CITY OF GOLETA

Agenda Item F.2
DISCUSSION/ACTION ITEM
Meeting Date: July 17, 2018

TO: Mayor and Councilmembers

FROM: Peter Imhof, Director, Planning & Environmental Review

CONTACT: Cindy Moore, Sustainability Coordinator

SUBJECT: Community Choice Energy Technical Feasibility Study Results and Resolution of Intent

RECOMMENDATION:

A. Receive a report from Pacific Energy Advisors, Inc. on the results of the Santa Barbara County Community Choice Energy Technical Study; and

B. Adopt Resolution 18-__, entitled, "A Resolution of the City Council of the City of Goleta, California, Affirming the City's Intent to Participate in Governance and Financing Discussions for a Proposed Community Choice Energy Joint Powers Authority".

BACKGROUND:

At its December 5, 2017 meeting, Council adopted a 100% renewable energy goal for the electricity sector for both municipal facilities and for the City at large by 2030. The adopting Resolution 17-52 requires that the City develop a Renewable Energy Plan by July 1, 2019 to identify how it will reach the goal. The Plan is to identify options, methods, and financial resources needed, and an associated timeline and milestones to achieve the goal.

At the same meeting in December, Council authorized staff to participate in additional actions to support achievement of the 100% renewable electricity goal. The actions correspond to distinct, but related efforts to support a more sustainable and resilient local energy supply in line with broader goals set forth in the City's Strategic Plan, General Plan, Climate Action Plan, and Economic Development Strategic Plan.

Specifically, one of the Council actions at the December meeting included a budget appropriation of $7,500 for participation in an additional feasibility assessment of regional Community Choice Energy (CCE) with Santa Barbara County. This action is consistent with the City's Climate Action Plan Measure No. CCA-1, which describes working with other agencies to create a framework for a CCE program.

Community Choice Energy

Community choice energy, also known as community choice aggregation (CCA), enables local governments to leverage the purchasing power of their residents, businesses, and governmental entities to purchase or generate power for their communities. Currently, there are seventeen CCE programs in operation throughout California with many more in formation.[1]

When a CCE program is formed, the CCE provider purchases the electricity and sets the rates charged to customers, while the Investor Owned Utility (IOU) continues to deliver the electricity purchased by the CCE provider over the IOU's power lines and provide metering, billing, and other customer service. Southern California Edison (SCE) is the IOU in our area. The CCE model puts energy purchasing and pricing options into the hands of local decision-makers and allows the community to determine what type of energy mix is offered to customers. For example, a CCE may choose to purchase more renewable energy to meet local climate action goals.

Tri-County Regional Community Choice Energy Feasibility Study

On June 9, 2015, the Santa Barbara County Board of Supervisors approved $400,000 to fund the initial phase of evaluating the formation of a CCE program in the County. Ten jurisdictions and the Community Environmental Council joined the County of Santa Barbara in creating Central Coast Power, a consortium to fund a feasibility study to help determine whether CCE is a good fit for the Tri-County Region (Santa Barbara, Ventura and San Luis Obispo). The County formed an Advisory Working Group composed of representatives from cities and counties that contributed financially in order to help guide and oversee the feasibility analysis, provide outreach support, and monitor policy and program developments related to CCE. As a non-contributing City, Goleta did not participate in the Advisory Working Group.

Willdan Financial Services conducted the Tri-County CCE feasibility study, and MRW and Associates performed a peer review to evaluate the reasonableness of Willdan's study. The results were released in September 2017 and indicated that a new regional CCE program spanning Santa Barbara, San Luis Obispo, and Ventura Counties, under the assumptions used in the feasibility study and peer review, was not likely to be able to offer competitive rates in SCE territory and remain a solvent organization.

Following the presentation of the Tri-County Study results, Ventura and San Luis Obispo jurisdictions opted to pursue other paths. The County of Ventura and many of its cities joined the Clean Power Alliance, the CCE program serving parts of Los Angeles and Ventura Counties. The County of San Luis Obispo discontinued its exploration of CCE, and the City of San Luis Obispo is pursuing its own CCE program potentially in partnership with the City of Morro Bay and others.

[1] For a list of operational and in-development CCE programs, please visit https://cleanpowerexchange.org/california-community-choice/.

Given that evaluating the feasibility of CCE is a difficult and complex task, and in consideration of public input regarding various assumptions utilized in the Tri-County analysis, the County Board of Supervisors at its October 3, 2017 meeting directed County staff to conduct additional analysis of CCE options and viability.

DISCUSSION:

As previously stated, Council authorized participation in the additional feasibility assessment, which was funded by the County; the Cities of Goleta, Carpinteria, and Santa Barbara; and the Community Environmental Council. County staff subsequently engaged Pacific Energy Advisors, Inc. ("PEA") to prepare the current Santa Barbara County feasibility study to assess the viability of CCE for all or part of Santa Barbara County.

Santa Barbara County Feasibility Study

Methodology

PEA evaluated the feasibility of CCE for three geographic participation scenarios:

- All Santa Barbara County (unincorporated + incorporated cities),
- Unincorporated Santa Barbara County Only, and
- City of Santa Barbara Only

For each geographic scenario, PEA evaluated total program costs, rate competitiveness, and financial position for the following three electricity supply scenarios over an 11-year study period (2020-2030):

- Compliant with the State Renewable Portfolio Standard[2],
- 50% Renewable All Years, and
- 75% Renewable All Years

As part of its analysis, PEA built two indicative electricity supply scenarios (one for customers in PG&E territory and another for SCE territory) to illustrate how a potential CCE program's electricity mix might compare to the IOUs' portfolios. Table 1 illustrates how PEA's model of the CCE program's portfolio would compare to SCE's portfolio in terms of renewable energy[3] and greenhouse gas (GHG)-free[4] content, as Goleta is wholly within SCE territory. Because the IOUs are on track to have more than 33% renewable energy content in 2020, the remainder of this report assumes a 50%

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[2] The RPS increases from 33% renewable in 2020 to 50% renewable in 2030.

[3] The term "renewable energy" refers to renewable energy resources that comply with the California Renewable Portfolio Standard (RPS), which excludes large-scale hydroelectric generation.

[4] The term "GHG-free" refers to electric energy generated from sources that do not emit (or emit very low amounts of) gases that contribute to the greenhouse effect, such as carbon dioxide, methane, and nitrous oxide. GHG-free electricity sources typically include RPS-eligible renewable energy and hydroelectric generation of any size.

renewable energy supply for the CCE program in the All Santa Barbara County scenario.

Table 1. All Santa Barbara County 50% Renewable Scenario: Comparison of CCE and SCE Renewable Energy and GHG-Free Electricity Supply Portfolios

Electricity Provider	Renewable Energy			GHG-Free Energy		
	2017	2020	2030	2017	2020	2030
SCE	32%[2] (actual)	41%[1] (contracted)	50% (planned)	46%[3] (actual)	Unknown	Unknown
CCE for SCE Territory	N/A	50% (modeled)	50% (modeled)	N/A	64% (modeled)	72% (modeled)

1 http://www.cpuc.ca.gov/rps_homepage/, accessed August 2017

2 Santa Barbara County personal communication with SCE, June 2018

Assumptions and Findings

PEA's key assumptions are detailed in Exhibit 1 of the technical study (Attachment 1). Some highlights include:

- A single phase for customer enrollment
- A customer opt-out rate of 10%
- Start-up costs of $9.3M for the All Santa Barbara County Scenario
- Staffing costs benchmarked to currently operating CCEs
- 4% of annual revenues contributed to the reserve fund

PEA concluded that any of the three geographic scenarios can offer cleaner electricity at a comparable rate to Pacific Gas and Electric (PG&E) or Southern California Edison (SCE), as applicable. For each geographic scenario, the costs, and therefore rates, increase with higher renewable energy content. The All Santa Barbara County option offers the greatest potential for the increased use of greenhouse gas-free electricity with a slight energy bill savings for residential customers, while the City of Santa Barbara Only scenario is the most financially challenging. Table 2 shows the financial information for the All Santa Barbara County scenario with a 50% renewable energy supply.

Table 2. 50% Renewable Scenario: Financial Information for All Santa Barbara County

Scenario	Start-up Capital ($)	Break Even (Year)	Net Surplus/ (Deficit) ($)		Average Residential Customer Bill Impact ($/Year)*	
			Year 1	Year 11	Year 1	Year 11
All SB County	$9.3M	Year 1	$4.3M	$24.6M	SCE: ↓ $8	SCE: ↓ $55

* Based on average electricity consumption for Santa Barbara County residents

Key Differences Between the Santa Barbara County and Tri-County Feasibility Studies

PEA was engaged to conduct this new feasibility study in part because of reservations about the appropriateness of some of the cost and rate assumptions used in the previous Tri-County Study (Willdan) and peer review (MRW).

Table 3 summarizes how each consultant's assumptions compare to values reported by staff from existing CCE programs to Santa Barbara County staff for the following cost variables: power costs, start-up capital requirements, financial reserve policies, and staffing levels.

Table 3. All Scenarios: Consultant Assumptions Compared to Operational CCE Reported Values

Consultant	Power Costs	Start-Up Capital	Financial Reserve	Staffing
PEA	At high end, but in line with CCE reported values	In line with CCE reported values	At low end, but in line with CCE reported values	In line with CCE reported values
Willdan	Higher than CCE reported values	Higher than CCE reported values	Higher than CCE reported values	Higher than CCE reported values
MRW	At high end, but in line with CCE reported values	In line with CCE reported values	At high end, but in line with CCE reported values	Higher than CCE reported values

Tables 4 through 7 provide comparison detail for each of the key variables for the All Santa Barbara County geographic participation scenario, unless otherwise noted. PEA's assumptions align with reported data from existing CCE programs.

Table 4. 50% Renewable Scenario: Comparison of Power Cost Assumptions

Source	$/MWh – All County										
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PEA	$53.40	$56.80	$58.50	$59.80	$61.00	$62.10	$64.40	$65.60	$66.20	$67.70	$69.20
Willdan	$75.00	$74.00	$73.00	$71.00	$71.00	$71.00	$69.00	$69.00	$69.00	$68.00	$67.00
MRW	$51.00	$53.00	$54.00	$55.00	$57.00	$58.00	$59.00	$60.00	$61.00	$62.00	$63.00
Other CCEs	Varies. Current short-term contract values are low $40s to low $50s.										

Table 5. 50% Renewable Scenario: Comparison of Start-Up Capital Assumptions

Source	Start-Up Capital Requirement	Payback	Financing Mechanism
	All County	All County	
PEA	$9.3M	Year 1	Bank loan
Willdan	$238.9M	Never within 11-year study period	30-year bond
MRW	Not Analyzed		
Other CCEs	Varies by program size. Less than $1M to $50M.	Varies by size of capital requirement, loan terms, etc. Less than 1 year to 5 years (projected).	Bank loan and/or general fund loan

Table 6. All Scenarios: Comparison of Financial Reserve Policy Assumptions

Source	Reserve Contribution	Contribution Frequency	Drawdown Frequency
PEA	4% of annual revenues	Annually until target achieved	Never during 11-year study period
Willdan	5 months operating capital + 12% of annual power costs + 10% of annual non-power costs	Included in start-up capital bond and then annually during 11-year study period	Annually during 11-year study period
MRW	12% of annual power costs +10% of non-power costs	Annually for 1st 3-5 years until target achieved	Never during 11-year study period
Other CCEs	Varies based on risk tolerance, market conditions, etc. For example: • 3-5% of annual revenues • 90 days operating capital + 15% of annual revenues • 50% of annual expenses	Annually until target achieved; few if any have achieved targets to date	Unknown

Table 7. All Scenarios: Comparison of Staffing Assumptions

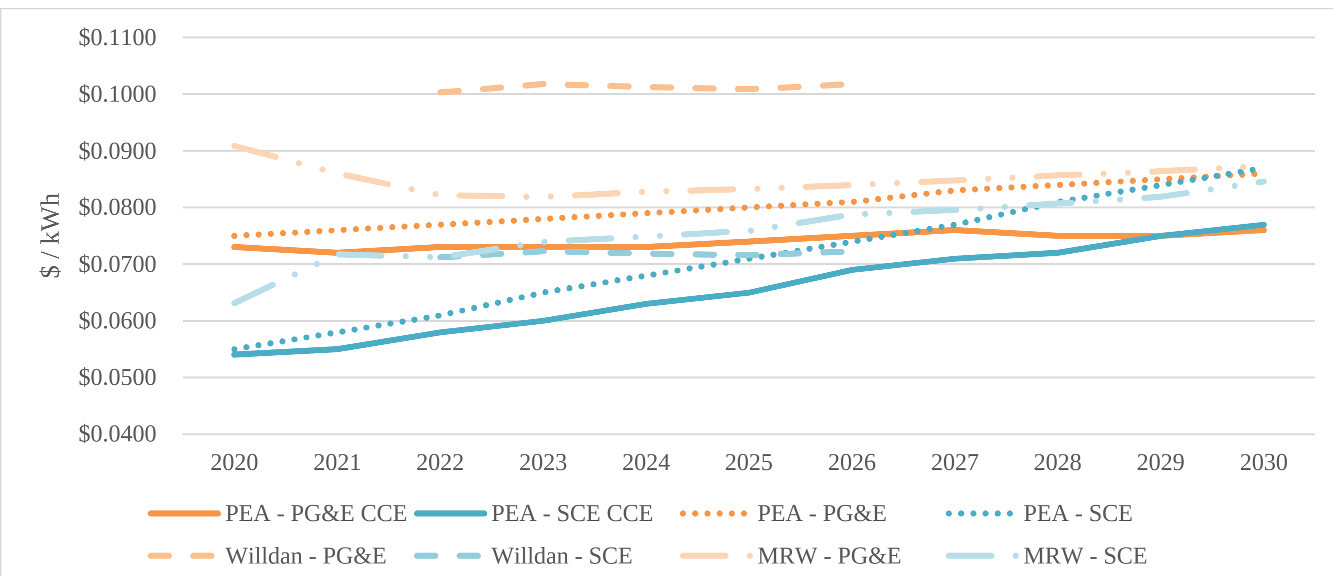
Source	All County	
	Full-Time Equivalents	$
PEA	~20	$3.5M
Willdan	36	$6.1M
MRW	29	$4.2M
Other CCEs	Varies. 3-45 FTEs	

In the Tri-County Study, Willdan was asked to develop a single set of uniform CCE rates that would be paid by all customers across PG&E and SCE territories. Because SCE's generation rates are lower than PG&E's generation rates, designing a single set of CCE rates to compete in both IOU territories meant the CCE rates had to be the same or lower than SCE's rates. Willdan projected that setting the rates low enough to compete in SCE territory for all CCE customers would not allow the CCE program to fully recover its costs, making the modeled CCE program a non-viable undertaking in the Tri-County Study.

Because of these complications, PEA was asked to develop two different sets of CCE rates: one for customers in PG&E territory and another for customers in SCE territory. Figure 1 illustrates how PEA's projected CCE rates compare to each consultant's estimated IOU rate projections. The solid orange line is PEA's estimate of the CCE rates in PG&E territory, and the dotted orange lines are each consultant's estimates of PG&E's rates. The solid blue line is PEA's estimate of the CCE rates in SCE territory, and the dotted blue lines are each consultant's estimates of SCE's rates. The CCE rates are inclusive of the PCIA and other exit fees.[5]

Despite differences in consultants' assumptions about how PG&E's and SCE's rates will change over time, PEA's projected CCE rates are expected to remain comparable or below the applicable IOU's rates throughout the study period.

Figure 1. All Santa Barbara County 50% Renewable Scenario: Comparison of PEA CCE Rate vs. Consultants' IOU Rates



[5] The Power Cost Indifference Adjustment (PCIA) charge is a charge assessed by the IOU to cover generation costs acquired prior to a customer's change in service provider. This fee is collected by the IOU and is effectively an "exit fee" assessed to customers which receive their generation services from another provider.

Benefits and Risks

Because a CCE is a non-profit, CCE revenues can be reinvested in the community and, once a sufficient reserve is established, the CCE partners could choose to use the accumulated revenues to build new, local renewable energy projects, offer incentive programs (e.g., energy efficiency, electric vehicles, rooftop solar), or reduce customer electricity rates. A joint powers authority (JPA) governing board would decide how to invest this new revenue source.

In addition to the benefits listed above, Council should carefully note that there are risks faced by CCE formation. The electricity market and policy environment are rapidly transforming. The IOUs have had time to adjust to a more competitive market in a way that poses a greater risk to new CCE program formation. Additionally, the CPUC and Legislature are trying to determine how to manage the growth of CCEs and level the playing field for all types of electricity providers. The PEA study findings are predicated on current market and policy conditions and PEA's firsthand knowledge of CCA operations and costs. However, uncertainties exist related to the following issues:

- Maintenance of competitive rates - particularly given SCE's lower rates relative to PG&E;
- Energy price volatility driven by increased integration of distributed renewable energy resources on the grid and a changing electricity provider landscape as more CCE programs form;
- Potential regulatory and legislative changes that could affect CCE program viability, including the determination of the methodology to calculate the PCIA charge. Examples of possible legislative changes include centralized power procurement at the state level and the CPUC gaining regulatory oversight authority for CCAs, which would diminish or remove the element of local control.

Next Steps

To pursue one of the scenarios, the County and any interested cities would partner to form a new Joint Powers Authority[6] that would administer the new CCE program serving residents, businesses, and governments located within the jurisdictional boundaries of the JPA member agencies. This option spreads operational control, risks, and start-up costs through the JPA model. Council would have representation on the JPA board. The governance structure and operating rules would be negotiated among the participating jurisdictions, likely using outside counsel to draft a JPA agreement and supporting documentation.

The earliest a multi-jurisdiction, JPA-run CCE program could launch is anticipated to be January 2021 due to new CPUC requirements and the time required to negotiate a JPA agreement and operating guidelines among multiple parties. To launch on this date, the CPUC requires an implementation plan be filed by January 1, 2020. The County would likely remain the lead agency and provide staffing and services (e.g., human resources, information technology, procurement) until a JPA can staff up and operate on its own.

[6] A JPA is the model available to offer CCE when multiple local governments wish to partner on joint CCE implementation.

To indicate support to move forward with this option, Council would adopt the Resolution of Intent included in Attachment B.

Resolution of Intent

Adoption of a Resolution of Intent would authorize City staff to participate in discussions in anticipation of JPA formation and CCE program launch. It does not, however, bind the City to membership in the JPA, allocation of general funds, or participation in a future CCE program. If the City of Goleta chooses to move forward, staff would need to return to Council at a later date to consider: (1) passing a resolution for JPA membership, (2) authorizing a pro-rata share of credit support, and (3) passing a CCE ordinance, as required by Public Utilities Code. At that time, the financial analysis would be updated to reflect the PCIA calculation methodology that is expected to be finalized later this summer, and identify participating jurisdictions in preparation of an implementation plan.

City Council Energy and Green Issues Standing Committee

At the June 13, 2018 City Council Energy and Green Issues Standing Committee meeting, the Standing Committee members unanimously supported bringing the item forward to the full City Council with a recommendation to authorize working with other jurisdictions to discuss formation of a JPA to create a CCE program and adopt the corresponding Resolution of Intent.

GOLETA STRATEGIC PLAN:

The recommended items in this report relate to the following 2017-19 Strategic Plan strategies, goals, and objectives:

City-Wide Strategy: Support Environmental Vitality
Strategic Goal: Adopt best practices in sustainability

The recommendation to participate in the County's additional feasibility assessment of Community Choice Energy directly relates to the following objective:

Objective: Participate in the Central Coast Power consortium of local governments to explore the feasibility of Community Choice Energy

FISCAL IMPACTS:

No immediate fiscal impact would result from adoption of the Resolution of Intent to proceed with discussions of a county-wide community choice energy program. However, JPA formation and early program development costs are expected to be shared equitably among participating jurisdictions. Once such costs are determined, staff would return to Council with a request to consider funding options and potentially the need for additional appropriations.

PEA's estimated start-up costs for the All Santa Barbara County scenario are $9.3 million, which will likely necessitate a secured bank loan that PEA estimates can be paid back in full within the first year of operations. The participating jurisdictions would need to negotiate a cost-share arrangement, options for securing the loan for full program launch and power procurement costs, and repayment terms. If a CEE program launches, all funds expended to date are reimbursable through future CCE revenues. Estimated annual revenues for the All Santa Barbara County option range from $4.3 million to $24.6 million. Once a sufficient reserve fund is established, the JPA board could make policy decisions about how to spend this new revenue source, as previously mentioned.

ALTERNATIVES:

Council may direct staff to discontinue further exploration of CCE at this time. If Council chooses not to proceed with the CCE Resolution of Intent, staff is prepared—with ongoing funding as identified in the following item on the Council's agenda—to continue efforts to pursue other strategies in support of the City's sustainability goals, including the 100% renewable energy goal. Specifically, staff has been participating in a solicitation process with the County of Santa Barbara and the cities of Carpinteria and Santa Barbara to engage a consultant to provide strategic energy planning services and develop a clean energy roadmap for participating jurisdictions.

Reviewed By:	**Legal Review By:**	**Approved By:**
Carmen Nichols Deputy City Manager	Michael Jenkins City Attorney	Michelle Greene City Manager

ATTACHMENTS:

1. PEA Community Choice Aggregation Technical Study
2. Resolution 18-, entitled, "A Resolution of the City Council of the City of Goleta, California, Affirming the City's Intent to Participate in Governance and Financing Discussions for a Proposed Community Choice Energy Joint Powers Authority"

ATTACHMENT 1

PEA Community Choice Aggregation Technical Study

PEA
Pacific Energy Advisors, Inc.

Memorandum

To: Jennifer Cregar, Co-Division Chief, Sustainability, County of Santa Barbara

From: Pacific Energy Advisors, Inc.

Subject: Community Choice Aggregation Technical Study

Date: May 25, 2018

Executive Summary

This Community Choice Aggregation (CCA) Technical Study (Study) was prepared for the County of Santa Barbara (SBC or the County), by Pacific Energy Advisors, Inc. (PEA) under contract with SBC, for purposes of determining the potential feasibility of forming a CCA program within Santa Barbara County. Such a program would provide electric generation service to residential, business and government customers located within Santa Barbara County. Three prospective membership configurations were assessed: 1) all Santa Barbara County, which included unincorporated areas of the County as well as each municipality located therein (the All-County Configuration, or Scenario 1); 2) only the unincorporated areas of Santa Barbara County (the Unincorporated County-Only Configuration, or Scenario 2); and 3) only the City of Santa Barbara (the City-Only Configuration, or Scenario 3). Under each membership configuration, three distinct supply scenarios were evaluated, each reflecting varying levels of greenhouse gas (GHG)-free energy[1] supply and associated costs.

Based on the analyses conducted during this Study, PEA concludes that SBC would likely have several electric supply options that would yield competitive customer rates compared to the incumbent investor-owned utilities (IOUs), Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) (see Exhibits 2-4). The All-County Configuration offered the greatest potential for the increased use of GHG-free energy at competitive electric rates, while the City-Only Configuration is projected to be the most financially challenging. To the extent that increased amounts of renewable energy[2] and hydroelectricity are used in place of conventional power sources, as illustrated in the aforementioned three supply scenarios, anticipated SBC costs and related customer rates would increase, and the opportunity for savings relative to the IOUs would decrease.

Ultimately, SBC's ability to demonstrate rate competitiveness (while also offering environmental benefits) would hinge on prevailing market prices at the time of power supply contract negotiation and execution. Depending on inevitable changes to market prices and other assumptions such as IOU generation rates and exit fees (e.g., the Power Charge Indifference Adjustment (PCIA)), SBC's actual electric rates may be somewhat lower or higher than similar rates charged by the IOUs and would be expected to fall within a

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[1] GHG-free electricity refers to electric energy generated from sources that do not emit (or emit very low amounts of) gases which contribute to the greenhouse effect, such as carbon dioxide, methane, and nitrous oxide. GHG-free power sources typically include RPS-eligible renewable energy and hydroelectric generating resources.

[2] While the U.S. Environmental Protection Agency defines hydroelectric energy of any size as a renewable energy resource, the State of California's RPS excludes large hydroelectric projects greater than or equal to 30 MW from its definition of renewable energy. Therefore, the term "renewable energy" throughout this report refers to renewable energy resources that comply with the California RPS.

competitive range needed for program viability.

Introduction

This Study addresses the potential benefits and liabilities associated with forming a CCA program over an eleven-year planning horizon (2020-2030). Projected operating results are based on a variety of factors and assumptions, including but not limited to:

- Recent wholesale energy and capacity product pricing and availability;
- The County's desired electric power portfolio composition, which is expected to include significant use of renewable energy and other GHG-free energy sources;
- Anticipated retail generation rates of SCE and PG&E, the incumbent IOUs within the County;
- Estimated PCIA rates and other surcharges, or exit fees, which are imposed on CCA customers;
- Expected financing and administrative costs of the CCA program;
- Other cost elements at the time of assessment completion; and
- PEA's extensive direct experience with many of California's operational CCA programs.[3]

As requested by SBC, PEA evaluated the operating feasibility of three specific CCA membership configurations: ***Scenario 1***) formation of a regional CCA initiative serving all municipalities located within Santa Barbara County (unincorporated areas of the County as well as each municipality located therein); ***Scenario 2***) formation of a CCA program exclusively serving customers located within the unincorporated areas of Santa Barbara County; and ***Scenario 3***) formation of a CCA program exclusively serving customers located in the City of Santa Barbara (City). PEA was tasked to deliver the following items for each membership Scenario:

1. Rate comparisons for SCE and PG&E under three (3) different supply scenarios, for which the SBC project team specified the amount of renewable energy to be included - RPS tracking, 50% renewable, and 75% renewable;
2. Portfolio composition comparisons for SCE and PG&E under the three (3) aforementioned supply scenarios; and
3. Pro forma cash flow reports for SCE and PG&E under each of SBC's three (3) supply scenarios – such cash flow reports were to include detail regarding anticipated revenues and costs associated with CCA program operation, including power supply costs, administrative and overhead costs, start-up costs and planned financial reserves.

Unless otherwise noted, the term "SBC" is used throughout this document to depict all three membership Scenarios.

SBC's Prospective Customers

Currently, electric customers within SBC are served by either SCE or PG&E, depending on the geographic area in which such customers reside. Collectively, the IOUs serve approximately 150,000 combined

[3] PEA has unique experience with California CCA program evaluation, development and operation, having provided broad functional support to many operational California CCAs, including Marin Clean Energy, Sonoma Clean Power, Lancaster Choice Energy, CleanPowerSF, Peninsula Clean Energy, Silicon Valley Clean Energy, Pioneer Community Energy and Monterey Bay Community Power.

electric accounts (85,377 by SCE, and 65,142 by PG&E) within all the communities of Santa Barbara County, representing a mix of residential (≈85%), commercial (≈13%) and agricultural (≈2%) accounts.[4] These customers consume nearly 2.6 billion kilowatt hours ("kWh") of electric energy each year.[5] While the majority of customers fall under the residential classification, such accounts historically consume only 26% of the total electricity delivered by the IOUs. The balance of SBC's historical electricity sales (74% of the total) are substantially related to commercial (≈32%), industrial (≈30%) and agricultural (≈10%) usage. Based on historical data that was evaluated during this Study, peak annual customer demand in SBC, which represents the highest level of instantaneous energy consumption during a particular year, occurred during the month of September and totaled 428 megawatts (MW), which is equivalent to the amount of electricity produced by a small combined-cycle natural gas-fired power plant. In consideration of the unique membership scenarios that are being evaluated as part of this Study, it is also noteworthy that unincorporated SBC (reflective of Scenario 2 membership) has approximately 52,000 total customer accounts served by the IOUs; such accounts consume approximately 1.3 billion total kWh annually. The City of Santa Barbara (which reflects the Scenario 3 membership configuration) has approximately 41,000 customer accounts, all of which are located within the SCE service territory, that consume approximately 400 million kWh annually.

Under CCA service, each of these accounts could be enrolled in the SBC program; the precise timing of customer enrollment phasing, if any, would be determined during the implementation period. For purposes of this study it was assumed that all customers would be enrolled during the month of January 2020, which is the earliest time that a CCA program could launch under current State regulations. Consistent with California law, customers may elect to take service from the CCA provider or remain with SCE or PG&E, a process known as "opting-out." For purposes of the Study, PEA utilized current participatory statistics compiled by the operating CCA programs to derive an assumed participation rate of 90% for the SBC program; the remaining 10% of regional customers (not including Direct Access customers, which would not be enrolled by the CCA program for purposes of avoiding duplicative customer charges and/or contractual issues for such accounts) are assumed to opt-out of the SBC program and would continue receiving generation service from the IOUs. Customer account and energy usage projections referenced throughout this Study reflect such adjustment.

SBC's Indicative Supply Scenarios

For purposes of the Study, SBC identified three indicative supply scenarios which were designed to test the viability of prospective CCA operations under a variety of energy resource compositions, balancing SBC's interest in reducing GHG emissions through increased use of GHG-free electric energy sources with SBC's desire for rate affordability.

The following supply scenarios were identified by the SBC project team for purposes of completing this CCA Study:

- **Supply Scenario 1**: RPS tracking (33% renewable energy content in 2020, annually increasing to

[4] Prospective account totals reflect only bundled customers served exclusively by the applicable IOU and exclude Direct Access customers who procure their electricity supply from a provider other than PG&E or SCE.

[5] Reflects bundled customer electricity usage in calendar year 2015.

50% in 2030).[6, 7]

- **Supply Scenario 2**: Constant 50% renewable energy content throughout the entirety of the study period.
- **Supply Scenario 3**: Constant 75% renewable energy content throughout the entirety of the study period.

When considering the prospective supply scenarios evaluated in this Study, SBC should understand that it is not limited to any particular scenario assessed in this Study. The Study's supply scenarios serve to demonstrate the potential operating outcomes of a new CCA program under a broad range of energy resource compositions that generally reflect key objectives of SBC. Prior to the procurement of any particular energy products, SBC would have an opportunity to refine its desired resource mix, which may differ from the prospective scenarios reflected herein.

Portfolio Composition

When considering SBC's projected portfolio composition, it is important to note that current market pricing for renewable and GHG-free power sources is becoming increasingly cost competitive when compared to conventional generating technologies. This trend has allowed for the inclusion of high proportions of GHG-free electricity within each of SBC's prospective supply scenarios while generally retaining cost competitiveness.

In calculating the portfolio composition for each supply scenario in years 1 and 11, PEA was instructed to maintain SBC's projected GHG-free energy content at a level that did not fall below similar projections for the IOUs. The GHG estimates for PG&E were significantly influenced by its ongoing use of nuclear generation, which is generally recognized as GHG-free. In particular, the Diablo Canyon Power Plant (DCPP) produces approximately 24% of the utility's total annual electric energy requirements[8]; although the facility's two reactor units will discontinue operations (in 2024 and 2025, respectively) during the latter portion of the Study period, potential sources of necessary replacement power remain unknown. Furthermore, it remains to be seen if any replacement power will be necessary at the time of DCPP closure, as increased CCA expansion throughout California has transitioned a significant portion of PG&E's historical generation service obligation to CCA providers.

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[6] Consistent with California's RPS laws, retail sellers of electric energy, including CCAs, must procure a minimum 33% of all electricity from eligible renewable energy sources by 2020; with the recent enrollment of Senate Bill 350, California's RPS procurement mandate has been increased to 50% by 2030.

[7] Industry accepted GHG accounting practices generally recognize eligible renewable energy sources as GHG-free. However, California's ongoing implementation of Assembly Bill 1110 (Ting, 2016) will likely alter such practices, imposing a new retail-level GHG emissions calculation methodology that may eliminate the emissions benefits historically attributed to certain renewable energy products. In particular, the California Energy Commission's recent staff proposal regarding AB 1110 implementation suggests that many Bucket 2 renewable energy products and all Bucket 3 products would be ascribed a non-zero GHG emissions rate generally equivalent to system-wide purchases. Specific details regarding AB 1110 implementation remain under development and will not be finalized until later in 2018 or early 2019. Note that AB 1110 will be effective for all power purchases occurring on and after January 1, 2019. Also, under all supply scenarios, incremental purchases of non-RPS-eligible GHG-free sources, specifically electricity produced by larger hydroelectric resources (with nameplate generating capacity in excess of 30 megawatts) would be procured by SBC to achieve targeted GHG emissions reductions.

[8] As reflected in PG&E's 2016 Power Content Label.

In substantial part, the forecasted increase in PG&E's GHG-free supply directly results from the large amount of departing load, much of which is related to CCA expansion, within its service territory. When such transitions occur, certain GHG-free generation sources within PG&E's supply portfolio, namely nuclear power plants, hydroelectric generation and certain renewable generating technologies, generally continue to operate without adjustment for such load/sales reductions. This has the effect of inducing meaningful increases in the proportion of GHG-free energy reflected within PG&E's supply mix. In fact, PG&E recently reported a significant year-over-year reduction in its portfolio GHG emissions factor for calendar year 2016, which reflects the aforementioned phenomenon. During 2016, the proportion of PG&E's supply portfolio attributable to GHG-free resources approximated 69%; in 2017, PG&E announced that its GHG-free portfolio had increased to nearly 79%[9], which will likely translate to further reductions in the utility's emissions factor. PEA anticipates further GHG emissions reductions for PG&E as additional customers continue to depart for CCA alternatives.[10] Separately, SCE's GHG-free energy content has stayed relatively flat from 2015 to 2016, but is expected to trend higher with the 2018 launch of Clean Power Alliance of Southern California (formerly known as Los Angeles Community Choice Energy) and other existing and emerging CCAs (e.g., City of Lancaster, Apple Valley Clean Energy). This noted, the IOUs have sold, and may continue to sell, some of their respective renewable energy supplies in anticipation of reduced customer sales. Depending on the magnitude of such renewable energy sales, which are contingent upon CPUC approval, the anticipated increase in GHG-free power content within each IOU's supply portfolio may be somewhat moderated.

The various energy supply components underlying each supply scenario are broadly categorized as:

- Conventional Supply (generally electric energy produced through the combustion of fossil fuels, particularly natural gas within the California energy market);
- "Bucket 1" Renewable Energy Supply (generally renewable energy produced by generating resources located within or delivering power directly to California);
- "Bucket 2" Renewable Energy Supply (generally renewable generation produced outside of California with associated energy import requirements);
- "Bucket 3" Renewable Energy Supply (environmental attributes of metered renewable energy production, conferred in the form of a renewable energy certificate (REC), which is sold separately from the electric power; Bucket 3 renewable energy is commonly produced outside of California and is colloquially referred to as an "unbundled REC"); and
- Additional GHG-Free Supply (generally power produced by regionally located hydroelectric generating facilities, which do not meet the eligibility requirements of California's RPS program – such requirements render larger hydroelectric generators in excess of 30 MW ineligible to participate in California's RPS program).

Table 1 below displays PG&E's and SCE's proportionate use of various power sources during the most recent reporting year (2016) compared with California's aggregate resource mix. During the Study period, planned increases in California's RPS procurement mandate and various other factors, including customer departures for CCA service, will contribute to periodic changes in PG&E's and SCE's noted resource mix. Such changes will affect projected GHG emissions comparisons between SBC and PG&E/SCE.

[9] http://www.pgecurrents.com/2018/02/20/pge-clean-energy-deliveries-already-meet-future-goals/.
[10] http://www.pgecurrents.com/2018/03/26/independent-registry-confirms-record-low-carbon-emissions-for-pge/.

Table 1: 2016 PG&E, SCE and California Power Mix

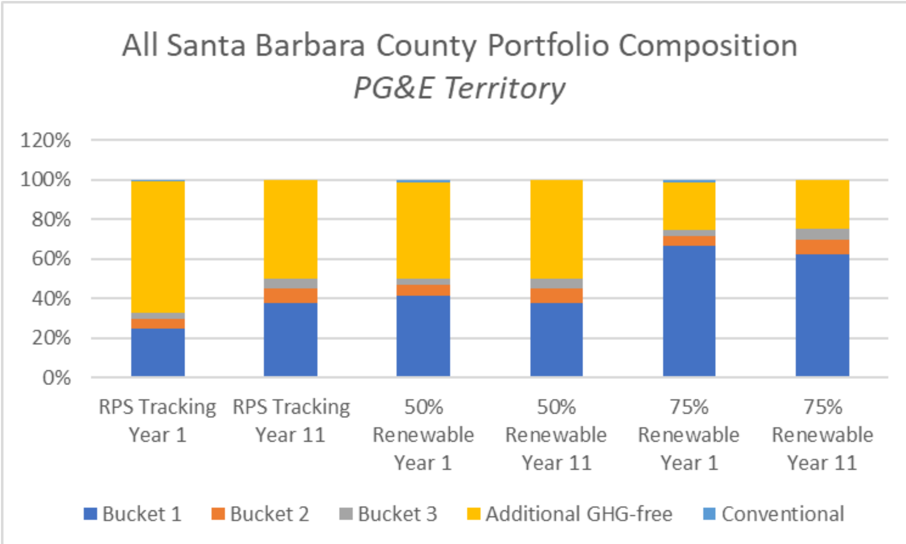
Energy Resource	2016 PG&E Power Mix[1]	2016 SCE Power Mix[2]	2016 California Power Mix[3]
Eligible Renewable	**33%**	**28%**	**25%**
--Biomass & Waste	4%	1%	2%
--Geothermal	5%	7%	4%
--Small Hydroelectric	3%	0%	2%
--Solar	13%	10%	8%
--Wind	8%	10%	9%
Coal	0%	0%	4%
Large Hydroelectric	12%	6%	10%
Natural Gas	17%	19%	37%
Nuclear	24%	6%	9%
Unspecified Sources of	14%	41%	15%
Total[4]	**100%**	**100%**	**100%**

[1]*Source: PG&E 2016 Power Source Disclosure Report*
[2]*Source: SCE 2016 Power Source Disclosure Report*
[3]*Source: California Energy Commission - http://www.energy.ca.gov/almanac/electricity_data/total_system_power.html*
[4]*Numbers may not add due to rounding*

Regarding SBC's anticipated clean energy supply, each prospective supply scenario yielded different environmental benefits, resulting from the diverse composition of clean energy sources within each unique resource mix. In comparison to PG&E's and SCE's prospective supply portfolios, all supply scenarios would yield GHG emissions that are at parity with or below similar projections for the IOUs. As previously noted, PG&E's proportionate share of GHG-free supply has increased in recent years and is expected to further increase as additional CCA organizations commence operations within its service territory. In order to maintain a favorable relationship with regard to this key element of SBC's CCA service offering (within areas currently served by PG&E), PEA projected minimal use of conventional power sources and/or market purchases throughout the Study period. The expected portfolio composition within SCE's service territory is rather different, as this IOU is not expected to offer the same level of GHG-free supply to its customers. As such, conventional power and/or market purchases range from approximately 25% to 36% within the SCE service territory throughout the Study period.

More specifically, within the PG&E service territory, Years 1 and 11 of the Study period reflected an anticipated resource mix that was approximately 99% and 100% GHG-free, respectively. Such a portfolio composition was necessary to remain competitive with PG&E in terms of SBC's GHG-free energy content – due to PG&E's anticipated resource composition and the SBC Study Team's interest in retaining year-over-year portfolio compositions that did not regress in terms of GHG-free supply, the CCA's supply portfolio within PG&E's service territory reflected near-zero use of conventional power sources during each year of the Study period. When comparing each of the projected supply scenarios, the aforementioned GHG-free content was achieved by interlacing varying portions of renewable energy and hydroelectricity to balance SBC's somewhat competing environmental and rate-related objectives. Additional detail regarding the projected CCA supply portfolio in Years 1 and 11 of the Study period is provided in Chart 1.

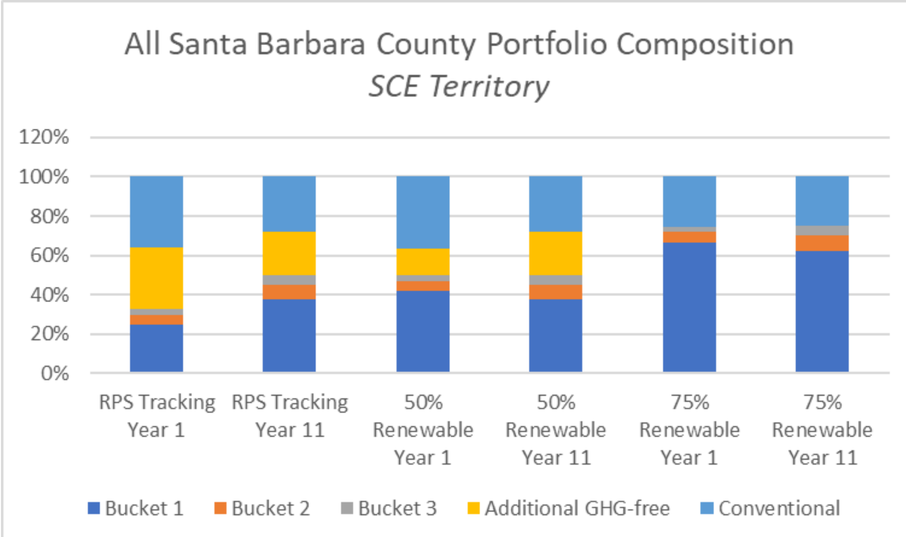
Chart 1 – All Santa Barbara County Portfolio Composition PG&E Territory



PG&E (All Santa Barbara County)	Bucket 1	Bucket 2	Bucket 3	Additional GHG-free	Total GHG-free	Conventional	Emissions Factor (lbs. CO2e/MWh)
Supply Scenario 1 (RPS Tracking Year 1)	25%	5%	3%	66%	99%	1%	9
Supply Scenario 1 (RPS Tracking Year 11)	38%	8%	5%	50%	100%	0%	-
Supply Scenario 2 (50% Renewable Year 1)	42%	5%	3%	49%	99%	1%	12
Supply Scenario 2 (50% Renewable Year 11)	38%	8%	5%	50%	100%	0%	-
Supply Scenario 3 (75% Renewable Year 1)	67%	5%	3%	24%	99%	1%	12
Supply Scenario 3 (75% Renewable Year 11)	63%	8%	5%	25%	100%	0%	-

For the SCE service territory, the CCA's projected use of GHG-free energy resources was proportionately lower, as SCE is not expected to offer the same composition of clean resources relative to PG&E. As reflected in Chart 2, the CCAs use of conventional power sources and/or market purchases is expected to range from 25% to 36% within the SCE service territory throughout the Study period; the balance of the CCA's resource mix would be sourced from a variety of renewable and additional GHG-free supply.

Chart 2 – All Santa Barbara County Portfolio Composition SCE Territory



SCE (All Santa Barbara County)	Bucket 1	Bucket 2	Bucket 3	Additional GHG-free	Total GHG-free	Conventional	Emissions Factor (lbs. CO2e/MWh)
Supply Scenario 1 (RPS Tracking Year 1)	25%	5%	3%	31%	64%	36%	340
Supply Scenario 1 (RPS Tracking Year 11)	38%	8%	5%	22%	72%	28%	264
Supply Scenario 2 (50% Renewable Year 1)	42%	5%	3%	14%	64%	36%	342
Supply Scenario 2 (50% Renewable Year 11)	38%	8%	5%	22%	72%	28%	264
Supply Scenario 3 (75% Renewable Year 1)	67%	5%	3%	0%	75%	25%	238
Supply Scenario 3 (75% Renewable Year 11)	63%	8%	5%	0%	75%	25%	236

Residential Rate Cost Impacts

PEA was also requested to evaluate the anticipated cost impacts resulting from CCA service commencement for a typical residential customer during each year of the Study period. Such impacts vary with the quantity of renewable energy that is assumed to be included within each of the three projected supply scenarios and the amount of electricity that a typical residential customer is expected to use (under the All-County membership configuration, an average residential customer is expected to use 436 kWh/month within the PG&E service territory and 462 kWh/month within the SCE service territory).[11] On average, residential bill impacts throughout the Study period were favorable (meaning that residential customers were generally expected to experience slightly reduced costs under CCA service) across all three membership configurations. In particular, supply scenarios 1 (33% to 50% renewable) and 2 (50% renewable) demonstrated rate/cost savings under all of the membership configurations while supply scenario 3 (75% renewable) was only rate-favorable under the All-County membership configuration. Details of the cost impact on residential bills of the varying levels of GHG-free resources can be found in Table 2.

[11] Monthly average usage figures were derived using historical usage data for residential customers within Santa Barbara County.

Table 2 – Residential Bill Impacts

Residential Bill Impacts ($/Month)															
KWh/Mo	Membership	Supply	IOU	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Average
436	All	RPS	PG&E	$ (2.68)	$ (3.33)	$ (3.17)	$ (3.32)	$ (3.50)	$ (3.70)	$ (3.36)	$ (3.53)	$ (4.24)	$ (4.29)	$ (4.38)	$ (3.59)
436	All	50%	PG&E	$ (0.90)	$ (2.04)	$ (2.06)	$ (2.32)	$ (2.62)	$ (2.93)	$ (2.71)	$ (3.01)	$ (3.85)	$ (4.03)	$ (4.25)	$ (2.79)
436	All	75%	PG&E	$ 1.20	$ (0.02)	$ (0.09)	$ (0.35)	$ (0.63)	$ (0.92)	$ (0.67)	$ (0.94)	$ (1.78)	$ (1.95)	$ (2.16)	$ (0.76)
512	Unincorporated	RPS	PG&E	$ (0.22)	$ (1.87)	$ (1.59)	$ (1.63)	$ (1.73)	$ (1.85)	$ (1.45)	$ (1.50)	$ (2.43)	$ (2.44)	$ (2.45)	$ (1.74)
512	Unincorporated	50%	PG&E	$ 1.15	$ (0.86)	$ (0.71)	$ (0.82)	$ (1.00)	$ (1.21)	$ (0.90)	$ (1.04)	$ (2.06)	$ (2.16)	$ (2.27)	$ (1.08)
512	Unincorporated	75%	PG&E	$ 3.54	$ 1.46	$ 1.55	$ 1.46	$ 1.31	$ 1.13	$ 1.48	$ 1.38	$ 0.37	$ 0.29	$ 0.22	$ 1.29
462	All	RPS	SCE	$ (2.08)	$ (2.69)	$ (2.67)	$ (2.91)	$ (3.17)	$ (3.46)	$ (3.24)	$ (3.51)	$ (4.34)	$ (4.52)	$ (4.73)	$ (3.39)
462	All	50%	SCE	$ (0.69)	$ (1.65)	$ (1.73)	$ (2.03)	$ (2.37)	$ (2.74)	$ (2.62)	$ (2.99)	$ (3.94)	$ (4.25)	$ (4.60)	$ (2.69)
462	All	75%	SCE	$ 0.93	$ (0.01)	$ (0.08)	$ (0.31)	$ (0.57)	$ (0.86)	$ (0.65)	$ (0.94)	$ (1.82)	$ (2.06)	$ (2.33)	$ (0.79)
642	Unincorporated	RPS	SCE	$ (0.20)	$ (1.77)	$ (1.57)	$ (1.66)	$ (1.83)	$ (2.02)	$ (1.64)	$ (1.75)	$ (2.91)	$ (3.00)	$ (3.09)	$ (1.95)
642	Unincorporated	50%	SCE	$ 1.04	$ (0.82)	$ (0.69)	$ (0.84)	$ (1.06)	$ (1.32)	$ (1.01)	$ (1.21)	$ (2.47)	$ (2.66)	$ (2.87)	$ (1.26)
642	Unincorporated	75%	SCE	$ 3.21	$ 1.38	$ 1.53	$ 1.49	$ 1.38	$ 1.24	$ 1.68	$ 1.60	$ 0.45	$ 0.36	$ 0.27	$ 1.33
376	City	RPS	SCE	$ (0.12)	$ 0.03	$ (0.43)	$ (1.20)	$ (1.20)	$ (1.98)	$ (1.85)	$ (2.64)	$ (3.93)	$ (5.29)	$ (6.04)	$ (2.24)
376	City	50%	SCE	$ 0.89	$ 0.93	$ 0.35	$ (0.50)	$ (0.58)	$ (1.45)	$ (1.42)	$ (2.31)	$ (3.71)	$ (5.17)	$ (6.04)	$ (1.73)
376	City	75%	SCE	$ 2.48	$ 2.49	$ 1.90	$ 1.07	$ 2.80	$ 1.96	$ 2.04	$ 1.19	$ (0.21)	$ (3.40)	$ (4.24)	$ 0.73

General Operating Projections

When reviewing the pro forma financial results associated with each of the prospective supply scenarios, the projected "Net Surplus/Deficit" during each year of the Study period reflects the projected net revenues (or deficits) that would be realized by SBC if the program decided to offer customer electric rates that were equivalent to similar rates charged by the IOUs. To the extent that the Net Surplus/Deficit is positive, SBC would have the potential to offer comparatively lower customer rates/charges, relative to similar rates imposed by the IOUs; to the extent that the Net Surplus/Deficit is negative, SBC would need to impose comparatively higher generation rates to recover expected costs, or risk running an operating deficit that would need to be funded through accrued reserves or other unanticipated revenue sources.

The initial results for the combined-IOU pro formas indicate several instances of projected net surpluses under all membership configurations. For the All-County membership configuration, both the RPS-tracking and the 50% renewable energy supply scenario scenarios project a net surplus starting in 2020 (see Exhibits 5 and 6); the 75% renewable energy supply scenario projects a net surplus starting a year later in 2021 (see Exhibit 7). For the Unincorporated County-only membership configuration, the RPS-tracking and 50% renewable energy supply scenarios project a net surplus starting in 2020 and 2021 respectively (see Exhibits 8-9); the 75% renewable energy supply scenario is expected to generate budget deficits in each year of the Study period (see Exhibit 10), unless rates are set above the IOUs. In the City-only membership configuration, the RPS-tracking supply scenario projects a net surplus starting in 2020; the 50% renewable energy supply and 75% energy supply scenarios project a net surplus starting in 2023 and 2028, respectively (see Exhibits 11-13). Key assumptions used in PEA pro forma analyses are listed in Exhibit 1.

Ultimately, the use of any projected net revenues will be determined by SBC leadership during periodic budgeting and rate-setting processes. Such net revenues could be passed through to SBC customers in the form of comparatively lower electric rates/charges, utilized as working capital for program operations in an attempt to reduce program financing requirements, or SBC leadership could strike a balance between reduced rates and increased funding for complementary energy programs, such as Net Energy Metering, customer rebates (to promote local distributed renewable infrastructure buildout or energy efficiency, for example) as well as other similarly focused programs. SBC leadership would have considerable flexibility in administering the disposition of any projected net revenues, subject to any financial covenants that may be entered into by the program.

Findings and Conclusions

Based on the analyses conducted throughout this Study, PEA has identified several electric supply options that could provide rate savings compared with the incumbent IOUs. The All-County membership configuration (Scenario 1) proved to be the most promising as it incorporated the combined rates of both IOUs, while the City-Only membership scenario (Scenario 3) was the most financially challenging as it only included the comparatively lower SCE generation rate (which necessitates lower CCA generation rates to remain competitive in this aspect of service delivery). Projected rate savings varied with the amount of renewable energy included in the CCA's supply portfolio, with the lower range of renewables (RPS-tracking supply scenario) offering greater savings over the supply scenarios with higher renewable content (50% and 75% renewable supply scenarios).

Ultimately, SBC's rate competitiveness (while also offering environmental benefits) would hinge on prevailing market prices at the time of power supply contract negotiation and execution. Depending on inevitable changes to market prices and other assumptions, such as IOU generation rates and exit fees (e.g., the PCIA), SBC's actual electric rates may be somewhat lower or higher than similar rates charged by the IOUs and would be expected to fall within a competitive range needed for program viability.

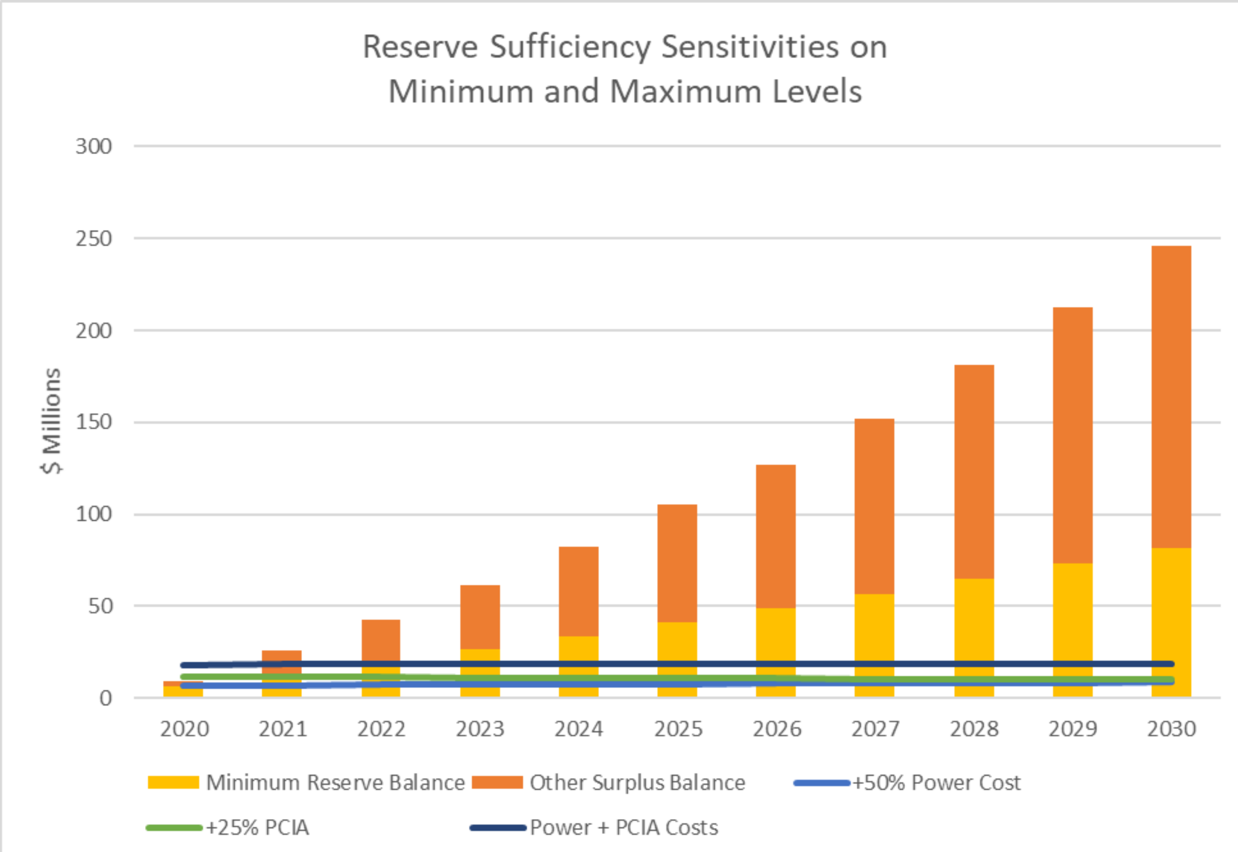
Sensitivity Analyses

In response to SBC's request to better understand the ability of the modeled reserve fund to weather adverse changes in power prices and PCIA costs, PEA performed sensitivity analyses involving the variability of those costs. The increased cost was evaluated by year relative to: 1) accumulated reserves (Minimum Reserve Levels); and 2) accumulated reserves plus accumulated surpluses (Maximum Reserve Levels). Baseline PCIA projections comprise approximately 30-40% of the CCA customer's generation costs. To represent a reasonable range of outcomes, PCIA costs were increased by 25% relative to the baseline projections. Power costs were stressed assuming a 50% increase in costs associated with the CCA program's annual open position, which is expected to be approximately 10% of total energy requirements during each year of program operation.[12]

When compared to Minimum Reserve Levels, a 50% increase in spot market power costs could be fully absorbed as early as 2020. In the unlikely event that both contingencies were to occur at the same time, the Minimum Reserve balance would be sufficient to cover the combined cost increase beginning in 2022. As compared to Maximum Reserve Levels, SBC could absorb a 50% increase in power costs as early as 2020, and could manage the impact of both a 25% increase in PCIA costs and 50% increase in power prices as early as 2021. Further details can be seen in Chart 3.

[12] Volatility on power prices was derived using historical prices over the past 10 years, which captures the market movements during the natural gas boom/bust and the Great Recession. In order to capture extreme movements, the prices were stressed using a 95% confidence interval. The PCIA sensitivity is similarly expected to capture a range of reasonably likely outcomes for that cost variable.

Chart 3 – All Santa Barbara County 50% Renewable Energy Supply Sensitivity Analyses



All Santa Barbara County 50% Renewable											
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Minimum Reserve Balance	6	13	19	26	34	41	49	57	65	73	82
Other Surplus Balance	3	13	23	35	48	64	79	95	117	140	164
Maximum Reserve Balance	9	26	42	61	82	105	127	152	181	213	246
+50% Power Cost	6	7	7	7	7	8	8	8	8	8	9
+25% PCIA	12	12	11	11	11	11	11	10	10	10	10
Power + PCIA Costs	18	18	18	18	18	18	19	19	19	19	19
Total	-9	7	24	43	64	87	109	133	163	194	227

EXHIBIT 1 – KEY ASSUMPTIONS

Generally

- Customer opt-out rate of 10% for all scenarios.
- Start-up costs of approximately $7-10 million (consisting predominantly of 80% working capital, and 20% startup costs), sourced from an interest-free General Fund loan for the City of Santa Barbara only scenario, and a 3% interest-only bank loan with a 1 - year balloon principal payment for All Santa Barbara County and Unincorporated Santa Barbara scenarios.
- Annual reserve contributions fixed at 4% of annual revenue.
- Based on published market prices and recent transactions for similar energy products, average energy costs were modeled as follows:

PG&E ($/MWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Shaped Energy	$ 34.24	$ 37.10	$ 38.45	$ 39.41	$ 40.40	$ 41.41	$ 42.44	$ 43.50	$ 44.59	$ 45.70	$ 46.85
Bucket 1	$ 18.25	$ 18.50	$ 18.75	$ 19.22	$ 19.70	$ 20.19	$ 20.70	$ 21.21	$ 21.74	$ 22.29	$ 22.85
Bucket 2	$ 8.50	$ 9.00	$ 9.00	$ 9.23	$ 9.46	$ 9.69	$ 9.93	$ 10.18	$ 10.44	$ 10.70	$ 10.97
Bucket 3	$ 2.25	$ 2.50	$ 2.75	$ 2.82	$ 2.89	$ 2.96	$ 3.04	$ 3.11	$ 3.19	$ 3.27	$ 3.35
System RA ($/KW-Mo)	$ 2.38	$ 2.43	$ 2.48	$ 2.54	$ 2.60	$ 2.67	$ 2.74	$ 2.80	$ 2.88	$ 2.95	$ 3.02
Bay Area RA ($/KW-Mo)	$ 3.88	$ 3.93	$ 3.98	$ 4.08	$ 4.18	$ 4.29	$ 4.39	$ 4.50	$ 4.61	$ 4.73	$ 4.85
Other PG&E RA ($/KW-Mo)	$ 3.38	$ 3.43	$ 3.48	$ 3.57	$ 3.66	$ 3.75	$ 3.84	$ 3.94	$ 4.03	$ 4.14	$ 4.24
Carbon Free Premium	$ 2.50	$ 3.00	$ 3.50	$ 3.59	$ 3.68	$ 3.77	$ 3.86	$ 3.96	$ 4.06	$ 4.16	$ 4.26

SCE ($/MWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Shaped Energy	$ 34.24	$ 37.10	$ 38.45	$ 39.19	$ 40.18	$ 40.83	$ 43.62	$ 44.32	$ 43.56	$ 44.59	$ 45.45
Bucket 1	$ 18.25	$ 18.50	$ 18.75	$ 19.22	$ 19.70	$ 20.19	$ 20.70	$ 21.21	$ 21.74	$ 22.29	$ 22.85
Bucket 2	$ 8.50	$ 9.00	$ 9.00	$ 9.23	$ 9.46	$ 9.69	$ 9.93	$ 10.18	$ 10.44	$ 10.70	$ 10.97
Bucket 3	$ 2.25	$ 2.50	$ 2.75	$ 2.82	$ 2.89	$ 2.96	$ 3.04	$ 3.11	$ 3.19	$ 3.27	$ 3.35
System RA ($/KW-Mo)	$ 3.15	$ 3.23	$ 3.31	$ 3.39	$ 3.48	$ 3.56	$ 3.65	$ 3.74	$ 3.84	$ 3.93	$ 4.03
LA Basin ($/KW-Mo)	$ 3.15	$ 3.23	$ 3.31	$ 3.39	$ 3.48	$ 3.56	$ 3.65	$ 3.74	$ 3.84	$ 3.93	$ 4.03
BC/Ventura ($/KW-Mo)	$ 3.15	$ 3.23	$ 3.31	$ 3.39	$ 3.48	$ 3.56	$ 3.65	$ 3.74	$ 3.84	$ 3.93	$ 4.03
Flexible ($/KW-Mo)	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11	$ 0.11
Carbon Free Premium	$ 2.50	$ 3.00	$ 3.50	$ 3.59	$ 3.68	$ 3.77	$ 3.86	$ 3.96	$ 4.06	$ 4.16	$ 4.26

- No utility-scale local generation supply sources were assumed within Santa Barbara County. Bucket 1 supply is generally from in-state renewable resources, Buckets 2 and 3 are from out-of-state, and additional GHG-free is assumed to be coming from large hydro electric generators in California and the Pacific Northwest.
- Approximately 10% of SBC's load would be met by purchases from the CAISO market.
- The required CCA bond is assumed at $100,000, consistent with current requirements.
- Annual staffing costs were derived by benchmarking to currently operating CCAs of similar size that range from approximately $558,000 for City-only to $3,500,000 for All Santa Barbara and Unincorporated Santa Barbara, with corresponding staffing levels ranging from 3 to approximately 20, respectively.
- All scenarios consider a single phase of customer enrollments.
- Uncollectable debts are assumed at 0.5% of revenue, consistent with current bad debt levels seen by other CCAs.
- No voluntary 100% opt-up renewable energy program was modeled; the estimated impact of offering a voluntary opt-up program is de minimus with respect to portfolio planning and program finances.

- The impact of DERs on CCA load is considered to the extent that it will be offset by growth in other areas such as the increase in demand from electric vehicles.

SCE Inputs

Annual Rate Growth[13]

- Generation rates:

SCE Generation Annual Average Rates ($/MWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
D	$ 60.26	$ 63.99	$ 67.73	$ 71.47	$ 75.21	$ 78.98	$ 82.76	$ 86.58	$ 90.43	$ 94.32	$ 98.25
GS-1	$ 67.24	$ 70.49	$ 73.77	$ 77.08	$ 80.42	$ 83.80	$ 87.22	$ 90.69	$ 94.22	$ 97.80	$ 101.44
TC-1	$ 52.71	$ 55.16	$ 57.64	$ 60.15	$ 62.68	$ 65.24	$ 67.84	$ 70.48	$ 73.17	$ 75.90	$ 78.67
GS-2	$ 54.26	$ 57.50	$ 60.74	$ 63.98	$ 67.24	$ 70.52	$ 73.81	$ 77.14	$ 80.50	$ 83.89	$ 87.33
TOU-GS	$ 53.27	$ 56.20	$ 59.14	$ 62.09	$ 65.06	$ 68.06	$ 71.08	$ 74.13	$ 77.22	$ 80.35	$ 83.52
TOU-8-Sec	$ 52.66	$ 55.40	$ 58.16	$ 60.93	$ 63.73	$ 66.55	$ 69.40	$ 72.29	$ 75.21	$ 78.18	$ 81.19
TOU-8-Pri	$ 48.76	$ 51.30	$ 53.85	$ 56.42	$ 59.01	$ 61.62	$ 64.26	$ 66.94	$ 69.64	$ 72.39	$ 75.18
TOU-8-Sub	$ 43.85	$ 46.20	$ 48.55	$ 50.92	$ 53.30	$ 55.70	$ 58.13	$ 60.58	$ 63.06	$ 65.58	$ 68.14
TOU-PA-2	$ 49.83	$ 52.53	$ 55.23	$ 57.94	$ 60.68	$ 63.43	$ 66.22	$ 69.03	$ 71.88	$ 74.77	$ 77.70
TOU-PA-3	$ 42.32	$ 44.37	$ 46.43	$ 48.51	$ 50.61	$ 52.74	$ 54.89	$ 57.07	$ 59.29	$ 61.54	$ 63.84
Street Lights	$ 43.38	$ 44.68	$ 46.02	$ 47.40	$ 48.83	$ 50.29	$ 51.80	$ 53.36	$ 54.96	$ 56.61	$ 58.31

- Exit fees (Cost responsibility surcharge):

Cost Responsibility Surcharge SCE Average Rates ($/MWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
D	$ 21.45	$ 20.16	$ 18.95	$ 17.82	$ 16.75	$ 15.74	$ 14.80	$ 13.91	$ 13.08	$ 12.29	$ 11.55
GS-1	$ 13.76	$ 12.93	$ 12.16	$ 11.43	$ 10.74	$ 10.10	$ 9.49	$ 8.92	$ 8.39	$ 7.88	$ 7.41
TC-1	$ 9.74	$ 9.15	$ 8.60	$ 8.09	$ 7.60	$ 7.15	$ 6.72	$ 6.31	$ 5.93	$ 5.58	$ 5.24
GS-2	$ 17.89	$ 16.82	$ 15.81	$ 14.86	$ 13.97	$ 13.13	$ 12.34	$ 11.60	$ 10.91	$ 10.25	$ 9.64
TOU-GS	$ 14.81	$ 13.92	$ 13.09	$ 12.30	$ 11.57	$ 10.87	$ 10.22	$ 9.61	$ 9.03	$ 8.49	$ 7.98
TOU-8-Sec	$ 12.93	$ 12.16	$ 11.43	$ 10.74	$ 10.10	$ 9.49	$ 8.92	$ 8.39	$ 7.88	$ 7.41	$ 6.97
TOU-8-Pri	$ 11.99	$ 11.27	$ 10.59	$ 9.96	$ 9.36	$ 8.80	$ 8.27	$ 7.77	$ 7.31	$ 6.87	$ 6.46
TOU-8-Sub	$ 11.43	$ 10.74	$ 10.10	$ 9.49	$ 8.92	$ 8.39	$ 7.88	$ 7.41	$ 6.97	$ 6.55	$ 6.16
TOU-PA-2	$ 13.32	$ 12.52	$ 11.77	$ 11.06	$ 10.40	$ 9.77	$ 9.19	$ 8.64	$ 8.12	$ 7.63	$ 7.17
TOU-PA-3	$ 8.65	$ 8.13	$ 7.64	$ 7.18	$ 6.75	$ 6.35	$ 5.97	$ 5.61	$ 5.27	$ 4.96	$ 4.66
Street Lights	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.01	$ 0.01	$ 0.01	$ 0.01
TOU-8-S-Pri	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

- Annual load growth is assumed at 0.5%

CAISO costs

- CAISO cost: $1.60/MWh
- Distribution losses: 6%
- Scheduling fees: $0.40/MWh

Other costs

- Data Manager Charges of $1.15 per account per month
- Utility Service Fees of $1.25 per account per month

[13] Rate projections are based on current rates which are then projected forward consistent with PEA price assumptions and the resource plans published by the IOUs.

PG&E Inputs

Annual Rate Growth

- Generation rates:

PG&E Generation Annual Average Rates ($/MWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
E-1	$ 73.79	$ 74.82	$ 75.86	$ 76.91	$ 77.98	$ 79.06	$ 80.16	$ 81.28	$ 82.41	$ 83.55	$ 84.71
E-7	$ 67.63	$ 68.57	$ 69.52	$ 70.49	$ 71.47	$ 72.46	$ 73.47	$ 74.49	$ 75.53	$ 76.58	$ 77.64
A-1	$ 81.85	$ 82.99	$ 84.15	$ 85.31	$ 86.50	$ 87.70	$ 88.92	$ 90.16	$ 91.41	$ 92.68	$ 93.97
A-6	$ 95.51	$ 96.84	$ 98.18	$ 99.55	$ 100.93	$ 102.34	$ 103.76	$ 105.20	$ 106.66	$ 108.15	$ 109.65
A-10	$ 85.57	$ 86.76	$ 87.96	$ 89.18	$ 90.42	$ 91.68	$ 92.95	$ 94.25	$ 95.56	$ 96.89	$ 98.23
E-19-S	$ 81.01	$ 82.14	$ 83.28	$ 84.43	$ 85.61	$ 86.80	$ 88.00	$ 89.23	$ 90.47	$ 91.73	$ 93.00
E-19-P	$ 74.02	$ 75.05	$ 76.09	$ 77.15	$ 78.22	$ 79.31	$ 80.41	$ 81.53	$ 82.66	$ 83.81	$ 84.98
E-19-T	$ 55.42	$ 56.19	$ 56.97	$ 57.77	$ 58.57	$ 59.38	$ 60.21	$ 61.04	$ 61.89	$ 62.75	$ 63.63
E-20-S	$ 78.32	$ 79.41	$ 80.51	$ 81.63	$ 82.77	$ 83.92	$ 85.08	$ 86.26	$ 87.46	$ 88.68	$ 89.91
E-20-P	$ 75.80	$ 76.85	$ 77.92	$ 79.00	$ 80.10	$ 81.21	$ 82.34	$ 83.48	$ 84.65	$ 85.82	$ 87.01
E-20-T	$ 67.50	$ 68.44	$ 69.39	$ 70.35	$ 71.33	$ 72.32	$ 73.33	$ 74.35	$ 75.38	$ 76.43	$ 77.49
TC-1	$ 69.76	$ 70.73	$ 71.71	$ 72.71	$ 73.72	$ 74.74	$ 75.78	$ 76.84	$ 77.91	$ 78.99	$ 80.09
Ag	$ 73.42	$ 74.44	$ 75.48	$ 76.53	$ 77.59	$ 78.67	$ 79.76	$ 80.87	$ 82.00	$ 83.14	$ 84.29
Street Lights	$ 81.03	$ 82.16	$ 83.30	$ 84.46	$ 85.63	$ 86.82	$ 88.03	$ 89.25	$ 90.49	$ 91.75	$ 93.02

- Exit fees (PCIA and franchise fees surcharge):

PCIA and Franchise Fee Surcharge PG&E Average Rates ($/MWh)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
E-1	$ 34.01	$ 33.86	$ 33.72	$ 33.57	$ 33.43	$ 33.29	$ 33.14	$ 33.00	$ 32.86	$ 32.72	$ 32.58
E-7	$ 34.01	$ 33.86	$ 33.72	$ 33.57	$ 33.43	$ 33.29	$ 33.14	$ 33.00	$ 32.86	$ 32.72	$ 32.58
A-1	$ 25.28	$ 25.17	$ 25.06	$ 24.96	$ 24.85	$ 24.74	$ 24.63	$ 24.53	$ 24.42	$ 24.32	$ 24.21
A-6	$ 25.28	$ 25.17	$ 25.06	$ 24.96	$ 24.85	$ 24.74	$ 24.63	$ 24.53	$ 24.42	$ 24.32	$ 24.21
A-10	$ 25.68	$ 25.57	$ 25.46	$ 25.35	$ 25.24	$ 25.13	$ 25.02	$ 24.92	$ 24.81	$ 24.70	$ 24.60
E-19-S	$ 21.65	$ 21.56	$ 21.46	$ 21.37	$ 21.28	$ 21.19	$ 21.10	$ 21.01	$ 20.92	$ 20.83	$ 20.74
E-19-P	$ 21.65	$ 21.56	$ 21.46	$ 21.37	$ 21.28	$ 21.19	$ 21.10	$ 21.01	$ 20.92	$ 20.83	$ 20.74
E-19-T	$ 21.65	$ 21.56	$ 21.46	$ 21.37	$ 21.28	$ 21.19	$ 21.10	$ 21.01	$ 20.92	$ 20.83	$ 20.74
E-20-S	$ 20.83	$ 20.74	$ 20.65	$ 20.56	$ 20.47	$ 20.39	$ 20.30	$ 20.21	$ 20.12	$ 20.04	$ 19.95
E-20-P	$ 19.44	$ 19.36	$ 19.27	$ 19.19	$ 19.11	$ 19.03	$ 18.94	$ 18.86	$ 18.78	$ 18.70	$ 18.62
E-20-T	$ 17.86	$ 17.78	$ 17.71	$ 17.63	$ 17.55	$ 17.48	$ 17.40	$ 17.33	$ 17.25	$ 17.18	$ 17.11
TC-1	$ 25.28	$ 25.17	$ 25.06	$ 24.96	$ 24.85	$ 24.74	$ 24.63	$ 24.53	$ 24.42	$ 24.32	$ 24.21
Ag	$ 25.16	$ 25.05	$ 24.94	$ 24.84	$ 24.73	$ 24.62	$ 24.52	$ 24.41	$ 24.31	$ 24.20	$ 24.10
SL	$ 6.50	$ 6.47	$ 6.44	$ 6.42	$ 6.39	$ 6.36	$ 6.33	$ 6.31	$ 6.28	$ 6.25	$ 6.23

- Annual load growth is assumed at 0.5%

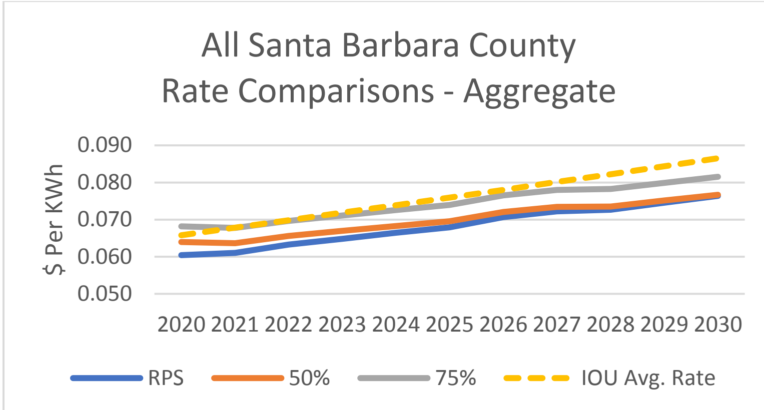
CAISO costs

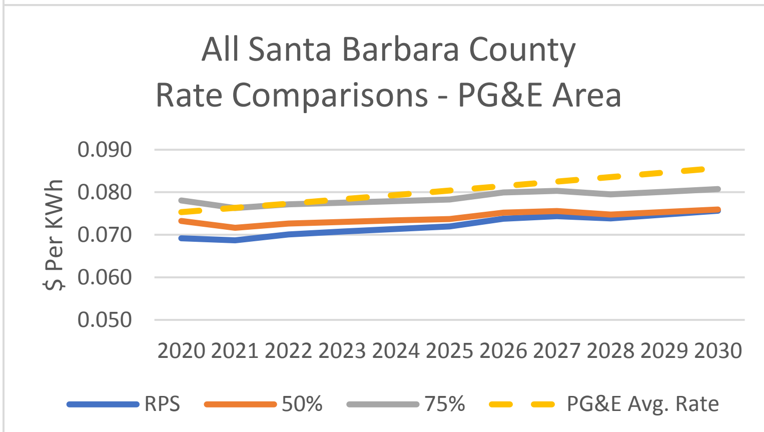
- CAISO cost: $1.60/MWh
- Distribution losses: 6%
- Scheduling fees: $0.40/MWh

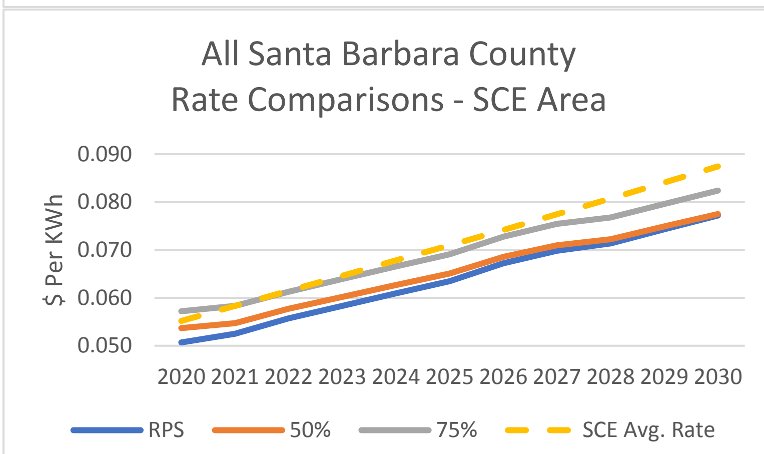
Other costs

- Data Manager Charges of $1.15 per account per month
- Utility Service Fees of $0.37 per account per month

EXHIBIT 2 – All Santa Barbara County

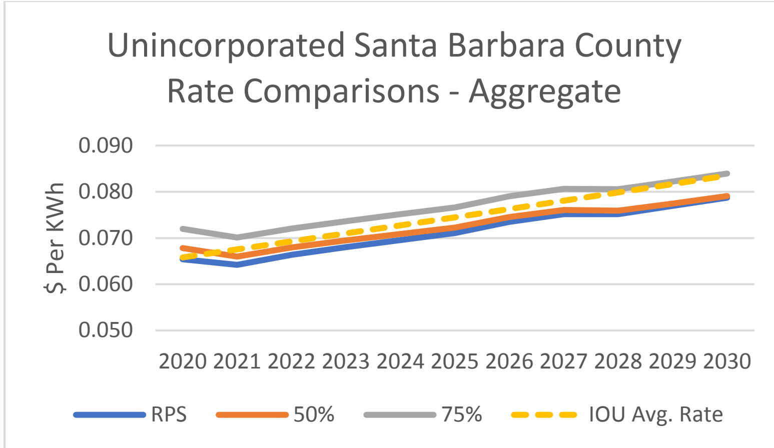


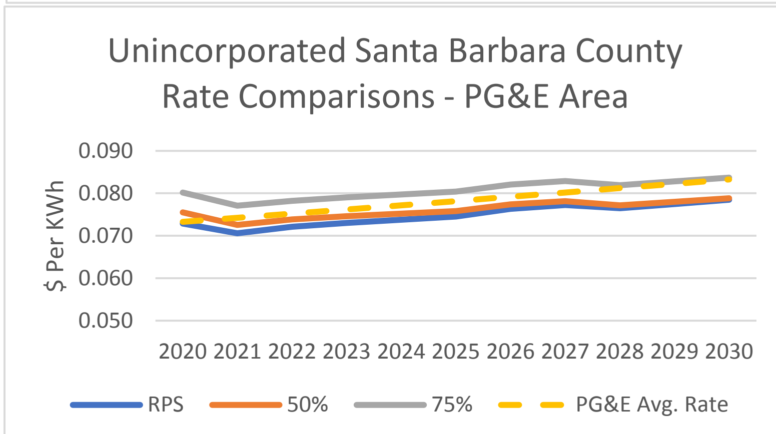


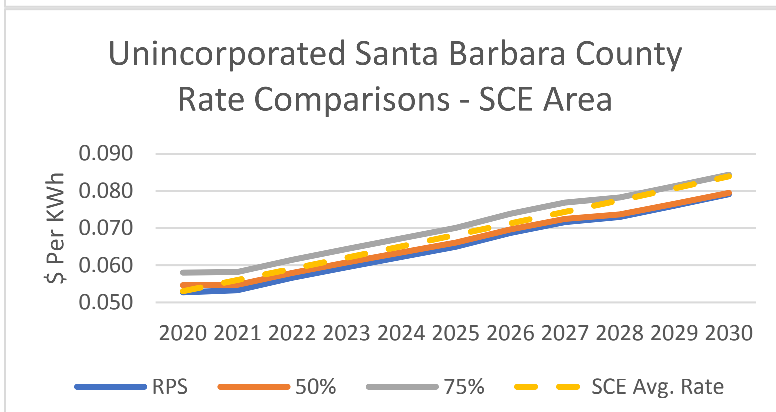


All Santa Barbara		**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
IOU Avg. Rate		0.066	0.068	0.070	0.072	0.074	0.076	0.078	0.080	0.082	0.084	0.087
CCA Avg. Cost	RPS	0.060	0.061	0.063	0.065	0.066	0.068	0.071	0.072	0.073	0.075	0.076
CCA Avg. Cost	50%	0.064	0.064	0.066	0.067	0.068	0.070	0.072	0.073	0.074	0.075	0.077
CCA Avg. Cost	75%	0.068	0.068	0.070	0.071	0.073	0.074	0.077	0.078	0.078	0.080	0.082
PG&E Avg. Rate		0.075	0.076	0.077	0.078	0.079	0.080	0.081	0.083	0.084	0.085	0.086
PG&E CCA	RPS	0.069	0.069	0.070	0.071	0.071	0.072	0.074	0.074	0.074	0.075	0.076
PG&E CCA	50%	0.073	0.072	0.073	0.073	0.073	0.074	0.075	0.076	0.075	0.075	0.076
PG&E CCA	75%	0.078	0.076	0.077	0.078	0.078	0.078	0.080	0.080	0.079	0.080	0.081
SCE Avg. Rate		0.055	0.058	0.061	0.065	0.068	0.071	0.074	0.077	0.081	0.084	0.087
SCE CCA	RPS	0.051	0.052	0.056	0.058	0.061	0.064	0.067	0.070	0.071	0.074	0.077
SCE CCA	50%	0.054	0.055	0.058	0.060	0.063	0.065	0.069	0.071	0.072	0.075	0.077
SCE CCA	75%	0.057	0.058	0.061	0.064	0.067	0.069	0.073	0.075	0.077	0.080	0.082

EXHIBIT 3 – Unincorporated Santa Barbara County

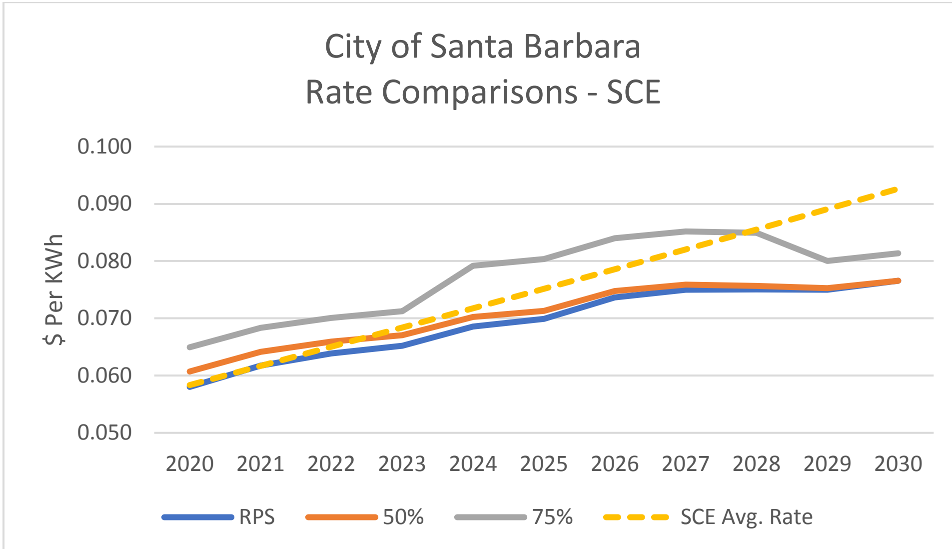






Unincorporated Santa Barbara		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
IOU Avg. Rate		0.066	0.068	0.070	0.072	0.074	0.076	0.078	0.080	0.082	0.084	0.087
CCA Avg. Cost	RPS	0.065	0.064	0.066	0.068	0.070	0.071	0.074	0.075	0.075	0.077	0.079
CCA Avg. Cost	50%	0.068	0.066	0.068	0.069	0.071	0.072	0.075	0.076	0.076	0.077	0.079
CCA Avg. Cost	75%	0.072	0.070	0.072	0.074	0.075	0.077	0.079	0.081	0.081	0.082	0.084
PG&E Avg. Rate		0.073	0.074	0.075	0.076	0.077	0.078	0.079	0.080	0.081	0.082	0.083
PG&E CCA	RPS	0.073	0.071	0.072	0.073	0.074	0.075	0.076	0.077	0.076	0.077	0.078
PG&E CCA	50%	0.076	0.073	0.074	0.075	0.075	0.076	0.077	0.078	0.077	0.078	0.079
PG&E CCA	75%	0.080	0.077	0.078	0.079	0.080	0.080	0.082	0.083	0.082	0.083	0.084
SCE Avg. Rate		0.053	0.056	0.059	0.062	0.065	0.068	0.071	0.074	0.078	0.081	0.084
SCE CCA	RPS	0.053	0.053	0.057	0.059	0.062	0.065	0.069	0.072	0.073	0.076	0.079
SCE CCA	50%	0.055	0.055	0.058	0.061	0.063	0.066	0.070	0.072	0.074	0.077	0.079
SCE CCA	75%	0.058	0.058	0.061	0.064	0.067	0.070	0.074	0.077	0.078	0.081	0.084

EXHIBIT 4 – City of Santa Barbara County



City of Santa Barbara		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
SCE Avg. Rate		0.058	0.062	0.065	0.068	0.072	0.075	0.079	0.082	0.086	0.089	0.093
CCA Avg. Cost	RPS	0.058	0.062	0.064	0.065	0.069	0.070	0.074	0.075	0.075	0.075	0.077
CCA Avg. Cost	50%	0.061	0.064	0.066	0.067	0.070	0.071	0.075	0.076	0.076	0.075	0.077
CCA Avg. Cost	75%	0.065	0.068	0.070	0.071	0.079	0.080	0.084	0.085	0.085	0.080	0.081

Exhibit 5 - All Santa Barbara County RPS-Tracking Pro Forma

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
I. Revenue	-	156,561,067	162,162,930	167,832,371	173,576,391	179,401,948	185,315,967	191,325,356	197,437,017	203,657,862	209,994,821	216,454,861
II. Operating Expenses												
Power Supply	-	120,053,563	129,522,094	135,157,290	139,355,182	143,454,880	147,509,281	154,505,510	158,909,698	161,743,262	167,052,712	172,284,297
Staff	583,333	3,500,000	3,587,500	3,677,188	3,769,117	3,863,345	3,959,929	4,058,927	4,160,400	3,500,000	3,500,000	3,500,000
Marketing and Communications	349,005	1,234,676	1,164,759	1,194,594	1,225,196	1,256,586	1,288,784	1,321,810	1,355,686	1,141,194	1,141,900	1,142,610
Legal, Consulting, other Prof. Services	300,000	1,500,000	1,537,500	1,575,938	1,615,336	1,655,719	1,697,112	1,739,540	1,783,029	1,500,000	1,500,000	1,500,000
Data Management	-	1,898,527	1,908,014	1,917,550	1,927,134	1,936,753	1,946,435	1,956,166	1,965,931	1,975,746	1,985,623	1,995,536
Utility Service Fees	-	431,280	426,917	436,131	445,605	455,346	465,364	475,666	425,709	427,814	429,931	432,056
Miscellaneous Admin. & General	83,333	500,000	512,500	525,313	538,445	551,906	565,704	579,847	594,343	500,000	500,000	500,000
Uncollectibles/Other	-	782,805	810,815	839,162	867,882	897,010	926,580	956,627	987,185	1,018,289	1,049,974	1,082,274
Subtotal Operating Expenses	1,315,672	129,900,851	139,470,098	145,323,164	149,743,898	154,071,546	158,359,189	165,594,092	170,181,982	171,806,305	177,160,140	182,436,774
Operating Margin	(1,315,672)	26,660,216	22,692,832	22,509,207	23,832,492	25,330,402	26,956,778	25,731,264	27,255,036	31,851,556	32,834,681	34,018,087
III. Financing												
Startup Funding Repayment	87,500	7,637,500	-	-	-	-	-	-	-	-	-	-
Reserve Contribution	-	6,262,443	6,486,517	6,713,295	6,943,056	7,176,078	7,412,639	7,653,014	7,897,481	8,146,314	8,399,793	8,658,194
Subtotal Financing	87,500	13,899,943	6,486,517	6,713,295	6,943,056	7,176,078	7,412,639	7,653,014	7,897,481	8,146,314	8,399,793	8,658,194
IV. Total Revenue Requirement	1,403,172	143,800,794	145,956,616	152,036,459	156,686,954	161,247,624	165,771,828	173,247,106	178,079,462	179,952,620	185,559,933	191,094,968
V. Net Surplus/(Deficit)	(1,403,172)	12,760,273	16,206,315	15,795,912	16,889,437	18,154,324	19,544,139	18,078,250	19,357,555	23,705,242	24,434,888	25,359,893
VI. Cumulative Reserve	-	6,262,443	12,748,960	19,462,255	26,405,310	33,581,388	40,994,027	48,647,041	56,544,522	64,690,836	73,090,629	81,748,824
VII. Cumulative Net Surplus	(1,403,172)	11,357,101	27,563,416	43,359,328	60,248,765	78,403,089	97,947,228	116,025,478	135,383,033	159,088,274	183,523,162	208,883,055
VIII. Program Average Rate ($/MWh)	-	65.8	67.8	69.8	71.9	73.9	75.9	78.0	80.1	82.2	84.4	86.5
IX. Power Supply ($/MWh)	-	50.4	54.2	56.2	57.7	59.1	60.5	63.0	64.5	65.3	67.1	68.9
X. Program Average Cost ($/MWh)	-	60.4	61.0	63.2	64.9	66.4	67.9	70.6	72.3	72.7	74.5	76.4
XI. Annual Sales (MWh)	-	2,379,904	2,391,804	2,403,763	2,415,782	2,427,861	2,440,000	2,452,200	2,464,461	2,476,783	2,489,167	2,501,613

Exhibit 6 - All Santa Barbara County 50% Renewable Pro Forma

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
I. Revenue	-	156,561,067	162,162,930	167,832,371	173,576,391	179,401,948	185,315,967	191,325,356	197,437,017	203,657,862	209,994,821	216,454,861
II. Operating Expenses												
Power Supply	-	127,017,386	135,779,407	140,721,284	144,444,843	148,036,579	151,547,796	157,963,954	161,749,459	163,923,925	168,531,988	173,017,950
Staff	583,333	3,500,000	3,587,500	3,677,188	3,769,117	3,863,345	3,959,929	4,058,927	4,160,400	3,500,000	3,500,000	3,500,000
Marketing and Communications	349,005	1,234,676	1,164,759	1,194,594	1,225,196	1,256,586	1,288,784	1,321,810	1,355,686	1,141,194	1,141,900	1,142,610
Legal, Consulting, other Prof. Services	300,000	1,500,000	1,537,500	1,575,938	1,615,336	1,655,719	1,697,112	1,739,540	1,783,029	1,500,000	1,500,000	1,500,000
Data Management	-	1,898,527	1,908,014	1,917,550	1,927,134	1,936,753	1,946,435	1,956,166	1,965,931	1,975,746	1,985,623	1,995,536
Utility Service Fees	-	431,280	426,917	436,131	445,605	455,346	465,364	475,666	425,709	427,814	429,931	432,056
Miscellaneous Admin. & General	83,333	500,000	512,500	525,313	538,445	551,906	565,704	579,847	594,343	500,000	500,000	500,000
Uncollectibles/Other	-	782,805	810,815	839,162	867,882	897,010	926,580	956,627	987,185	1,018,289	1,049,974	1,082,274
Subtotal Operating Expenses	1,315,672	136,864,674	145,727,411	150,887,158	154,833,559	158,653,246	162,397,704	169,052,537	173,021,742	173,986,968	178,639,416	183,170,426
Operating Margin	(1,315,672)	19,696,393	16,435,520	16,945,213	18,742,832	20,748,702	22,918,263	22,272,819	24,415,275	29,670,894	31,355,405	33,284,434
III. Financing												
Startup Funding Repayment	102,500	9,167,500	-	-	-	-	-	-	-	-	-	-
Reserve Contribution	-	6,262,443	6,486,517	6,713,295	6,943,056	7,176,078	7,412,639	7,653,014	7,897,481	8,146,314	8,399,793	8,658,194
Subtotal Financing	102,500	15,429,943	6,486,517	6,713,295	6,943,056	7,176,078	7,412,639	7,653,014	7,897,481	8,146,314	8,399,793	8,658,194
IV. Total Revenue Requirement	1,418,172	152,294,617	152,213,928	157,600,453	161,776,615	165,829,323	169,810,343	176,705,551	180,919,223	182,133,282	187,039,209	191,828,621
V. Net Surplus/(Deficit)	(1,418,172)	4,266,450	9,949,003	10,231,918	11,799,776	13,572,624	15,505,624	14,619,805	16,517,794	21,524,579	22,955,612	24,626,240
VI. Cumulative Reserve	-	6,262,443	12,748,960	19,462,255	26,405,310	33,581,388	40,994,027	48,647,041	56,544,522	64,690,836	73,090,629	81,748,824
VII. Cumulative Net Surplus	(1,418,172)	2,848,278	12,797,281	23,029,199	34,828,975	48,401,599	63,907,223	78,527,028	95,044,823	116,569,402	139,525,014	164,151,254
VIII. Program Average Rate ($/MWh)	-	65.8	67.8	69.8	71.9	73.9	75.9	78.0	80.1	82.2	84.4	86.5
IX. Power Supply ($/MWh)	-	53.4	56.8	58.5	59.8	61.0	62.1	64.4	65.6	66.2	67.7	69.2
X. Program Average Cost ($/MWh)	-	64.0	63.6	65.6	67.0	68.3	69.6	72.1	73.4	73.5	75.1	76.7
XI. Annual Sales (MWh)	-	2,379,904	2,391,804	2,403,763	2,415,782	2,427,861	2,440,000	2,452,200	2,464,461	2,476,783	2,489,167	2,501,613

Exhibit 7 - All Santa Barbara County 75% Renewable Pro Forma

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
I. Revenue	-	156,561,067	162,162,930	167,832,371	173,576,391	179,401,948	185,315,967	191,325,356	197,437,017	203,657,862	209,994,821	216,454,861
II. Operating Expenses												
Power Supply	-	136,994,213	145,646,244	150,493,869	154,470,758	158,364,525	162,186,871	168,968,425	173,085,439	175,506,123	180,364,952	185,156,829
Staff	583,333	3,500,000	3,587,500	3,677,188	3,769,117	3,863,345	3,959,929	4,058,927	4,160,400	3,500,000	3,500,000	3,500,000
Marketing and Communications	349,005	1,234,676	1,164,759	1,194,594	1,225,196	1,256,586	1,288,784	1,321,810	1,355,686	1,141,194	1,141,900	1,142,610
Legal, Consulting, other Prof. Services	300,000	1,500,000	1,537,500	1,575,938	1,615,336	1,655,719	1,697,112	1,739,540	1,783,029	1,500,000	1,500,000	1,500,000
Data Management	-	1,898,527	1,908,014	1,917,550	1,927,134	1,936,753	1,946,435	1,956,166	1,965,931	1,975,746	1,985,623	1,995,536
Utility Service Fees	-	431,280	426,917	436,131	445,605	455,346	465,364	475,666	425,709	427,814	429,931	432,056
Miscellaneous Admin. & General	83,333	500,000	512,500	525,313	538,445	551,906	565,704	579,847	594,343	500,000	500,000	500,000
Uncollectibles/Other	-	782,805	810,815	839,162	867,882	897,010	926,580	956,627	987,185	1,018,289	1,049,974	1,082,274
Subtotal Operating Expenses	1,315,672	146,841,502	155,594,248	160,659,743	164,859,474	168,981,191	173,036,779	180,057,007	184,357,723	185,569,166	190,472,380	195,309,305
Operating Margin	(1,315,672)	9,719,565	6,568,682	7,172,628	8,716,917	10,420,757	12,279,188	11,268,348	13,079,295	18,088,695	19,522,441	21,145,555
III. Financing												
Startup Funding Repayment	102,500	9,167,500	-	-	-	-	-	-	-	-	-	-
Reserve Contribution	-	6,262,443	6,486,517	6,713,295	6,943,056	7,176,078	7,412,639	7,653,014	7,897,481	8,146,314	8,399,793	8,658,194
Subtotal Financing	102,500	15,429,943	6,486,517	6,713,295	6,943,056	7,176,078	7,412,639	7,653,014	7,897,481	8,146,314	8,399,793	8,658,194
IV. Total Revenue Requirement	1,418,172	162,271,444	162,080,765	167,373,038	171,802,530	176,157,269	180,449,418	187,710,022	192,255,203	193,715,481	198,872,173	203,967,500
V. Net Surplus/(Deficit)	(1,418,172)	(5,710,377)	82,165	459,333	1,773,861	3,244,679	4,866,549	3,615,334	5,181,814	9,942,381	11,122,648	12,487,361
VI. Cumulative Reserve	-	6,262,443	12,748,960	19,462,255	26,405,310	33,581,388	40,994,027	48,647,041	56,544,522	64,690,836	73,090,629	81,748,824
VII. Cumulative Net Surplus	(1,418,172)	(7,128,549)	(7,046,384)	(6,587,051)	(4,813,190)	(1,568,511)	3,298,038	6,913,372	12,095,186	22,037,567	33,160,215	45,647,576
VIII. Program Average Rate ($/MWh)	-	65.8	67.8	69.8	71.9	73.9	75.9	78.0	80.1	82.2	84.4	86.5
IX. Power Supply ($/MWh)	-	57.6	60.9	62.6	63.9	65.2	66.5	68.9	70.2	70.9	72.5	74.0
X. Program Average Cost ($/MWh)	-	68.2	67.8	69.6	71.1	72.6	74.0	76.5	78.0	78.2	79.9	81.5
XI. Annual Sales (MWh)	-	2,379,904	2,391,804	2,403,763	2,415,782	2,427,861	2,440,000	2,452,200	2,464,461	2,476,783	2,489,167	2,501,613

Exhibit 8 - Unincorporated Santa Barbara County RPS-Tracking Pro Forma

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
I. Revenue	-	80,827,550	83,353,846	85,911,542	88,503,408	91,132,196	93,800,647	96,511,498	99,267,484	102,071,345	104,925,832	107,833,708
II. Operating Expenses												
Power Supply	-	63,167,842	67,945,133	70,761,437	72,919,922	74,951,598	76,966,000	80,238,610	82,521,579	84,089,589	86,706,738	89,367,346
Staff	583,333	3,500,000	3,587,500	3,677,188	3,769,117	3,863,345	3,959,929	4,058,927	4,160,400	3,500,000	3,500,000	3,500,000
Marketing and Communications	291,219	1,097,703	1,083,186	1,110,563	1,138,635	1,167,417	1,196,928	1,227,187	1,258,213	1,058,783	1,059,077	1,059,373
Legal, Consulting, other Prof. Services	300,000	1,500,000	1,537,500	1,575,938	1,615,336	1,655,719	1,697,112	1,739,540	1,783,029	1,500,000	1,500,000	1,500,000
Data Management	-	665,105	668,424	671,780	675,144	678,530	681,926	685,344	688,771	692,221	695,679	699,161
Utility Service Fees	-	173,579	163,903	167,659	171,522	175,496	179,584	183,791	162,909	163,702	164,498	165,299
Miscellaneous Admin. & General	83,333	500,000	512,500	525,313	538,445	551,906	565,704	579,847	594,343	500,000	500,000	500,000
Uncollectibles/Other	-	404,138	416,769	429,558	442,517	455,661	469,003	482,557	496,337	510,357	524,629	539,169
Subtotal Operating Expenses	1,257,885	71,008,366	75,914,914	78,919,434	81,270,637	83,499,674	85,716,187	89,195,803	91,665,581	92,014,652	94,650,622	97,330,347
Operating Margin	(1,257,885)	9,819,184	7,438,931	6,992,108	7,232,770	7,632,522	8,084,460	7,315,695	7,601,903	10,056,693	10,275,210	10,503,361
III. Financing												
Startup Funding Repayment	72,500	6,107,500	-	-	-	-	-	-	-	-	-	-
Reserve Contribution	-	3,233,102	3,334,154	3,436,462	3,540,136	3,645,288	3,752,026	3,860,460	3,970,699	4,082,854	4,197,033	4,313,348
Subtotal Financing	72,500	9,340,602	3,334,154	3,436,462	3,540,136	3,645,288	3,752,026	3,860,460	3,970,699	4,082,854	4,197,033	4,313,348
IV. Total Revenue Requirement	1,330,385	80,348,968	79,249,068	82,355,895	84,810,774	87,144,961	89,468,213	93,056,263	95,636,280	96,097,506	98,847,655	101,643,695
V. Net Surplus/(Deficit)	(1,330,385)	478,582	4,104,778	3,555,647	3,692,634	3,987,234	4,332,434	3,455,235	3,631,203	5,973,840	6,078,177	6,190,013
VI. Cumulative Reserve	-	3,233,102	6,567,256	10,003,718	13,543,854	17,189,142	20,941,168	24,801,627	28,772,327	32,855,181	37,052,214	41,365,562
VII. Cumulative Net Surplus	(1,330,385)	(851,804)	3,252,974	6,808,621	10,501,255	14,488,489	18,820,923	22,276,158	25,907,361	31,881,201	37,959,378	44,149,391
VIII. Program Average Rate ($/MWh)	-	65.8	67.5	69.2	71.0	72.7	74.5	76.3	78.0	79.8	81.7	83.5
IX. Power Supply ($/MWh)	-	51.4	55.0	57.0	58.5	59.8	61.1	63.4	64.9	65.8	67.5	69.2
X. Program Average Cost ($/MWh)	-	65.4	64.2	66.4	68.0	69.5	71.0	73.5	75.2	75.2	76.9	78.7
XI. Annual Sales (MWh)	-	1,228,384	1,234,526	1,240,699	1,246,902	1,253,137	1,259,402	1,265,699	1,272,028	1,278,388	1,284,780	1,291,204

Exhibit 9 - Unincorporated Santa Barbara County 50% Renewable Pro Forma

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
I. Revenue	-	80,827,550	83,353,846	85,911,542	88,503,408	91,132,196	93,800,647	96,511,498	99,267,484	102,071,345	104,925,832	107,833,708
II. Operating Expenses												
Power Supply	-	65,608,392	70,153,778	72,742,449	74,751,626	76,623,200	78,466,192	81,555,546	83,642,858	85,002,227	87,397,147	89,821,308
Staff	583,333	3,500,000	3,587,500	3,677,188	3,769,117	3,863,345	3,959,929	4,058,927	4,160,400	3,500,000	3,500,000	3,500,000
Marketing and Communications	291,219	1,097,703	1,083,186	1,110,563	1,138,635	1,167,417	1,196,928	1,227,187	1,258,213	1,058,783	1,059,077	1,059,373
Legal, Consulting, other Prof. Services	300,000	1,500,000	1,537,500	1,575,938	1,615,336	1,655,719	1,697,112	1,739,540	1,783,029	1,500,000	1,500,000	1,500,000
Data Management	-	665,105	668,424	671,780	675,144	678,530	681,926	685,344	688,771	692,221	695,679	699,161
Utility Service Fees	-	173,579	163,903	167,659	171,522	175,496	179,584	183,791	162,909	163,702	164,498	165,299
Miscellaneous Admin. & General	83,333	500,000	512,500	525,313	538,445	551,906	565,704	579,847	594,343	500,000	500,000	500,000
Uncollectibles/Other	-	404,138	416,769	429,558	442,517	455,661	469,003	482,557	496,337	510,357	524,629	539,169
Subtotal Operating Expenses	1,257,885	73,448,916	78,123,560	80,900,446	83,102,341	85,171,276	87,216,379	90,512,740	92,786,860	92,927,290	95,341,031	97,784,309
Operating Margin	(1,257,885)	7,378,634	5,230,286	5,011,096	5,401,066	5,960,920	6,584,268	5,998,758	6,480,624	9,144,055	9,584,801	10,049,399
III. Financing												
Startup Funding Repayment	77,500	6,617,500	-	-	-	-	-	-	-	-	-	-
Reserve Contribution	-	3,233,102	3,334,154	3,436,462	3,540,136	3,645,288	3,752,026	3,860,460	3,970,699	4,082,854	4,197,033	4,313,348
Subtotal Financing	77,500	9,850,602	3,334,154	3,436,462	3,540,136	3,645,288	3,752,026	3,860,460	3,970,699	4,082,854	4,197,033	4,313,348
IV. Total Revenue Requirement	1,335,385	83,299,518	81,457,714	84,336,908	86,642,478	88,816,563	90,968,404	94,373,200	96,757,560	97,010,144	99,538,064	102,097,657
V. Net Surplus/(Deficit)	(1,335,385)	(2,471,968)	1,896,132	1,574,634	1,860,930	2,315,632	2,832,242	2,138,298	2,509,924	5,061,201	5,387,768	5,736,051
VI. Cumulative Reserve	-	3,233,102	6,567,256	10,003,718	13,543,854	17,189,142	20,941,168	24,801,627	28,772,327	32,855,181	37,052,214	41,365,562
VII. Cumulative Net Surplus	(1,335,385)	(3,807,353)	(1,911,221)	(336,587)	1,524,343	3,839,975	6,672,218	8,810,516	11,320,440	16,381,641	21,769,409	27,505,460
VIII. Program Average Rate ($/MWh)	-	65.8	67.5	69.2	71.0	72.7	74.5	76.3	78.0	79.8	81.7	83.5
IX. Power Supply ($/MWh)	-	53.4	56.8	58.6	59.9	61.1	62.3	64.4	65.8	66.5	68.0	69.6
X. Program Average Cost ($/MWh)	-	67.8	66.0	68.0	69.5	70.9	72.2	74.6	76.1	75.9	77.5	79.1
XI. Annual Sales (MWh)	-	1,228,384	1,234,526	1,240,699	1,246,902	1,253,137	1,259,402	1,265,699	1,272,028	1,278,388	1,284,780	1,291,204

Exhibit 10 - Unincorporated Santa Barbara County 75% Renewable Pro Forma

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
I. Revenue	-	80,827,550	83,353,846	85,911,542	88,503,408	91,132,196	93,800,647	96,511,498	99,267,484	102,071,345	104,925,832	107,833,708
II. Operating Expenses												
Power Supply	-	70,752,936	75,241,688	77,779,902	79,924,314	81,951,715	83,955,229	87,227,997	89,486,191	90,983,269	93,518,891	96,107,137
Staff	583,333	3,500,000	3,587,500	3,677,188	3,769,117	3,863,345	3,959,929	4,058,927	4,160,400	3,500,000	3,500,000	3,500,000
Marketing and Communications	291,219	1,097,703	1,083,186	1,110,563	1,138,635	1,167,417	1,196,928	1,227,187	1,258,213	1,058,783	1,059,077	1,059,373
Legal, Consulting, other Prof. Services	300,000	1,500,000	1,537,500	1,575,938	1,615,336	1,655,719	1,697,112	1,739,540	1,783,029	1,500,000	1,500,000	1,500,000
Data Management	-	665,105	668,424	671,780	675,144	678,530	681,926	685,344	688,771	692,221	695,679	699,161
Utility Service Fees	-	173,579	163,903	167,659	171,522	175,496	179,584	183,791	162,909	163,702	164,498	165,299
Miscellaneous Admin. & General	83,333	500,000	512,500	525,313	538,445	551,906	565,704	579,847	594,343	500,000	500,000	500,000
Uncollectibles/Other	-	404,138	416,769	429,558	442,517	455,661	469,003	482,557	496,337	510,357	524,629	539,169
Subtotal Operating Expenses	1,257,885	78,593,461	83,211,470	85,937,899	88,275,030	90,499,791	92,705,415	96,185,191	98,630,194	98,908,332	101,462,775	104,070,138
Operating Margin	(1,257,885)	2,234,089	142,376	(26,357)	228,378	632,405	1,095,231	326,307	637,290	3,163,013	3,463,057	3,763,570
III. Financing												
Startup Funding Repayment	77,500	6,617,500	-	-	-	-	-	-	-	-	-	-
Reserve Contribution	-	3,233,102	3,334,154	3,436,462	3,540,136	3,645,288	3,752,026	3,860,460	3,970,699	4,082,854	4,197,033	4,313,348
Subtotal Financing	77,500	9,850,602	3,334,154	3,436,462	3,540,136	3,645,288	3,752,026	3,860,460	3,970,699	4,082,854	4,197,033	4,313,348
IV. Total Revenue Requirement	1,335,385	88,444,063	86,545,624	89,374,361	91,815,166	94,145,079	96,457,441	100,045,650	102,600,893	102,991,186	105,659,808	108,383,486
V. Net Surplus/(Deficit)	(1,335,385)	(7,616,513)	(3,191,778)	(3,462,819)	(3,311,758)	(3,012,883)	(2,656,795)	(3,534,153)	(3,333,409)	(919,840)	(733,976)	(549,778)
VI. Cumulative Reserve	-	3,233,102	6,567,256	10,003,718	13,543,854	17,189,142	20,941,168	24,801,627	28,772,327	32,855,181	37,052,214	41,365,562
VII. Cumulative Net Surplus	(1,335,385)	(8,951,898)	(12,143,677)	(15,606,495)	(18,918,253)	(21,931,137)	(24,587,931)	(28,122,084)	(31,455,493)	(32,375,334)	(33,109,310)	(33,659,088)
VIII. Program Average Rate ($/MWh)	-	65.8	67.5	69.2	71.0	72.7	74.5	76.3	78.0	79.8	81.7	83.5
IX. Power Supply ($/MWh)	-	57.6	60.9	62.7	64.1	65.4	66.7	68.9	70.3	71.2	72.8	74.4
X. Program Average Cost ($/MWh)	-	72.0	70.1	72.0	73.6	75.1	76.6	79.0	80.7	80.6	82.2	83.9
XI. Annual Sales (MWh)	-	1,228,384	1,234,526	1,240,699	1,246,902	1,253,137	1,259,402	1,265,699	1,272,028	1,278,388	1,284,780	1,291,204

Exhibit 11 – City of Santa Barbara RPS-Tracking Pro Forma

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
I. Revenue	-	21,902,544	23,272,184	24,656,799	26,058,751	27,480,381	28,924,018	30,391,982	31,886,589	33,410,156	34,965,004	36,553,463
II. Operating Expenses												
Power Supply	-	18,913,576	20,343,912	21,160,448	21,683,519	22,202,960	22,737,477	24,213,970	24,781,316	24,836,882	25,644,778	26,299,792
Staff	279,000	558,000	566,370	583,361	600,862	618,888	637,454	656,578	676,275	696,564	717,461	738,984
Marketing and Communications	173,066	263,066	269,643	276,384	283,293	290,376	297,635	305,076	312,703	320,520	328,533	336,747
Legal, Consulting, other Prof. Services	220,000	420,000	430,500	441,263	452,294	463,601	475,191	487,071	499,248	511,729	524,522	537,636
Data Management	-	515,858	518,438	521,033	523,641	526,263	528,899	531,548	534,212	536,889	539,580	542,271
Utility Service Fees	-	71,726	72,062	72,401	72,741	73,083	73,427	73,772	74,120	74,469	74,820	75,171
Miscellaneous Admin. & General	30,000	60,000	61,500	63,038	64,613	66,229	67,884	69,582	71,321	73,104	74,932	76,805
Uncollectibles/Other	-	104,011	111,312	115,590	118,405	121,207	124,090	131,688	134,746	135,251	139,523	143,037
Subtotal Operating Expenses	702,066	20,906,237	22,373,737	23,233,516	23,799,369	24,362,607	24,942,058	26,469,286	27,083,941	27,185,408	28,044,149	28,750,443
Operating Margin	(702,066)	996,307	898,446	1,423,283	2,259,382	3,117,774	3,981,960	3,922,696	4,802,648	6,224,748	6,920,855	7,803,020
III. Financing												
Startup Funding Repayment	-	-	-	-	-	800,000	800,000	800,000	800,000	800,000	-	-
Reserve Contribution	-	876,102	930,887	986,272	1,042,350	1,099,215	1,156,961	1,215,679	1,275,464	1,336,406	1,398,600	1,462,139
Subtotal Financing	-	876,102	930,887	986,272	1,042,350	1,899,215	1,956,961	2,015,679	2,075,464	2,136,406	1,398,600	1,462,139
IV. Total Revenue Requirement	702,066	21,782,339	23,304,625	24,219,788	24,841,719	26,261,822	26,899,019	28,484,965	29,159,405	29,321,814	29,442,749	30,212,582
V. Net Surplus/(Deficit)	(702,066)	120,205	(32,441)	437,011	1,217,032	1,218,559	2,024,999	1,907,017	2,727,185	4,088,342	5,522,254	6,340,882
V. Cumulative Reserve	-	876,102	1,806,989	2,793,261	3,835,611	5,734,826	7,691,787	9,707,466	11,782,930	13,919,336	15,317,936	16,780,075
VII. Cumulative Net Surplus/(Deficit)	(702,066)	(581,861)	(614,302)	(177,291)	1,039,742	2,258,301	4,283,300	6,190,317	8,917,502	13,005,844	18,528,098	24,868,980
VI. Program Average Rate ($/MWh)	-	58.3	61.7	65.0	68.4	71.8	75.2	78.6	82.0	85.5	89.1	92.6
VII. Power Supply ($/MWh)	-	50.4	53.9	55.8	56.9	58.0	59.1	62.6	63.7	63.6	65.3	66.7
VIII. Program Average Cost ($/MWh)	-	58.0	61.8	63.9	65.2	68.6	69.9	73.6	75.0	75.1	75.0	76.6
IX. Annual Sales (MWh)	-	375,396	377,273	379,160	381,055	382,961	384,876	386,800	388,734	390,678	392,631	394,594

Exhibit 12 – City of Santa Barbara 50% Renewable Pro Forma

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
I. Revenue	-	21,902,544	23,272,184	24,656,799	26,058,751	27,480,381	28,924,018	30,391,982	31,886,589	33,410,156	34,965,004	36,553,463
II. Operating Expenses												
Power Supply	-	19,918,700	21,238,616	21,946,825	22,392,327	22,828,813	23,274,733	24,656,722	25,123,384	25,071,797	25,765,773	26,299,792
Staff	279,000	558,000	566,370	583,361	600,862	618,888	637,454	656,578	676,275	696,564	717,461	738,984
Marketing and Communications	173,066	263,066	269,643	276,384	283,293	290,376	297,635	305,076	312,703	320,520	328,533	336,747
Legal, Consulting, other Prof. Services	220,000	420,000	430,500	441,263	452,294	463,601	475,191	487,071	499,248	511,729	524,522	537,636
Data Management	-	515,858	518,438	521,033	523,641	526,263	528,899	531,548	534,212	536,889	539,580	542,271
Utility Service Fees	-	71,726	72,062	72,401	72,741	73,083	73,427	73,772	74,120	74,469	74,820	75,171
Miscellaneous Admin. & General	30,000	60,000	61,500	63,038	64,613	66,229	67,884	69,582	71,321	73,104	74,932	76,805
Uncollectibles/Other	-	109,037	115,786	119,522	121,949	124,336	126,776	133,902	136,456	136,425	140,128	143,037
Subtotal Operating Expenses	702,066	21,916,386	23,272,915	24,023,825	24,511,721	24,991,589	25,482,000	26,914,252	27,427,719	27,421,497	28,165,750	28,750,443
Operating Margin	(702,066)	(13,842)	(731)	632,974	1,547,030	2,488,793	3,442,018	3,477,731	4,458,871	5,988,659	6,799,254	7,803,020
III. Financing												
Startup Funding Repayment	-	-	-	-	-	800,000	800,000	800,000	800,000	800,000	-	-
Reserve Contribution	-	876,102	930,887	986,272	1,042,350	1,099,215	1,156,961	1,215,679	1,275,464	1,336,406	1,398,600	1,462,139
Subtotal Financing	-	876,102	930,887	986,272	1,042,350	1,899,215	1,956,961	2,015,679	2,075,464	2,136,406	1,398,600	1,462,139
IV. Total Revenue Requirement	702,066	22,792,488	24,203,802	25,010,097	25,554,071	26,890,804	27,438,961	28,929,931	29,503,183	29,557,904	29,564,350	30,212,582
V. Net Surplus/(Deficit)	(702,066)	(889,944)	(931,618)	(353,298)	504,680	589,577	1,485,058	1,462,051	2,383,407	3,852,252	5,400,654	6,340,882
V. Cumulative Reserve	-	876,102	1,806,989	2,793,261	3,835,611	5,734,826	7,691,787	9,707,466	11,782,930	13,919,336	15,317,936	16,780,075
VII. Cumulative Net Surplus/(Deficit)	(702,066)	(1,592,010)	(2,523,628)	(2,876,926)	(2,372,246)	(1,782,669)	(297,611)	1,164,440	3,547,847	7,400,099	12,800,753	19,141,635
VI. Program Average Rate ($/MWh)	-	58.3	61.7	65.0	68.4	71.8	75.2	78.6	82.0	85.5	89.1	92.6
VII. Power Supply ($/MWh)	-	53.1	56.3	57.9	58.8	59.6	60.5	63.7	64.6	64.2	65.6	66.7
VIII. Program Average Cost ($/MWh)	-	60.7	64.2	66.0	67.1	70.2	71.3	74.8	75.9	75.7	75.3	76.6
IX. Annual Sales (MWh)	-	375,396	377,273	379,160	381,055	382,961	384,876	386,800	388,734	390,678	392,631	394,594

Exhibit 13 – City of Santa Barbara 75% Renewable Pro Forma

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
I. Revenue	-	21,902,544	23,272,184	24,656,799	26,058,751	27,480,381	28,924,018	30,391,982	31,886,589	33,410,156	34,965,004	36,553,463
II. Operating Expenses												
Power Supply	-	21,500,057	22,802,413	23,498,536	23,977,113	24,461,340	24,956,440	26,404,035	26,923,334	26,894,255	27,610,464	28,183,227
Staff	279,000	558,000	566,370	583,361	600,862	618,888	637,454	656,578	676,275	696,564	717,461	738,984
Marketing and Communications	173,066	263,066	269,643	276,384	283,293	290,376	297,635	305,076	312,703	320,520	328,533	336,747
Legal, Consulting, other Prof. Services	220,000	420,000	430,500	441,263	452,294	463,601	475,191	487,071	499,248	511,729	524,522	537,636
Data Management	-	515,858	518,438	521,033	523,641	526,263	528,899	531,548	534,212	536,889	539,580	542,271
Utility Service Fees	-	71,726	72,062	72,401	72,741	73,083	73,427	73,772	74,120	74,469	74,820	75,171
Miscellaneous Admin. & General	30,000	60,000	61,500	63,038	64,613	66,229	67,884	69,582	71,321	73,104	74,932	76,805
Uncollectibles/Other	-	116,944	123,605	127,280	129,873	132,499	135,185	142,638	145,456	145,538	149,352	152,454
Subtotal Operating Expenses	702,066	23,505,650	24,844,531	25,583,294	26,104,431	26,632,279	27,172,116	28,670,301	29,236,669	29,253,069	30,019,664	30,643,295
Operating Margin	(702,066)	(1,603,106)	(1,572,348)	(926,495)	(45,680)	848,102	1,751,903	1,721,682	2,649,921	4,157,087	4,945,340	5,910,169
III. Financing												
Startup Funding Repayment	-	-	-	-	-	2,600,000	2,600,000	2,600,000	2,600,000	2,600,000	-	-
Reserve Contribution	-	876,102	930,887	986,272	1,042,350	1,099,215	1,156,961	1,215,679	1,275,464	1,336,406	1,398,600	1,462,139
Subtotal Financing	-	876,102	930,887	986,272	1,042,350	3,699,215	3,756,961	3,815,679	3,875,464	3,936,406	1,398,600	1,462,139
IV. Total Revenue Requirement	702,066	24,381,752	25,775,419	26,569,566	27,146,781	30,331,494	30,929,076	32,485,980	33,112,132	33,189,475	31,418,264	32,105,433
V. Net Surplus/(Deficit)	(702,066)	(2,479,208)	(2,503,235)	(1,912,767)	(1,088,030)	(2,851,113)	(2,005,058)	(2,093,997)	(1,225,543)	220,681	3,546,740	4,448,030
V. Cumulative Reserve	-	876,102	1,806,989	2,793,261	3,835,611	7,534,826	11,291,787	15,107,466	18,982,930	22,919,336	24,317,936	25,780,075
VII. Cumulative Net Surplus/(Deficit)	(702,066)	(3,181,274)	(5,684,509)	(7,597,276)	(8,685,306)	(11,536,418)	(13,541,477)	(15,635,474)	(16,861,017)	(16,640,336)	(13,093,596)	(8,645,566)
VI. Program Average Rate ($/MWh)	-	58.3	61.7	65.0	68.4	71.8	75.2	78.6	82.0	85.5	89.1	92.6
VII. Power Supply ($/MWh)	-	57.3	60.4	62.0	62.9	63.9	64.8	68.3	69.3	68.8	70.3	71.4
VIII. Program Average Cost ($/MWh)	-	64.9	68.3	70.1	71.2	79.2	80.4	84.0	85.2	85.0	80.0	81.4
IX. Annual Sales (MWh)	-	375,396	377,273	379,160	381,055	382,961	384,876	386,800	388,734	390,678	392,631	394,594

ATTACHMENT 2

Resolution 18-, entitled, "A Resolution of the City Council of the City of Goleta, California, Affirming the City's Intent to Participate in Governance and Financing Discussions for a Proposed Community Choice Energy Joint Powers Authority"

RESOLUTION NO. 18-__

A RESOLUTION OF THE CITY COUNCIL OF THE CITY OF GOLETA, CALIFORNIA, AFFIRMING THE CITY'S INTENT TO PARTICIPATE IN GOVERNANCE AND FINANCING DISCUSSIONS FOR A PROPOSED COMMUNITY CHOICE ENERGY JOINT POWERS AUTHORITY

WHEREAS, the City Council of the City of Goleta has considered options to provide a community choice energy (CCE), also known as community choice aggregation, program to customers within the City with the intent of achieving greater local control and involvement related to the provision of electric service in the City of Goleta; and

WHEREAS, in 2002, the State Legislature adopted Assembly Bill 117, establishing CCE as an option for local governments; and

WHEREAS, the City Council adopted a Climate Action Plan in 2014, establishing a goal to reduce greenhouse gas emissions to 11 percent below 2007 levels by 2020; and

WHEREAS, consistent with the City's legislative platform, in 2017 Mayor Perotte joined the Climate Mayors organization (aka the Mayors National Climate Action Agenda), pledging to work together with other U.S. mayors to strengthen local efforts for reducing greenhouse gas emissions; and

WHEREAS, on December 5, 2017, the City Council adopted a 100% renewable energy goal for the electricity sector for both municipal facilities and the community at large by 2030; and

WHEREAS, a Community Choice Aggregation Technical Study has been completed for the County of Santa Barbara. The study concluded that a CCE program serving all or part of Santa Barbara County can offer cleaner electricity at a comparable rate to Pacific Gas and Electric and Southern California Edison, and that it is financially beneficial to include multiple participating jurisdictions.

NOW, THEREFORE, BE IT RESOLVED BY THE CITY COUNCIL OF THE CITY OF GOLETA, AS FOLLOWS:

SECTION 1.
The City of Goleta affirms its intent to participate in governance and financing discussions for a joint powers authority (JPA) to create and administer a CCE program serving part or all of Santa Barbara County under the following general terms:

I. The JPA is anticipated to be formed in early 2019, and the JPA is expected to begin providing electric service to customers in 2021 or earlier if allowed under California Public Utilities Commission rules.
II. The JPA is expected to be composed of jurisdictions within Santa Barbara County who choose to participate by adopting an ordinance as required by Public Utilities Code Section 366.2(c)(10). The target deadline for passage of said resolution(s) and ordinance(s) is December 31, 2018.
III. Joint powers authority and CCE program start-up costs are expected to be shared equitably among participating jurisdictions.
IV. Adoption of this resolution authorizes staff of the City of Goleta to participate in discussions in anticipation of JPA formation and CCE program launch. It does not, however, bind the City of Goleta to membership in the JPA, allocation of general funds, or participation in a future CCE program. If the City of Goleta chooses to move forward, anticipated next steps for the City Council are: (1) pass a resolution for JPA membership, (2) authorize a pro-rata share of credit support, and (3) pass a CCE ordinance.

SECTION 2.
The City Clerk shall certify to the passage and adoption of this resolution and enter it into the book of original resolutions.

PASSED, APPROVED AND ADOPTED this 17th day of July 2018.

____
PAULA PEROTTE, MAYOR

ATTEST: APPROVED AS TO FORM:

____________________________ ____________________________

DEBORAH S. LOPEZ	MICHAEL JENKINS
CITY CLERK	CITY ATTORNEY

STATE OF CALIFORNIA)
COUNTY OF SANTA BARBARA) ss.
CITY OF GOLETA)

I, DEBORAH S. LOPEZ, City Clerk of the City of Goleta, California, DO HEREBY CERTIFY that the foregoing Resolution No. 18-__ was duly adopted by the City Council of the City of Goleta at a regular meeting held on the 17th day of July, 2018 by the following vote of the Council:

AYES:

NOES:

ABSENT:

(SEAL)

____

DEBORAH S. LOPEZ
CITY CLERK