0
EXPENDED OR COMMITTED	$50,000	$102,083	$144,167	$182,350	$234,433	$291,517	$348,600	$430,683	$1,724,371	$1,986,972	$2,219,747

SOUTH BAY CLEAN POWER