Attachment A

DRAFT

Technical Study for Community Choice Aggregation Program in Contra Costa County

Prepared by:

With

MRW & Associates, LLC
1814 Franklin Street, Ste 720
Oakland, CA 94612

Economic
Development
Research Group
Boston, MA

Sage Renewables
San Francisco, CA

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List of Acronyms

AAEE	Additional Achievable Energy Efficiency
CAISO	California Independent System Operator
CBA	Collective Bargaining Agreement
CCA	Community Choice Aggregation
CCE	Community Choice Energy
CEC	California Energy Commission
CPUC	California Public Utilities Commission
EE	Energy Efficiency
EBCE	East Bay Community Energy
ESPs	Energy Service Providers
FY	Fiscal Year
GHG	Greenhouse Gas
GRP	Gross Regional Product
GWh	Gigawatt-hour (= 1,000 MWhs)
IOU	Investor-Owned Utility
I/T	Information Technology
JEDI	Jobs and Economic Impact (model)
JPA	Joint Powers Authority
kWh	Kilowatt-hour
MW	Megawatt
MWh	Megawatt-hour
NREL	National Renewable Energy Laboratory
PCIA	Power Charge Indifference Adjustment
PEIR	Programmatic Environmental Impact Report
PG&E	Pacific Gas & Electric
REC	Renewable Energy Credit
REMI	Regional Economic Modeling Inc
RPS	Renewable Portfolio Standard
SB 350	Senate Bill 350
TURN	The Utility Reform Network

Executive Summary

Main Findings

1. This study finds that the jurisdictions in Contra Costs County studied in this report have several options for implementing a Community Choice Energy (CCE) program that would likely result in lower GHG emissions, increased local renewable energy generation, and increased local job creation compared to remaining with current electricity service from the Pacific Gas and Electric Company (PG&E).

2. The electricity rates charged under various CCE scenarios available to the jurisdictions covered in this study would likely be similar or less than the rates charged by PG&E for comparable service. The degree to which CCE rates are reduced below comparable PG&E rates depends in large part on the extent to which the CCE pursues policy objectives other that rate minimization in its energy procurement practices. Competing policy objectives may include increasing the supply of locally generated renewable energy, promote energy efficiency, and maximizing local employment generated from a CCE program.

3. This study finds that Contra Costa County includes enough technically feasible locations to meet a significant proportion of electricity demand for the area studied through locally generated renewable energy. Forty percent of the technically feasible sites fall within the Northern Waterfront Economic Development Initiative area.

4. The implementation of a CCE program within the studied area is projected to create between 500 and 1000 new jobs within Contra Costa County compared to remaining with current PG&E service, depending on the CCE option implemented.

5. This study compares three CCE program alternatives to current PG&E service and identifies the tradeoffs associated with these four alternatives. The decision of which program alternative to implement will require policy makers to balance costs and potential risks and benefits of each option, which are described in detail.

Purpose of this Study

California Assembly Bill 117, passed in 2002, established Community Choice Aggregation in California to provide the opportunity for local governments or special jurisdictions to procure or provide electric power for their residents and businesses. On March 15, 2016, the Contra Costa County (County) Board of Supervisors directed County staff to work with cities within the County to obtain electrical load data from PG&E for conducting a technical study of options for implementing CCE within the County's unincorporated area and the 14 cities within the County not currently participating in a CCE program. The Board of Supervisors further directed the CCE technical study to compare alternatives for implementing CCE (i.e., establishing a Contra Costa County-Only CCE or joining one of the neighboring CCEs – MCE Clean Energy or East Bay Community Energy) to the option of remaining with PG&E.

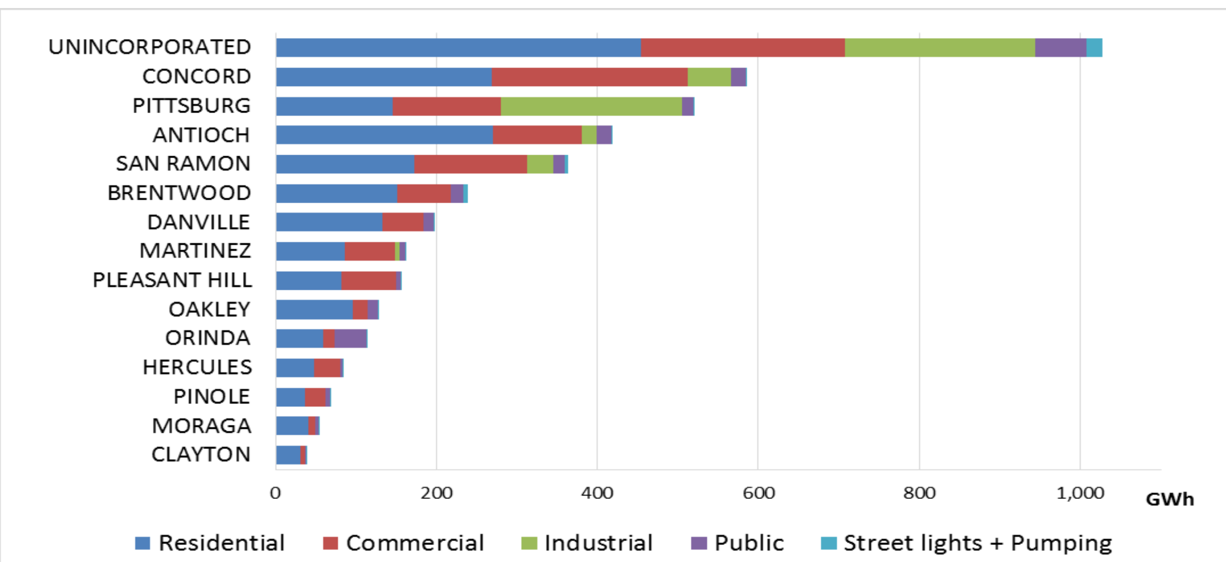
To assess whether a stand-alone CCE is "feasible" in Contra Costa County, the local objectives must be laid out and understood. Based on the specifications of the initial request for proposals and input from the County, this study:

- Quantifies the electric loads that a Contra Costa County CCE would serve;
- Includes analysis of in-county renewable generation;
- Compares the rates that could be offered by the CCE to PG&E's rates;
- Calculates the macroeconomic development and employment benefits of CCE formation; and
- Compares the benefits and risks of forming a CCE or joining a neighboring CCE versus remaining on PG&E bundled service.

Loads and Forecast

Figure ES-1 provides a snapshot of Contra Costa County bundled electric load in 2015 by city and by rate class.[1] As the figure shows, total bundled electricity load in 2014 from Contra Costa County was approximately 4,000 GWh. The unincorporated areas of the County represented 25% of County load, and the cities of Concord and Pittsburg were together responsible for another 25%. Residential and commercial customers made up most the County load, with smaller contributions from the industrial and public sectors.

Figure ES-1. PG&E's 2015 Bundled Load in Contra Costa County by Jurisdiction and Rate Class



[1] "Bundled" load includes only load for which PG&E supplies the power; it excludes load from Direct Access customers, load in the jurisdiction of another CCA provider, and load met by customer self-generation. This excludes load originating in the cities of El Cerrito, Lafayette, Richmond, San Pablo, and Walnut Creek, which are served by Marin Clean Energy.

CCE Power Supplies

The CCE's primary function is to procure supplies to meet the electrical loads of its customers. By law, the CCE must also supply a certain portion of its sales to customers from eligible renewable resources. This Renewable Portfolio Standard (RPS) requires 33% renewable energy supply by 2020, increasing to 50% by 2030. The CCE may additionally choose to source a greater share of its supply from renewable sources than the minimum requirements, or may seek to otherwise reduce the environmental impact of its supply portfolio. The CCE may also use its procurement function to meet other objectives, such as sourcing a portion of its supply from local projects to promote economic development in the County. The four supply scenarios considered in this analysis are summarized in Table ES-1.

Table ES-1: Four Scenarios Modeled[2]

Scenario:	1	2	3	4
% RPS-Eligible in 2020	33%	50%	33%	50%
% RPS-Eligible in 2030	50%	80%	50%	80%
Share of RPS-Eligible from Local Resources	0%	0%	50%	50%

Local Renewable Development

The CCE may choose to contract with or develop renewable projects within Contra Costa County to promote economic development or reap other benefits. This study found 1,395 parcels that met the established criteria and 1,875 individual sites within the identified parcels where either a solar shade structure, large rooftop or ground mounted system could be developed. Table ES-2 shows the total solar PV generation capacity within the County based on the methodology and assumptions Chapter 3.

Table ES-2. Total PV Solar Generation Potential and Build Cost

	Ground Mount	Shade Structure	Roof Mounted	Total
PV Capacity (MW)	1,891	1,320	144	3,355
PV Production (GWh)	3,025	2,113	230	5,369
Build Cost ($ Millions)	$3,417	$3,977	$371	$7,660
Build Cost ($/Watt)	$1.99	$3.10	$2.62	$2.56
No of PV Systems	845	886	144	1,875

[2] Customer-sited solar is not considered RPS-eligible in California and is not included in the RPS procurement in these scenarios. Customer-sited solar is incorporated in this analysis as a reduction to the CCE's load.

CCE Rate Analysis Results

Scenarios 1 and 3 (Simple Renewable Compliance)

In Scenario 1, the CCE meets the mandated 33% RPS requirement in 2020 and the 50% RPS requirement in 2030, plus the 55% proposed target between 2030 and 2038. Annual GHG emissions are 50% lower on average than PG&E's forecasted annual GHG emissions by assuming a fraction of the non-RPS power is provided by large hydroelectric resources.

Figure ES-2 summarizes the results of Scenario 1. The figure shows the total average cost of the Contra Costa County CCE to serve its customers (vertical bars) and the comparable PG&E generation rate (line).[3] Of the CCE cost elements, the greatest cost is for non-renewable generation (including large hydroelectric), followed by the cost for renewable generation, which increases over the years per the RPS requirements. Another important CCE customer cost is the Power Charge Indifference Adjustment (PCIA), which is the CPUC-mandated charge that PG&E must impose on all CCE customers.[4]

Under Scenario 1, the differential between PG&E generation rates and the average cost for the Contra Costa County CCE to serve its customers (*aka* the CCE rates) is positive in each year (*i.e.*, CCE rates are lower than PG&E rates). As a result, Contra Costa County CCE customers' average generation rate (including contributions to the reserve fund) can be set at a level that is lower than PG&E's average customer generation rate in each year.

Scenario 3 is the same as Scenario 1 except that by 2028 one-half of the renewable power is provided by local resources. The differential between PG&E generation rates and Contra Costa County CCE customer rates in Scenario 3 is lower than in Scenario 1; however, the expected Contra Costa County CCE rates continue to be lower than the forecast PG&E generation rates for all years from 2018 to 2038.

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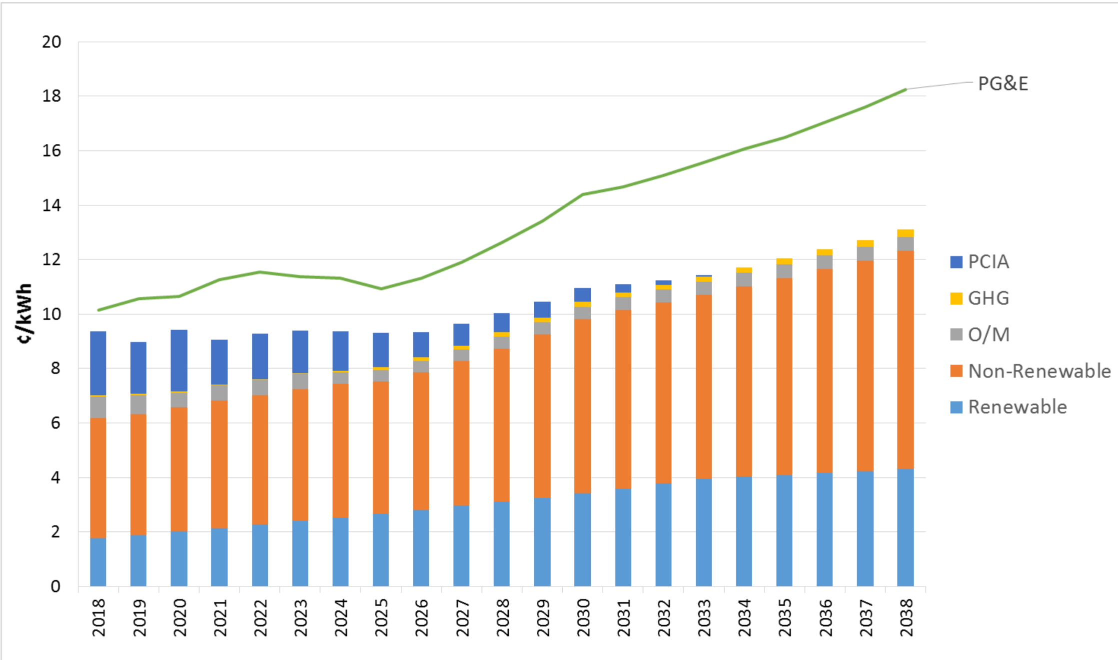
[3] All rates are in nominal dollars. Note that these are NOT the full rates shown on PG&E bills. They are only the generation portion of the rates. Other parts of the rate, such as transmission and distribution, are not included, as customers pay the same charges for these components regardless of who is providing their power.

[4] Per current regulations, the PCIA fee is expected to decrease in most years beginning in 2019 and to have less of an impact on CCE customer rates over time as resources expire from PCIA-eligibility for CCE customers. However, given that PCIA regulations are subject to change, the possibility that PCIA rates may not fall as expected is considered in the High PCIA scenario.

Figure ES-2. Scenario 1 Forecast Average CCE Cost and PG&E Rates, 2018-2038



Scenarios 2 and 4 (Accelerated RPS)

Under Scenario 2, the Contra Costa County CCE starts with 50% of its load being served by renewable sources in 2017, and increases this at a quick pace to 80% renewable energy content by 2030. Scenario 4 is the same as Scenario 2 except that by 2027 one-half of the renewable power is provided by local resources.

The differential between PG&E generation rates and Contra Costa County CCE customer rates in Scenario 2 and 4 is lower than in Scenarios 1 and 3; however, the expected Contra Costa County CCE rates continue to be lower than the forecast PG&E generation rates for all years from 2018 to 2038.

Greenhouse Gas Emissions

Under Scenarios 1 and 3, we include enough GHG-free hydroelectric power so that the Contra Costa County CCE's GHG emissions rate is about half of PG&E's GHG emissions rate. This requires using large hydroelectric power for 35% of the CCE's generation portfolio, on average from 2018 to2038. Though this large hydroelectric power would not qualify for RPS requirements, it is considered a non-GHG emitting resource. [5] Under Scenario 2 and 4 these additions of large hydro power are not needed once the high renewable targets are met. The result is a portfolio that averages 20% large hydro from 2018 to 2028.

[5] While there is a limited supply of uncontracted large hydroelectric power, Marin Clean Energy and Sonoma Clean Power have been successful in procuring this resource. To account for the limited supply, we added a 10% premium to the cost of this power.

Figure ES-4 compares the Scenario 2 GHG emissions from 2018-2038 for the Contra Costa County CCE with what PG&E's emissions would be for the same load if no CCE were formed. Since Scenario 2 has a higher renewable generation target (80% by 2030), the hydroelectric generation necessary to achieve the same GHG emissions reduction is lower. Because of trading off large hydro for RPS-eligible energy, GHG emissions in Scenario 2 are the same as Scenario 1 through 2030, after which the CCE's portfolio will produce half the GHG emissions compared to PG&E.

Note that the analysis assumes "normal" hydroelectric output for PG&E. During the drought years, PG&E's hydro output has been at about 50% of normal, and the utility has made up these lost megawatt-hours through additional gas generation. This means that the "normal" PG&E emissions shown here are lower than the "current" emissions. If, as is expected by many experts, the recent drought conditions are closer to the "new normal", then PG&E's GHG emissions in the first 8 years would be approximately 30% higher. Depending on whether the CCE were similarly affected by limited hydroelectric supply, the CCE's emissions may increase as well.

Table ES-4. Comparative GHG total emissions for PG&E and Contra Costa CCA

GHG emissions	PG&E (KTonnes)[6]	Contra Costa CCA (KTonnes)	Savings (%)
Scenario 1	5,882	2,957	50%
Scenario 2	5,882	2,693	54%
Scenario 3	5,882	2,957	50%
Scenario 4	5,882	2,693	54%

Macroeconomic and Job Impacts

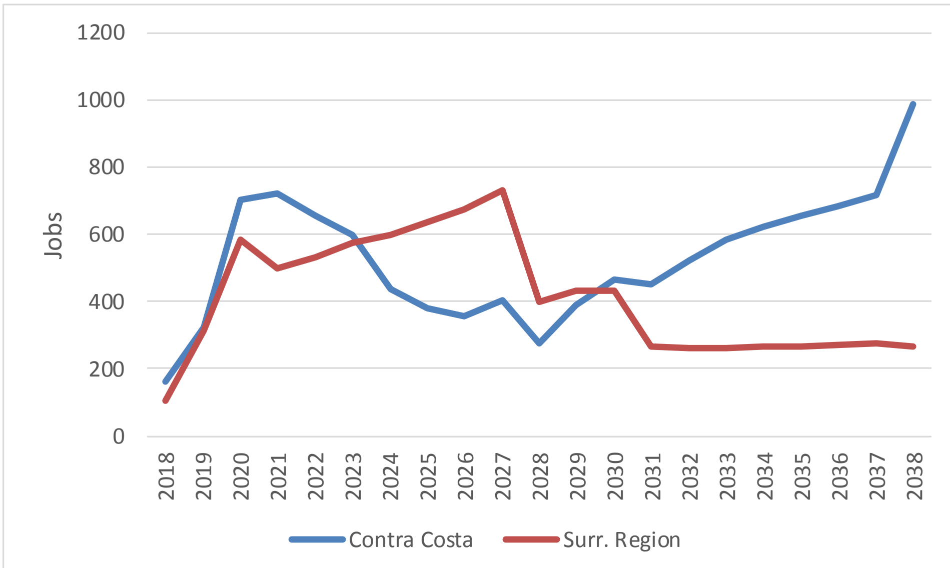
The local economic development and jobs impacts for the four scenarios were analyzed using the dynamic input-output macroeconomic model developed by Regional Economic Models, Inc. (REMI). The model accounts for not only the impact of direct CCE activities (e.g., local project installations for two of the four scenarios, program administration), but also how the rate savings that County households and businesses might experience with a CCE ripple through the local economy, creating more jobs and regional economic growth.

A CCE can also offer positive economic development and employment benefits to the County. The CCE could create approximately 500 to 1000 additional annual jobs in the County plus an additional 80 to 700 jobs in the neighboring counties depending on the scenario. The job

[6] Thousands of metric tons

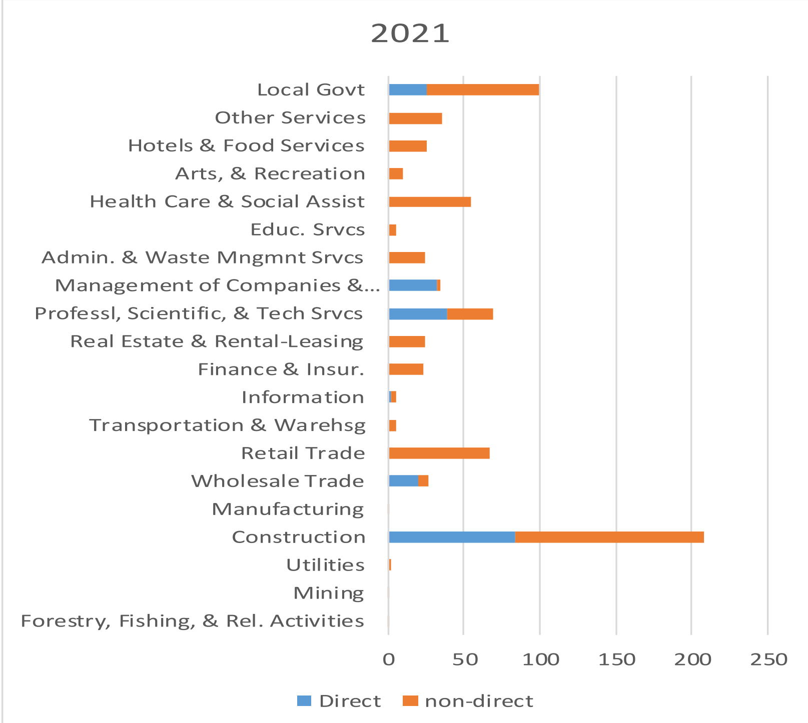
impacts include not just the stimulus from program-related effects but jobs resulting from *multiplier effects* and *competitiveness effects.* Scenario 4 – with the smallest of *net* rate savings for the County's electric customers poses the largest investment for small-solar across the local economy. Figure ES-3 illustrate this through high-level results expressed as annual job changes for the Scenario 4.

Figure ES-3. Scenario 4 Regional Annual Jobs Impacts, 2018 to 2038



The economic activity generated by the CCE results in incremental employment in a variety of sectors. Figure ES-4 shows the job impacts (direct and indirect) by sector for Scenario 4 in 2021 (the year in which the CCE's assumed solar investment is maximum).

Figure ES-4. Contra Costa Job Impacts by Sector Scenario 4, 2021 and 2038



Comparative Analysis of CCE Options

Having the County and its cities form its own Joint Powers Authority (JPA) and CCE Program is not the only possibility for CCE participation. First, the Counties and/or its cities may join MCE Clean Energy (MCE). In fact, five cities in the County—El Cerrito, Lafayette, Richmond, San Pablo, and Walnut Creek—are already members of MCE. These cities joined between 2012 and 2016, and have full standing on MCE's board of directors. Second, the County and/or its cities could join East Bay Community Energy (Alameda County, EBCE). While this CCE has not formally been formed—the Alameda County Board of Supervisors and the respective city Councils are currently taking up the matter, and the JPA board may be seated as early as January 2017, with delivery of power beginning in late 2017. Furthermore, the County and each city need not join one or other CCE *en masse*, but instead can join one or the other CCEs individually (or neither).

Table ES-6 below provides a qualitative summary of the differences and similarities among these options. While a quantitative comparison would appear to provide more rigor, in this case it would provide only false precision. First and foremost, two of the potential CCE options are with entities which, while potentially viable, do not yet exist. Without power contracts, portfolios or procurement guidelines and policies, it would be unwise to claim that EBCE or a potential Contra Costa-only CCE would have rates or greenhouse gas emissions higher or lower than the other. Comparisons against MCE can be somewhat more reasonably asserted; however, its stated goals—greater renewable energy content, lower greenhouse gas emissions, local generation, and comparable rates—are nearly identical to those stated by EBCE, so as to make long-range rate and emissions distinctions immaterial. Thus, the qualitative comparisons provided in the table do not provide sharp distinctions between the CCE options.[7] All these options are expected to provide similar rates and GHG emissions, with differences arising from variations in the priorities and procurement decisions of the individual governance boards. What truly distinguishes these options are primarily governance options (i.e., in-county only versus shared with other entities) and the amount of risk assumed (i.e., developing or signing on with a new CCE versus joining one with a record of satisfactory performance).

Table ES-5. Comparison of Contra Costa CCE Options

Criterion	Form CCCo JPA	Join MCE	Join EBCE	Stay with PG&E
Rates	Likely lower	Likely Lower	Likely Lower	Base
GHG Reduction Potential Over Forecast Period	Some	Some	Some	Base
Local Control/Governance	Greatest	Some	Greater	None
Local Economic Benefits	Greatest	Some	Greater	Minimal
Start Up Costs/Cost to Join	Low, but greater risk[8]	None	Unknown, but likely to be none	None
Level of Effort	Greatest	Minimal	Greater	None
Program Risks	Greatest	Minimal	Some	Base
Timing (earliest)	Mid-Late-2018	Late-2017	Mid-2018	N/A

[7] Differences between the CCE options and the option to stay with PG&E are more marked and better quantifiable, given that information on PG&E's power portfolios, procurement plans, and costs are at least partially available through various filings and applications PG&E has made before the CPUC. The comparisons provided above between the CCE's rates and PG&E's rates takes advantage of this information and market data on power procurement costs to develop quantitative comparisons between the CCE and PG&E options.
[8] Start-up costs incurred by the County or others are likely to be reimbursed by the JPA.

Conclusions

Overall, a CCE in Contra Costa County appears feasible. Given current and expected market and regulatory conditions, a Contra Costa County CCE should be able to offer its residents and businesses electric rates that are less than those available from PG&E.

Sensitivity analyses suggest that these results are relatively robust. Only when very high amounts of renewable energy are assumed in the CCE portfolio, combined with other negative factors, such as higher PCIA rates, higher prices for local renewable power, and lower PG&E costs, do PG&E's rates become consistently more favorable than the CCE's.

A Contra Costa County CCE would also be well positioned to help facilitate greater amounts of renewable generation to be installed in the County. Because the CCE would have a much greater interest in developing local solar than PG&E, it is much more likely that such development would occur with a CCE in the County than without it.

The CCE can also reduce the amount greenhouse gases emitted by the County if the CCE prioritizes this goal. Because PG&E's supply portfolio has significant carbon-free generation (from large hydroelectric and nuclear generators), the CCE would need to contract for significant amounts of hydroelectric or other carbon-free power above and beyond the required qualifying renewables to reduce the County's GHG footprint from electricity use. This analysis assumes that the CCE procures enough GHG-free generation to halve PG&E's GHG emissions rate, subject to constraints on the minimum share of market supplies in the CCE portfolio.

A CCE can also offer positive economic development and employment benefits to the County. At the peak, the CCE could create approximately 500 to 1000 new jobs in the County plus additional jobs in neighboring counties. What may be surprising is that much of the economic benefits come from reduced rates: residents and, more importantly, businesses can spend and reinvest their bill savings, and thus generate greater economic impacts.

While the analytical focus of this report has been on a stand-alone Contra Costa County CCE, that is not the only choice for Contra Costa communities. Overall, there is insufficient data to suggest that a stand-alone Contra Costa CCE would offer lower rates or greater GHG savings than joining MCE or EBCE. Either forming or joining a CCE would likely offer modestly lower rates, more local economic development, and similar or lower GHG emissions than remaining with PG&E. Joining MCE would likely result in the quickest path to CCE implementation, however at a loss of local control and CCE policy formation. Because it has yet to be formed, joining with EBCE would take longer than joining the already-established MCE, but would offer greater input into the CCE's policies and formation.

Although all the CCE program options available to the jurisdictions studied would likely provide both environmental and economic benefits compared to PG&E, continuing service from PG&E remains an option for not only a community but also for any individual or business whose community has selected CCE service. PG&E is an experienced power provider and is regulated by the state. Furthermore, remaining with PG&E takes no city action. Lastly, simply because a Contra Costa community does not join a CCE in 2017 or 2018 does not necessarily preclude it from doing so in the future, although waiting may result in an "entry fee" or perhaps a high PCIA rate.

Chapter 1: Introduction

On March 15, 2016, the Contra Costa County (County) Board of Supervisors directed County staff to work with cities within the County to obtain electrical load data from the Pacific Gas and Electric Company (PG&E) for the purpose of conducting a technical study of options for implementing Community Choice Energy (CCE) within the County's unincorporated area and the 14 cities within the County not currently participating in a CCE program. The Board of Supervisors further directed the CCE technical study to compare the following alternatives for implementing CCE to the option of remaining with current electrical service from PG&E:

1. Form a new Joint Powers Authority (JPA) of the County and interested cities within Contra Costa County for the purpose of CCE;

2. Form a new JPA in partnership with Alameda County and interested cities in both counties; and

3. Join the existing CCE program initiated in Marin County, known as Marin Clean Energy (MCE).

The County and the 14 Contra Costa cities not currently participating in a CCE program all authorized the collection of load data from PG&E for this technical study. In addition, the County and the cities of Brentwood, Clayton, Concord, Martinez, Pleasant Hill, Pittsburg and San Ramon, and the Towns of Danville and Moraga, contributed funding for the completion of this study.

What is a CCE?

California Assembly Bill 117, passed in 2002, established Community Choice Aggregation (also known as Community Choice Energy or "CCE") in California, for the purpose of providing the opportunity for local governments or special jurisdictions to procure or provide electric power for their residents and businesses.

Under existing rules administered by the California Public Utilities Commission, PG&E must use its transmission and distribution system to deliver the electricity supplied by a CCE in a non-discriminatory manner. That is, it must provide these delivery services at the same price and at the same level of reliability to customers taking their power from a CCE as it does for its own full-service customers. By state law, PG&E also must provide all metering and billing services such that customers receive a single electric bill each month from PG&E, which would differentiate the charges for generation services provided by the CCE from the charges for PG&E delivery services. Money collected by PG&E on behalf of the CCE must be remitted in a timely fashion (e.g., within 3 business days).

As a power provider, the CCE must abide by the rules and regulations placed on it by the State and its regulating agencies, such as maintaining demonstrably reliable supplies, fully cooperating with the State's power grid operator, and meeting renewable procurement requirements. However, the State has no rate-setting authority over the CCE; the CCE may set rates as it sees fit so as to best serve its constituent customers.

Per California law, when a CCE is formed all the electric customers within its boundaries will be placed, by default, onto CCE service. However, customers retain the right to return to PG&E service at will, subject to whatever administrative fees the CCE may choose to impose.

California currently has five active CCE Programs: MCE, serving Marin County and selected neighboring jurisdictions; Sonoma Clean Power, serving Sonoma County; CleanPowerSF, serving San Francisco City and County; Peninsula Clean Energy, serving San Mateo County; and Lancaster Choice Energy, serving the City of Lancaster (Los Angeles County). Numerous other local governments are also investigating CCE formation, including Alameda County; Los Angeles County; Monterey Bay region; Santa Barbara, San Luis Obispo and Ventura Counties; and Humbolt County to name but a few.

Assessing CCE Feasibility

In order to assess whether a CCE is "feasible" in Contra Costa County, the local objectives must be laid out and understood. Based on the specifications of the initial request for proposals and input from the County, this study:

- Quantifies the electric loads that a Contra Costa County CCE would serve;
- Estimates the costs to start-up and operate the CCE;
- Considers four scenarios with differing assumptions concerning the amount of GHG-free power and local renewable power being supplied to the CCE so as to assess the costs, greenhouse gas emissions reductions, and local economic development opportunities possible with the CCE;
- Includes analysis of in-county renewable generation;
- Compares the rates that could be offered by the CCE to PG&E's rates;
- Quantitatively explores the rate competitiveness of the four scenarios to key input variables, such as the cost of natural gas;
- Calculates the macroeconomic development and employment benefits of CCE formation; and
- Compares the benefits and risks of forming a CCE or joining a neighboring CCE versus remaining on PG&E bundled service.

For comparison, the differences in the results between this study and that conducted for Alameda County will be described and underlying reasons explained.

This study was conducted by MRW & Associates, LLC (MRW). MRW was assisted by Sage Renewables, which conducted the local renewable energy potential study, and by Economic Development Research Group, which conducted the macroeconomic and jobs analysis contained in the study.

This study is based on the best information available at the time of its preparation, using publicly available sources for all assumptions to provide an objective assessment regarding the prospects of CCE operation in the County. It is important to keep in mind that the findings and recommendations reflected herein are substantially influenced by current market conditions within the electric utility industry, which are subject to sudden and significant changes.

Chapter 2: Economic Study Methodology and Key Inputs

This Chapter summarizes the key inputs and methodologies used to evaluate the cost-effectiveness and cost-competitiveness of a Contra Costa CCE relative to PG&E under different scenarios.[9] It considers the regulatory requirements that a Contra Costa County CCE would need to meet (e.g., compliance with renewable portfolio standard (RPS) requirements), the resources that the County has available or could obtain to meet these requirements, and the PG&E rates against which the CCE would be compete. It also describes the pro forma analysis methodology that is used to evaluate the financial feasibility of the CCE.

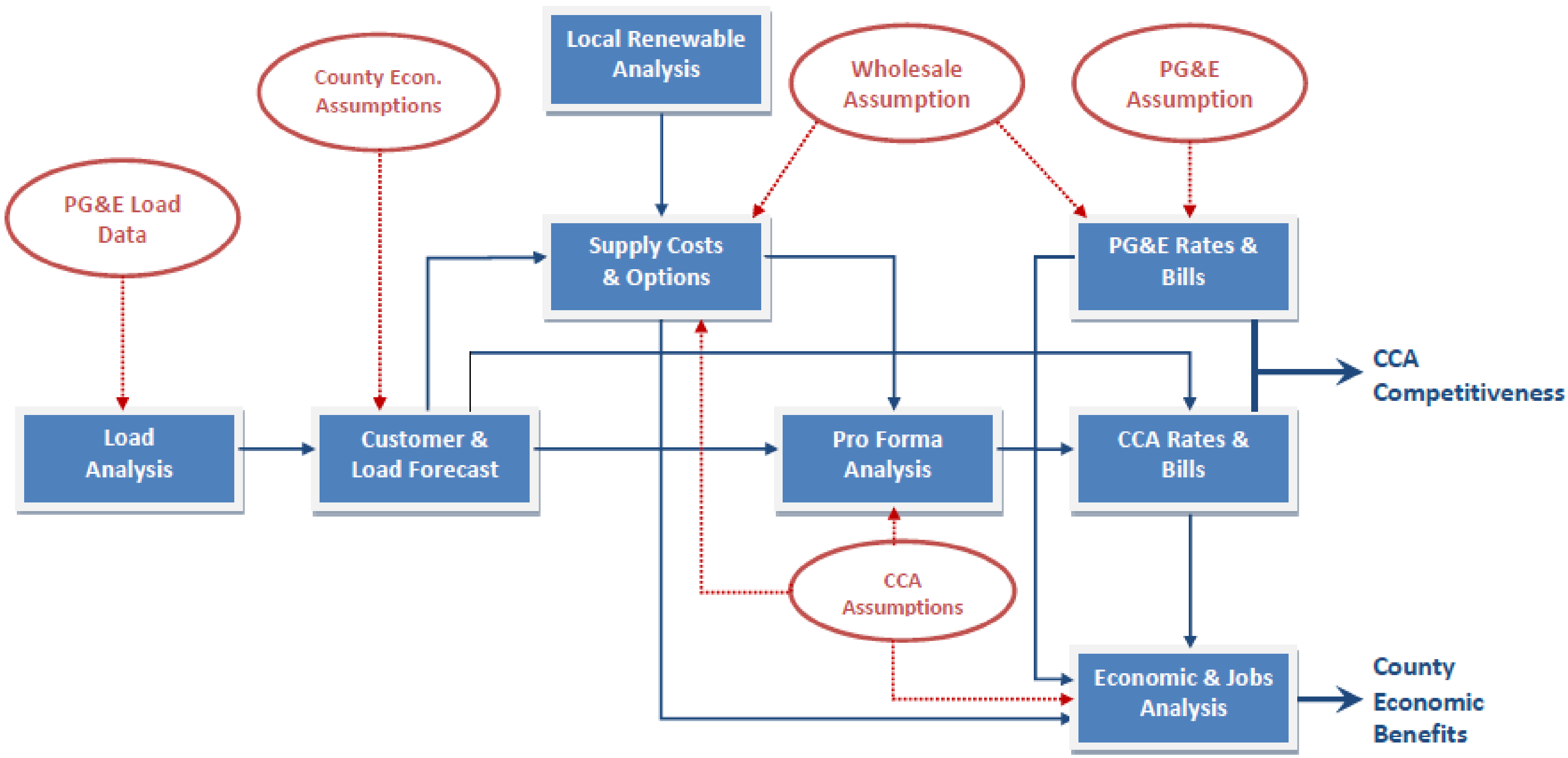
The load and rate forecasts go out twenty years—through 2038. While all forecasting contains an element of uncertainty, the years beyond 2030 are particularly uncertain and should be seen as broadly indicative and not predictive.

Understanding the interrelationships of all the tasks and using consistent and coherent assumptions throughout are critical to developing a meaningful analysis. Figure 1 shows the analysis elements (blue boxes) and major assumptions (red ovals) and how they relate to each other. As the figure illustrates, there are numerous interrelationships between the tasks. For example, the load forecast is a function of not only the load analysis, but also of projections of economic activity in the County.

Two important points are highlighted in this figure. First, it is critical that wholesale power market assumptions are consistent between the CCE and PG&E. While there are reasons that one might have lower or higher costs than the other for a particular product (e.g., CCEs can use tax-free debt to finance generation projects while PG&E cannot), both will participate in the wider Western US gas and power markets and therefore will be subject to the same underlying market forces. Applying different power cost assumptions to the CCE than to PG&E, such as simply escalating PG&E rates while deriving the CCE rates using a bottom-up approach, would produce erroneous results. Second, virtually all elements of the analysis feed into the economic and jobs assessment. As is described in detail in Chapter 5, this Study uses a state-of-the art macroeconomic model that can account for numerous activities in the economy, which allows for a much more comprehensive—and accurate—assessment than a simple input-output model.

[9] The relative costs and merits of joining CCEs in neighboring counties are addressed in Chapter 7.)

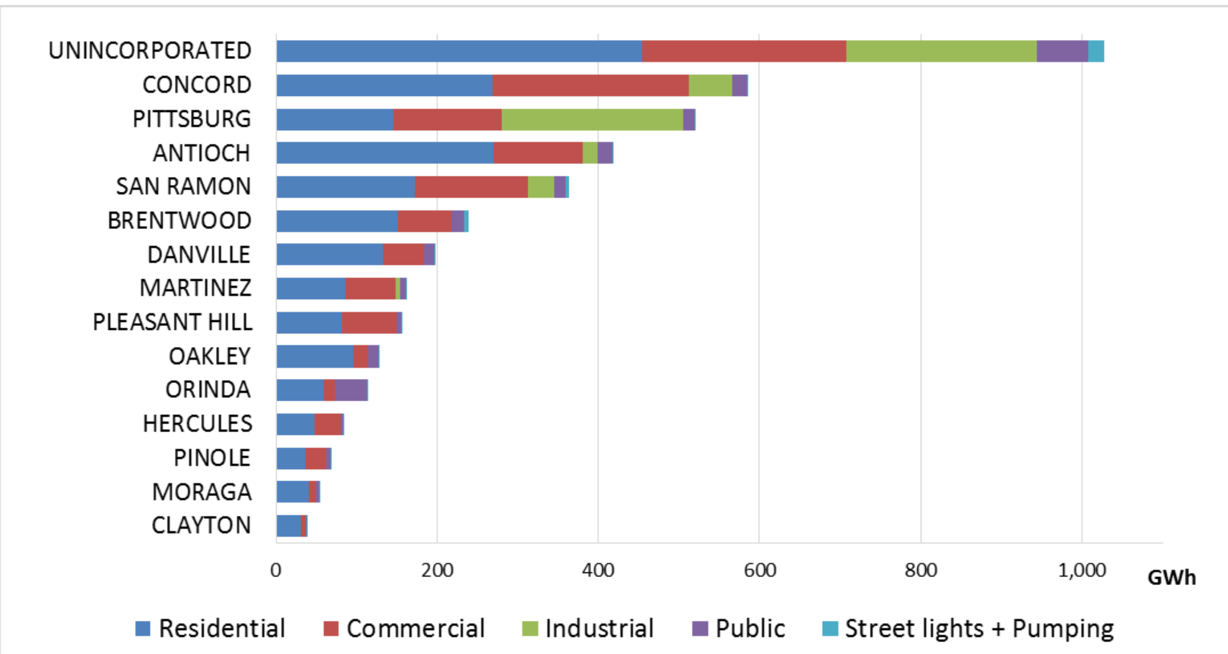
Figure 1. Task Map



Contra Costa County Loads and CCE Load Forecasts

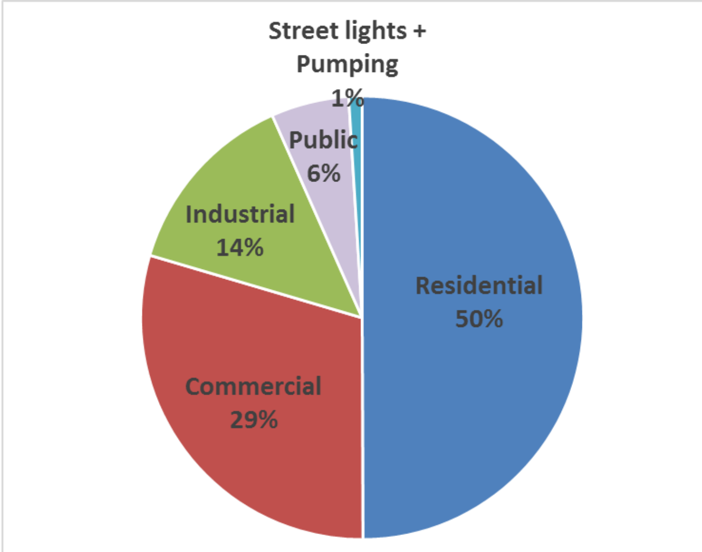
MRW used PG&E bills from 2015 for all PG&E bundled service customers within the Contra Costa County region as the starting point for developing electrical load and peak demand forecasts for the Contra Costa County CCE program.[10] Figure 2 provides a snapshot of Contra Costa County bundled load in 2015 by city and by rate class. PG&E's total electricity load in 2015 from these customers was approximately 4,000 GWh.[11] The unincorporated areas of the county represented 25% of county load, and the cities of Concord and Pittsburg were together responsible for another 25%. Residential and commercial customers made up most of the County load, with smaller contributions from the industrial and public sectors (Figure 3). This same sector-level distribution of load is also apparent at the jurisdictional level for most cities, except for the city of Pittsburg, which has a significant industrial-sector footprint.

Figure 2. PG&E's 2015 Bundled Load in Contra Costa County by Jurisdiction and Rate Class



[10] Detailed monthly usage data provided by PG&E to Contra Costa County. "Bundled" load includes only load for which PG&E supplies the power; it excludes load from Direct Access customers, load in the jurisdiction of another CCA provider, and load met by customer self-generation. This excludes load originating in the cities of El Cerrito, Lafayette, Richmond, San Pablo, and Walnut Creek, which are served by Marin Clean Energy.
[11] As determined from bill data provided by PG&E.

Figure 3. PG&E's 2015 Bundled Load in Contra Costa County by Rate Class



To estimate CCE loads from PG&E's 2015 bundled loads, MRW assumed a CCE participation rate of 85% (*i.e.*, 15% of customers opt to stay with PG&E) and a three-year phase in period from 2018 to 2020, with 33% of potential CCE load included in the CCE in 2018, 67% in 2019, and 100% in 2020. To forecast CCE loads through 2038, MRW used a 0.4% annual average growth rate, consistent with the California Energy Commission's most recent electricity demand forecast for PG&E's planning area.[12] The CCE load forecast is summarized in Figure 4, which shows annual projected CCE loads by class.

To estimate the CCE's peak demand in 2015,[13] MRW multiplied the load forecast for each customer class by PG&E's 2015 hourly ratio of peak demand to load for that customer class.[14] MRW extended the peak demand forecast to 2038 using the same growth rates used for the load forecast. The peak demand forecast is summarized in Figure 5.

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[12] California Energy Commission. Form 1.1c California Energy Demand Updated Forecast, 2015 - 2025, Mid Demand Baseline Case, Mid AAEE Savings. January 20, 2015 http://www.energy.ca.gov/2014_energypolicy/documents/demand_forecast_cmf/LSE_and_BA/

[13] Peak demand is the maximum amount of power the CCE would use at any time during the year. It is measured in megawatts (MW). The CCE must have enough power plants on (or contracted with) at all times to meet 115% of the expected peak demand.

[14] Data obtained from PG&E's dynamic load profiles for Public, Industrial, Commercial and Residential customers (https://www.pge.com/nots/rates/tariffs/energy_use_prices.shtml) and static load profiles for Pumping and Streetlight customers (https://www.pge.com/nots/rates/2016_static.shtml#topic2).

Figure 4: CCE Load Forecast by Class, 2018-2038[15]

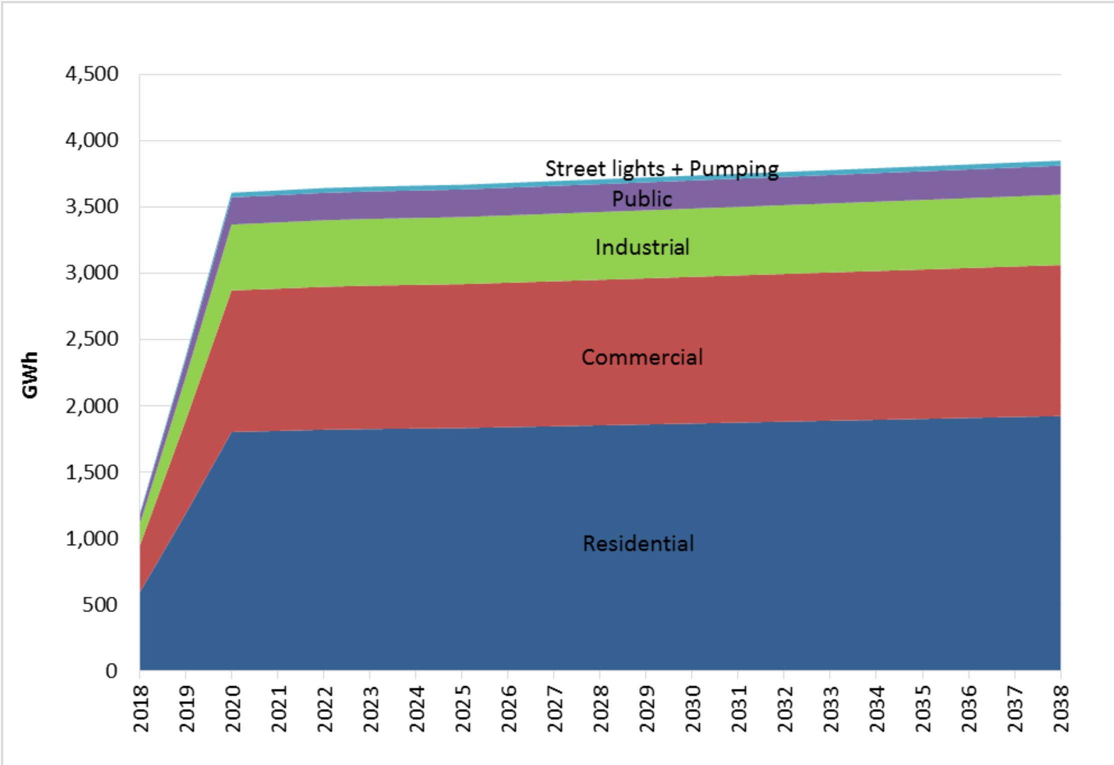
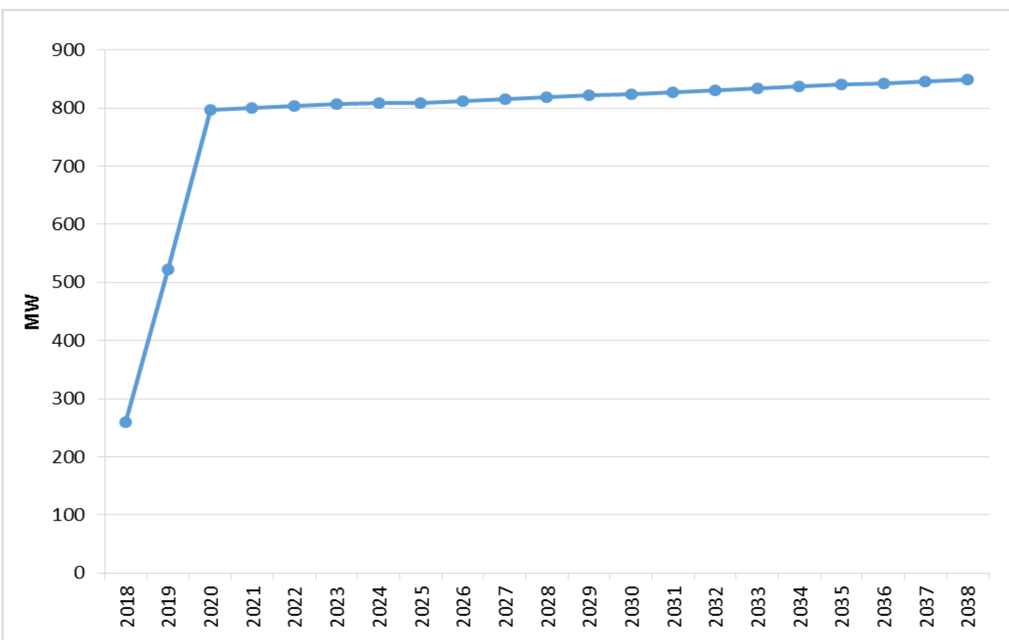


Figure 5. CCE Peak Demand Forecast, 2017-2038



[15] Load forecasted assumes 85% participation and three-year phase-in.

CCE Supplies

The CCE's primary function is to procure supplies to meet the electrical loads of its customers. This requires balancing energy supply and demand on an hourly basis. It also requires procuring generating capacity (i.e. the ability to provide energy when needed) to ensure that customer loads can be met reliably.[16] In addition to meeting the energy and capacity needs of its customers, the CCE must meet other procurement objectives. By law, the CCE must supply a certain portion of its sales to customers from eligible renewable resources. This Renewable Portfolio Standard (RPS) requires 33% renewable energy supply by 2020, increasing incrementally to 50% by 2030. According to PG&E's Diablo Canyon nuclear plant retirement application, PG&E may commit to purchasing additional renewable supply, targeting up to 55% of the total generation between 2030 and 2038, which the CCE would presumably at least match. The CCE may additionally choose to source a greater share of its supply from renewable sources than the minimum requirements, or may seek to otherwise reduce the environmental impact of its supply portfolio. The CCE may also use its procurement function to meet other objectives, such as sourcing a portion of its supply from local projects to promote economic development in the County.

The Contra Costa County CCE would be taking over these procurement responsibilities from PG&E for those customers who do not opt out of the CCE to remain bundled customers of PG&E. To retain customers, the CCE's offerings and rates must compete favorably with those of PG&E.

The CCE's specific procurement objectives, and its strategy for meeting those objectives, will be determined by the CCE through an implementation plan, startup activities, and ongoing management of the CCE. A primary purpose of this portion of the study is to assess the feasibility of establishing a CCE to serve Contra Costa County based on a forecast of costs and benefits. This forecast requires making certain assumptions about how the CCE will operate and the objectives it will pursue. To address the uncertainty associated with these assumptions, we have evaluated four different supply scenarios and have generally made conservative assumptions about the ways in which the CCE would meet the objectives discussed above. In no way does this study prescribe actions to be taken by the CCE should one be established.

The four supply scenarios that we considered in this analysis are summarized in Table 1 and described as follows:

1. **Minimum RPS Compliance:** The CCE meets the mandated 33% RPS requirement in 2020 and the 50% RPS requirement in 2030, plus the 55% RPS target after 2030. Annual GHG emissions from the CCE portfolio are halved relative to PG&E's bundled portfolio

[16] The California Public Utilities Commission (CPUC) requires that CCEs and other load serving entities demonstrate that they have procured resource adequacy capacity to meet at least 115% of their expected peak load. Since Contra Costa County falls within the Greater Bay Area Local Reliability Area, the Contra Costa County CCE must also meet its share of local resource adequacy requirements.

through the addition of large hydroelectric power purchases, subject to a constraint that 5% of the CCE supply come from non-renewable market sources.[17]

2. **Accelerated RPS:** The CCE's supply portfolio is set at 50% RPS in the first year and increases to 80% RPS by 2030. As in Scenario 1, the remaining supply is a mix of hydroelectric power and market purchases aimed at halving PG&E's annual emissions subject to a 5% minimum supply from market purchases.

3. **Minimum RPS Compliance plus Local:** The CCE meets the mandated 33% RPS requirement in 2020 and the 50% RPS requirement in 2030, plus the 55% RPS target after 2030. In addition, 50% of the total RPS generation is provided by local resources by 2030. Large hydroelectric and market supplies, and thus GHG emissions, are the same as in Scenario 1.

4. **Accelerated RPS plus Local:** The CCE's supply portfolio is set at 50% RPS in the first year and increases to 80% RPS by 2030. In addition, 50% of the total RPS generation is provided by local resources by 2030. Large hydroelectric and market supplies, and thus GHG emissions, are the same as in Scenario 2.

Table 1: RPS-Eligible Procurement and GHG Emissions in Each Scenario[18]

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Percent RPS-Eligible in 2020	33%	50%	33%	50%
Percent RPS-Eligible in 2030	50%	80%	50%	80%
Share of RPS-Eligible from Local Resources	0%	0%	50%	50%
GHG Emissions compared to PG&E	50% Lower	54% Lower	50% Lower	54% Lower

To evaluate these scenarios, we assumed a simple portfolio consisting of RPS-eligible resources and additional GHG-free resources in an amount dictated by the particular scenario, with the balance of supply provided by non-renewable wholesale market purchases. In each case, we

[17] For all scenarios we assume a minimum 5% non-renewable market supply to reflect operating constraints that require flexible, dispatchable generation on the system and in local areas. The CCE may be able to reduce emissions further through the use of energy storage or other measures to reduce the need for non-renewable power supplies, likely at additional cost.

[18] Customer-sited solar is not considered RPS-eligible in California and is not included in the RPS procurement in these scenarios. Customer-sited solar is incorporated in this analysis as a reduction to the CCE's load.

assumed that the RPS portfolio was predominately supplied with solar and wind resources, which are currently the low-cost sources of renewable energy. We assumed that solar and wind each contributes 45% of the renewable energy supply on an annual basis. To provide resource diversity and partly address the need for supply at times when solar and wind production are low, we assumed the remaining 10% of renewable supply would be provided by higher-cost baseload resources, such as geothermal or biomass.

In the early years, the CCE would have to purchase its required renewable power from the market and existing resources. However, the study assumes that the CCE would contract with new renewable resources, such that by 2030 most of its renewable power would come from new resources. Figures 6 and 7 show the assumed build-out of these new resources under the first (Minimum RPS Compliance) and the fourth (Accelerated RPS plus Local) scenarios described above.

Figure 6. Senario 1 CCE Build-Out

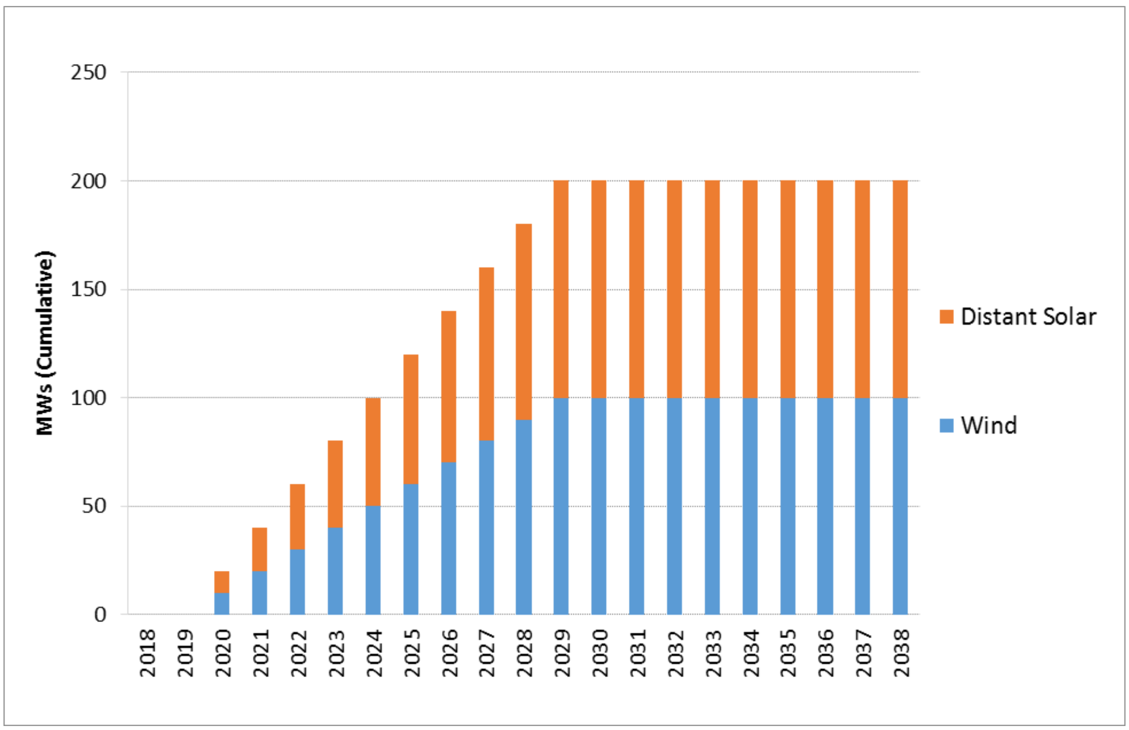
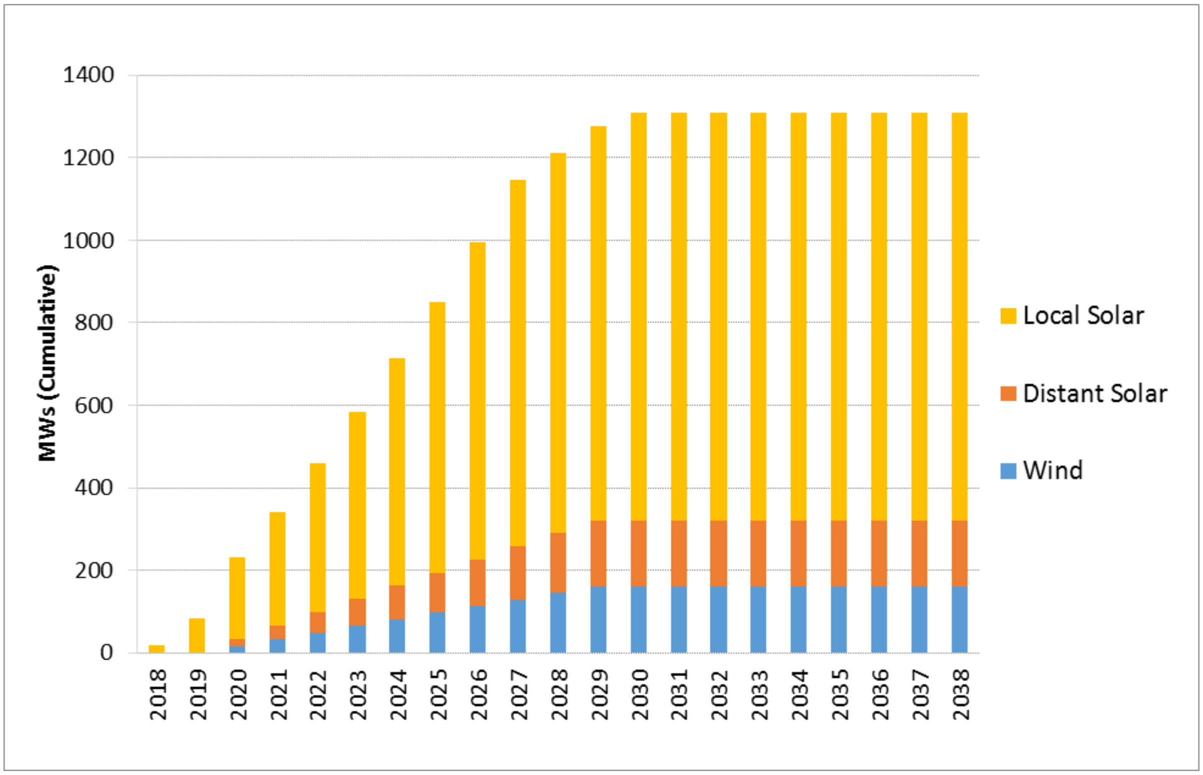


Figure 7. Scenario 4 CCE Build-Out

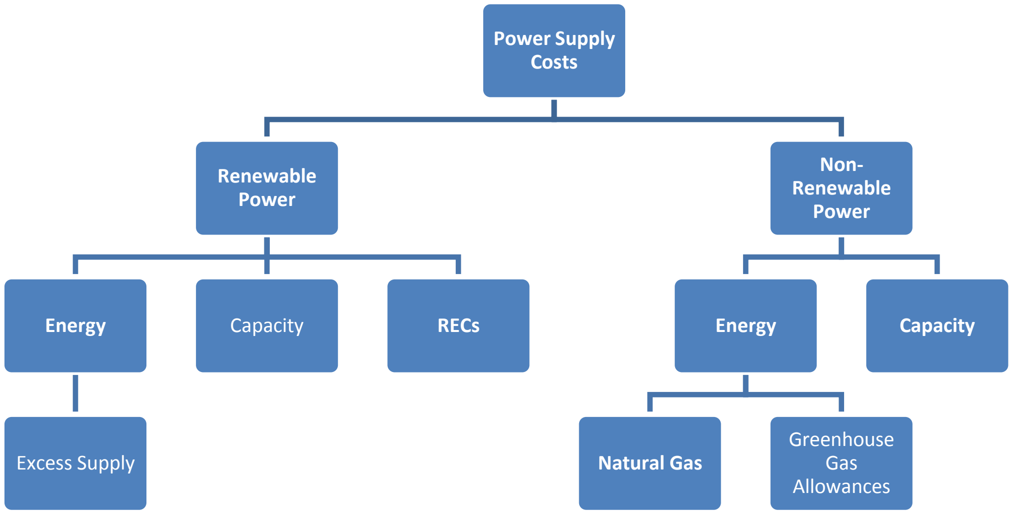


Power Supply Cost Assumptions

As discussed above, the CCE would procure a portfolio of resources to meet its customers' needs, which would consist of a mix of renewable and non-renewable (i.e., wholesale market) resources. As shown in Figure 8, the products to be purchased by the CCE consist generally of energy, capacity and renewable attributes (which for counting purposes take the form of renewable energy credits, or RECs).[19]

[19] RECs are typically bundled with energy deliveries from renewable energy projects, with each REC representing 1 MWh of renewable energy. A limited number of unbundled RECs may be used to meet RPS requirements. For the purpose of this study we have not considered unbundled RECs and have rather estimated costs based on renewable energy contracts where the RECs are bundled.

Figure 8. Power Supply Cost Elements



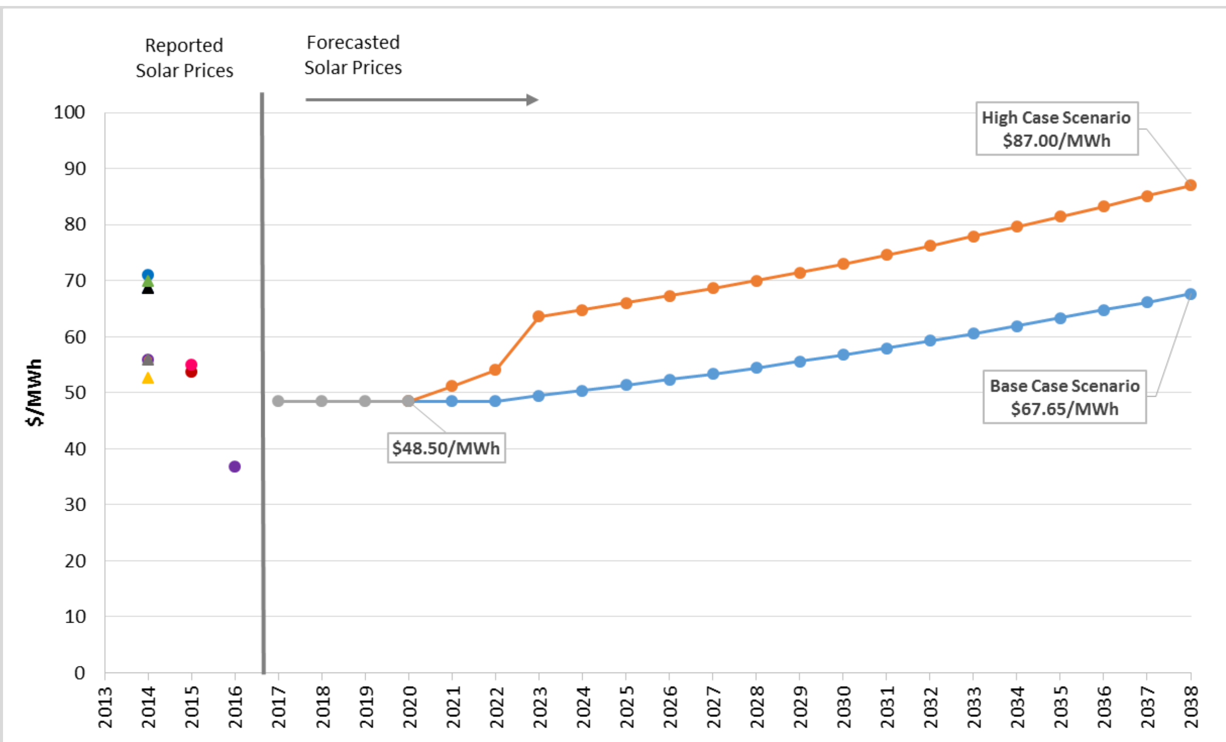
The CCE will procure supplies from the same competitive market for resources as PG&E. Thus, we assume that the costs for renewable and non-renewable energy and for resource adequacy (RA) capacity for the CCE are the same as for new purchases made by PG&E (discussed further in our forecast of PG&E rates). Wholesale market prices for electricity in California are largely driven by the cost of operating natural gas power plants, since these plants typically have the highest operating costs and are the marginal units. Market prices are a function of the efficiency of the marginal generators, the price of natural gas and the cost of GHG allowances. MRW developed forecasts of these elements to derive a power price forecast to determine costs for the CCE and PG&E. Large hydroelectric power prices are based on the market price forecast with a 10% premium to reflect the value of GHG benefits, flexibility and increasing demand from load serving entities seeking clean power like the CCE. Capacity prices are based on prices for RA contracts reported by the CPUC and on the cost to build a new combustion turbine power plant.

MRW developed a forecast of non-local utility scale renewable generation prices starting from an assessment of the current market price for renewable power. For the current market price, MRW relied on wind and solar contract prices reported by California municipal utilities and CCEs in 2015 and early 2016, finding an average price of $49/MWh for the solar contracts, $55/MWh for wind power and $80/MWh for geothermal.[20] We used these prices as the starting point for our forecast of CCE renewable energy procurement costs. For geothermal, which is a relatively mature technology, we assumed that new contract prices would simply escalate with inflation.

[20] MRW relied exclusively on prices from municipal utilities and CCEs because investor-owned utility contract prices from this period are not yet public. We included all reported wind and solar power purchase agreements, excluding local builds (which generally come at a price premium), as reported in *California Energy Markets*, an independent news service from Energy Newsdata, from January 2015-January 2016 (see issues dated July 31, August 14, October 16, October 30, 2015, and January 15, 2016).

Solar and wind prices are a function of technology costs, which have generally been declining over time; financing costs, which have been very low in recent years; and tax incentives, which significantly reduce project costs, but phase out over time. In the near-term we would not expect prices to increase as technology costs and continued tax incentives provide downward pressure and likely offset any increase in financing costs or other competitive pressure from an increasing demand for renewable energy in California. For utility scale wind prices, we relied on an expert elicitation survey[21] developed by Lawrence Berkeley National Laboratory (LBNL). According to this survey, wind prices will decrease 24% by 2030 and 35% by 2050.[22] For solar, we held prices constant in nominal dollars through 2020. Beyond 2020, with increasing competitive pressure due to the drive to a 50% RPS and the anticipated phase-out of federal tax incentives (offset in part by declining technology costs), we would expect prices to increase somewhat and have assumed they escalate at the rate of inflation. In addition, we also considered a high solar cost scenario based on work performed by LBNL on the value of tax incentives. In the high scenario, we assume that costs increase with the phase-out of federal tax incentives, without being offset by declining technology costs. Figure 9 shows the resulting solar price forecasts for the two scenarios.

Figure 9. Large-Scale Non-Local Solar Price Forecast



Local Solar Analysis

Pivotal to the evaluation of the local economic impacts of a Contra Costa CCE is an understanding how much renewable energy can be developed within the County. This

[21] "Expert elicitation survey on future wind and energy costs," *Nature Energy*, September 12, 2016.
[22] Relative to the 2014 wind prices. MRW also added the annual inflation increase.

assessment focused on identifying local solar photovoltaic (PV) siting potential. Wind and biomass energy were also evaluated, but were determined to be less feasible for Contra Costa County.

The solar PV assessment is based on a comprehensive desktop review of countywide parcel data, geographic features and solar energy potential. Table 2 shows the total solar PV generation capacity within the County based on the methodology and assumptions described below.

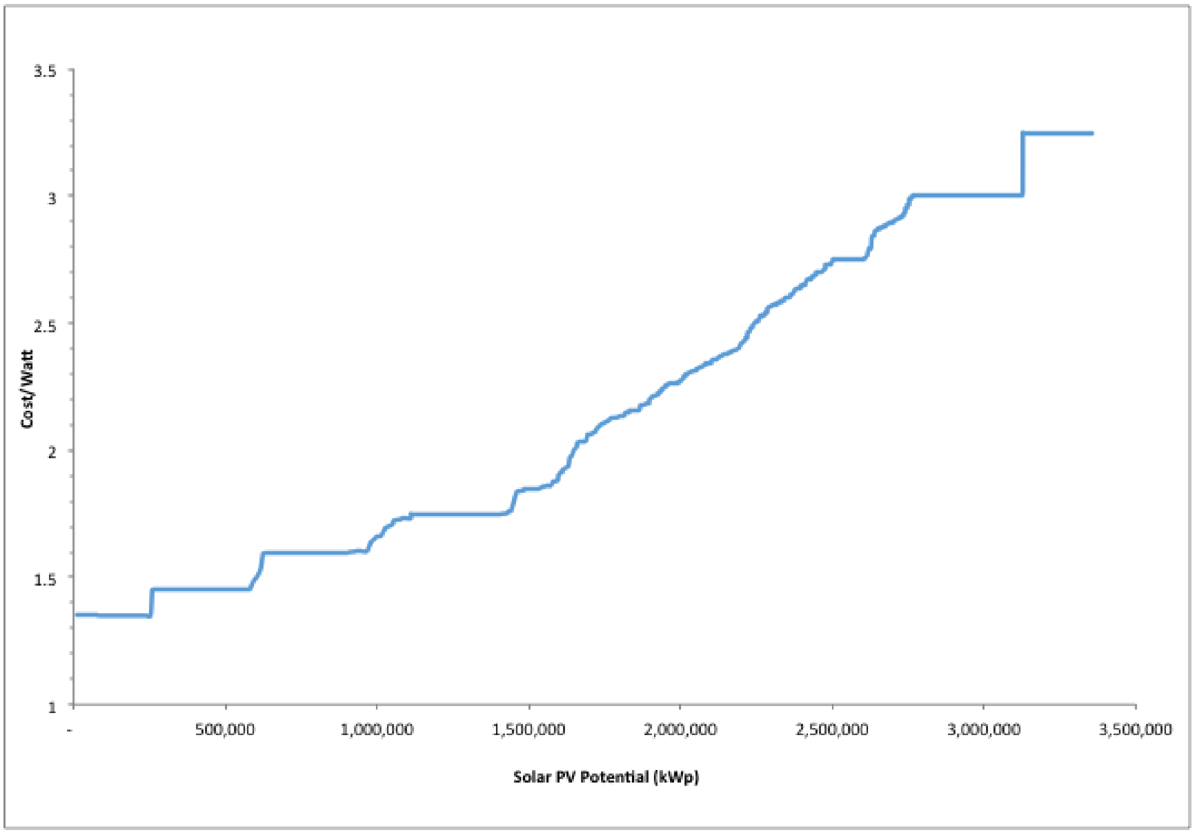
Table 2. Total PV Solar Generation Potential and Build Cost

	Ground Mount	Shade Structure	Roof Mounted	Total
PV Capacity (MW[23])	1,891	1,320	144	3,355
PV Production (GWh)	3,025	2,113	230	5,369
Build Cost ($ Millions)	$3,417	$3,977	$371	$7,660
Build Cost ($/Watt)	$1.99	$3.10	$2.62	$2.56
No of PV Systems	845	886	144	1,875

Generation capacity was determined for the three types of possible solar PV installations: Ground Mount, Shade Structure/Carport, and Roof Mount. The findings show that the County has a solar PV generation capacity of 3,355 MW and annual solar electricity production potential of 5,369 GWh. Figure 10 shows the aggregate Solar PV supply curve for all County jurisdictions.

[23] Local solar PV capacity measured at the panel (i.e., pre-inverter).

Figure 10. Aggregate Solar PV Supply Cost Curve, All County



Siting Analysis

To assess the potential locations in Contra Costa County where solar PV could be developed, this study utilized a Geographic Information System (GIS)-based desktop review, incorporating aerial imagery and land-based data. The collected data was analyzed and potential solar PV development sites were identified from criteria established through industry knowledge and input from County stakeholders.

The agreed upon criteria are as follows:

- The minimum acceptable parcel size is three acres. Smaller parcels will not be able to hold an economically viable project. If a potential solar PV system size is below 500 kW it was excluded from the list of potentially feasible sites and overall solar energy capacity.[24] Again, this measure ensures only realistic and economically feasible sites are identified.

- Based on input from the County, only specific tax codes and zoning areas were evaluated. For example, areas such as Open Space or Parks have sufficient land area for solar PV

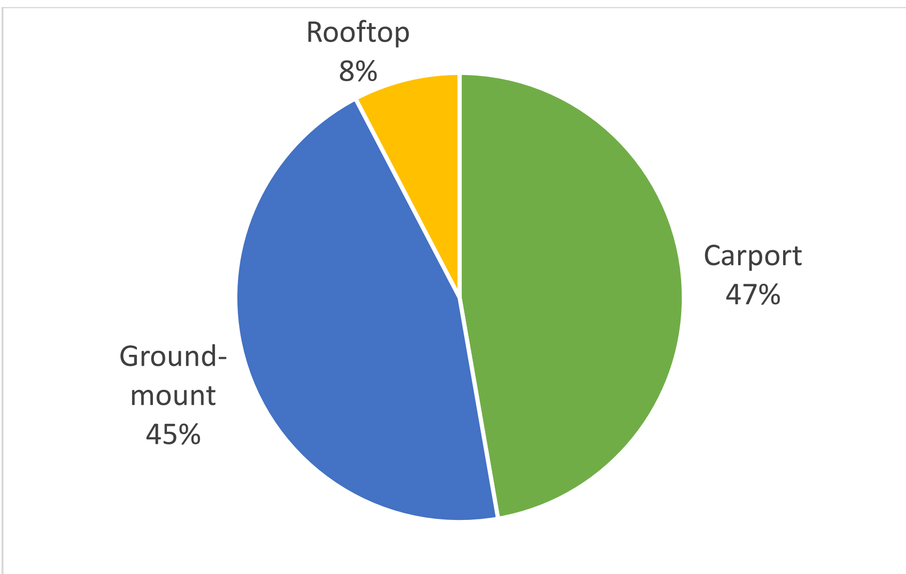
[24] Residential and other small rooftop solar are accounted for in the California Energy Commission sales forecast used to develop the CCE's demand forecast.

projects, but zoning restrictions would not allow for the development of these projects, and these areas were removed from the approved scope.

- In addition, to size and tax/zoning code designations, areas with poor ground quality (marshland), excessive tree density or excessive sloping would prohibit cost-effective solar PV development and were removed from the analysis.
- Lastly, sites with existing solar were removed from the pool of potential parcels/sites.

Within each identified parcel is the potential for three different types of solar PV development. On impervious land, such as a parking lot, it was assumed that solar PV carports would be installed. On grassland or bare land areas, this analysis assumed a ground-mounted solar PV system would be installed. Lastly, roof-mounted solar PV was assumed for any buildings found in the parcel data that matched the approved criteria. Countywide, 92% of potential installation sites were found to be either carport or ground-mount sites, with only 8% of the sites amenable to roof-mounted PV (Figure 11). The size of the estimated solar PV system was found by analyzing the total land area against the needed land required for solar PV development.

Figure 11. Potential Solar PV Sites by Installation Type



This study found 1,395 parcels that met the established criteria and 1,875 individual sites within the identified parcels where either a solar shade structure, rooftop or ground-mounted system could be developed. Table 3 shows the individual sites organized by type of solar PV system for each jurisdiction in Contra Costa County.[25]

[25] For maps, please see https://www.dropbox.com/s/cb3rig66shny68j/Contra%20Costa%20CCE%20Solar%20Siting%20DRAFT%20Report%20SA%202016-11-15%20Reduced%20Size.pdf?dl=0.

This assessment also calculated the amount of solar energy production for each of the potential sites identified. The amount of energy production was found by multiplying the estimated system size by an average solar yield. The average solar energy yield was created by designing sample projects that matched the estimated system size in the solar software platform Helioscope. Because Contra Costa County has a variety of solar exposure, multiple sites across the County were designed/tested to find an average yield. Based on our testing, the average yield for Contra Costa County is 1,600 (kWh/kW). The resulting amount of potential PV production per jurisdiction is also provided in Table 3.

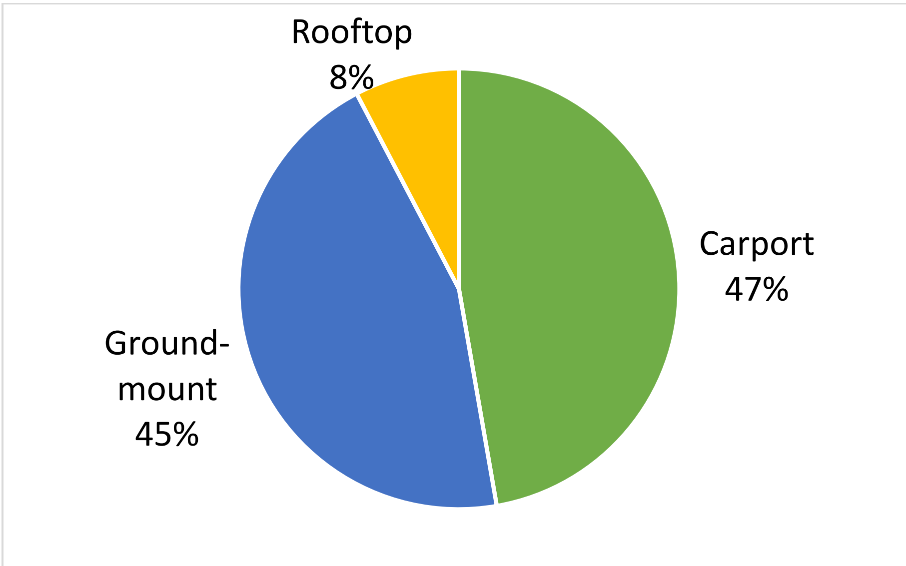
Table 3. Potential PV Production and Build Cost by Location

Jurisdiction	PV Potential (MW)	PV Production (GWh)	Build Cost ($ Millions)
Alamo	14	23	$30,779,000
Antioch	462	739	$1,010,374,000
Brentwood	287	460	$599,685,000
Clayton	38	62	$71,171,000
Concord	370	593	$900,603,000
Crockett	58	93	$125,187,000
Danville	80	129	$177,801,000
El Cerrito	29	48	$73,161,000
El Sobrante	19	31	$42,020,000
Hercules	90	144	$200,511,000
Lafayette	8	13	$23,641,000
Martinez	313	502	$654,701,000
Moraga	24	39	$55,957,000
Oakley	121	194	$285,786,000
Orinda	22	36	$43,554,000
Pinole	47	77	$126,870,000
Pittsburg	314	502	$705,202,000
Pleasant Hill	60	96	$164,364,000
Port Costa	8	13	$13,501,000
Richmond	502	804	$1,261,541,000
Rodeo	35	57	$85,874,000
San Pablo	191	307	$459,784,000
San Ramon	158	254	$384,634,000
Walnut Creek	95	152	$269,795,000
Grand Total	**3,355**	**5,369**	**$7,766,496,000**

Ranking

After the feasible solar sites and the corresponding solar PV capacity were identified, each site was ranked. The ranking was weighted based on how important it was to the actual feasibility of developing the site for solar PV and based on input from County stakeholders. The ranking consisted of the following measures:

Figure 12. Weighted Ranking Categories



An overall ranking score was then applied to each individual site to illustrate the best and worst sites for solar PV development. Sites were then grouped in tiers one through five, with one being the best. In addition to the ranking score, industry knowledge indicates the best sites to develop a feasible solar PV project will be larger than 1 MW, located on government land and will be a ground-mounted solar array, the most cost-effective installation type. Below is a table showing the key characteristics of the ranking analysis.

Table 4. Ranking Values for All Sites

Ranking Tier	Sum of PV Production (GWh)	Sum of Total Price	Average Price per Watt
1	1,309	$1,591,810,000	$2.13
2	1,167	$1,578,770,000	$2.37
3	1,105	$1,622,236,000	$2.57
4	868	$1,251,547,000	$2.56
5	919	$1,722,142,000	$3.07

Local Solar Modeled in the CCE Scenarios

To estimate the contribution of local solar to Contra Costa CCA's supply costs, we used the supply curve shown in Figure 10. To translate the $/kW costs in the figure to $/MWh generation costs, we used the pro forma model contained in the CPUC's RPS Calculator and the cost and performance assumptions provided by Sage for the County. For example, the lowest-cost projects at $1350/kW were estimated to have a generation cost of $68/MWh.

The generation cost was assumed to scale with installed cost. Since it is unlikely that all of the identified sites would be developed in order of their increasing cost (and some sites may never be developed regardless of economics), we assumed that 50% of the capacity identified in the cost curve would be developed for the purpose of conservatively estimating average costs at each level of local solar penetration. We calculated the average price for the cumulative developed capacity forecast for each year (again, counting only 50% of the capacity of each developed project towards the cumulative total). For Scenarios 3 and 4, we assumed that 50% of the CCA's RPS supply would be provided by local solar by 2027, adding 620 MW of local solar under Scenario 3 and 990 MW under Scenario 4 by 2030. (Scenarios 1 and 2 do not include any local solar.)

Greenhouse Gas Costs

MRW estimated that the price of GHG allowances would equal the auction floor price stipulated by the California Air Resources Board's cap-and-trade regulations, consistent with recent auction outcomes.[26]

Table 5. GHG Allowances price[27]

	2017	2018	2019	2025	2030	2035	2038
$/tonne	13.2	14.7	15.9	24.4	34.7	49.8	61.8

Total GHG costs were calculated by multiplying the allowance price by the amount of carbon emitted per megawatt-hour for each assumed resource. For "system" purchases, MRW assumed that the GHG emissions corresponded to a natural gas generator operating at the market heat rate. This worked out to be, on average over 2018-2038, approximately $1.5/MWh delivered.[28]

Other CCE Supply Costs

The CCE is expected to incur additional costs associated with its procurement function. For example, if the CCE relies on a third-party energy marketing company to manage its portfolio it will likely incur broker fees or other expenses equal to roughly 5% of the forecasted contract costs. The CCE would also incur costs charged by the California Independent System Operator (CAISO) for ancillary services (activities required to ensure reliability) and other expenses.

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[26] California Code of Regulations, Title 17, Article 5, Section 95911. Auction results available at http://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf.

[27] For 2017, the amount listed corresponds to the GHG allowance price for PG&E according to the most recent ERRA 2017 update. Pacific Gas & Electric ERRA 2017, A.16-06-003, Testimony November 2, 2016, Table 12-1.

[28] The amount GHG emissions will depend on the generation portfolio. $1.5/MWh corresponds to the GHG emissions costs under Scenario 1.

MRW added 5.5% to the CCE's power supply cost to cover these CAISO costs. Finally, we added an expense associated with managing the CCE's renewable supply portfolio. Based on an analysis of the expected CCE load shape and the typical generation profile of California solar and wind resources, we observed that there will be hours in which the expected deliveries from renewable contracts will be greater than the CCE's load in that hour. This results from the amount of renewable capacity that must be contracted to meet annual RPS targets and the variability in renewable generation that leads to higher deliveries in some hours and lower deliveries in other hours. When high renewable energy deliveries coincide with low loads, the CCE will need to sell the excess energy, likely at a loss, or curtail deliveries, and potentially have to make up those renewable energy purchases during higher load hours to comply with the RPS. The result is that the procurement costs will be somewhat higher than simply contracting with sufficient capacity to meet the annual RPS.

PG&E Rate and Exit Fee Forecasts

MRW developed a forecast of PG&E's bundled generation rates and CCE exit fees in order to compare the projected rates that customers would pay as Contra Costa County CCE customers to the projected rates and fees they would pay as bundled PG&E customers.

PG&E Bundled Generation Rates

To ensure a consistent and reliable financial analysis, MRW developed a 20-year forecast of PG&E's bundled generation rates using market prices for renewable energy purchases, market power purchases, greenhouse gas allowances, and capacity that are consistent with those used in the forecast of Contra Costa County CCE's supply costs. MRW additionally forecast the cost of PG&E's existing resource portfolio, adding in market purchases only when necessary to meet projected demand. MRW assumed that near-term changes to PG&E's generation portfolio would be driven primarily by increases to the Renewable Portfolio Standard requirement in the years leading up to 2030 and by the retirement of the Diablo Canyon nuclear units at the end of their current license periods in 2024 and 2025. More information about this forecast is provided in Appendix B.

MRW forecasts that, on average, PG&E's generation rates will increase faster than inflation through 2038, with 2038 rates more than 20% higher than today's rates when considered on a constant dollar basis (i.e., assuming zero inflation). Underlying this result are three distinct rate periods:

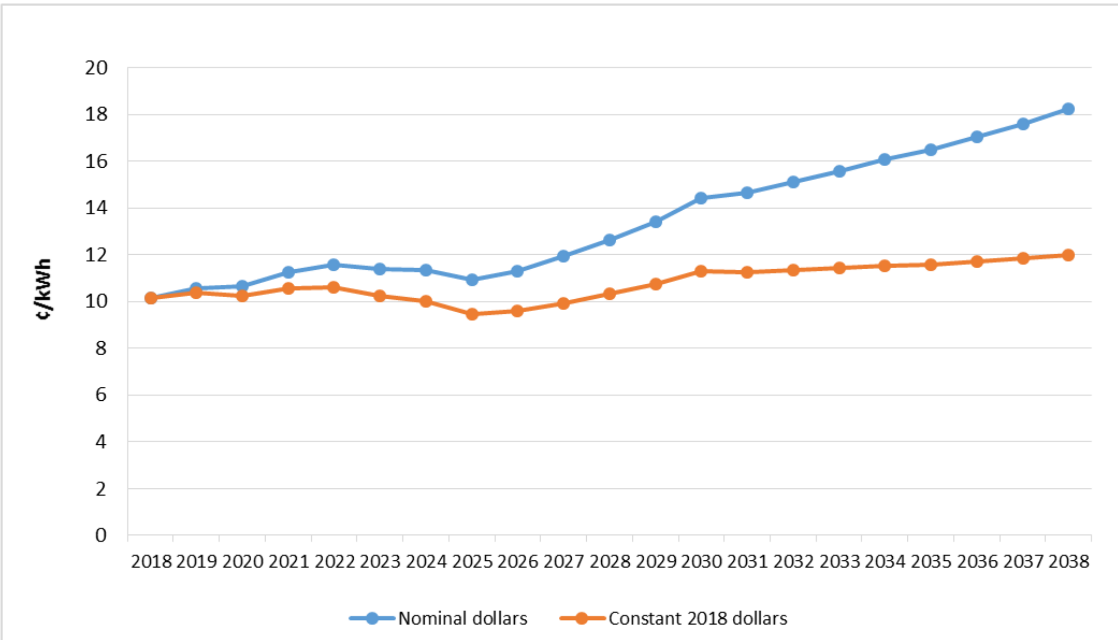
1. An initial period of faster rate growth from 2018 to 2022 (1% annually above inflation);
2. A period of rate decline from 2023 to 2025 (3.5% annually below inflation), primarily due to the retirement of Diablo Canyon[29]; and
3. A period of steeper rate growth between 2026 and 2030 (3.5% annually above inflation), primarily due to the replacement of Diablo Canyon with more expensive resources: energy efficiency, renewable generation, and fuel-fired generation. In addition, the retirement of Diablo Canyon increases the demand in capacity with a consequent increase in capacity prices.

[29] More information can be found in the Appendix C

4. A final period of moderate rate growth through 2038 (1% annually above inflation), primarily due to the replacement of high-cost renewable power contracts currently in PG&E's portfolio with new lower-priced contracts (reflecting the significant fall in renewable power prices in recent years).

PG&E's bundled generation rates in each year of MRW's forecast are shown in Figure 13, on both a nominal and constant-dollar basis.

Figure 13: PG&E Bundled Generation Rates, nominal and constant-dollar forecasts



PG&E Exit Fee Forecast

In addition to the bundled rate forecast, MRW developed a forecast of the Power Charge Indifference Adjustment ("PCIA"), which is a PG&E exit fee that is charged to CCE customers. The PCIA is intended to pay for the above-market costs of PG&E generation resources that were acquired, or which PG&E committed to acquire, prior to the customer's departure to CCE. The total cost of these resources is compared to a market-based price benchmark to calculate the "stranded costs" associated with these resources, and CCE customers are charged what is determined to be their fair share of the stranded costs through the PCIA.

MRW forecasted the PCIA charge by modeling expected changes to PCIA-eligible resources and to the market-based price benchmark through 2038, using assumptions consistent with those used in the PG&E rate model. Based on our modelling, we expect the PCIA to decline in most years until it drops off completely around 2034. MRW's forecast of the residential PCIA charge through 2038 is summarized in Table 6.

Table 6. PG&E Residential PCIA Charges

	2018	2019	2020	2025	2030	2035	2038
¢/kWh	2.4	1.9	2.3	1.3	0.5	0.0	0.0

Pro Forma Elements and CCE Costs of Service

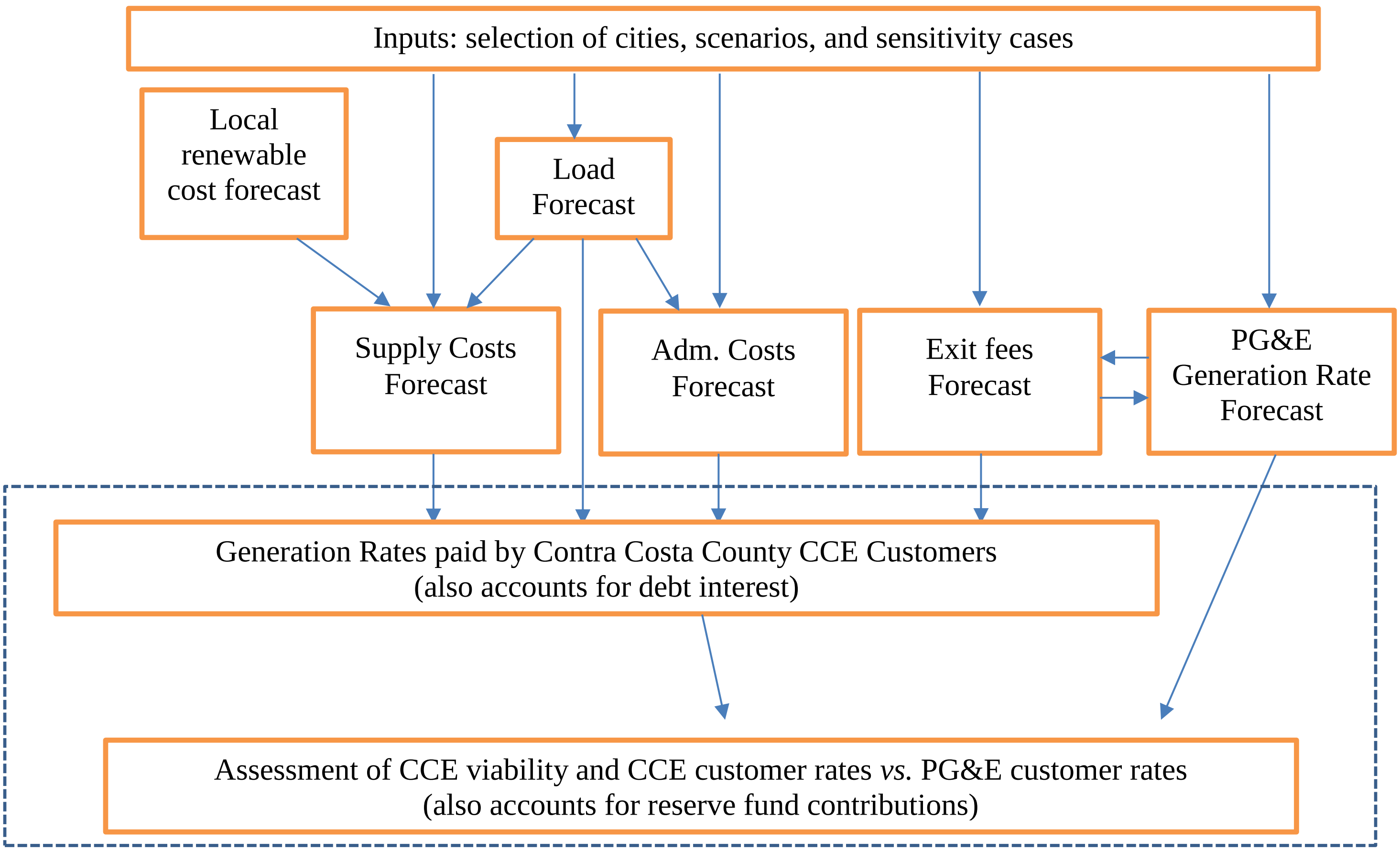
MRW conducted a pro forma analysis to evaluate the expected financial performance of the CCE and the CCE's competitive position *vis a vis* PG&E. The analysis was conducted on a forward-looking basis from the expected start of CCE operations in 2018 through the year 2038, with several cases considered to address uncertainty in future circumstances.

Pro Forma Elements

Figuer 14 provides a schematic of the pro forma analysis, outlining the input elements of the analysis and the output results. The analysis involves a comparison between the generation-related costs that would be paid by Contra Costa County CCE customers and the generation-related costs that would be paid by PG&E bundled service customers. Costs paid by CCE customers include all CCE-related costs (*i.e.*, supply portfolio costs and administrative and general costs) and exit fee payments that CCE customers will be required to make to PG&E.

As discussed in previous sections, supply portfolio costs are informed and affected by CCE loads, by the requirements the CCE will need to meet (or will choose to meet) such as with respect to renewable procurement, and by CCE participation levels, which can vary depending on whether or not all cities in the County choose to join the CCE. Administrative and general costs are discussed further below.

Figure 14. Pro forma Analysis



Startup Costs

Table 7 shows the estimated CCE startup costs. They are based on the experience of existing CCEs as well as from other CCE technical and feasibility assessments. Working capital is set to equal one hundred days of CCE revenue[30], or approximately $22 million. This amount would cover the timing lag between when invoices for power purchases (and other account payables) must be remitted and when income is received from the customers. Initially, the working capital is provided to the CCE on credit from a bank. Typical power purchase contracts require payment for the prior month's purchases by the 20th of the current month. Customers' payments are typically received 60 to 90 days from when the power is delivered.

These startup costs are assumed to be financed over 5 years at 5% interest.

[30] The working capital has been calculated in base to Scenario 1.

Table 7. Estimated Start-Up Costs

Item	Cost
Technical Study	$200,000
JPA Formation/Development	$100,000
Implementation Plan Development	$50,000
Power Supplier Solicitation & Contracting	$75,000
Staffing	$700,000
Consultants and Legal Counsel	$400,000
Marketing & Communications	$250,000
PG&E Service Fees	$75,000
CCA Bond	$100,000
Miscellaneous	$300,000
Total	**$2,250,000**
Working Capital	$21,500,000
Total	**$23,750,000**

Administrative and General Cost Inputs

Administrative and general costs cover the everyday operations of the CCE, including costs for billing, data management, customer service, employee salaries, contractor payments, and fees paid to PG&E. MRW conducted a survey of the financial reports of existing CCEs to develop estimates of the costs that would be faced by a Contra Costa County CCE. Administrative and general costs are phased in from 2018 to 2020, as the CCE operations expand to cover the entire territory of the County; after that, costs are escalated by 2% each year to account for the effects of inflation.

Administrative and general costs are unchanged under the three renewable level scenarios, but do vary based on how many cities join the CCE and the number of participating customer accounts. As previously mentioned, a 15% opt-out rate has been assumed for customer participation.

Cost of Service Analysis and Reserve Fund

To determine annual CCE costs and the rates that would need to be charged to CCE customers to cover these costs, MRW summed the two categories of CCE costs (*i.e.*, supply portfolio costs, and administrative and general costs) and added in debt financing to cover start-up costs and initial working capital. Financing was assumed to be for a five-year period at an interest rate of 5%. These costs were divided by projected CCE loads to develop the average rate the CCE would need to charge customers to cover its costs ("minimum CCE rate").

To establish the Contra Costa County CCE rate, MRW adjusted the minimum CCE rate, if needed, based on the competitive position of the CCE. In particular, when the total CCE customer rate (*i.e.*, the minimum CCE rate plus the PG&E exit fee) was below the projected PG&E generation rate,[31] MRW increased the minimum CCE rate up to the amount needed to meet the reserve refund targets while still maintaining a discount. MRW used the surplus CCE revenue from these rate increases ("Reserve Fund") in order to maintain Contra Costa County CCE competitiveness with PG&E rates in years in which total CCE customer rates would otherwise be higher than PG&E generation rates.[32]

[31] For this analysis, MRW used the average of the projected PG&E generation rates across all rate classes, weighted by the projected Contra Costa County CCE load in each rate class.
[32] MRW applied a Reserve Fund cap of 15% of the annual operating cost. After this cap was reached, no further rate increases were applied for the purpose of Reserve Fund contributions.

Chapter 3: Cost and Benefit Analysis

As described in the prior chapter, as part of the pro forma analysis, MRW calculated Contra Costa County CCE rates that would, where feasible, cover CCE costs and maintain long-term competitiveness with PG&E. This chapter uses those rates to compare the costs and benefits of the Contra Costa County CCE across four scenarios: (1) Minimum RPS Compliance, (2) Accelerated RPS, (3) Minimum RPS Compliance plus Local Procurement, and (4) Accelerated RPS plus Local Procurement. Costs and benefits are evaluated by comparing total CCE customer rates (including PG&E exit fees) to PG&E generation.

Scenario 1 (Minimum RPS Compliance)

Under Scenario 1, the Contra Costa County CCE meets all RPS requirements (including California State Senate Bill 350 and Diablo Canyon retirement proposal requirements), and 35% of the total load over the 20-year period is met through large hydroelectricity[33].

CCE Average Costs

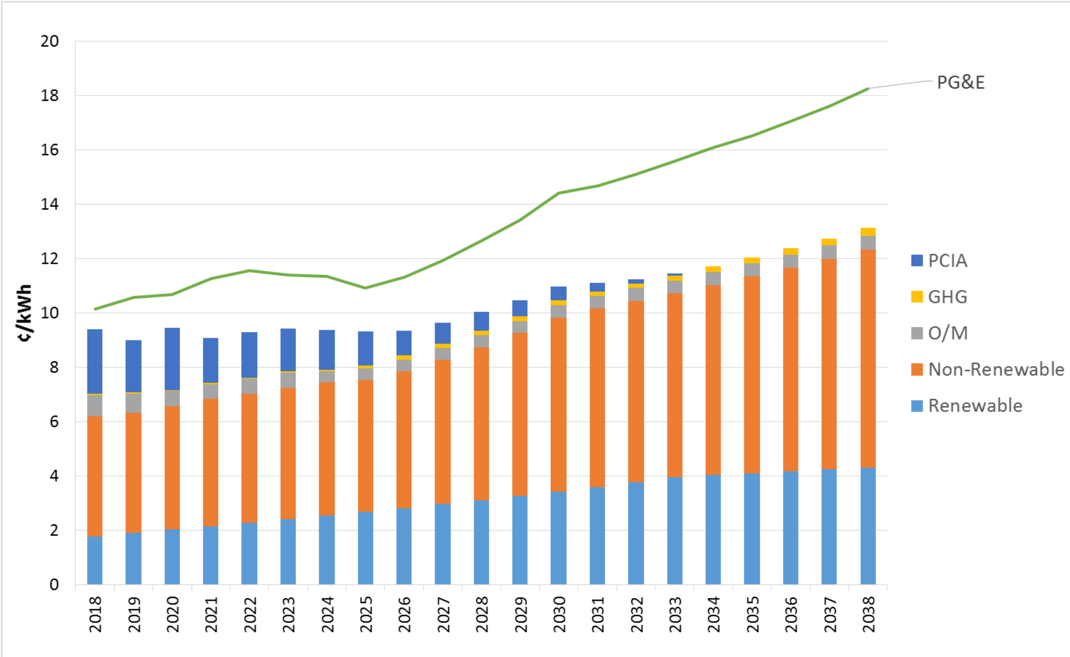
Figure 15 summarizes the results of this scenario. The vertical bars represent the total Contra Costa County CCE customer rate and the green line represents a comparable PG&E generation rate.[34] Non-renewable generation (including large hydroelectric) is responsible for the bulk of the CCE's costs. Renewable generation costs will continue to increase throughout the forecast period due to the increasing RPS standards. Regarding customer costs, the PCIA exit fee is expected to decrease after 2020. Finally, the GHG allowance purchases represent a small portion of the total costs because 60% of the non-renewable generation is met by hydroelectricity. This non-carbon emitting resource therefore limits the need to purchase GHG allowances.

Note that this figure and the analogous ones to follow do not account for contributions to a rate reserve fund or other potential CCE activities such as efficiency or other community programs.

Under Scenario 1, the differential between PG&E generation rates and Contra Costa County CCE customer rates is positive in each year (*i.e.*, CCE rates are lower than PG&E rates). As a result, Contra Costa County CCE customers' average generation rates (including contributions to the reserve fund) can be set at a level that is lower than PG&E's average customer generation rate in each year. The annual differential between the PG&E rate and the total CCE customer rate is expected to vary significantly over the course of this period (Figure 15). During the initial period from 2018-2022, the differential between the two rates increases (i.e., the CCE becomes more cost-competitive) as PG&E's rates rise, and the exit fees charged to Contra Costa County CCE customers fall as PG&E-owned gas plants expire from PCIA eligibility. Beginning in 2024, the rate differential narrows due to a decrease in PG&E generation rates stemming from the closure of the Diablo Canyon nuclear plant. After 2026, the difference between the two rates is expected to increase as PG&E's generation rates continue to increase and exit fees decline with the expiration of additional resources from PCIA eligibility.

[33] 60% of the non-RPS generation in average for 2018-2038.
[34] All rates are in nominal dollars

Figure 15. Scenario 1 Forecast Average CCE Cost and PG&E Rates, 2018-2038[35]



Residential Bill Impacts

Table 8 shows the average annual savings for Residential customers under Scenario 1. The average annual bill for the residential customer on the Contra Costa County CCE program will be on average 8% lower than the same bill on PG&E rates. Note that these rate impacts assume that a rate stabilization reserve is funded during the first few years of the CCE's existence.

Table 8. Scenario 1 Savings for Residential CCE Customers

Residential	Monthly Consumption (kWh)	Bill with PG&E ($)	Bill with Contra Costa County CCA ($)	Savings ($)	Savings (%)
2018	500	121	121	0	0%
2020	500	129	124	5	4%
2030	500	189	171	18	10%
2038	500	254	227	27	11%

[35] This chart doesn't include the reserve fund.

Greenhouse Gas Emissions

Under Scenario 1, we model the Contra Costa County CCE to be 50% below PG&E's GHG emission rate. It can meet this goal by using large hydroelectric power to meet 35% of its resource needs (60% of the non-RPS load). Though this large hydro power would not qualify for RPS requirements, it is nevertheless a non-carbon emitting resource.

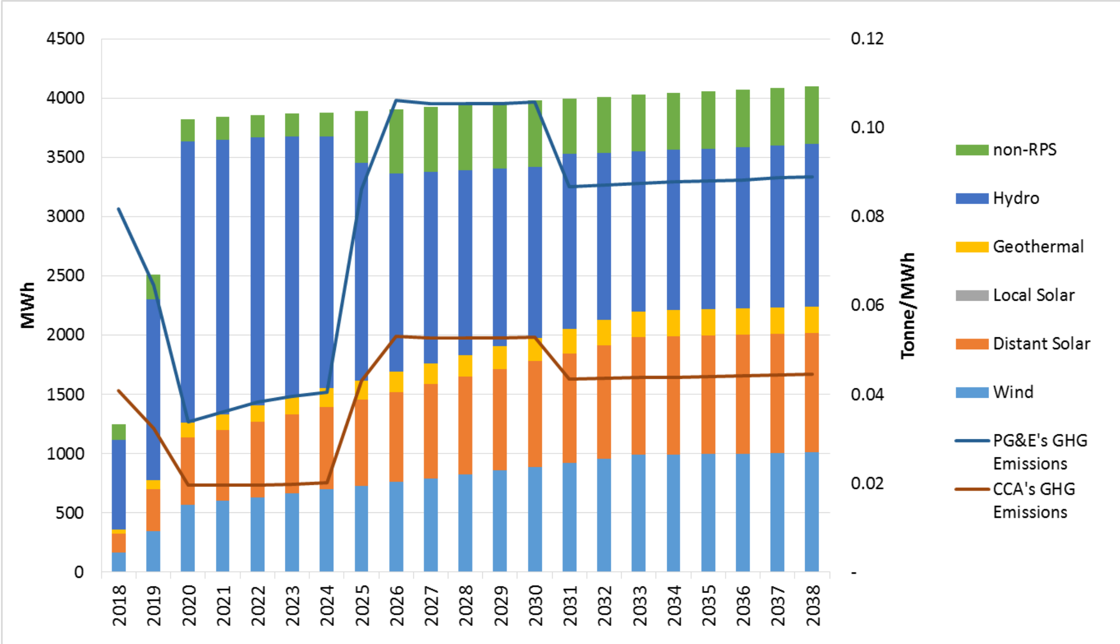
Figure 16 shows Contra Costa CCE's generation portfolio mix (vertical bars) and GHG emissions rate (brown line) under Scenario 1, along with PG&E's GHG emissions rate for comparison (blue line). Additional GHG savings can occur if additional renewables are added to the portfolio (see Scenarios 2 and 4) or if a greater fraction of GHG-free resources (like large hydro) is used.

PG&E GHG emissions are relatively low due to the diversity in PG&E's electric mix. In addition to renewable generation, over 40% of PG&E's supply portfolio is made up of nuclear and large hydroelectric generation, both of which are considered GHG-free generation technologies. PG&E's GHG emissions rate is expected to fall between 2018 and 2020 due to increases in RPS procurement. In 2025, the retirement of the Diablo Canyon nuclear generation plant is expected to more than double PG&E's GHG emission rate as the utility increases its gas-fired generation to make up for a share of the loss.[36] In the following years PG&E's GHG emissions are expected to decrease as PG&E ramps up renewable procurement to meet its mandated RPS goals and the additional RPS procurement required under the Diablo Canyon retirement proposal.[37] In this scenario, the CCA's emissions rate is set to be approximately 50% of PG&E's in each year, subject to a 5% minimum supply from market purchases.

[36] Even if PG&E replaces the nuclear generation with renewable power and other GHG-free resources, as proposed, the new renewable resources will need to be balanced by flexible resources, which are likely to be at least in part provided by fossil-fueled power and which will therefore increase PG&E's GHG emissions.

[37] Starting in 2030, the required RPS increases from 50% to 55% under PG&E's proposal.

Figure 16. Scenario 1 Contra Costa County CCE Supply Portfolio (vertical bars) and GHG Emissions (lines) ("Normal" PG&E Hydro Conditions)



Scenario 2 (Accelerated RPS)

Scenario 2, from a renewable procurement perspective, is a more aggressive scenario. Under this scenario, the Contra Costa County CCE starts with 50% of its load served by renewable sources in 2018, and rapidly increases to 80% of its load served by renewable sources in 2030. In addition, between 2018 and 2038 Contra Costa County will provide an average of 20% of its supply though large hydroelectric sources[38].

CCE Average Costs

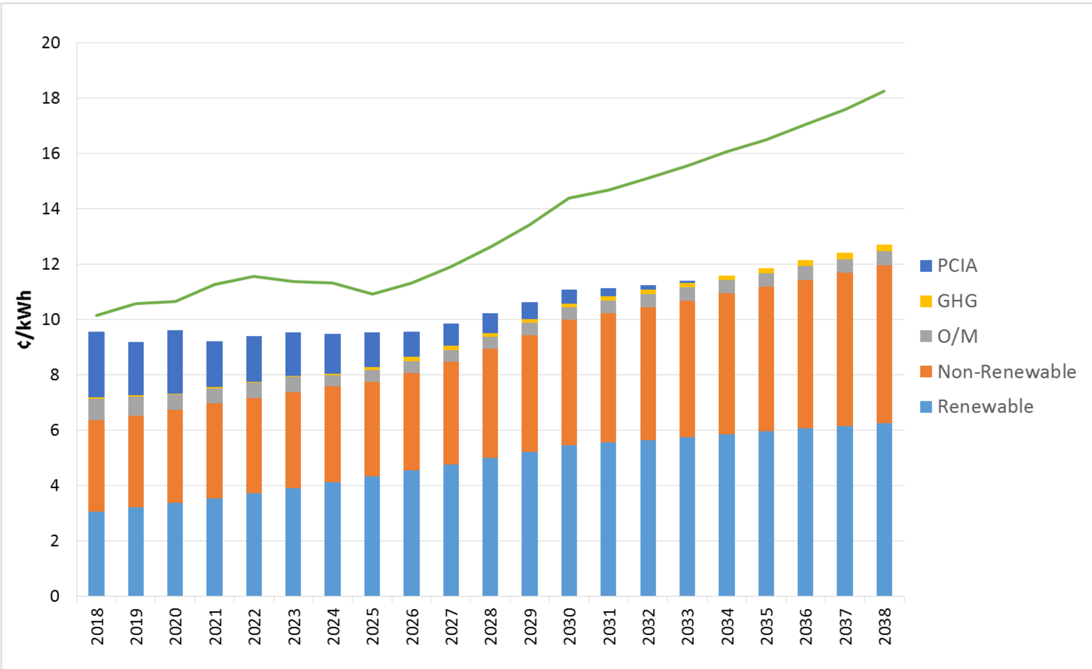
Figure 17 summarizes the results for this scenario. The vertical bars represent the Contra Costa County CCE customer rate, and the green line represents the PG&E generation rate. In this scenario, the renewable power cost is the single largest element of the CCE rate, reflecting the higher renewable content of this scenario. Non-renewable generation and the PCIA exit fee are the second and third most expensive components, respectively. As in Scenario 1, the PCIA exit fee is expected to decrease in most years beginning in 2020. Because of this scenario's larger share of GHG-free generation between 2028 and 2038, the GHG allowance purchases are an even lower portion of the total costs.

Compared to Scenario 1, Scenario 2 exhibits a lower differential between PG&E's and the CCE's customer generation rates between 2018 and 2033. After 2033, the price of renewable generation is expected to undercut the wholesale electricity market for non-RPS supplies, rendering a higher differential in Scenario 2 than in Scenario 1. With respect to PG&E's rates, this differential will

[38] 50% of the non-RPS generation for 2018-2028

continue to follow a similar pattern: positive for all years from 2018 to 2038. And as was the case in Scenario 1, Scenario 2 enables the CCE to reliably price its average generation rates lower than those of PG&E.

Figure 17. Scenario 2 Forecast Average CCE Cost and PG&E Rates, 2018-2038[39]



Residential Bill Impacts

Table 9 summarizes the average annual savings for residential customers under Scenario 2. For the 2018-2038 period, the average annual bill for a residential customer of the Contra Costa County CCE program will be 8% lower than the same bill under PG&E rates. This is a little less than, but close to, the bill savings under Scenario 1. Note that these rate impacts assume that a rate stabilization reserve is funded during the first few years of the CCE's existence. Thus, even though a "gap" between the CCE costs and PG&E rates can be seen in Figure 17, the bill savings in 2018 is zero, as the additional CCE funds are assume to go to the reserve rather than as a customer bill savings.

[39] This chart doesn't include the reserve fund.

Table 9. Scenario 2 Savings for Residential CCE Customers

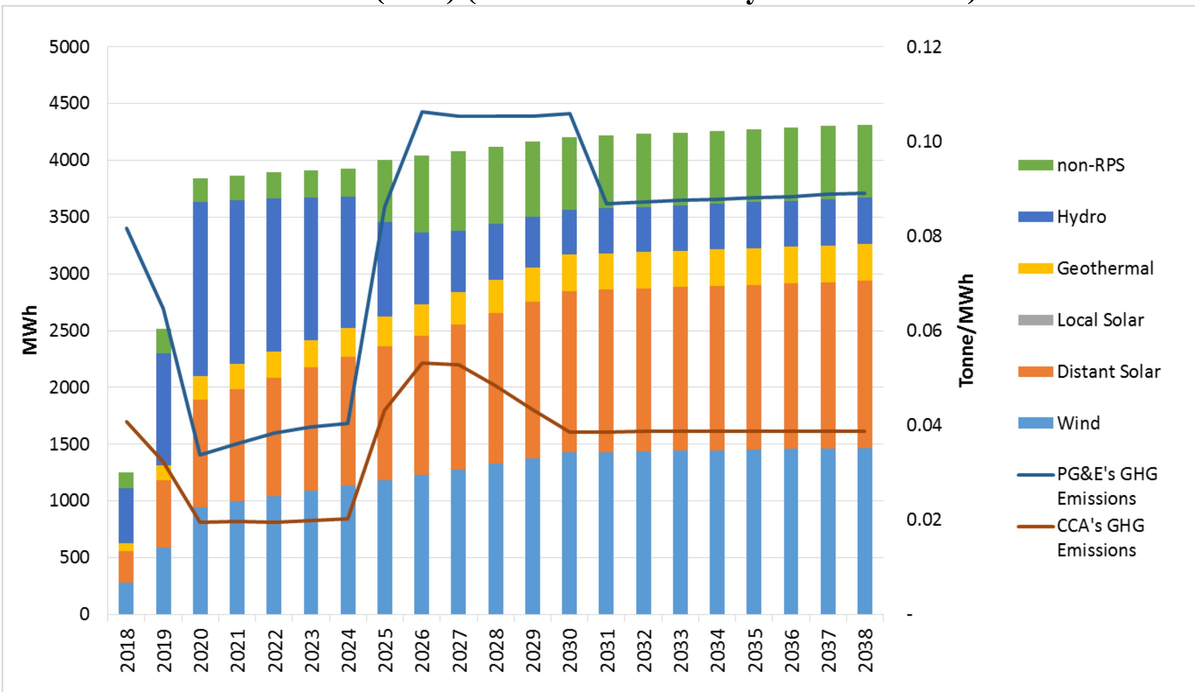
Residential	Monthly Consumption (kWh)	Bill with PG&E ($)	Bill with Contra Costa County CCE ($)	Savings ($)	Savings (%)
2018	500	121	121	0	0%
2020	500	129	125	4	3%
2030	500	189	172	17	9%
2038	500	254	225	29	11%

GHG Emissions

Under Scenario 2, we model the Contra Costa County CCE to at least as much carbon-free generation as PG&E. As in Scenario 1, in years where the assumed renewables would not result in the CCE halving PG&E's GHG emissions, we add large hydroelectric generation to the CCE's resource portfolio to make up the difference, subject to a 5% minimum supply from market purchases. In other years when the CCE's RPS targets are sufficient to provide GHG savings relative to PG&E, we assume that emissions are further reduced by sourcing 50% of the non-RPS supply from large hydro. The end result is a portfolio that averages 20% large hydro.

Figure 18 compares the Scenario 2 GHG emissions from 2018-2038 for the Contra Costa County CCE with what PG&E's emissions would be for the same load if no CCE were formed. Since Scenario 2 has a higher renewable generation target (80% by 2030), the hydroelectric generation necessary to achieve the same GHG emissions reduction is lower. As a result of trading off large hydro for RPS-eligible energy, GHG emissions in Scenario 2 are the same as Scenario 1 through 2027, after which the CCE's portfolio will produce less than half the GHG emissions compared to PG&E.

Figure 18. Scenario 2 Contra Costa County CCE Supply Portfolio (vertical bars) and GHG Emissions (lines) ("Normal" PG&E Hydro Conditions)



Scenario 3 (Minimum RPS Compliance plus Local Procurement)

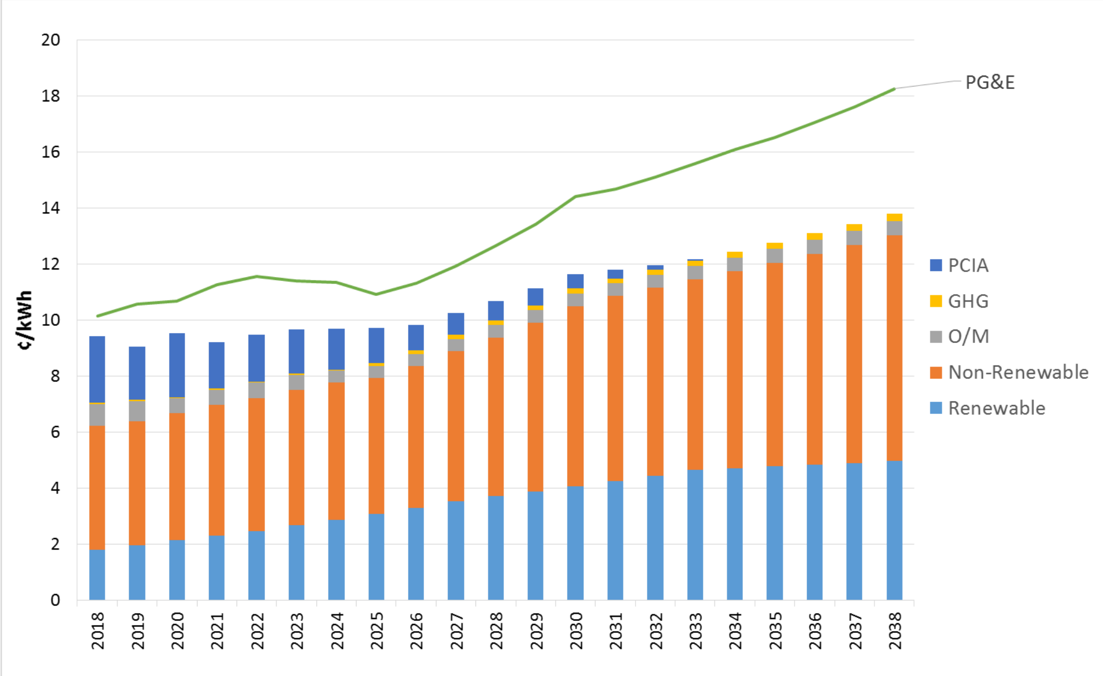
Scenario 3 is identical to Scenario 1, save for a greater portion of locally sourced renewables. Under Scenario 3, local renewables increase annually, reaching 50% of the renewable supply by 2027 and continues at 50% through 2038.

CCE Costs

Figure 19 summarizes the results for this scenario. The vertical bars represent the Contra Costa County CCE customer rate, and the green line represents the PG&E generation rate. As with Scenario 1, the non-renewable cost is the largest component of the CCE's rates, followed by renewable generation costs. The latter are greater than in Scenario 1 due to the higher prices of local generation resources. As with previous scenarios, the PCIA exit fee is the third largest expenditure and it is expected to decrease most years after 2020. As with Scenario 1, the costs associated with GHG allowance purchases are responsible for a marginally larger percentage of the CCE's total costs between 2028 and 2038. This is mostly due to the lower share of GHG-free emissions.

The Scenario 3 differential between PG&E generation rates and Contra Costa County CCE falls in the middle of Scenario 1 and 2 until 2028. Afterwards, the Scenario 3 differential, decreases further, pushing it below Scenarios 1 and 2. However, the CCE rates are expected to be lower than PG&E's generation rates for the entire forecast period, which will allow the CCE to collect reserve fund contributions annually from 2018 to 2038.

Figure 19. Scenario 3: Forecast Average CCE Cost and PG&E Rates, 2018-2038



Residential Bill Impacts

Table 10 summarizes the average residential bill impacts under Scenario 3. Between 2018 and 2038, the annual bill for a residential customer of the Contra Costa County CCE program will be, on average, 6% lower than a corresponding PG&E bill.

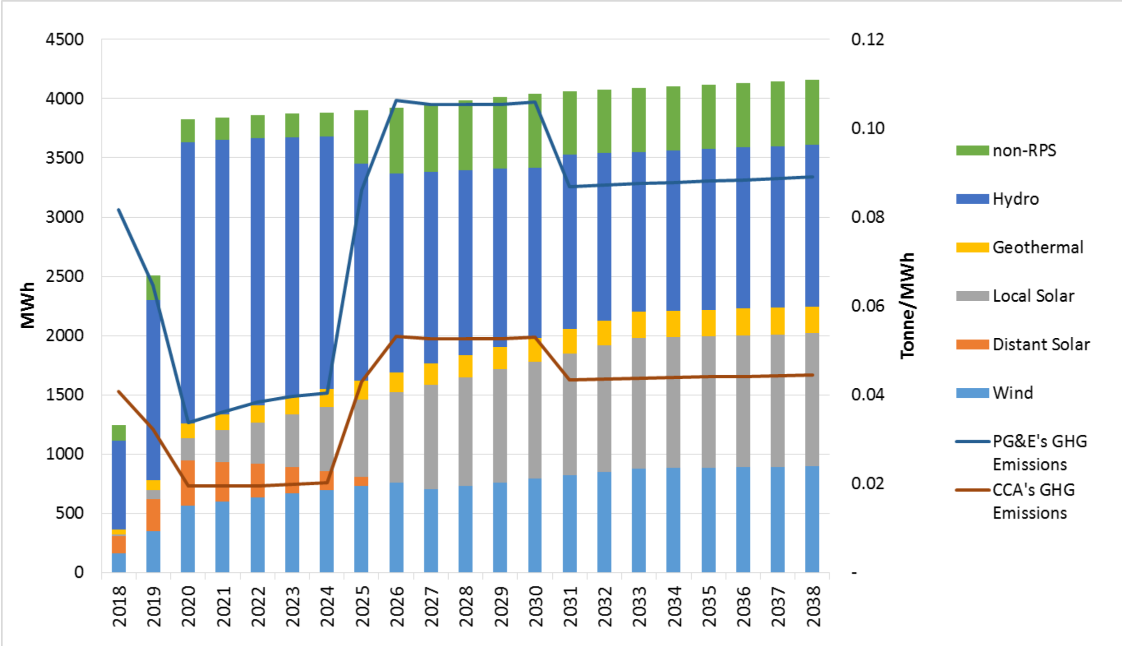
Table 10. Scenario 3 Savings for Residential CCE Customers

Residential	Monthly Consumption (kWh)	Bill with PG&E ($)	Bill with Contra Costa County CCE ($)	Savings ($)	Savings (%)
2018	500	121	121	0	0%
2020	500	129	125	4	3%
2030	500	189	175	14	7%
2038	500	254	231	23	9%

GHG Emissions

The emissions pattern for Scenario 3 is identical to Scenario 1 due to the equal GHG-free generation proportion. The only difference is that part of this generation is provided by local sources. Figure 20 shows the GHG emissions from 2018-2038 for the Contra Costa County CCE under Scenario 3. Note that GHG emissions from the Contra Costa CCE supply and PG&E supply are the same as in Scenario 1.

Figure 20. Scenario 3 Contra Costa County CCE Supply Portfolio (vertical bars) and GHG Emissions (lines) ("Normal" PG&E Hydro Conditions)



Scenario 4 (Accelerated RPS plus Local Procurement)

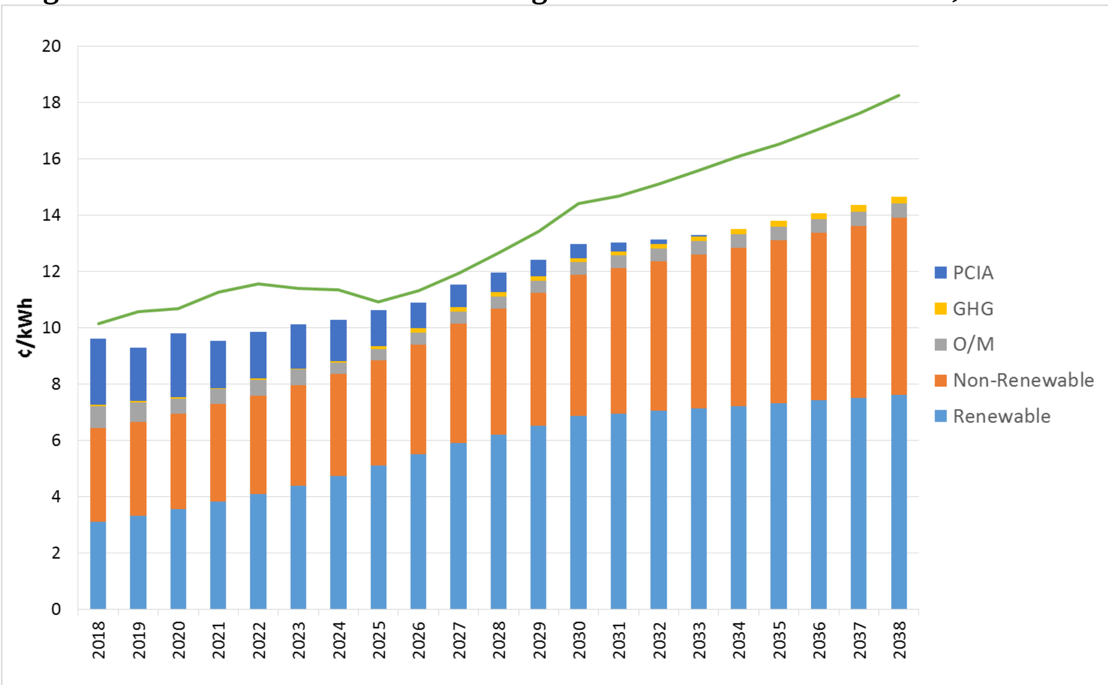
Scenario 4 is the same scenario as Scenario 2 but with a more substantial portion of the generation sourced from local renewable sources: increasing annually and achieving 50% of the total RPS supply by 2027 through 2038.

CCE Average Costs

Figure 21 summarizes the results for this scenario. The vertical bars represent the Contra Costa County CCE customer rate, and the green line represents the PG&E generation rate. Under Scenario 4, the cost for renewables forms the largest component of the CCE's rates and grows steadily to account for nearly 60% of the total CCE rate in 2030. Non-renewable generation is the next largest cost component of the rate, followed by the PCIA exit fee, which is expected to decrease in most years beginning 2020. As with Scenario 2, the costs for GHG allowance purchases in Scenario 4 are a smaller portion of total costs because of more RPS power.

The differential between PG&E generation rates and Contra Costa County CCE customer rates in Scenario 4 is the lowest of the four scenarios between 2018 and 2028. This is because Scenario 4 has the most expensive supply portfolio, comprised of more locally sources renewables. However, after 2028, when the price of the renewable generation is expected to be lower than the wholesale electric market, the differential in Scenario 4 will be higher than the differential in Scenarios 1 and 3, but lower than Scenario 2. Similar to the other scenarios, the Contra Costa County CCE rates in Scenario 4 are forecasted to be lower than expected PG&E generation rates for all years from 2018 to 2038. And as such, this enables the collection of reserve fund contributions through the CCE's rates in every year of the forecast period.

Figure 21. Scenario 4: Forecast Average CCE Cost and PG&E Rates, 2017-2030



Residential Bill Impacts

Table 11 summarizes the average residential bill impacts under Scenario 4. Over the 2018-2038 study period, the annual bill for a residential customer of the Contra Costa County CCE program will be, on average, 4% lower than the same bill under PG&E rates under Scenario 4. Again, note that these rate impacts assume that a rate stabilization reserve is funded during the first few years of the CCE's existence. Thus, even though a "gap" between the CCE costs and PG&E rates can be seen in Figure 21, the bill savings in 2018 is zero, as the additional CCE funds are assume to go to the reserve rather than as a customer bill savings.

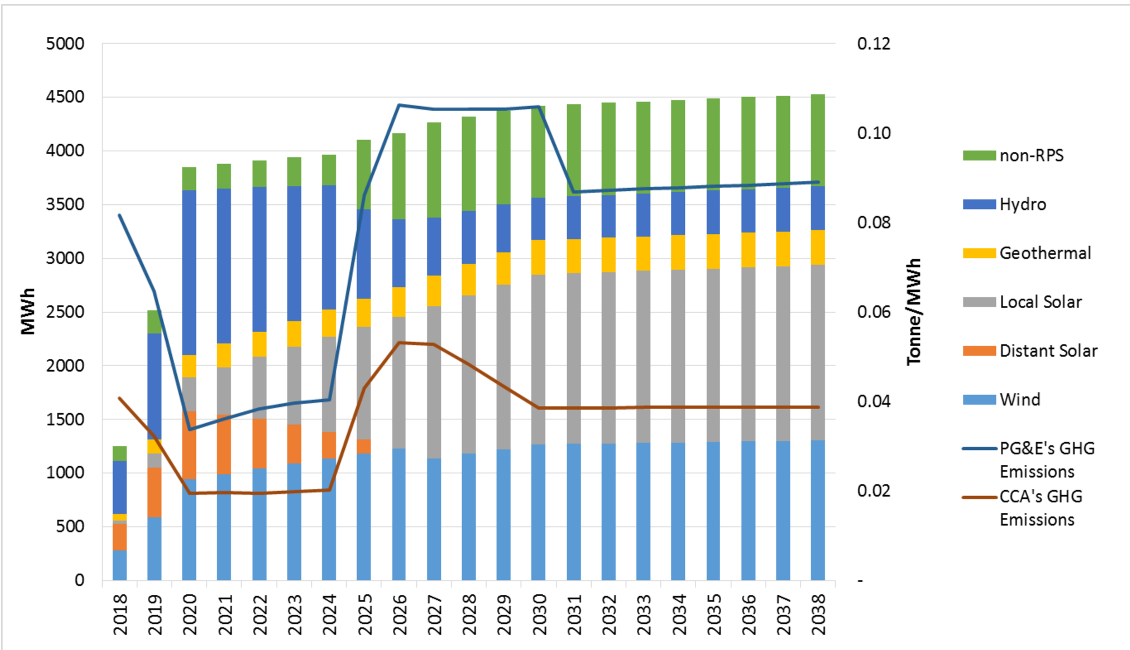
Table 11. Scenario 4 Savings for Residential CCE Customers

Residential	Monthly Consumption (kWh)	Bill with PG&E ($)	Bill with Contra Costa County CCE ($)	Savings ($)	Savings (%)
2018	500	121	121	0	0%
2020	500	129	126	3	2%
2030	500	189	182	7	4%
2038	500	254	235	19	7%

GHG Emissions

The GHG emissions pattern for Scenario 4 is to the same as Scenario 2 due to the scenarios having the same shares of GHG-free generation; the only difference being that local solar generation is assumed to replace solar supplies from more distant locations. . Figure 22 compares the GHG emissions from 2018-2038 for the Contra Costa County CCE under Scenario 4 with what PG&E's emissions would be for the same load were no CCE formed.

Figure 22 Scenario 4 Contra Costa County CCE Supply Portfolio (vertical bars) and GHG Emissions (lines) ("Normal" PG&E Hydro Conditions)



Chapter 4: Sensitivity of Results to Key Inputs

In addition to the base case forecast described above, MRW has assessed alternative cases to evaluate the sensitivity of the results to possible conditions that would have an impact on Contra Costa County CCE's technical study. The metric considered to compare the alternative sensitivity cases to the base case is the differential between the annual average generation rates for PG&E bundled customers and for Contra Costa County CCE customers over the first ten years (2018-2028).[40] The latter 10 years were not included as they are both uncertain and skew the average results due to the widening gap between modeled PG&E's rates and the CCE's average cost.

The base-case analysis (Chapter 3 –Scenario 1) was developed as a reasonable and conservative assessment of the Contra Costa County CCE. In addition to the base case analysis, MRW analyzed alternative cases to address seven risks: (1) low participation, (2) higher local renewable power prices, (3) higher renewable power prices, (4) higher natural gas prices, (5) lower PG&E portfolio costs, (6) higher PCIA charges, and (7) a combination of these six risks (stress scenario).

Lower Participation Sensitivity

This sensitivity case evaluates the impact of lower participation on the CCE program. Lower Participation could be due to a higher customer opt-out rates, or if some of the cities included in the study choose not to participate in the CCE program. If fewer customers join, CCE rates will generally be higher because about $7 million of annual CCE costs are invariant to the amount of CCE load. In Lower Participation sensitivity, we assume that the load for the Contra Costa County CCE is 70% of the potential load.[41] Average administration costs in this scenario are 12% higher than in the base case scenario. These higher administration costs don't have a big impact on the CCE rates due to the fact that administration costs are a small part of the total CCE rate (5% in average). The impact of this sensitivity case is to reduce the 2018-2028 average rate differential by 0.07¢/kWh relative to the base case.

Table 12. Lower Participation Sensitivity Results, 2018-2028

Period 2018-2028	Average Admin costs (¢/kWh)	Average rate differential (¢/kWh)
Base	0.45	1.86
Low participation	0.51	1.79

[40]The Contra Costa County CCE rate includes the PG&E exit fees (PCIA charges) that will be charged to CCE customers but does not include the rate adjustment for the reserve fund or other possible CCE activities.
[41] In the Base case we considered 85% of the potential load.

Higher Local Renewable Power Prices Sensitivity

This sensitivity case evaluates the impact of higher local renewable power prices on the CCE's financial viability. As discussed in Appendix B, in the base case, solar local renewable power price starts at $68/MWh in 2018 and it increases following the price curve. In the Higher Local Renewable Power Prices sensitivity, we assume that local renewable prices would be 20% higher than the base case prices. These higher prices affect only CCE rates for Scenario 3 and Scenario 4 (Scenario 1 and Scenario 2 don't include local generation), reducing the 2018-2028 average rate differential by 0.21¢/kWh relative to the base case.

Table 13. Higher Local Renewable Power Prices Sensitivity Results, 2018-2028[42]

Period 2018-2028	Average local renewable prices ($/MWh)	Average rate differential (¢/kWh)
Base	69.30	1.57
High local renewable prices	83.20	1.36

Higher Renewable Power Prices Sensitivity

This sensitivity case evaluates the impact of higher renewable power prices on the CCE's financial viability. As discussed in Appendix B, in the base case, renewable power prices are flat in nominal dollars through 2022, based on the assumption that projected declines in renewable development costs will offset increases associated with the planned expiration of federal renewable tax credits.[43,44] In the Higher Renewable Power Prices sensitivity, we assume that renewable prices would be flat in nominal dollars through 2022 if it were not for the tax credit expirations and add the impact of the tax credit expirations to the base case prices. Average renewable power prices in this scenario are 0-10% higher than in the base case scenario through 2021, about 20% higher in 2021 and 2022, and 30% higher after 2022 when the solar investment tax credit is reduced to 10%. These higher prices affect both the CCE and PG&E, but they have a greater effect on the CCE because PG&E has significant amounts of renewable resources under

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[42] Results for Scenario 3

[43] Investment Tax Credit (ITC) which is commonly used by solar developers, is scheduled to remain at its current level of 30% through 2019 and then to fall over three years to 10%, where it is to remain. The federal Production Tax Credit (PTC), which is commonly used by wind developers, is scheduled to be reduced for facilities commencing construction in 2017-2019 and eliminated for subsequent construction.
U.S. Department of Energy. Business Energy Investment Tax Credit (ITC). http://energy.gov/savings/business-energy-investment-tax-credit-itc; U.S. Department of Energy. Electricity Production Tax Credit (PTC). http://energy.gov/savings/renewable-electricity-production-tax-credit-ptc

[44] The base case forecast would also be consistent with a scenario in which the tax credit expirations are delayed.

long-term contract. The impact of this stress case is to reduce the 2018-2028 average rate differential by 0.35¢/kWh relative to the base case.

Table 14. Higher Renewable Power Prices Sensitivity Results, 2018-2028

	Average RPS prices ($/MWh)	Resulting average rate differential (¢/kWh)
Base	53.2	1.86
High renewable prices	65.1	1.51

Higher Exit Fee (PCIA) Sensitivity

PG&E's PCIA exit fees are subject to considerable uncertainty. Under the current methodology, PCIA rates can swing dramatically from one year to the next, and this methodology is currently under review and may be adjusted in the coming years. MRW therefore evaluated a stress case in which PCIA rates don't fall after 2018, as anticipated in the base case, but instead remain at 2018 levels through 2028. This increases the 2028 PCIA more than 300% of its base case value. The impact of this stress case is to reduce the 2018-2028 average rate differential by 0.86¢/kWh relative to the base case.

Table 15. Higher PCIA Exit Fee Sensitivity Results, 2018-2028

	Average PCIA prices (¢/kWh)	Resulting average rate differential (¢/kWh)
Base	1.5	1.86
High PCIA	2.4	1.00

Lower PG&E Portfolio Cost Sensitivity

While changes to natural gas prices and renewable power prices affect both the CCE and PG&E, dampening the impact on the CCE's cost competitiveness, reductions to the costs to operate and maintain PG&E's nuclear and hydroelectric facilities would provide cost savings to PG&E that would not be offset by cost savings to the CCE. MRW considered a case in which PG&E's overall generation rates are 10% below the base case, driven by reductions to PG&E's nuclear, and hydroelectric portfolio costs. Under such a scenario, the 2018-2028 average rate differential would be reduced by 1.12¢/kWh relative to the base case scenario.

Table 16. Lower PG&E Portfolio Sensitivity Results, 2018-2038

	Average PG&E Rate (¢/kWh)	Resulting average rate differential (¢/kWh)
Base	11.2	1.86
Low PG&E portfolio costs	10.1	0.74

Higher Natural Gas Prices Sensitivity

Natural gas prices have been low and relatively steady over the last few years, but they have historically been quite volatile and subject to significant swings from local supply disruptions (*e.g.*, Hurricanes Katrina and Rita in 2005). MRW analyzed a gas price sensitivity case using the U.S. Energy Information Administration's High Scenario natural gas prices forecast,[45] which is in average 50% higher than MRW's base case forecast for the period 2018-2028. Natural gas price increases affect power supply costs for both Contra Costa County CCE and PG&E; however, the nuclear and hydroelectric capacity in PG&E's resource mix makes PG&E less sensitive than Contra Costa County CCE to changes in natural gas prices. The net effect of higher natural gas prices is therefore to increase CCE rates relative to PG&E rates[46] (i.e., reduce the average rate differential). Under the sensitivity conditions considered, the 2018-2038 average rate differential decreases relative to the base case by 1.68¢/kWh.

Table 17. Higher Natural Gas Prices Sensitivity Results, 2018-2028

	Average PG&E Rate (¢/kWh)	Resulting average rate differential (¢/kWh)
Base	11.2	1.86
Low PG&E portfolio costs	10.1	0.18

Stress Case and Sensitivity Comparisons

All rate differentials (i.e., the CCE's competitive positions) are lower in the sensitivity cases than in the base case scenario for all years from 2018 to 2028 (**Table 18**). To evaluate a more extreme scenario, MRW developed a stress case that combines all the sensitivity cases: (1) low participation, (2) higher local renewable power prices, (3) higher renewable power prices, (4) higher natural gas prices, (5) lower PG&E portfolio costs, and (6) higher PCIA charges. The

[45] U.S. Energy Information Administration. "2015 Annual Energy Outlook," Table 13
[46] For the Scenario 2 and 4 the high gas natural prices case has less negative impact due to the high proportion of renewable generation.

2018-2028 average rate differential for this stress case is negative, at -4.08¢/kWh, meaning that CCE customer costs would exceed PG&E customer costs under this scenario.

Table 18. Stress Test Results, 2018-2028

	Resulting average rate differential (¢/kWh)
Base	1.86
Stress Scenario	-2.3

Figure 23. Difference Between PG&E Customer Rates and CCE Customer Rates Under Each Sensitivity Case, 2018-2028

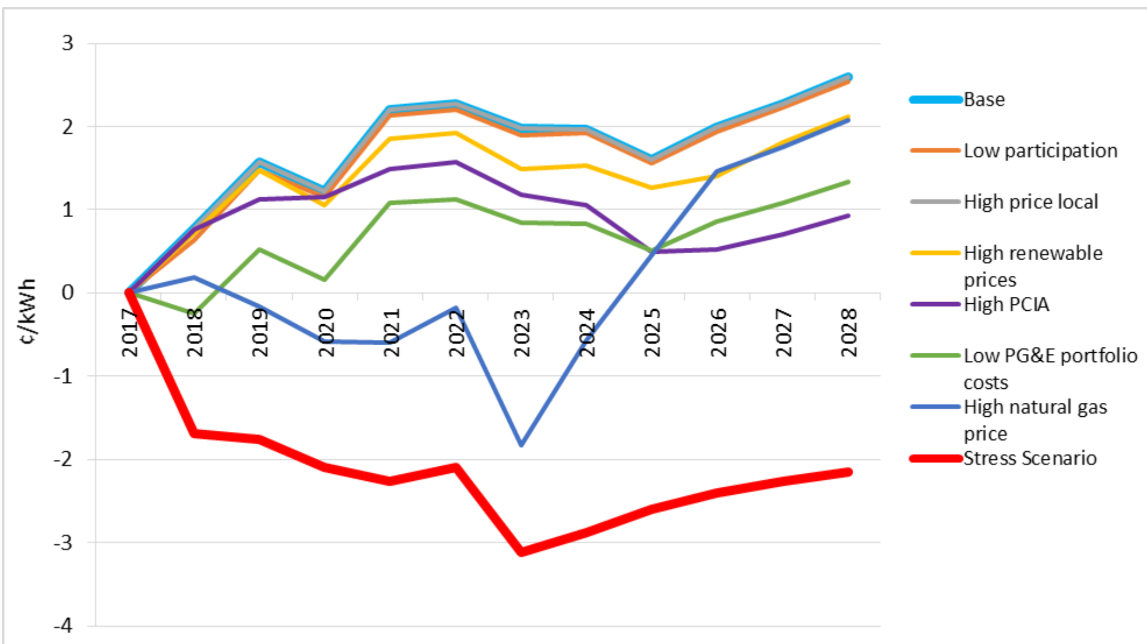
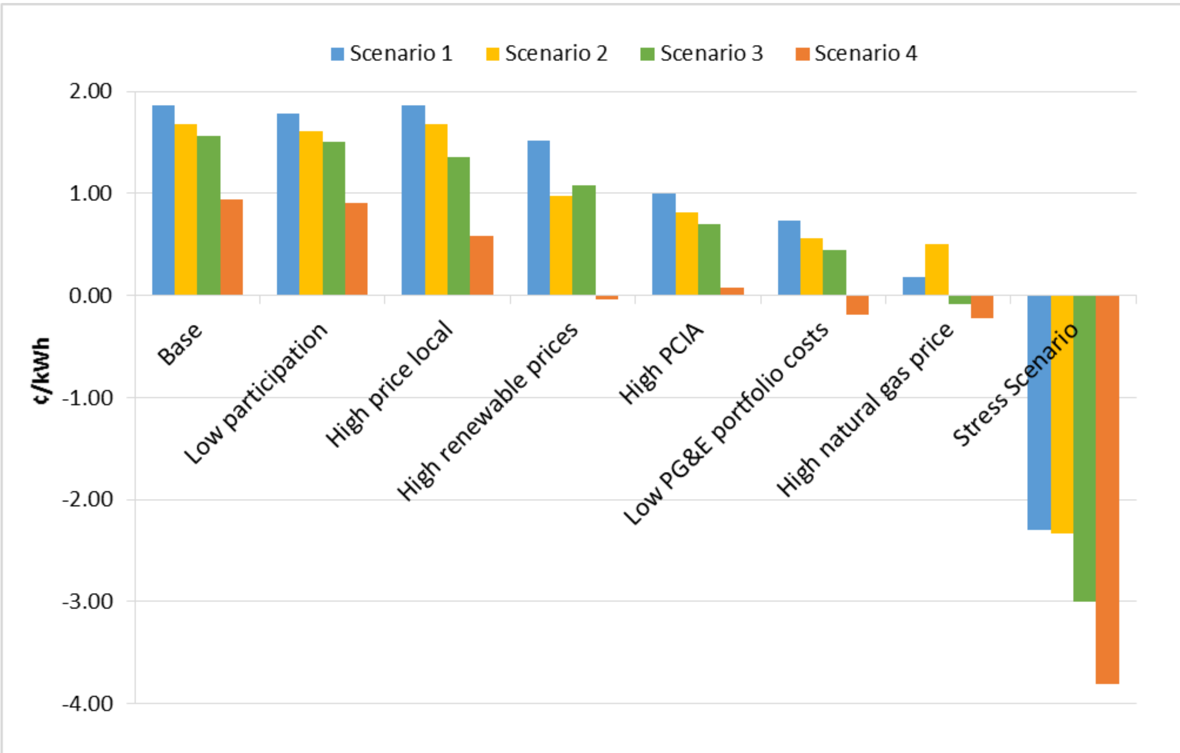


Figure 23 shows the difference between the PG&E customer rates and the Contra Costa County CCE customer rates (including exit fees) in the base case, and in each of the sensitivity scenarios, for each year from 2018 to 2028. As Figure 23 illustrates, CCE customer rates are lower than PG&E customer rates in each of the individual sensitivity cases in each year.[47] Under the Stress Scenario case, the rate differential is negative for each year (i.e., CCE rates are higher than PG&E generation rates).

[47] For High Natural Gas Price sensitivity case, in 2023 the rate differential drops following the decrease on PG&E rate. The decrease on PG&E rate in 2023 under the high natural gas price case is due to an increase on the PCIA. PCIA is highly sensitive to the natural gas prices.

The results shown above reflect the Minimum RPS Compliance supply scenario (Scenario 1). MRW additionally evaluated each sensitivity scenario under the four alternative supply scenarios: (1) Minimum RPS Compliance, (2) Accelerated RPS, (3) Minimum RPS Compliance plus Local Procurement, and (4) Accelerated RPS plus Local Procurement. Figure 24 depicts the average rate differentials for 2018-2028 for each sensitivity case under the four supply scenarios.

Figure 24. Difference Between PG&E Customer Rates and CCE Customer Rates Under Each Sensitivity Case and Supply Scenario, 2018-2028 Average



Looking at 2018-2028, Scenario 1 (Minimum RPS Compliance) is the least costly scenario for the CCE, and therefore has the highest rate differential under most of the sensitivity cases considered.[48] Scenario 2 (Accelerated RPS), though still quite competitive with PG&E, fares slightly worse, with a rate differential approximately 10-20% lower than in Scenario 1 for most of the sensitivity cases considered. The one exception is the High Natural Gas Price sensitivity case, in which Scenario 1 has lower results than Scenario 2. This is due to the higher gas-fired generation content in Scenario 1, which makes the supply portfolio more susceptible to volatility in natural gas prices than Scenario 2. For most the sensitivity cases, rate differentials for Scenario 3 are lower than Scenario 1 and Scenario 2. Scenario 4 is the costliest scenario, with rate differentials much lower than those in Scenario 1, Scenario 2, and Scenario 3.

[48] This is only looking at the period 2018-2028. If we consider the period 2018-2038, Scenario 2 would be the least costly scenario. After 2028 the prices of renewable generation are expected to be lower than the wholesale electric market, which makes Scenario 2 less costly than Scenario 1 in the period 2028-2038.

In the stress case, Contra Costa County CCE customer rates exceed PG&E customer rates on average over the 2018-2028 period for all four scenarios, with the rate differential being highest in Scenario 4 at -3.8¢/kWh.

Conclusions

Under Scenarios 1 and 2, Contra Costa County CCE customer rates compare quite favorably to PG&E rates in all years from 2018 to 2038 under all four supply scenarios. Furthermore, under Scenario (Minimum RPS compliance), Contra Costa County CCE customer rates remain below PG&E rates under all but the most extreme sensitivity case considered (however at the price of possible higher GHG emissions). Under the stress case, irrespective of the supply scenario considered, CCE rates are higher than PG&E rates. While the stress case may appear extreme given that it involves seven adverse sensitivities simultaneously occurring, cost volatility in the power industry is well established, and the possibility of adverse conditions arising should be understood and planned for in any CCE venture.

Chapter 5: Macroeconomic Impacts

This chapter discusses the job impacts within Contra Costa County for each of the four scenarios. All four scenarios modeled showed positive economic and job impacts. The mix and amount of jobs created would depend upon policy decisions made by the CCE board, primarily trading off the economic stimulus from lower electricity bills versus the direct jobs created by local (higher cost) renewable energy projects sponsored by the CCE.

To understand just how job impacts can come about, and the extent of those changes (positive or negative), a brief description of elements associated with the CCE and how they influence the existing economy is provided.

How a CCE interacts with the Surrounding Economy

The establishment and operation of a CCE creates a new set of spending elements (also referred to as "demands") as a community changes the type of electricity generation they want to purchase, where the new mix of generation is to be located, adjustments necessary for existing generating assets of the provider utility, and implications on customers' bills because of retail rate differentials. Some of these new elements have temporary effects, while others have long-term effects. Investment in locally sited solar will result in temporary direct creation of jobs whereas subsequent *maintenance* will support some on-going direct jobs. Regardless of the duration, when a direct job is created in a sector, there will be a multiplier response on "backwardly-linked" jobs with supplier businesses if the supplier is present in the economy. The new elements include:

- **Administration** – [direct jobs, long-term effect] county staffing, professional-technical services and I/T-database services
- **Net Rate Savings (or bill savings)** – [long-term effect] county households have an increase in their spending ability, county commercial and industrial energy customers experience a reduction in their costs-of-doing business which makes them each more competitive, garnering more business that requires more employees, and municipal energy customers can provide more local services which requires more local government staff.
- **New Renewable Capacity Investment within County & Surrounding counties** – [direct jobs, short-term, two of the four scenarios]
- **New Renewable Operations within County** & Surrounding counties – [direct jobs, long-term, two of the four scenarios]
- **Net Generating Capacity and Operations offsets for PG&E outside of county** – [direct jobs, short & long-term, none since we are not focused on the *rest of CA* economy]

To frame expectations around how many direct jobs can be created in the County from the above CCE elements, consideration must be given to (a) how much of the spending associated with the CCE scenario is fulfilled by a within county business or resident workforce, and (b) what do these locally-fulfilled dollars represent in terms of current annual county business activity (e.g., is this a large spending event?).

Job Impacts of Proposed CCE Scenarios

We examine each of the four scenarios for their influence on the County economy and the economy of the four surrounding counties combined (a ring region comprised of Alameda, Sacramento, San Joaquin and Solano counties). The basis for including the surrounding counties is (i) interdependence of the economies in terms of business-to-business transactions (in part due to proximity) and labor commuting flows (both in and out), as well as (ii) the siting of 50 percent of the proposed CCE funded small-scale solar projects beyond Contra Costa county. The scenario structures assume no electric customer participation from beyond Contra Costa County therefore the proposed *bill savings* are allocated across customer segments solely within Contra Costa County.

The possible sources of *initial* job change in any of the scenarios include:

- CCE Administration *spending* 2018 to 2038 (within Contra Costa County)
- Bill Savings *less* Customer's expense for on-site solar deployed 2018 to 2038 (within Contra Costa County)
- Investment in small-scale Solar 2018 to 2030 (Contra Costa and the 4-county ring region)
- O&M spending on small-scale Solar 2018 to 2038 (Contra Costa and the 4-county ring region)

Only scenarios 3 and 4 include investment for small-solar projects in Contra Costa County and the surrounding region of counties. Once each regional economy experiences its initial change related to any of the above scenario elements, a macroeconomic forecasting tool (the REMI model[49]) captures impacts from inter-regional transactions (of commuters, of business sales), and impacts from changes in Contra Costa County's relative *cost-of-living* and *cost-of-doing business* resulting from bill savings, and impacts associated with *multiplier effects*.

Overview of Scenario Effects

It is helpful to understand how the various scenarios "stack up" in terms of the four sources that will exert an influence on the local economies. Table 19 presents the cumulative (2018 to 2038) stimuli - bill savings, administrative spending, and where relevant, demands related to investment, O&M. The amounts are a roll-up of nominal values. Scenario 1 poses the greatest amount of Rate Savings for county CCE customers ($2,390 million), and Scenario 4 poses the largest amount of solar investment *demand* ($827 million) for in-county installations. Ensuing O&M spending (Scenarios 3 and 4) will increase as the investment *demand* increases. None of the displaced renewable capacity by PG&E (investments under the "business-as-usual" or "without CCE" case) occurs in either Contra Costa or the surrounding 4 counties.

[49] Regional Economic Models, Inc. of Amherst, MA. www.remi.com

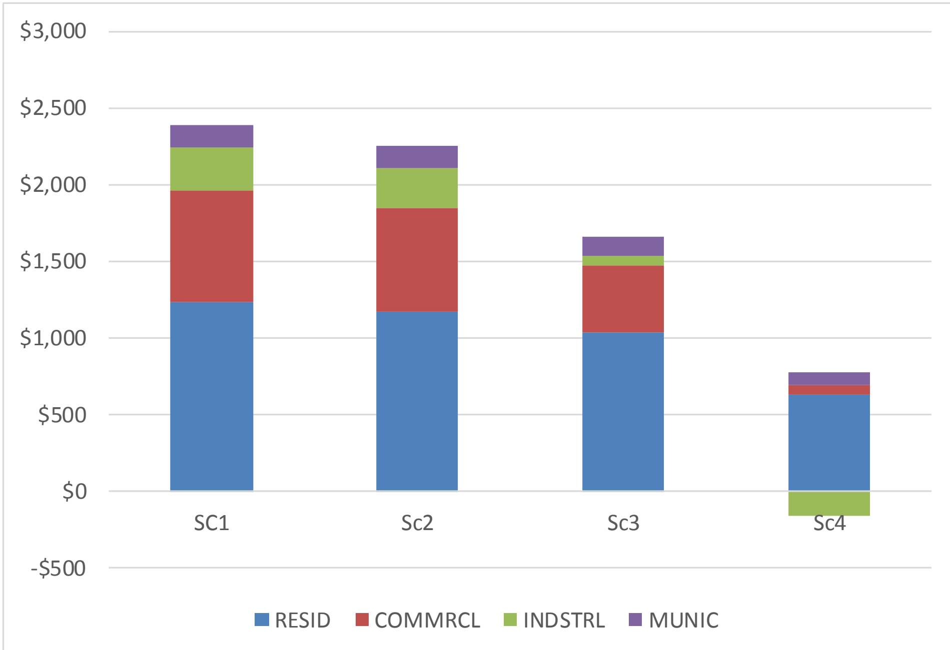
Table 19. CCE Scenario Economic Characteristics (2018-2038, Millions of nominal dollars)[50]

Scen.	Net Rate savings County customers	CCE Small Solar Investment		CCE Small Solar O&M	
		Contra Costa County	Neighboring Counties	Contra Costa County	Neighboring Counties
1	$2,390	$0	$0	$0	$0
2	$2,251	$0	$0	$0	$0
3	$1,656	$456	$456	$234	$234
4	$614	$827	$827	$375	$375

Figure 25 **Figure 25**presents the estimated *net* rate savings for various customer-segments in the County by CCE scenario. The rate savings benefit accrues foremost to the residential segment, followed by the Commercial segment. The Municipal segment has fairly constant rate savings regardless of scenario. In addition to the magnitude of overall net rate savings and local solar-related business opportunities, this segment distribution across customer segments influences part of the job impact response (amidst solar investments). Households spend money saved on electric bills on other consumer basket items, which would include a mix of goods and services; some local, some imported, which all rely on different jobs at different wages. Commercial or Industrial electric customers experience a savings as making their operations more cost competitive, which returns some positive (though not equal across all type of activities) market share growth (e.g., more sales which means more jobs and other inputs to their operations.) Municipal segment savings allow the state/local government entity to redirect dollars into other forms of public spending.

[50] *Net* Rate Savings are net of customer out-of-pocket for on-site solar additions. under scenarios 3 and 4. For the County projects, 25 percent of the investment is paid by *Industrial* customers, 25 percent by *Commercial* customers, with the balance funded by outside investors. Small-solar projects in the surrounding counties are assumed to be funded by outside investors. Under scenarios 1 and 2 *net* is equal to gross rate savings.

Figure 25. Cumulative net Rate Savings in Contra Costa County, Proposed CCE structures



The opportunity for the small-solar investment episode (2018 through 2030), for scenarios 3 and 4, to generate "within region" job requirements is determined by how much of the investment dollars connect with (procure from) 'within region' construction labor and businesses that provide project components. The allocations of small-solar investment dollars into these two major types of purchases (with additional breakdown on non-labor expenditures) is done using the National Renewable Energy Laboratory (NREL) Jobs and Economic Development Impact (JEDI) small-solar PV JEDI model[51] (CA) allocation. As shown in Table 20 for scenarios 3 and 4, no less than 50 percent of the various budgets enlists local workforce, and firms that provide supplies or services. Manufacturing of solar panels is outside of the 5-county economy but within region wholesale distributors are assumed to bring "product local."

[51] The Jobs and Economic Development Impact (JEDI) models are user-friendly screening tools that estimate the economic impacts of constructing and operating power plants, fuel production facilities, and other projects at the local (usually state) level. JEDI results are intended to be estimates, not precise predictions. See: http://www.nrel.gov/analysis/jedi/about_jedi.html

Table 20. Local Fulfillment of CCE Budgets (millions of nominal dollars)

	CCA Admin	Solar Invest	Solar O&M	CCA Admin	Solar Invest	Solar O&M
		Scenario 1			Scenario 3	
Budget	$316	*na*	*na*	$316	$456	$233
In-County						
locally procured	$189	*na*	*na*	$189	$234	$146
% capture local	60%	*na*	*na*	60%	51%	63%
Surrounding Counties						
locally procured	*na*	*na*	*na*	*na*	$234	$146
% capture local	*na*	*na*	*na*	*na*	51%	63%
		Scenario 2			Scenario 4	
Budget	$316	*na*	*na*	$316	$ 827	$375
In-County						
locally procured	$189	*na*	*na*	$189	$425	$235
% capture local	60%	*na*	*na*	60%	51%	63%
Surrounding Counties						
locally procured	*na*	*na*	*na*	*na*	$450	$219
% capture local	*na*	*na*	*na*	*na*	51%	63%

Resulting Impacts on Jobs

This section will present several views of the job impacts by scenario. As shown in Table 21, Scenario 1 yields the largest annual job impact for the County over the interval – the result of the maximum rate savings under the CCE program. Job impacts are not limited to the direct job requirements from a CCE but include jobs resulting from *multiplier effects* and *competitiveness effects*. Scenario 4 – with the smallest of *net* rate savings for the County's electric customers poses the largest investment for small-solar across the 5-county economy. This more than compensates for the reduced role of the rate savings and thus Scenario 4 yields the greatest annual job gain for the 5-county economy, 941 jobs (compared to Scenario 1 with 731). As the amount of small-solar investment increases (with subsequent O&M spending to follow), the percent of job impact that occurs within the surrounding multi-county region increases (Scenario 4 has 44%). The county's annual job increase under Scenario 4 however is moderated (by 160 jobs) when compared to Scenario 1. This is understood by (i) all CCE customers' realizing smaller rate savings when the CCE attempts to invest in *local* solar, combined with (ii) commercial/industrial businesses in the County picking up 50 percent of the solar investment cost. Also, influencing the "surrounding county region" job impact is the fact that a neighboring economy (the County) is experiencing lower electric bills (regardless of the magnitude) and a solar installation "boom" – namely, economic stimulating events. This can create a positive bounce for the surrounding counties on some of the background business (supplier) transactions as well as with working-age households who commute into the County (this point is illustrated in Figure 26) And when the surrounding region is host to its own solar installation boom, this will engage the Contra Costa County economy as well.

Table 21. Average Annual Employment Impacts 2018 through 2038 (Jobs)

Scenario	Contra Costa	Surrounding 4 Counties	All 5 counties	% in Region
1	681	50	731	7%
2	638	48	686	7%
3	654	268	922	29%
4	529	412	941	44%

For Scenario 4 (with the smallest *net* rate savings and the highest local solar-investment/O&M spend) a time-path of the resulting job impacts is shown in Figure 26. To be clear, the results are not depicting *cumulative* job impacts, simply a plot of each year's resulting impact. After 2030 no more solar installations occur in either region[52]. The surrounding region remains slightly buoyed with job impacts due to some continued O&M spending and feedback from the Contra Costa economy that is still benefitting now from *gross* rate savings (no more project expenses) and some O&M spending.

Figure 26. Scenario 4 – Annual Job Impacts, 2018 to 2038

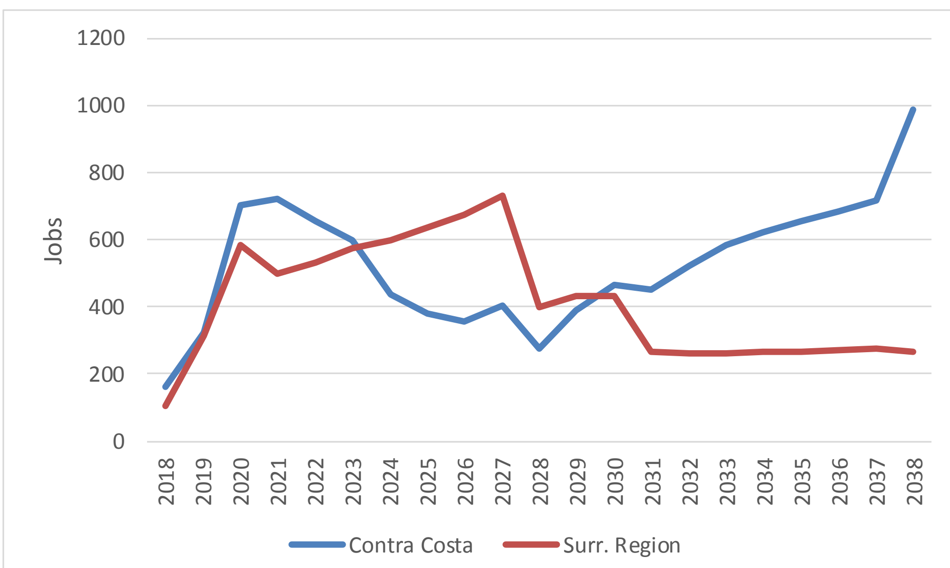


Figure 27 helps explain 'the dip' in the above *blue* series of positive job impacts *(for Contra Costa*) between 2024 and 2030. The estimated forecast of *net* rate savings follows such a trajectory (becoming *negative* between 2024 and 2028 when some customers bear a portion of

[52] This is because the targeted renewable penetration was met and not new generation is needed by the CCE. If the study looked further out, then replacement solar would being to have an effect and generate jobs.

the investment cost) and even the *local* capture on the solar investment comes off a local maximum in 2020 and a global maximum in 2027 (the latter occurs in the surrounding region as well).

Figure 27. Scenario 4 – Contra Costa's "Local" Benefit

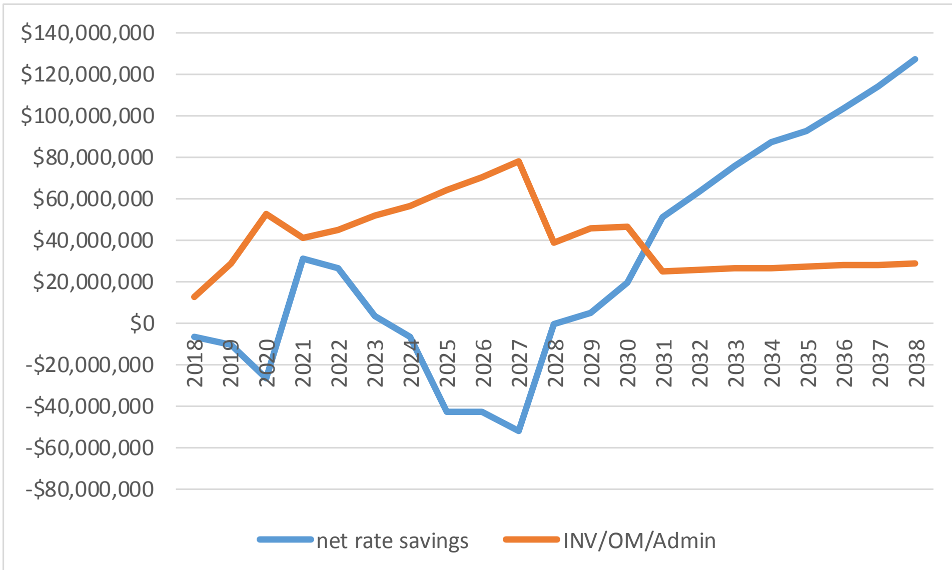
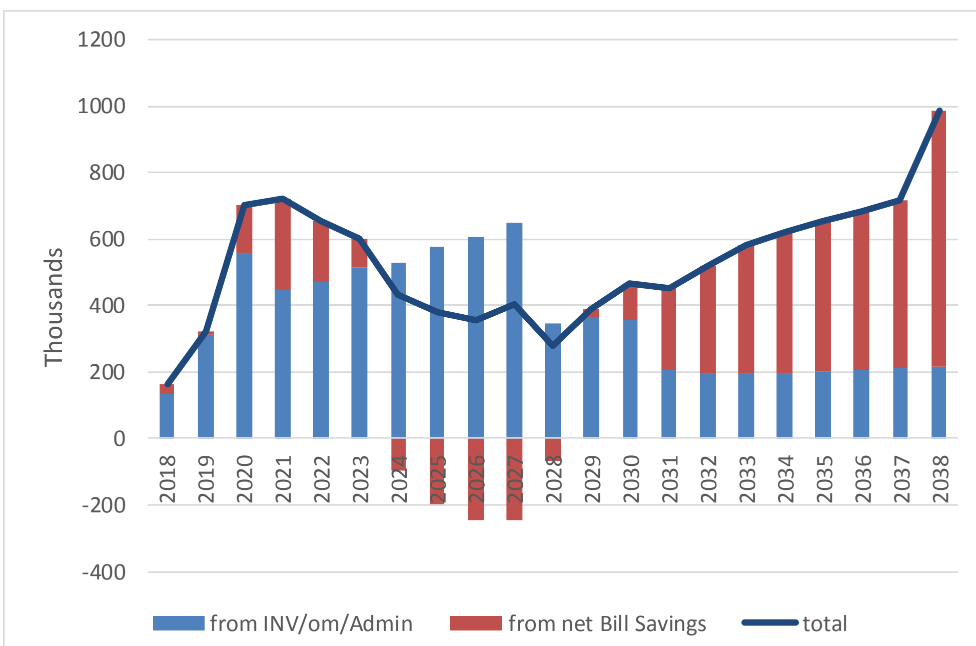


Figure 28 shows what contributes to Contra Costa's job impact under Scenario 4. The dark blue line is the line from Figure 26. Through 2030 largest influence on the County's *positive* job impacts is the stimulus of solar project investment. Afterwards it is the role of *net* Rate Savings exerted through the customers' roles in the local economy that creates local jobs.

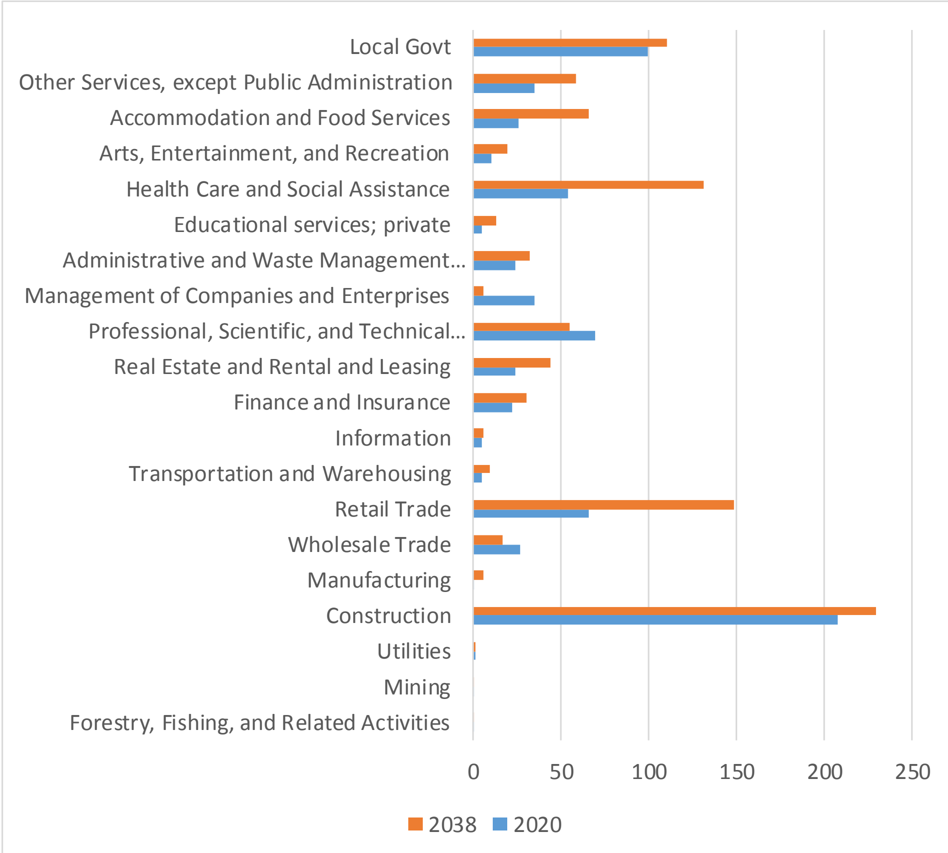
Figure 28. Scenario 4 – Contra Costa Job Impact by Source



A look at two points in the policy interval illustrates of the types of jobs that comprise the impact results. In 2020 there are 704 additional jobs (when solar investment is at a maximum with little of the *net rate savings* realized*)* and 2038, 989 additional jobs in the County (after the investment hang-over is past and only a small influence is exerted through O&M and administrative spending, and the County economy is still experiencing a ramp up of rate savings). Figure 29 shows a pattern and an amplitude for each of the *snapshot* years that is indicative of the major CCE influence on the County's industry base. In 2020 there was approximately $26 million of *local benefit* for the County based on the scenario's structure ($53 million was invest/O&M/admin spend, and -$26 million of early stage *dis-benefit* via net rate savings). By 2038 the *local benefit* to the County was $157 million ($29 million as O&M/admin spend and $128 million as gross rate savings). These amounts can be approximated looking back at Figure 27 and summing the height of the orange and blue points for 2020 and again for 2038.

In 2020, county job additions are explained foremost by the predominant effect emanating from the CCE scenario – namely solar project investment and program administration (net rate savings are *negative* at this point as a result of C/I customers paying for part of the solar investment cost). So, jobs occur in *Construction*, in State/Local *Government*, in *Professional Technical Services*, and with *Wholesale suppliers.* Project developer overhead payments (part of the investment cost) is why job additions are showing for *Management of Companies and Enterprises*. But not all of the job additions in these sectors are directly related to solar installations. Some of these – as well as jobs gains in other non-investment sectors like health care, and food establishments, and retail- are the result of the initial labor income gains (construction paychecks) which drives added household spending (the *induced* stage of economic multiplier effects), and some are the result of increases in "within county" business-to-business transactions and elevated business needs from the adjacent region (the *indirect* stage of multiplier effects.)

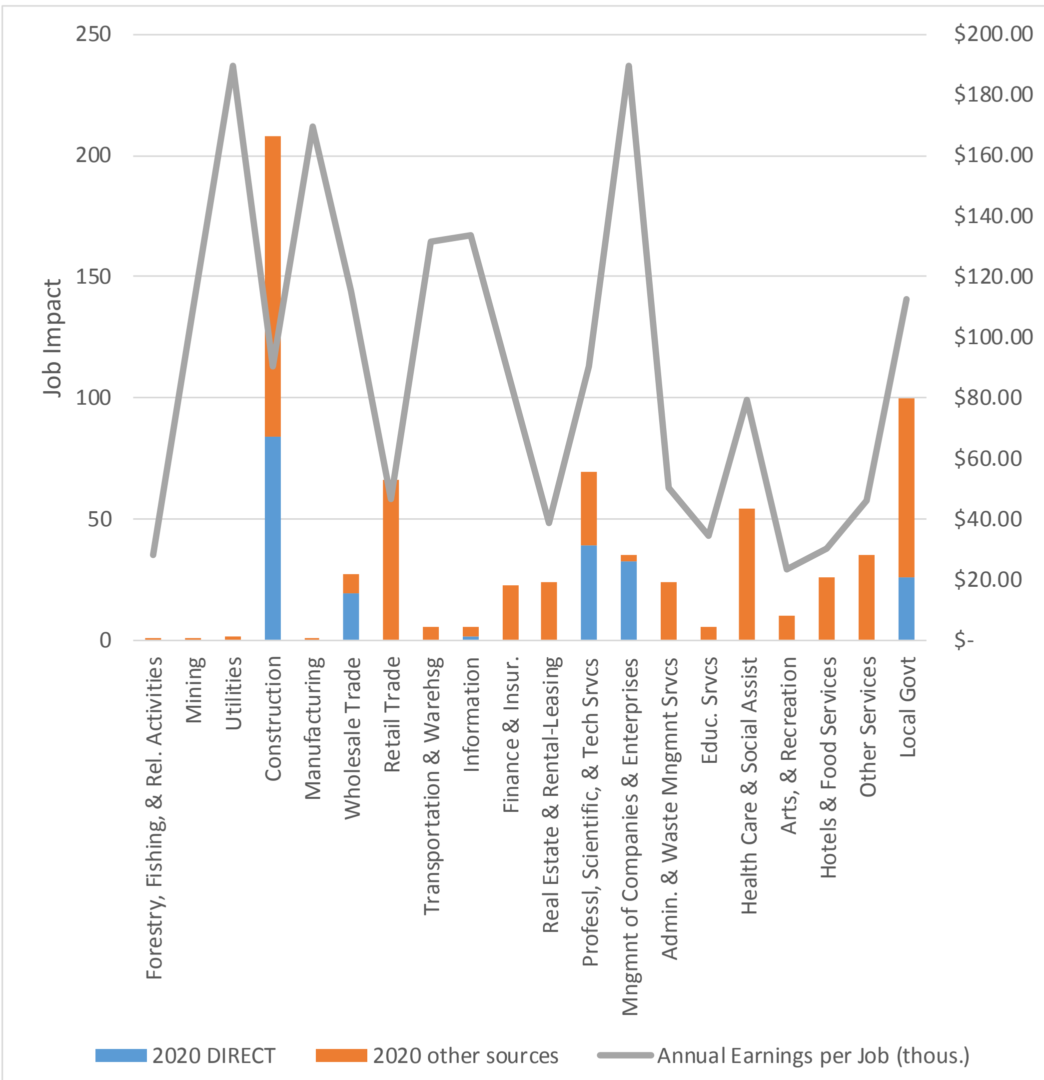
Figure 29. Scenario 4 - Jobs added Among Contra Costa Sectors, 2020 and 2038



In 2038 (the orange series) the predominant ‘economy’ effect from the CCE is the *net* rate savings with a majority benefitting the *residential segment*. Households will redirect these savings into additional household spending (e.g. health care, retail, food establishments). But the municipal segment receives savings as well which drives additional public spending and requires some growth in staff in addition to the local government staff to administer the CCE (an average of 23 *administrative* staff). Commercial and industrial sectors also experience some job increases as their bill savings improve their bottom lines and grow their respective market shares for business. The pronounced gain in local government jobs is more than the (averaged) 23 staff mentioned above. By 2038 the County will have retained a significant number of its working-age residents that would otherwise out-migrated (under the business-as-usual case) due to a combination of *relative* employment opportunities and inflation adjusted wages. The CCE activity creates job opportunity, mitigates in-county inflation (vis a vis bill savings) so there is real wage appreciation, and helps stem the tide of out-migration of key working-age cohorts. This further bolsters the positive population growth the County was forecast to have (under the BAU case), and local government spending (and staffing) increase on a *per capita* basis. In addition, the S/L government activity increases as the productive capacity of the County grows (in terms of dollars of gross regional product). The *Construction* sector posts strong job increases but now it is more the response to growth in the County (due to CCE influences) and this sector is key during investment (for both residential and non-residential structures) responses to close the gap between actual and optimal capital requirements in a growing economy.

Figure 30 shows for 2020 which of the affected sectors' job increases (a total of 704 added jobs) are due to direct involvement (blue bars) with some aspect of the CCE and which are the result of subsequent economic responses. The gray line series is read off the right-hand axis and indicates the annual pay quality (nominal and with benefits) of a job in a specific sector. The *Construction* jobs have annual earnings of $90,000, the *Local Government* positions approximately $112,000, *Wholesale trade* $115,000, *Retail trade* $46,000, *Professional Technical Services* $90,000 and *Management of Enterprises* (solar developer overhead) $189,000.

Figure 30. Scenario 4 – Contra Costa Job Creation by Sector, Impact Stage & Pay-scale, 2020



Allocation of Earned Income Gains

A majority but not all jobs added in Contra Costa County will be held by the County's working-age resident households. The same is true for jobs added in the 4-county surrounding region. Which means the household spending effects from the take-home pay on the above impacted jobs occur where the worker *resides*. The above job impacts are measured by *place-of-work.* The commuter from another county registers the induced effects of their earned income on a *place-of-residence* basis.

Again, we focus on Scenario 4 in the year 2020 (year of maximum investment activity that is split 50:50 across both regions). Before we even allocate the impacts across the County boundary, it is helpful to reveal the broad commuting propensity (this is not industry-specific but rather across all activities within an economy) for these two interconnected regions. These relationships are captured in county data on personal (earned) income flows and the journey-to-work data – both federally collected. Table 22 shows the extent of *linkage* on earned income generated in one region and where its workers reside.

Table 22. Earnings-Commuter Reliance between Contra Costa County and the Surrounding region

		Earnings Place-of-Work	
		Contra Costa	Surrounding region
Worker resides	Contra Costa	79%	8.5%
	Surrounding Counties	15%	73%
	Elsewhere	6%	18%
		100%	**100%**

Based on each of the model region's reliance on jobs situated beyond their border there will be "earned income" imported for both Contra Costa and the Surrounding region since both economies experience job increases under the CCE activity. For workplace earnings generated in Contra Costa County, 15 percent is earned by residents of the surrounding counties (we ignore the *elsewhere* since it is not part of our macroeconomic consideration). Likewise, of workplace earnings generated in the surrounding counties region, 8.5 percent is by commuters from Contra Costa County. Table 23 shows for 2020 the extent of extra jobs and earnings that will be held by a worker who resides in the other region. Of the 704 jobs added in Contra Costa County in 2020, 83 of these jobs (and $7 million of earnings) belong to commuters from the adjacent region. Of the 584 jobs added in the surrounding region in 2020, 41 of these jobs (and $4 million of earnings) belong to commuters from Contra Costa County.

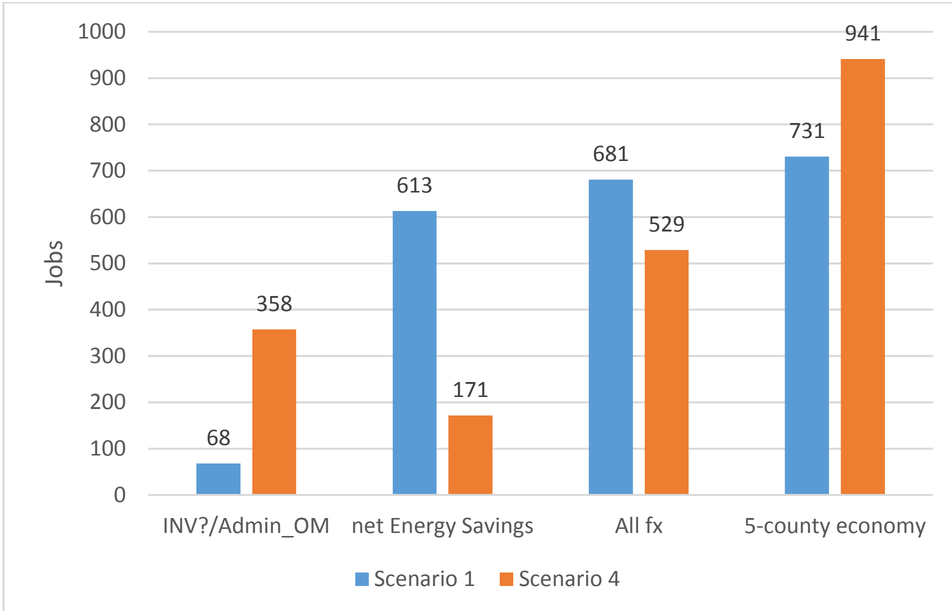
Table 23. Scenario 4 - Earnings Impact by Place-of-Residence, 2020[53]

Scenario 4, Year 2020	Place-of-Work	
	Contra Costa County	**Surrounding region**
Job impact	704	584
Earnings impact	$48 million	$42 million
Earnings per Job	$86,290	$87,560
% Commuter earnings (Surrounding counties)	15%	na
% Commuter earnings (Contra Costa)	na	8.5%
Impact Commuter earnings for Surrounding counties	$7 million	na
Impact Commuter earnings for Contra Costa	na	$4 million
Equiv. # of Surrounding County Commuters	83	na
Equiv. # of Contra Costa Commuters	na	41

Last, a high-level decomposition of the job impact result in the County is shown in Figure 30 for the scenario 1 (the highest customer savings, no investment in local solar capacity) and scenario 4. Under Scenario 1 the County realizes most job creation through the effects of rate savings on the County's economy. This response is 3.5-fold of what Scenario 4 would show as a job impact from rate savings. Yet Scenario 4 exhibits a more than 5-fold job creation impact from the combined *investment/O&M/administration* effects. Including job creation impacts in the adjacent region of the 4-surrounding counties, scenario 4 produces over 200 more jobs (average annual) than Scenario 1. This is predominantly explained by the surrounding region being the location for 50 percent of the small-solar investment that the CCE might choose to fund.

[53] Earnings per Job are weighted estimates.

Figure 30. Average Annual Job Impact in Contra Costa County by Source



Chapter 6: Other Risks

Aside from the risks identified above, the CCE or the political jurisdictions that are part of the CCE could be at risk for several other reasons. This section addresses some of those risks, which are summarized in Table 24.[54]

Table 24. Summary of CCE Risks

Risk	Magnitude	Mitigation
Financial Risks to CCE Members	Low	Keep CCE JPA's financial obligations separate from jurisdiction's/
Procurement-Related Risks (i.e., can't meet rate or GHG targets)	Medium-low	Enter into balanced portfolio of power contracts
Legislative and Regulatory Risks	High	Monitor and advocate at legislature and CPUC
PCIA Uncertainty	High	Establish rate-stabilization fund to account for volatile PCIA
PCIA Policy Uncertainty	High	Monitor and advocate at legislature and CPUC
Availability/price of low-carbon resources	Medium	Enter into balanced portfolio of power contracts
Bonding Risk	Low	Monitor and advocate at CPUC

Financial Risks to CCE Members

A CCE is effectively an association of various political subdivisions. The formation documents for the CCE define the rights and responsibilities of each member of the CCE. Given the large number of political subdivisions that might participate in a Contra Costa County CCE, MRW assumes that the Contra Costa County CCE would be formed under a Joint Powers Authority, in much the same way as MCE Clean Energy and Sonoma Clean Power.

The CCE will ultimately take on various financial obligations. These include obtaining start-up financing, establishing lines of credit, and entering into contracts with suppliers. Because a CCE will take on such financial obligations, it is likely very important to the prospective member political subdivisions that the financial obligations of the CCE cannot be assigned to the members.

[54] Note that this section does not provide legal opinion regarding specific risks, especially those related to the formation or the structure of the Joint Powers Authority under which MRW assumes the CCE will be established.

As a result, it is critical that the Joint Powers Authority and any other structuring documents are carefully drafted to ensure that the member agencies are not jointly obligated on behalf of the CCE (unless a member agency chooses to bear such obligations). The CCE should obtain competent legal assistance when developing the formation documents.[55]

Procurement-Related Risks

Because a CCE is responsible for procurement of supply for its customers, the CCE must develop a portfolio of supply that meets the resource preferences of its customers (e.g., ratio of renewable versus non-renewable supply) while controlling risks (e.g., ratio of short-term versus long-term purchase agreements) and meeting regulatory mandates (e.g., resource adequacy and RPS requirements). Thus, it is tempting to assume that customers would prefer a fully hedged supply portfolio. However, such insurance comes at a cost and a CCE must be mindful of the potential competition from PG&E. Thus, the CCE's portfolio must be both flexible while meeting the needs of its customers.

The CCE will likely need to negotiate a flexible supply arrangement with its initial set of suppliers. Such an arrangement is important since the CCE's loads are highly uncertain during CCE ramp-up. Without such an arrangement, the CCE faces the risk of either under- or over-procuring renewable or non-renewable supplies. Excessive mismatches between supply and demand of these different products would expose the CCE's customers to major purchases or sales in the spot markets. These spot purchases could have a major impact on the CCE's financials.

The CCE will by necessity have to procure a certain amount of short-term supplies. These short-term supplies bring with them price volatility for that element of the supply portfolio. While this volatility is not unexpected, the CCE must be mindful that such volatility could increase the need for reserve funds to help buffer rate volatility for the CCE's customers. Funding such reserve funds could be challenging in this time of low gas prices (resulting in high PCIA charges).

The CCE will be entering the renewable market at an interesting time. While all LSEs must meet the expanded RPS targets by 2030, at least the IOUs are currently over-procured relative to their 2020 RPS targets. Whether the IOUs will attempt to sell off some of their near-term renewable supplies is unknown. However, if the IOUs believe that this is a good time to acquire additional renewables, the CCE could face stiff competition for renewable supplies, meaning that the green portfolio costs for the CCE might be higher than expected.

Finally, it should be noted that as greater levels of renewables are developed to meet the State's very aggressive RPS goals, it is possible that the traditional peak period will change. Adding significant amounts of solar could depress prices during the middle of the day. This could result in the need to try to sell power to out-of-state market participants during the middle of the day, possibly even at a loss. It could also result in the curtailment of renewable resources (even

[55] Cities such as El Cerrito and Benicia have conducted legal analyses when they were considering joining MCE. which should also be consulted.

resources owned or controlled by the CCE). This could force the CCE to acquire greater levels of renewable supplies, thereby increasing costs.

Legislative and Regulatory Risks

As noted above, the CCE must meet various procurement requirements established by the state and implemented by the CPUC or other agencies. These include procuring sufficient resource adequacy capacity of the proper type and meeting RPS requirements that are evolving.[56] Additional rules and requirements might be established. These could affect the bottom line of the CCE.

PCIA Uncertainty

Assembly Bill 117, which established the CCE program in California, included a provision that states that customers that remain with the utility should be “indifferent” to the departure of customers from utility service to CCE service. This has been broadly interpreted by the CPUC to mean that the departure of customers to CCE service cannot cause the rates of the remaining utility “bundled” customers to go up. To maintain bundled customer rates, the CPUC has instituted an exit fee, known as the “Power Charge Indifference Adjustment” or “PCIA” that is charged to all CCE customers. The PCIA is intended to ensure that generation costs incurred by PG&E before a customer transitions to CCE service are not shifted to remaining PG&E bundled service customers.

Even though there is an explicit formula for calculating the PCIA, forecasting the PCIA is difficult, since many of the key inputs to the calculation are not publicly available, and the results are very sensitive to these key assumptions. For PG&E, the PCIA has varied widely; for example, at one time the PCIA was negative.

Current CCEs have chosen to have customers bear the financial risk associated with the level of exit fees they will pay to PG&E. Thus, for a customer taking CCE service to be economically better off (i.e., pay less for electricity), the sum of the CCE charges plus the PCIA must be lower than PG&E’s generation rate.

This risk can be mitigated in two ways. First, as discussed in more detail elsewhere, a rate stabilization fund can be created. Second, the CCE can actively monitor and vigorously participate in CPUC proceedings that impact cost recovery and the PCIA.

Impact of High CCE Penetration on the PCIA

Currently, the PCIA calculation is based on the cost and value of a utility's portfolio, without regard to how much of that portfolio is to be paid for by bundled customers and how much by Direct Access (DA) and CCE customers. As such, the PCIA is not affected by the number of DA/CCE customers.

[56] Rules to establish RPS requirements under the new 50% RPS mandate are currently being debated at the CPUC.

Currently, for bundled customers the rate impacts associated with fluctuating PCIAs are relatively small, but this will change as the number of DA/CCE customers grows. At some point, bundled customers' rates may experience marked volatility as the impacts of the annual PCIA rate swings reverberate to bundled rates. This may be unacceptable to ratepayer advocates and the Commission.

The PCIA rate volatility in part reflects changes to the utilities' generation costs, which is appropriately reflected in bundled customers' rates. But, often to a large degree, it reflects changes to the market price benchmark, which should not be relevant to bundled customer rates. For example, for a utility with flat RPS costs, a reduction to the market price benchmark for renewable power would increase the RPS-related PCIA, which would reduce bundled rates, even though there was no change in RPS costs. This could also happen in the reverse direction, increasing bundled rates when there is no increase in underlying generation costs.

Once DA/CCE load gets large enough that there are real stranded contracts, we suspect that the Commission is going to look much more closely at the value of these stranded contracts (and how to get the most value for them).

Impact of High CCE Penetration on Low-Carbon (Hydro) Resources

Virtually all the CCEs forming in California include carbon reduction as a goal. As the analysis has shown, CCEs will likely need to purchase both RPS-eligible power and other carbon-free power to meet their goals, namely large hydropower. This has been the approached used by MCE and Peninsula Clean Power, who both beat PG&E's GHG emissions rate through contracts for hydropower. This increased demand for carbon-free hydropower a can change the "supply-demand" balance and in theory increase the cost of these resources. To address this risk, the Contra Costa County CCE should consider locking in longer-term contracts for non-RPS eligible resources early in the process so as to guarantee their availability in the longer term when there could be greater demand for them.

Bonding Risk

Pursuant to CPUC Decision 05-12-041, a new CCE must include in its registration packet evidence of insurance or bond that will cover such costs as potential re-entry fees, specifically, the cost to PG&E if the CCE were to suddenly fail and be forced to return all its customers back to PG&E bundled service. Currently, a bond amount for CCEs is set at $100,000.

This $100,000 is an interim amount. In 2009, a Settlement was reached in CPUC Docket 03-10-003 between the three major California electric utilities (including PG&E), two potential CCEs (San Joaquin Valley Power Authority and the City of Victorville) and The Utility Reform Network (TURN) concerning how a bonding amount would be calculated. The settlement was vigorously opposed by MCE and San Francisco and never adopted.

Since then, the issue of CCE bond requirements has not been revisited by the CPUC. If it is, the bonding requirement will likely follow that set for Energy Service Providers (ESPs) serving direct access customers. This ESP bond amount covers PG&E's administrative cost to reintegrate a failed ESP's customers back into bundled service, plus any positive difference between market-based costs for PG&E to serve the unexpected load and PG&E's retail generation rates. Since the ESP bonding requirement has been in place, retail rates have always exceeded wholesale market prices, and thus the ESP's bond requirement has been simply the equal to a modest administrative cost.

If the ESP bond protocol is adopted for CCEs, during normal conditions, the CCE Bond amount will not be a concern. However, during a wholesale market price spike, the bond amount could potentially increase to millions of dollars. But the high bond amount would likely be only short term, until more stable market conditions prevailed. Also, it is important to note that high power prices (that would cause a high bond requirement) would also depress PG&E's exit fee and would also raise PG&E rates, which would in turn likely provide the CCE sufficient headroom to handle the higher bonding requirement and keep its customers' overall costs competitive with what they would have paid had they remained with PG&E. As discussed above, JPA member entities would not be individually liable for any increase in the bond amount.

Chapter 7: Comparative Analysis of CCE Options

Having the County and its cities form its own JPA and CCE Program is not the only possibility for CCE participation. First, the Counties and/or its cities may join Marin Clean Energy (MCE). In fact, 5 cities in the County—El Cerrito, Lafayette, Richmond, San Pablo, Walnut Creek—are already members of MCE. These cities joined in 2015 and 2016, and have full standing on MCE's Board of Directors. Second, the County and/or its cities could possibly join the East Bay Community Energy (Alameda County) CCE. While this CCE has not formally been formed—the Alameda County Board of Supervisors and the respective city Councils are currently taking up the matter—the Alameda CCE Steering Committee is aiming to have the JPA board seating in January 2017, with delivery of power beginning in late 2017. Furthermore, the County and each city need not joint one or other CCE *en masse*, but instead can join one or the other CCEs individually (or neither).

This chapter presents the benefits and drawbacks of joining either MCE or EBCE, forming a new CCE with the County and its cities (which has been the focus of most of the analysis in this report), or remaining with PG&E. This chapter considers the rate-competitiveness, GHG reduction, local economic development, local control and governance, cost risks, and CCE formation timing of each option. Some of the benefits may depend upon how much of the County chooses which path. Each community chooses for itself; thus, it is perfectly reasonable to have some join MCE, some join EBCE, and others remain on PG&E service. To the extent that it matters, this will be highlighted in the sections that follow.

Note that MRW & Associates are not attorneys, and that the MCE and EBCE JPA agreements are legal documents. Therefore, nothing herein should be interpreted as a legal opinion – only an informed lay-reading of the documents. MRW would strongly recommend that Contra Costa County and any city considering becoming a member of MCE or EBCE have its counsel conduct a thorough review of the respective JPA and related documents prior to committing to a CCE.

Table 25, below summarizes our results. While it is desirable to quantify some (or all) of the criteria, to do so would be an exercise in false precision. First and foremost, two of the potential CCE options are with entities which, while potentially viable, do not exist. Without power contracts, portfolios or procurement guidelines and policies, it would be unwise to claim that EBCE or a potential Contra Costa-only CCE would have rates or greenhouse gas emissions higher or lower than the other. Comparisons against MCE can be somewhat more reasonably asserted; however, its stated goals—greater renewable energy content, lower greenhouse gas emissions, local generation, and comparable rates—are nearly identical to those stated by EBCE, so at to make long-range rate and emissions distinctions immaterial. This is in contrast to PG&E, whose power portfolios, procurement plans and costs are readily available through various filings and applications it has made before the CPUC. Thus, the qualitative comparisons provided in the table do not provide sharp distinctions between the CCE options. All these options are expected to provide similar rates and GHG emissions, with differences arising from variations in the priorities and procurement decisions of the individual governance boards. What truly distinguish these options are primarily governance options (i.e., in-county only versus shared with other entities) and the amount of risk assumed (i.e., developing or signing on with a new CCE versus joining one with a record of satisfactory performance).

Each of the lines on the table are discussed in greater detail in the sections that follow.

Table 25. Comparison of Contra Costa CCE Options

Criterion	Form CCCo JPA	Join MCE	Join EBCE	Stay with PG&E
Rates	Likely lower	Likely Lower	Likely Lower	Base
GHG Reduction Potential Over Forecast Period	Some	Some	Some	Base
Local Control/Governance	Greatest	Some	Greater	None
Local Economic Benefits	Greatest	Some	Greater	Minimal
Start Up Costs/Cost to Join	Low, but greater risk[57]	None	Unknown, but likely to be none	None
Level of Effort	Greatest	Minimal	Greater	None
Program Risks	Greatest	Minimal	Some	Base
Timing (earliest)	Mid-Late-2018	Late-2017	Mid-2018	N/A

Rates

In general, any of the three CCE options can result, in the long run, with rates that are at or slightly below those of PG&E. This is not to say that in some years PG&E's rates may be lower, or that one CCE would consistently have rates that are lower than the others. Rather, given that a CCE's rates are a function if its communities' values—amount of local renewable generation, promotion of energy efficiency or distributed generation, overall rate minimization— and that two of the three CCEs being compared do not yet exist, let alone have rate or procurement

[57] Start-up costs provided by the County or others are likely to be reimbursed by the JPA.

policies, MRW cannot assert that one CCE option will have lower rates that the other two. Both MCE and EBCE have commitments to higher-cost local renewable development, which suggest that they are willing to trade off somewhat lower rates for other benefits. A Contra Costa CCE that focuses more on rate reduction could in principle offer marginally lower rates than the other two.

GHG Reduction

For climate action planning and reporting purposes, the amount of GHG reduction that can be attributed to a CCE formation is a function of the difference between the average GHG emissions from PG&E and that of the CCE. PG&E's power portfolio is already relatively "clean," with large fractions coming from not only qualifying renewables but also nuclear power (through 2024) and large hydroelectric generators. As Table 26 shows, 59% of PG&E's 2015 power came from GHG-Free resources. This number would be closer to 67% GHG-free but for the poor hydroelectric generation due to the ongoing drought.[58] Therefore, for any CCE to have a reduced average carbon footprint requires not only the same or greater amount of qualifying renewable generation, but additional sources of GHG-free generation.

Table 26. PG&E and MCE Power Content (2015)

	PG&E 2015	MCE 2015
Eligible renewable	30%	56%
Large Hydro	6%	12%
Nuclear	23%	0%
GHG-Free subtotal	**59%**	**68%**
Unspecified/Market	17%	25%
Natural Gas	25%	12%
Fossil subtotal	**41%**	**32%**

An approach taken by some of the currently operating Northern California CCEs is to (a) use more qualifying renewable generation than PG&E, and (b) contract with and use power from large hydroelectric resources. This is shown in MCE's power content mix, and to the extent possible, what was modeled here for Contra Costa County and for MRW's study of an Alameda County CCE.

Given that both MCE and EBCE have made GHG reductions a very high priority, one can reasonably assume that either will have some GHG-emissions benefit relative to PG&E, but there is no concrete rationale to assume that either MCE or EBCE will have a significantly-lower GHG emissions rate than the other.

[58] However given climate change, one can sensibly argue that the lower-than-historic-average hydroelectric output in California seen over the past few years may be more predictive than the historical average.

Local Economic Benefits

As noted earlier in the report, the amount of local economic benefits is a function of rate reduction and local construction and CCE staffing. The number of local renewable energy projects will be a function of at least two factors. The first is any cost competitiveness advantage of renewable resources in the County; i.e., others will want to build renewable generation in the County because of cost advantages (including interconnection ease). Second, local generation development will be fostered by a preference for local generation by the CCE serving Contra Costa County. While all three CCE options have expressed a preference for "local" renewables, what the extent of "local" is will contribute to Contra Costa development. MRW would expect that a Contra Costa CCE would have the greatest interest in developing in-county renewables and thus could potentially have the greatest positive economic impact. Teaming with either of the other CCEs would dilute the interest. Given the particularly strong interest of the EBCE group in local renewables, the notion that "local" might encompass the whole "East Bay," and the fact that Contra Costa cities might have greater say in the formation of generation polities with a new group like EBCE than a more established one like MCE all suggest that EBCE might be more responsive in developing in-county renewables than MCE.

Contra Costa County makes up but a small fraction of PG&E's service area. While PG&E's local community engagement is admirable, it cannot focus on the County in a way that a smaller CCE can. As such, any of the three CCE scenarios will likely result in greater local economic benefits than remaining with PG&E.

CCE Governance: Voting

Per its current proposed JPA, EBCE would have a two-stage vote. Under most circumstances, each board member (each representing a single entity) would have one vote, regardless of his or her entity's size. That is, both Oakland and Piedmont would have an equal vote. In the event of a non-unanimous affirmative vote, three cities can call for a weighted vote. In that case, each Representative Board Member's vote would be weighted according to the size (in kilowatt-hours) of the entity being represented. These two voting shares are shown in Table 27.

Table 27. EBCE Voting Shares, With and Without Contra Costa

	Simple Voting		Load-Weighted Voting*	
	Alameda Only	Alameda + Contra Costa	Alameda Only	Alameda + Contra Costa
Oakland	7.1%	3.4%	24.8%	16.4%
Fremont	7.1%	3.4%	16.2%	10.7%
Hayward	7.1%	3.4%	10.1%	6.6%
Berkeley	7.1%	3.4%	8.5%	5.6%
Pleasanton	7.1%	3.4%	6.6%	4.3%
San Leandro	7.1%	3.4%	6.4%	4.2%
Livermore	7.1%	3.4%	6.2%	4.1%
Unincorporated Ala.	7.1%	3.4%	6.4%	4.2%
Other Alameda Cities	42.9%	20.7%	14.9%	9.9%
Alameda Total	***100.0%***	***48.3%***	***100.0%***	***66.0%***
Unincorporated C.C.		3.4%		8.4%
Concord		3.4%		4.8%
Pittsburg		3.4%		4.3%
Antioch		3.4%		3.4%
San Ramon		3.4%		3.0%
Brentwood		3.4%		2.0%
Danville		3.4%		1.6%
Martinez		3.4%		1.3%
Pleasant Hill		3.4%		1.3%
Oakley		3.4%		1.0%
Orinda		3.4%		0.9%
Hercules		3.4%		0.7%
Pinole		3.4%		0.6%
Moraga		3.4%		0.4%
Clayton		3.4%		0.3%
Contra Costa Total	***N/A***	***51.7%***	***N/A***	***34.0%***
****Only in cases where called upon by 3 Board Members***				

As noted in Table 28 if EBCE consisted of Alameda County alone, the combination of the three largest entities (Oakland, Fremont, and Hayward) could carry the weighted vote. If all of Contra Costa county joined EBCE, then it would take the six largest entities (Oakland, Fremont, and Hayward plus Berkeley, Concord and Unincorporated Contra Costa county) to carry the vote.

Table 28. EBCE Minimum Cities Needed to Carry Weighted Vote

Alameda Only	**3 cities**	**(Oakland, Fremont Hayward)**
Alameda + Contra Costa	6 cities	(Oakland, Fremont, Hayward, Unincorporated CC, Berkeley, Concord)

MCE's voting structure differs from EBCE's in two important ways. First, each board member's vote is a weighted. Half of each board member's weighting is equal to his or her entity's share of MCE's total load. The other half is an equal share for each entity. Thus, if a community is one of 26 members representing 18% of MCE's load, the board member's vote would be 10.9% (18%x(1/2) + (1/26)x(1/2)= 9% + 1.9% = 9.9%) Second, multiple entities have the option to be represented by a single board member. For example, Napa County and all the towns/cities within the County are represented by a single board member. While this may dilute the voting share of each entity represented by the single board member, it allows for less administrative burden on the represented entities and "streamlines communication and policy setting."

Table 29 shows what the voting shares might be if all the Contra Costa communities joined MCE and each claimed its own board member. Together, the Contra Costs communities would represent 47.4% of MCE's load and have a total 42.9% of the voting share.

Table 29. MCE Voting Shares With Each Contra Costa Community Having Its Own Board Member

VOTING SHARES	Load Share	Entity Share	Voting Share
Antioch	4.8%	2.6%	3.7%
Brentwood	2.7%	2.6%	2.6%
Clayton	0.4%	2.6%	1.5%
Concord	6.7%	2.6%	4.6%
Danville	2.3%	2.6%	2.4%
Hercules	1.0%	2.6%	1.8%
Martinez	1.8%	2.6%	2.2%
Moraga	0.6%	2.6%	1.6%
Oakley	1.5%	2.6%	2.0%
Orinda	1.3%	2.6%	1.9%
Pinole	0.8%	2.6%	1.7%
Pittsburg	5.9%	2.6%	4.3%
Pleasant Hill	1.8%	2.6%	2.2%
San Ramon	4.1%	2.6%	3.4%
Unincorporated Contra Costa County	11.7%	2.6%	7.1%
TOTAL CONTRA COSTA COUNTY	**47.4%**	**38.5%**	**42.9%**
Rest of MCE	**52.6%**	**61.5%**	**57.1%**

Table 30 shows what the voting and load shares might be if all or 1/3 of the Contra Costa communities joined MCE but opted to be represented by a single board member. In these cases, the entity share would be low—4%—while the load share would remain pro-rata, resulting in somewhat lower overall Contra Costa representation.

Table 30. MCE Voting Shares With Contra Costa Communities Sharing a Single Board Member

VOTING SHARES	Load Share	Entity Share	Voting Share
All of Contra Costa represented by 1 Board Member	47.4%	4%	25.7%
Rest of MCE	52.6%	96%	74.3%
1/3 of Contra Costa load joins and is represented by 1 Board Member	23.1%	4%	13.5%
Rest of MCE	76.9%	96%	86.5%

CCE Governance: Other

The proposed EBCE JPA Agreement also calls for a formal Community Advisory Committee (Section 4.9). The relevant section states that the Committee:

> "shall be to advise the Board of Directors on all subjects related to the operation of the CCA Program … with the exception of personnel and litigation decisions. The Community Advisory Committee is advisory only, and shall not have decision-making authority… The Board shall appoint members of the Community Advisory Committee from those individuals expressing interest in serving, and who represent a diverse cross-section of interests, skill sets and geographic regions."

The Chair of the Community Advisory Committee will serve as a non-voting *ex officio* member of the EBCE Board of Directors.

MCE has no analogous official community advisory committee originating from its JPA agreement. Nonetheless, there is a "Community Power Coalition" that provides input to MCE (*see*, https://www.mcecleanenergy.org/community-power-coalition/). The Coalition works "on a variety of issues ranging from local renewable energy project development – like MCE Solar One in Richmond – to outreach for MCE's Spanish-speaking constituents, to environmental justice and consumer protection issues affecting MCE's low-income customers."

The recitals to EBCE's JPA agreement lay out what can be described as its envisioned values. Besides offering competitive rates and lowering greenhouse gasses, this includes (Recitals, Section 6):

- Establishing an energy portfolio that prioritizes the use and development of local renewable resources and minimizes the use of unbundled renewable energy credits;
- Promoting an energy portfolio that incorporates energy efficiency and demand response programs and has aggressive reduced consumption goals;
- Demonstrating quantifiable economic benefits to the region (e.g. union and prevailing wage jobs, local workforce development, new energy programs, and increased local energy investments);
- Recognize the value of workers in existing jobs that support the energy infrastructure of Alameda County and Northern California. The Authority, as a leader in the shift to a clean energy, commits to ensuring it will take steps to minimize any adverse impacts to these workers to ensure a "just transition" to the new clean energy economy;
- Delivering clean energy programs and projects using a stable, skilled workforce through such mechanisms as project labor agreements, or other workforce programs that are cost effective, designed to avoid work stoppages, and ensure quality;
- Promoting personal and community ownership of renewable resources, spurring equitable economic development and increased resilience, especially in low income communities;
- Provide and manage lower cost energy supplies in a manner that provides cost savings to low-income households and promotes public health in areas impacted by energy production; and
- Create an administering agency that is financially sustainable, responsive to regional priorities, well managed, and a leader in fair and equitable treatment of employees through adopting appropriate best practices employment policies, including, but not limited to, promoting efficient consideration of petitions to unionize, and providing appropriate wages and benefits.

Contra Costa communities considering joining EBCE should consider these enunciated values prior to committing to membership.

Timing and Process to Join/Form

The timing required to serve Contra Costa businesses and residents vary markedly among the CCE options. The quickest path the CCE service would be to join with MCE. Based on MCE's currently Inclusion Period, Contra Costa County and its cities could begin MCE service as early as late 2017.

The first step for a community to join MCE is for its governing body or representative (e.g., city manager) to provide MCE a non-binding letter of interest. The entity's governing body would then need to adopt a resolution requesting MCE membership; have a first reading of an ordinance to join MCE; execute a memorandum of understanding between the entity and MCE to address preliminary data and communication issues; and provide a signed request for PG&E to provide MCE its load data. These steps would need to occur during MCE's "inclusion period" which currently runs from December 1, 2016 through May 31, 2017. Only communities in Contra Costa County are eligible to request MCE membership during this period.

MCE would then evaluate the impact of the new load on its system. If the net result of adding the new community is that MCE's rates would increase, then that community's membership would be tabled until a future date. If the MCE analysis shows that adding the community is favorable, then the MCE Board would vote to accept (or not) the community into MCE. At that point, the local ordinance for MCE membership would receive a second reading and adoption. MCE would them modify its official Implementation Plan to reflect the new community, and submit the updated plan to the California Public Utility Commission. Once approved (none have been rejected), the phase-in of community into MCE can occur.

The timing and process to join EBCE is more speculative. While the Steering Committee has strongly suggested that Contra Costa County entities would be welcome to join in, so far, the EBCE efforts have been solely aimed at getting the CCE going in Alameda County.

The current (draft) JPA documents states in Section 3.1, Addition of Parties:

> Subject to Section 2.2, relating to certain rights of Initial Participants, other incorporated municipalities and counties may become Parties upon (a) the adoption of a resolution by the governing body of such incorporated municipality or county requesting that the incorporated municipality or county, as the case may be, become a member of the Authority, (b) the adoption by an affirmative vote of a majority of all Directors of the entire Board satisfying the requirements described in Section 4.12, of a resolution authorizing membership of the additional incorporated municipality or county, specifying the membership payment, if any, to be made by the additional incorporated municipality or county to reflect its pro rata share of organizational, planning and other pre-existing expenditures, and describing additional conditions, if any, associated with membership, (c) the adoption of an ordinance required by Public Utilities Code Section 366.2(c)(12) and execution of this Agreement and other necessary program agreements by the incorporated municipality or county, (d) payment of the membership fee, if any, and (e) satisfaction of any conditions established by the Board..

Thus, a Contra Costa Community would need to adopt a resolution requesting membership in the EBCE, the board of Directors of EBCE would have to vote to authorize the applying community's membership, followed by the applying entity passing an ordinance to join. The EBCE can charge the applying entity fee or subject it to other restrictions, although given the likely receptivity to new East Bay membership, it is doubtful that those fees or restrictions would be onerous.

Furthermore, given its intent to create a JPA—solely with Alameda County representation—in January, and the further intent to begin its first phase of service as soon as practicable, 3rd or 4th quarter 2017, it is unlikely that any Contra Costa County city would be enrolled into EBCE service prior to the middle of 2018. It is also possible that the EBCE JPA would want to get the program established with Alameda County members before integrating in members from another county. In this case, EBCE service to Contra Costa County and its cities might not occur until 2019 or 2020.

Implementing a Contra Costa County only CCE would likely have a time line similar to joining EBCE. If the County and its cities were committed to this path, it could potentially begin service as early as 2018. This is consistent with Peninsula Clean Energy, which went from putting out an RFP for a technical study to phase-1 implementation in 18 months (April 2, 2015 to October 1, 2016). A more measured timeline would suggest that a new Contra Costa CCE would spend much of 2017, planning and generating local support, with implementation beginning in late 2018 or 2019.

Costs to Join the CCE

This section discusses direct, non-reimbursable costs to cities for joining either EBCE or MCE. So far, cities joining MCE have not had to pay for any of the costs incurred by MCE to plan for or integrate their load. They have often spent on the order of $10,000 to $15,000 for consultants to evaluate the risks to the city and its residents and businesses that could come from joining MCE.

As EBCE has not seated its board or set any bylaws, one cannot say if, or how much, EBCE would charge any Contra Costa cities to join. Given its Steering Committee's interest in including Contra Costa into its program, one can assume that it would be minimal or zero.

The start-up costs for a new Contra Costa CCE would be significant—Alameda County has committed $3.4 million to its effort. However, consistent with other CCEs, these costs would be initially reimbursed to the County and funding cities by a loan taken out by the CCE's JPA, which would in turn be paid down via CCE rates over the initial few years. As such, the only "cost to join" a Contra Costa CCE felt by any individual city would be indirect at best (i.e., asked to backstop any CCE loads with the entities' credit.

Exiting the CCE

MCE's JPA Section 7.0 lays out the process and ramifications of a MEC member withdrawing from the JPA. First, an entity may withdraw from the JPA within 30 days of its notification of joining the JPA, assuming that MCE has not entered into any wholesale power agreements to serve the entity. (Section 7.1.1.1) After MCE has entered into wholesale power agreements to serve the entity, the entity may withdraw from MCE, effective the beginning of the JPA's fiscal year by giving at least 6 months' written notice of its intent to withdraw. The withdrawing entity may be subject to "certain continuing liabilities" as laid out in Section 7.3:

> **7.3 Continuing Liability; Refund**. Upon a withdrawal or involuntary termination of a Party, the Party shall remain responsible for any claims, demands, damages, or liabilities arising from the Party's membership in the Authority through the date of its withdrawal or involuntary termination, it being agreed that the Party shall not be responsible for any claims, demands, damages, or liabilities arising after the date of the Party's withdrawal or involuntary termination. In addition, such Party also shall be responsible for any costs or obligations associated with the Party's participation in any program in accordance with the provisions of any agreements relating to such program provided such costs or obligations were incurred prior to the withdrawal of the Party. The Authority may withhold funds otherwise owing to the Party or may require the Party to deposit sufficient funds with the Authority, as reasonably determined by the Authority, to cover the Party's liability for the costs described above. Any amount of the Party's funds held on deposit with the Authority above that which is required to pay any liabilities or obligations shall be returned to the Party.

Neither the precise calculation of the liabilities nor now it would be collected is specified.

The proposed EBCE JPA Agreement contains no language concerning a community's exit from EBCE or the JPA.

Remaining With PG&E

Although this study suggests CCE program options would likely produce both environmental and economic benefits for the jurisdictions included in the study, continuing service with PG&E remains an option for not only a community but also for any individual or business whose community has selected CCE service (i.e., each individual account maintains its right to opt-out of CCE service). There are benefits of remaining with PG&E, even at a community level. First, remaining with PG&E takes no city action. Thus, a city's leadership and staff can concentrate their limited resources on matters that may be more pressing. Second, PG&E is regulated by the state via the California Public Utilities Commission (CPUC), which oversees its power procurement and approves its rates. While CCEs are partially regulated by the CPUC (e.g., ensuring that the CCE complies with any applicable laws), they are not subject to rate regulation. Some may see state oversight as a benefit, with an official "watchdog" overseeing power supply and procurement, while others might see the local CCE board accountability as a benefit. Third, PG&E is much larger than any of the CCE options that Contra Costa Communities might pursue, which (as discussed) might reduce community input and value but also provides some economies of scale. For example, one poor power contract entered might have significant rate or operational ramifications for a CCE. For PG&E, given its size, the impact of that same poor contract would be diluted. Lastly, simply because a Contra Costa community does not join a CCE in 2017 or 2018 does not necessarily preclude it from doing so in the future, although waiting may result in an "entry fee" or perhaps a high PCIA rate.

Summary

The following lays out the principal benefits and risks of each of the options considered.

Potential Benefits of Forming Contra Costa CCE (relative to joining MCE or EBCE)

- More local control (voting shares not diluted)
- Can form JPA and policies to fully reflect County interests and values
- Greatest potential for local economic development (due largely to more local control)
- Even if formed, individuals may still select PG&E as their power provider

Potential Risks/Downsides of Forming Contra Costa CCE (relative to joining MCE or EBCE)

- Commitment of County and city resources to establish a new CCE agency
- Higher risks due lack of experience, fewer partners
- Would need to establish programs, contractors, credit, etc.
- Longest time line to begin enrolling customers

Potential Benefits of joining MCE (relative to joining EBCE)

- 5 other Contra Costa County communities have already joined
- Established, successful program with credit capacity and programs in place
- Likely easier transition/implementation
- Likely will be able to enroll customers sooner than EBCE

Potential Risks/Downsides of joining MCE (relative to joining EBCE)

- May have less Board representation (if all of Contra Costa County and its jurisdictions are represented by a shared seat)
- May be less of a "fit" compared to East Bay identification and sensibilities (or, for some cities, this may be a benefit)
- Programs are already in place; less/minimal input into their formation
- joining a large Board serving a very diverse customer base and geography

Potential Benefits of joining EBCE (relative to joining MCE)

- Coming in closer to the "ground floor" — opportunity to influence policy direction and program development
- May be more mission or cultural alignment (East Bay vs. Marin) (or perhaps for some communities, not)
- Board will more likely be one seat per member jurisdiction (not a shared seat)
- Weighted voting process is a little clearer
- EBCE working on a local development business plan with emphasis on local power production in the East Bay

Potential Risks/Downsides of joining EBCE (relative to joining MCE)

- Likely to take longer to enroll County communities
- Path to joining is not clear
- May be a small fish among some very large fishes (Oakland, Hayward)
- Union focused policies may be difficult for some

Potential Benefits of Remaining with PG&E (relative to joining or forming a CCE)

- Experienced provider
- State regulatory protection
- Continuity- same firm provides all services
- No action needed by City/County—status quo
- May be able to join a CCE at a later date (but perhaps at some cost)

Potential Risks/Downsides Benefits of Remaining with PG&E (relative to joining or forming a CCE)

- Higher GHG emissions
- Less local renewable generation
- Higher electricity rates than CCE rates under most scenarios
- Less local control
- Less local input into policies and offerings
- Less local economic development
- Individuals can remain on bundled PG&E service even though their community is a CCE member.

Chapter 8: Other Issues Investigated

Synergies on the Northern Waterfront

Contra Costa County has an ongoing initiative to economically develop its Northern Waterfront. The Northern Waterfront stretches from the City of Hercules at San Pablo Bay, along the southern shore of the Carquinez Straight and Suisun Bay, and out to the San Joaquin Delta region of Oakley. The County's Northern Waterfront Economic Development Initiative is a regional cluster-based economic development strategy with a goal of creating 18,000 new jobs by 2035. The Initiative leverages existing competitive advantages and assets by focusing on advanced manufacturing sub-sectors in five targeted clusters (advanced transportation fuels, bio-tech/bio medical, diverse manufacturing, food processing, and clean tech).

To assess the potential positive impacts a CCE might have on this Area, the study looked at the Northern Waterfront to assess local generation potential within the area. Of the potential 3,350 MW of solar resources in the County, approximately 40% lies within the Northern Waterfront. As shown in Table 31, there are over 700 potential solar sites in the Area, which could theoretically generate over 2,000 GWhs. Of these sites, over 800 MW have the highest potential ranking, meaning that they are the most appropriate for actual development. In fact, all the local solar capacity specified in Scenarios 3 or 4 could be met at sites in the Northern Waterfront alone.

Table 31 Solar Potential in the Northern Waterfront

Location	Solar Sites	PV Potential (MW)	PV Production (GWh)	Build Cost ($ Thousands)
Antioch	189	327	524	$747,130
Concord	108	191	306	$442,015
Crockett	21	58	93	$125,187
Hercules	52	90	144	$200,512
Martinez	139	300	480	$629,130
Oakley	43	76	121	$178,390
Pinole	17	24	39	$57,208
Pittsburg	153	298	477	$679,851
Rodeo	14	35	57	$85,875
Grand Total	**736**	**1,400**	**2,241**	**$3,145,298**

How much solar could actually be sited in the Northern Waterfront would depend upon (a) the degree to which there is competition for sites for perhaps higher-value projects (b) the CCE's policies toward fostering local projects.

In addition to this renewable potential, the Northern Waterfront also hosts six major power plants (Table 32). In addition to these, the refineries in the area also generate much of their own power. A Contra Costa CCE could contract with one of more of these facilities to provide the CCE's Resource Adequacy Requirements or a portion of its energy needs. Alone, a Contra Costa CCE would not be able to use all—or even most—of the power produced by any of these or other major power plant of this magnitude (e.g., the cancelled Oakley power plant).

Table 32. Natural Gas Power Plants in the Northern Waterfront

Plant	Location	Capacity (MW)	Year in Service	Owner	Type
Crockett Cogen	Crocket	275	1995		Steam-Cogen
Los Medanos	Pittsburg	555	2001	Calpine	Combined cycle -Cogen
Delta Energy Facility	Pittsburg	887	2002	Calpine	Combined cycle
Gateway	Antioch	530	2009	PG&E	Combined cycle
March Landing	Antioch	760	2013	Mirant	combined cycle
Pittsburg	Pittsburg	1,029	1970s	NRG	Steam, combined cycle

"Minimum" CCE Size?

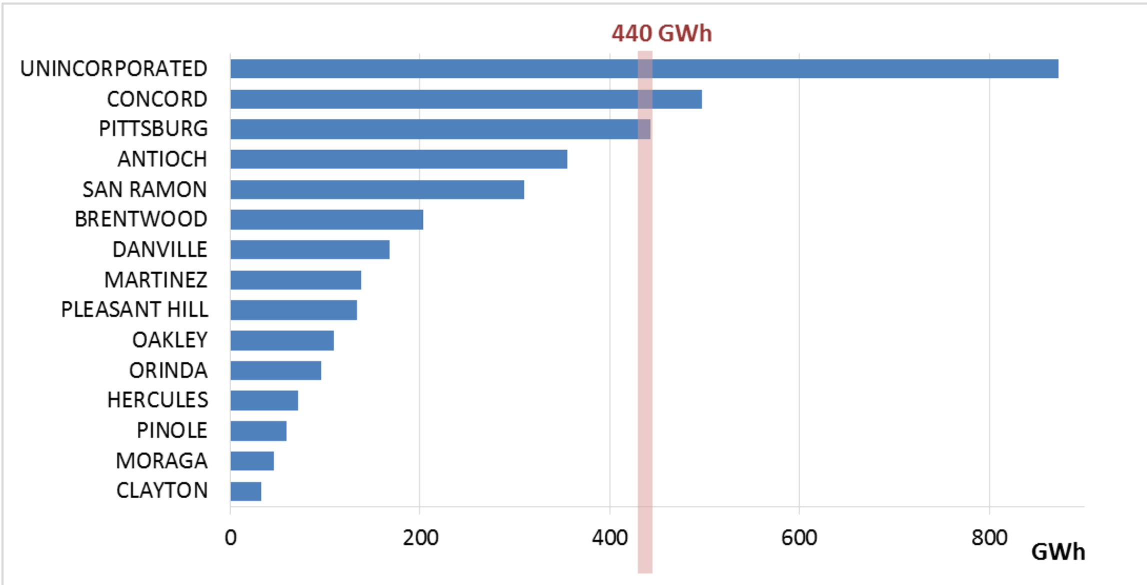
MRW's analysis above assumed that all eligible Contra Costa County cities join the Contra Costa County CCE program with a participation rate of 85% from each city, resulting in an anticipated CCE load of about 3.6 million MWh per year.[59] If fewer customers join, CCE rates will generally be higher because about $7 million of annual CCE costs are invariant to the amount of CCE load. Along with the number of customers, the customer make-up is also important. For example, a higher share of residential customers would improve the competitiveness of the CCE, while a higher share of commercial customers or industrial customers would weaken the competitiveness of the CCE. Since cities vary in their distribution of customers by rate class, a city opting out of the CCE could affect the competitiveness of the CCE due to both the reduction in CCE load and the shift in customer make-up.

To identify the "minimum" load needed for CCE customer rates to be no higher than PG&E customer rates, we will analyze only the period between 2018 and 2030. The "minimum" load for this period is approximately 440,000 MWh per year, assuming the average customer portfolio for Contra Costa County and Supply Scenario 1. This value was estimated by assuming that the fixed costs remained the same (i.e., did not scale with sales) and then lowering the sales until the hypothetical reduced CCE's rates were equal to PG&E's. As shown in Figure 31, this is roughly the load from the big cities (Concord and Pittsburg) and is much smaller than the load from the unincorporated area. As long as two medium-sized cities or one larger city joins the CCE, this "minimum" load will be met. It is not a true minimum, however, because the true minimum depends on the make-up of the customer portfolio; for example, for the stand-alone city of

[59] In the alternate supply scenarios, the "minimum" annual load assuming the average customer portfolio for Contra Costa County and the base case is 550,000 MWh (Scenario 2).

Pittsburg[60], due to its load with more industrial proportion, the CCE program wouldn't be cost-competitive.

Figure 31. Potential load (85% participation) per city



Individuals and Communities Self-Selecting 100% Renewables

The existing CCEs all offer customers an option to choose to receive 100% of their power from renewable resources in exchange for a rate premium. However, each CCE's program is different. MCE Clean Energy has offered its "Deep Green" at a rate premium of 1¢/kWh since its inception. Sonoma Clean Power offers its "Evergreen" option at approximately the same price as PG&E's "Solar Choice" rate. Lancaster Choice Energy offers its Smart Choice as a fixed monthly premium rather than a variable rate. In all cases, only a very modest number of CCE customers—on the order of a few percent—have selected the 100% green rate option.

Table 33. CCE 100% Green Rate Premiums

CCE	Rate Option	Increment Above Default Rate
Marin Clean Energy	Deep Green	1¢/kWh
Sonoma Clean Power	EverGreen	3.5¢/kWh
Lancaster Choice Energy	Smart Choice	$10/month
Peninsula Clean Energy	ECO100	1¢/kWh
Potential Contra Costa Co. CCE	**TBD**	**~1.5¢/kWh**

60 See Figure 2. Pittsburg is the only city with this highly industrial profile.

Any full renewable pricing option offered by the Contra Costa County CCE would have to be set by the CCE's management. The value shown in Table 33, ~1.5¢/kWh, is the average incremental cost of green power used in the CCE supply assessment (Scenario 2) over the study period. (Initially, it would have to be ~1.9¢/kWh.) The number of customers selecting the rate would not impact the economics of the CCE customer who remain on the standard rate.

- Separate CCE opt-out notifications would be needed. A key feature of the opt-out notification is the price comparisons against PG&E. As the default rate would be different for these communities, a different notice would have to be sent. This would simply increase the start-up cost for the CCE, the increment could be paid for by the city electing a different default rate.
- Having a higher default rate might increase the number of oft-outs in the community.
- PG&E's billing system would have to be able to handle city- or zip code-specific default options. That is, as new residential or businesses move to a self-selected green community, the billing system would need to know to default them on a different rate schedule than a customer in a different CCE community. This may or may not be an issue.

Competition with a PG&E Solar Choice Program

PG&E has been offering a solar choice program known as Green Tariff Shared Renewable Program since February 2015.[61] The program was established under Senate Bill 43, and pursuant to Decision 15-01-051 from the CPUC, to extend access to renewable energy to ratepayers that are currently unable to install onsite generation.[62] It offers homes and businesses the option to purchase 50% or 100% of their energy use from solar resources. The program provides those with homes or apartments or businesses that cannot support rooftop solar the opportunity to meet their electricity requirements through renewable energy and support the growth of renewable energy resources.

PG&E's current Solar Choice program costs residential customers an additional 3.58¢/kWh. Given that MRW projects that the CCE can offer 100% green power at ~1.5¢/kWh over its own Scenario 1 or Scenario 2 rate (which is projected to be less than PG&E's), we do not believe PG&E's Community Solar Program will be price competitive with similar CCE product options.

The program is open for enrollment until subscriptions reach 272 MW or January 1, 2019, whichever comes first.[63] While this does limit the ability for PG&E to provide a 100% renewable

[61] PG&E website http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/RFO/CommunitySolarChoice.page?WT.mc_id=Vanity_communitysolarchoice . Accessed 5/16/2016
[62] California Public Utilities Commission, Decision 15-01-051, p.3
[63] Solar Choice Program FAQs website, https://www.pge.com/en/myhome/saveenergymoney/solar/choice/faq/index.page Accessed, 5/16/2016

option in the long-run, at the start of the CCE this program it provides an opportunity for customers who desire 100% renewable power to remain with PG&E.

Differences Between the Analyses for Contra Costa and Alameda Counties

In the first half of 2016, MRW prepared a similar CCE analysis for Alameda County. [64] Although the fundamental approach and results of study and this one are the same, there are several differing assumptions resulting in differing results. If we compare the results of the present study with the results obtained in the Alameda CCE study, we observe that the savings for CCE customers are very similar in both studies, though PG&E rates and CCE rates are both approximately 1¢/kWh higher in the current study than in the prior study (**Table 34**).

Table 34. Average prices for 2018-2030 Scenario 1 for Contra Costa and Alameda County CCE programs

Average Period 2018-2030	Contra Costa County	Alameda County
Price natural gas ($/MMBtu)	5.70	4.90
Wholesale ($/MWh)	51.30	44.80
PG&E Capacity ($/MWh)	74	39
CCE Capacity ($/MWh)	52	39
Wind ($/MWh)	56	57
Solar Distant ($/MWh)	51	51
Solar Local ($/MWh)	70	74
% Local Solar by 2030	25%	10%
PG&E rate (¢/kWh)	11.7	10.4
PCIA rate (¢/kWh)	1.4	1.4
CCE rate (¢/kWh)	9.4	8.3
Difference CCE-PGE (¢/kWh)	2.3	2.1

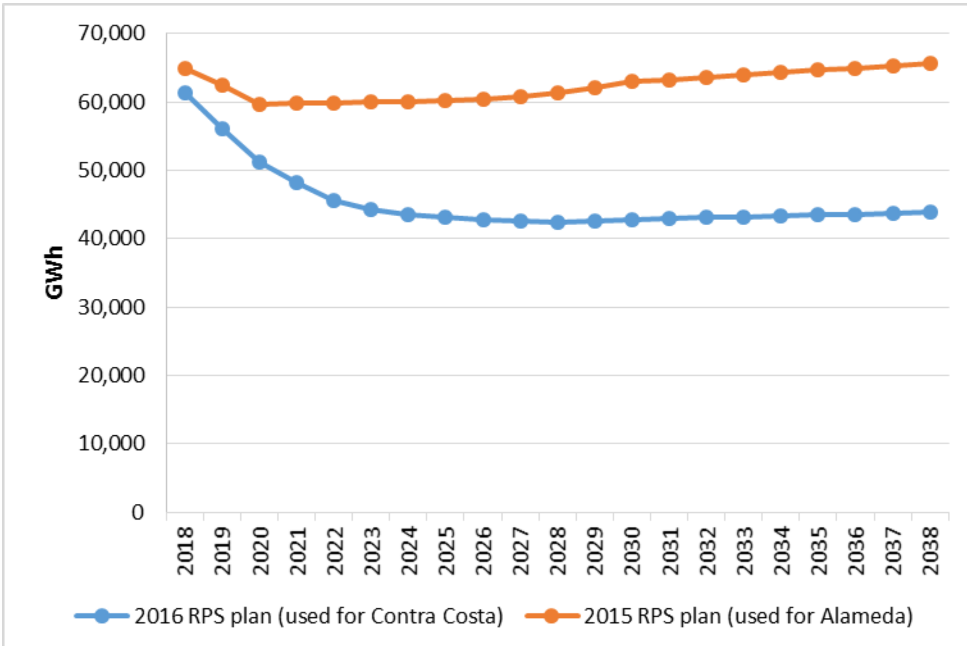
The results of the present study for Contra Costa County differ from the prior results for Alameda County because we updated our forecast to reflect new PG&E rate fillings and other public forecasts. The main changes between the models are as follows:

- **Bundled Load Forecast**: As a result of increased interest in CCE, PG&E's most recent bundled load forecasts are 3% below the previously available forecasts for 2017 and an average of 25% below the previously available forecasts over the 2018-2030 period (see

[64] The final version of the Alameda CCE technical study was published on July 1, 2016. https://www.acgov.org/cda/planning/cca/documents/Feas-TechAnalysisDRAFT5312016.pdf

Figure 32).[65] Less load reduces PG&E's procurement costs, increases the share of fixed costs paid by remaining bundled customers, and increases the revenue provided to bundled customers from CCE exit fees. These effects mostly offset each other, resulting in little net change to bundled rates.[66]

Figure 32: Bundled Load Forecasts used in the Alameda and Contra Costa County Analyses



- **Natural gas prices**: Projections for natural gas prices are about $0.80/MMBtu higher than they were in the spring when the Alameda County report was developed. The higher natural gas prices increase wholesale market prices by $7/MWh (14%).
- **Diablo Canyon Retirement application**: In July 2016, PG&E, together with other entities, submitted a proposal to retire the two units of Diablo Canyon when their licenses expire in November 2024 and August 2025. Per the proposal, PG&E would replace Diablo Canyon production with energy efficiency and greenhouse gas-free generation resources. These resources would include the following: (1) 2,000 GWh of load reduction from additional energy efficiency to be installed by January 2025, (2) 2,000 GWh of load reduction or generation from GHG-free generation resources to be on-line between 2025 and 2030, and (3) a voluntary commitment from PG&E to meet a 55% RPS for 2031-2045 (instead of the

[65] The sources for the 2017 bundled load forecasts are PG&E's 2017 preliminary and final ERRA forecasts. (The June 2016 preliminary forecast was used in the Alameda County CCE study, and the November 2016 final forecast was used in the present study.) The sources for the 2018-2030 bundled load forecasts are PG&E's RPS plans for 2015 (filed in January 2016, used for Alameda County) and for 2016 (draft filed in August 2016, used for Contra Costa).

[66] CCE exit fees are designed so that bundled customers' rates are not affected by CCE departures. In practice, some impact is likely in one direction or the other, and the magnitude and direction of this impact may each vary year by year.

50% requirement currently in effect). The joint proposal estimated that the retirement of Diablo Canyon would result in a need for new generation capacity (“load-resource balance”) around 2030, which is about five years earlier than previously anticipated.

The new energy efficiency resources together with other costs of the nuclear plant retirement would be recovered through non-generation rates (mostly Public Purpose Program and Nuclear Decommissioning charges), and the new RPS resources would be recovered through a new “Clean Energy Charge” applied to all PG&E retail customers. For those load serving entities that are willing to commit to procuring the equivalent new RPS resources, PG&E has proposed a “self-provision” option that would exempt existing DA and CCE loads from the Clean Energy Charge. In the analysis for Contra Costa County, MRW assumed that Contra Costa CCE would choose the “self-provision” option.

MRW assumed for this study that the Diablo Canyon retirement proposal would be adopted, though the proposal is under evaluation by the Commission and is subject to modification. Based on this proposal, we modified the PG&E and Contra Costa County CCE power supply forecasts as follows:[67]

1) PG&E’s RPS requirements were increased for 2030-2038 from 50% to 55%,[68]
2) Contra Costa County CCE’s RPS requirements were increased for 2030-2038 to 55% (vs. the 50% that was used in the Alameda County CCE study), and
3) We began increasing the price of capacity five years earlier than we had in the Alameda County CCE study, reflecting the earlier load-resource balance date due to the retirement of Diablo Canyon. For both Alameda and Contra Costa counties, MRW assumed that the CCEs would build their own power plants (alone or in combination with other public entities) in place of purchasing market capacity when market prices rise above the cost of a new self-build.

[67] We also accounted for the changes in the Public Purpose Program and Nuclear Decommissioning fees in our calculation of the Residential bills.

[68] The generation share of the 2025-2030 commitment for 2,000 GWh of load reduction or GHG-free generation was assumed to be subsumed by procurement needed to meet a 50% RPS by 2030 and therefore did not result in incremental renewable generation in our model.

Chapter 9: Conclusions

Overall, a CCE in Contra Costa County appears feasible. Given current and expected market and regulatory conditions, a Contra Costa County CCE should be able to offer its residents and business electric rates that are less than that available from PG&E.

Sensitivity analyses suggest that these results are relatively robust. Only when very high amounts of renewable energy are assumed in the CCE portfolio (Scenario 3), combined with other negative factors, do PG&E's rates become consistently more favorable than the CCEs.

A Contra Costa County CCE would also be well positioned to help facilitate greater amounts renewable generation to be installed in the County. Because the CCE would have a much greater interest in developing local solar than PG&E, it is much more likely that such development would actually occur with a CCE in the County than without it.

The CCE can also reduce the amount greenhouse gases emitted by the County, but only under certain circumstances. Because PG&E's supply portfolio has significant carbon-free generation (large hydroelectric and nuclear generators), the CCE must contract for significant amounts of carbon-fee power above and beyond the required qualifying renewables in order to actually reduce the County's electric carbon footprint. Therefore, if carbon reductions are a high priority for the CCE, a concerted effort to contract with hydroelectric or other carbon-free generators would be needed.

A CCE can also offer positive economic development and employment benefits to the County. At the peak, the CCE could create approximately 500 to 1000 new jobs in the County, plus an additional 200 jobs in the neighboring counties if local renewable development is prioritized.

While the analytical focus of this report has been on a stand-alone Contra Costa County CCE, that is not the only, nor necessarily best, choice for Contra Costa Communities. Overall, there is insufficient data to suggest that a stand-alone Contra Costa CCE would offer lower rates or greater GHG savings that joining MCE or EBCE. Either forming or joining a CCE would likely offer modestly lower rates and more local economic development that remaining with PG&E. Joining MCE would likely result in the quickest path to CCE implementation, however at a loss of local control and CCE policy formation. Because it has yet to be formed, joining with EBCE would take longer than joining the already-established MCE, but would offer greater input into the CCE's policies and formation.

Although this study suggests CCE program options would likely produce both environmental and economic benefits for the jurisdictions included in the study, continuing service with PG&E remains an option for not only a community but also for any individual or business whose community has selected CCE service. PG&E is an experienced power provider, and is regulated by the state. Furthermore, remaining with PG&E takes no city action. Lastly, simply because a Contra Costa community does not join a CCE in 2017 or 2018 does not necessarily preclude it from doing so in the future, although waiting may result in an "entry fee" or perhaps a high PCIA rate.

DRAFT FOR REVIEW

Technical Study for Community Choice Aggregation Program in Costa County

Appendices

Prepared by:

With

MRW & Associates, LLC
1814 Franklin Street, Ste 720
Oakland, CA 94612

Economic
Development
Research Group
Boston, MA

Sage Renewables
San Francisco, CA

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Appendix A. Loads and Forecast

Appendix B. Power Supply Cost

Appendix C. Forecast of PG&E's Generation Rates

Appendix D. Detailed Pro Forma and CCA Rates

Appendix E. Greenhouse Gas Emissions and Costs

Appendix F. Macroeconomic Analysis

Appendix G. Proforma

Appendix H. MCE and EBCE's Joint Power Agreements

Appendix I. MCE's approval for inclusion of Contra Costa

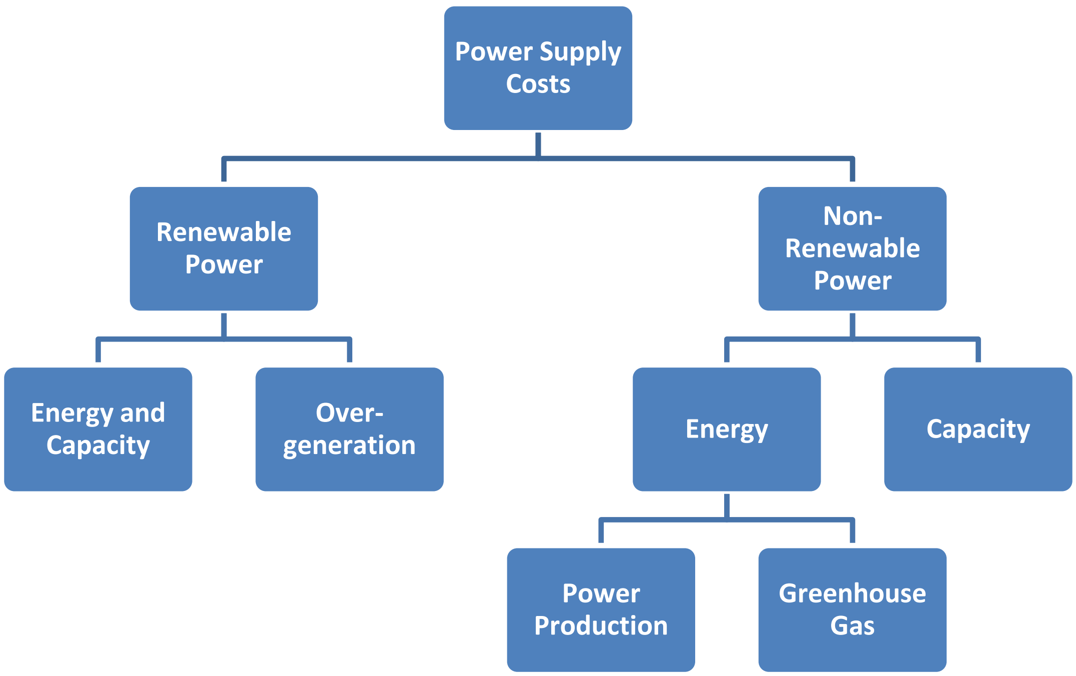
Appendix A. Loads and Forecast

2014 Load (MWh)	Residential	Commercial	Industrial	Public	Street lights + Pumping
UNINCORPORATED	454,716	252,156	237,085	63,574	19,925
CONCORD	269,024	242,584	53,969	18,228	885
PITTSBURG	145,304	134,197	225,362	14,807	1,635
ANTIOCH	270,761	109,487	18,340	18,694	1,077
SAN RAMON	172,364	140,696	32,012	14,458	4,461
BRENTWOOD	150,827	66,635	0	16,407	4,970
DANVILLE	133,085	51,478	0	11,944	1,394
MARTINEZ	86,638	61,730	6,372	6,121	1,140
PLEASANT HILL	82,411	67,087	0	5,905	1,270
OAKLEY	96,389	18,236	0	12,431	901
ORINDA	58,779	14,719	0	39,747	215
HERCULES	48,162	32,749	0	2,751	700
PINOLE	36,629	26,028	0	5,877	963
MORAGA	40,593	8,818	0	3,701	456
CLAYTON	31,795	4,759	0	1,808	661
TOTAL	**2,077,476**	**1,231,360**	**573,139**	**236,454**	**40,652**

Appendix B. Power Supply Cost

MRW has developed a bottoms-up calculation of Costa County CCA's power supply costs, separately forecasting the cost of each power supply element. These elements are renewable energy, non-renewable energy (including power production costs and greenhouse gas costs), resource adequacy (RA) capacity (both renewable and non-renewable supplies) and related costs (e.g., CAISO expenses and broker fees).[1] Figure 1 illustrates the components of Costa County CCA's expected supply costs.

Figure 1: Power Supply Cost Forecast



Renewable Power Cost Forecast

MRW developed a forecast of renewable generation prices starting from an assessment of the current market price for renewable power. For the current market price, MRW relied on wind and solar contract prices reported by California municipal utilities and Community Choice Aggregation (CCA) entities in 2015 and early 2016, finding an average price of $52 per MWh for these contracts.[2]

[1] MRW included a 5.5% adder in the power supply cost for CAISO costs (ancillary services, etc.), and a 5% premium for contracted supplies to reflect broker fees and similar expenses.

[2] MRW relied exclusively on prices from municipal utilities and CCAs because investor-owned utility contract prices from this period are not yet public. We included all reported wind and solar power purchase agreements, excluding local builds (which generally come at a price premium), as reported in California Energy Markets, an

To forecast the future price of renewable purchases, MRW considered a number of factors:

- Researchers from the National Renewable Energy Laboratory (NREL) and Lawrence Berkeley National Laboratory (LBNL) developed a set of forecasts of utility-scale solar costs based on market data and preliminary data from other research efforts.[3] Their base case forecast predicts a 3.8% annual decline in utility-scale solar capital costs on a nominal basis, from $1,932/kW-DC in 2016 to $1,652/kW-DC in 2020, with costs then remaining roughly constant in nominal dollars through 2030.[4] Additional scenarios predict even steeper price declines, with the most aggressive scenario predicting an 11% annual nominal decline through 2020, with increases at the rate of inflation after that.
- The federal Investment Tax Credit (ITC), which is commonly used by solar developers, is scheduled to remain at its current level of 30% through 2019 and then to fall over three years to 10%, where it is to remain.[5] The federal Production Tax Credit, which is commonly used by wind developers, is scheduled to be reduced for facilities commencing construction in 2017-2019 and eliminated for subsequent construction.[6] The loss of these credits would put upward pressure on prices.
- NREL and LBNL researchers predicted in 2015 that the cost increase associated with an ITC reduction would be roughly offset by other solar cost reductions even if the full reduction to 10% were to be implemented by 2018, rather than spread out through 2022 as is currently planned.[7]
- Lawrence Berkeley National Laboratory researchers conducted a study anticipating a reduction of the wind costs of 24% by 2030 and 35% by 2050.[8]

independent news service from Energy Newsdata, from January 2015-January 2016 (see issues dated July 31, August 14, October 16, October 30, 2015, and January 15, 2016).

[3] National Renewable Energy Laboratory. Impact of Federal Tax Policy on Utility-Scale Solar Deployment Given Financing Interactions, September 28, 2015, Slide 16. http://www.nrel.gov/docs/fy16osti/65014.pdf

[4] Ibid. Costs converted to nominal dollars using the inflation forecast used throughout the rate forecast model (U.S. EIA's forecast of the Gross Domestic Product Implicit Price Deflator).

[5] U.S. Department of Energy. Business Energy Investment Tax Credit (ITC). http://energy.gov/savings/business-energy-investment-tax-credit-itc

[6] U.S. Department of Energy. Electricity Production Tax Credit (PTC). http://energy.gov/savings/renewable-electricity-production-tax-credit-ptc

[7] National Renewable Energy Laboratory. Impact of Federal Tax Policy on Utility-Scale Solar Deployment Given Financing Interactions, September 28, 2015, Slide 28.

[8] Lawrence Berkeley National Laboratory . Expert elicitation survey on future wind and energy costs. Nature Energy, September 12th, 2016.

- The production tax credit has been extended six times from 2000-2014,[9] and the solar ITC has been extended three times since 2007.[10] Further tax credit extensions are therefore plausible.
- The major California investor-owned utilities have significantly slowed their renewable procurement because lower-than-expected customer sales and higher-than-expected contracting success rates have led to procurement in excess of the RPS requirements through 2020. When the utilities start ramping their procurement back up to meet the 50%-by-2030 RPS requirement, the supply-demand balance in the market may shift, resulting in higher-than-expected prices unless an increase in suppliers and development opportunities matches the increase in demand.

Given the potential upward price pressures from tax credits that are currently expected to expire and from higher demand for renewable power to meet the 50%-by-2030 requirement and the potential downward price pressures from falling renewable development costs, the possibility for lower cost procurement through the use of RECs, and the possibility that the expiry of the tax credits will be further delayed, it is unclear whether renewable prices will continue to fall (as NREL, LBNL, and others are predicting) or will start to stabilize and rise.

MRW has addressed this uncertainty by considering two scenarios for this sensitivity case:

- In the solar base renewable cost forecast, MRW used the $48.5 per MWh average price of recent municipal utility and CCA solar contracts as the price through 2022 (in nominal dollars), which will increase with inflation in subsequent years. This results in a solar price of $57 per MWh in 2030, and of $67 per MWh in 2038. In the wind base renewable cost forecast, MRW used the $55.0 per MWh average price of recent municipal utility and CCA solar contracts as starting point, and extended it applying an annual decrease of 2% through 2030 and 1% through 2038, offset by inflation. This results in a wind price of $57 per MWh in 2030, and of $62 per MWh in 2038.
- In the high renewable cost scenario, MRW increased both wind and solar base case prices to account for the expected expiration of the tax credits, resulting in average a price of $75 per MWh in 2030 and $86 per MWh in 2038. These scenarios provide a reasonable window of renewable price projections based on current market conditions and analysts' expectations.

MRW used these same renewable prices to calculate PG&E's renewable power costs. However, as described in Appendix B in the PG&E forecast, these renewable energy prices are used only

[9] Union of Concerned Scientists. Production Tax Credit for Renewable Energy. http://www.ucsusa.org/clean_energy/smart-energy-solutions/increase-renewables/production-tax-credit-for.html

[10] Solar Energy Industries Association. Solar Investment Tax Credit. http://www.seia.org/policy/finance-tax/solar-investment-tax-credit; and U.S. Department of Energy. Business Energy Investment Tax Credit (ITC). http://energy.gov/savings/business-energy-investment-tax-credit-itc

for incremental power that is needed above PG&E's existing RPS contracts. For Costa County CCA, these prices are used as the basis for its entire RPS-eligible portfolio.

MRW additionally included a premium for the portion of Costa County CCA's RPS portfolio assumed in each scenario to be located in Costa County County. While solar energy is anticipated to provide the largest share of incremental supply located in-county, the solar resource in Costa County is not as strong as in the areas being developed to supply the contracts discussed above. As a result, the cost of solar generation in Costa County is expected to be higher than the assumed contract prices for non-Costa County supplies. Based on information provided in the CPUC's current RPS calculator, combined with SAGE inputs (performance assumptions and capital cost of the projects[11]), the current cost for solar generation in Costa County is expected to be approximately $68 per MWh. In addition, it is assumed the local solar generation cost will scale with installed capacity, resulting in a local solar generation cost of $82 per MWh for 1000 MW of installed capacity.

Non-Renewable Energy Cost Forecast

MRW separated the costs of non-renewable energy generation into two components: power production costs and greenhouse gas costs. The forecast methodologies for these cost elements, described below, are consistent with the forecast methodologies used for these cost elements in the PG&E rate forecast.

Since natural gas generation is typically on the margin in the California wholesale power market, power production costs for market power are driven by the price for natural gas. MRW forecasted natural gas prices based on current NYMEX market futures prices for natural gas, projected long-term natural gas prices in the EIA's *2016 Annual Energy Outlook,*[12] and PG&E's tariffed natural gas transportation rates.[13] MRW used a standard methodology of multiplying the natural gas price by the expected heat rate for a gas-fired unit and adding in variable operations and maintenance costs to calculate total power production costs.

In addition to power production costs, the cost of energy generated in or delivered to California also includes the cost of greenhouse gas allowances that, per the state's cap-and-trade program, must be procured to cover the greenhouse gases emitted by the energy generation. MRW estimated the price of GHG allowances to equal the auction floor price stipulated by the ARB's cap-and-trade regulation, consistent with recent auction outcomes.[14] MRW estimated the

[11] Capital cost for local solar projects in Contra Costa County, according to SAGE price curve, is $1,350 per kW installed for the first 400MW solar installed in the county. MRW calculated the average price for the cumulative developed capacity forecast for each year (counting only 50% of the capacity of each developed project towards the cumulative total).

[12] U.S. Energy Information Administration. "2016 Annual Energy Outlook," Table 13.

[13] Pacific Gas & Electric, Burnertip Transporation Charges. Tariff G-EG, Advice Letter 3664-G, January 2016 and Tariff G-SUR, Advice Letter 3699-G, April 2016.

[14] California Code of Regulations, Title 17, Article 5, Section 95911.

emissions rate of Costa County CCA non-renewable power supply based on an estimated heat rate for market power multiplied by the emissions factor for natural gas combustion.[15]

Capacity Cost Forecast for Non-Renewable Power

To estimate Costa County CCA's capacity requirements, MRW developed a forecast of Costa County CCA's peak demand in each year and subtracted the net qualifying capacity credits provided by Costa County CCA's renewable power purchases. This is appropriate because the renewable energy prices used in this analysis reflect prices for contracts that supply both energy and capacity. If Costa County CCA purchases renewable energy via energy-only contracts, Costa County CCA's need for capacity will be greater than forecasted here, but these higher costs will be fully offset by the lower costs for the renewable energy.

MRW estimated current peak demand for Costa County CCA's load using the 2015 monthly bills for all the current PG&E clients in Costa County county[16] and PG&E's class-average load profiles. We forecasted changes to this peak demand based on the Contra Costa load forecast.[17] We calculated capacity requirements as 115% of the expected peak demand in order to include sufficient capacity to fulfill resource adequacy requirements. We applied a consistent methodology to obtain the peak demand growth rates and capacity requirements for PG&E.

To estimate the cost of Costa County CCA's capacity needs, MRW priced capacity purchases at the median price of recent Resource Adequacy purchases, escalated with inflation.[18]

To estimate the cost of Costa County CCA's capacity needs, MRW considered two time periods: the period before system load-resource balance when there is excess capacity on the system, and the period following system-load resource balance when additional supply must be developed. MRW assumed a system load-resource balance year of 2030.[19] Through 2025, MRW priced capacity at the median price of recent resource adequacy purchases, escalated with inflation. MRW increased the capacity price incrementally starting in 2026 to reflect an increase in the market price for capacity during the transition from the lower near-term prices to the higher post-load-resource balance prices. MRW assumed that Costa County CCA would build its own power plant (alone or in combination with other public entities) in place of purchasing market capacity when market prices rise above the cost of a new self-build. In MRW's model, this occurs in

[15] U.S. EIA. Electric Power Annual (EPA), February 16, 2016, Table A.3. https://www.eia.gov/electricity/annual/html/epa_a_03.html

[16] Monthly bills corresponding to 2015 for all the clients in Contra Costa County provided by PG&E.

[17] California Energy Commission. Demand Forecast. PG&E Forecast Zone Results Mid Demand Case, Sales Forecast, Central Valley Region. December 14, 2015.

[18] CPUC 2013-2014 Resource Adequacy Report Final, August 5, 2015, page 23 Table 11.

[19] According to the assumption adopted by the CPUC in December 2015 for long-term forecasting purposes, the load resource balance year was 2035. MRW opted to advance this to 2030 due to the retirement of the Diablo Canyon nuclear facility.

2030. From this point on, MRW assumed that the market price for Costa County CCA's capacity would be equal to the levelized fixed cost of a new advanced combustion turbine developed by a publicly owned utility, minus levelized gross margins from energy sales. A similar methodology was used to forecast the cost of capacity for PG&E; however, PG&E's post-load-resource balance price forecast is based on the price of a combustion turbine developed by a merchant developer (see Appendix C).

Appendix C. Forecast of PG&E's Generation Rates

MRW developed a forecast of PG&E's generation rates for comparison with the rates that Costa County CCA will need to charge to cover its costs of service. MRW developed the forecast for the years 2018-2038 using publicly available inputs, including cost and procurement data from PG&E, market price data, and data from California state regulatory agencies and the U.S. Energy Information Administration. The structure of the rate forecast model and the basic assumptions and inputs used are described below.

Generation Charges

PG&E's generation costs fall into four broad categories: (1) renewable generation costs, (2) fixed costs of non-renewable utility-owned generation, (3) fuel and purchased power costs for non-renewable generation, and (4) capacity costs. Each of these categories is evaluated separately in the rate forecast model, and underlying these forecasts is a forecast of PG&E's generation sales.

Sales Forecast

PG&E's generation cost forecast is driven in large part by the amount of generation that PG&E will need to obtain to meet customer demand. To forecast PG&E's electricity sales, MRW started with the 2016-2030 sales forecast that PG&E provided in its August 2016 Renewable Energy Procurement Plan ("RPS Plan") filing with the CPUC.[20] This forecast predicts an 8% annual sales reduction through 2020, a 2% reduction per year from 2021-2028, and a rather anemic sales growth of 0.2% per year from 2029-2030.[21] MRW extended the sales forecast through 2038, maintaining this 0.2% increase per year.

Renewable Generation

The starting point for MRW's analysis is PG&E's "RPS Plan," in which PG&E discusses its plan for meeting California's Renewable Portfolio Standard (RPS) targets and provides the annual amount and cost of renewable generation currently under contract through 2030. PG&E's RPS Plan shows that PG&E's current renewable procurement is in excess of the RPS requirement in each year through 2026. After 2022, PG&E's renewable generation from current contracts falls below the RPS requirements, but PG&E is projected to have enough banked Renewable Energy Credits (RECs) from excess renewable procurement in prior years to meet the RPS requirements until 2034.

[20] Pacific Gas & Electric. *Renewables Portfolio Standard 2016 Renewable Energy Procurement Plan (Draft Version).* August 8, 2016. Appendix D.

[21] The near-term decline in sales in PG&E's forecast is likely attributable to the growth in CCA, in which a municipality procures electric power on behalf of its constituents instead of having them purchase their power from PG&E. While customers in the jurisdictions of these municipalities have the option to opt-out of CCA and to continue to procure power from PG&E, so far, most CCA-eligible customers have not elected for this option. CCA customers continue to procure electricity delivery services from PG&E; it is only generation services that they obtain through the CCA.

MRW adopted PG&E's RPS Plan forecast of the amount and cost of renewable generation that is currently under contract. For the period starting in 2034 when PG&E's RPS Plan shows a need for incremental renewable procurement to meet RPS requirements, MRW added in the necessary renewable generation to meet current statutory requirements (i.e., 33% of procurement in 2020, increasing to 50% of procurement in 2030, and to 55% of procurement in 2031).[22] To project PG&E's cost of this incremental renewable generation, MRW used the same renewable prices used for Costa County CCA's renewable power cost forecast (see Appendix B).

Fixed Cost of Non-Renewable Utility-Owned Generation

PG&E's rates include payment for the fixed costs of the PG&E-owned non-renewable generation facilities, which are primarily natural gas, nuclear, and hydroelectric power plants. Because these costs are not tied to the volume of electricity that PG&E sells, their annual escalation is not driven by the price of fuel and other variable inputs. Instead, they escalate at a rate that stems from a combination of cost increases and depreciation reductions. These escalation rates are determined in General Rate Case (GRC) proceedings, which occur roughly every three years.

As a starting point for the forecast, MRW used the proposed 2017 fixed costs for these facilities.[23] For the period between 2018 and 2020, MRW increased the fixed cost based on PG&E's 2017 GRC settlements.[24] For subsequent years, MRW estimated in the base case that PG&E's generation fixed costs would increase by the 6.2% annual average growth rate approved and implemented for these cost over the last ten years.[25] These escalation rates are in nominal dollars (i.e., some of the escalation is accounted for by inflation).

[22] MRW additionally allowed for the purchase of additional renewable generation when renewable prices are below market prices, subject to some purchase limits, including a 50% cap on renewable generation relative to the entire generation portfolio. This leads to additional renewable purchases from 2027-2029 in the Low Renewable Price scenario. Starting in 2030, the RPS requirement is 50%, and no additional renewable purchases are allowed, per the rules of the model, in order to maintain grid reliability.

[23] Pacific Gas & Electric. Annual Electric True-Ups for 2017. Advice Letter 4902 E-A. September 13, 2016. Table 2 and Pacific Gas & Electric 2017 GRC Settlements, A.15-09-001, Appendix A and B.

[24] Pacific Gas & Electric 2017 GRC Settlements, A.15-09-001, Appendix A and B

[25] Historic growth rates calculated from Pacific Gas & Electric Advice Letters 2706-E-A, AL 3773-E, 4459-E, 4647-E, and 4755-E. New power plant costs were excluded from these calculations since costs of new plants are offset, at least in part, by a reduction in fuel and purchased power costs.

Table 1: PG&E's Generation Fixed Costs, 2011-2016[26]
(Nominal $ Million)

	2011	2012	2013	2014	2015	2016
Generation Fixed Costs	1,400	1,530	1,550	1,710	1,860	1,840
Annual Cost Increase		9%	1%	10%	9%	-1%

MRW made adjustments to this GRC forecast to account for the retirement of the Diablo Canyon nuclear units at the end of the units' current licenses in 2024 and 2025.

Fuel and Purchased Power Costs for Non-Renewable Generation

Each spring, PG&E files a forecast with the CPUC of its fuel and purchased power costs for the upcoming year in its "ERRA" filing, which PG&E updates and finalizes in November. MRW relied on PG&E's November 2017 ERRA testimony,[27] adjusted to remove renewable generation costs, as the starting point for the forecast of fuel and purchased power costs for PG&E's non-renewable generation.

To escalate these costs through the forecast period, MRW forecasted changes to natural gas prices and greenhouse gas cap-and-trade program compliance costs, which are the major drivers of change to these costs. The natural gas price forecast is based on current NYMEX market futures prices for natural gas, forecasted natural gas prices in the U.S. EIA's 2016 *Annual Energy Outlook*, and PG&E's tariffed natural gas transportation rates. This forecast is the same forecast used in the forecast of Costa County CCA's wholesale power costs (see Appendix B).

Cap-and-trade program compliance costs are estimated based on (1) PG&E's forecast of carbon dioxide emissions in 2017;[28] (2) a forecast of PG&E's fossil generation supply, developed by subtracting expected renewable, hydroelectric, and nuclear generation from PG&E's projected wholesale power requirement; and (3) a forecast of greenhouse gas allowance prices. The greenhouse gas allowance price forecast is the same as used in the forecast of Costa County CCA wholesale power costs and is based on the auction floor price stipulated by the ARB's cap-and-trade regulation (see Appendix B).

[26] 2011-2013: CPUC Decision 11-05-018, pages 2 and 15; and 2014-2016: CPUC Decision 14-08-032, Appendix C, Table 1 and Appendix D, Table 1.

[27] PG&E Update To Prepared 2017 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation, filed with the CPUC in proceeding A.16-06-003 on Nov 2, 2016, Table 11-3.

[28] PG&E Update To Prepared 2017 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation, filed with the CPUC in proceeding A.16-06-003 on Nov 2, 2016, Table 12-2.

The MRW rate model calculates total fuel and purchased power costs by escalating natural gas prices based on the natural gas price forecast described above, escalating nuclear fuel prices based on the EIA forecast of fuel costs for nuclear plants, escalating water costs for hydroelectric projects and the capacity costs of power purchase contracts with inflation, and pricing market power at the same market power price used for Costa County CCA's purchases. The model then sums the cost for each of these resources and adds in projected cap-and-trade compliance costs to this total cost.

Capacity Costs

PG&E must procure capacity to meet 115% of its anticipated peak demand in order to fulfill its resource adequacy requirement. PG&E's own power plants can be used to meet this requirement, as can power plants with which PG&E has contracts.

To estimate PG&E's capacity requirements, MRW started with the Capacity Supply Plan that PG&E submitted to the California Energy Commission in 2015,[29] which forecasts PG&E's peak demand and existing capacity resources for each of the years 2013-2024. With limited exception,[30] MRW used PG&E's data where publicly available and extended the forecasts to 2038. In extending these forecasts, we used assumptions that are consistent with those used in our assessments of energy sales and costs, including load growth escalation and the projected retirement of PG&E's nuclear plant. We also added in anticipated capacity from new renewable procurement and from new energy storage and adjusted the calculation to account for the portion of Resource Adequacy credits that is allocated to non-bundled customers.

As with the Costa County CCA's capacity cost forecast, MRW priced capacity at the median price of recent Resource Adequacy capacity sales, escalated with inflation.[31]

Rate Development

Following the methodologies described above, MRW developed a forecast of PG&E's generation revenue requirement and divided these expenses by the expected PG&E sales in order to obtain a forecast of the system-average generation rate. We calculated annual escalators based on these system-average rates and applied them to the generation rates that are currently in effect for each customer class.[32]

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[29] California Energy Commission, Energy Almanac, Utility Capacity Supply Plans from 2015. September 4, 2015

[30] The two main exceptions are that 1) MRW increased energy efficiency and demand response growth to comply with SB 350 requirements to double energy efficiency by 2030 and the anticipated continuation of CPUC demand response initiatives, and 2) MRW accounted for the energy efficiency and renewable capacity expected to be installed because of the Diablo Canyon retirement application.

[31] CPUC 2013-2014 Resource Adequacy Report Final, August 5, 2015, page 23 Table 11.

[32] PG&E Advice Letter AL-4805-E, effective March 24, 2016.

Appendix D. Detailed Pro Forma and CCA Rates

Case-Legend	
Base	BASE
Low participation	LP
High price local	LOC
High renewable prices	RPS
High natural gas price	GAS
Low PG&E portfolio costs	LPGE
High PCIA	PCIA
Stress Scenario	STRS

Scenario	Sensitivity Case	Rates (¢/kWh)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	BASE	CCA gen	7.0	7.1	7.1	7.4	7.6	7.8	7.9	8.0	8.4	8.8	9.3	9.9	10.5	10.8	11.1	11.4	11.7	12.0	12.4	12.7	13.1
1	BASE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
1	BASE	CCA Res Fund	0.8	0.7	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	BASE	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
1	LP	CCA gen	7.1	7.2	7.2	7.5	7.7	7.9	8.0	8.1	8.5	8.9	9.4	9.9	10.5	10.8	11.1	11.4	11.8	12.1	12.4	12.8	13.2
1	LP	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
1	LP	CCA Res Fund	0.6	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	LP	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
1	LOC	CCA gen	7.0	7.1	7.1	7.4	7.6	7.8	7.9	8.0	8.4	8.8	9.3	9.9	10.5	10.8	11.1	11.4	11.7	12.0	12.4	12.7	13.1
1	LOC	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
1	LOC	CCA Res Fund	0.8	0.7	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	LOC	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
1	RPS	CCA gen	7.1	7.2	7.3	7.8	8.1	8.5	8.6	8.8	9.2	9.7	10.2	10.8	11.4	11.8	12.2	12.5	12.9	13.2	13.6	14.0	14.4
1	RPS	Exit fees	2.4	1.9	2.3	1.6	1.6	1.5	1.3	1.1	0.9	0.7	0.6	0.5	0.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0
1	RPS	CCA Res Fund	0.7	0.7	0.4	0.1	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	RPS	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.5	11.4	11.1	11.5	12.2	12.9	13.8	14.9	15.7	16.5	17.3	17.3	17.8	18.4	18.7	19.4
1	GAS	CCA gen	8.1	8.5	8.8	9.2	9.5	9.4	9.4	9.6	10.0	10.4	10.8	11.3	11.9	12.3	12.6	12.9	13.3	13.7	14.2	14.6	15.0
1	GAS	Exit fees	2.2	2.6	2.7	2.8	2.6	3.4	2.4	1.7	0.8	0.7	0.7	0.6	0.5	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1
1	GAS	CCA Res Fund	0.2	-0.1	0.0	0.0	0.0	0.0	0.0	1.4	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	GAS	PG&E gen	10.5	10.9	11.0	11.4	11.9	11.0	11.3	11.8	12.3	12.9	13.5	14.3	15.3	15.4	15.8	16.2	16.7	17.1	17.7	18.3	19.0
1	LPGE	CCA gen	7.0	7.1	7.1	7.4	7.6	7.8	7.9	8.0	8.4	8.8	9.3	9.9	10.5	10.8	11.1	11.4	11.7	12.0	12.4	12.7	13.1
1	LPGE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
1	LPGE	CCA Res Fund	0.0	1.1	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	LPGE	PG&E gen	9.1	9.5	9.6	10.1	10.4	10.2	10.2	9.8	10.2	10.7	11.4	12.1	13.0	13.2	13.6	14.0	14.5	14.9	15.3	15.8	16.4
1	PCIA	CCA gen	7.0	7.1	7.1	7.4	7.6	7.8	7.9	8.0	8.4	8.8	9.3	9.9	10.5	10.8	11.1	11.4	11.7	12.0	12.4	12.7	13.1
1	PCIA	Exit fees	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

1	PCIA	CCA Res Fund	0.8	0.7	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	PCIA	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
1	STRS	CCA gen	8.2	8.7	9.1	9.6	9.9	10.1	10.2	10.3	10.8	11.2	11.7	12.3	12.9	13.3	13.7	14.1	14.6	15.0	15.4	15.9	16.4
1	STRS	Exit fees	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
1	STRS	CCA Res Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	STRS	PG&E gen	9.4	9.8	9.9	10.2	10.7	9.9	10.2	10.6	11.3	11.8	12.4	13.2	14.0	14.3	14.8	15.3	15.7	16.2	16.8	17.4	18.1

Scenario	Sensitivity Case	Rates (¢/kWh)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
2	BASE	CCA gen	7.2	7.3	7.3	7.6	7.8	8.0	8.0	8.3	8.6	9.1	9.5	10.0	10.6	10.8	11.1	11.3	11.6	11.9	12.1	12.4	12.7
2	BASE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
2	BASE	CCA Res Fund	0.6	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
2	BASE	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
2	LP	CCA gen	7.3	7.4	7.4	7.6	7.8	8.1	8.1	8.3	8.7	9.1	9.6	10.1	10.6	10.9	11.1	11.4	11.7	11.9	12.2	12.5	12.8
2	LP	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
2	LP	CCA Res Fund	0.5	0.9	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
2	LP	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
2	LOC	CCA gen	7.2	7.3	7.3	7.6	7.8	8.0	8.0	8.3	8.6	9.1	9.5	10.0	10.6	10.8	11.1	11.3	11.6	11.9	12.1	12.4	12.7
2	LOC	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
2	LOC	CCA Res Fund	0.6	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
2	LOC	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
2	RPS	CCA gen	7.3	7.5	7.6	8.2	8.5	9.1	9.2	9.5	10.0	10.5	11.0	11.6	12.3	12.5	12.8	13.1	13.4	13.7	14.0	14.4	14.7
2	RPS	Exit fees	2.4	1.9	2.3	1.6	1.6	1.5	1.3	1.1	0.9	0.7	0.6	0.5	0.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0
2	RPS	CCA Res Fund	0.5	0.9	0.4	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
2	RPS	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.5	11.4	11.1	11.5	12.2	12.9	13.8	14.9	15.7	16.5	17.3	17.3	17.8	18.4	18.7	19.4
2	GAS	CCA gen	8.0	8.3	8.7	9.0	9.3	8.9	9.0	9.2	9.6	9.9	10.3	10.8	11.3	11.6	11.9	12.2	12.5	12.8	13.1	13.4	13.8
2	GAS	Exit fees	2.2	2.6	2.7	2.8	2.6	3.4	2.4	1.7	0.8	0.7	0.7	0.6	0.5	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1
2	GAS	CCA Res Fund	0.3	0.0	-0.1	0.0	1.4	-1.4	0.0	1.4	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
2	GAS	PG&E gen	10.5	10.9	11.0	11.4	11.9	11.0	11.3	11.8	12.3	12.9	13.5	14.3	15.3	15.4	15.8	16.2	16.7	17.1	17.7	18.3	19.0
2	LPGE	CCA gen	7.2	7.3	7.3	7.6	7.8	8.0	8.0	8.3	8.6	9.1	9.5	10.0	10.6	10.8	11.1	11.3	11.6	11.9	12.1	12.4	12.7
2	LPGE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
2	LPGE	CCA Res Fund	0.0	1.1	0.0	0.4	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
2	LPGE	PG&E gen	9.1	9.5	9.6	10.1	10.4	10.2	10.2	9.8	10.2	10.7	11.4	12.1	13.0	13.2	13.6	14.0	14.5	14.9	15.3	15.8	16.4
2	PCIA	CCA gen	7.2	7.3	7.3	7.6	7.8	8.0	8.0	8.3	8.6	9.1	9.5	10.0	10.6	10.8	11.1	11.3	11.6	11.9	12.1	12.4	12.7
2	PCIA	Exit fees	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

2	PCIA	CCA Res Fund	0.6	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
2	PCIA	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
2	STRS	CCA gen	8.2	8.6	9.0	9.7	9.9	10.1	10.2	10.5	10.9	11.4	11.9	12.4	13.0	13.4	13.7	14.0	14.4	14.7	15.1	15.4	15.8
2	STRS	Exit fees	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
2	STRS	CCA Res Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	STRS	PG&E gen	9.4	9.8	9.9	10.2	10.7	9.9	10.2	10.6	11.3	11.8	12.4	13.2	14.0	14.3	14.8	15.3	15.7	16.2	16.8	17.4	18.1

Scenario	Sensitivity Case	Rates (¢/kWh)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
3	BASE	CCA gen	7.0	7.1	7.2	7.5	7.8	8.1	8.2	8.5	8.9	9.5	10.0	10.5	11.1	11.5	11.8	12.1	12.4	12.8	13.1	13.4	13.8
3	BASE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
3	BASE	CCA Res Fund	0.7	0.7	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	BASE	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
3	LP	CCA gen	7.2	7.3	7.3	7.6	7.9	8.2	8.3	8.5	8.9	9.5	10.0	10.5	11.1	11.5	11.8	12.1	12.4	12.8	13.1	13.4	13.8
3	LP	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
3	LP	CCA Res Fund	0.6	0.8	0.4	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	LP	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
3	LOC	CCA gen	7.1	7.2	7.3	7.7	8.0	8.3	8.5	8.7	9.3	9.9	10.4	11.0	11.6	12.0	12.3	12.6	13.0	13.3	13.6	14.0	14.4
3	LOC	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
3	LOC	CCA Res Fund	0.7	0.7	0.4	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	LOC	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
3	RPS	CCA gen	7.1	7.2	7.4	7.9	8.3	8.9	9.1	9.4	10.0	10.6	11.2	11.8	12.5	12.9	13.3	13.7	14.1	14.4	14.8	15.2	15.6
3	RPS	Exit fees	2.4	1.9	2.3	1.6	1.6	1.5	1.3	1.1	0.9	0.7	0.6	0.5	0.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0
3	RPS	CCA Res Fund	0.7	0.7	0.4	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	RPS	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.5	11.4	11.1	11.5	12.2	12.9	13.8	14.9	15.7	16.5	17.3	17.3	17.8	18.4	18.7	19.4
3	GAS	CCA gen	8.1	8.5	8.9	9.3	9.5	9.6	9.8	10.0	10.5	11.0	11.5	12.0	12.6	13.0	13.3	13.7	14.1	14.5	14.9	15.3	15.8
3	GAS	Exit fees	2.2	2.6	2.7	2.8	2.6	3.4	2.4	1.7	0.8	0.7	0.7	0.6	0.5	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1
3	GAS	CCA Res Fund	0.2	-0.1	0.0	0.0	0.0	0.0	0.0	1.5	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	GAS	PG&E gen	10.5	10.9	11.0	11.4	11.9	11.0	11.3	11.8	12.3	12.9	13.5	14.3	15.3	15.4	15.8	16.2	16.7	17.1	17.7	18.3	19.0
3	LPGE	CCA gen	7.0	7.1	7.2	7.5	7.8	8.1	8.2	8.5	8.9	9.5	10.0	10.5	11.1	11.5	11.8	12.1	12.4	12.8	13.1	13.4	13.8
3	LPGE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
3	LPGE	CCA Res Fund	0.0	1.1	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	LPGE	PG&E gen	9.1	9.5	9.6	10.1	10.4	10.2	10.2	9.8	10.2	10.7	11.4	12.1	13.0	13.2	13.6	14.0	14.5	14.9	15.3	15.8	16.4
3	PCIA	CCA gen	7.0	7.1	7.2	7.5	7.8	8.1	8.2	8.5	8.9	9.5	10.0	10.5	11.1	11.5	11.8	12.1	12.4	12.8	13.1	13.4	13.8
3	PCIA	Exit fees	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

3	PCIA	CCA Res Fund	0.7	0.7	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	PCIA	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
3	STRS	CCA gen	8.3	8.8	9.2	9.8	10.2	10.8	11.0	11.4	12.1	12.8	13.3	14.0	14.7	15.2	15.7	16.2	16.7	17.1	17.6	18.1	18.6
3	STRS	Exit fees	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
3	STRS	CCA Res Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	STRS	PG&E gen	9.4	9.8	9.9	10.2	10.7	9.9	10.2	10.6	11.3	11.8	12.4	13.2	14.0	14.3	14.8	15.3	15.7	16.2	16.8	17.4	18.1

Scenario	Sensitivity Case	Rates (¢/kWh)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
4	BASE	CCA gen	7.3	7.4	7.5	7.9	8.2	8.6	8.8	9.3	10.0	10.7	11.2	11.8	12.5	12.7	13.0	13.2	13.5	13.8	14.1	14.3	14.6
4	BASE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
4	BASE	CCA Res Fund	0.5	0.8	0.4	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
4	BASE	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
4	LP	CCA gen	7.4	7.5	7.6	7.9	8.2	8.6	8.8	9.3	9.9	10.7	11.2	11.7	12.3	12.6	12.8	13.1	13.3	13.6	13.9	14.2	14.5
4	LP	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
4	LP	CCA Res Fund	0.4	0.9	0.4	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
4	LP	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
4	LOC	CCA gen	7.3	7.5	7.6	8.0	8.4	8.9	9.2	9.8	10.6	11.4	12.0	12.6	13.3	13.5	13.8	14.1	14.4	14.7	14.9	15.2	15.6
4	LOC	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
4	LOC	CCA Res Fund	0.5	0.9	0.4	0.1	0.1	0.1	0.1	-0.2	-0.1	-0.3	0.0	1.2	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
4	LOC	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
4	RPS	CCA gen	7.3	7.6	7.8	8.5	9.0	9.9	10.3	11.0	11.8	12.7	13.4	14.1	14.9	15.2	15.5	15.8	16.1	16.5	16.8	17.1	17.5
4	RPS	Exit fees	2.4	1.9	2.3	1.6	1.6	1.5	1.3	1.1	0.9	0.7	0.6	0.5	0.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0
4	RPS	CCA Res Fund	0.4	0.9	0.4	0.1	0.1	0.1	-0.2	-0.9	-0.3	0.0	0.0	0.0	0.0	2.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1
4	RPS	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.5	11.4	11.1	11.5	12.2	12.9	13.8	14.9	15.7	16.5	17.3	17.3	17.8	18.4	18.7	19.4
4	GAS	CCA gen	8.0	8.4	8.8	9.1	9.4	9.5	9.8	10.3	11.0	11.7	12.2	12.7	13.3	13.6	13.9	14.3	14.6	14.9	15.2	15.5	15.9
4	GAS	Exit fees	2.2	2.6	2.7	2.8	2.6	3.4	2.4	1.7	0.8	0.7	0.7	0.6	0.5	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1
4	GAS	CCA Res Fund	0.2	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	1.6	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
4	GAS	PG&E gen	10.5	10.9	11.0	11.4	11.9	11.0	11.3	11.8	12.3	12.9	13.5	14.3	15.3	15.4	15.8	16.2	16.7	17.1	17.7	18.3	19.0
4	LPGE	CCA gen	7.3	7.4	7.5	7.9	8.2	8.6	8.8	9.3	10.0	10.7	11.2	11.8	12.5	12.7	13.0	13.2	13.5	13.8	14.1	14.3	14.6
4	LPGE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
4	LPGE	CCA Res Fund	0.0	1.1	-0.2	0.7	0.1	0.1	-0.1	-0.8	-0.4	0.0	0.0	0.0	0.0	1.9	0.0	0.0	0.0	0.0	0.0	0.1	0.1
4	LPGE	PG&E gen	9.1	9.5	9.6	10.1	10.4	10.2	10.2	9.8	10.2	10.7	11.4	12.1	13.0	13.2	13.6	14.0	14.5	14.9	15.3	15.8	16.4
4	PCIA	CCA gen	7.3	7.4	7.5	7.9	8.2	8.6	8.8	9.3	10.0	10.7	11.2	11.8	12.5	12.7	13.0	13.2	13.5	13.8	14.1	14.3	14.6
4	PCIA	Exit fees	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

4	PCIA	CCA Res Fund	0.5	0.8	0.4	0.1	0.1	0.1	0.0	-0.8	-0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	0.0	0.1	0.1
4	PCIA	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
4	STRS	CCA gen	8.3	8.8	9.3	10.0	10.5	11.4	11.8	12.7	13.6	14.7	15.4	16.1	16.8	17.2	17.6	18.0	18.4	18.9	19.3	19.7	20.2
4	STRS	Exit fees	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
4	STRS	CCA Res Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	STRS	PG&E gen	9.4	9.8	9.9	10.2	10.7	9.9	10.2	10.6	11.3	11.8	12.4	13.2	14.0	14.3	14.8	15.3	15.7	16.2	16.8	17.4	18.1

Appendix E. Greenhouse Gas Emissions and Costs

In Chapter 3 of the report, MRW provided an estimate of Costa County CCA's annual Greenhouse Gas (GHG) emissions and compared these with the emissions for the same load under the PG&E supply portfolio. The methodology used to calculate both figures is included in this appendix, along with an estimate of Costa County CCA's cost of emissions from purchased power ("indirect emissions").

Methodology for calculating Costa County CCA's indirect GHG emissions

GHG emissions for Costa County CCA will be indirect since the CCA does not plan to generate its own power (*i.e.*, the emissions are embedded in fossil-fuel power that the CCA purchases). These emissions are estimated based on (1) a forecast of the emissions rate for Costa County CCA's fossil generation supply and (2) a forecast of the amount of Costa County CCA's fossil generation supply, developed by subtracting expected renewable and hydroelectric generation from the projected wholesale power requirement to serve the CCA's load.[33]

MRW calculated the emissions rate for Costa County CCA's fossil generation supply by estimating the amount of natural gas that will need to be burned to generate the CCA's fossil generation and the GHG emissions rate for natural gas combustion.[34] The amount of natural gas needed was estimated based on the average heat rate for the marginal generation plants on the CAISO system. MRW used public data from CAISO's OASIS platform and Platt's Gas Daily reports to calculate this average heat rate for 2015.[35] MRW extended the forecast to 2030 using the expected changes to the average heat rate in California from the EIA's 2016 *Annual Energy Outlook.*[36]

MRW estimated the total annual GHG emissions for the Costa County CCA program as a product of the total energy purchased at wholesale electric market (kWh) and the rate of GHG emissions (tonnes $CO_{2\text{-equivalent}}$/kWh).

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[33] MRW assumed no GHG emissions for the renewable and hydroelectric supply.

[34] The GHG emissions rate for natural gas combustion is obtained from U.S. EIA. Electric Power Annual (EPA), February 16, 2016, Table A.3. https://www.eia.gov/electricity/annual/html/epa_a_03.html

[35] MRW calculated the average heat rate of the marginal generation plants in 2015 by dividing the monthly average wholesale electric market price, net of operations and maintenance costs and GHG emissions costs, by the monthly average natural gas price. For the electricity prices, we used the average of the 2015 hourly locational marginal price for node TH_NP15_GEN-APND; for the natural gas prices, we used the average of burnertip natural gas price for PG&E.

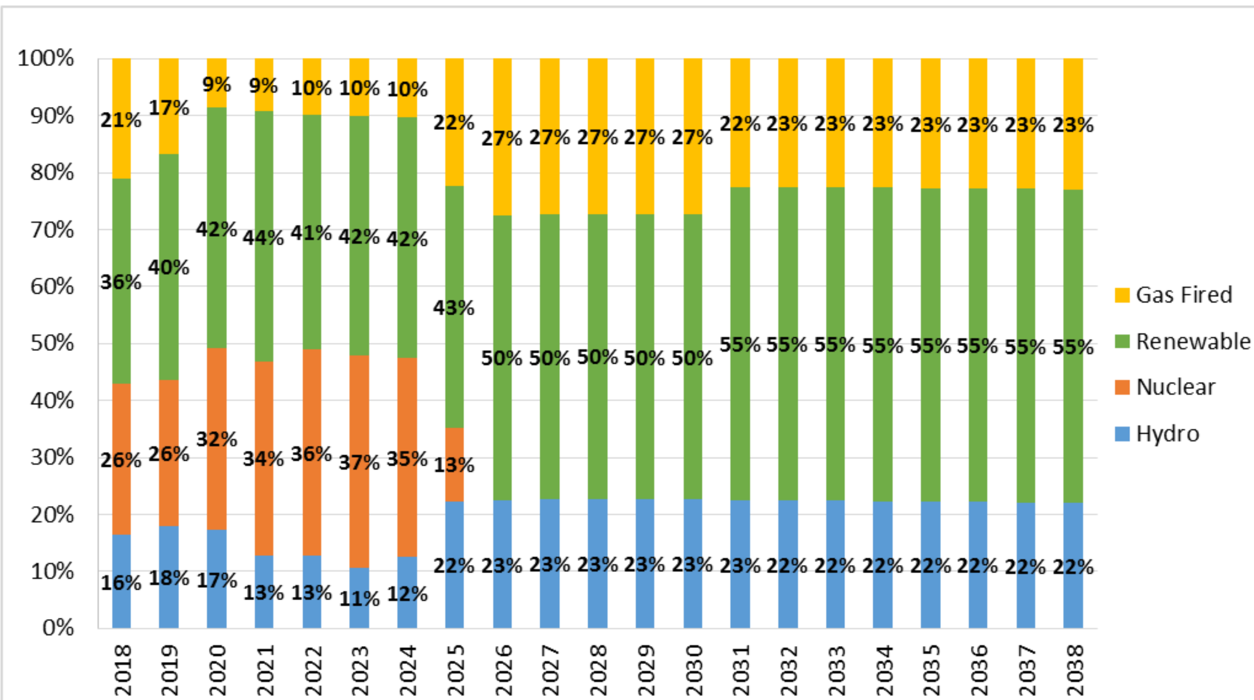
[36] U.S. Energy Information Administration. "2016 Annual Energy Outlook," Table 55.20, Western Electricity Coordinating Council. (Note that EIA does not provide a forecast of the marginal heat rate.)

Methodology for calculating GHG emissions under PG&E's supply portfolio

MRW calculated the GHG emissions for the Costa County CCA load under the PG&E supply portfolio by summing the emissions from all resources in PG&E's portfolio. MRW assumed no GHG emissions from renewable power, hydroelectric power, or nuclear generation. In order to maintain a consistent comparison, MRW used the same emissions rate to calculate the emissions from PG&E's fossil-fuel power as used for the Costa County CCA wholesale market purchases.

In order to support the analysis on Chapter 3 of the report, Figure 2 shows the PG&E portfolio. Before the closure of the Diablo Canyon, MRW estimated 80%-90% of PG&E's generation portfolio based on non-fuel-fired resources. After 2025, the non-fuel-fired resources share falls to 70% according MRW estimates.

Figure 2 PG&E's generation portfolio[37]



GHG allowance prices and GHG indirect costs

[37] Before 2025 the hydroelectric generation is below its potential because MRW estimated that PG&E sells the over-procurement in hydroelectric power. MRW has assumed a minimum of fuel-fired generation to facilitate the RPS integration according to PG&E's Diablo Canyon retirement application, A.16-08-006. Table 2-3. In addition, after 2026 MRW estimated the price of the wholesale electric market below PG&E's new RPS prices. In those conditions, according to MRW assumptions, PG&E would procure up to 50% of its portfolio from renewable resources.

MRW developed a forecast of the prices for GHG allowances based on the auction floor price stipulated by the ARB's cap-and-trade regulation, consistent with recent auction outcomes.[38]

Table 2 GHG Allowances price, $ per allowance[39]

	2017	2018	2019	2025	2030	2035	2038
$/tonne	13.2	14.7	15.9	24.4	34.7	49.8	61.8

MRW used these GHG allowances prices to calculate both PG&E's GHG allowances costs (direct and indirect), which are included in the PG&E rate forecast, and Costa County CCA's indirect GHG costs. The indirect GHG costs for Costa County CCA will be included in the cost of the wholesale market energy purchases. MRW estimated that these costs will be, on average, $12 per MWh delivered over the 2018-2038 period.

[38] California Code of Regulations, Title 17, Article 5, Section 95911.

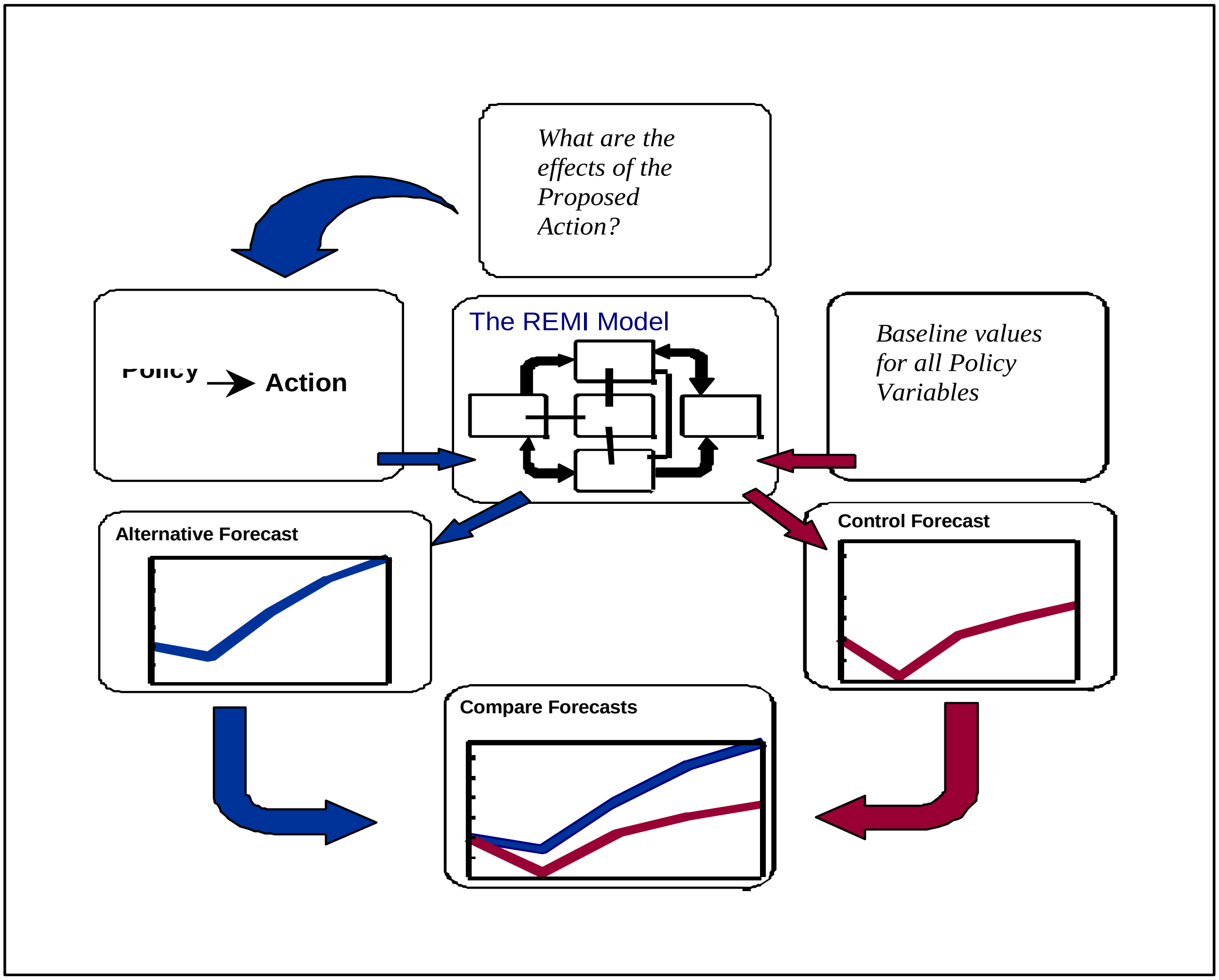
[39] For 2017, the amount listed corresponds to the GHG allowance price for PG&E according to the most recent ERRA 2017 update. Pacific Gas & Electric ERRA 2017, A.16-06-003, Testimony November 2, 2016, Table 12-1.

Appendix F. Macroeconomic Analysis

About the REMI Policy Insight Model

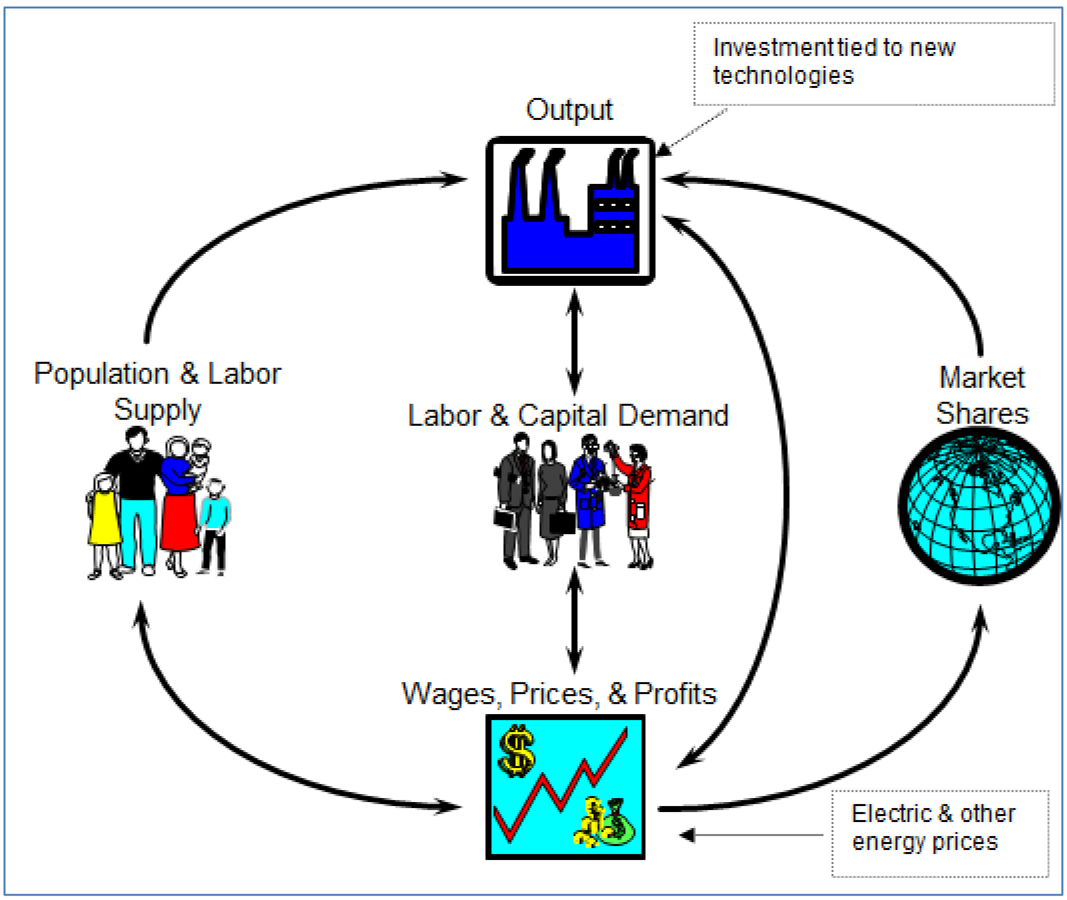
A software analysis forecasting model developed by Regional Economic Models, Inc. (REMI) of Amherst Massachusetts in the mid 1980's. It has a broad national customer base among public agencies, academic institutions, and the private-sector. It is also used in Canada (NRCan), and among other international clients. The model configuration used for this study consisted of 18 aggregate private-sector industries, plus a farm sector, a combined state/local government sector and two federal government sectors.

Economic Impacts Identified with the REMI Model



In the above figure, the central box "The REMI model" is the engine for predicting the economic and demographic dimensions of a *region-of-impact* (here Costa County County) under *no-action* (or Control forecast) and with a proposed CCA (alternative forecast). The engine is a combination structural econometric model, part input-output transactions, all with general equilibrium features – meaning *an economy can encounter a disruption (positive or negative), and over time (typically 1-3 years depending on the scale of the region and the size of the shock) re-adjust back to an equilibrium*. The diagram below depicts the organization of the REMI regional model in terms of the major blocks functioning in an economy and the arrows denote the feedback accounted for. Keep in mind this portrayal is at a very high-level, sparing the industry-specific details. Scenario specific changes are inserted through policy variable *levers* into the appropriate block of the model. There is another important dimension of economic response for the key region-of-impact that effectively layers on top of the below diagram – interactions with another regional economy. That additional region - *rest of California* -was explicitly modeled at the same time. The REMI model captures the flows of monetized goods and services, and commuter labor between regions when one (or both) is *shocked* by introduction of a CCA.

Core Logic of the REMI Model



Appendix G. Proforma

Scenario 1

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Expenses																					
Cost of Power (including losses)	$73,495,453	$151,069,291	$238,312,375	$248,611,457	$257,237,071	$265,886,720	$274,183,543	$279,728,463	$294,209,869	$310,824,883	$329,903,546	$350,515,984	$373,621,644	$386,946,608	$399,254,590	$411,812,091	$425,651,977	$439,658,506	$454,135,582	$468,721,683	$484,831,280
O&M/A&G Costs	$9,081,989	$11,047,477	$14,037,456	$14,312,982	$14,596,957	$14,871,929	$15,146,845	$15,425,482	$15,722,408	$16,025,074	$16,333,641	$16,648,197	$16,968,859	$17,295,746	$17,628,978	$17,968,678	$18,314,999	$18,668,042	$19,027,938	$19,394,819	$19,768,820
Energy Efficiency Programming Costs																					
Total Expenses	**$82,577,443**	**$162,116,767**	**$252,349,831**	**$262,924,440**	**$271,834,028**	**$280,758,650**	**$289,330,388**	**$295,153,945**	**$309,932,277**	**$326,849,957**	**$346,237,187**	**$367,164,181**	**$390,590,503**	**$404,242,354**	**$416,883,567**	**$429,780,769**	**$443,966,976**	**$458,326,548**	**$473,163,520**	**$488,116,502**	**$504,600,100**
Debt Service	**$0**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Total Revenue Requirement	**$82,577,443**	**$167,605,774**	**$257,838,838**	**$268,413,446**	**$277,323,035**	**$286,247,656**	**$289,330,388**	**$295,153,945**	**$309,932,277**	**$326,849,957**	**$346,237,187**	**$367,164,181**	**$390,590,503**	**$404,242,354**	**$416,883,567**	**$429,780,769**	**$443,966,976**	**$458,326,548**	**$473,163,520**	**$488,116,502**	**$504,600,100**
Total Load, MWh	**1,177,121**	**2,366,944**	**3,607,181**	**3,623,598**	**3,641,698**	**3,652,169**	**3,659,921**	**3,666,956**	**3,680,582**	**3,694,258**	**3,707,985**	**3,721,763**	**3,735,593**	**3,749,473**	**3,763,406**	**3,777,390**	**3,791,426**	**3,805,514**	**3,819,655**	**3,833,848**	**3,848,093**
Contra Costa CCA Customer Charges, $/MWh (before Reserve Fund Adjustment)																					
Average Contra Costa CCA generation	$70.2	$70.8	$71.5	$74.1	$76.2	$78.4	$79.1	$80.5	$84.2	$88.5	$93.4	$98.7	$104.6	$107.8	$110.8	$113.8	$117.1	$120.4	$123.9	$127.3	$131.1
PG&E average exit fees for CCA load	$23.7	$19.1	$22.9	$16.6	$16.6	$15.7	$14.6	$12.6	$9.1	$8.0	$7.0	$6.0	$5.1	$3.1	$1.7	$0.6	$0.0	$0.0	$0.0	$0.0	$0.0
Total CCA customer rate	**$93.8**	**$89.9**	**$94.3**	**$90.6**	**$92.7**	**$94.1**	**$93.6**	**$93.1**	**$93.3**	**$96.4**	**$100.4**	**$104.6**	**$109.7**	**$110.9**	**$112.4**	**$114.4**	**$117.1**	**$120.4**	**$123.9**	**$127.3**	**$131.1**
PG&E average gen rate for CCA load, $/MWh	**$101.5**	**$105.7**	**$106.6**	**$112.7**	**$115.5**	**$113.8**	**$113.3**	**$109.2**	**$113.2**	**$119.2**	**$126.3**	**$134.2**	**$144.0**	**$146.7**	**$151.0**	**$155.7**	**$160.8**	**$165.0**	**$170.5**	**$176.0**	**$182.5**
Reserve Fund Adjustment																					
Target	$12,386,616	$25,140,866	$38,675,826	$40,262,017	$41,598,455	$42,937,148	$43,399,558	$44,273,092	$46,489,842	$49,027,494	$51,935,578	$55,074,627	$58,588,575	$60,636,353	$62,532,535	$64,467,115	$66,595,046	$68,748,982	$70,974,528	$73,217,475	$75,690,015
Reserve Fund Adjustment																					
Potential Reserve potential	$9,037,817	$37,373,117	$44,318,310	$79,873,437	$82,994,739	$72,190,684	$72,076,358	$58,860,584	$73,135,250	$84,142,452	$96,221,651	$110,201,860	$128,194,145	$134,215,487	$145,270,805	$156,288,619	$165,801,447	$169,687,264	$178,229,235	$186,523,044	$197,789,460
Potential Reserve additions	$9,037,817	$16,103,049	$13,534,960	$1,586,191	$1,336,438	$1,338,693	$462,410	$873,533	$2,216,750	$2,537,652	$2,908,084	$3,139,049	$3,513,948	$2,047,778	$1,896,182	$1,934,580	$2,127,931	$2,153,936	$2,225,546	$2,242,947	$2,472,540
Subtractions from reserve fund	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reserve fund total	**$9,037,817**	**$25,140,866**	**$38,675,826**	**$40,262,017**	**$41,598,455**	**$42,937,148**	**$43,399,558**	**$44,273,092**	**$46,489,842**	**$49,027,494**	**$51,935,578**	**$55,074,627**	**$58,588,575**	**$60,636,353**	**$62,532,535**	**$64,467,115**	**$66,595,046**	**$68,748,982**	**$70,974,528**	**$73,217,475**	**$75,690,015**
Contra Costa CCA Customer Charges, $/MWh (with Reserve Fund Adjustment)																					
Rate adjustment from Reserve Fund	$7.7	$6.8	$3.8	$0.4	$0.4	$0.4	$0.1	$0.2	$0.6	$0.7	$0.8	$0.8	$0.9	$0.5	$0.5	$0.5	$0.6	$0.6	$0.6	$0.6	$0.6
Average Contra Costa CCA rate	$77.8	$77.6	$75.2	$74.5	$76.5	$78.7	$79.2	$80.7	$84.8	$89.2	$94.2	$99.5	$105.5	$108.4	$111.3	$114.3	$117.7	$121.0	$124.5	$127.9	$131.8
PG&E average exit fees for CCA load	$23.7	$19.1	$22.9	$16.6	$16.6	$15.7	$14.6	$12.6	$9.1	$8.0	$7.0	$6.0	$5.1	$3.1	$1.7	$0.6	$0.0	$0.0	$0.0	$0.0	$0.0
Total CCA customer rate	**$101.5**	**$96.7**	**$98.1**	**$91.1**	**$93.1**	**$94.4**	**$93.8**	**$93.4**	**$93.9**	**$97.1**	**$101.2**	**$105.5**	**$110.6**	**$111.5**	**$112.9**	**$114.9**	**$117.7**	**$121.0**	**$124.5**	**$127.9**	**$131.8**
Note: Reserve fund revenue is used to reduce CCA rates if (i) CCA rates are lower than PG&E rates or (ii) the reserve fund reaches the ceiling of half a year of expenses.																					
Contra Costa CCA CO2 emissions																					
Emissions (Tonnes/MWh)	0.04	0.03	0.02	0.02	0.02	0.02	0.02	0.04	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Total emissions (Tonnes)	48,104	76,449	70,394	71,051	71,298	72,351	73,983	158,002	195,517	194,741	195,332	196,074	197,642	162,803	163,997	165,333	166,460	167,595	168,634	170,197	171,328

Scenario 2

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Expenses																					
Cost of Power (including losses)	$75,667,208	$155,562,573	$244,603,605	$253,936,224	$262,178,133	$270,821,465	$279,147,605	$288,420,808	$302,569,437	$318,621,199	$336,840,252	$356,586,893	$378,456,407	$388,844,347	$399,378,659	$410,314,502	$421,560,027	$432,993,327	$444,699,721	$456,541,793	$469,291,025
O&M/A&G Costs	$9,081,989	$11,047,477	$14,037,456	$14,312,982	$14,596,957	$14,871,929	$15,146,845	$15,425,482	$15,722,408	$16,025,074	$16,333,641	$16,648,197	$16,968,859	$17,295,746	$17,628,978	$17,968,678	$18,314,999	$18,668,042	$19,027,938	$19,394,819	$19,768,820
Energy Efficiency Programming Costs																					
Total Expenses	**$84,749,197**	**$166,610,049**	**$258,641,061**	**$268,249,207**	**$276,775,090**	**$285,693,394**	**$294,294,450**	**$303,846,289**	**$318,291,846**	**$334,646,273**	**$353,173,892**	**$373,235,090**	**$395,425,266**	**$406,140,093**	**$417,007,637**	**$428,283,180**	**$439,875,026**	**$451,661,369**	**$463,727,659**	**$475,936,612**	**$489,059,845**
Debt Service	**$0**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Total Revenue Requirement	**$84,749,197**	**$172,099,056**	**$264,130,067**	**$273,738,213**	**$282,264,096**	**$291,182,400**	**$294,294,450**	**$303,846,289**	**$318,291,846**	**$334,646,273**	**$353,173,892**	**$373,235,090**	**$395,425,266**	**$406,140,093**	**$417,007,637**	**$428,283,180**	**$439,875,026**	**$451,661,369**	**$463,727,659**	**$475,936,612**	**$489,059,845**
Total Load, MWh	**1,177,121**	**2,366,944**	**3,607,181**	**3,623,598**	**3,641,698**	**3,652,169**	**3,659,921**	**3,666,956**	**3,680,582**	**3,694,258**	**3,707,985**	**3,721,763**	**3,735,593**	**3,749,473**	**3,763,406**	**3,777,390**	**3,791,426**	**3,805,514**	**3,819,655**	**3,833,848**	**3,848,093**
Contra Costa CCA Customer Charges, $/MWh (before Reserve Fund Adjustment)																					
Average Contra Costa CCA generation	$72.0	$72.7	$73.2	$75.5	$77.5	$79.7	$80.4	$82.9	$86.5	$90.6	$95.2	$100.3	$105.9	$108.3	$110.8	$113.4	$116.0	$118.7	$121.4	$124.1	$127.1
PG&E average exit fees for CCA load	$23.7	$19.1	$22.9	$16.6	$16.6	$15.7	$14.6	$12.6	$9.1	$8.0	$7.0	$6.0	$5.1	$3.1	$1.7	$0.6	$0.0	$0.0	$0.0	$0.0	$0.0
Total CCA customer rate	**$95.7**	**$91.8**	**$96.1**	**$92.1**	**$94.1**	**$95.4**	**$95.0**	**$95.5**	**$95.6**	**$98.5**	**$102.2**	**$106.2**	**$111.0**	**$111.4**	**$112.5**	**$114.0**	**$116.0**	**$118.7**	**$121.4**	**$124.1**	**$127.1**
PG&E average gen rate for CCA load, $/MWh	**$101.5**	**$105.7**	**$106.6**	**$112.7**	**$115.5**	**$113.8**	**$113.3**	**$109.2**	**$113.2**	**$119.2**	**$126.3**	**$134.2**	**$144.0**	**$146.7**	**$151.0**	**$155.7**	**$160.8**	**$165.0**	**$170.5**	**$176.0**	**$182.5**
Reserve Fund Adjustment																					
Target	$12,712,380	$25,814,858	$39,619,510	$41,060,732	$42,339,614	$43,677,360	$44,144,167	$45,576,943	$47,743,777	$50,196,941	$52,976,084	$55,985,264	$59,313,790	$60,921,014	$62,551,146	$64,242,477	$65,981,254	$67,749,205	$69,559,149	$71,390,492	$73,358,977
Reserve Fund Adjustment																					
Potential Reserve potential	$6,866,063	$32,879,835	$38,027,080	$74,548,670	$78,053,677	$67,255,940	$67,112,296	$50,168,239	$64,775,682	$76,346,136	$89,284,946	$104,130,951	$123,359,382	$132,317,748	$145,146,736	$157,786,207	$169,893,397	$176,352,443	$187,665,096	$198,702,934	$213,329,715
Potential Reserve additions	$6,866,063	$18,948,796	$13,804,652	$1,441,222	$1,278,883	$1,337,746	$466,807	$1,432,776	$2,166,833	$2,453,164	$2,779,143	$3,009,180	$3,328,526	$1,607,224	$1,630,132	$1,691,331	$1,738,777	$1,767,951	$1,809,944	$1,831,343	$1,968,485
Subtractions from reserve fund	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reserve fund total	**$6,866,063**	**$25,814,858**	**$39,619,510**	**$41,060,732**	**$42,339,614**	**$43,677,360**	**$44,144,167**	**$45,576,943**	**$47,743,777**	**$50,196,941**	**$52,976,084**	**$55,985,264**	**$59,313,790**	**$60,921,014**	**$62,551,146**	**$64,242,477**	**$65,981,254**	**$67,749,205**	**$69,559,149**	**$71,390,492**	**$73,358,977**
Contra Costa CCA Customer Charges, $/MWh (with Reserve Fund Adjustment)																					
Rate adjustment from Reserve Fund	$5.8	$8.0	$3.8	$0.4	$0.4	$0.4	$0.1	$0.4	$0.6	$0.7	$0.7	$0.8	$0.9	$0.4	$0.4	$0.4	$0.5	$0.5	$0.5	$0.5	$0.5
Average Contra Costa CCA rate	$77.8	$80.7	$77.1	$75.9	$77.9	$80.1	$80.5	$83.3	$87.1	$91.2	$96.0	$101.1	$106.7	$108.7	$111.2	$113.8	$116.5	$119.2	$121.9	$124.6	$127.6
PG&E average exit fees for CCA load	$23.7	$19.1	$22.9	$16.6	$16.6	$15.7	$14.6	$12.6	$9.1	$8.0	$7.0	$6.0	$5.1	$3.1	$1.7	$0.6	$0.0	$0.0	$0.0	$0.0	$0.0
Total CCA customer rate	**$101.5**	**$99.8**	**$99.9**	**$92.5**	**$94.4**	**$95.8**	**$95.1**	**$95.9**	**$96.1**	**$99.2**	**$103.0**	**$107.1**	**$111.9**	**$111.9**	**$112.9**	**$114.4**	**$116.5**	**$119.2**	**$121.9**	**$124.6**	**$127.6**
Note: Reserve fund revenue is used to reduce CCA rates if (i) CCA rates are lower than PG&E rates or (ii) the reserve fund reaches the ceiling of half a year of expenses.																					
Contra Costa CCA CO2 emissions																					
Emissions (Tonnes/MWh)	0.04	0.03	0.02	0.02	0.02	0.02	0.02	0.04	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Total emissions (Tonnes)	48,104	76,449	70,394	71,051	71,298	72,351	73,983	158,002	195,517	194,741	179,036	161,586	144,182	144,830	145,465	146,223	146,793	147,369	147,857	148,803	149,369

Scenario 3

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Expenses																					
Cost of Power (including losses)	$73,821,840	$152,481,196	$241,777,679	$253,556,146	$264,094,600	$275,032,738	$285,950,513	$294,594,258	$312,594,056	$333,441,830	$353,576,083	$374,999,146	$398,607,664	$412,772,050	$425,891,475	$439,246,520	$452,905,747	$466,709,445	$480,979,253	$495,335,405	$511,232,007
O&M/A&G Costs	$9,081,989	$11,047,477	$14,037,456	$14,312,982	$14,596,957	$14,871,929	$15,146,845	$15,425,482	$15,722,408	$16,025,074	$16,333,641	$16,648,197	$16,968,859	$17,295,746	$17,628,978	$17,968,678	$18,314,999	$18,668,042	$19,027,938	$19,394,819	$19,768,820
Energy Efficiency Programming Costs																					
Total Expenses	**$82,903,829**	**$163,528,673**	**$255,815,136**	**$267,869,129**	**$278,691,558**	**$289,904,667**	**$301,097,358**	**$310,019,739**	**$328,316,464**	**$349,466,905**	**$369,909,723**	**$391,647,343**	**$415,576,523**	**$430,067,796**	**$443,520,453**	**$457,215,198**	**$471,220,746**	**$485,377,487**	**$500,007,190**	**$514,730,224**	**$531,000,828**
Debt Service	**$0**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Total Revenue Requirement	**$82,903,829**	**$169,017,679**	**$261,304,142**	**$273,358,135**	**$284,180,564**	**$295,393,673**	**$301,097,358**	**$310,019,739**	**$328,316,464**	**$349,466,905**	**$369,909,723**	**$391,647,343**	**$415,576,523**	**$430,067,796**	**$443,520,453**	**$457,215,198**	**$471,220,746**	**$485,377,487**	**$500,007,190**	**$514,730,224**	**$531,000,828**
Total Load, MWh	**1,177,121**	**2,366,944**	**3,607,181**	**3,623,598**	**3,641,698**	**3,652,169**	**3,659,921**	**3,666,956**	**3,680,582**	**3,694,258**	**3,707,985**	**3,721,763**	**3,735,593**	**3,749,473**	**3,763,406**	**3,777,390**	**3,791,426**	**3,805,514**	**3,819,655**	**3,833,848**	**3,848,093**
Contra Costa CCA Customer Charges, $/MWh (before Reserve Fund Adjustment)																					
Average Contra Costa CCA generation	$70.4	$71.4	$72.4	$75.4	$78.0	$80.9	$82.3	$84.5	$89.2	$94.6	$99.8	$105.2	$111.2	$114.7	$117.9	$121.0	$124.3	$127.5	$130.9	$134.3	$138.0
PG&E average exit fees for CCA load	$23.7	$19.1	$22.9	$16.6	$16.6	$15.7	$14.6	$12.6	$9.1	$8.0	$7.0	$6.0	$5.1	$3.1	$1.7	$0.6	$0.0	$0.0	$0.0	$0.0	$0.0
Total CCA customer rate	**$94.1**	**$90.5**	**$95.3**	**$92.0**	**$94.6**	**$96.6**	**$96.8**	**$97.2**	**$98.3**	**$102.6**	**$106.8**	**$111.2**	**$116.4**	**$117.8**	**$119.5**	**$121.6**	**$124.3**	**$127.5**	**$130.9**	**$134.3**	**$138.0**
PG&E average gen rate for CCA load, $/MWh	**$101.5**	**$105.7**	**$106.6**	**$112.7**	**$115.5**	**$113.8**	**$113.3**	**$109.2**	**$113.2**	**$119.2**	**$126.3**	**$134.2**	**$144.0**	**$146.7**	**$151.0**	**$155.7**	**$160.8**	**$165.0**	**$170.5**	**$176.0**	**$182.5**
Reserve Fund Adjustment																					
Target	$12,435,574	$25,352,652	$39,195,621	$41,003,720	$42,627,085	$44,309,051	$45,164,604	$46,502,961	$49,247,470	$52,420,036	$55,486,459	$58,747,101	$62,336,479	$64,510,169	$66,528,068	$68,582,280	$70,683,112	$72,806,623	$75,001,079	$77,209,534	$79,650,124
Reserve Fund Adjustment																					
Potential Reserve potential	$8,711,430	$35,961,212	$40,853,005	$74,928,748	$76,137,209	$63,044,667	$60,309,388	$43,994,789	$54,751,063	$61,525,504	$72,549,115	$85,718,698	$103,208,125	$108,390,045	$118,633,920	$128,854,190	$138,547,677	$142,636,325	$151,385,564	$159,909,323	$171,388,732
Potential Reserve additions	$8,711,430	$16,641,221	$13,842,969	$1,808,099	$1,623,364	$1,681,966	$855,553	$1,338,357	$2,744,509	$3,172,566	$3,066,423	$3,260,643	$3,589,377	$2,173,691	$2,017,899	$2,054,212	$2,100,832	$2,123,511	$2,194,456	$2,208,455	$2,440,591
Subtractions from reserve fund	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reserve fund total	**$8,711,430**	**$25,352,652**	**$39,195,621**	**$41,003,720**	**$42,627,085**	**$44,309,051**	**$45,164,604**	**$46,502,961**	**$49,247,470**	**$52,420,036**	**$55,486,459**	**$58,747,101**	**$62,336,479**	**$64,510,169**	**$66,528,068**	**$68,582,280**	**$70,683,112**	**$72,806,623**	**$75,001,079**	**$77,209,534**	**$79,650,124**
Contra Costa CCA Customer Charges, $/MWh (with Reserve Fund Adjustment)																					
Rate adjustment from Reserve Fund	$7.4	$7.0	$3.8	$0.5	$0.4	$0.5	$0.2	$0.4	$0.7	$0.9	$0.8	$0.9	$1.0	$0.6	$0.5	$0.5	$0.6	$0.6	$0.6	$0.6	$0.6
Average Contra Costa CCA rate	$77.8	$78.4	$76.3	$75.9	$78.5	$81.3	$82.5	$84.9	$89.9	$95.5	$100.6	$106.1	$112.2	$115.3	$118.4	$121.6	$124.8	$128.1	$131.5	$134.8	$138.6
PG&E average exit fees for CCA load	$23.7	$19.1	$22.9	$16.6	$16.6	$15.7	$14.6	$12.6	$9.1	$8.0	$7.0	$6.0	$5.1	$3.1	$1.7	$0.6	$0.0	$0.0	$0.0	$0.0	$0.0
Total CCA customer rate	**$101.5**	**$97.5**	**$99.1**	**$92.5**	**$95.1**	**$97.0**	**$97.1**	**$97.5**	**$99.0**	**$103.4**	**$107.6**	**$112.1**	**$117.3**	**$118.4**	**$120.1**	**$122.2**	**$124.8**	**$128.1**	**$131.5**	**$134.8**	**$138.6**
Note: Reserve fund revenue is used to reduce CCA rates if (i) CCA rates are lower than PG&E rates or (ii) the reserve fund reaches the ceiling of half a year of expenses.																					
Contra Costa CCA CO2 emissions																					
Emissions (Tonnes/MWh)	0.04	0.03	0.02	0.02	0.02	0.02	0.02	0.04	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Total emissions (Tonnes)	48,104	76,449	70,394	71,051	71,298	72,351	73,983	158,002	195,517	194,741	195,332	196,074	197,642	162,803	163,997	165,333	166,460	167,595	168,634	170,197	171,328

Scenario 4

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Expenses																					
Cost of Pow er (including losses)	$76,298,847	$158,353,376	$251,613,719	$264,966,652	$277,857,664	$291,930,494	$307,270,279	$327,315,270	$351,172,361	$379,984,062	$400,711,371	$422,894,433	$448,135,664	$459,135,226	$470,252,191	$481,804,642	$493,681,157	$505,723,842	$518,057,626	$530,499,789	$543,962,195
O&M/A&G Costs	$9,081,989	$11,047,477	$14,037,456	$14,312,982	$14,596,957	$14,871,929	$15,146,845	$15,425,482	$15,722,408	$16,025,074	$16,333,641	$16,648,197	$16,968,859	$17,295,746	$17,628,978	$17,968,678	$18,314,999	$18,668,042	$19,027,938	$19,394,819	$19,768,820
Energy Efficiency Programming Costs																					
Total Expenses	**$85,380,836**	**$169,400,852**	**$265,651,176**	**$279,279,634**	**$292,454,621**	**$306,802,423**	**$322,417,124**	**$342,740,752**	**$366,894,769**	**$396,009,136**	**$417,045,012**	**$439,542,630**	**$465,104,523**	**$476,430,971**	**$487,881,169**	**$499,773,320**	**$511,996,156**	**$524,391,884**	**$537,085,564**	**$549,894,608**	**$563,731,016**
Debt Service	**$0**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Total Revenue Requirement	**$85,380,836**	**$174,889,859**	**$271,140,182**	**$284,768,640**	**$297,943,628**	**$312,291,430**	**$322,417,124**	**$342,740,752**	**$366,894,769**	**$396,009,136**	**$417,045,012**	**$439,542,630**	**$465,104,523**	**$476,430,971**	**$487,881,169**	**$499,773,320**	**$511,996,156**	**$524,391,884**	**$537,085,564**	**$549,894,608**	**$563,731,016**
Total Load, MWh	**1,177,121**	**2,366,944**	**3,607,181**	**3,623,598**	**3,641,698**	**3,652,169**	**3,659,921**	**3,666,956**	**3,680,582**	**3,694,258**	**3,707,985**	**3,721,763**	**3,735,593**	**3,749,473**	**3,763,406**	**3,777,390**	**3,791,426**	**3,805,514**	**3,819,655**	**3,833,848**	**3,848,093**
Contra Costa CCA Customer Charges, $/MWh (before Reserve Fund Adjustment)																					
Average Contra Costa CCA generation	$72.5	$73.9	$75.2	$78.6	$81.8	$85.5	$88.1	$93.5	$99.7	$107.2	$112.5	$118.1	$124.5	$127.1	$129.6	$132.3	$135.0	$137.8	$140.6	$143.4	$146.5
PG&E average exit fees for CCA load	$23.7	$19.1	$22.9	$16.6	$16.6	$15.7	$14.6	$12.6	$9.1	$8.0	$7.0	$6.0	$5.1	$3.1	$1.7	$0.6	$0.0	$0.0	$0.0	$0.0	$0.0
Total CCA customer rate	**$96.2**	**$93.0**	**$98.0**	**$95.1**	**$98.4**	**$101.2**	**$102.7**	**$106.1**	**$108.8**	**$115.2**	**$119.5**	**$124.1**	**$129.6**	**$130.2**	**$131.3**	**$132.9**	**$135.0**	**$137.8**	**$140.6**	**$143.4**	**$146.5**
PG&E average gen rate for CCA load, $/MWh	**$101.5**	**$105.7**	**$106.6**	**$112.7**	**$115.5**	**$113.8**	**$113.3**	**$109.2**	**$113.2**	**$119.2**	**$126.3**	**$134.2**	**$144.0**	**$146.7**	**$151.0**	**$155.7**	**$160.8**	**$165.0**	**$170.5**	**$176.0**	**$182.5**
Reserve Fund Adjustment																					
Target	$12,807,125	$26,233,479	$40,671,027	$42,715,296	$44,691,544	$46,843,714	$48,362,569	$51,411,113	$55,034,215	$59,401,370	$62,556,752	$65,931,394	$69,765,678	$71,464,646	$73,182,175	$74,965,998	$76,799,423	$78,658,783	$80,562,835	$82,484,191	$84,559,652
Reserve Fund Adjustment																					
Potential Reserve potential	$6,234,424	$30,089,033	$31,016,965	$63,518,242	$62,374,145	$46,146,910	$38,989,622	$11,273,777	$16,172,758	$14,983,272	$25,413,827	$37,823,411	$53,680,125	$62,026,869	$74,273,204	$86,296,068	$97,772,267	$103,621,928	$114,307,191	$124,744,938	$138,658,544
Potential Reserve additions	$6,234,424	$19,999,055	$14,437,549	$2,044,269	$1,976,248	$2,152,170	$1,518,854	$3,048,544	$3,623,103	$4,367,155	$3,155,381	$3,374,643	$3,834,284	$1,698,967	$1,717,530	$1,783,823	$1,833,425	$1,859,359	$1,904,052	$1,921,357	$2,075,461
Subtractions from reserve fund	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reserve fund total	**$6,234,424**	**$26,233,479**	**$40,671,027**	**$42,715,296**	**$44,691,544**	**$46,843,714**	**$48,362,569**	**$51,411,113**	**$55,034,215**	**$59,401,370**	**$62,556,752**	**$65,931,394**	**$69,765,678**	**$71,464,646**	**$73,182,175**	**$74,965,998**	**$76,799,423**	**$78,658,783**	**$80,562,835**	**$82,484,191**	**$84,559,652**
Contra Costa CCA Customer Charges, $/MWh (with Reserve Fund Adjustment)																					
Rate adjustment from Reserve Fund	$5.3	$8.4	$4.0	$0.6	$0.5	$0.6	$0.4	$0.8	$1.0	$1.2	$0.9	$0.9	$1.0	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
Average Contra Costa CCA rate	$77.8	$82.3	$79.2	$79.2	$82.4	$86.1	$88.5	$94.3	$100.7	$108.4	$113.3	$119.0	$125.5	$127.5	$130.1	$132.8	$135.5	$138.3	$141.1	$143.9	$147.0
PG&E average exit fees for CCA load	$23.7	$19.1	$22.9	$16.6	$16.6	$15.7	$14.6	$12.6	$9.1	$8.0	$7.0	$6.0	$5.1	$3.1	$1.7	$0.6	$0.0	$0.0	$0.0	$0.0	$0.0
Total CCA customer rate	**$101.5**	**$101.4**	**$102.0**	**$95.7**	**$98.9**	**$101.8**	**$103.1**	**$106.9**	**$109.7**	**$116.3**	**$120.3**	**$125.0**	**$130.6**	**$130.6**	**$131.8**	**$133.4**	**$135.5**	**$138.3**	**$141.1**	**$143.9**	**$147.0**
Note: Reserve fund revenue is used to reduce CCA rates if (i) CCA rates are lower than PG&E rates or (ii) the reserve fund reaches the ceiling of half a year of expenses.																					
Contra Costa CCA CO2 emissions																					
Emissions (Tonnes/MWh)	0.04	0.03	0.02	0.02	0.02	0.02	0.02	0.04	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Total emissions (Tonnes)	48,104	76,449	70,394	71,051	71,298	72,351	73,983	158,002	195,517	194,741	179,036	161,586	144,182	144,830	145,465	146,223	146,793	147,369	147,857	148,803	149,369

Appendix H. MCE and EBCE's Joint Power Agreements

MARIN CLEAN ENERGY

ADDENDUM NO. 4 TO THE REVISED COMMUNITY CHOICE AGGREGATION IMPLEMENTATION PLAN AND STATEMENT OF INTENT

TO ADDRESS MCE EXPANSION TO THE CITIES OF AMERICAN CANYON, CALISTOGA, LAFAYETTE, NAPA, SAINT HELENA, WALNUT CREEK, AND THE TOWN OF YOUNTVILLE

MCE Clean Energy
My community. My choice.

April 21, 2016

For copies of this document contact Marin Clean Energy in San Rafael, California or visit www.mcecleanenergy.org

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CHAPTER 1 – Introduction

The purpose of this document is to make certain revisions to the Marin Clean Energy Implementation Plan and Statement of Intent in order to address the expansion of Marin Clean Energy ("MCE") to the Cities of American Canyon, Calistoga, Lafayette, Napa, Saint Helena, Walnut Creek, and the Town of Yountville. MCE is a public agency that was formed in December 2008 for purposes of implementing a community choice aggregation ("CCA") program and other energy-related programs targeting significant greenhouse gas emissions ("GHG") reductions. At that time, the Member Agencies of MCE included eight of the twelve municipalities located within the geographic boundaries of Marin County: the cities/towns of Belvedere, Fairfax, Mill Valley, San Anselmo, San Rafael, Sausalito and Tiburon and the County of Marin (together the "Members" or "Member Agencies"). In anticipation of CCA program implementation and in compliance with state law, MCE submitted the Marin Energy Authority Community Choice Aggregation Implementation Plan and Statement of Intent ("Implementation Plan") to the California Public Utilities Commission ("CPUC" or "Commission") on December 9, 2009. Consistent with its expressed intent, MCE successfully launched its CCA program, Marin Clean Energy ("MCE" or "Program"), on May 7, 2010 and has been serving customers since that time.

During the second half of 2011, four additional municipalities within Marin County, the cities of Novato and Larkspur and the towns of Ross and Corte Madera, joined MCE, and a revised Implementation Plan reflecting updates related to said expansion was filed with the CPUC on December 3, 2011.

Subsequently, the City of Richmond, located in Contra Costa County, joined MCE, and a revised Implementation Plan reflecting updates related to this expansion was filed with the CPUC on July 6, 2012.

A revision to MCE's Implementation Plan was then filed with the Commission on November 6, 2012 to ensure compliance with Commission Decision 12-08-045, which was issued on August 31, 2012. In Decision 12-08-045, the Commission directed existing CCA programs to file revised Implementation Plans to conform to the privacy rules in Attachment B of this Decision.

During 2015, the County of Napa and the Cities of Benicia, El Cerrito, and San Pablo joined MCE; service was extended to customers in unincorporated Napa County during February, 2015 and to customers in Benicia, El Cerrito and San Pablo during May, 2015. To address the anticipated effects of these expansions, MCE filed with the Commission a revision to its Implementation Plan on July 18, 2014 to address expansion to the County of Napa (the Commission subsequently certified this revision on September 15, 2014); following this revision, MCE submitted Addendum #1 to the Revised Community Choice Aggregation Implementation Plan and Statement of Intent to Address MCE Expansion to the City of San Pablo (Addendum #1) on September 25, 2014 (the Commission subsequently certified Addendum #1 on October 29, 2014); and Addendum #2 to the Revised Community Choice Aggregation Implementation Plan and Statement of Intent to Address MCE Expansion to the City of Benicia (Addendum #2) on November 21, 2014 (the Commission subsequently certified Addendum #2 on December 1, 2014); and Addendum #3 to the Revised Community Choice Aggregation Implementation Plan and Statement of Intent to Address MCE Expansion to the City of El Cerrito (Addendum #3) on January 8, 2015 (the Commission subsequently certified Addendum #3 on January 16, 2015)

Numerous communities continue to contact MCE regarding membership opportunities, including specific requests to join MCE and initiate related CCA service within these various jurisdictions. In response to these inquiries, MCE's governing board adopted Policy 007, which establishes a formal process and specific criteria for new member additions. In particular, this policy identifies several threshold requirements, including the specification that any prospective member evaluation demonstrate rate-related savings (based on prevailing market prices for requisite energy products at the time of each analysis) as well as environmental benefits (as measured by anticipated reductions in greenhouse gas emissions and increased renewable energy sales to CCA customers) before proceeding with expansion activities, including the filing of related revisions/addenda to this Implementation Plan. As MCE receives new membership requests, staff will follow the prescribed evaluative process of Policy 007 and will present related results at future public meetings. To the extent that membership evaluations demonstrate favorable results and any new community completes the process of joining MCE, this Implementation Plan will be revised through a related addendum, highlighting key impacts and consequences associated with the addition of such new community/communities.

The MCE program now provides electric generation service to approximately 170,000 customers, including a cross section of residential and commercial accounts. During its more than five-year operating history, non-member municipalities have monitored MCE progress, evaluating the potential opportunity for membership, which would enable customer choice with respect to electric generation service. In response to public interest and MCE's successful operational track record, the each of Cities of American Canyon, Calistoga, Lafayette, Napa, Saint Helena, Walnut Creek and the Town of Yountville requested MCE membership, consistent with MCE Policy 007, and adopted the requisite ordinance for joining MCE. MCE's Board of Directors approved the membership requests at a duly noticed public meeting on April 21, 2016 through the approval of Resolution No. 2016-01.

This Addendum No. 4 to the Marin Clean Energy Community Choice Aggregation Implementation Plan and Statement of Intent ("Addendum No. 3") describes MCE's expansion plans to include the Cities of American Canyon, Calistoga, Lafayette, Napa, Saint Helena, Walnut Creek and the Town of Yountville. According to the Commission, the Energy Division is required to receive and review a revised MCE implementation plan reflecting changes/consequences of additional members. With this in mind, MCE has reviewed its revised Implementation Plan, which was filed with the Commission on July 18, 2014, as well as previous Addendums, and has identified certain information that requires updating to reflect the changes and consequences of adding the new municipalities as well as other forecast modifications reflecting the most recent historical electric energy use within MCE's existing service territory. This Addendum No. 4 reflects pertinent changes related to the new member additions as well as projections that account for MCE's planned expansion and recent operations. This document format, including references to MCE's most recent Implementation Plan revision (filed with the Commission on July 18, 2014 and certified by the Commission on September 15, 2014), which is incorporated by reference and attached hereto as Appendix D, addresses all requirements identified in PU Code Section 366.2(c)(4), including universal access, reliability, equitable treatment of all customer classes and any requirements established by state law or by the CPUC concerning aggregated service, while streamlining public review of pertinent changes related to MCE expansion.

CHAPTER 2 – Changes to Address MCE Expansion to the Cities of American Canyon, Calistoga, Lafayette, Napa, Walnut Creek, and the Town of Yountville

This Addendum No. 4 addresses the anticipated impacts of MCE's planned expansion to the Cities of American Canyon, Calistoga, Lafayette, Napa, Walnut Creek, and the Town of Yountville, as well as other forecast modifications reflecting the most recent historical electric energy use within MCE's existing service territory. As a result of these member additions, certain assumptions regarding MCE's future operations have changed, including customer energy requirements, peak demand, renewable energy purchases, revenues and expenses as well as various other items. The following section highlights pertinent changes related to this planned expansion. To the extent that certain details related to membership expansion are not specifically discussed within this Addendum No. 4, MCE represents that such information shall remain unchanged relative to the July 18, 2014 Implementation Plan revision, which was certified by the Commission on September 15, 2014.

With regard to the defined terms Members and Member Agencies, the following communities are now signatories to the MCE Joint Powers Agreement and represent MCE's current membership:

Member Agencies
City of American Canyon
City of Belvedere
City of Benicia
City of Calistoga
Town of Corte Madera
City of El Cerrito
Town of Fairfax
City of Lafayette
City of Larkspur
City of Mill Valley
County of Marin
City of Napa
County of Napa
City of Novato
City of Richmond
Town of Ross
Town of San Anselmo
City of San Pablo
City of San Rafael
City of Sausalito
Town of Tiburon
City of Walnut Creek
Town of Yountville

Throughout this document, use of the terms Members and Member Agencies shall now include the aforementioned communities. To the extent that discussion addresses the process of aggregation and MCE organization, each of these communities is now an MCE Member and its electric customers will be offered CCA service consistent with the noted phase-in schedule.

Aggregation Process

MCE's aggregation process was discussed in Chapter 2 of MCE's July 18, 2014 Revised Implementation Plan. This first paragraph of Chapter 2 is replaced in its entirety with the following verbiage:

As previously noted, MCE successfully launched its CCA Program, MCE, on May 7, 2010 after meeting applicable statutory requirements and in consideration of planning elements described in its initial Implementation Plan. At this point in time, MCE plans to expand agency membership to include the Cities of American Canyon, Calistoga, Lafayette, Napa, Saint Helena, Walnut Creek and the Town of Yountville. These communities have requested MCE membership, and MCE's Board of Directors subsequently approved the membership requests at a duly noticed public meeting on April 21, 2016.

Program Phase-In

Program phase-in was discussed in Chapter 5 of MCE's July 18, 2014 Revised Implementation Plan. Chapter 5 is replaced in its entirety with the following verbiage:

MCE will continue to phase-in the customers of its CCA Program as communicated in this Implementation Plan. To date, six phases have been successfully implemented, and a seventh phase will commence in September 2016. The seventh phase will now include service commencement to customers located within the Cities of American Canyon, Calistoga, Lafayette, Napa, Saint Helena, Walnut Creek and the Town of Yountville, as reflected in the following table.

MCE Phase No.	Status & Description of Phase	Implementation Date
Phase 1	**Complete**: MCE Member (municipal) accounts & a subset of residential, commercial and/or industrial accounts, comprising approximately 20 percent of total customer load within MCE's original Member Agencies.	May 7, 2010
Phase 2	**Complete**: Additional commercial and residential accounts, comprising approximately 20 percent of total customer load within MCE's original Member Agencies (incremental addition to Phase 1).	August 2011
Phase 3	**Complete**: Remaining accounts within Marin County.	July 2012
Phase 4	**Complete**: Residential, commercial, agricultural, and street lighting accounts within the City of Richmond.	July 2013
Phase 5	**Complete**: Residential, commercial, agricultural, and street lighting accounts within the unincorporated areas of Napa County, subject to economic and operational constraints.	February 2015

MCE Phase No.	Status & Description of Phase	Implementation Date
Phase 6	**Complete**: Residential, commercial, agricultural, and street lighting accounts within the City of San Pablo, the City of Benicia and the City of El Cerrito, subject to economic and operational constraints.	May 2015
Phase 7	**September 2016**: Residential, commercial, agricultural, and street lighting accounts within the Cities of American Canyon, Calistoga, Lafayette, Napa, Saint Helena, Walnut Creek and the Town of Yountville, subject to economic and operational constraints.	September 2016

This approach has provided MCE with the ability to start slow, addressing any problems or unforeseen challenges on a small manageable program before gradually building to full program integration for an expected customer base of approximately 256,000 accounts, following completion of Phase 7 customer enrollments. This approach has also allowed MCE and its energy supplier(s) to address all system requirements (billing, collections, payments) under a phase-in approach to minimize potential exposure to uncertainty and financial risk by "walking" prior to ultimately "running". The Board may evaluate other phase-in options based on then-current market conditions, statutory requirements and regulatory considerations as well as other factors potentially affecting the integration of additional customer accounts.

Sales Forecast

With regard to MCE's sales forecast, which is addressed in Chapter 6, Load Forecast and Resource Plan, MCE assumes that total annual retail sales will increase to approximately 2,800 GWh following Phase 7 expansion. The following tables have also been updated to reflect the impacts of planned expansion to MCE's new membership.

Chapter 6, Resource Plan Overview

Marin Clean Energy
Proposed Resource Plan
(GWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
MCE Demand (GWh)										
Retail Demand	-91	-185	-570	-1,110	-1,252	-1,710	-2,103	-2,802	-2,816	-2,830
Distributed Generation	0	2	4	5	9	14	19	24	31	40
Energy Efficiency	0	0	0	0	1	1	22	31	43	58
Losses and UFE	-5	-11	-34	-66	-74	-102	-124	-165	-165	-164
Total Demand	-97	-195	-601	-1,172	-1,315	-1,796	-2,185	-2,913	-2,906	-2,897
MCE Supply (GWh)										
Renewable Resources										
Generation	0	0	0	0	0	0	0	0	0	0
Power Purchase Contracts	23	50	289	564	645	927	1,130	1,602	1,695	1,784
Total Renewable Resources	23	50	289	564	645	927	1,130	1,602	1,695	1,784
Conventional Resources										
Generation	0	0	0	0	0	0	0	0	0	0
Power Purchase Contracts	74	145	312	608	670	869	1,056	1,310	1,212	1,112
Total Conventional Resources	74	145	312	608	670	869	1,056	1,310	1,212	1,112
Total Supply	97	195	601	1,172	1,315	1,796	2,185	2,913	2,906	2,897
Energy Open Position (GWh)	0	0	0	0	0	0	0	0	0	0

Chapter 6, Customer Forecast

Marin Clean Energy
Enrolled Retail Service Accounts
Phase-In Period (End of Month)

	May-10	Aug-11	Jul-12	Jul-13	Feb-15	May-15	Sep-16
MCE Customers							
Residential	7,354	12,503	77,345	106,510	120,204	149,610	225,128
Commercial & Industrial	579	1,114	9,913	13,098	15,316	19,147	27,274
Street Lighting & Traffic	138	141	443	748	1,014	1,219	1,866
Ag & Pumping	-	<15	113	109	1,467	1,625	1,700
Total	8,071	13,759	87,814	120,465	138,001	171,601	255,968

Marin Clean Energy
Retail Service Accounts (End of Year)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
MCE Customers										
Residential	7,354	12,503	77,345	106,510	106,510	149,610	225,128	225,128	226,254	227,385
Commercial & Industrial	579	1,114	9,913	13,098	13,098	19,147	27,274	27,274	27,410	27,547
Street Lighting & Traffic	138	141	443	748	748	1,219	1,866	1,866	1,875	1,885
Ag & Pumping	-	<15	113	109	109	1,625	1,700	1,700	1,709	1,717
Total	8,071	13,759	87,814	120,465	120,465	171,601	255,968	255,968	257,248	258,534

Chapter 6, Sales Forecast

Marin Clean Energy
Energy Requirements
(GWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
MCE Energy Requirements (GWh)										
Retail Demand	91	185	570	1,110	1,252	1,710	2,103	2,802	2,816	2,830
Distributed Generation	0	-2	-4	-5	-9	-14	-19	-24	-31	-40
Energy Efficiency	0	0	0	0	-1	-1	-22	-31	-43	-58
Losses and UFE	5	11	34	66	74	102	124	165	165	164
Total Load Requirement	97	195	601	1,172	1,315	1,796	2,185	2,913	2,906	2,897

Chapter 6, Capacity Requirements

Marin Clean Energy
Capacity Requirements
(MW)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Demand (MW)										
Retail Demand	28	46	182	233	234	318	447	499	501	504
Distributed Generation	-	(1)	(2)	(3)	(5)	(8)	(11)	(14)	(18)	(23)
Energy Efficiency	-	-	-	(0)	(0)	(0)	(5)	(7)	(10)	(13)
Losses and UFE	2	3	11	14	14	19	26	29	28	28
Total Net Peak Demand	30	47	191	244	243	328	457	507	502	496
Reserve Requirement (%)	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Capacity Reserve Requirement	4	7	29	37	36	49	69	76	75	74
Capacity Requirement Including Reserve	34	55	220	281	279	377	526	583	578	571

Chapter 6, Renewable Portfolio Standards Energy Requirements

Marin Clean Energy
RPS Requirements
(MWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Retail Sales	91,219	183,741	566,640	1,105,385	1,240,992	1,694,449	2,061,766	2,747,986	2,741,727	2,732,840
Baseline	-	18,244	36,748	113,328	221,077	269,295	394,807	515,442	741,956	795,101
Incremental Procurement Target	18,244	18,504	76,580	107,749	48,218	125,511	120,635	226,515	53,145	52,080
Annual Procurement Target	18,244	36,748	113,328	221,077	269,295	394,807	515,442	741,956	795,101	847,180
% of Current Year Retail Sales	20%	20%	20%	20%	22%	23%	25%	27%	29%	31%

Marin Clean Energy
RPS Requirements and Program Renewable Energy Targets
(MWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Retail Sales (MWh)	91,219	183,741	566,640	1,105,385	1,240,992	1,694,449	2,061,766	2,747,986	2,741,727	2,732,840
Annual RPS Target (Minimum MWh)	18,244	36,748	113,328	221,077	269,295	394,807	515,442	741,956	795,101	847,180
Program Target (% of Retail Sales)	25%	27%	51%	51%	52%	55%	55%	58%	62%	65%
Program Renewable Target (MWh)	**22,805**	**49,610**	**288,986**	**563,746**	**645,316**	**926,796**	**1,129,889**	**1,602,464**	**1,694,720**	**1,784,435**
Surplus In Excess of RPS (MWh)	**4,561**	**12,862**	**175,658**	**342,669**	**376,021**	**531,989**	**614,448**	**860,508**	**899,619**	**937,255**
Annual Increase (MWh)	22,805	26,805	239,376	274,760	81,569	281,480	203,094	472,575	92,256	89,715

Chapter 6, Energy Efficiency

Marin Clean Energy
Energy Efficiency Savings Goals
(GWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
MCE Retail Demand	91	185	570	1,110	1,252	1,710	2,103	2,802	2,816	2,830
MCE Energy Efficiency Goal	0	0	0	0	-1	-1	-22	-31	-43	-58

Chapter 6, Demand Response

Marin Clean Energy
Demand Response Goals
(MW)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Capacity Requirement (MW)	34	55	220	281	279	377	526	583	578	571
Greater Bay Area Capacity Requirement (MW)	5	9	35	44	44	40	56	62	61	61
Demand Response Target	-	-	-	-	-	-	-	7	14	29
Percentage of Local Capacity Requirment	0%	0%	0%	0%	0%	0%	0%	12%	23%	47%

Chapter 6, Distributed Generation

Marin Clean Energy
Distributed Generation Projections
(MW)
to

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
DG Capacity	-	1	2	3	5	8	11	14	18	23

Financial Plan

With regard to MCE's financial plan, which is addressed in Chapter 7, Financial Plan, MCE has updated its expected operating results, which now include projected impacts related to service expansion within MCE's new member communities. The following table reflects updated operating projections in consideration of these planned expansions.

Chapter 7, CCA Program Implementation Feasibility Analysis

Marin Clean Energy
Summary of CCA Program Phase-In
(January 2013 through December 2021)

CATEGORY	2013	2014	2015	2016	2017	2018	2019	2020	2021
I. REVENUES FROM OPERATIONS ($)									
ELECTRIC SALES REVENUE	79,097,747	96,963,884	135,021,092	169,271,724	216,452,212	213,543,823	214,611,542	220,764,561	228,524,436
LESS UNCOLLECTIBLE ACCOUNTS	(395,489)	(484,819)	(675,105)	(846,359)	(1,082,261)	(1,067,719)	(1,073,058)	(1,103,823)	(1,142,622)
LESS NET ENERGY METERING CREDITS	(314,809)	(385,916)	(546,879)	(362,202)	(425,212)	(427,338)	(429,475)	(431,621)	(433,781)
TOTAL REVENUES	78,702,259	96,479,065	134,345,986	168,425,365	215,369,951	212,476,104	213,538,484	219,660,739	227,381,813
II. COST OF OPERATIONS ($)									
(A) ADMINISTRATIVE AND GENERAL (A&G)									
STAFFING	1,386,303	1,825,000	2,710,500	4,598,125	5,485,201	5,649,757	5,819,250	5,993,828	6,173,642
CONTRACT SERVICES	4,457,964	4,572,751	4,838,757	6,351,549	7,383,653	7,477,211	7,572,972	7,670,983	7,771,338
IOU FEES (INCLUDING BILLING)	584,729	660,114	877,953	1,101,770	1,444,734	1,495,516	1,548,084	1,602,499	1,658,827
OTHER A&G	302,806	373,125	610,500	519,624	472,850	486,017	499,579	513,549	527,937
SUBTOTAL A&G	6,731,802	7,430,990	9,037,711	12,571,067	14,786,438	15,108,502	15,439,885	15,780,858	16,131,744
(B) COST OF ENERGY	67,886,604	82,928,413	115,624,967	142,856,566	183,655,605	166,704,670	175,122,240	182,541,059	190,601,655
(C) DEBT SERVICE	1,195,162	1,195,162	2,450,457	455,000	455,000	455,000	455,000	455,000	455,000
TOTAL COST OF OPERATION	75,813,568	91,554,564	127,113,135	155,882,633	198,897,043	182,268,172	191,017,125	198,776,917	207,188,399
CCA PROGRAM SURPLUS/(DEFICIT)	2,888,691	4,924,500	7,232,851	12,542,733	16,472,908	30,207,932	22,521,359	20,883,822	20,193,415

Expansion Addendum Appendices

Appendix A: Marin Clean Energy Resolution 2016-01
Appendix B: Joint Powers Agreement
Appendix C: Member Ordinances
Appendix D: Marin Clean Energy Revised Implementation Plan and Statement of Intent (July 18, 2014)

APPROVED

APR 21 2016

MARIN CLEAN ENERGY

APPENDIX A

RESOLUTION NO. 2016-01

A RESOLUTION OF THE BOARD OF DIRECTORS OF MCE APPROVING THE CITIES OF AMERICAN CANYON, CALISTOGA, LAFAYETTE, NAPA, ST. HELENA, WALNUT CREEK AND THE TOWN OF YOUNTVILLE AS MEMBERS OF MCE

WHEREAS, on September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, Ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation ("CCA"); and,

WHEREAS, the Act expressly authorizes participation in a CCA program through a joint powers agency, and on December 19, 2008, Marin Clean Energy ("MCE"), (formerly the Marin Energy Authority) was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time ("MCE Joint Powers Agreement"); and,

WHEREAS, on February 2, 2010, the California Public Utilities Commission certified the "Implementation Plan" of MCE, confirming MCE's compliance with the requirements of the Act; and,

WHEREAS, MCE members include the following communities: the County of Marin, the City of Belvedere, the City of Benicia, the Town of Corte Madera, the City of El Cerrito, the Town of Fairfax, the City of Larkspur, the City of Mill Valley, the County of Napa, the City of Novato, the City of Richmond, the Town of Ross, the Town of San Anselmo, the City of San Pablo, the City of San Rafael, the City of Sausalito and the Town of Tiburon; and

WHEREAS, requested membership in MCE was made by the Cities of American Canyon and Calistoga on September 2, 2015, Lafayette on August 11, 2015, Napa on August 31, 2015, St. Helena on August 7, 2015, Walnut Creek on August 10, 2015 and the Town of Yountville on August 4, 2015; and,

WHEREAS, the ordinance approving membership in MCE was made by the Cities of American Canyon on November 17, 2015, Calistoga on November 3, 2015, Lafayette on March 14, 2015, Napa on February 2, 2016, St. Helena on January 12, 2016, Walnut Creek on March 15, 2016, and the Town of Yountville on March 15, 2016 and,

WHEREAS, the membership analyses for the Cities of American Canyon, Calistoga, Lafayette, Napa, St. Helena, Walnut Creek and the Town of Yountville was completed on April 8, 2016, and yielded a positive result,

NOW, THEREFORE, BE IT RESOLVED AND ORDERED, by the Board of Directors of MCE that the Cities of American Canyon, Calistoga, Lafayette, Napa, St. Helena, Walnut Creek and the Town of Yountville are approved as members of MCE.

PASSED AND ADOPTED at a regular meeting of the MCE Board of Directors on the twenty-first day of April, 2016 by the following vote:

	AYES	NOES	ABSTAIN	ABSENT
City of Belvedere	✓			
City of Benicia	✓			
Town of Corte Madera	✓			
City of El Cerrito	✓			
Town of Fairfax	✓			
City of Larkspur				✓
County of Marin				✓
City of Mill Valley	✓			
County of Napa	✓			
City of Novato	✓			
City of Richmond	✓			
Town of Ross				✓
Town of San Anselmo				✓
City of San Pablo				✓
City of San Rafael	✓			
City of Sausalito	✓			
Town of Tiburon				✓

TOM BUTT, VICE CHAIR

APPROVED
APR 21 2016
MARIN CLEAN ENERGY

ATTEST:

DAWN WEISZ, SECRETARY

APPENDIX B

Marin Energy Authority
- Joint Powers Agreement -

Effective December 19, 2008
As amended by Amendment No. 1 dated December 3, 2009
As further amended by Amendment No. 2 dated March 4, 2010
As further amended by Amendment No. 3 dated May 6, 2010
As further amended by Amendment No. 4 dated December 1, 2011
As further amended by Amendment No. 5 dated July 5, 2012
As further amended by Amendment No. 6 dated September 5, 2013
As further amended by Amendment No. 7 dated December 5, 2013
As further amended by Amendment No. 8 dated September 4, 2014
As further amended by Amendment No. 9 dated December 4, 2014
As further amended by Amendment No. 10 dated April 21, 2016

Among The Following Parties:
City of American Canyon
City of Belvedere
City of Benicia
City of Calistoga
Town of Corte Madera
City of El Cerrito
Town of Fairfax
City of Lafayette
City of Larkspur
City of Mill Valley
City of Napa
City of Novato
City of Richmond
Town of Ross
Town of San Anselmo
City of San Pablo
City of San Rafael
City of Sausalito
City of St. Helena
Town of Tiburon
City of Walnut Creek
Town of Yountville
County of Marin
County of Napa

MARIN ENERGY AUTHORITY
JOINT POWERS AGREEMENT

This **Joint Powers Agreement** ("Agreement"), effective as of December 19, 2008, is made and entered into pursuant to the provisions of Title 1, Division 7, Chapter 5, Article 1 (Section 6500 et seq.) of the California Government Code relating to the joint exercise of powers among the parties set forth in Exhibit B ("Parties"). The term "Parties" shall also include an incorporated municipality or county added to this Agreement in accordance with Section 3.1.

RECITALS

1. The Parties are either incorporated municipalities or counties sharing various powers under California law, including but not limited to the power to purchase, supply, and aggregate electricity for themselves and their inhabitants.

2. In 2006, the State Legislature adopted AB 32, the Global Warming Solutions Act, which mandates a reduction in greenhouse gas emissions in 2020 to 1990 levels. The California Air Resources Board is promulgating regulations to implement AB 32 which will require local government to develop programs to reduce greenhouse emissions.

3. The purposes for the Initial Participants (as such term is defined in Section 2.2 below) entering into this Agreement include addressing climate change by reducing energy related greenhouse gas emissions and securing energy supply and price stability, energy efficiencies and local economic benefits. It is the intent of this Agreement to promote the development and use of a wide range of renewable energy sources and energy efficiency programs, including but not limited to solar and wind energy production.

4. The Parties desire to establish a separate public agency, known as the Marin Energy Authority ("Authority"), under the provisions of the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 et seq.) ("Act") in order to collectively study, promote, develop, conduct, operate, and manage energy programs.

5. The Initial Participants have each adopted an ordinance electing to implement through the Authority Community Choice Aggregation, an electric service enterprise agency available to cities and counties pursuant to California Public Utilities Code Section 366.2 ("CCA Program"). The first priority of the Authority will be the consideration of those actions necessary to implement the CCA Program. Regardless of whether or not Program Agreement 1 is approved and the CCA Program becomes operational, the parties intend for the Authority to continue to study, promote, develop, conduct, operate and manage other energy programs.

AGREEMENT

NOW, THEREFORE, in consideration of the mutual promises, covenants, and conditions hereinafter set forth, it is agreed by and among the Parties as follows:

ARTICLE 1
CONTRACT DOCUMENTS

1.1 **Definitions**. Capitalized terms used in the Agreement shall have the meanings specified in Exhibit A, unless the context requires otherwise.

1.2 **Documents Included**. This Agreement consists of this document and the following exhibits, all of which are hereby incorporated into this Agreement.

Exhibit A:	Definitions
Exhibit B:	List of the Parties
Exhibit C:	Annual Energy Use
Exhibit D:	Voting Shares

1.3 **Revision of Exhibits**. The Parties agree that Exhibits B, C and D to this Agreement describe certain administrative matters that may be revised upon the approval of the Board, without such revision constituting an amendment to this Agreement, as described in Section 8.4. The Authority shall provide written notice to the Parties of the revision of any such exhibit.

ARTICLE 2
FORMATION OF MARIN ENERGY AUTHORITY

2.1 **Effective Date and Term**. This Agreement shall become effective and Marin Energy Authority shall exist as a separate public agency on the date this Agreement is executed by at least two Initial Participants after the adoption of the ordinances required by Public Utilities Code Section 366.2(c)(10). The Authority shall provide notice to the Parties of the Effective Date. The Authority shall continue to exist, and this Agreement shall be effective, until this Agreement is terminated in accordance with Section 7.4, subject to the rights of the Parties to withdraw from the Authority.

2.2 **Initial Participants**. During the first 180 days after the Effective Date, all other Initial Participants may become a Party by executing this Agreement and delivering an executed copy of this Agreement and a copy of the adopted ordinance required by Public Utilities Code Section 366.2(c)(10) to the Authority. Additional conditions, described in Section 3.1, may apply (i) to either an incorporated municipality or county desiring to become a Party and is not an Initial Participant and (ii) to Initial Participants that have not executed and delivered this Agreement within the time period described above.

2.3 **Formation**. There is formed as of the Effective Date a public agency named the Marin Energy Authority. Pursuant to Sections 6506 and 6507 of the Act, the Authority is a public agency separate from the Parties. The debts, liabilities or obligations of the Authority shall not be debts, liabilities or obligations of the individual Parties unless the governing board of a Party agrees in writing to assume any of the debts, liabilities or obligations of the Authority. A Party who has not agreed to assume an Authority debt, liability or obligation shall not be responsible in any way for such debt, liability or obligation even if a majority of the Parties agree to assume the debt, liability or obligation of the Authority. Notwithstanding Section 8.4 of this Agreement, this Section 2.3 may not be amended unless such amendment is approved by the governing board of each Party.

2.4 **Purpose**. The purpose of this Agreement is to establish an independent public agency in order to exercise powers common to each Party to study, promote, develop, conduct, operate, and manage energy and energy-related climate change programs, and to exercise all other powers necessary and incidental to accomplishing this purpose. Without limiting the generality of the foregoing, the Parties intend for this Agreement to be used as a contractual mechanism by which the Parties are authorized to participate as a group in the CCA Program, as further described in Section 5.1. The Parties intend that subsequent agreements shall define the terms and conditions associated with the actual implementation of the CCA Program and any other energy programs approved by the Authority.

2.5 **Powers**. The Authority shall have all powers common to the Parties and such additional powers accorded to it by law. The Authority is authorized, in its own name, to exercise all powers and do all acts necessary and proper to carry out the provisions of this Agreement and fulfill its purposes, including, but not limited to, each of the following:

2.5.1 make and enter into contracts;
2.5.2 employ agents and employees, including but not limited to an Executive Director;
2.5.3 acquire, contract, manage, maintain, and operate any buildings, works or improvements;
2.5.4 acquire by eminent domain, or otherwise, except as limited under Section 6508 of the Act, and to hold or dispose of any property;
2.5.5 lease any property;
2.5.6 sue and be sued in its own name;
2.5.7 incur debts, liabilities, and obligations, including but not limited to loans from private lending sources pursuant to its temporary borrowing powers such as Government Code Section 53850 et seq. and authority under the Act;
2.5.8 issue revenue bonds and other forms of indebtedness;
2.5.9 apply for, accept, and receive all licenses, permits, grants, loans or other aids from any federal, state or local public agency;

2.5.10 submit documentation and notices, register, and comply with orders, tariffs and agreements for the establishment and implementation of the CCA Program and other energy programs;

2.5.11 adopt rules, regulations, policies, bylaws and procedures governing the operation of the Authority ("Operating Rules and Regulations"); and

2.5.12 make and enter into service agreements relating to the provision of services necessary to plan, implement, operate and administer the CCA Program and other energy programs, including the acquisition of electric power supply and the provision of retail and regulatory support services.

2.6 **Limitation on Powers**. As required by Government Code Section 6509, the power of the Authority is subject to the restrictions upon the manner of exercising power possessed by the County of Marin.

2.7 **Compliance with Local Zoning and Building Laws**. Notwithstanding any other provisions of this Agreement or state law, any facilities, buildings or structures located, constructed or caused to be constructed by the Authority within the territory of the Authority shall comply with the General Plan, zoning and building laws of the local jurisdiction within which the facilities, buildings or structures are constructed.

ARTICLE 3
AUTHORITY PARTICIPATION

3.1 **Addition of Parties**. Subject to Section 2.2, relating to certain rights of Initial Participants, other incorporated municipalities and counties may become Parties upon (a) the adoption of a resolution by the governing body of such incorporated municipality or such county requesting that the incorporated municipality or county, as the case may be, become a member of the Authority, (b) the adoption, by an affirmative vote of the Board satisfying the requirements described in Section 4.9.1, of a resolution authorizing membership of the additional incorporated municipality or county, specifying the membership payment, if any, to be made by the additional incorporated municipality or county to reflect its pro rata share of organizational, planning and other pre-existing expenditures, and describing additional conditions, if any, associated with membership, (c) the adoption of an ordinance required by Public Utilities Code Section 366.2(c)(10) and execution of this Agreement and other necessary program agreements by the incorporated municipality or county, (d) payment of the membership payment, if any, and (e) satisfaction of any conditions established by the Board. Notwithstanding the foregoing, in the event the Authority decides to not implement a CCA Program, the requirement that an additional party adopt the ordinance required by Public Utilities Code Section 366.2(c)(10) shall not apply. Under such circumstance, the Board resolution authorizing membership of an additional incorporated municipality or county shall be adopted in accordance with the voting requirements of Section 4.10.

3.2 **<u>Continuing Participation</u>**. The Parties acknowledge that membership in the Authority may change by the addition and/or withdrawal or termination of Parties. The Parties agree to participate with such other Parties as may later be added, as described in Section 3.1. The Parties also agree that the withdrawal or termination of a Party shall not affect this Agreement or the remaining Parties' continuing obligations under this Agreement.

ARTICLE 4
GOVERNANCE AND INTERNAL ORGANIZATION

4.1 **<u>Board of Directors</u>**. The governing body of the Authority shall be a Board of Directors ("Board") consisting of one director for each Party appointed in accordance with Section 4.2.

4.2 **<u>Appointment and Removal of Directors</u>**. The Directors shall be appointed and may be removed as follows:

4.2.1 The governing body of each Party shall appoint and designate in writing one regular Director who shall be authorized to act for and on behalf of the Party on matters within the powers of the Authority. The governing body of each Party also shall appoint and designate in writing one alternate Director who may vote on matters when the regular Director is absent from a Board meeting. The person appointed and designated as the Director or the alternate Director shall be a member of the governing body of the Party.

4.2.2 The Operating Rules and Regulations, to be developed and approved by the Board in accordance with Section 2.5.11, shall specify the reasons for and process associated with the removal of an individual Director for cause. Notwithstanding the foregoing, no Party shall be deprived of its right to seat a Director on the Board and any such Party for which its Director and/or alternate Director has been removed may appoint a replacement.

4.3 **<u>Terms of Office</u>**. Each Director shall serve at the pleasure of the governing body of the Party that the Director represents, and may be removed as Director by such governing body at any time. If at any time a vacancy occurs on the Board, a replacement shall be appointed to fill the position of the previous Director in accordance with the provisions of Section 4.2 within 90 days of the date that such position becomes vacant.

4.4 **<u>Quorum</u>**. A majority of the Directors shall constitute a quorum, except that less than a quorum may adjourn from time to time in accordance with law.

4.5 **Powers and Function of the Board**. The Board shall conduct or authorize to be conducted all business and activities of the Authority, consistent with this Agreement, the Authority Documents, the Operating Rules and Regulations, and applicable law.

4.6 **Executive Committee**. The Board may establish an executive committee consisting of a smaller number of Directors. The Board may delegate to the executive committee such authority as the Board might otherwise exercise, subject to limitations placed on the Board's authority to delegate certain essential functions, as described in the Operating Rules and Regulations. The Board may not delegate to the Executive Committee or any other committee its authority under Section 2.5.11 to adopt and amend the Operating Rules and Regulations.

4.7 **Commissions, Boards and Committees**. The Board may establish any advisory commissions, boards and committees as the Board deems appropriate to assist the Board in carrying out its functions and implementing the CCA Program, other energy programs and the provisions of this Agreement.

4.8 **Director Compensation**. Compensation for work performed by Directors on behalf of the Authority shall be borne by the Party that appointed the Director. The Board, however, may adopt by resolution a policy relating to the reimbursement of expenses incurred by Directors.

4.9 **Board Voting Related to the CCA Program**.

4.9.1. To be effective, on all matters specifically related to the CCA Program, a vote of the Board shall consist of the following: (1) a majority of all Directors shall vote in the affirmative or such higher voting percentage expressly set forth in Sections 7.2 and 8.4 (the "percentage vote") and (2) the corresponding voting shares (as described in Section 4.9.2 and Exhibit D) of all such Directors voting in the affirmative shall exceed 50%, or such other higher voting shares percentage expressly set forth in Sections 7.2 and 8.4 (the "percentage voting shares"), provided that, in instances in which such other higher voting share percentage would result in any one Director having a voting share that equals or exceeds that which is necessary to disapprove the matter being voted on by the Board, at least one other Director shall be required to vote in the negative in order to disapprove such matter.

4.9.2. Unless otherwise stated herein, voting shares of the Directors shall be determined by combining the following: (1) an equal voting share for each Director determined in accordance with the formula detailed in Section 4.9.2.1, below; and (2) an additional voting share determined in accordance with the formula detailed in Section 4.9.2.2, below.

4.9.2.1 Pro Rata Voting Share. Each Director shall have an equal voting share as determined by the following formula: (1/total number of

Directors) multiplied by 50, and

4.9.2.2 Annual Energy Use Voting Share. Each Director shall have an additional voting share as determined by the following formula: (Annual Energy Use/Total Annual Energy) multiplied by 50, where (a) "Annual Energy Use" means, (i) with respect to the first 5 years following the Effective Date, the annual electricity usage, expressed in kilowatt hours ("kWhs"), within the Party's respective jurisdiction and (ii) with respect to the period after the fifth anniversary of the Effective Date, the annual electricity usage, expressed in kWhs, of accounts within a Party's respective jurisdiction that are served by the Authority and (b) "Total Annual Energy" means the sum of all Parties' Annual Energy Use. The initial values for Annual Energy use are designated in Exhibit C, and shall be adjusted annually as soon as reasonably practicable after January 1, but no later than March 1 of each year

4.9.2.3 The voting shares are set forth in Exhibit D. Exhibit D may be updated to reflect revised annual energy use amounts and any changes in the parties to the Agreement without amending the Agreement provided that the Board is provided a copy of the updated Exhibit D.

4.10 **Board Voting on General Administrative Matters and Programs Not Involving CCA.** Except as otherwise provided by this Agreement or the Operating Rules and Regulations, each member shall have one vote on general administrative matters, including but not limited to the adoption and amendment of the Operating Rules and Regulations, and energy programs not involving CCA. Action on these items shall be determined by a majority vote of the quorum present and voting on the item or such higher voting percentage expressly set forth in Sections 7.2 and 8.4.

4.11 **Board Voting on CCA Programs Not Involving CCA That Require Financial Contributions.** The approval of any program or other activity not involving CCA that requires financial contributions by individual Parties shall be approved only by a majority vote of the full membership of the Board subject to the right of any Party who votes against the program or activity to opt-out of such program or activity pursuant to this section. The Board shall provide at least 45 days prior written notice to each Party before it considers the program or activity for adoption at a Board meeting. Such notice shall be provided to the governing body and the chief administrative officer, city manager or town manager of each Party. The Board also shall provide written notice of such program or activity adoption to the above-described officials of each Party within 5 days after the Board adopts the program or activity. Any Party voting against the approval of a program or other activity of the Authority requiring financial contributions by individual Parties may elect to opt-out of participation in such program or activity by providing written notice of this election to the Board within 30 days after the program or activity is approved by the Board. Upon timely exercising its opt-out election, a Party shall not have any financial obligation or any liability whatsoever for the conduct or operation of such program or activity.

4.12 **<u>Meetings and Special Meetings of the Board</u>**. The Board shall hold at least four regular meetings per year, but the Board may provide for the holding of regular meetings at more frequent intervals. The date, hour and place of each regular meeting shall be fixed by resolution or ordinance of the Board. Regular meetings may be adjourned to another meeting time. Special meetings of the Board may be called in accordance with the provisions of California Government Code Section 54956. Directors may participate in meetings telephonically, with full voting rights, only to the extent permitted by law. All meetings of the Board shall be conducted in accordance with the provisions of the Ralph M. Brown Act (California Government Code Section 54950 et seq.).

4.13 **<u>Selection of Board Officers</u>.**

4.13.1 **Chair and Vice Chair**. The Directors shall select, from among themselves, a Chair, who shall be the presiding officer of all Board meetings, and a Vice Chair, who shall serve in the absence of the Chair. The term of office of the Chair and Vice Chair shall continue for one year, but there shall be no limit on the number of terms held by either the Chair or Vice Chair. The office of either the Chair or Vice Chair shall be declared vacant and a new selection shall be made if: (a) the person serving dies, resigns, or the Party that the person represents removes the person as its representative on the Board or (b) the Party that he or she represents withdraws form the Authority pursuant to the provisions of this Agreement.

4.13.2 **Secretary**. The Board shall appoint a Secretary, who need not be a member of the Board, who shall be responsible for keeping the minutes of all meetings of the Board and all other official records of the Authority.

4.13.3 **Treasurer and Auditor**. The Board shall appoint a qualified person to act as the Treasurer and a qualified person to act as the Auditor, neither of whom needs to be a member of the Board. If the Board so designates, and in accordance with the provisions of applicable law, a qualified person may hold both the office of Treasurer and the office of Auditor of the Authority. Unless otherwise exempted from such requirement, the Authority shall cause an independent audit to be made by a certified public accountant, or public accountant, in compliance with Section 6505 of the Act. The Treasurer shall act as the depositary of the Authority and have custody of all the money of the Authority, from whatever source, and as such, shall have all of the duties and responsibilities specified in Section 6505.5 of the Act. The Board may require the Treasurer and/or Auditor to file with the Authority an official bond in an amount to be fixed by the Board, and if so requested the Authority shall pay the cost of premiums associated with the bond. The Treasurer shall report directly to the Board and shall comply with the requirements of treasurers of incorporated municipalities. The Board may transfer the responsibilities of Treasurer to any person or entity as the law may provide at the time. The duties and obligations of the Treasurer are further specified in Article 6.

4.14 **<u>Administrative Services Provider</u>.** The Board may appoint one or more administrative services providers to serve as the Authority's agent for planning, implementing, operating and administering the CCA Program, and any other program approved by the Board, in accordance with the provisions of a written agreement between the Authority and the appointed administrative services provider or providers that will be known as an Administrative Services Agreement. The Administrative Services Agreement shall set forth the terms and conditions by which the appointed administrative services provider shall perform or cause to be performed all tasks necessary for planning, implementing, operating and administering the CCA Program and other approved programs. The Administrative Services Agreement shall set forth the term of the Agreement and the circumstances under which the Administrative Services Agreement may be terminated by the Authority. This section shall not in any way be construed to limit the discretion of the Authority to hire its own employees to administer the CCA Program or any other program.

ARTICLE 5
IMPLEMENTATION ACTION AND AUTHORITY DOCUMENTS

5.1 **<u>Preliminary Implementation of the CCA Program.</u>**

5.1.1 **Enabling Ordinance**. Except as otherwise provided by Section 3.1, prior to the execution of this Agreement, each Party shall adopt an ordinance in accordance with Public Utilities Code Section 366.2(c)(10) for the purpose of specifying that the Party intends to implement a CCA Program by and through its participation in the Authority.

5.1.2 **Implementation Plan**. The Authority shall cause to be prepared an Implementation Plan meeting the requirements of Public Utilities Code Section 366.2 and any applicable Public Utilities Commission regulations as soon after the Effective Date as reasonably practicable. The Implementation Plan shall not be filed with the Public Utilities Commission until it is approved by the Board in the manner provided by Section 4.9.

5.1.3 Effect of Vote On Required Implementation Action. In the event that two or more Parties vote to approve Program Agreement 1 or any earlier action required for the implementation of the CCA Program ("Required Implementation Action"), but such vote is insufficient to approve the Required Implementation Action under Section 4.9, the following will occur:

5.1.3.1 The Parties voting against the Required Implementation Action shall no longer be a Party to this Agreement and this Agreement shall be terminated, without further notice, with respect to each of the Parties voting against the Required Implementation Action at the time this vote is final. The Board may take a provisional vote on a Required Implementation Action in order to initially determine the position of the Parties on the Required Implementation Action. A vote, specifically stated in the record of the Board meeting to be a provisional vote, shall not be considered a final vote with the consequences stated above. A Party who is terminated from this Agreement pursuant to this section shall be considered the same as a Party that voluntarily withdrew from the Agreement under Section 7.1.1.1.

5.1.3.2 After the termination of any Parties pursuant to Section 5.1.3.1, the remaining Parties to this Agreement shall be only the Parties who voted in favor of the Required Implementation Action.

5.1.4 Termination of CCA Program. Nothing contained in this Article or this Agreement shall be construed to limit the discretion of the Authority to terminate the implementation or operation of the CCA Program at any time in accordance with any applicable requirements of state law.

5.2 **Authority Documents**. The Parties acknowledge and agree that the affairs of the Authority will be implemented through various documents duly adopted by the Board through Board resolution, including but not necessarily limited to the Operating Rules and Regulations, the annual budget, and specified plans and policies defined as the Authority Documents by this Agreement. The Parties agree to abide by and comply with the terms and conditions of all such Authority Documents that may be adopted by the Board, subject to the Parties' right to withdraw from the Authority as described in Article 7.

ARTICLE 6
FINANCIAL PROVISIONS

6.1 **Fiscal Year**. The Authority's fiscal year shall be 12 months commencing July 1 and ending June 30. The fiscal year may be changed by Board resolution.

6.2 **Depository**.

6.2.1 All funds of the Authority shall be held in separate accounts in the name of the Authority and not commingled with funds of any Party or any other person or entity.

6.2.2 All funds of the Authority shall be strictly and separately accounted for, and regular reports shall be rendered of all receipts and disbursements, at least quarterly during the fiscal year. The books and records of the Authority shall be open to inspection by the Parties at all reasonable times. The Board shall contract with a certified public accountant or public accountant to make an annual audit of the accounts and records of the Authority, which shall be conducted in accordance with the requirements of Section 6505 of the Act.

6.2.3 All expenditures shall be made in accordance with the approved budget and upon the approval of any officer so authorized by the Board in accordance with its Operating Rules and Regulations. The Treasurer shall draw checks or warrants or make payments by other means for claims or disbursements not within an applicable budget only upon the prior approval of the Board.

6.3 **Budget and Recovery Costs**.

6.3.1 **Budget**. The initial budget shall be approved by the Board. The Board may revise the budget from time to time through an Authority Document as may be reasonably necessary to address contingencies and unexpected expenses. All subsequent budgets of the Authority shall be prepared and approved by the Board in accordance with the Operating Rules and Regulations.

6.3.2 **County Funding of Initial Costs**. The County of Marin shall fund the Initial Costs of the Authority in implementing the CCA Program in an amount not to exceed $500,000 unless a larger amount of funding is approved by the Board of Supervisors of the County**.** This funding shall be paid by the County at the times and in the amounts required by the Authority. In the event that the CCA Program becomes operational, these Initial Costs paid by the County of Marin shall be included in the customer charges for electric services as provided by Section 6.3.4 to the extent permitted by law, and the County of Marin shall be reimbursed from the payment of such charges by customers of the Authority. The Authority may establish a reasonable time period over which such costs are recovered. In the event that the CCA Program does not become operational, the County of Marin shall not be entitled to any reimbursement of the Initial Costs it has paid from the Authority or any Party.

6.3.3 **CCA Program Costs**. The Parties desire that, to the extent reasonably practicable, all costs incurred by the Authority that are directly or indirectly attributable to the provision of electric services under the CCA Program, including the establishment and maintenance of various reserve and performance funds, shall be recovered through charges to CCA customers receiving such electric services.

6.3.4 **General Costs**. Costs that are not directly or indirectly attributable to the provision of electric services under the CCA Program, as determined by the Board, shall be defined as general costs. General costs shall be shared among the Parties on such basis as the Board shall determine pursuant to an Authority Document.

6.3.5 **Other Energy Program Costs**. Costs that are directly or indirectly attributable to energy programs approved by the Authority other than the CCA Program shall be shared among the Parties on such basis as the Board shall determine pursuant to an Authority Document.

ARTICLE 7
WITHDRAWAL AND TERMINATION

7.1 **<u>Withdrawal</u>**.

7.1.1 **General.**

7.1.1.1 Prior to the Authority's execution of Program Agreement 1, any Party may withdraw its membership in the Authority by giving no less than 30 days advance written notice of its election to do so, which notice shall be given to the Authority and each Party. To permit consideration by the governing body of each Party, the Authority shall provide a copy of the proposed Program Agreement 1 to each Party at least 90 days prior to the consideration of such agreement by the Board.

7.1.1.2 Subsequent to the Authority's execution of Program Agreement 1, a Party may withdraw its membership in the Authority, effective as of the beginning of the Authority's fiscal year, by giving no less than 6 months advance written notice of its election to do so, which notice shall be given to the Authority and each Party, and upon such other conditions as may be prescribed in Program Agreement 1.

7.1.2 Amendment. Notwithstanding Section 7.1.1, a Party may withdraw its membership in the Authority following an amendment to this Agreement in the manner provided by Section 8.4.

7.1.3 Continuing Liability; Further Assurances. A Party that withdraws its membership in the Authority may be subject to certain continuing liabilities, as described in Section 7.3. The withdrawing Party and the Authority shall execute and deliver all further instruments and documents, and take any further action that may be reasonably necessary, as determined by the Board, to effectuate the orderly withdrawal of such Party from membership in the Authority. The Operating Rules and Regulations shall prescribe the rights if any of a withdrawn Party to continue to participate in those Board discussions and decisions affecting customers of the CCA Program that reside or do business within the jurisdiction of the Party.

7.2 **<u>Involuntary Termination of a Party</u>**. This Agreement may be terminated with respect to a Party for material non-compliance with provisions of this Agreement or the Authority Documents upon an affirmative vote of the Board in which the minimum percentage vote and percentage voting shares, as described in Section 4.9.1, shall be no less than 67%, excluding the vote and voting shares of the Party subject to possible termination. Prior to any vote to terminate this Agreement with respect to a Party, written notice of the proposed termination and the reason(s) for such termination shall be delivered to the Party whose termination is proposed at least 30 days prior to the regular Board meeting at which such matter shall first be discussed as an agenda item. The written notice of proposed termination shall specify the particular provisions of this Agreement or the Authority Documents that the Party has allegedly violated. The Party subject to possible termination shall have the opportunity at the next regular Board meeting to respond to any reasons and allegations that may be cited as a basis for termination prior to a vote regarding termination. A Party that has had its membership in the Authority terminated may be subject to certain continuing liabilities, as described in Section 7.3. In the event that the Authority decides to not implement the CCA Program, the minimum percentage vote of 67% shall be conducted in accordance with Section 4.10 rather than Section 4.9.1.

7.3 **<u>Continuing Liability; Refund</u>**. Upon a withdrawal or involuntary termination of a Party, the Party shall remain responsible for any claims, demands, damages, or liabilities arising from the Party's membership in the Authority through the date of its withdrawal or involuntary termination, it being agreed that the Party shall not be responsible for any claims, demands, damages, or liabilities arising after the date of the Party's withdrawal or involuntary termination. In addition, such

Party also shall be responsible for any costs or obligations associated with the Party's participation in any program in accordance with the provisions of any agreements relating to such program provided such costs or obligations were incurred prior to the withdrawal of the Party. The Authority may withhold funds otherwise owing to the Party or may require the Party to deposit sufficient funds with the Authority, as reasonably determined by the Authority, to cover the Party's liability for the costs described above. Any amount of the Party's funds held on deposit with the Authority above that which is required to pay any liabilities or obligations shall be returned to the Party.

7.4 **Mutual Termination**. This Agreement may be terminated by mutual agreement of all the Parties; provided, however, the foregoing shall not be construed as limiting the rights of a Party to withdraw its membership in the Authority, and thus terminate this Agreement with respect to such withdrawing Party, as described in Section 7.1.

7.5 **Disposition of Property upon Termination of Authority**. Upon termination of this Agreement as to all Parties, any surplus money or assets in possession of the Authority for use under this Agreement, after payment of all liabilities, costs, expenses, and charges incurred under this Agreement and under any program documents, shall be returned to the then-existing Parties in proportion to the contributions made by each.

ARTICLE 8
MISCELLANEOUS PROVISIONS

8.1 **Dispute Resolution**. The Parties and the Authority shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. Should such efforts to settle a dispute, after reasonable efforts, fail, the dispute shall be settled by binding arbitration in accordance with policies and procedures established by the Board.

8.2 **Liability of Directors, Officers, and Employees**. The Directors, officers, and employees of the Authority shall use ordinary care and reasonable diligence in the exercise of their powers and in the performance of their duties pursuant to this Agreement. No current or former Director, officer, or employee will be responsible for any act or omission by another Director, officer, or employee. The Authority shall defend, indemnify and hold harmless the individual current and former Directors, officers, and employees for any acts or omissions in the scope of their employment or duties in the manner provided by Government Code Section 995 et seq. Nothing in this section shall be construed to limit the defenses available under the law, to the Parties, the Authority, or its Directors, officers, or employees.

8.3 **Indemnification of Parties.** The Authority shall acquire such insurance coverage as is necessary to protect the interests of the Authority, the Parties and the public. The Authority shall defend, indemnify and hold harmless the Parties and each of their respective Board or Council members, officers, agents and employees, from any and all claims, losses, damages, costs, injuries and liabilities of every kind arising directly or indirectly from the conduct, activities, operations, acts, and omissions of the Authority under this Agreement.

8.4 **Amendment of this Agreement**. This Agreement may be amended by an affirmative vote of the Board in which the minimum percentage vote and percentage voting shares, as described in Section 4.9.1, shall be no less than 67%. The Authority shall provide written notice to all Parties of amendments to this Agreement, including the effective date of such amendments. A Party shall be deemed to have withdrawn its membership in the Authority effective immediately upon the vote of the Board approving an amendment to this Agreement if the Director representing such Party has provided notice to the other Directors immediately preceding the Board's vote of the Party's intention to withdraw its membership in the Authority should the amendment be approved by the Board. As described in Section 7.3, a Party that withdraws its membership in the Authority in accordance with the above-described procedure may be subject to continuing liabilities incurred prior to the Party's withdrawal. In the event that the Authority decides to not implement the CCA Program, the minimum percentage vote of 67% shall be conducted in accordance with Section 4.10 rather than Section 4.9.1.

8.5 **Assignment**. Except as otherwise expressly provided in this Agreement, the rights and duties of the Parties may not be assigned or delegated without the advance written consent of all of the other Parties, and any attempt to assign or delegate such rights or duties in contravention of this Section 8.5 shall be null and void. This Agreement shall inure to the benefit of, and be binding upon, the successors and assigns of the Parties. This Section 8.5 does not prohibit a Party from entering into an independent agreement with another agency, person, or entity regarding the financing of that Party's contributions to the Authority, or the disposition of proceeds which that Party receives under this Agreement, so long as such independent agreement does not affect, or purport to affect, the rights and duties of the Authority or the Parties under this Agreement.

8.6 **Severability**. If one or more clauses, sentences, paragraphs or provisions of this Agreement shall be held to be unlawful, invalid or unenforceable, it is hereby agreed by the Parties, that the remainder of the Agreement shall not be affected thereby. Such clauses, sentences, paragraphs or provision shall be deemed reformed so as to be lawful, valid and enforced to the maximum extent possible.

8.7 **<u>Further Assurances</u>**. Each Party agrees to execute and deliver all further instruments and documents, and take any further action that may be reasonably necessary, to effectuate the purposes and intent of this Agreement.

8.8 **<u>Execution by Counterparts</u>**. This Agreement may be executed in any number of counterparts, and upon execution by all Parties, each executed counterpart shall have the same force and effect as an original instrument and as if all Parties had signed the same instrument. Any signature page of this Agreement may be detached from any counterpart of this Agreement without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of this Agreement identical in form hereto but having attached to it one or more signature pages.

8.9 **<u>Parties to be Served Notice</u>**. Any notice authorized or required to be given pursuant to this Agreement shall be validly given if served in writing either personally, by deposit in the United States mail, first class postage prepaid with return receipt requested, or by a recognized courier service. Notices given (a) personally or by courier service shall be conclusively deemed received at the time of delivery and receipt and (b) by mail shall be conclusively deemed given 48 hours after the deposit thereof (excluding Saturdays, Sundays and holidays) if the sender receives the return receipt. All notices shall be addressed to the office of the clerk or secretary of the Authority or Party, as the case may be, or such other person designated in writing by the Authority or Party. Notices given to one Party shall be copied to all other Parties. Notices given to the Authority shall be copied to all Parties.

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: Leon Garcia

Name: Leon Garcia

Title: Mayor

Date: 4.7.16

Party: City of American Canyon

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the Marin Energy Authority.

By: ______________________

Name: Thomas Cromwell

Title: Mayor

Date: December 8, 2008

Party: City of Belvedere

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: ______________________

Name: Elizabeth Patterson

Title: Mayor

Date: 12·29·14

Party: City of Benicia

APPROVED AS TO FORM

CITY ATTORNEY

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: ______________________

Name: Dylan Feik

Title: City Manager

Date: April 7, 2016

Party: City of Calistoga

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the Marin Energy Authority.

By: ______________________

Name: Alexandra Cock

Title: Mayor

Date: December 6, 2011

Party: Town of Corte Madera

ATTEST

____
Christine Green, Town Clerk

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: ______________________

Name: Mike Parness

Title: City Manager

Date: 4-11-16

Party: City of Napa

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the Marin Energy Authority.

By: ______________________

Name: CHARLES F. McGLASHAN

Title: PRESIDENT, BD OF SUPERVISORS

Date: November 18 2008

Party: COUNTY OF MARIN

ARTICLE 9

Marin Clean Energy JPA Agreement

SIGNATURE

Amendment No. 8

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: ____________________

Name: Mark Luce,

Title: Chairman, Napa County Board of Supervisors

Date: 7/22/14

Party: Napa County

Approved as to form:

____________________ Date 7/21/14

Minh Tran,

County Counsel

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: ______________________

Name: Scott Hanin

Title: City Manager

Date: 1/8/14

Party: City of El Cerrito

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the Marin Energy Authority.

By: David Weinsoff ______________________________

Name: David Weinsoff

Title: Mayor

Date: 2. 12. 09 ______________________________

Party: Town of Fairfax

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: ____________________

Name: Mark Mitchell

Title: Mayor

Date: 3-14-16

Party: City of Lafayette

Attest:

Joanne Robbins

Joanne Robbins, City Clerk

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the Marin Energy Authority.

By: ______________________

Name: Larry Chu

Title: Mayor, Larkspur

Date: November 16, 2011

Party: CITY OF LARKSPUR

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the Marin Energy Authority.

By: S. Marshall

Name: Shawn E. Marshall

Title: Mayor

Date: December 2, 2008

Party: City of Mill Valley

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the Marin Energy Authority.

By: Madeline R. Kellner

Name: Madeline R. Kellner

Title: Mayor

Date: October 7, 2011

Party: City of Novato

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing the Marin Energy Authority

By: Gayle McLaughlin

Name: Gayle McLaughlin

Title: Mayor

Date: 7/5/12

Party: City of Richmond

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the Marin Energy Authority.

By: ______________________

Name: Carla Small

Title: Mayor

Date: 11/16/11

Party: Town of Ross

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the Marin Energy Authority.

By: ______________________________

Name: ____Peter Breen__________________

Title: ____Mayor_______________________

Date: ____January 9, 2009__ ___________

Party: ____Town of San Anselmo_________

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: ______________________

Name: Paul V. Morris

Title: Mayor, City of San Pablo

Date: SEPT. 16, 2014

Party: City of San Pablo

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the Marin Energy Authority.

By: Cyr N. Miller

Name: Cyr N. Miller

Title: Vice Mayor

Date: DECEMBER 1, 2008

Party: CITY OF SAN RAFAEL

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the Marin Energy Authority.

By: Amy Belser

Name: Amy Belser

Title: Mayor

Date: November 18, 2008

Party: City of Sausalito

Attest:

Debbie Pagliaro

Deputy City Clerk

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: Alan Galbraith

Name: Alan Galbraith

Title: Mayor

Date: 4/14/16

Party: City of St. Helena

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the Marin Energy Authority.

By: ____________________

Name: ALICE FREDERICKS

Title: MAYOR

Date: 2/10/09

Party: TOWN OF TIBURON

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: Luella Haskew

Name: LOELLA HASKEW

Title: MAYOR

Date: 4/13/16

Party: City of Walnut Creek

ARTICLE 9

SIGNATURE

IN WITNESS WHEREOF, the parties hereto have executed this Joint Powers Agreement establishing Marin Clean Energy (formerly, Marin Energy Authority)

By: ______________________

Name: Steven R. Rogers

Title: Town Manager

Date: 4/12/16

Party: Town of Yountville

APPENDIX C

ORDINANCE NO. 2015-12

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF AMERICAN CANYON APPROVING THE MARIN CLEAN ENERGY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

WHEREAS, the City of American Canyon has been actively investigating options to provide electric services to constituents within its service area with the intent of promoting use of renewable energy and reducing energy related greenhouse gas emissions; and

WHEREAS, on September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation; and

WHEREAS, the Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and on December 19, 2008, the Marin Clean Energy (MCE) was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time; and

WHEREAS, on February 2, 2010 the California Public Utilities Commission certified the "Implementation Plan" of the MCE, confirming the MCE's compliance with the requirements of the Act; and

WHEREAS, in order to become a member of the MCE, the Act requires the City of American Canyon to adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the MCE.

NOW, THEREFORE, BE IT ORDAINED, by the City Council of the City of American Canyon as follows:

SECTION 1: Based upon all of the above, the City Council elects to implement a Community Choice Aggregation program within the City of American Canyon's jurisdiction by and through the City of American Canyon's participation in the Marin Clean Energy. The Mayor is hereby authorized to execute the MCE Joint Powers Agreement.

SECTION 2: This ordinance shall take effect on the later of (a) the date the Board of Directors of MCE adopts a Resolution adding the City as a member of MCE, or (b) 30 days after the adoption of this ordinance.

The foregoing Ordinance was introduced at a regular meeting of the City Council of the City of American Canyon, State of California, held on the 3rd day of November, 2015 by the following vote:

AYES:	Council Members Bennett, Joseph, Ramos, Vice Mayor Leary and Mayor Garcia
NOES:	None
ABSTAIN:	None
ABSENT:	None

The foregoing Ordinance was adopted at a regular meeting of the City Council of the City of American Canyon, State of California, held on the 17th day of November, 2015 by the following vote:

AYES:	Council Members Bennett, Joseph, Ramos, Vice Mayor Leary, Mayor Garcia
NOES:	None
ABSTAIN:	None
ABSENT:	None

Leon Garcia

Leon Garcia, Mayor

ATTEST:

Cherri Walton, CMC, Deputy City Clerk

APPROVED AS TO FORM:

William D. Ross, City Attorney

CITY OF BELVEDERE

ORDINANCE NO. 2008-5

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF BELVEDERE APPROVING THE MARIN ENERGY AUTHORITY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

THE CITY COUNCIL OF THE CITY OF BELVEDERE DOES ORDAIN AS FOLLOWS:

SECTION 1. The City of Belvedere has been actively investigating options to provide electric services to constituents within its service area with the intent of achieving greater local involvement over the provisions of electric services and promoting competitive and renewable energy.

SECTION 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation.

SECTION 3. The Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and to this end the City has been participating since 2003 in the evaluation of a CCA program for the County of Marin and the cities and towns within it.

SECTION 4. On June 22, 2006, the City joined a Local Government Task Force (LGTF), which was comprised of elected officials and representatives of the County of Marin and each municipality in the County. The purpose of the LGTF was to jointly participate in the investigation of CCA for Marin communities and customers. The LGTF had five meetings with the final meeting taking place on March 6, 2008. The LGTF meetings looked at issues including:

A. The costs, benefits and risks of a CCA including legal liability issues.

B. The governance and business planning of a CCA.

C. The feasibility of a CCA and deciding whether to pursue formation of a countywide CCA organization.

D. Public education.

SECTION 5. Through Docket No. R.03-10-003, the California Public Utilities Commission has issued various decisions and rulings addressing the implementation of Community Choice Aggregation programs, including the recent issuance of a procedure by which the California Public Utilities Commission will review "Implementation Plans," which are required for submittal under the Act as the means of describing the Community Choice Aggregation program and assuring compliance with various elements contained in the Act.

SECTION 6. Representatives from the City along with the other LGTF members have developed the Marin Energy Authority Joint Powers Agreement ("Joint Powers Agreement") (attached hereto as Exhibit A) in order to accomplish the following:

A. To form a Joint Powers Authority (JPA) known as "Marin Energy."

B. To specify the terms and conditions by which participants may participate as a group in energy programs, including but not limited to the preliminary implementation of a Community Choice Aggregation program.

SECTION 7. Representatives from the City along with the LGTF members have developed a Business Plan (attached hereto as Exhibit B) that describes the formation of Marin Clean Energy and the Community Choice Aggregation program to be implemented by and through the Marin Energy Authority.

SECTION 8. A final Implementation Plan will be submitted for review and adoption by the Board of Directors of the Marin Energy Authority as soon after the formation of the Authority as reasonably practicable.

SECTION 9. As described in the Business Plan, Community Choice Aggregation by and through the Marin Energy Authority appears to provide a reasonable opportunity to accomplish all of the following:

A. To provide greater levels of local involvement in and collaboration on energy decisions.

B. To increase significantly the amount of renewable energy available to Marin customers.

C. To provide initial price stability, long-term electricity cost savings and other benefits for the community.

D. To reduce green house gases that are emitted by creating electricity for the community.

SECTION 10. The Act requires Community Choice Aggregation program participants to individually adopt an ordinance ("CCA Ordinance") electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the Marin Energy Authority.

SECTION 11. The Joint Powers Agreement expressly allows the City to withdraw its membership in the Marin Energy Authority (and its participation in the Community Choice Aggregation program) prior to the actual implementation of a Community Choice Aggregation program through Program Agreement 1.

SECTION 12. A city, town or county may not participate in the Marin Energy Joint Powers Authority without also participating in the Community Choice Aggregation program unless the Board of Directors of the Marin Energy Joint Powers Authority decides to not implement or operate a Community Choice Aggregation program after the Authority is established.

SECTION 13. Based upon all of the above, the Council approves the Joint Powers Agreement attached hereto as Exhibit A and elects to implement a Community Choice Aggregation program within the City's jurisdiction by and through the City's participation in the Marin Energy Authority, as described in the Business Plan in substantially the form attached hereto as Exhibit B, and subject to the City's right to forego the actual implementation of a Community Choice Aggregation program pursuant to specified withdrawal rights described in the Joint Powers Agreement. The Mayor is hereby authorized to execute the attached Joint Powers Agreement.

SECTION 14. This ordinance shall take effect and be in force thirty (30) days after the date of its passage. Within fifteen (15) days following its passage, a summary of the ordinance shall be published with the names of those city council members voting for and against the ordinance and the city clerk shall post in the office of the city clerk a certified copy of the full text of the adopted ordinance along with the names of the members voting for and against the ordinance.

INTRODUCED AT A PUBLIC HEARING on November 10, 2008, and adopted at a regular meeting of the Belvedere City Council on December 8, 2008, by the following vote:

AYES: Gerald Butler, Sandra Donnell, John C. Telischak, and Mayor Thomas Cromwell
NOES: None
ABSENT: Barbara Morrison
ABSTAIN: None

APPROVED: Thomas Cromwell
Thomas Cromwell, Mayor

ATTEST: Leslie Carpentiers
Leslie Carpentiers, Deputy City Clerk

CITY OF BENICIA

ORDINANCE NO. 14-9

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF BENICIA APPROVING THE MARIN CLEAN ENERGY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

NOW, THEREFORE, THE CITY COUNCIL OF THE CITY OF BENICIA DOES ORDAIN as follows:

Section 1. The City of Benicia has been actively investigating options to provide electric services to constituents within its service area with the intent of achieving greater local involvement over the provision of electric services and promoting competitive and renewable energy.

Section 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation (CCA).

Section 3. The Act expressly authorizes participation in a CCA program through a joint powers agency, and on December 19, 2008, Marin Clean Energy (MCE), formerly known as the Marin Energy Authority, was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time.

Section 4. On February 2, 2010, the California Public Utilities Commission certified the "Implementation Plan" of MCE, confirming MCE's compliance with the requirements of the Act.

Section 5. In order to become a member of MCE, the Act requires the City to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in Marin Clean Energy.

Section 6. Based upon all of the above, the Council elects to implement a Community Choice Aggregation program within the City's jurisdiction by and through the City's participation in Marin Clean Energy. The President of the Board of Directors is hereby authorized to execute the MCE Joint Powers Agreement.

Section 7. This ordinance shall take effect and be in force 30 days after its adoption, and, before the expiration of 30 days after its passage, a summary of this ordinance shall be published once with the names of the members of the Council voting for and against the same in the Benicia Herald, a newspaper of general circulation published in the City of Benicia.

****

On motion of Vice Mayor **Campbell**, seconded by Council Member **Schwartzman**, the foregoing Ordinance was introduced at a regular meeting of the City Council on the 4th day of November, 2014, and adopted at a regular meeting of the Council held on the 18th day of November, 2014, by the following vote:

Ayes: **Council Members Campbell, Schwartzman, Strawbridge, and Mayor Patterson**

Noes: **None**

Absent: **None**

Abstain: **Council Member Hughes**

E Patterson

Elizabeth Patterson, Mayor

Attest:

Lisa Wolfe

Lisa Wolfe, City Clerk

11-20-14

Date

ORDINANCE NO. 718

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF CALISTOGA APPROVING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM AND AUTHORIZING THE MARIN CLEAN ENERGY JOINT POWERS AGREEMENT

WHEREAS, the City of Calistoga has been actively investigating options to provide electric services to constituents within its service area with the intent of promoting use of renewable energy and reducing energy related greenhouse gas emissions; and

WHEREAS, Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act") authorizes any California city whose governing body so elects to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation (CCA); and

WHEREAS, the Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and on December 19, 2008, Marin Clean Energy (MCE) was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time; and

WHEREAS, on February 2, 2010 the California Public Utilities Commission certified MCE's "Implementation Plan," confirming MCE's compliance with the requirements of the Act; and

WHEREAS, participating in MCE will gives city customers the choice of having 50% to 100% of their electricity supplied from renewable sources—such as wind, bioenergy, and hydroelectric—as compared to Calistoga's existing provider PG&E, whose energy mix in 2013 was about 22% from renewable sources, at rates that are competitive with PG&E.

WHEREAS, in order to become a member of MCE, the Act requires the City to adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in MCE.

NOW, THEREFORE, THE CALISTOGA CITY COUNCIL DOES HEREBY ORDAIN AS FOLLOWS:

SECTION ONE

Findings. The above recitals are incorporated herein as if set forth herein in full and each is relied upon independently by the City Council for its adoption of this ordinance.

SECTION TWO

Based upon all of the above, the City Council elects to implement a Community Choice Aggregation program within the City of Calistoga's jurisdiction by and through the City's participation in Marin Clean Energy.

SECTION THREE

The City Council hereby authorizes the Mayor to execute the MCE Joint Powers Agreement attached hereto as Exhibit A.

SECTION FOUR

Severability. If any section, subsection, subdivision, paragraph, sentence, clause, or phrase in this ordinance or any part thereof is for any reason held to be unconstitutional or invalid or ineffective by any court of competent jurisdiction, such decision shall not affect the validity or effectiveness of the remaining portions of this ordinance or any part thereof. The City Council hereby declares that it would have passed each section, subsection, subdivision, paragraph, sentence, clause, or phrase thereof irrespective of the fact that any one or more subsections, subdivisions, paragraphs, sentences, clauses, or phrases be declared unconstitutional, or invalid, or ineffective.

SECTION FIVE

Effective Date. This ordinance shall take effect on the later of (a) the date the MCE Board of Directors adopts a resolution adding the City of Calistoga as a member of MCE, or (b) 30 days after its passage. Before the expiration of fifteen (15) days after its passage, the ordinance shall be published in accordance with law in a newspaper of general circulation published and circulated in the city of Calistoga.

THIS ORDINANCE was introduced with the first reading waived at the City of Calistoga City Council meeting of the **20th day of October, 2015,** and was passed and adopted at a regular meeting of the Calistoga City Council **on November 3, 2015**, by the following vote:

AYES: **Councilmember Kraus, Councilmember Lopez-Ortega, Councilmember Barnes and Mayor Canning**
NOES: **None**
ABSENT: **Vice Mayor Dunsford**
ABSTAIN: **None**

Chris Canning, Mayor

ATTEST:

Melissa Velasquez

Melissa Velasquez, ~~Deputy~~ City Clerk

ORDINANCE NO. 930

ORDINANCE OF THE TOWN COUNCIL OF THE TOWN OF CORTE MADERA APPROVING THE MARIN ENERGY AUTHORITY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

The Town Council of the Town of Corte Madera ordains as follows:

SECTION 1. The Town of Corte Madera has been actively investigating options to provide electric services to constituents within its service area with the intent of achieving greater local involvement over the provision of electric services and promoting competitive and renewable energy.

SECTION 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation (CCA).

SECTION 3. The Act expressly authorizes participation in a CCA program through a joint powers agency, and on December 19, 2008, the Marin Energy Authority (MEA) was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time.

SECTION 4. On February 2, 2010, the California Public Utilities Commission certified the "Implementation Plan" of the MEA, confirming the MEA's compliance with the requirements of the Act.

SECTION 5. In order to become a member of the MEA, the Act requires the City/Town to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the Marin Energy Authority.

SECTION 6. Based upon all of the above, the Council elects to implement a Community Choice Aggregation program within the City's/Town's jurisdiction by and through the City's/Town's participation in the Marin Energy Authority. The Mayor is hereby authorized to execute the MEA Joint Powers Agreement.

SECTION 7. This ordinance shall take effect and be in force 30 days after its adoption, and, before the expiration of 30 days after its passage, a summary of this ordinance shall be published once with the names of the members of the Council voting for and against the same in the Twin Cities Times,, a newspaper of general circulation.

The foregoing ordinance was introduced at a meeting of the Town Council of the Town of Corte Madera held on November 1, 2011, and adopted at a meeting held on November 15, 2011, by the following vote:

AYES Councilmembers: Cock, Condon, Lappert, Ravasio

NOES Councilmembers: - None -

ABSENT Councilmembers: - None -

Mayor Alexandra Cock

ATTEST:

Christine Green, Town Clerk

ORDINANCE NO. 2015–02

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF EL CERRITO AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM, APPROVING THE MARIN CLEAN ENERGY JOINT POWERS AGREEMENT, AND AUTHORIZING THE CITY MANAGER TO EXECUTE THE JOINT POWERS AGREEMENT WITH MARIN CLEAN ENERGY

THE CITY COUNCIL OF THE CITY OF EL CERRITO DOES HEREBY ORDAIN AS FOLLOWS:

SECTION 1. FINDINGS

On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, Ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "CCA Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation (CCA); and

The CCA Act expressly authorizes participation in a CCA program through a joint powers agency, and on December 19, 2008, Marin Clean Energy (MCE), formerly known as Marin Energy Authority, was established as a joint powers authority pursuant to a Joint Powers Agreement, as amended from time to time ("MCE Joint Powers Agreement"); and

The purpose of MCE is to address climate change by reducing energy related greenhouse gas emissions and securing energy supply, price stability, energy efficiencies and local economic and workforce benefits; and

On February 2, 2010, the California Public Utilities Commission certified the "Implementation Plan" of MCE, confirming MCE's compliance with the requirements of the Act; and

The City of El Cerrito adopted a Climate Action Plan on May 21, 2013 with the goal of reducing greenhouse gas emissions from the El Cerrito community and its own city operations by 15% below 2005 emissions levels by 2020 and 30% below 2005 levels by 2035; and

The El Cerrito Climate Action Plan contains goals and objectives to reduce reliance on fossil fuel based energy by increasing renewable energy throughout El Cerrito, including membership in a CCA, which it identified to be one of the most cost-effective greenhouse gas emissions reductions strategies available to the City; and

The City Council supports the mission of MCE and its intent to promote the development and use of a wide range of renewable energy sources and energy efficiency programs, including solar and wind energy production at competitive rates for customers; and

In order to become a member of MCE, the Act requires the City to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in Marin Clean Energy; and

This administrative action is exempt from CEQA, pursuant to State CEQA Guidelines Section 15378, which states there cannot be a project unless the proposed action will result in "either a direct physical change in the environment or a reasonably foreseeable indirect physical change in the environment." State CEQA Guidelines Section 15378(b)(5) states that "Organization or administrative activities of governments that will not result in direct or indirect physical changes in the environments" are not projects. Joining a CCA presents no foreseeable significant adverse impact to the environment because California State regulations such as the Renewable Portfolio Standard and the Resource Adequacy requirements apply equally to CCAs as they do the City's current electricity supplier, PG&E.

SECTION 2. COMPLIANCE WITH THE CALIFORNIA ENVIRONMENTAL QUALITY ACT

Pursuant to Title 14 of the California Administrative Code, the City Council finds that this Ordinance is exempt from the requirements of the California Environmental Quality Act (CEQA) for the following reasons: (1) Pursuant to State CEQA Guidelines Section 15378, there cannot be a project unless the proposed action will result in "either a direct physical change in the environment or a reasonably foreseeable indirect physical change in the environment;" and (2) State CEQA Guidelines Section 15378(b)(5) states that "organization or administrative activities of governments that will not result in direct or indirect physical changes in the environments" are not projects.

SECTION 3. APPROVAL

The City Council of the City of El Cerrito elects to implement a Community Choice Aggregation program within the City's jurisdiction by and through the City's participation in MCE. The City Manager is hereby authorized to execute the MCE Joint Powers Agreement.

SECTION 4. NOTICING, POSTING, AND PUBLICATION

This ordinance is adopted pursuant to the procedures established by state law, and all required notices have been given, and the public hearing has been properly held and conducted.

SECTION 5. EFFECTIVE DATE

This ordinance shall not take effect until thirty days after the second reading, January 6, 2015.

THE FOREGOING ORDINANCE was introduced at a regular meeting of the City Council on December 16, 2014 and passed by the following vote:

AYES:	Councilmembers Abelson, Bridges, Lyman, Quinto and Mayor Friedman
NOES:	None

ABSTAIN:	None
ABSENT:	None

ADOPTED AND ORDERED published at a regular meeting of the City Council held on January 6, 2015 and passed by the following vote:

AYES:	Councilmembers Abelson, Bridges, Lyman, Quinto and Mayor Friedman
NOES:	None
ABSTAIN:	None
ABSENT:	None

APPROVED:

Mark Friedman, Mayor

ATTEST:

Cheryl Morse, City Clerk

IN WITNESS of this action, I sign this document and affix the corporate seal of the City of El Cerrito on January 6, 2015.

Cheryl Morse, City Clerk

ORDINANCE CERTIFICATION

I, Cheryl Morse, City Clerk of the City of El Cerrito, do hereby certify that this Ordinance is the true and correct original Ordinance No. 2014-02 of the City of El Cerrito; that said Ordinance was duly enacted and adopted by the City Council of the City of El Cerrito at a meeting of the City Council held on the 6th day of January, 2015; and that said Ordinance has been published and/or posted in the manner required by law.

WITNESS my hand and the Official Seal of the City of El Cerrito, California, this 6th day of January, 2015.

Cheryl Morse, City Clerk

ORDINANCE NO. 739

AN ORDINANCE OF THE TOWN COUNCIL OF THE TOWN OF FAIRFAX APPROVING THE MARIN ENERGY AUTHORITY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

The Town Council of the Town of Fairfax ordains as follows:

SECTION 1. The Town of Fairfax has been actively investigating options to provide electric services to constituents within its service area with the intent of achieving greater local involvement over the provisions of electric services and promoting competitive and renewable energy.

SECTION 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation.

SECTION 3. The Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and to this end the Town has been participating since 2003 in the evaluation of a CCA program for the County of Marin and the cities and towns within it.

SECTION 4. On June 22, 2006, the Town joined a Local Government Task Force (LGTF), which was comprised of elected officials and representatives of the County of Marin and each municipality in the County. The purpose of the LGTF was to jointly participate in the investigation of CCA for Marin communities and customers. The LGTF had five meetings with the final meeting taking place on March 6, 2008. The LGTF meetings looked at issues including:

(a) The costs, benefits and risks of a CCA including legal liability issues.

(b) The governance and business planning of a CCA.

(c) The feasibility of a CCA and deciding whether to pursue formation of a countywide CCA organization.

(d) Public education.

SECTION 5. Through Docket No. R.03-10-003, the California Public Utilities Commission has issued various decisions and rulings addressing the implementation of Community Choice Aggregation programs, including the recent issuance of a procedure by which the California Public Utilities Commission will review "Implementation Plans," which are required for submittal under the Act as the means of describing the Community Choice Aggregation program and assuring compliance with various elements contained in the Act.

SECTION 6. Representatives from the Town along with the other LGTF members have developed the Marin Energy Authority Joint Powers Agreement ("Joint Powers Agreement") (attached hereto as Exhibit A) in order to accomplish the following:

(a) To form a Joint Powers Authority (JPA) known as "Marin Energy" and

(b) To specify the terms and conditions by which participants may participate as a group in energy programs, including but not limited to the preliminary implementation of a Community Choice Aggregation program.

SECTION 7. Representatives from the Town along with the LGTF members have developed a Business Plan (attached hereto as Exhibit B that describes the formation of Marin Clean Energy and the Community Choice Aggregation program to be implemented by and through the Marin Energy Authority.

SECTION 8. A final Implementation Plan will be submitted for review and adoption by the Board of Directors of the Marin Energy Authority as soon after the formation of the Authority as reasonably practicable.

SECTION 9. As described in the Business Plan, Community Choice Aggregation by and through the Marin Energy Authority appears to provide a reasonable opportunity to accomplish all of the following:

(a) To provide greater levels of local involvement in and collaboration on energy decisions,

(b) To increase significantly the amount of renewable energy available to Marin customers,

(c) To provide initial price stability, long-term electricity cost savings and other benefits for the community, and

(d) To reduce green house gases that are emitted by creating electricity for the community.

SECTION 10. The Act requires Community Choice Aggregation program participants to individually adopt an ordinance ("CCA Ordinance") electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the Marin Energy Authority.

SECTION 11. The Joint Powers Agreement expressly allows the Town to withdraw its membership in the Marin Energy Authority (and its participation in the Community Choice Aggregation program) prior to the actual implementation of a Community Choice Aggregation program through Program Agreement 1.

SECTION 12. A city, town or county may not participate in the Marin Energy Joint Powers Authority without also participating in the Community Choice Aggregation program unless the Board of Directors of the Marin Energy Joint Powers Authority decides to not implement or operate a Community Choice Aggregation program after the Authority is established.

SECTION 13. Based upon all of the above, the Council approves the Joint Powers Agreement attached hereto as Exhibit A and elects to implement a Community Choice Aggregation program within the Town's jurisdiction by and through the Town's participation in the Marin Energy Authority, as described in the Business Plan in substantially the form attached hereto as Exhibit B, and subject to the Town's right to forego the actual implementation of a Community Choice Aggregation program pursuant to specified withdrawal rights described in the Joint Powers Agreement. The Mayor is hereby authorized to execute the attached Joint Powers Agreement.

SECTION 14. This ordinance shall take effect and be in force 30 days after its adoption.

Copies of the foregoing ordinance shall, within fifteen (15) days after its final passage and adoption, be posted in three public places in the Town of Fairfax, to wit: Bulleting Board, Fairfax Town Offices, Town Hall; Bulletin Board, Fairfax Post Office; and Bulletin Board, Fairfax Women's Club Building, which said places are hereby designated for that purpose.

The foregoing ordinance was duly and regularly introduced at a regular meeting of the Town Council of the Town of Fairfax held in said town on the 5th day of November, 2008, and thereafter adopted on the 19th day of November, 2008 by the following vote, to wit:

AYES: Bragman, Brandborg, Maggiore, Tremaine

NOES: None

ABSENT: Weinsoff

Maryann Maggiore
MARY ANN MAGGIORE, MAYOR

Attest:
J. Anderson
Town Clerk

The foregoing document is a correct copy of the original on record in this office.
J. Anderson
City Clerk of the Town of Fairfax

BEFORE THE CITY COUNCIL OF THE CITY OF LAFAYETTE

IN THE MATTER OF:

An Ordinance of the City Council of the City of Lafayette approving the Marin Clean Energy Joint Powers Agreement and authorizing the Implementation of a Community Choice Aggregation Program)	Ordinance 644

WHEREAS, the City of Lafayette of has been actively investigating options to provide electric services to constituents within its service area since June 2014 with the intent of promoting use of renewable energy, reducing energy related greenhouse gas emissions, and providing Lafayette residents and businesses with alternatives to Pacific Gas & Electric Company; and

WHEREAS, on September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, Ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation (CCA); and

WHEREAS, on September 27, 2006, AB32 was signed into law establishing the goal of reducing the state's greenhouse gas emissions to 1990 levels by 2020; and

WHEREAS, on November 13, 2006, the Lafayette City Council adopted the Environmental Strategy which recognizes the importance of environmental sustainability and encourages community awareness, responsibility, participation, and education to promote an environmentally sustainable community; and

WHEREAS, the Act expressly authorizes participation in a CCA program through a joint powers agency, and on December 19, 2008, Marin Clean Energy (MCE) was established as a joint powers authority pursuant to a Joint Powers Agreement, as amended from time to time; and

WHEREAS, on February 2, 2010, the California Public Utilities Commission certified the "Implementation Plan" of MCE, confirming MCE's compliance with the requirements of the Act; and

WHEREAS, the City of Lafayette is committed to the development of renewable energy generation and energy efficiency improvements, reduction of greenhouse gases, protection of the environment, and fully supports MCE's current electricity procurement plan, which targets more than 50% renewable energy content; and

WHEREAS, approximately 89-percent of housing in the City of Lafayette was built prior to Title 24 standards and is less energy efficient than newer construction; and

WHEREAS, in 2010, 22-percent of overall community wide greenhouse gas emissions in Lafayette was caused by energy use and Lafayette has a considerable opportunity to impact emissions through energy conservation, energy efficiency, and the use of renewable energy sources; and

WHEREAS, electricity in Lafayette is generated and provided by Pacific Gas and Electric Company (PG&E) and there is not presently an alternative provider in the City. PG&E is currently working to add more renewable energy to its power mix under California's renewable portfolio standard and is on track to have 33-percent renewables by the end of 2020; and

WHEREAS, the City finds it important that its customers- residents, businesses, and public facilities- have alternative choices to energy procurement beyond PG&E; and

WHEREAS, the City of Lafayette finds that joining MCE will offer Lafayette customers choice in their power provider and will help Lafayette meet the state goal set out in AB32 and the goals outlined in the City's Environmental Strategy; and

WHEREAS, on August 10, 2015 the Lafayette City Council authorized a Letter of Intent to be sent to Marin Clean Energy requesting that they conduct a membership analysis for Lafayette; and

WHEREAS, in order to become a member of MCE, the MCE Joint Powers Agreement requires the City to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in MCE.

THE CITY COUNCIL OF THE CITY OF LAFAYETTE DOES ORDAIN AS FOLLOWS:

Section 1. The City of Lafayette has been actively investigating options to provide electric services to constituents within its service area with the intent of promoting use of renewable energy, reducing energy related greenhouse gas emissions, and providing Lafayette residents and businesses with alternatives to Pacific Gas & Electric Company.

Section 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch . 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation (CCA).

Section 3. The Act expressly authorizes participation in CCA program through a joint powers agency, and on December 19, 2008, Marin Clean Energy (MCE) was established as a joint powers authority pursuant to a Joint Powers Agreement, as amended from time to time.

Section 4. On February 2, 2010 the California Public Utilities Commission certified the "Implementation Plan" of the MCE, confirming the MCE's compliance with the requirements of the Act.

Section 5. In order to become a member of MCE, the Act requires the City of Lafayette to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the MCE.

Section 6. Based upon all of the above, the City of Lafayette Council elects to implement a Community Choice Aggregation program within the City of Lafayette's jurisdiction by and through the City of Lafayette's participation in Marin Clean Energy. The Mayor is hereby authorized to execute the MCE Joint Powers Agreement.

Section 7. If any section, subsection, subdivision, sentence, clause, phrase, or portion of this Ordinance for any reason is held to be invalid or unconstitutional by the decision of any court of competent jurisdiction, such decision shall not affect the validity of the remaining portions of this Ordinance. The City Council hereby declares that it would have adopted this Ordinance, and each section, subsection, subdivision, sentence, clause, phrase, or portion thereof, irrespective of the fact that any one or more sections, subsections, subdivisions, sentences, clauses, phrases, or portions thereof be declared invalid or unconstitutional.

Section 8. This ordinance shall take effect on the later of (a) the date the - Board of Directors of MCE adopts a Resolution adding the City/Town as a member of MCE, or (b) 30 days after its adoption and, before the expiration of 30 days after its passage.

Section 9. The City Clerk shall either (a) have this Ordinance published in a newspaper of general circulation once within fifteen (15) days after its adoption, or (b) have a summary of this Ordinance published twice in a newspaper of general circulation, once five (5) days before its adoption and again within fifteen (15) days after adoption.

The foregoing Ordinance was introduced at a meeting of the City Council of the City of Lafayette held on January 25, 2016, and adopted and ordered published at a meeting of the City Council held on March 14, 2016, by the following vote:

AYES: **Mitchell, B. Andersson, Reilly and Tatzin**
NOES: **None**
ABSTAIN: **None**
ABSENT: **M. Anderson**

ATTEST:

Joanne Robbins

Joanne Robbins, City Clerk

APPROVED:

Mark Mitchell, Mayor

ORDINANCE No. 980

AN ORDINANCE OF THE CITY COUNCILOF THE CITY OF LARKSPUR APPROVING THE MARIN ENERGY AUTHORITY JOINT POWERS AGREEMENT AND AUTHORIZINGTHE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

The City Council of the City of Larkspur of hereby ordains as follows:

SECTION 1. The City of Larkspur has been actively investigating options to provide electric services to constituents within its service area with the intent of achieving greater local involvement over the provision of electric services and promoting competitive and renewable energy.

SECTION 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation (CCA).

SECTION 3. The Act expressly authorizes participation in a CCA program through a joint powers agency, and on December 19, 2008, the Marin Energy Authority (MEA) was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time.

SECTION 4. On February 2, 2010, the California Public Utilities Commission certified the "Implementation Plan" of the MEA, confirming the MEA's compliance with the requirements of the Act.

SECTION 5. In order to become a member of the MEA, the Act requires the City of Larkspur to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the Marin Energy Authority.

SECTION 6. Based upon all of the above, the Council elects to implement a Community Choice Aggregation program within the City's/Town's jurisdiction by and through the City's/Town's participation in the Marin Energy Authority. The Mayor is hereby authorized to execute the MEA Joint Powers Agreement.

SECTION 7. This ordinance shall take effect and be in force 30 days after its adoption, and, before the expiration of 30 days after its passage, the ordinance or a summary thereof shall be published once in a newspaper of general circulation published and circulated in the City of Larkspur, along with the names of the members of the City Council voting for and against its passage.

IT IS HEREBY CERTIFIED that the foregoing ordinance was introduced at a meeting of the City of Larkspur Council of the City of Larkspur of held on October 5, 2011 and adopted at a meeting held on October 19, 2011, by the following vote, to wit:

AYES:	COUNCILMEMBER:	Chu, Hartzell, Hillmer, Rifkind
NOES:	COUNCILMEMBER:	None
ABSENT:	COUNCILMEMBER:	None
ABSTAIN:	COUNCILMEMBER:	None

Ly Chu

MAYOR

ATTEST:

Cynthia Huisman

CITY CLERK

ORDINANCE NO. 1237

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF MILL VALLEY APPROVING THE MARIN ENERGY AUTHORITY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

The City Council of the City of Mill Valley ordains as follows:

SECTION 1. The City of Mill Valley has been actively investigating options to provide electric services to constituents within its service area with the intent of achieving greater local involvement over the provisions of electric services and promoting competitive and renewable energy.

SECTION 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation.

SECTION 3. The Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and to this end the City has been participating since 2003 in the evaluation of a CCA program for the County of Marin and the cities and towns within it.

SECTION 4. On June 22, 2006, the City joined a Local Government Task Force (LGTF), which was comprised of elected officials and representatives of the County of Marin and each municipality in the County. The purpose of the LGTF was to jointly participate in the investigation of CCA for Marin communities and customers. The LGTF had five meetings with the final meeting taking place on March 6, 2008. The LGTF meetings looked at issues including:

(a) The costs, benefits and risks of a CCA including legal liability issues.

(b) The governance and business planning of a CCA.

(c) The feasibility of a CCA and deciding whether to pursue formation of a countywide CCA organization.

(d) Public education.

SECTION 5. Through Docket No. R.03-10-003, the California Public Utilities Commission has issued various decisions and rulings addressing the implementation of Community Choice Aggregation programs, including the recent issuance of a procedure by which the California Public Utilities Commission will review "Implementation Plans," which are required for submittal under the Act as the means of describing the Community Choice Aggregation program and assuring compliance with various elements contained in the Act.

SECTION 6. Representatives from the City along with the other LGTF members have developed the Marin Energy Authority Joint Powers Agreement ("Joint Powers Agreement") (attached hereto as Exhibit A) in order to accomplish the following:

(a) To form a Joint Powers Authority (JPA) known as "Marin Energy" and

(b) To specify the terms and conditions by which participants may participate as a group in energy programs, including but not limited to the preliminary implementation of a Community Choice Aggregation program.

SECTION 7. Representatives from the City along with the LGTF members have developed a Business Plan (attached hereto as Exhibit B that describes the formation of Marin Clean Energy and the Community Choice Aggregation program to be implemented by and through the Marin Energy Authority).

SECTION 8. A final Implementation Plan will be submitted for review and adoption by the Board of Directors of the Marin Energy Authority as soon after the formation of the Authority as reasonably practicable.

SECTION 9. As described in the Business Plan, Community Choice Aggregation by and through the Marin Energy Authority appears to provide a reasonable opportunity to accomplish all of the following:

(a) To provide greater levels of local involvement in and collaboration on energy decisions.

(b) To increase significantly the amount of renewable energy available to Marin customers,

(c) To provide initial price stability, long – term electricity cost savings and other benefits for the community, and

(d) To reduce green house gases that are emitted by creating electricity for the community.

SECTION 10. The Act requires Community Choice Aggregation program participants to individually adopt an ordinance ("CCA Ordinance") electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the Marin Energy Authority.

SECTION 11. The Joint Powers Agreement expressly allows the City to withdraw its membership in the Marin Energy Authority (and its participation in the Community Choice Aggregation program) prior to the actual implementation of a Community Choice Aggregation program through Program Agreement 1.

SECTION 12. A city, town or county may not participate in the Marin Energy Joint Powers Authority without also participating in the Community Choice Aggregation program unless the Board of Directors of the Marin Energy Joint Powers Authority decides to not implement or operate a Community Choice Aggregation program after the Authority is established.

SECTION 13. Based upon all of the above, the Council approves the Joint Powers Agreement attached hereto as Exhibit A and elects to implement a Community Choice Aggregation program within the City's jurisdiction by and through the City's participation in the Marin Energy Authority, as described in the Business Plan in substantially the form attached hereto as Exhibit B, and subject to the City's right to forego the actual implementation of a Community Choice Aggregation program pursuant to specified withdrawal rights described in the Joint Powers Agreement. The Mayor is hereby authorized to execute the attached Joint Powers Agreement.

SECTION 14. This ordinance shall take effect and be in force 30 days after its adoption, and, before the expiration of 30 days after its passage, a summary of this ordinance shall be published once with the names of the members of the Council voting for and against the same in the Marin Independent Journal, a newspaper of general circulation published in the County of Marin.

THE FOREGOING ORDINANCE was first read at a regular meeting of the Mill Valley City Council on 17th day of November, 2008, and adopted at a regular meeting of the Mill Valley City Council on 1st day of December, 2008, by the following vote:

AYES:	Councilmember Berman, Lion, Wachtel and Mayor Marshall
NOES:	None
ABSTAIN:	Councilmember Moulton-Peters
ABSENT:	None

S. Marshall

Shawn Marshall, Mayor

ATTEST:

Kimberly Wilson

Kimberly Wilson, Deputy City Clerk

ORDINANCE O2016-3

ORDINANCE OF THE CITY COUNCIL OF THE CITY OF NAPA, STATE OF CALIFORNIA, APPROVING THE MARIN CLEAN ENERGY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

WHEREAS, the City of Napa has been actively investigating options to provide electric services to constituents within its service area with the intent of promoting use of renewable energy and reducing energy related greenhouse gas emissions; and

WHEREAS, on September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation; and

WHEREAS, the Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and on December 19, 2008, the Marin Clean Energy (MCE) was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time; and

WHEREAS, on February 2, 2010, the California Public Utilities Commission certified the "Implementation Plan" of the MCE, confirming the MCE's compliance with the requirements of the Act; and

WHEREAS, in order to become a member of the MCE, the Act requires the City of Napa to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the MCE; and

WHEREAS, the City Council has considered all information related to this matter, as presented at the public meeting of the City Council identified herein, including any supporting reports by City Staff, and any information provided during public meetings.

NOW, THEREFORE, BE IT ORDAINED, by the City Council of the City of Napa as follows:

SECTION 1: Based upon all of the above, the City Council elects to implement a Community Choice Aggregation program within the City of Napa's jurisdiction by and through the City of Napa's participation in Marin Clean Energy. The City Manager is hereby authorized to execute the MCE Joint Powers Agreement.

SECTION 2: Severability. If any section, sub-section, subdivision, paragraph, clause or phrase in this Ordinance, or any part thereof, is for any reason held to be invalid or unconstitutional, such decision shall not affect the validity of the remaining sections or portions of this Ordinance or any part thereof. The City Council hereby declares that it would have passed each section, sub-section, subdivision, paragraph, sentence, clause or phrase of this Ordinance, irrespective of the fact that any one or more sections, sub-sections, subdivisions, paragraphs, sentences, clauses or phrases may be declared invalid or unconstitutional.

SECTION 3: Effective Date. This Ordinance shall become effective on the later of (a) the date the Board of Directors of MCE adopts a Resolution adding the City of Napa as a member of MCE, or (b) 30 days after the adoption of this ordinance.

City of Napa, a municipal corporation

MAYOR: Jill Techel

ATTEST: Lisa Blackmon

FOR CITY CLERK OF THE CITY OF NAPA
Lisa Blackmon, Deputy City Clerk

STATE OF CALIFORNIA
COUNTY OF NAPA } SS:
CITY OF NAPA

I, Dorothy Roberts, City Clerk of the City of Napa, do hereby certify that the foregoing Ordinance had its first reading and was introduced during the regular meeting of the City Council on the 19th day of January, 2016, and had its second reading and was adopted and passed during the regular meeting of the City Council on the 2nd day of February, 2016, by the following vote:

AYES:	Inman, Luros, Mott. Sedgley, Techel
NOES:	None
ABSENT:	None
ABSTAIN:	None

ATTEST: Lisa Blackmon
Lisa Blackmon, Deputy City Clerk
FOR Dorothy Roberts
City Clerk

Approved as to Form:

Michael W. Barrett
City Attorney

ORIGINAL

CITY COUNCIL OF THE CITY OF NOVATO

ORDINANCE NO. 1565

AN ORDINANCE OF THE NOVATO CITY COUNCIL, APPROVING THE MARIN ENERGY AUTHORITY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

THE CITY COUNCIL OF THE CITY OF NOVATO DOES ORDAIN AS FOLLOWS:

SECTION 1: The City of Novato has been actively investigating options to provide electric services to constituents within its service area with the intent of achieving greater local involvement over the provision of electric services and promoting competitive and renewable energy.

SECTION 2: On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation (CCA).

SECTION 3: The Act expressly authorizes participation in a CCA program through a joint powers agency, and on December 19, 2008, the Marin Energy Authority (MEA) was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time.

SECTION 4: On February 2, 2010, the California Public Utilities Commission certified the "Implementation Plan" of the MEA, confirming the MEA's compliance with the requirements of the Act.

SECTION 5: In order to become a member of the MEA, the Act requires the City of Novato to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the Marin Energy Authority.

SECTION 6: Based upon all of the above, the Council elects to implement a Community Choice Aggregation program within the City's jurisdiction by and through the City's participation in the Marin Energy Authority. The Mayor is hereby authorized to execute the MEA Joint Powers Agreement.

SECTION 7: Severability:

If any section, subsection, sentence, clause, phrase or portion of this ordinance is for any reason held invalid or unconstitutional, such decision shall not affect the validity of the remaining portions of the ordinance.

The City Council hereby declares that it would have passed this and each section, subsection, phrase or clause thereof irrespective of the fact that any one or more sections, subsections, phrases, or clauses be declared unconstitutional on their face or as applied.

SECTION : Publication and Effective Date:

This ordinance shall be published in accordance with applicable provisions of law, by either:

> publishing the entire ordinance once in the *Novato Advance*, a newspaper of general circulation, published in the City of Novato, within fifteen (15) days after its passage and adoption, or

> publishing the title or appropriate summary in the *Novato Advance* at least five (5) days prior to adoption, and a second time within fifteen (15) days after its passage and adoption with the names of those City Councilmembers voting for and against the ordinance, and

This ordinance shall go into effect thirty (30) days after the date of its passage and adoption.

* * * * * *

THE FOREGOING ORDINANCE was first read at a regular meeting of the Novato City Council on the 27th day of September, 2011, and was passed and adopted at a regular meeting of the Novato City Council on the 11th day of October, 2011.

AYES:	Councilmembers	Athas, Dillon-Knutson, Kellner
NOES:	Councilmembers	Eklund, MacLeamy
ABSTAIN:	Councilmembers	None
ABSENT:	Councilmembers	None

Madeline R Kellner

Mayor of the City of Novato

Attest:

City Clerk of the City of Novato

Approved as to form:

City Attorney of the City of Novato

ORDINANCE NO. 03-12 N.S.

ORDINANCE OF THE CITY COUNCIL OF THE CITY OF RICHMOND APPROVING THE MARIN ENERGY AUTHORITY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

The City Council of the City of Richmond ordains as follows:

SECTION 1. The City of Richmond has been actively investigating options to provide electric services to constituents within its service area with the intent of achieving greater local involvement over the provision of electric services and promoting competitive and renewable energy.

SECTION 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation (CCA).

SECTION 3. The Act expressly authorizes participation in a CCA program through a joint powers agency, and on December 19, 2008, the Marin Energy Authority (MEA) was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time.

SECTION 4. On February 2, 2010, the California Public Utilities Commission certified the "Implementation Plan" of the MEA, confirming the MEA's compliance with the requirements of the Act.

SECTION 5. In order to become a member of the MEA, the Act requires the City of Richmond to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the Marin Energy Authority.

SECTION 6. Based upon all of the above, the City Council elects to implement a Community Choice Aggregation program within the City of Richmond's jurisdiction by and through the City of Richmond's participation in the Marin Energy Authority. The Mayor is hereby authorized to execute the MEA Joint Powers Agreement.

SECTION 7. This ordinance shall take effect and be in force 30 days after its adoption, and, before the expiration of 30 days after its passage, a summary of this ordinance shall be published once with the names of the members of the City Council voting for and against the same in the West Contra Costa Times, a newspaper of general circulation published in Contra Costa County.

First read at a regular meeting of the Council of the City of Richmond, California, held May 15, 2012, and finally passed and adopted at a regular meeting thereof held June 19, 2012, by the following vote:

AYES:	Councilmembers Beckles, Butt, Ritterman, Vice Mayor Rogers, and Mayor McLaughlin.
NOES:	Councilmembers Bates and Booze.
ABSTENTIONS:	None.
ABSENT:	None.

DIANE HOLMES
CLERK OF THE CITY OF RICHMOND

(SEAL)

Approved:

GAYLE MCLAUGHLIN
Mayor

Approved as to form:

BRUCE REED GOODMILLER
City Attorney

Certified as a True Copy
DIANE HOLMES
CLERK OF THE CITY OF RICHMOND, CALIF
BY Ursula Weston
DEPUTY

State of California }
County of Contra Costa : ss.
City of Richmond }

I certify that the foregoing is a true copy of Ordinance No. 03-12 N.S., finally passed and adopted by the City Council of the City of Richmond at a joint meeting held on June 19, 2012.

TOWN OF ROSS

ORDINANCE NO. 612
ORDINANCE OF THE TOWN COUNCIL OF THE TOWN OF ROSS APPROVING THE MARIN ENERGY AUTHORITY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

The Town Council of the Town of Ross ordains as follows:

SECTION 1. The Town of Ross has been actively investigating options to provide electric services to constituents within its service area with the intent of achieving greater local involvement over the provisions of electric services and promoting competitive and renewable energy.

SECTION 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation.

SECTION 3. The Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and to this end the Town has been participating since 2003 in the evaluation of a CCA program for the County of Marin and the cities and towns within it.

SECTION 4. On June 22, 2006, the Town joined a Local Government Task Force (LGTF), which was comprised of elected officials and representatives of the County of Marin and each municipality in the County. The purpose of the LGTF was to jointly participate in the investigation of CCA for Marin communities and customers. The LGTF had five meetings with the final meeting taking place on March 6, 2008. The LGTF meetings looked at issues including:

(a) The costs, benefits and risks of a CCA including legal liability issues.

(b) The governance and business planning of a CCA.

(c) The feasibility of a CCA and deciding whether to pursue formation of a countywide CCA organization.

(d) Public education.

SECTION 5. Through Docket No. R.03-10-003, the California Public Utilities Commission has issued various decisions and rulings addressing the implementation of Community Choice Aggregation programs, including the recent issuance of a procedure by which the California Public Utilities Commission will review "Implementation Plans," which are required for submittal under the Act as the means of describing the Community Choice Aggregation program and assuring compliance with various elements contained in the Act.

SECTION 6. Representatives from the Town along with the other LGTF members have developed the Marin Energy Authority Joint Powers Agreement ("Joint Powers Agreement") (attached hereto as Exhibit A) in order to accomplish the following:

(a) To form a Joint Powers Authority (JPA) known as "Marin Energy" and

(b) To specify the terms and conditions by which participants may participate as a group in energy programs, including but not limited to the preliminary implementation of a Community Choice Aggregation program.

SECTION 7. Representatives from the Town along with the LGTF members have developed a Business Plan (attached hereto as Exhibit B that describes the formation of Marin Clean Energy and the Community Choice Aggregation program to be implemented by and through the Marin Energy Authority.

SECTION 8. A final Implementation Plan will be submitted for review and adoption by the Board of Directors of the Marin Energy Authority as soon after the formation of the Authority as reasonably practicable.

SECTION 9. As described in the Business Plan, Community Choice Aggregation by and through the Marin Energy Authority appears to provide a reasonable opportunity to accomplish all of the following:

(a) To provide greater levels of local involvement in and collaboration on energy decisions,

(b) To increase significantly the amount of renewable energy available to Marin customers,

(c) To provide initial price stability, long – term electricity cost savings and other benefits for the community, and

(d) To reduce green house gases that are emitted by creating electricity for the community.

SECTION 10. The Act requires Community Choice Aggregation program participants to individually adopt an ordinance ("CCA Ordinance") electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the Marin Energy Authority.

SECTION 11. The Joint Powers Agreement expressly allows the Town to withdraw its membership in the Marin Energy Authority (and its participation in the Community Choice

Aggregation program) prior to the actual implementation of a Community Choice Aggregation program through Program Agreement 1.

SECTION 12. A city, town or county may not participate in the Marin Energy Joint Powers Authority without also participating in the Community Choice Aggregation program unless the Board of Directors of the Marin Energy Joint Powers Authority decides to not implement or operate a Community Choice Aggregation program after the Authority is established.

SECTION 13. Based upon all of the above, the Council approves the Joint Powers Agreement attached hereto as Exhibit A and elects to implement a Community Choice Aggregation program within the Town's jurisdiction by and through the Town's participation in the Marin Energy Authority, as described in the Business Plan in substantially the form attached hereto as Exhibit B, and subject to the Town's right to forego the actual implementation of a Community Choice Aggregation program pursuant to specified withdrawal rights described in the Joint Powers Agreement. The Mayor is hereby authorized to execute the attached Joint Powers Agreement.

SECTION 14. This ordinance shall take effect and be in force 30 days after its adoption, and, before the expiration of 30 days after its passage, a summary of this ordinance shall be published once with the names of the members of the Council voting for and against the same in the Marin Independent Journal, a newspaper of general circulation published in the county of Marin.

The foregoing ordinance was introduced at a meeting of the Town Council of the Town of Ross held on November 13, 2008, and adopted at a meeting held on December 11, 2008, by the following vote:

AYES: Council members Cahill, Hunter, Martin, Skall, Strauss

NOES:

ABSENT:

ABSTAIN:

William R. Cahill, Mayor

ATTEST:

Gary Broad, Town Manager

ORDINANCE NO. 1067

ORDINANCE OF THE TOWN COUNCIL
OF THE TOWN OF SAN ANSELMO APPROVING THE
MARIN ENERGY AUTHORITY
JOINT POWERS AGREEMENT AND AUTHORIZING THE
IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION
PROGRAM

The Town Council of the Town of San Anselmo ordains as follows:

SECTION 1. The Town of San Anselmo has been actively investigating options to provide electric services to constituents within its service area with the intent of achieving greater local involvement over the provisions of electric services and promoting competitive and renewable energy.

SECTION 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation.

SECTION 3. The Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and to this end the Town has been participating since 2003 in the evaluation of a CCA program for the County of Marin and the cities and towns within it.

SECTION 4. On June 22, 2006, the Town joined a Local Government Task Force (LGTF), which was comprised of elected officials and representatives of the County of Marin and each municipality in the County. The purpose of the LGTF was to jointly participate in the investigation of CCA for Marin communities and customers. The LGTF had five meetings with the final meeting taking place on March 6, 2008. The LGTF meetings looked at issues including:

(a) The costs, benefits and risks of a CCA including legal liability issues.

(b) The governance and business planning of a CCA.

(c) The feasibility of a CCA and deciding whether to pursue formation of a countywide CCA organization.

(d) Public education.

SECTION 5. Through Docket No. R.03-10-003, the California Public Utilities Commission has issued various decisions and rulings addressing the implementation of Community Choice Aggregation programs, including the recent issuance of a procedure by which the California Public Utilities Commission will review "Implementation Plans," which are required for submittal under the Act as the means of describing the Community Choice Aggregation program and assuring compliance with various elements contained in the Act.

SECTION 6. Representatives from the Town along with the other LGTF members have developed the Marin Energy Authority Joint Powers Agreement ("Joint Powers Agreement") (attached hereto as Exhibit A) in order to accomplish the following:

(a) To form a Joint Powers Authority (JPA) known as "Marin Energy" and

(b) To specify the terms and conditions by which participants may participate as a group in energy programs, including but not limited to the preliminary implementation of a Community Choice Aggregation program.

SECTION 7. Representatives from the Town along with the LGTF members have developed a Business Plan (attached hereto as Exhibit B that describes the formation of Marin Clean Energy and the Community Choice Aggregation program to be implemented by and through the Marin Energy Authority.

SECTION 8. A final Implementation Plan will be submitted for review and adoption by the Board of Directors of the Marin Energy Authority as soon after the formation of the Authority as reasonably practicable.

SECTION 9. As described in the Business Plan, Community Choice Aggregation by and through the Marin Energy Authority appears to provide a reasonable opportunity to accomplish all of the following:

(a) To provide greater levels of local involvement in and collaboration on energy decisions.

(b) To increase significantly the amount of renewable energy available to Marin customers,

(c) To provide initial price stability, long – term electricity cost savings and other benefits for the community, and

(d) To reduce green house gases that are emitted by creating electricity for the community.

SECTION 10. The Act requires Community Choice Aggregation program participants to individually adopt an ordinance ("CCA Ordinance") electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the Marin Energy Authority.

SECTION 11. The Joint Powers Agreement expressly allows the Town to withdraw its membership in the Marin Energy Authority(and its participation in the Community Choice Aggregation program) prior to the actual implementation of a Community Choice Aggregation program through Program Agreement 1.

SECTION 12. A city, town or county may not participate in the Marin Energy Joint Powers Authority without also participating in the Community Choice Aggregation program unless the Board of Directors of the Marin Energy Joint Powers Authority decides to not implement or operate a Community Choice Aggregation program after the Authority is established.

SECTION 13. Based upon all of the above, the Council approves the Joint Powers Agreement attached hereto as Exhibit A and elects to implement a Community Choice Aggregation program within the Town's jurisdiction by and through the Town's participation in the Marin Energy Authority, as described in the Business Plan in substantially the form attached hereto as Exhibit B, and subject to the Town's right to forego the actual implementation of a Community Choice Aggregation program pursuant to specified withdrawal rights described in the Joint Powers Agreement. The Mayor is hereby authorized to execute the attached Joint Powers Agreement.

SECTION 14. This ordinance shall take effect and be in force 30 days after its adoption, and, before the expiration of 30 days after its passage, a summary of this ordinance shall be published once with the names of the members of the Council voting for and against the same in the Marin IJ, a newspaper of general circulation published in the County of Marin.

The foregoing ordinance was introduced at a meeting of the Town Council of the Town of San Anselmo, held on November 25, 2008, and adopted at a meeting held on December 9, 2008, by the following vote:

AYES:	Freeman, Greene, Thornton
NOES:	Breen, House
ABSENT:	None

Peter Breen, Mayor

Barbara Chambers, Town Clerk

ORDINANCE 2014-010

ORDINANCE OF THE CITY COUNCIL OF THE CITY OF SAN PABLO APPROVING THE MARIN CLEAN ENERGY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

The City Council of the City of San Pablo ordains as follows:

SECTION 1. The City of San Pablo has been actively investigating options to provide electric services to constituents within its service area with the intent of achieving greater local involvement over the provision of electric services and promoting competitive and renewable energy.

SECTION 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation (CCA).

SECTION 3. The Act expressly authorizes participation in a CCA program through a joint powers agency, and on December 19, 2008, Marin Clean Energy (MCE), formerly known as the Marin Energy Authority, was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time.

SECTION 4. On February 2, 2010, the California Public Utilities Commission certified the "Implementation Plan" of MCE, confirming MCE's compliance with the requirements of the Act.

SECTION 5. In order to become a member of MCE, the Act requires the City to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in Marin Clean Energy.

SECTION 6. Based upon all of the above, the Council elects to implement a Community Choice Aggregation program within the City's jurisdiction by and through the City's participation in Marin Clean Energy. The Mayor is hereby authorized to execute the MCE Joint Powers Agreement at such time as the City Manager and City Attorney advise is optimal.

SECTION 7. This ordinance shall become effective thirty (30) days following its adoption and shall be published once within fifteen (15) days after adoption in the *West County Times*, a newspaper of general circulation in the City of San Pablo, or, in the alternative, the City Clerk may cause to be published a summary or display advertisement prepared by the City Attorney's office of this ordinance and a certified copy of the text of this ordinance shall be posted in the office of the City Clerk five (5) days prior to the date of adoption of this ordinance. Within fifteen (15) days after adoption, a certified copy of this ordinance together with the vote for and against, shall be posted in the office of the City Clerk.

* * * * * * * * * *

First read and introduced at a regular meeting of the City Council of the City of San Pablo on August 4, 2014, and finally passed and adopted at a regular meeting of said City Council held on September 15, 2014, by the following vote:

AYES:	COUNCILMEMBERS:	Calloway, Valdez, Kinney, Chao Rothberg and Morris
NOES:	COUNCILMEMBERS:	None
ABSENT:	COUNCILMEMBERS:	None
ABSTAIN:	COUNCILMEMBERS:	None

ATTEST:

Ted J. Denney, City Clerk

APPROVED:

Paul V. Morris, Mayor

ORDINANCE NO. 1871
(Uncodified)

AN ORDINANCE OF THE CITY OF SAN RAFAEL
APPROVING THE MARIN ENERGY AUTHORITY
JOINT POWERS AGREEMENT AND
AUTHORIZING THE IMPLEMENTATION OF
A COMMUNITY CHOICE AGGREGATION PROGRAM

The City Council of the City of San Rafael does hereby ordain as follows:

SECTION 1. The City of San Rafael has been actively investigating options to provide electric services to constituents within its service area with the intent of achieving greater local involvement over the provisions of electric services and promoting competitive and renewable energy.

SECTION 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation.

SECTION 3. The Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and to this end the City of San Rafael has been participating since 2003 in the evaluation of a CCA program for the County of Marin and the cities and towns within it.

SECTION 4. On June 22, 2006, the City of San Rafael joined a Local Government Task Force (LGTF), which was comprised of elected officials and representatives of the County of Marin and each municipality within the County of Marin. The purpose of the LGTF was to jointly participate in the investigation of CCA for Marin communities and customers. The LGTF had five meetings with the final meeting taking place on March 6, 2008. The LGTF meetings looked at issues including:

(a) The costs, benefits and risks of a CCA including legal liability issues.

(b) The governance and business planning of a CCA.

(c) The feasibility of a CCA and deciding whether to pursue formation of a countywide CCA organization.

(d) Public education.

SECTION 5. Through Docket No. R.03-10-003, the California Public Utilities Commission has issued various decisions and rulings addressing the implementation of Community Choice Aggregation programs, including the recent issuance of a procedure by which the California Public Utilities Commission will review "Implementation Plans," which are required for submittal under the Act as the means of describing the Community Choice Aggregation program and assuring compliance with various elements contained in the Act.

SECTION 6. Representatives from the City of San Rafael along with the other LGTF members have developed the Marin Energy Authority Joint Powers Agreement ("Joint Powers Agreement", attached hereto as Exhibit A) in order to accomplish the following:

(a) To form a Joint Powers Authority (JPA) known as "Marin Energy Authority" and,

(b) To specify the terms and conditions by which participants may participate as a group in energy programs, including but not limited to the preliminary implementation of a Community Choice Aggregation program.

SECTION 7. Representatives from the City of San Rafael along with the LGTF members have developed a Business Plan (attached hereto as Exhibit B) that describes the formation of Marin Clean Energy and the Community Choice Aggregation program to be implemented by and through the Marin Energy Authority.

SECTION 8. A final Implementation Plan will be submitted for review and adoption by the Board of Directors of the Marin Energy Authority as soon after the formation of the Authority as reasonably practicable.

SECTION 9. As described in the Business Plan, Community Choice Aggregation by and through the Marin Energy Authority appears to provide a reasonable opportunity to accomplish all of the following:

(a) To provide greater levels of local involvement in and collaboration on energy decisions.

(b) To increase significantly the amount of renewable energy available to Marin customers,

(c) To provide initial price stability, long – term electricity cost savings and other benefits for the community, and

(d) To reduce green house gases which are emitted by creating electricity for the community.

SECTION 10. The Act requires Community Choice Aggregation program participants to individually adopt an ordinance ("CCA Ordinance") electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the Marin Energy Authority.

SECTION 11. The Joint Powers Agreement expressly allows the City of San Rafael to withdraw its membership in the Marin Energy Authority (and its participation in the Community Choice Aggregation program) prior to the actual implementation of a Community Choice Aggregation program through Program Agreement 1.

SECTION 12. A city, town or county may not participate in the Marin Energy Joint Powers Authority without also participating in the Community Choice Aggregation program unless the Board of Directors of the Marin Energy Joint Powers Authority decides to not implement or operate a Community Choice Aggregation program after the Authority is established.

SECTION 13. Based upon all of the above, the City Council of the City of San Rafael approves the Joint Powers Agreement attached hereto as Exhibit A and elects to implement a Community Choice Aggregation program within the City's jurisdiction by and through the City's participation in the Marin Energy Authority, as described in the Business Plan in substantially the form attached hereto as Exhibit B, and subject to the City's right to forego the actual implementation of a Community Choice Aggregation program pursuant to specified withdrawal rights described in the Joint Powers Agreement. The Vice Mayor is hereby authorized to execute the attached Joint Powers Agreement.

SECTION 14. A summary of this Ordinance shall be published and a certified copy of the full text of this Ordinance shall be posted in the office of the City Clerk at least five (5) days prior to the City Council meeting at which it is adopted. This Ordinance shall be in full force and effect thirty (30) days after its final passage, and the summary of this Ordinance shall be published within fifteen (15) days after the adoption, together with the names of the Councilmembers voting for or against same, in the Marin Independent Journal, a newspaper of general circulation published and circulated in the City of San Rafael, County of Marin, State of California. Within fifteen (15) days after adoption, the City Clerk shall also post in the office of the City Clerk, a certified copy of the full text of this Ordinance along with the names of those Councilmembers voting for or against the Ordinance

Cyr N. Miller
CYR N. MILLER, Vice Mayor

ATTEST:

Esther Beirne
ESTHER BEIRNE, City Clerk

The foregoing Ordinance No. 1871 was read and introduced at a Regular Meeting of the City Council of the City of San Rafael, held on the 1st day of December, 2008 and ordered passed to print by the following vote, to wit:

AYES: Councilmembers: Brockbank, Connolly and Heller

NOES: Councilmembers: Vice-Mayor Miller

ABSENT: Councilmembers: Mayor Boro, due to potential conflict of interest.

and will come up for adoption as an Ordinance of the City of San Rafael at a Regular Meeting of the Council to be held on the 15th day of December, 2008.

Esther Beirne
ESTHER BEIRNE, City Clerk

ORDINANCE NO. 1193

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF SAUSALITO APPROVING THE MARIN ENERGY AUTHORITY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

The City Council of the City of Sausalito ordains as follows:

SECTION 1. The City of Sausalito has been actively investigating options to provide electric services to constituents within its service area with the intent of achieving greater local involvement over the provisions of electric services and promoting competitive and renewable energy.

SECTION 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, Ch 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California City or County, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation.

SECTION 3. The Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and to this end the City has been participating since 2003 in the evaluation of a CCA program for the County of Marin and the cities and towns within.

SECTION 4. On June 22, 2006, the City joined a Local Government Task Force (LGTF), which was comprised of elected officials and representatives of the County of Marin and each municipality in the County. The purpose of the LGTF was to jointly participate in the investigation of CCA for Marin Communities and customers. The LGTF had five meetings with the final meeting taking place on March 6, 2008. The LGTF meetings looked at issues including:

(a) The costs, benefits and risks of a CCA including legal liability issues.

(b) The governance and business planning of a CCA.

(c) The feasibility of a CCA and deciding whether to pursue formation of a countywide CCA organization.

(d) Public education.

SECTION 5. Through Docket No. R.03-10-003, the California Public Utilities Commission has issued various decisions and rulings addressing the implementation of community choice Aggregation programs, including the recent issuance of a procedure by which the California Public Utilities commission will review "Implementation Plans", which are required for submittal under the Act as the means of describing the Community Choice Aggregation program and assuring compliance with various elements contained in the Act.

SECTION 6. Representatives from the City along with the other LGTF members have developed the Marin Energy Authority Joint Powers Agreement ("Joint Powers Agreement") (attached hereto as Exhibit A) in order to accomplish the following:

(a) To form a Joint Powers Authority (JPA) known as "Marin Energy" and

(b) To specify the terms and conditions by which participants may participate as a group in energy programs, including but not limited to the preliminary implementation of a Community Choice Aggregation program.

SECTION 7. Representatives from the City along with the LGTF members have developed a Business Plan (attached hereto as Exhibit B) that describes the formation of Marin clean Energy and the Community Choice Aggregation program to be implemented by and through the Marin Energy Authority.

SECTION 8. A final Implementation Plan will be submitted for review and adoption by the Board of Directors of the Marin Energy authority as soon after the formation of the authority as reasonably practicable.

SECTION 9. As described in the Business Plan, Community Choice Aggregation by and through the Marin Energy authority appears to provide a reasonable opportunity to accomplish all the following.

(a) To provide greater levels of local involvement in and collaboration on energy decisions,

(b) To increase significantly the amount of renewable energy available to Marin customers,

(c) To provide initial price stability, long-term electricity cost savings and other benefits for the community, and

(d) To reduce green house gases that are emitted by creating electricity for the community.

SECTION 10. The Act requires Community Choice Aggregation program participants to individually adopt an ordinance ("CCA Ordinance") electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the Marin Energy Authority.

SECTION 11. The Joint Powers Agreement expressly allows the city to withdraw its membership in the Marin Energy Authority (and its participation in the Community Choice Aggregation program) prior to the actual implementation of a Community Choice Aggregation program through Program Agreement 1.

SECTION 12. A city, town or county may not participate in the Marin Energy Joint Powers Authority without also participating in the Community Choice Aggregation program unless the Board of Directors of the Marin Energy Joint Powers Authority decides to not implement or operate a Community Choice Aggregation program after the Authority is established.

SECTION 13. Based upon all of the above, the Council approves the Joint Powers Agreement attached hereto as Exhibit A and elects to implement a Community Choice Aggregation program within the City's jurisdiction by and through the City's participation in the Marin Energy Authority, as described in the Business Plan in substantially the form attached hereto as Exhibit B, and subject to the City's right to forego the actual implementation of a Community Choice Aggregation program pursuant to specified withdrawal rights described in the Joint Powers Agreement. The Mayor is hereby authorized to execute the attached Joint Powers Agreement.

SECTION 14. This ordinance shall take effect and be in force 30 days after its adoption, and, before the expiration of 30 days after its passage, a summary of this ordinance shall be published once with the names and the members of the Council voting for and against the same in the Marin Scope, a newspaper of general circulation published in the City of Sausalito.

The foregoing ordinance was introduced at a meeting of the City Council of the City of Sausalito held on November 18, 2008, and adopted at meeting held on November 25, 2008, by the following vote:

AYES:	Councilmembers:	Albritton, Kelly, Leone, Weiner, and Mayor Belser
NOES:	Councilmembers:	None
ABSTAIN:	Councilmembers:	None
ABSENT:	Councilmembers:	None

Amy Belser

MAYOR OF THE CITY OF SAUSALITO

ATTEST:

Debbie Pagliaro

DEPUTY CITY CLERK

CITY OF ST. HELENA

ORDINANCE NO. 2016-1

ORDINANCE OF CITY OF ST. HELENA APPROVING THE MARIN CLEAN ENERGY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

The City Council of the City of St. Helena ordains as follows:

SECTION 1. The City of St. Helena has been actively investigating options to provide electric services to constituents within its service area with the intent of promoting use of renewable energy and reducing energy related greenhouse gas emissions.

SECTION 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation.

SECTION 3. The Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and on December 19, 2008, the Marin Clean Energy (MCE) was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time.

SECTION 4. On February 2, 2010 the California Public Utilities Commission certified the "Implementation Plan" of the MCE, confirming the MCE's compliance with the requirements of the Act.

SECTION 5. In order to become a member of the MCE, the Act requires the City of St. Helena to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the MCE.

SECTION 6. Based upon all of the above, the City Council elects to implement a Community Choice Aggregation program within the City of St. Helena's jurisdiction by and through the City of St. Helena's participation in the Marin Clean Energy. The Mayor is hereby authorized to execute the MCE Joint Powers Agreement.

SECTION 7. This ordinance shall take effect on the later of (a) the date the Board of Directors of MCE adopts a Resolution adding the City as a member of MCE, or (b) 30 days after its adoption and, before the expiration of 30 days after its passage, a summary of this ordinance shall be published once with the names of the members of the Council voting for and against the same in the St. Helena Star, a newspaper of general circulation published in the City of. St. Helena.

The foregoing ordinance was introduced at a meeting of the City Council of the City of St. Helena held on November 24, 2015, and adopted at a meeting held on January 12, 2016, by the following vote:

Mayor Galbraith:	yes
Vice Mayor White:	yes
Councilmember Crull:	absent
Councilmember Dohring:	yes
Councilmember Pitts:	yes

APPROVED:

Alan Galbraith, Mayor

ATTEST:

Cindy Black, City Clerk

ORDINANCE NO. 513 N.S.

AN ORDINANCE OF THE TOWN COUNCIL
OF THE TOWN OF TIBURON APPROVING THE
MARIN ENERGY AUTHORITY
JOINT POWERS AGREEMENT AND AUTHORIZING THE
IMPLEMENTATION OF A
COMMUNITY CHOICE AGGREGATION PROGRAM

The Town Council of the Town of Tiburon ordains as follows:

SECTION 1. The Town of Tiburon has been actively investigating options to provide electric services to constituents within its service area with the intent of achieving greater local involvement over the provisions of electric services and promoting competitive and renewable energy.

SECTION 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation.

SECTION 3. The Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and to this end the Town has been participating since 2003 in the evaluation of a CCA program for the County of Marin and the cities and towns within it.

SECTION 4. On June 22, 2006, the Town joined a Local Government Task Force (LGTF), which was comprised of elected officials and representatives of the County of Marin and each municipality in the County. The purpose of the LGTF was to jointly participate in the investigation of CCA for Marin communities and customers. The LGTF had five meetings with the final meeting taking place on March 6, 2008. The LGTF meetings looked at issues including:

(a) The costs, benefits and risks of a CCA including legal liability issues.

(b) The governance and business planning of a CCA.

(c) The feasibility of a CCA and deciding whether to pursue formation of a countywide CCA organization.

(d) Public education.

SECTION 5. Through Docket No. R.03-10-003, the California Public Utilities Commission has issued various decisions and rulings addressing the implementation of Community Choice Aggregation programs, including the recent issuance of a procedure by which the California Public Utilities Commission will review "Implementation Plans," which are required for submittal under the Act as the means of describing the Community Choice Aggregation program and assuring compliance with various elements contained in the Act.

SECTION 6. Representatives from the Town along with the other LGTF members have developed the Marin Energy Authority Joint Powers Agreement ("Joint Powers Agreement") (attached hereto as Exhibit A) in order to accomplish the following:

(a) To form a Joint Powers Authority (JPA) known as "Marin Energy" and

(b) To specify the terms and conditions by which participants may participate as a group in energy programs, including but not limited to the preliminary implementation of a Community Choice Aggregation program.

SECTION 7. Representatives from the Town along with the LGTF members have developed a Business Plan (attached hereto as Exhibit B) that describes the formation of Marin Clean Energy and the Community Choice Aggregation program to be implemented by and through the Marin Energy Authority.

SECTION 8. A final Implementation Plan will be submitted for review and adoption by the Board of Directors of the Marin Energy Authority as soon after the formation of the Authority as reasonably practicable.

SECTION 9. As described in the Business Plan, Community Choice Aggregation by and through the Marin Energy Authority appears to provide a reasonable opportunity to accomplish all of the following:

(a) To provide greater levels of local involvement in and collaboration on energy decisions.

(b) To increase significantly the amount of renewable energy available to Marin customers,

(c) To provide initial price stability, long-term electricity cost savings and other benefits for the community, and

(d) To reduce green house gases that are emitted by creating electricity for the community.

SECTION 10. The Act requires Community Choice Aggregation program participants to individually adopt an ordinance ("CCA Ordinance") electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the Marin Energy Authority.

SECTION 11. The Joint Powers Agreement expressly allows the Town to withdraw its membership in the Marin Energy Authority (and its participation in the Community Choice Aggregation program) prior to the actual implementation of a Community Choice Aggregation program through Program Agreement 1.

SECTION 12. A city, town or county may not participate in the Marin Energy Joint Powers Authority without also participating in the Community Choice Aggregation program unless the Board of Directors of the Marin Energy Joint Powers Authority decides to not implement or operate a Community Choice Aggregation program after the Authority is established.

SECTION 13. Based upon all of the above, the Council approves the Joint Powers Agreement attached hereto as Exhibit A and elects to implement a Community Choice Aggregation program within the Town's jurisdiction by and through the Town's participation in the Marin Energy Authority, as described in the Business Plan in substantially the form attached hereto as Exhibit B, and subject to the Town's right to forego the actual implementation of a Community Choice Aggregation program pursuant to specified withdrawal rights described in the Joint Powers Agreement. The Mayor is hereby authorized to execute the attached Joint Powers Agreement.

SECTION 14. This ordinance shall take effect and be in force 30 days after its adoption, and, before the expiration of 30 days after its passage, a summary of this ordinance shall be published once with the names of the members of the Council voting for and against the same in a newspaper of general circulation published in the Town of Tiburon.

The foregoing ordinance was introduced at a meeting of the Town Council of the Town of Tiburon held on November 5, 2008, and adopted at a meeting held on November 19, 2008, by the following vote:

AYES:	COUNCILMEMBERS:	Berger, Fredericks, Gram, Slavitz
NOES:	COUNCILMEMBERS:	None
ABSENT:	COUNCILMEMBERS:	Collins

JEFF SLAVITZ, MAYOR
TOWN OF TIBURON

ATTEST:

DIANE CRANE-IACOPI, TOWN CLERK

THIS IS A TRUE AND CERTIFIED COPY.
TOWN CLERK

THE CITY OF WALNUT CREEK
ORDINANCE NO. 2149

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF WALNUT CREEK APPROVING THE MARIN CLEAN ENERGY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

The City Council of the City of Walnut Creek ordains as follows:

Section 1. The City of Walnut Creek has been actively investigating options to provide electric services to constituents within its service area with the intent of promoting use of renewable energy and reducing energy related greenhouse gas emissions.

Section 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation.

Section 3. The Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and on December 19, 2008, the Marin Clean Energy (MCE) was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time.

Section 4. On February 2, 2010 the California Public Utilities Commission certified the "Implementation Plan" of the MCE, confirming the MCE's compliance with the requirements of the Act.

Section 5. In order to become a member of the MCE, the Act requires the City of Walnut Creek to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the MCE.

Section 6. Based upon all of the above, the City Council elects to implement a Community Choice Aggregation program within the City of Walnut Creek's jurisdiction by and through the City of Walnut Creek's participation in the Marin Clean Energy. The Mayor is hereby authorized to execute the MCE Joint Powers Agreement.

Section 7. Pursuant to the provisions of Government Code Section 36933, a summary of this Ordinance shall be prepared by the City Attorney. At least five (5) days prior to the Council meeting at which this Ordinance is scheduled to be adopted, the City Clerk shall (1) publish the summary, and (2) post in the City Clerk's Office a certified copy of this Ordinance. Within fifteen (15) days after the adoption of this Ordinance, the City Clerk shall (1) publish the summary, and (2) post in the City Clerk's Office a certified copy of the full text of this Ordinance along with the names of those City Council members voting for and against this Ordinance or otherwise voting. This Ordinance shall become effective on the 31st day after its adoption.

PASSED AND ADOPTED by the City Council of the City of Walnut Creek at a regular meeting thereof held on the 15th day of March, 2016 by the following called vote:

AYES: Councilmembers: Simmons, Carlston, Mayor Haskew

NOES:	Councilmembers:	Wedel
ABSTAIN:	Councilmembers:	Silva
ABSENT:	Councilmembers:	None

Loella Haskew
Mayor of the City of Walnut Creek

Attest:

Suzie Martinez, CMC
City Clerk of the City of Walnut Creek

I HEREBY CERTIFY the foregoing to be a true and correct copy of Ordinance No. 2149 duly passed and adopted by the City Council of Walnut Creek, County of Contra Costa, State of California, at a regular meeting of said Council held on the 15th day of March, 2016.

Suzie Martinez, CMC
City Clerk of the City of Walnut Creek

Town of Yountville
Ordinance Number 16-448

Approving the Marin Clean Energy Joint Powers Agreement and Authorizing the Implementation of a Community Choice Aggregation Program

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Recitals

Whereas,

A. The Town of Yountville has been actively investigating options to provide electric services to constituents within its service areas with the intent of promoting use of renewable energy and reducing energy related greenhouse gas emissions.

B. On September 24, 2002, the Governor of California signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and business in a community-wide electricity aggregation program known as Community Choice Aggregation.

C. The Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and on December 19, 2008, the Marin Clean Energy (MCE) was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time.

D. On February 2, 2010, the California Public Utilities Commission certified the "Implementation Plan" of the MCE, confirming the MCE's compliance with the requirements of the Act.

E. During its January 26 regular meeting, the Yountville Go Green Team received presentations from representatives of MCE and unanimously recommended to the Town Council that the Town become a member of MCE.

F. In order to become a member of the MCE, the Act requires the Town of Yountville to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the MCE.

Now therefore, the Town Council of the Town of Yountville does ordain as follows:

1. Implement a Community Choice Aggregation program within the Town of Yountville's jurisdiction by and through the Town of Yountville's participation in the Marin Clean Energy.

2. The Mayor is hereby authorized to execute the MCE Joint Powers Agreement.

3. Effective Date. This ordinance shall take effect on the later of (a) the date the Board of Directors of MCE adopts a Resolution adding the Town of Yountville as a member of MCE, or (b) 30 days after its adoption and, before the expiration of 30 days after its passage, a summary of this ordinance shall be published once with the names of the members of the Council voting for and against the same in the Yountville Sun, a newspaper of general circulation published in the Town of Yountville.

4. Posting. Within 15 days from the date of passage of this ordinance, the Town Clerk shall post a copy of the ordinance in accordance with California Government Code in at least three public places in the Town.

INTRODUCED by the Town Council on the first day of March 2016; and

PASSED AND ADOPTED at a regular meeting of the Town Council on the fifteenth day of March 2016 by the following vote:

AYES: DORENBECHER, HALL, DURHAM AND DUNBAR
NOES: MOHLER
ABSENT: NONE
ABSTAIN: NONE

John F. Dunbar, Mayor

ATTEST:

TOWN OF YOUNTVILLE

Julie Baldia, Deputy Town Clerk

I, JULIE BALDIA, DEPUTY TOWN CLERK of the Town of Yountville, California, do hereby certify that the foregoing Ordinance was regularly introduced and placed upon its first reading at a regular meeting of the Town Council on the first day of March, 2016. That thereafter said Ordinance was duly adopted and passed at a regular meeting of the Town Council on the fifteenth day of March, 2016 by the following vote:

AYES: HALL, DORENBECHER, DURHAM AND DUNBAR
NOES: MOHLER
ABSENT:
ABSTAIN:

Julie Baldia, Deputy Town Clerk

APPROVED AS TO FORM:

Michael Cobden, Town Attorney

ORDINANCE NO. 3505

ORDINANCE OF THE MARIN COUNTY BOARD OF SUPERVISORS APPROVING THE MARIN ENERGY AUTHORITY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

THE BOARD OF SUPERVISORS OF THE COUNTY OF MARIN ORDAINS AS FOLLOWS:

SECTION 1. The County of Marin has been actively investigating options to provide electric services to constituents within its service area with the intent of achieving greater local involvement over the provisions of electric services and promoting competitive and renewable energy.

SECTION 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation.

SECTION 3. The Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and to this end the County has been participating since 2003 in the evaluation of a CCA program for the County and the cities and towns within it.

SECTION 4. On June 22, 2006, the County of Marin joined a Local Government Task Force (LGTF), which was comprised of elected officials and representatives of each municipality in the County. The purpose of the LGTF was to jointly participate in the investigation of CCA for Marin communities and customers. The LGTF had five meetings with the final meeting taking place on March 6, 2008. The LGTF meetings looked at issues including:

(a) The costs, benefits and risks of a CCA including legal liability issues.

(b) The governance and business planning of a CCA.

(c) The feasibility of a CCA and deciding whether to pursue formation of a countywide CCA organization.

(d) Public education.

SECTION 5. Through Docket No. R.03-10-003, the California Public Utilities Commission has issued various decisions and rulings addressing the implementation of Community Choice Aggregation programs, including the recent issuance of a procedure by which the California Public Utilities Commission will review "Implementation Plans," which are required for submittal under the Act as the means of describing the

Community Choice Aggregation program and assuring compliance with various elements contained in the Act.

SECTION 6. Representatives from the County along with the other LGTF members have developed the Marin Energy Authority Joint Powers Agreement ("Joint Powers Agreement") (attached hereto as Exhibit A) in order to accomplish the following:

(a) To form a Joint Powers Authority (JPA) known as "Marin Energy" and

(b) To specify the terms and conditions by which participants may participate as a group in energy programs, including but not limited to the preliminary implementation of a Community Choice Aggregation program.

SECTION 7. Representatives from the County along with the LGTF members have developed a Business Plan (attached hereto as Exhibit B that describes the formation of Marin Clean Energy and the Community Choice Aggregation program to be implemented by and through the Marin Energy Authority.

SECTION 8. A final Implementation Plan will be submitted for review and adoption by the Board of Directors of the Marin Energy Authority as soon after the formation of the Authority as reasonably practicable.

SECTION 9. As described in the Business Plan, Community Choice Aggregation by and through the Marin Energy Authority appears to provide a reasonable opportunity to accomplish all of the following:

(a) To provide greater levels of local involvement in and collaboration on energy decisions.

(b) To increase significantly the amount of renewable energy available to Marin customers,

(c) To provide initial price stability, long – term electricity cost savings and other benefits for the community, and

(d) To reduce green house gases that are emitted by creating electricity for the community.

SECTION 10. The Act requires Community Choice Aggregation program participants to individually adopt an ordinance ("CCA Ordinance") electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the Marin Energy Authority.

SECTION 11. The Joint Powers Agreement expressly allows the County to withdraw its membership in the Marin Energy Authority (and its participation in the Community Choice Aggregation program) prior to the actual implementation of a Community Choice Aggregation program through Program Agreement 1.

SECTION 12. A city, town or county may not participate in the Marin Energy Joint Powers Authority without also participating in the Community Choice Aggregation program unless the Board of Directors of the Marin Energy Joint Powers Authority decides to not implement or operate a Community Choice Aggregation program after the Authority is established

SECTION 13. Based upon all of the above, the Board approves the Joint Powers Agreement attached hereto as Exhibit A and elects to implement a Community Choice Aggregation program within the County's jurisdiction by and through the County's participation in the Marin Energy Authority, as described in the Business Plan in substantially the form attached hereto as Exhibit B, and subject to the County's right to forego the actual implementation of a Community Choice Aggregation program pursuant to specified withdrawal rights described in the Joint Powers Agreement. The Chairman of the Board is hereby authorized to execute the attached Joint Powers Agreement.

SECTION 14. This ordinance shall take effect and be in force 30 days after its adoption, and, before the expiration of 30 days after its passage, a summary of this ordinance shall be published once with the names of the members of the Board of Supervisors voting for and against the same in the Marin Independent Journal, a newspaper of general circulation published in the County of Marin.

PASSED AND ADOPTED at a regular meeting of the Board of Supervisors of the County of Marin held on this 18th day of November, 2008, by the following vote:

AYES: SUPERVISORS Steve Kinsey, Harold C. Brown, Jr., Judy Arnold, Susan L. Adams, Charles McGlashan

NOES: NONE

ABSENT: NONE

PRESIDENT, BOARD OF SUPERVISORS

ATTEST:

CLERK

ORDINANCE NO. 1391

AN ORDINANCE OF THE BOARD OF SUPERVISORS OF NAPA COUNTY, STATE OF CALIFORNIA, APPROVING THE MARIN CLEAN ENERGY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

The Board of Supervisors of the County of Napa, State of California, ordains as follows:

SECTION 1. Napa County has been actively investigating options to provide electric services to constituents within its service area with the intent of achieving greater local involvement over the provision of electric services and promoting competitive and renewable energy.

SECTION 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation ("CCA").

SECTION 3. The Act expressly authorizes participation in a CCA program through a joint powers agency, and on December 19, 2008, Marin Clean Energy ("MCE"), formerly known as the Marin Energy Authority, was established as a joint powers authority pursuant to a Joint Powers Agreement, as amended from time to time.

SECTION 4. On February 2, 2010, the California Public Utilities Commission certified the "Implementation Plan" of MCE, confirming MCE's compliance with the requirements of the Act.

SECTION 5. In order to become a member of MCE, the Act requires Napa County to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in Marin Clean Energy.

SECTION 6. Based upon all of the above, the Board elects to implement a Community Choice Aggregation program within the Unincorporated County's jurisdiction by and through the County's participation in Marin Clean Energy. The Chairman of the Board of Supervisors is hereby authorized to execute the MCE Joint Powers Agreement and any other related documents for program implementation.

SECTION 7. If any section, subsection, sentence, clause, phrase or word of this Ordinance is for any reason held to be invalid by a court of competent jurisdiction, such decision shall not affect the validity of the remaining portions of this Ordinance. The Board of Supervisors of the County of Napa hereby declares it would have passed and adopted this Ordinance and each and all provisions hereof irrespective of the fact that any one or more of said provisions be declared invalid.

SECTION 8. This Ordinance shall be effective thirty (30) days from and after the date of its passage.

SECTION 9. A summary of this Ordinance shall be published at least once 5 days before adoption and at least once before the expiration of 15 days after its passage in the Napa Valley Register, a newspaper of general circulation published in the County of Napa, together with the names of members voting for and against the same.

The foregoing Ordinance was introduced and read at a regular meeting of the Board of Supervisors of the County of Napa, State of California, held on the 3rd day of June, 2014, and passed at a regular meeting of the Board of Supervisors of the

County of Napa, State of California, held on the 15th day of July, 2014, by the following vote:

AYES:	SUPERVISORS	WAGENKNECHT, CALDWELL and LUCE
NOES:	SUPERVISORS	DILLON AND DODD
ABSTAIN:	SUPERVISORS	NONE
ABSENT:	SUPERVISORS	NONE

MARK LUCE, Chairman
Napa County Board of Supervisors

ATTEST: GLADYS I. COIL
Clerk of the Board of Supervisors

By: Gladys I. Coil

APPROVED AS TO FORM Office of County Counsel	Approved by the Napa County Board of Supervisors
By: Robert W. Paul (by e-signature) Deputy County Counsel By: *Sue Ingalls* (by e-signature) County Code Services Date: May 19, 2014	Date: 7/15/14 Processed by: Greg Morgan Deputy Clerk of the Board

I HEREBY CERTIFY THAT THE ORDINANCE ABOVE WAS POSTED IN THE OFFICE OF THE CLERK OF THE BOARD IN THE ADMINISTRATIVE BUILDING, 1195 THIRD STREET ROOM 310, NAPA, CALIFORNIA ON May 22, 2014.

Kaula Prescott, DEPUTY
GLADYS I. COIL, CLERK OF THE BOARD

MARIN CLEAN ENERGY

REVISED COMMUNITY CHOICE AGGREGATION IMPLEMENTATION PLAN AND STATEMENT OF INTENT

July 18, 2014

For copies of this document contact Marin Clean Energy in San Rafael, California or visit www.mcecleanenergy.org

Table of Contents

CHAPTER 1 – Introduction

Marin Clean Energy ("MCE"; MCE was formerly known as the "Marin Energy Authority" or "MEA"), a public agency, was formed in December 2008 for the purposes of implementing a community choice aggregation ("CCA") program and other energy-related programs targeting significant greenhouse gas emissions ("GHG") reductions. At that time, the Member Agencies of MCE included eight of the twelve municipalities located within the geographic boundaries of Marin County: the cities/towns of Belvedere, Fairfax, Mill Valley, San Anselmo, San Rafael, Sausalito and Tiburon and the County of Marin (together the "Members" or "Member Agencies"). In anticipation of CCA program implementation and in compliance with state law, MCE submitted the Marin Energy Authority Community Choice Aggregation Implementation Plan and Statement of Intent ("Implementation Plan") to the California Public Utilities Commission ("CPUC" or "Commission") on December 9, 2009. Consistent with its expressed intent, MCE successfully launched its CCA program, Marin Clean Energy ("MCE" or "Program"), on May 7, 2010 and has been successfully serving customers since that time.

During the second half of 2011, four additional municipalities within Marin County, the cities of Novato and Larkspur and the towns of Ross and Corte Madera, joined MCE, and a revised Implementation Plan reflecting updates related to said expansion was filed with the CPUC on December 3, 2011.

Subsequently, the City of Richmond, located in Contra Costa County, joined MCE, and a revised Implementation Plan reflecting updates related to this expansion was filed with the CPUC on July 6, 2012.

A revision to MCE's Implementation Plan was then filed with the Commission on November 6, 2012 to ensure compliance with Commission Decision 12-08-045, which was issued on August 31, 2012. In Decision 12-08-045, the Commission directed existing CCA programs to file revised Implementation Plans to conform to the privacy rules in Attachment B of this Decision.

Since its expansion to the City of Richmond, numerous communities have contacted MCE regarding membership opportunities, including specific requests to join MCE and initiate related CCA service within these respective jurisdictions. In response to these inquiries, MCE's governing board adopted Policy 007, which establishes a formal process and specific criteria for new member additions. In particular, this policy identifies several threshold requirements, including the specification that any prospective member evaluation demonstrate rate-related savings (based on prevailing market prices for requisite energy products at the time of each analysis) as well as environmental benefits (as measured by anticipated reductions in greenhouse gas emissions and increased renewable energy sales to CCA customers) before proceeding with expansion activities, including the filing of related revisions to this Implementation Plan. As MCE receives new membership requests, staff will follow the prescribed evaluative process of Policy 007 and will present related results at future public meetings. To the extent that membership evaluations demonstrate favorable results and any new community completes the process of joining MCE, this Implementation Plan will be revised through an amendment to highlight key impacts and consequences related to the addition of the new community/communities.

Also, consistent with MCE's mission statement, MCE launched its first energy efficiency portfolio in late 2012, initially providing multi-family energy efficiency services to MCE customers only. In early 2013, MCE launched a portfolio of energy efficiency programs available to all ratepayers in its service territory, not just MCE customers. Energy efficiency and other local programs continue to be a robust and growing portion of MCE's operating activities.

MCE gives electric customers of the Member Agencies an opportunity to procure electricity from competitive suppliers, with such electricity being delivered over PG&E's transmission and distribution system. To date, the electricity delivered to MCE customers has included over 27 percent Renewables Portfolio Standard ("RPS") qualifying renewable energy, an amount which has surpassed all reporting entities, including the incumbent utility. Over the course of MCE's phased implementation schedule, all current PG&E customers within MCE's service area will receive information describing the Program and will have multiple opportunities to express their desire to remain bundled customers of PG&E, in which case they will not be enrolled in the Program. Thus, participation in the CCA Program is completely voluntary; however, customers, as provided by law, will be automatically enrolled unless they affirmatively elect to opt-out of the CCA Program.

The MCE program has received considerable interest from other communities in response to its innovative, environmentally-focused energy service alternative, which now provides electric generation service to approximately 120,000 customers, including a cross section of residential and commercial accounts. During its four-year operating history, non-member municipalities have monitored MCE progress, evaluating the potential opportunity for membership, which would enable customer choice with respect to electric generation service. In response to public interest and MCE's successful operational track record, the County of Napa has requested MCE membership, consistent with MCE Policy 007, and adopted the requisite ordinances for joining MCE. MCE's Board of Directors approved the County of Napa's membership request at a duly noticed public meeting on June 5, 2014 (through the approval of Resolution No. 2014-03) and the County of Napa's Board of Supervisors completed its final reading of the requisite CCA ordinance (Ordinance No. 1391) on July 15, 2014.

This revision of the Marin Clean Energy Community Choice Aggregation Implementation Plan and Statement of Intent ("Revised Implementation Plan") describes MCE's expansion plans to include the County of Napa. According to the Commission, the Energy Division is required to receive and review a revised MCE implementation plan reflecting changes/consequences of additional members. With this in mind, MCE has reviewed its revised Implementation Plan, which was filed with the Commission on November 6, 2012, and has identified certain information that requires updating to reflect the changes and consequences of adding the new member and to address MCE's name change (from MEA to MCE), which occurred via Resolution No. 2013-11 of MCE's Governing Board on December 5, 2013. This Revised Implementation Plan reflects such changes and includes related projections that account for MCE's planned expansion.

Implementation of MCE has enabled customers within MCEs service area to take advantage of the opportunities granted by Assembly Bill 117 ("AB 117"), the Community Choice Aggregation Law. MCE's primary objective in implementing this Program continues to focus on increased utilization of renewable energy supplies for the purpose of promoting significant GHG emissions reductions. To date, MCE has achieved this objective by offering customers two energy supply options: 1) a minimum 50 percent renewable content, which will be the default service option for participating customers[1]; or 2) 100 percent renewable content. The prospective benefits to consumers include a substantial increase in renewable energy supply, stable and competitive electric rates, public participation in determining which technologies are utilized to meet local electricity needs, and local/regional economic benefits.

To ensure successful operation of the MCE program, MCE has received assistance from experienced energy suppliers and contractors in providing energy services to Program customers. As a result of a competitive solicitation process and subsequent contract negotiations, a highly qualified firm, Shell Energy North America ("SENA") was selected as MCE's initial energy services provider and scheduling coordinator. Since this initial solicitation, MCE has completed numerous procurement activities in an effort to accommodate the increasing electric energy requirements of a growing customer base, including the execution of various power purchase agreements with new and existing renewable energy projects. Such purchases have served to diversify MCE's energy supply portfolio, reflecting the use of multiple fuel sources, contract term lengths and resource locations, among other considerations. To serve the increasing energy requirements resulting from expanded membership MCE anticipates that its existing supply agreement with SENA may be amended and/or supplemented with additional purchases from other qualified suppliers of requisite energy products to reflect the Program's increased future needs. Information regarding SENA is contained in Chapter 10.

MCE's Implementation Plan reflects a collaborative effort among MCE, its Members, and the private sector to bring the benefits of competition and choice to Member residents and businesses. By exercising its legal right to form a CCA Program, MCE has enabled its Members' constituents to access the competitive market for energy services and obtain access to increased renewable energy supplies and resultant reductions in GHG emissions. Absent action by MCE or its individual Members, most customers would have no ability to choose an electric supplier and would remain captive customers of their incumbent utility.

The California Public Utilities Code provides the relevant legal authority for MCE to become a Community Choice Aggregator and invests the California Public Utilities Commission ("CPUC" or "Commission") with the responsibility for establishing the cost recovery mechanism that must be in place before customers can begin receiving electrical service through MCE's CCA Program. The CPUC has also registered MCE as a Community Choice Aggregator and continues to ensure compliance with basic consumer protection rules. The Public Utilities Code requires that an Implementation Plan be adopted at a duly noticed public hearing and

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[1] MCE customers received nearly 29 percent RPS-qualifying renewable energy in 2013. The default renewable energy content, which includes RPS-qualifying renewable energy and supplemental renewable energy credit purchases, was voluntarily increased from 25% to 50% beginning in January, 2012.

that it be filed with the Commission in order for the Commission to determine the cost recovery mechanism to be paid by customers of the Program in order to prevent shifting of costs. Each of these milestones has been accomplished. The Commission has established the methodology that will be used to determine the cost recovery mechanism, and PG&E now has approved tariffs for imposition of the cost recovery mechanism. Finally, each of MCE's Members has adopted an ordinance to implement a CCA program through its participation in MCE (copies of the ordinance adopted by MCE's newest member, the County of Napa, is included as Appendix D). Following the CPUC's certification of its receipt of this Revised Implementation Plan and resolution of any outstanding issues, MCE will take the final steps needed to expand CCA service to MCE's new member, including customer notification and enrollment.

Organization of this Implementation Plan

The content of this Revised Implementation Plan complies with the statutory requirements of AB 117. Because MCE has already successfully implemented its CCA program, this Revised Implementation Plan includes narrative discussion, updates and projections focused on on-going operation and expansion of the MCE program rather than previously completed implementation efforts. As a result, certain sections of this document are now substantially abbreviated. Consistent with requirements identified in PU Code Section 366.2(c)(4), this Revised Implementation Plan addresses:

- Universal access;
- Reliability;
- Equitable treatment of all customer classes; and
- Any requirements established by state law or by the CPUC concerning aggregated service.

To promote consistency with MCE's original January 25, 2010 Implementation Plan, the remainder of this Revised Implementation Plan is organized as follows:

Chapter 2: Aggregation Process
Chapter 3: Organizational Structure
Chapter 4: CCA Startup
Chapter 5: Program Phase-In
Chapter 6: Load Forecast and Resource Plan
Chapter 7: Financial Plan
Chapter 8: Ratesetting
Chapter 9: Customer Rights and Responsibilities
Chapter 10: Procurement Process
Chapter 11: Contingency Plan for Program Termination
Appendix A: Marin Clean Energy Resolution 2014-03
Appendix B: County of Napa, Resolution 2014-59
Appendix C: Joint Powers Agreement
Appendix D: County of Napa, CCA Ordinance – Ordinance No. 1391

The requirements of AB 117 are cross-referenced to Chapters of this Implementation Plan in the following table.

AB 117 Cross References

AB 117 REQUIREMENT	IMPLEMENTATION PLAN CHAPTER
Process and consequences of aggregation	Chapter 2: Aggregation Process
Organizational structure of the program, its operations and funding	Chapter 3: Organizational Structure Chapter 4: Startup Plan and Funding Chapter 7: Financial Plan
Ratesetting and other costs to participants	Chapter 8: Ratesetting Chapter 9: Customer Rights and Responsibilities
Disclosure and due process in setting rates and allocating costs among participants	Chapter 8: Ratesetting
Methods for entering and terminating agreements with other entities	Chapter 10: Procurement Process
Participant rights and responsibilities	Chapter 9: Customer Rights and Responsibilities
Termination of the program	Chapter 11: Contingency Plan for Program Termination
Description of third parties that will be supplying electricity under the program, including information about financial, technical and operational capabilities	Chapter 10: Procurement Process
Statement of Intent	Chapter 1: Introduction

CHAPTER 2 – Aggregation Process

Introduction

As previously noted, MCE successfully launched its CCA Program, MCE, on May 7, 2010 after meeting applicable statutory requirements and in consideration of planning elements described in its January 25, 2010 Implementation Plan. At this point in time, MCE plans to expand agency membership to include the County of Napa. This community has requested MCE membership, and MCE's Board of Directors subsequently approved the membership request at a duly noticed public meeting.

As planned, the residents and businesses within MCE's expanded service territory will be offered electric generation service from MCE's currently operating CCA program, MCE, which represents a culmination of planning efforts that are responsive to the expressed needs and priorities of the citizenry and business community within the region. Through the MCE program eligible customers have received expanded energy choices, including the creation of a 100% renewable energy product and 100% local solar product. In effect, MCE provides Marin residents and businesses with four electric service options, which include: 1) the default 50% (minimum) renewable energy service option – Light Green; 2) a 100% renewable energy service option – Deep Green – which can be chosen on a voluntary basis; 3) a 100% local solar energy service option – Sol Shares – in which customers can enroll on a voluntary basis[2]; or 4) bundled energy service from the incumbent utility. It remains MCE's long-term goal to supply its customers entirely with clean, renewable energy, subject to economic and operational constraints.

Each of the Member Agencies has adopted an ordinance to implement a CCA program through its participation in MCE. A Revised Implementation Plan was adopted at a duly noticed public hearing of MCE on June 5, 2014.

Process of Aggregation

All customers currently enrolled in the MCE program were appropriately noticed. Before additional phases of customers are enrolled in the Program, MCE will mail at least two written notices to customers, beginning at least two calendar months, or sixty days, in advance of the date of commencing automatic enrollment, that will provide information needed to understand the Program's terms and conditions of service and explain how these customers can opt-out of the Program, if desired. All customers that do not follow the opt-out process specified in the customer notices will be automatically enrolled, and service will begin at their next regularly scheduled meter read date at least one calendar month, or thirty days following the date of automatic enrollment, subject to the service phase-in plan described in Chapter 5. At least two follow-up opt-out notices will be mailed to these customers within the first two calendar months, or sixty days, of service.

[2] The Sol Shares program is currently accepting customer enrollments but will not begin delivering electric power to participating customers until the 2015 calendar year. In the meantime, Sol Shares enrollees may continue taking MCE service under the Light Green or Deep Green service options.

Customers enrolled in the Program will continue to have their electric meters read and be billed for electric service by the distribution utility (PG&E). The electric bill for Program customers will show separate charges for generation procured by the Program and all other charges related to delivery of the electricity and other utility charges that will continue to be assessed by PG&E.

After service cutover, customers will be given two additional opportunities to opt-out of the Program and return to the distribution utility (PG&E) following receipt of their first and second bills. Customers that opt-out between the initial cutover date and the close of the post enrollment opt-out period will be responsible for program charges for the time they were served by MCE but will not otherwise be subject to any penalty for leaving the program. Customers that have not opted-out within thirty days of the fourth opt-out notice will be deemed to have elected to become a participant in the Program and to have agreed to the Program's terms and conditions, including those pertaining to requests for termination of service, as further described in Chapter 8.

Consequences of Aggregation

Rate Impacts

Customers will pay the generation charges set by MCE and no longer pay the costs of PG&E generation. Customers enrolled in the Program will be subject to the Program's terms and conditions, including responsibility for payment of all Program charges as described in Chapter 9. MCE's rate setting policies are described in Chapter 7. MCE will establish rates sufficient to recover all costs related to operation of the Program, and actual rates will be adopted by MCE's governing board.

Information regarding current Program rates will be disclosed along with other terms and conditions of service in the pre-enrollment opt-out notices sent to potential customers.

Program customers are not expected to be responsible in any way for costs associated with the utilities' future electricity procurement contracts or power plant investments that are made on behalf of utility bundled service customers. Certain pre-existing generation costs will continue to be charged by PG&E to CCA customers through a separate rate component, called the Cost Responsibility Surcharge or CRS. This charge is shown in PG&E's tariff, which can be accessed from the utility's website.

Renewable Energy Impacts

The MCE program has substantially increased the proportion of energy generated and supplied to its customers by renewable resources. The resource plan includes procurement of renewable energy sufficient to meet a minimum of 50 percent of the Program's electricity needs. Customers of MCE may voluntarily participate in a 100 percent renewable supply option. To the extent that customers choose to participate in this voluntary program, the renewable content of MCE's power supply would increase. The renewable energy requirements of MCE customers are being supplied through contractual arrangements, but may be delivered, at an indeterminate point in the future, by new renewable generation resources developed by or for

MCE subject to then-current considerations (such as development costs, regulatory requirements and other concerns).

Energy Efficiency Impacts

Energy efficiency is an important component of the MCE mission statement. MCE currently administers over $4 million in ratepayer funded energy efficiency programs under the purview of the California Public Utilities Commission. MCE launched energy efficiency programs in late 2012 under the authority of Public Utilities Code section 381.1 (e-f). This 2012 plan focused specifically on providing multi-family energy efficiency services to MCE customers only. In early 2013, MCE launched a full portfolio of energy efficiency services, available to all ratepayers in MCE service territory, under the authority in PUC 381.1 (a-d). Energy efficiency is included in the MCE Integrated Resources Plan, and both local energy efficiency potential and energy efficiency accomplishments are utilized to inform future estimates of procurement needs. This relationship is described further in Chapter 6.

CHAPTER 3 – Organizational Structure

This section provides an overview of the organizational structure of MCE

Organizational Overview

The MCE program is governed by MCE's Board of Directors ("Board"), appointed by the Members. MCE is a joint powers agency created in December 2008 and formed under California law. Originally, the County of Marin and eight municipalities within the geographic boundaries of the County became Members of MCE and elected to offer the Program to their constituents. Since that time, the remaining four municipalities within Marin, which include the cities of Novato and Larkspur and the towns of Ross and Corte Madera, have requested and received approval for MCE membership as has the City of Richmond and, most recently, the County of Napa. MCE (formerly known as "The Marin Energy Authority") is the CCA entity that has registered with the CPUC and has been responsible for implementing and managing the program pursuant to MCE's Joint Powers Agreement ("JPA Agreement" or "Agreement"). The Program is operated under the direction of an Executive Officer, who has been appointed by the Board. The Executive Officer reports to the Board comprised of one representative from each participating Member of MCE. Those who are eligible to serve as representatives on the Board include elected officials from the then-current County Board of Supervisors representing Marin County as well as the County of Napa (one Board representative has been selected from the Marin County Board of Supervisors; another Board representative, who will soon begin serving on MCE's governing board, has been selected by the County of Napa's Board of Supervisors) and the City and Town Councils (one representative has been selected from each of the City and Town Councils) of the Members.

The Board's primary duties are to establish program policies, set rates and provide policy direction to the Executive Officer, who has general responsibility for program operations, consistent with the policies established by the Board. The Board has also determined necessary staffing levels, individual titles and related compensation ranges for the organization. The Board may also adjust staffing levels and compensation over time in response to varying workloads, specific programs and/or general responsibilities of MCE.

The Executive Officer is an employee of MCE, and the Board is responsible for evaluating the Executive Officer's performance.

The Board has established a Chairman and other officers from among its membership and has established an Executive Committee and Technical Committee and may establish other committees and sub-committees as needed to address issues that require greater expertise in particular areas (e.g., finance or contracts). MCE may also establish an "Energy Commission" formed of Board-selected designees. The Energy Commission would have responsibility for evaluating various issues that may affect MCE and its customers, including rate setting, and would provide analytical support and recommendations to the Board in these regards.

The Executive Officer has responsibilities over the functional areas of Finance, Regulatory Affairs, and Operations. In performing these responsibilities, the Executive Officer utilizes a combination of internal staff and contractors. Certain specialized functions needed for program operations, namely the electric supply and customer account management functions described below, are performed by experienced third-party contractors.

Governance
MCE has a Board of Directors consisting of one representative from each Member. Following satisfaction of certain administrative conditions, the Board will soon add an additional representative from the County of Napa. The Board meets at regular intervals to provide the overall management and guidance for MCE. All Board meetings are public and held in accordance with the Ralph M. Brown Act.

Decisions by MCE are under voting procedures defined in the JPA Agreement, attached hereto as Appendix C. All votes on a particular matter are subject to the two-tiered approval process described in the JPA Agreement.

Officers
MCE has a Chair and Vice-Chair elected to one-year terms by the Board of Directors. Both the Chair and Vice-Chair must be members of the Board. In addition, MCE has a Board Clerk and Auditor; neither of which will be members of the Board of Directors. The JPA Agreement provides further detail with respect to each of these positions.

Committees
MCE may form various committees comprised of Board designees from the Member communities. Appointments would be made based on various skill sets and expertise that will be useful in evaluating matters affecting MCE and its customers, specifically issues related to rate setting, procurement of energy products and other technical matters. These committees would provide the Board with recommendations and related analysis to support policy-level decisions of the Board. MCE may elect to have additional committees or working groups to address various topics. Any additional committees and their functions will be determined by the Board of Directors at the time each committee is created. At present, MCE has formed the following standing committees: 1) the Executive Committee; and 2) the Technical Committee. MCE also utilizes Ad Hoc Committees from time to time on an as-needed basis.

Addition/Termination of Participation
The JPA Agreement provides for the addition of new participants subject to the affirmative vote of MCE's Board of Directors pursuant to the voting structure described in the Agreement. The Board has determined the specific terms and conditions under which new Members can be admitted and has recently approved the membership request received from the County of Napa. Following the satisfaction of certain administrative requirements determined by the

Board, a representative from the new Member will be added to the Board and will begin participating in governance activities.

A JPA Member can withdraw itself from the JPA subject to the specific terms and conditions contained in the JPA Agreement.

Agreements Overview

There are two principal agreements that govern MCE and the initial operation of its CCA Program: the JPA Agreement and Program Agreement No. 1 (PA-1). Each of these agreements and its functions are discussed below.

Joint Powers Agreement

The JPA Agreement created MCE and delineates a broad set of powers related to the study, promotion, development, and conduct of electricity-related projects and programs. The JPA Agreement describes MCE as having broad powers, but a very limited role without implementing agreements ("program agreements") to carry out specific programs. This structure is intended to provide flexibility for MCE to undertake other programs in the future that may be unrelated to CCA on behalf of all or a subset of MCE's Members. The Board has limited decision making authority regarding land use within the Member communities. Any issues involving land use within Member communities will be raised with the potentially affected Member. The land use and building regulations of each Member shall apply to any JPA facilities located within the jurisdiction of that Member. Any amendments to the JPA Agreement will be subject to prior approval by the Board.

The first program agreement or PA-1, discussed in greater detail below, provides for electric generation service to customers of the CCA Program. At MCE's Members' discretion, future program agreements could provide for other energy related programs or subsequent energy transactions.

Program Agreement No. 1

PA-1 consists of three components: 1) the Edison Electric Institute ("EEI") Master Power Purchase & Sale Agreement ("Master EEI Agreement"), which is a standard industry contract used by public and private utilities across the United States; 2) the EEI Master Power Purchase & Sale Agreement Cover Sheet, which provides additional detail related to MCE's specific transaction, identifying exceptions, clarifications and areas of applicability that modify the standard terms and conditions of the Master EEI Agreement; and 3) one or more Confirmations, inclusive of any amendments thereto, which is referenced in the Master EEI Agreement and defines the commercial terms of MCE's transaction. PA-1 is the agreement under which MCE currently procures a significant portion of the electric supply services for MCE customers. PA-1 specifies a five year delivery period, which commenced on May 7, 2010 and ends on May 6, 2015. PA-1 specifies a full requirements energy product, including electric energy, renewable energy, capacity, ancillary services and scheduling coordination services. Based on contract negotiations, PA-1 specifies fixed annual prices for each year of the delivery period and insulates municipal funds/budgets of the Member Agencies before, during and after the delivery period. PA-1 was executed by MCE and its energy supplier, SENA, on February 5, 2010 and has since incorporated a series of amendments to accommodate Program expansion. It is MCE's intent to provide for the additional energy requirements of future MCE customers by negotiating other contracts for requisite energy products and/or subsequent amendments to PA-1, which will be completed prior to commencement of service to CCA customers located within the unincorporated areas of the County of Napa. MCE anticipates that SENA will continue in its role as MCE's primary energy supplier and scheduling coordinator over the near-term (through December 31, 2016) but will also pursue supply arrangements with renewable energy generators to supplement planned renewable energy deliveries from SENA.

Agency Operations

MCE conducts program operations through its own internal staff and through contracts for services with third parties. MCE has its own General Counsel to manage its legal affairs. MCE's Executive Officer will have responsibility for day-to-day operations of the Program. To assist the Executive Officer, MCE has hired a full-time Administrative Assistant and a Clerk. Other staff positions may be added as necessary to include positions in finance, customer services, energy efficiency and other local energy programs, and operations.

Major MCE functions that are performed and managed by the Executive Officer are summarized below.

Resource Planning

MCE is charged with developing both short (one and two-year) and long-term resource plans for the program. The Executive Officer manages staff and contractors to develop the resource plan under the guidance provided by the Board and in compliance with California Law, and other requirements of California regulatory bodies (CPUC and CEC).

Long-term resource planning includes load forecasting and supply planning on a ten- to twenty-year time horizon. MCE's technical team develops integrated resource plans that meet program supply objectives and balance cost, risk and environmental considerations. Integrated resource planning considers demand side energy efficiency and demand response programs as well as traditional supply options. The CCA Program requires an independent planning function despite day-to-day supply operations being contracted to a third party energy supplier. Plans are updated and adopted by the Board on an annual basis.

Portfolio Operations

Portfolio operations encompass the activities necessary for wholesale procurement of electricity to serve end use customers. These highly specialized activities include the following:

- *Electricity Procurement* – assemble a portfolio of electricity resources to supply the electric needs of program customers.

- *Risk Management* – standard industry techniques are employed to reduce exposure to the volatility of energy markets and insulate customer rates from sudden changes in wholesale market prices.
- *Load Forecasting* – develop accurate load forecasts, both long-term for resource planning and short-term for the electricity purchases and sales needed to maintain a balance between hourly resources and loads.
- *Scheduling Coordination* – scheduling and settling electric supply transactions with the CAISO.

MCE has initially contracted with an experienced and financially sound third party, SENA, to perform most of the portfolio operation requirements for the CCA Program. These requirements include the procurement of energy and ancillary services, scheduling coordinator services, and day-ahead and real-time trading. PA-1 is the contractual instrument that has been developed for this purpose; additional detail related to PA-1 is provided in the preceding discussion.

MCE will approve and adopt a set of Program Controls that will serve as the risk management tools for the Executive Officer and any third party involved in the program's portfolio operations. Program Controls will define risk management policies and procedures and a process for ensuring compliance throughout the organization. During initial operations, SENA will bear the majority of program operational risks, pursuant to the terms and conditions of PA-1.

Operations & Local Energy Programs

A key focus of the CCA Program will be the development and implementation of local energy programs for its Members, including energy efficiency programs, net energy metering, distributed generation programs and other energy programs responsive to Member interests. The Executive Officer is responsible for further development of these Programs. To assist the Executive Officer in this regard, MCE has hired additional staff to oversee program operations and local energy program administration as well as develop energy efficiency marketing strategies, perform customer outreach and conduct related analyses to support chosen courses of action. As experience is gained from the retail energy side of the CCA Program, MCE will continue enhancing its local energy programs to achieve MCE's desired goals and objectives.

MCE is currently administering energy efficiency and distributed (solar) generation programs that can be used as alternatives to procurement of supply-side resources. MCE may also implement demand response programs in the future. For the time being, MCE has launched various small-scale pilot projects to explore demand response opportunities within its service territory. MCE will attempt to consolidate existing demand side programs into this organization and leverage the structure to expand energy efficiency offerings to customers throughout its service territory.

Rate Setting

The Board of Directors has the ultimate responsibility for setting the electric generation rates for the Program's customers. The Executive Officer in cooperation with technical staff and appropriate advisors, consultants and committees of the Board is responsible for developing proposed rates and options for the Board to consider before finalization. The final approved rates must, at a minimum, meet the annual revenue requirement developed by the Executive Officer, including any reserves or coverage requirements set forth in electric supply agreements and/or bond covenants. The Board has the flexibility to consider rate adjustments within certain ranges, provided that the overall revenue requirement is achieved; this provides an opportunity for economic development rates or other rate incentives.

Financial Management/Accounting

The Executive Officer in cooperation with technical staff, advisors and consultants is responsible for managing the financial affairs of MCE, including the development of an annual budget and revenue requirement; managing and maintaining cash flow requirements; potential bridge loans and other financial tools; and a large volume of billing settlements. The Executive Officer uses contractors and/or staff in support of these activities, as appropriate.

The Finance function arranges financing for capital projects, prepares financial reports, and ensures sufficient cash flow for the Program. This function also plays an important role in risk management by monitoring the credit of suppliers so that credit risk is properly understood and mitigated by the Program. In the event that changes in a supplier's financial condition and/or credit rating are identified, the Program will be able to take appropriate action, as would be provided for in the electric supply agreement. The Finance function establishes credit policies that the program must follow.

The retail settlements (customer billing) is contracted out to an organization with the necessary infrastructure and capability to handle in excess of 138,000 accounts during full Program phase-in and near-term expansion (to the County of Napa), which is scheduled to occur in February 2015. This function is described under Customer Services, below.

Customer Services

In addition to general program communications and marketing, a significant focus on customer service, particularly representation for key accounts, is necessary. This includes both a call center designed to field customer inquiries and routine interaction with customer accounts. The Executive Officer is responsible for the Customer Services function and uses staff and/or contractors in support of these activities as appropriate.

The Customer Account Services function performs retail settlements-related duties and manages customer account data. It processes customer service requests and administers customer enrollments and departures from the Program, maintaining a current database of customers enrolled in the Program. This function coordinates the issuance of monthly bills through the distribution utility's billing process and tracks customer payments. Activities include the electronic exchange of usage, billing, and payments data with the distribution utility and MCE, tracking of customer payments and accounts receivable, issuance of late payment and/or service termination notices, and administration of customer deposits in accordance with MCE credit policies.

The Customer Account Services function also manages billing related communications with customers, customer call centers, and routine customer notices. MCE has initially contracted with a third party, Noble Americas Energy Solutions ("Noble"), which has demonstrated the necessary experience and administers appropriate computer systems (customer information system), to perform the customer account and billing services functions.

MCE conducts Program marketing and key customer account management functions. These responsibilities will include the assignment of account representatives to key accounts, which will ensure high levels of customer service to these businesses, and implementation of a marketing strategy to promote customer satisfaction with the CCA Program. Effectively administering communications, marketing messages, and delivering information regarding the CCA Program to all customers is critical for the overall success of the CCA Program.

Legal and Regulatory Representation

The CCA Program requires ongoing regulatory representation to file resource plans, resource adequacy, compliance with California RPS, and overall representation on issues that will impact MCE, its Members and MCE customers. MCE maintains an active role at the CPUC, CEC, and, as necessary, FERC and the California legislature. Day-to-day analysis and reporting of pertinent legal and regulatory issues is completed by the Program's in-house legal and regulatory staff and/or qualified contractors.

MCE also retains legal services, as necessary, to administer MCE, review contracts, and provide overall legal support to the activities of MCE.

Roles and Functions

The Board performs the functions inherent in its policy-making, management and planning roles. MCE is the public face of the Program and has a direct role in marketing, communications and customer service. Other highly specialized functions, such as energy supply and data management, are contracted out to third parties with sufficient experience, technical and financial capabilities. The functions that are currently being performed by MCE's Board of Directors, the Executive Officer and third parties are specified below:

Organization	***Roles/Functions/Activities***
MCE Board of Directors	*Executive/Policy/Legal*
Executive Officer	*Finance*
	Legal and Regulatory - *Legal support* - *Participation in regulatory proceedings* - *Regulatory reporting*
	Marketing/Communications
	Rates & Support - *Rate policy* - *Rate design* - *Cost-of-service planning*
	Resource Planning - *Load research* - *Load forecasting* - *Supply-side/Demand side portfolio planning*
	Supply Operations - *Procurement* - *Contract Negotiation* - *Invoice Reconciliation*
	Contract Management - *RFP/RFQ Administration* - *Invoice Reconciliation & Issue Resolution* - *Project Development Status Monitoring*
	Customer Service - *Account representatives* - *Energy efficiency/DG program management*
Energy Suppliers	*Supply Operations* - *Procurement* - *Scheduling coordination* - *Settlements (ISO/Wholesale)* - *Short-term load forecasting*
Customer Account Services Provider/Data Manager (Noble)	*Account Management (Customer Information System)* - *Customer switching* - *New customer processing* - *Data exchange (EDI)* - *Payment processing (AR/AP)* - *Billing and retail settlements* - *Call center*

Staffing

Staffing requirements for the above MCE functions will be approximately ten full time equivalent positions, once the customer phase-in is complete and the program is fully operational. These staffing requirements are in addition to the services provided by the third party energy suppliers and the data manager. The Executive Officer will have discretion whether to internally staff these required functions or to contract for these services.

The following table shows the staffing plan for Marin Clean Energy at initial full-scale operational levels, following full phase-in. Customer service for the mass market residential and small commercial customers will be provided by the Program's third party customer account services provider.

Current Staffing for the Marin Clean Energy
Community Choice Aggregation Program

Position	Staff (Full Time Equivalents)
Executive Officer	1
Internal Operations	
Director of Internal Operations	1
Business Analyst	1
Clerk	1
Human Resources Coordinator	0.5
Administrative Associate	1
Public Affairs	
Communications Director	1
Manager of Account Services	1
Account Manager 1	2
Community Affairs Coordinator	1
Communications Associate	1
Energy Efficiency	
Energy Efficiency Director	1
Energy Efficiency Specialist	2
Legal & Regulatory	
Legal Director	1
Regulatory Counsel	1
Regulatory Analyst	1
Regulatory Assistant	1
Electric Supply	
Director of Power Resources	1
Program Specialist	1
Special Assignment Intern	0.5
Total Staffing	21

Longer-term staffing needs will include additional energy efficiency and distributed generation activities and potentially the creation of an internal organization to perform the portfolio operations and account services functions that are currently performed under contract arrangements.

CHAPTER 4 – CCA Startup

As previously noted, MCE successfully launched the MCE program on May 7, 2010. To ensure successful operation during the implementation and start-up period, MCE utilized a mix of staff and contractors in its CCA Program implementation. The following table illustrates start-up responsibilities as well as expectations for near-term (two to five years), and long-term staffing roles.

Expectations for Staffing Roles

Function	Start-Up	Near-Term (2 to 5 Years)	Long-Term
Program Governance	MCE Board	MCE Board	MCE Board
Program Management	MCE EO	MCE EO	MCE EO
Outreach	MCE EO	MCE EO	MCE EO
Customer Service	MCE EO	MCE EO	MCE EO
Key Account Management	MCE EO	MCE EO	MCE EO
Regulatory	Third Party (MCE EO support)	MCE EO (Regulatory Analyst support)	MCE EO (Regulatory Analyst support)
Legal	MCE EO	MCE EO	MCE EO
Finance	MCE EO	MCE EO	MCE EO
Rates: Develop & Approve	MCE EO (third Party support) MCE Board	MCE EO (third Party support) MCE Board	MCE EO (third party support) MCE Board
Resource Planning	Third Party (MCE EO support)	MCE EO (third party support)	MCE EO (third party support)
Energy Efficiency	MCE EM (third Party Support)	MCE EO (Program Energy Efficiency Staff)	MCE EO (Program Energy Efficiency Staff)
Resource Development	MCE EO (third party support)	MCE EO (third party support)	MCE EO (third party support)
Portfolio Operations	Third Party	Third Party (MCE EO support)	MCE EO (third party support)
Scheduling Coordinator	Third Party	Third Party	Third Party (potentially MCE EO)
Data Management	Third Party	Third Party	Third Party (potentially MCE EO)

Staffing Requirements

Staff will be added incrementally to match workloads involved in forming the new organization, managing contracts, and initiating customer outreach/marketing during the pre-operations period. Actual staff will be dependent upon several factors, including the ability to recruit and hire qualified staff and personnel policies ultimately established by the Executive Officer and the Board of Directors.

CHAPTER 5 – Program Phase-In

MCE will continue to phase-in the customers of its CCA Program as communicated in this Implementation Plan. To date, four phases have been successfully implemented, and a fifth phase will commence in February 2015.

Phase 1. Complete: MCE Member (municipal) accounts & a subset of residential, commercial and/or industrial accounts, comprising approximately 20 percent of total customer load.

Phase 2. Complete: Additional commercial and residential accounts, comprising an approximately 20 percent of total customer load (incremental addition to Phase 1).

Phase 3. Complete: Remaining accounts within Marin County.

Phase 4. Complete: Residential, commercial, agricultural, and street lighting accounts within the City of Richmond.

Phase 5. February 2015: Residential, commercial, agricultural, and street lighting accounts within the unincorporated areas of Napa County, subject to economic and operational constraints.

This approach has provided MCE with the ability to start slow, addressing any problems or unforeseen challenges on a small manageable program before gradually building to full program integration for an expected customer base of approximately 138,000 accounts, following service commencement to customers within the unincorporated areas of the County of Napa. This approach has also allowed MCE and its energy supplier(s) to address all system requirements (billing, collections, payments) under a phase-in approach to minimize potential exposure to uncertainty and financial risk by "walking" prior to ultimately "running".

MCE will offer service to all customers on a phased basis expected to be completed within twenty four to thirty six months of initial service to Phase 1 customers, which occurred on May 7, 2010. Phase 2 was implemented in August, 2011. Phase 3 of the Program began in July, 2012. Phase 4 was implemented in July, 2013 and included all residential, commercial, agricultural, and street lighting customers within the City of Richmond. Phase 5 is planned to begin in February 2015 and will include all residential, commercial, agricultural, and street lighting customers within the unincorporated areas of Napa County. The Board may evaluate other phase-in options based on then-current market conditions, statutory requirements and regulatory considerations as well as other factors potentially affecting the integration of additional customer accounts.

CHAPTER 6 - Load Forecast and Resource Plan

Introduction

This Chapter describes MCE's proposed ten-year integrated resource plan, which will create a highly renewable, diversified portfolio of electricity supplies capable of meeting the electric demands of MCE's retail customers, plus sufficient reliability reserves.

This integrated resource plan reflects a progression towards MCE's long-term, programmatic goal of 100 percent renewable energy supply. Within five years of program commencement (2015), this significant commitment to renewable resources is projected to result in MCE meeting approximately 52 percent of its total electric needs through renewable resources. As the Program moves forward, incremental renewable supply additions will be made based on resource availability as well as economic goals of the Program. MCE's aggressive commitment to renewable generation adoption may involve both direct investment in new renewable generating resources through partnerships with experienced public power developers/operators, significant purchases of renewable energy from third party suppliers and the purchase of Renewable Energy Certificates ("RECs") from the market. The resource plan also sets forth ambitious targets for improving customer side energy efficiency as well as for potential deployment of approximately 14 MW of new distributed solar capacity within the jurisdictional boundaries of MCE by 2019 (year ten of Program operations).

The plan described in this section would accomplish the following by 2019:

- Procure energy needed to offer two generation rate tariffs: 100 percent Deep Green and 50 percent (minimum) Light Green.
- Increase the aggregate RPS-eligible renewable energy supply of the Program to a minimum 33 percent by 2020.
- Continue increasing renewable energy supplies of the Program to approximately 52 percent by 2015 based on resource availability and economic goals of the program.
- Develop partnership(s) with experienced public power developer(s) to responsibly evaluate development opportunities for Program-owned/controlled renewable generating capacity.
- Achieve significant reductions in greenhouse gas emissions within the Member Agencies.

MCE is responsible for complying with regulatory rules applicable to California load serving entities. MCE has arranged for the scheduling of sufficient electric supplies to meet the hour-by-hour demands of its customers. MCE has adhered to capacity reserve requirements established by the CPUC and the CAISO designed to address uncertainty in load forecasts and potential supply disruptions caused by generator outages and/or transmission contingencies. These rules also ensure that physical generation capacity is in place to serve the Program's customers, even if there were to be a need for the Program to cease operations and return customers to PG&E. In addition, MCE is responsible for ensuring that its resource mix contains sufficient production from renewable energy resources needed to comply with the statewide renewable portfolio standards. The resource plan will meet or exceed all of the applicable regulatory requirements related to resource adequacy and the renewable portfolio standard.

Resource Plan Overview

The criteria used to guide development of the proposed resource plan included the following:

- Environmental responsibility and commitment to renewable resources;
- Price/rate stability;
- Reliability and maintenance of adequate reserves; and
- Cost effectiveness.

To meet these objectives and the applicable regulatory requirements, MCE's resource plan includes a diverse mix of power purchases, renewable energy, new energy efficiency programs, demand response, and distributed generation. A diversified resource plan minimizes risk and volatility that can occur from over-reliance on a single resource type or fuel source. The ultimate goal of MCE's resource plan is to maximize use of renewable resources subject to economic and operational constraints. The result is a resource plan that will source approximately 52 percent of MCE's resource mix from renewable resources by 2015. The planned resource mix is initially comprised of power and renewable energy credit purchases from third party electric suppliers and, in the longer-term, may also include renewable generation assets owned and/or controlled by MCE.

Eventually, MCE may begin evaluating opportunities for investment in renewable generating assets, subject to then-current market conditions, statutory requirements and regulatory considerations. Any renewable generation owned by MCE or controlled under long-term power purchase agreement with a proven public power developer, could provide a portion of MCE's electricity requirements on a cost-of-service basis. Electricity purchased under a cost-of-service arrangement should be more cost-effective than purchasing renewable energy from third party developers, which will allow the Program to pass on cost savings to its customers through competitive generation rates. Any investment decisions will be made following thorough environmental reviews and in consultation with the Marin Communities' financial advisors, investment bankers, attorneys, and potentially with customer input.

As an alternative to direct investment, MCE may consider partnering with an experienced public power developer and enter into a long-term (20-to-30 year) power purchase agreement that would support the development of new renewable generating capacity. Such an arrangement could be structured to greatly reduce the Program's operational risk associated with capacity ownership while providing Program customers with all renewable energy generated by the facility under contract. This option may be preferable to MCE as it works to achieve increasing levels of renewable energy supply to its customers.

MCE's resource plan will integrate supply-side resources with programs that will help customers reduce their energy costs through improved energy efficiency and other demand-side measures. As part of its integrated resource plan, MCE will actively pursue, promote and ultimately administer a variety of customer energy efficiency programs that can cost-effectively displace supply-side resources. Included in this plan is a targeted deployment of over 14 MW of distributed solar by 2019.

MCE's proposed resource plan for the years 2010 through 2019 is summarized in the following table:

Marin Clean Energy
Proposed Resource Plan
(GWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
MCE Demand (GWh)										
Retail Demand	-91	-185	-570	-1,110	-1,294	-1,545	-1,582	-1,582	-1,582	-1,582
Distributed Generation	0	1	1	5	12	16	22	23	25	25
Energy Efficiency	0	0	0	6	6	4	8	12	16	16
Losses and UFE	-5	-11	-34	-66	-77	-91	-93	-93	-92	-92
Total Demand	-96	-196	-603	-1,166	-1,353	-1,616	-1,646	-1,640	-1,634	-1,634
MCE Supply (GWh)										
Renewable Resources										
Generation	0	0	0	0	0	0	0	219	219	219
Power Purchase Contracts	23	50	291	566	673	803	838	635	651	667
Total Renewable Resources	23	50	291	566	673	803	838	854	870	886
Conventional Resources										
Generation	0	0	0	0	0	0	0	0	0	0
Power Purchase Contracts	73	146	312	599	680	813	807	786	764	748
Total Conventional Resources	73	146	312	599	680	813	807	786	764	748
Total Supply	96	196	603	1,166	1,353	1,616	1,646	1,640	1,634	1,634
Energy Open Position (GWh)	0	0	0	0	0	0	0	0	0	0

Supply Requirements

The starting point for MCE's resource plan is a projection of participating customers and associated electric consumption. Projected electric consumption is evaluated on an hourly basis, and matched with resources best suited to serving the aggregate of hourly demands or the program's "load profile". The electric sales forecast and load profile will be affected by MCE's plan to introduce the Program to customers in phases and the degree to which customers choose to remain with PG&E during the customer enrollment and opt-out periods. It is anticipated that MCE's contracted energy supplier will bear a portion of the financial risks associated with deviations from the electric sales forecast during the initial operating period. It will be the obligation of this energy supplier to appropriately reflect these risks in the full requirements energy price. MCE's phased roll-out plan and assumptions regarding customer participation rates are discussed below.

Customer Participation Rates

Customers will be automatically enrolled in MCE's electricity program unless they opt-out during the customer notification process conducted during the 60-day period prior to enrollment and continuing through the 60-day period following commencement of service. MCE anticipated an overall customer participation rate of approximately 80 percent during Phase 1, when service is being offered to the service accounts that are affiliated with MCE's participating members (municipal accounts) and a subset of residential, commercial and/or industrial customers, totaling approximately 20 percent of total customer load. The actual participation rate for Phase 1 was very similar to MCE's projection. Participation rates for

Phase 2 were approximately 80 percent of bundled service customers and 0 percent of direct access customers. Participation rates for Phases 3 and 4 are projected to range from 70 percent to 80 percent, with the lower figure used as the basis for load projections contained in this plan. The participation rate is not expected to vary significantly among customer classes, in part due to the fact that MCE will offer two distinct rate tariffs that will address the needs of cost-sensitive customers within the Marin Communities as well as the needs of both residential and business customers that prefer a highly renewable energy product. The assumed participation rates will be refined as MCE's public outreach and market research efforts continue to develop.

Customer Forecast

Once customers enroll in each phase, they will be switched over to service by MCE on their regularly scheduled meter read date over an approximately thirty day period. The number of accounts served by MCE at the end of each phase is shown in the table below.

Marin Clean Energy
Enrolled Retail Service Accounts
Phase-In Period (End of Month)

	May-10	Aug-11	Jul-12	Jul-13	Feb-15
MCE Customers					
Residential	7,354	12,503	77,345	106,510	120,204
Small Commercial	522	605	8,934	11,829	13,761
Medium And Large Commercial And Industrial	57	509	949	1,269	1,555
Street Lighting & Traffic	138	141	443	748	1,014
Ag & Pump.	-	< 15	113	109	1,467
Total	8,071	13,759	87,814	120,465	138,001

MCE assumes that MCE customer growth will generally offset customer attrition (opt-outs) over time, resulting in a relatively stable customer base over the noted planning horizon. Because MCE is the first program of its kind within California, it is very difficult to anticipate with any precision the actual levels of customer participation within this CCA program. MCE believes that its assumptions regarding the offsetting effects of growth and attrition are reasonable in consideration of the limited build-out potential within a significant portion of MCE's service territory and the observed rate of customer opt-outs following mandatory customer notification periods. The forecast of service accounts (customers) served by MCE for each of the referenced ten-year planning periods is shown in the following table:

Marin Clean Energy
Retail Service Accounts (End of Year)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
MCE Customers										
Residential	7,354	12,503	77,345	106,510	106,510	120,204	120,204	120,204	120,204	120,204
Small Commercial	522	605	8,934	11,829	11,829	13,761	13,761	13,761	13,761	13,761
Medium And Large Commercial And Industrial	57	509	979	1,269	1,269	1,555	1,555	1,555	1,555	1,555
Street Lighting & Traffic	138	141	443	748	748	1,014	1,014	1,014	1,014	1,014
Ag & Pump.	-	< 15	113	109	109	1,467	1,467	1,467	1,467	1,467
Total	8,071	13,759	87,814	120,465	120,465	138,001	138,001	138,001	138,001	138,001

Sales Forecast

MCE's forecast of kWh sales reflects the roll-out and customer enrollment schedule shown above. The annual electricity needed to serve MCE's retail customers increases from approximately 200 GWh in 2011 to approximately 1,600 GWh at full roll-out, which includes planned expansion to the County of Napa. Annual energy requirements are shown below.

Marin Clean Energy
Energy Requirements
(GWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
MCE Energy Requirements (GWh)										
Retail Demand	91	185	570	1,110	1,294	1,545	1,582	1,582	1,582	1,582
Distributed Generation	0	-1	-1	-5	-12	-16	-22	-23	-25	-25
Energy Efficiency	0	0	0	-6	-6	-4	-8	-12	-16	-16
Losses and UFE	5	11	34	66	77	91	93	93	92	92
Total Load Requirement	96	196	603	1,166	1,353	1,616	1,646	1,640	1,634	1,634

Capacity Requirements

The CPUC's resource adequacy standards applicable to MCE require a demonstration one year in advance that MCE has secured physical capacity for 90 percent of its projected peak loads for each of the five months May through September, plus a minimum 15 percent reserve margin. On a month-ahead basis, MCE must demonstrate 100 percent of the peak load plus a minimum 15 percent reserve margin.

A portion of MCE's capacity requirements must be procured locally, from the Greater Bay area as defined by the CAISO and another portion must be procured from local reliability areas outside the Greater Bay Area. MCE must also meet requirements for flexible capacity such that a portion of MCE's resource adequacy requirements are met from qualifying flexible resources. MCE is required to demonstrate its local and flexible capacity requirements for each month of the following calendar year. MCE must demonstrate compliance or request a waiver from the

CPUC requirement as provided for in cases where local capacity is not available. MCE complies with the forward and monthly resource adequacy requirements administered by the state regulatory agencies.

MCE's plan ensures sufficient reserves are procured to meet its peak load at all times. MCE's annual peak capacity requirements are shown in the following table:

Marin Clean Energy
Capacity Requirements
(MW)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Demand (MW)										
Retail Demand	28	46	182	233	233	286	286	286	286	286
Distributed Generation	(0)	(1)	(4)	(8)	(11)	(15)	(15)	(17)	(17)	(17)
Energy Efficiency	-	-	-	(1)	(1)	(1)	(2)	(3)	(3)	(3)
Losses and UFE	2	3	11	13	13	16	16	16	16	16
Total Net Peak Demand	30	47	189	237	235	287	285	283	282	282
Reserve Requirement (%)	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Capacity Reserve Requirement	4	7	28	36	35	43	43	42	42	42
Capacity Requirement Including Reserve	34	55	218	273	270	330	328	325	324	324

MCE will continue to coordinate with PG&E and appropriate state agencies to manage the transition of responsibility for resource adequacy from PG&E to MCE following load migration to CCA service. For system resource adequacy requirements, MCE will make month-ahead showings for each month that MCE plans to serve load, and any load migration issues will be addressed through the CPUC's approved procedures. MCE will work with the California Energy Commission and CPUC prior to commencing service to additional customers to ensure it meets its local, system and flexible resource adequacy obligations through its agreements with its chosen electric suppliers.

Renewable Portfolio Standards Energy Requirements

Basic RPS Requirements

As a CCA, MCE is required by law and ensuing CPUC regulations to procure a certain minimum percentage of its retail electricity sales from qualified renewable energy resources. For purposes of determining MCE's renewable energy requirements, the same standards for RPS compliance that are applicable to the distribution utilities are assumed to apply to MCE.

California's RPS program is currently undergoing reform. On April 12, 2011, Governor Jerry Brown signed SB x1 2, requiring public and private utilities as well as community choice aggregators to obtain 33 percent of their electricity from renewable energy sources by December 31, 2020. MCE is familiar with California's new RPS, including certain procurement quantity requirements identified in D.11-12-020 (December 1, 2011). To date, MCE has significantly exceeded California's RPS, providing MCE customers with over 29 percent RPS-eligible renewable energy delivered to MCE customers in 2012. A similar renewable energy percentage, approximating 28.7 percent, was supplied to MCE customers in 2013.

MCE's Renewable Portfolio Standards Requirement

MCE's annual RPS requirements are shown in the table below. When reviewing this table, it is important to note that MCE projects increases in energy efficiency savings as well as increases in locally situated distributed generation capacity (an additional 14 MW by 2019), resulting in a slight downward trend in projected retail electricity sales.

Marin Clean Energy
RPS Requirements
(MWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Retail Sales	91,219	185,493	570,144	1,110,487	1,293,681	1,544,971	1,581,999	1,581,999	1,581,999	1,581,999
Baseline	-	18,244	37,099	114,029	222,097	280,729	359,978	395,500	427,140	458,780
Incremental Procurement Target	18,244	18,855	76,930	108,069	58,631	79,249	35,522	31,640	31,640	31,640
Annual Procurement Target	18,244	37,099	114,029	222,097	280,729	359,978	395,500	427,140	458,780	490,420
% of Current Year Retail Sales	20%	20%	20%	20%	22%	23%	25%	27%	29%	31%

Based on planned renewable energy procurement objectives, MCE anticipates that it will significantly exceed the minimum RPS requirements as shown below.

Marin Clean Energy
RPS Requirements and Program Renewable Energy Targets
(MWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Retail Sales (MWh)	91,219	185,493	570,144	1,110,487	1,293,681	1,544,971	1,581,999	1,581,999	1,581,999	1,581,999
Annual RPS Target (Minimum MWh)	18,244	37,099	114,029	222,097	280,729	359,978	395,500	427,140	458,780	490,420
Program Target (% of Retail Sales)	25%	27%	51%	51%	52%	52%	53%	54%	55%	56%
Program Renewable Target (MWh)	**22,805**	**50,083**	**290,773**	**566,348**	**672,714**	**803,385**	**838,459**	**854,279**	**870,099**	**885,919**
Surplus In Excess of RPS (MWh)	**4,561**	**12,984**	**176,745**	**344,251**	**391,985**	**443,407**	**442,960**	**427,140**	**411,320**	**395,500**
Annual Increase (MWh)	22,805	27,278	240,690	275,575	106,366	130,671	35,075	15,820	15,820	15,820

Resources

MCE has begun evaluating opportunities for future investment in renewable generating assets. Such opportunities will be evaluated on a case by case basis in consideration of resource location, market conditions, statutory requirements and regulatory considerations. Any renewable generation owned by MCE or controlled under long-term power purchase agreement with a proven public power developer, could provide a portion of MCE's electricity requirements on a cost-of-service basis. Electricity purchased under a cost-of-service arrangement should be more cost-effective than purchasing renewable energy from third party developers, which will allow the Program to pass on cost savings to its customers through competitive generation rates. Any investment decisions will be made following thorough environmental reviews and in consultation with MCE's financial advisors, investment bankers, attorneys, and potentially with customer input.

As an alternative to direct investment, MCE may consider partnering with an experienced public power developer and enter into a long-term (20-to-30 year) power purchase agreement that would support the development of new renewable generating capacity. Such an arrangement could be structured to greatly reduce the Program's operational risk associated with capacity ownership while providing Program customers with all renewable energy generated by the facility under contract. This option may be preferable to MCE as it works to achieve increasing levels of renewable energy supply to its customers.

Purchased Power

Power purchased from utilities, power marketers, public agencies, and/or generators will likely be the predominant source of supply from 2010 to 2015 (MCE may consider the development of certain renewable energy projects, subject to Board approval, which may supply electric generation to MCE customers as soon as January 2016) and may still remain a significant source of power in the event that MCE considers the development of its own renewable generation assets. During the period from 2010 – 2016, MCE plans to contract with SENA for a substantial portion of its electricity needs under a full requirements power supply agreement, and SENA will be responsible for procuring a mix of power purchase contracts, including specified renewable energy targets, to provide a stable and cost-effective resource portfolio for the Program. Deliveries under this agreement have been supplemented with purchases of other energy products from qualified renewable project developers, asset owners and power marketers. Based on terms established in this third-party contract, MCE will continue to substitute electric energy generated by MCE-owned/controlled renewable resources for contract quantities in the event that such resources become operational during the delivery period.

Renewable Resources

MCE will initially secure necessary renewable power supply from SENA. MCE has supplemented the renewable energy provided under the initial full requirements contract with direct purchases of renewable energy from renewable energy facilities.

For planning purposes, MCE should anticipate procurement from the following types of large scale renewable resources in the near to midterm, which would require little or no transmission expansion to ensure deliverability:

- Local resources (solar, wind, biogas, biomass);
- Wind resources in Solano County;
- Existing Qualifying Facilities with expiring PG&E contracts;
- Expansion and re-powering of wind resources in Alameda County;
- Geothermal in Lake and Sonoma Counties;
- Local biomass projects; and

- Renewable Energy Certificates.

Medium and Long-Term Renewable Potential

For mid and long term planning purposes, MCE should anticipate procurement from the following types of large scale renewable resources[3]:

- Wind imports from the Tehachapi Area;
- Wind imports from the Pacific Northwest;
- Geothermal imports from Nevada;
- Geothermal imports from the Imperial Valley;
- Photovoltaic solar imports from California's Central Valley; and
- Solar CSP imports from Southern California (Riverside and San Bernardino Counties).

Although this resource plan identifies likely resource types and locations, it is not possible to predict what projects might be proposed in response to MCE's future solicitations for renewable energy or that may stem from discussions with other public agencies. Renewable projects that are located virtually anywhere in the Western Interconnection can be considered as long as the electricity is deliverable to the CAISO control area, as required to meet the Commission's RPS rules and any additional guidelines ultimately adopted by MCE's Board of Directors. The costs of transmission access and the risk of transmission congestion costs would need to be considered in the bid evaluation process if the delivery point is outside of MCE's load zone, as defined by the CAISO.

Energy Efficiency

This section addresses the treatment of energy efficiency as a component of MCE's integrated resource plan. As described below there are opportunities for significant cost effective energy efficiency programs within the region, and MCE will seek to maximize end-use customer energy efficiency to the greatest extent practical. MCE first received funding to implement energy efficiency programs through the 'elect to administer' portion of the Public Utilities Code (section 381.1 e-f), wherein MCE has the authority to collect funds which have already been collected from MCE customers to support an energy efficiency plan that complies with the legislative intent. MCE submitted a plan for the use of 2012 program funding, focusing exclusively on multi-family customers; this plan was certified by the Commission in August, 2012.[4]

On a parallel track, MCE submitted an application to administer funds as an independent program administrator, an option which was clarified by SB 790 (2011) and reinforced in a recent CPUC Decision on CCA and Energy Efficiency[5]. This suite of programs offers energy efficiency services for multi-family, small commercial and single family sectors with financing

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[3] In the long term, new technologies such as wave or tidal energy may become economically feasible as well.
[4] Resolution E-4815 California Public Utilities Commission. August 23, 2012.
[5] Decision 14-01-033. Decision Enabling Community Choice Aggregators to Administer Energy Efficiency Programs. January 16, 2014.

programs available to support all programs. MCE plans to grow the energy efficiency and local program department over time.

Baseline Energy Efficiency Potential Estimates

The National Action Plan for Energy Efficiency states among its key findings "consistently funded, well-designed efficiency programs are cutting annual savings for a given program year of 0.15 to 1 percent of energy sales."[6] The American Council for an Energy-Efficient Economy (ACEEE) reports for states already operating substantial energy efficiency programs energy efficiency goals of one percent, as a percentage of energy sales, is a reasonable level to target.[7] Forecast achievable energy efficiency equal to one percent of the CCA's forecast energy sales, as indicated in the table below, appears to be a reasonable and conservative baseline for the demand-side portion of CCA's resource plan. Targeted program savings would be in addition to the savings achieved by PG&E administered programs.

Marin Clean Energy
Energy Efficiency Savings Goals
(GWH)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
MCE Retail Demand	91	185	570	1,110	1,294	1,545	1,582	1,582	1,582	1,582
MCE Energy Efficiency Goal	0	0	0	-6	-6	-4	-8	-12	-16	-16

CCA Program Energy Efficiency Goals

The Program's energy efficiency goals reflect a strong commitment to increasing energy efficiency within the County and expanding beyond the savings achieved by PG&E's programs. MCE's goal is to increase annual savings through energy efficiency programs to two percent (combined MCE and PG&E programs) of annualized electric sales, as has been adopted by the State of New York, by the end of 2018. Achieving this goal would mean at least a doubling of energy savings relative to the status quo situation without the CCA program. MCE programs will focus on closing the gap between the vast economic potential of energy efficiency within MCE's service territory and what is actually achieved, while designing programs based on community input that align with MCE's mission statement.

The following table summarizes the estimated energy efficiency potential for each type of energy efficiency initiative:[8]

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[6] National Action Plan for Energy Efficiency, July 2006, Section 6: Energy Efficiency Program Best Practices (pages 5-6)

[7] Energy Efficiency Resource Standards: Experience and Recommendations, Steve Nadel, March 2006, ACEEE Report E063 (pages 28 - 30).

[8] California Energy Efficiency Potential Study Volume 1, California Measurement Advisory Council (CALMAC) Study ID: PGE0211.01, May 24, 2006, Figure 12-2: Distribution of Electric Energy Market Potential, Existing Incentive Levels through 2016.

California Energy Efficiency Market Potential

EXISTING RESIDENTIAL	53.0%
Existing Commercial	18.0%
Existing Industrial	14.0%
Residential New Construction	1.0%
Commercial New Construction	6.0%
Industrial New Construction	1.0%
Emerging Technologies	7.0%

The retrofit of existing buildings represents 85 percent of the total forecast energy efficiency market potential. Studies show that the residential customer sector presents the largest untapped efficiency gains.

MCE has ramped up the Energy Efficiency department since the first funding authorization in late 2012. MCE's energy efficiency department continues to refine energy savings estimates and develop portfolios in line with customer expectations and local patterns of energy use. Additional details of MCE's energy efficiency plans are set forth in a separate planning document.[9]

Demand Response

Demand response programs provide incentives to customers to reduce demand upon request by the load serving entity (i.e., MCE), reducing the amount of generation capacity that must be maintained as infrequently used reserves. Demand response programs can be cost effective alternatives to capacity otherwise needed to comply with the resource adequacy requirements. The programs also provide rate benefits to customers who have the flexibility to reduce or shift consumption for relatively short periods of time when generation capacity is most scarce. Like energy efficiency, demand response can be a win/win proposition, providing economic benefits to the electric supplier and customer service benefits to the customer.

In its ruling on local resource adequacy, the CPUC found that dispatchable demand response resources as well as distributed generation resources should be allowed to count for local capacity requirements. MCE has launched several small scale pilots to explore the possibilities for local DR programs. This resource plan anticipates that MCE's demand response programs would partially offset its local capacity requirements beginning in 2016.

PG&E offers several demand response programs to its customers, and MCE intends to recruit those customers that have shown a willingness to participate in utility programs into MCE's demand response programs.[10] The goal for this resource plan is to meet 5 percent of the Program's total capacity requirements (by 2018) through dispatchable demand response

[9] Marin Energy Authority's Proposal to Administer Energy Efficiency Programs Pursuant to Public Utilities Code 381.1(e) and (f) for 2012, June 22, 2012.

[10] These utility programs include the Base Interruptible Program (E-BIP), the Demand Bidding Program (E-DBP), Critical Peak Pricing (E-CPP), Optional Binding Mandatory Curtailment Plan (E-OBMC), the Scheduled Load Reduction Program (E-SLRP), and the Capacity Bidding Program (E-CBP). MCE has started to develop and implement its own demand response programs on a pilot basis.

programs that qualify to meet local resource adequacy requirements. This goal translates into approximately 13 MW of peak demand enrolled in MCE's demand response programs. Achievement of this goal would displace approximately 32 percent of MCE's local capacity requirement within the Greater Bay Area.

Marin Clean Energy
Demand Response Goals
(MW)
2010 to 2019

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Capacity Requirement (MW)	34	55	218	273	270	330	328	325	324	324
Demand Response Target	-	-	-	-	-	-	4	12	16	16
Percentage of Local Capacity Requirment	0%	0%	0%	0%	0%	0%	8%	24%	32%	32%

MCE's initial DR pilots offer the opportunity to explore DR programs and develop administrative capabilities related to this component of the MCE service offering. MCE plans to leverage experiences and lessons learned from these initial pilots to develop a demand response program that enables it to request customer demand reductions during times when capacity is in short supply or spot market energy costs are exceptionally high. The level of customer payments should be related to the cost of local capacity that can be avoided as a result of the customer's willingness to curtail usage upon request.

Appropriate limits on customer curtailments, both in terms of the length of individual curtailments and the total number of curtailment hours that can be called should be included in MCE's demand response program design. It will also be important to establish a reasonable measurement protocol for customer performance of its curtailment obligations. Performance measurement should include establishing a customer specific baseline of usage prior to the curtailment request from which demand reductions can be measured. MCE will likely utilize experienced third party contractors to design, implement and administer its demand response programs.

Distributed Generation

Consistent with MCE's environmental policies and the state's Energy Action Plan, clean distributed generation is a significant component of the integrated resource plan. MCE will work with state agencies and PG&E to promote deployment of photovoltaic (PV) systems within MCE's jurisdiction, with the goal of maximizing use of the available incentives that are funded through current utility distribution rates and public goods surcharges. MCE has also implemented an aggressive net energy metering program to promote local investment in distributed generation.

There are significant associated environmental benefits and strong customer interest in distributed PV systems. The economics of PV should improve over time as utility rates continue to increase and the costs of the systems decline with technological improvements and added manufacturing capacity. MCE can also promote distributed PV without providing direct financial assistance by being a source of unbiased consumer information and by facilitating customer purchases of PV systems through established networks of pre-qualified vendors. It may also provide direct financial incentives from revenues funded by customer rates to further support use of solar power within the Marin Communities. As previously noted, MCE has provided direct incentives for PV by offering an aggressive net metering rate to customers who install PV systems so that customers are able to sell excess energy to MCE.

MCE's CCA customers will contribute funds to the California Solar Initiative (CSI) through the public goods charge collected by PG&E, and will be eligible for the incentives provided under that program for installation of PV systems. The California Solar Initiative provides $2.2 billion of funding to target installation of 1,940 MW of solar systems within the investor owned utility service areas by 2017. All electric customers of PG&E, SCE, and SDG&E are eligible to apply for incentives. Approximately 44 percent of program funding is allocated to the PG&E service territory. Assuming solar deployment would be proportionate to funding, the program is intended to yield approximately 775 MW of solar within the PG&E service area. A minimum of 17 MW should be deployed within the service territory of MCE.

California Solar Initiative Deployment

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
IOU Territory Target (MW)	705	882	1,058	1,235	1,411	1,587	1,764	1,940	1,940	1,940
Total Funding ($Millions)	240	240	240	160	160	160	5	0	0	0
PG&E Funding ($Millions)	105	105	105	70	70	70	2	0	0	0
PG&E Incentives Share	44%	44%	44%	44%	44%	44%	40%	40%	40%	40%
PG&E Area Deployment (MW)	309	386	463	540	617	694	705	776	776	776
MCE Share of PG&E Load	0.1%	0.3%	0.8%	1.5%	1.8%	2.1%	2.1%	2.1%	2.1%	2.1%
MCE Solar Deployment (MW)	0	1	4	8	11	15	15	17	17	17

MCE will work to ensure that customers within its jurisdiction take full advantage of this solar incentive and will develop programs of its own with the goal of doubling the CSI deployment targets shown above.

CHAPTER 7 – Financial Plan

This Chapter examines the monthly cash flows expected during the phase-in period of the CCA Program and identifies the anticipated financing requirements for the overall CCA Program by MCE. It also describes the requirements for working capital and long-term financing for the potential investment in renewable generation, consistent with the resource plan contained in Chapter 6.

Description of Cash Flow Analysis

This cash flow analysis estimates the level of working capital that will be required during the phase-in period. In general, the components of the cash flow analysis can be summarized into two distinct categories: (1) Cost of CCA Program Operations, and (2) Revenues from CCA Program Operations. The cash flow analysis identifies and provides monthly estimates for each of these two categories. A key aspect of the cash flow analysis is to focus primarily on the monthly costs and revenues associated with the CCA Program phase-in period, and specifically account for the transition or "Phase-In" of CCA Customers from PG&E's service territory described in Chapter 5.

Cost of CCA Program Operations

The first category of the cash flow analysis is the Cost of CCA Program Operations. To estimate the overall costs associated with CCA Program Operations, the following components were taken into consideration:

- Electricity Procurement;
- Ancillary Service Requirements;
- Exit Fees;
- Staffing Requirements;
- Contractor Costs;
- Infrastructure Requirements;
- Billing Costs;
- Scheduling Coordination;
- Grid Management Charges;
- CCA Bond Premiums;
- Interest Expense; and
- Franchise Fees.

The focus of this cash flow analysis is during the phase-in period.

Revenues from CCA Program Operations

The cash flow analysis also provides estimates for revenues generated from CCA operations or from electricity sales to customers. In determining the level of revenues, the cash flow analysis assumes the customer phase-in schedule noted above, and assumes that MCE's CCA Program provides a Light Green Tariff at comparable generation rates to those of the existing distribution utility for each customer class and a 100 percent Green Tariff at a premium reflective of incremental renewable power costs. A third service option, which is planned to begin serving customers during the 2015 calendar year, is Sol Shares. The voluntary Sol Shares service option will supply participating customers with 100 percent locally generated solar electricity – MCE is currently accepting enrollments in the Sol Shares program.

Over time, MCE's preference for renewable energy will significantly reduce its exposure to volatile input costs (fuel – natural gas) associated with natural gas-fired generation, which are expected to increase steadily, and potentially significantly, for the foreseeable future. Because a significant portion of MCE's power supply will be from renewable energy sources, upward price pressures on its power supply should be significantly reduced over long-term operations.

Projected long-term cost savings can be passed on to Program customers in the form of lower generation rates or can be applied to the procurement of additional renewable energy supplies (moving the program's renewable energy supply closer to its 100 percent goal), energy efficiency programs or other energy/climate initiatives within the scope of broad-based powers established for MCE. Ultimately, MCE will have flexibility when making these decisions and can respond to the evolving needs of local residents and businesses when developing rate tariffs and energy/climate-focused programs.

Cash Flow Analysis Results

The results of the cash flow analysis provide an estimate of the level of working capital required for MCE to move through the CCA phase-in period. This estimated level of working capital is determined by examining the monthly cumulative net cash flows (revenues from CCA operations minus cost of CCA operations) based on assumptions for payment of costs by MCE, along with an assumption for when customer payments will be received. This identifies, on a monthly basis, what level of cash flow is available in terms of a surplus or deficit.

With the assumptions regarding payment streams, the cash flow analysis identifies funding requirements while recognizing the potential lag between payments received and payments made during the phase-in period. The estimated financing requirements for the phase-in period, including working capital, based on the phase-in of customers as described above is approximately $3 million. Working capital requirements reach this peak immediately after enrollment of the Phase 3 customers.

CCA Program Implementation Feasibility Analysis

In addition to developing a cash flow analysis which estimates the level of working capital required to get MCE through full CCA phase-in, a summary analysis that evaluates the feasibility of the CCA program during the phase-in period has been prepared. The difference between the cash flow analysis and the CCA feasibility analysis is that the feasibility analysis does not include a lag associated with payment streams. In essence, costs and revenues are reflected in the month in which service is provided. All other items, such as costs associated with CCA Program operations and rates charged to customers remain the same.

The results of the feasibility analysis are shown in the following table. Under these assumptions, over the entire phase-in period the CCA program is projected to accrue a reserve account balance of approximately $17 million.

Marin Clean Energy
Summary of CCA Program Phase-In
(January 2010 through December 2015)

CATEGORY	2010	2011	2012	2013	2014	2015
I. REVENUES FROM OPERATIONS ($)						
ELECTRIC SALES REVENUE	10,610,804	16,454,790	44,052,111	79,097,747	100,075,912	125,116,985
LESS UNCOLLECTIBLE ACCOUNTS	(21,453)	(102,807)	(220,261)	(395,489)	(500,380)	(625,585)
TOTAL REVENUES	10,589,351	16,351,983	43,831,851	78,702,259	99,575,532	124,491,400
II. COST OF OPERATIONS ($)						
(A) ADMINISTRATIVE AND GENERAL (A&G)						
STAFFING	321,117	430,659	1,077,759	1,386,303	1,825,000	1,993,875
CONTRACT SERVICES	1,035,333	848,063	3,131,840	4,457,964	4,611,420	4,898,007
IOU FEES (INCLUDING BILLING)	19,548	60,794	287,618	584,729	660,114	745,569
OTHER A&G	191,261	189,204	249,729	302,806	373,125	398,084
SUBTOTAL A&G	1,567,259	1,528,720	4,746,946	6,731,802	7,469,659	8,035,535
(B) COST OF ENERGY	7,418,662	11,881,494	35,566,066	69,037,682	85,826,553	111,605,979
(C) DEBT SERVICE	654,595	394,777	747,729	1,195,162	1,195,162	1,151,494
TOTAL COST OF OPERATION	9,640,516	13,804,991	41,060,742	76,964,646	94,491,374	120,793,009
CCA PROGRAM SURPLUS/(DEFICIT)	948,835	2,546,992	2,771,109	1,737,613	5,084,158	3,698,392

The surpluses achieved during the phase-in period serve as operating reserves for MCE in the event that operating costs (such as power purchase costs) exceed collected revenues for short periods of time.

Marin Clean Energy Financings

It is anticipated that three financings may be necessary in support of the CCA Program. The anticipated financings are listed below and discussed in greater detail.

CCA Program Start-up and Working Capital (Phases 1 and 2)

As previously discussed, the start-up and working capital requirements for the CCA Program were approximately $2 million. These costs are currently being recovered from retail customers through retail rates.

CCA Program Working Capital (Phase 3)

Working capital for Phase 3 was $3 million financed through a short term credit agreement from a commercial bank.

CCA Program Working Capital (Phase 4)

MCE utilized existing, internally generated funds to cover costs associated with the Phase 4 customer expansion.

CCA Program Working Capital (Phase 5)
MCE anticipates it will have sufficient internally generated funds to fund the Phase 5 customer expansion. If additional funds are required, a short term credit agreement would be used to support the expansion.

Renewable Resource Project Financing
MCE's CCA Program may consider large project financings for renewable resources (likely wind, solar, biomass or geothermal), which may total as much as $375 million (combined). These financings would only occur after a sustained period of successful Program operation and after appropriate project opportunities are identified and subjected to appropriate environmental review. Such financing would likely occur after several successful years of operating history have been observed and following MCE's receipt of an institutional credit rating. In the event that such financing becomes necessary, funds would include any short-term financing for the renewable resource project development costs, and would extend over a 20- to 30-year term.

The security for such bonds would likely be a hybrid of the revenue from sales to the retail customers of MCE, including a Termination Fee as described in Chapter 9, and the renewable resource project itself.

The following table summarizes the potential financings in support of the CCA Program:

Proposed Financing	Estimated Total Amount	Estimated Term	Estimated Issuance
Start-Up and Working Capital	$2 million	No longer than 7 years	Early 2010
Working Capital Phase 3	$3 million	No longer than 5 years	Mid 2012
Potential Renewable Resource Project Financings	$375 million (aggregate)	20 to 30 years	Undetermined

CHAPTER 8 - Ratesetting and Program Terms and Conditions

Introduction
This Chapter describes MCE's rate setting policies for electric aggregation services. These include policies regarding rate design, objectives, and provision for due process in setting Program rates. Program rates are ultimately approved by the Board. The Board would retain authority to modify program policies from time to time at its discretion.

Rate Policies
MCE has established rates sufficient to recover all costs related to operation of the program, including any reserves that may be required as a condition of financing and other discretionary reserve funds that may be approved by the Board of Directors. As a general policy, rates will be uniform for all similarly situated customers enrolled in the Program throughout the service area of MCE, comprised of the jurisdictional boundaries of its members.

The primary objectives of the ratesetting plan are to set rates that achieve the following:

- 100 percent renewable energy supply option – Deep Green Tariff;
- 100 percent local solar energy supply option – Sol Shares Tariff
- Rate competitive tariff option – Light Green Tariff (at 50 percent renewable energy);
- Rate stability;
- Equity among customers in each tariff;
- Customer understanding; and
- Revenue sufficiency.

Each of these objectives is described below.

Rate Competitiveness
The goal is to offer competitive rates for the electric services MCE provides to participating customers. For Deep Green participants, the goal is to offer the lowest possible customer rates with an incremental monthly cost premium of approximately 10 percent. For Sol Shares customers, the goal is to offer rates that are generally reflective of local, small utility scale solar development costs, which will initially relate to prices paid under MCE's Feed-In Tariff.

Competitive rates will be critical to attracting and retaining key customers. As discussed above, the principal long-term Program goal is to achieve 100 percent renewable energy supply subject to economic and operating constraints. As previously discussed, the Program will significantly increase renewable energy supply to Program customers, relative to the incumbent utility, by offering two distinct rate tariffs. The default tariff for Program customers will be the Light Green service option, which will maximize renewable energy supply (minimum 50 percent) while maintaining competitive generation rates to those currently offered by PG&E. MCE will also offer its customers a voluntary Deep Green Tariff, which will supply participating customers with 100 percent renewable energy supply at rates that reflect the Program's cost for procuring necessary energy supplies. As previously noted, MCE will be offering a third service option, Sol Shares, which is planned to begin serving customers during the 2015 calendar year. The voluntary Sol Shares service option will supply participating customers with 100 percent locally generated solar electricity – MCE is currently accepting enrollments in the Sol Shares program.

As previously suggested, the default tariff for Program customers will be the Light Green Tariff. Consistent with this MCE policy, participating qualified low- or fixed-income households, such as those currently enrolled in the California Alternate Rates for Energy (CARE) program, will be automatically enrolled in the Light Green Tariff and will continue to receive related discounts on monthly electricity bills. Based on projected participation in each tariff, the amount of renewable energy supplied to Program customers as a percentage of the Program's total energy requirements is projected to approximate 52 percent in 2015.

Rate Stability
MCE will offer stable rates by hedging its supply costs over multiple time horizons. Rate stability considerations may mean that program rates relative to PG&E's may differ at any point in time from the general rate targets set for the Program. Although MCE's rates will be stabilized through execution of appropriate price hedging strategies, the distribution utility's rates can fluctuate significantly from year-to-year based on energy market conditions such as natural gas prices, the utilities' hedging strategies, and hydro-electric conditions; and from rate impacts caused by periodic additions of generation to utility rate base. MCE will have more flexibility in procurement and ratesetting than PG&E to stabilize electricity costs for customers.

Equity among Customer Classes
MCE's policy will be to provide rate benefits to all customer classes relative to the rates that would otherwise be paid to the local distribution utility. Rate differences among customer classes will reflect the rates charged by the local distribution utility as well as differences in the costs of providing service to each class. Rate benefits may also vary among customers within the major customer class categories, depending upon the specific rate designs adopted by the Board of Directors.

Customer Understanding
The goal of customer understanding involves rate designs that are relatively straightforward so that customers can readily understand how their bills are calculated. This not only minimizes customer confusion and dissatisfaction but will also result in fewer billing inquiries to MCE's customer service call center. Customer understanding also requires rate structures to make sense (i.e., there should not be differences in rates that are not justified by costs or by other policies such as providing incentives for conservation).

Revenue Sufficiency
MCE's rates must collect sufficient revenue from participating customers to fully fund MCE's annual budget. Rates will be set to collect the adopted budget based on a forecast of electric

sales for the budget year. Rates will be adjusted as necessary to maintain the ability to fully recover all of MCE's costs, subject to the disclosure and due process policies described later in this chapter.

Rate Design

MCE will generally match the rate structures from the utilities' standard rates to avoid the possibility that customers would see significantly different bill impacts as a result of changes in rate structures when beginning service in MCE's program. MCE may also introduce new rate options for customers, such as rates designed to encourage economic expansion or business retention within MCE's service area.

Net Energy Metering

Customers with on-site generation eligible for net metering from PG&E will be offered a net energy metering rate from MCE. Net energy metering allows for customers with certain qualified solar or wind distributed generation to be billed on the basis of their net energy consumption. The PG&E net metering tariff (E-NEM) requires the CCA to offer a net energy metering tariff in order for the customer to continue to be eligible for service on Schedule E-NEM. The objective is that MCE's net energy metering tariff will apply to the generation component of the bill, and the PG&E net energy metering tariff will apply to the utility's portion of the bill. MCE will pay customers for excess power produced from net energy metered generation systems in accordance with the rate designs adopted by the MCE Board.

Disclosure and Due Process in Setting Rates and Allocating Costs among Participants

The Executive Officer, with support of appropriate staff, advisors and committees, will prepare an annual budget and corresponding customer rates and submit these as an application for a change in rates to the Board of Directors. The rates will be approved at a public meeting of the Board of Directors no sooner than thirty one (31) days following public posting of the proposed rates (which shall occur on MCE's website) - during this thirty one-day review period, affected customers will be able to provide comment on the proposed rate changes.

MCE will initially adopt customer noticing requirements similar to those the CPUC requires of PG&E. These notice requirements are described as follows:

Notice of rate changes will be published at least once in a newspaper of general circulation within the respective jurisdictions of MCE's Member Agencies. This notice will be published within ten days of MCE's public posting of the subject rate change. Such notice will state that a copy of said application and related exhibits may be examined at the offices of MCE and shall include the locations of such offices

MCE will furnish notice of its application to its customers affected by the proposed increase, either by including such notice as an on-bill message with the regular bill for charges transmitted to such customers or by mailing such notice postage prepaid to such customers.

The notice will state the amount of the proposed increase expressed in percentage terms, a brief statement of the reasons the increase is required or sought, and the mailing address of MCE to which any customer inquiries relative to the proposed increase, including a request by the customer to receive notice of the date, time, and place of any hearing on the application, may be directed.

CHAPTER 9 – Customer Rights and Responsibilities

This chapter discusses customer rights, including the right to opt-out of the CCA Program and the right to privacy of customer energy usage information, as well as obligations customers undertake upon agreement to enroll in the CCA Program. All customers that do not opt out within 30 days of the fourth opt-out notice will have agreed to become full status program participants and must adhere to the obligations set forth below, as may be modified and expanded by the MCE Board from time to time.

By adopting this Implementation Plan, the MCE Board approved the customer rights and responsibilities policies contained herein to be effective at Program initiation. The Board retains authority to modify program policies from time to time at its discretion.

Customer Notices

As part of the customer enrollment process, at least four notices will be provided to customers describing the Program, informing them of their opt-out rights to remain with utility bundled generation service, and containing a simple mechanism for exercising their opt-out rights. MCE will mail at least two written notices to customers, beginning at least two calendar months, or sixty days, in advance of the date of commencing automatic enrollment. MCE will likely use its own mailing service for requisite opt-out notices rather than including the notices in PG&E's monthly bills. This is intended to increase the likelihood that customers will read the opt-out notices, which may otherwise be ignored if included as a bill insert. Customers may opt out by notifying MCE using MCE's designated, telephone-based opt out processing service. Should customers choose to initiate an opt-out request by contacting PG&E, they will be transferred to MCE's call center to complete the opt-out request. Consistent with CPUC regulations, notices returned as undelivered mail would be treated as a failure to opt out, and the customer would be automatically enrolled.

Following automatic enrollment, at least two notices will be mailed to customers within the first two calendar months, or sixty days, of service. Opt-out requests made on or before the sixtieth day following start of MCE service would result in customer transfer to bundled utility service with no penalty. Such customers will be obligated to pay MCE's charges for electric services provided during the time the customer took service from the Program, but will otherwise not be subject to any penalty or transfer fee from MCE.

New customers who establish service within the Program service area will be automatically enrolled in the Program. Such customers will be mailed two opt-out notices within two calendar months, or sixty-days, of enrollment. MCE's Board of Directors will have the authority to implement entry fees for customers that initially opt out of the Program, but later decide to participate. Entry fees, if deemed necessary, would help prevent potential gaming, particularly by large customers, and aid in resource planning by providing additional control over the Program's customer base. Entry fees would not be practical to administer, nor would they be necessary, for residential and other small customers.

Termination Fee

Customers that are automatically enrolled in the Program can elect to transfer back to the incumbent utility without penalty within the first two months of service. After this free opt-out period, customers will be allowed to terminate their participation subject to payment of a Termination Fee. The Termination Fee may apply to all Program customers that elect to return to bundled utility service or elect to take "direct access" service from an energy services provider. Program customers that relocate within the Program's service territory would have their CCA service continued at the new address. If a customer relocating to an address within the Program service territory elected to cancel CCA service, the Termination Fee may apply. Program customers that move out of the Program's service territory would not be subject to the Program's Termination Fee.

The Termination Fee will consist of two parts: an Administrative Fee set to recover the costs of processing the customer transfer and other administrative or termination costs and a Cost Recovery Charge ("CRC") that would apply in the event MCE is unable to recover the costs of supply commitments attributable to the customer that is terminating service. PG&E will collect the Administrative Fee from returning customers as part of the final bill to the customer from the CCA Program and will collect the CRC as a lump sum or on a monthly basis pursuant to a negotiated servicing agreement between MCE and PG&E.

The Administrative Fee would vary by customer class as set forth in the table below.

Administrative Fee for Service Termination

Customer Class	**Fee**
Residential	$5
Non-Residential	$25

The customer CRC will be equal to a pro rata share of any above market costs of MCE's actual or planned supply portfolio at the time the customer terminates service. The proposed CRC is similar in concept to the Cost Responsibility Surcharge charged by PG&E, and it is designed to prevent shifting of costs to remaining Program customers. The CRC will be set on an annual basis by MCE's Governing Board as part of the annual ratemaking process. At this time, MCE's CRC is set to zero.

If customers terminate service, MCE anticipates it will re-market the excess supply and recover all or the majority of its costs. Depending upon market conditions, the CRC may not be needed for recovery of stranded costs. However, MCE's ability to assess a Cost Recovery Charge, if necessary, can be an important condition for obtaining financing for MCE's power supply. The low cost financing will, in turn, enable MCE to charge rates that are competitive with PG&E's.

The Termination Fee will be clearly disclosed in the four opt-out notices sent to customers during the sixty-day period before automatic enrollment and following commencement of service. The fee could be changed prospectively by MCE's Board of Directors, subject to MCE's customer noticing requirements. As previously noted, customers that opt-out during the statutorily mandated notification period will not pay the Termination Fee that may be imposed by MCE.

Customers electing to terminate service after the initial notification period that provided them with at least four opt-out notices would be transferred to PG&E on their next regularly scheduled meter read date if the termination notice is received a minimum of fifteen days prior to that date. Customers who voluntarily transfer back to PG&E after the initial notification period that provided them with at least four opt-out notices would also be liable for the nominal reentry fees imposed by PG&E as set forth in the applicable utility CCA tariffs. Such customers would also be required to remain on bundled utility service for a period of one year, as described in the utility tariffs.

Customer Confidentiality

MCE has established policies covering confidentiality of customer data. These policies are fully compliant with the California Public Utility Commission's required privacy protection rules for CCA customer energy usage information detailed within Decision D.12-08-045. MCE's policies will maintain confidentiality of individual customer data. Confidential data includes individual customers' name, service address, billing address, telephone number, account number and electricity consumption. Aggregate data may be released at MCE's discretion or as required by law or regulation.

Responsibility for Payment

Customers will be obligated to pay MCE charges for service provided through the date of transfer including any applicable Termination Fees. Pursuant to current CPUC regulations, MCE will not be able to direct that electricity service be shut off for failure to pay MCE's bill. However, PG&E has the right to shut off electricity to customers for failure to pay electricity bills, and Rule 23 mandates that partial payments are to be allocated pro rata between PG&E and the CCA. In most circumstances, customers would be returned to utility service for failure to pay bills in full and customer deposits would be withheld in the case of unpaid bills. PG&E would attempt to collect any outstanding balance from customers in accordance with Rule 23 and the related CCA Service Agreement. The proposed process is for two late payment notices to be provided to the customer within 30 days of the original bill due date. If payment is not received within 45 days from the original due date, service would be transferred to the utility on the next regular meter read date, unless alternative payment arrangements have been made. Consistent with the CCA tariffs, Rule 23, service cannot be discontinued to a residential customer for a disputed amount if that customer has filed a complaint with the CPUC, and that customer has paid the disputed amount into an escrow account.

Customer Deposits

Customers may be required to post a deposit equal to two months' estimated bills for MCE's charges to obtain service from the Program. MCE has adopted a related policy, Rule No. 002, which specifies the circumstances under which a customer deposit will be required. This policy specifies that "An applicant who previously has been a customer of PG&E or MCE and whose electric service has been discontinued by PG&E or MCE during the last twelve months of that prior service because of nonpayment of bills, may be required to reestablish credit by depositing the amount prescribed in Rule 003 (Deposits) for that purpose." Rule No. 002 also states that, "A customer who fails to pay bills before they become past due as defined in PG&E Electric Rule 11 (Discontinuance and Restoration of Service), and who further fails to pay such bills within five days after presentation of a discontinuance of service notice for nonpayment of bills, may be required to pay said bills and reestablish credit by depositing the amount prescribed in Rule 003 (Deposits). This rule will apply regardless of whether or not service has been discontinued for such nonpayment[11]." Rule 003 specifies that the amount of deposit for such a customer shall be equal to two months' estimated charges for MCE service. Failure to post deposit as required would cause the account service transfer request to be rejected, and the account would remain with PG&E. To date, MCE has not collected any customer deposits.

[11] A customer whose service is discontinued by MCE is returned to PG&E generation service.

CHAPTER 10 - Procurement Process

Introduction

This Chapter describes MCE's initial procurement policies and the key third party service agreements by which MCE has obtained operational services for the CCA Program. By adopting the original Implementation Plan, MCE's Board of Directors approved general procurement policies to be effective at Program initiation. The Board retains authority to modify Program policies from time to time at its discretion.

Procurement Methods

MCE has entered into agreements for a variety of services needed to support program development, operation and management. It is anticipated MCE will utilize Competitive Procurement, Direct Procurement or Sole Source Procurement, depending on the nature of the services to be procured. Direct Procurement is the purchase of goods or services without competition when multiple sources of supply are available. Sole Source Procurement is generally to be performed only in the case of emergency or when a competitive process would be an idle act.

MCE utilized a competitive solicitation process to enter into agreements with SENA, which provides electrical services for the program. Agreements with entities that provide professional legal or consulting services, and agreements pertaining to unique or time sensitive opportunities, may be entered into on a direct procurement or sole source basis at the discretion of MCE's Executive Officer or Board of Directors.

The Executive Officer periodically reports (e.g., quarterly) to the Board a summary of the actions taken with respect to the delegated procurement authority.

Authority for terminating agreements will generally mirror the authority for entering into the agreements.

Key Contracts

Electric Supply Contract

MCE successfully negotiated an electricity supply contract with SENA (through December 31, 2016). For the initial years of program operations (, SENA will supply a significant portion of the electricity delivered to MCE customers. For the post-2016 period, MCE will be obligated to complete additional solicitations to secure its resource requirements. In anticipation of this future obligation, MCE has initiated procurement efforts, focusing on necessary renewable energy supply and resource adequacy capacity, to facilitate the transition from full requirements service to a managed portfolio of contracts/resources. This proactive, ongoing approach will avoid dependence on market conditions existing at any single point in time. Under the initial full requirements contract, SENA has committed to serving the composite electrical loads of customers in the Program. SENA also serves as MCE's certified Scheduling

Coordinator and will schedule the loads of all customers in the Program, providing necessary electric energy, capacity/resource adequacy requirements, renewable energy and ancillary services. SENA is wholly responsible for the Program's portfolio operations functions and managing the predominant supply risks for the term of the contract. SENA must also meet the Program's renewable energy goals and comply with all applicable resource adequacy and regulatory requirements imposed by the CPUC or FERC.

Certain financial risks related to changes in Program loads during the term of the agreement are borne by SENA, within the ranges specified in the electric supply agreement. The supplier has also committed to deliver a specific quantity of RPS-eligible renewable energy, as determined by MCE, during each year of the agreement term. The supplier is also required to procure sufficient renewable energy to meet the requirements of serving customers enrolled in the Deep Green MCE service option.

Data Management Contract

Noble Americas Energy Solutions will provide the retail customer services of billing and other customer account services (electronic data interchange or EDI with PG&E, billing, remittance processing, and account management). Recognizing that some qualified wholesale energy suppliers do not typically conduct retail customer services whereas others (i.e., direct access providers) do, the data management contract is separate from the electric supply contract..[12]

The data manager is responsible for the following services:

- Data exchange with PG&E;
- Technical testing;
- Customer information system;
- Customer call center;
- Billing administration/retail settlements; and
- Reporting and audits of utility billing.

Utilizing a third party for account services eliminates a significant expense associated with implementing a customer information system. Such systems can cost from five to ten million dollars to implement and take significant time to deploy. A longer term contract is appropriate for this service because of the time and expense that would be required to migrate data to a new system. Separation of the data management contract from the energy supply contract gives MCE greater flexibility to change energy suppliers, if desired, without facing an expensive data migration issue.

[12] The contractor performing account services may be the same entity as the contractor supplying electricity for the program.

Electric Supply Procurement Process

As previously noted, MCE selected SENA as its energy supplier through a competitive solicitation process, which was administered in mid-2009. Additional information regarding SENA is provided below.

Shell Energy North America

Shell Energy North America (US), L.P. (SENA) is a leading supplier of energy and associated services in North America. SENA provides natural gas, electrical energy and capacity, scheduling and asset optimization, risk management, and renewable energy and environmental products to a wide variety of customers. SENA is 100% owned by Royal Dutch Shell Company and its subsidiaries. SENA owns and manages a variety of energy assets in the West, including generation, a portfolio of renewable energy, transmission capacity, natural gas production, liquefied natural gas capacity, natural gas storage capacity, and natural gas pipeline capacity. SENA's West Region operation includes regional offices in San Diego, Portland, Spokane, Berkeley, Salt Lake City, Denver and Mexico City, with 7 X 24 power and gas operations in San Diego and Spokane.

SENA has an extensive list of public and privately owned customers in the West, including all WECC region investor-owned utilities, twenty-five publicly owned (municipal) electric utilities/other public agencies in California, and publicly owned utilities/public agencies in neighboring states. SENA's West Region full requirements power experience includes provision of retail electric service, including provision of resource adequacy, for direct access customers in California.

Renewable energy products offered by SENA include renewable energy, bundled renewable energy, landfill gas, biogas and renewable energy credits. SENA states it is actively developing renewable portfolios and provides related services such as scheduling and shaping of intermittent energy. SENA's affiliate, Shell WindEnergy, develops and owns wind generation in California and other parts of North America. SENA also offers a variety of environmental products including emission offsets and other carbon reducing products.

SENA is rated A- by S&P and A2 by Moody's.

CHAPTER 11 – Contingency Plan for Program Termination

Introduction

This Chapter describes the process to be followed in the case of Program termination. By adopting the original Implementation Plan, MCE's Board of Directors approved the general termination process contained herein to be effective at Program initiation. In the unexpected event that MCE would terminate the Program and return its customers to PG&E service, the proposed process is designed to minimize the impacts on its customers and on PG&E. The proposed termination plan follows the requirements set forth in PG&E's tariff Rule 23 governing service to CCAs. The Board retains authority to modify program policies from time to time at its discretion.

Termination by Marin Clean Energy

MCE will offer services for the long term with no planned Program termination date. In the unanticipated event that the majority of the Member's governing bodies (County Board of Supervisors and/or City/Town Councils) decide to terminate the Program, each governing body would be required to adopt a termination ordinance or resolution and provide adequate notice to MCE consistent with the terms set forth in the JPA Agreement. Following such notice, MCE would vote on Program termination subject to a two-tiered vote, as described in the JPA Agreement. In the event that the Board affirmatively votes to proceed with JPA termination, the Board would disband under the provisions identified in its JPA Agreement.

After any applicable restrictions on such termination have been satisfied, notice would be provided to customers six months in advance that they will be transferred back to PG&E. A second notice would be provided during the final sixty-days in advance of the transfer. The notice would describe the applicable distribution utility bundled service requirements for returning customers then in effect, such as any transitional or bundled portfolio service rules.

At least one year advance notice would be provided to PG&E and the CPUC before transferring customers, and MCE would coordinate the customer transfer process to minimize impacts on customers and ensure no disruption in service. Once the customer notice period is complete, customers would be transferred *en masse* on the date of their regularly scheduled meter read date.

MCE will post a bond or maintain funds held in reserve to pay for potential transaction fees charged to the Program for switching customers back to distribution utility service. Reserves would be maintained against the fees imposed for processing customer transfers (CCASRs). The Public Utilities Code requires demonstration of insurance or posting of a bond sufficient to cover reentry fees imposed on customers that are involuntarily returned to distribution utility service under certain circumstances. The cost of reentry fees are the responsibility of the energy services provider or the community choice aggregator, except in the case of a customer returned for default or because its contract has expired. MCE will post financial security in the appropriate amount as part of its registration materials and will maintain the financial security in the required amount, as necessary.

Termination by Members

The JPA Agreement defines the terms and conditions under which Members may terminate their participation in the program.

CHAPTER 12 – Appendices

Appendix A: MCE Resolution 2014-03

Appendix B: County of Napa, Resolution 2014-59

Appendix C: Marin Clean Energy Joint Powers Agreement

Appendix D: County of Napa, CCA Ordinance – Ordinance No. 1391

<u>Exhibit A</u>

To the
Joint Powers Agreement
Marin Energy Authority

-Definitions-

"AB 117" means Assembly Bill 117 (Stat. 2002, ch. 838, codified at Public Utilities Code Section 366.2), which created CCA.

"Act" means the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 *et seq*.)

"Administrative Services Agreement" means an agreement or agreements entered into after the Effective Date by the Authority with an entity that will perform tasks necessary for planning, implementing, operating and administering the CCA Program or any other energy programs adopted by the Authority.

"Agreement" means this Joint Powers Agreement.

"Annual Energy Use" has the meaning given in Section 4.9.2.2.

"Authority" means the Marin Energy Authority.

"Authority Document(s)" means document(s) duly adopted by the Board by resolution or motion implementing the powers, functions and activities of the Authority, including but not limited to the Operating Rules and Regulations, the annual budget, and plans and policies.

"Board" means the Board of Directors of the Authority.

"CCA" or "Community Choice Aggregation" means an electric service option available to cities and counties pursuant to Public Utilities Code Section 366.2.

"CCA Program" means the Authority's program relating to CCA that is principally described in Sections 2.4 and 5.1.

"Director" means a member of the Board of Directors representing a Party.

"Effective Date" means the date on which this Agreement shall become effective and the Marin Energy Authority shall exist as a separate public agency, as further described in Section 2.1.

"Implementation Plan" means the plan generally described in Section 5.1.2 of this Agreement that is required under Public Utilities Code Section 366.2 to be filed with the

California Public Utilities Commission for the purpose of describing a proposed CCA Program.

"Initial Costs" means all costs incurred by the Authority relating to the establishment and initial operation of the Authority, such as the hiring of an Executive Director and any administrative staff, any required accounting, administrative, technical and legal services in support of the Authority's initial activities or in support of the negotiation, preparation and approval of one or more Administrative Services Provider Agreements and Program Agreement 1. Administrative and operational costs incurred after the approval of Program Agreement 1 shall not be considered Initial Costs.

"Initial Participants" means, for the purpose of this Agreement, the signatories to this JPA as of May 5, 2010 including City of Belvedere, Town of Fairfax, City of Mill Valley, Town of San Anselmo, City of San Rafael, City of Sausalito, Town of Tiburon and County of Marin.

"Operating Rules and Regulations" means the rules, regulations, policies, bylaws and procedures governing the operation of the Authority.

"Parties" means, collectively, the signatories to this Agreement that have satisfied the conditions in Sections 2.2 or 3.2 such that it is considered a member of the Authority.

"Party" means, singularly, a signatory to this Agreement that has satisfied the conditions in Sections 2.2 or 3.2 such that it is considered a member of the Authority.

"Program Agreement 1" means the agreement that the Authority will enter into with an energy service provider that will provide the electricity to be distributed to customers participating in the CCA Program.

"Total Annual Energy" has the meaning given in Section 4.9.2.2.

Exhibit B

To the
Joint Powers Agreement
Marin Energy Authority

-List of the Parties-

City of American Canyon
City of Belvedere
City of Benicia
City of Calistoga
Town of Corte Madera
City of El Cerrito
Town of Fairfax
City of Larkspur
City of Lafayette
City of Mill Valley
City of Napa
City of Novato
City of Richmond
Town of Ross
Town of San Anselmo
City of San Pablo
City of San Rafael
City of Sausalito
City of St. Helena
Town of Tiburon
City of Walnut Creek
Town of Yountville
County of Marin
County of Napa

Exhibit C
To the
Joint Powers Agreement
Marin Clean Energy

- Annual Energy Use -

This Exhibit C is effective as of April 21, 2016.

Party	**kWh***
City of American Canyon	83,543,443
City of Belvedere	9,973,170
City of Benicia	272,731,094
City of Calistoga	27,989,218
Town of Corte Madera	62,093,107
City of El Cerrito	109,836,169
Town of Fairfax	24,700,647
City of Lafayette	126,334,082
City of Larkspur	63,174,199
City of Mill Valley	69,176,164
City of Napa	386,262,547
City of Novato	286,565,119
City of Richmond	581,012,267
Town of Ross	13,529,793
Town of San Anselmo	46,642,417
City of San Pablo	97,383,170
City of San Rafael	347,362,327
City of Sausalito	48,099,763
City of St. Helena	55,556,737
Town of Tiburon	40,913,144
City of Walnut Creek	465,644,787
Town of Yountville	34,502,172
County of Marin	330,023,521
County of Napa	348,095,521
Authority Total Energy Use	**3,931,144,578**

*Data Provided by PG&E

Exhibit D
To the
Joint Powers Agreement
Marin Clean Energy

- Voting Shares -

This Exhibit D is effective as of April 21, 2016.

Party	kWh*	Section 4.9.2.1	Section 4.9.2.2	Voting Share
City of American Canyon	83,543,443	2.08%	1.06%	***3.15%***
City of Belvedere	9,973,170	2.08%	0.13%	***2.21%***
City of Benicia	272,731,094	2.08%	3.47%	***5.55%***
City of Calistoga	27,989,218	2.08%	0.36%	***2.44%***
Town of Corte Madera	62,093,107	2.08%	0.79%	***2.87%***
City of El Cerrito	109,836,169	2.08%	1.40%	***3.48%***
Town of Fairfax	24,700,647	2.08%	0.31%	***2.40%***
City of Lafayette	126,334,082	2.08%	1.61%	***3.69%***
City of Larkspur	63,174,199	2.08%	0.80%	***2.89%***
City of Mill Valley	69,176,164	2.08%	0.88%	***2.96%***
City of Napa	386,262,547	2.08%	4.91%	***7.00%***
City of Novato	286,565,119	2.08%	3.64%	***5.73%***
City of Richmond	581,012,267	2.08%	7.39%	***9.47%***
Town of Ross	13,529,793	2.08%	0.17%	***2.26%***
Town of San Anselmo	46,642,417	2.08%	0.59%	***2.68%***
City of San Pablo	97,383,170	2.08%	1.24%	***3.32%***
City of San Rafael	347,362,327	2.08%	4.42%	***6.50%***
City of Sausalito	48,099,763	2.08%	0.61%	***2.70%***
City of St. Helena	55,556,737	2.08%	0.71%	***2.79%***
Town of Tiburon	40,913,144	2.08%	0.52%	***2.60%***
City of Walnut Creek	465,644,787	2.08%	5.92%	***8.01%***
Town of Yountville	34,502,172	2.08%	0.44%	***2.52%***
County of Marin	330,023,521	2.08%	4.20%	***6.28%***
County of Napa	348,095,521	2.08%	4.43%	***6.51%***
*Data Provided by PG&E	**3,931,144,578**	**50.00%**	**50.00%**	***100.00%***

ORDINANCE NO. 2015-12

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF AMERICAN CANYON APPROVING THE MARIN CLEAN ENERGY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

WHEREAS, the City of American Canyon has been actively investigating options to provide electric services to constituents within its service area with the intent of promoting use of renewable energy and reducing energy related greenhouse gas emissions; and

WHEREAS, on September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation; and

WHEREAS, the Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and on December 19, 2008, the Marin Clean Energy (MCE) was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time; and

WHEREAS, on February 2, 2010 the California Public Utilities Commission certified the "Implementation Plan" of the MCE, confirming the MCE's compliance with the requirements of the Act; and

WHEREAS, in order to become a member of the MCE, the Act requires the City of American Canyon to adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the MCE.

NOW, THEREFORE, BE IT ORDAINED, by the City Council of the City of American Canyon as follows:

SECTION 1: Based upon all of the above, the City Council elects to implement a Community Choice Aggregation program within the City of American Canyon's jurisdiction by and through the City of American Canyon's participation in the Marin Clean Energy. The Mayor is hereby authorized to execute the MCE Joint Powers Agreement.

SECTION 2: This ordinance shall take effect on the later of (a) the date the Board of Directors of MCE adopts a Resolution adding the City as a member of MCE, or (b) 30 days after the adoption of this ordinance.

The foregoing Ordinance was introduced at a regular meeting of the City Council of the City of American Canyon, State of California, held on the 3rd day of November, 2015 by the following vote:

AYES:	Council Members Bennett, Joseph, Ramos, Vice Mayor Leary and Mayor Garcia
NOES:	None
ABSTAIN:	None
ABSENT:	None

The foregoing Ordinance was adopted at a regular meeting of the City Council of the City of American Canyon, State of California, held on the 17th day of November, 2015 by the following vote:

AYES:	Council Members Bennett, Joseph, Ramos, Vice Mayor Leary, Mayor Garcia
NOES:	None
ABSTAIN:	None
ABSENT:	None

Leon Garcia

Leon Garcia, Mayor

ATTEST:

Cherri Walton, CMC, Deputy City Clerk

APPROVED AS TO FORM:

William D. Ross, City Attorney

ORDINANCE NO. 718

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF CALISTOGA APPROVING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM AND AUTHORIZING THE MARIN CLEAN ENERGY JOINT POWERS AGREEMENT

WHEREAS, the City of Calistoga has been actively investigating options to provide electric services to constituents within its service area with the intent of promoting use of renewable energy and reducing energy related greenhouse gas emissions; and

WHEREAS, Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act") authorizes any California city whose governing body so elects to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation (CCA); and

WHEREAS, the Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and on December 19, 2008, Marin Clean Energy (MCE) was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time; and

WHEREAS, on February 2, 2010 the California Public Utilities Commission certified MCE's "Implementation Plan," confirming MCE's compliance with the requirements of the Act; and

WHEREAS, participating in MCE will gives city customers the choice of having 50% to 100% of their electricity supplied from renewable sources—such as wind, bioenergy, and hydroelectric—as compared to Calistoga's existing provider PG&E, whose energy mix in 2013 was about 22% from renewable sources, at rates that are competitive with PG&E.

WHEREAS, in order to become a member of MCE, the Act requires the City to adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in MCE.

NOW, THEREFORE, THE CALISTOGA CITY COUNCIL DOES HEREBY ORDAIN AS FOLLOWS:

SECTION ONE

Findings. The above recitals are incorporated herein as if set forth herein in full and each is relied upon independently by the City Council for its adoption of this ordinance.

SECTION TWO

Based upon all of the above, the City Council elects to implement a Community Choice Aggregation program within the City of Calistoga's jurisdiction by and through the City's participation in Marin Clean Energy.

SECTION THREE

The City Council hereby authorizes the Mayor to execute the MCE Joint Powers Agreement attached hereto as Exhibit A.

SECTION FOUR

Severability. If any section, subsection, subdivision, paragraph, sentence, clause, or phrase in this ordinance or any part thereof is for any reason held to be unconstitutional or invalid or ineffective by any court of competent jurisdiction, such decision shall not affect the validity or effectiveness of the remaining portions of this ordinance or any part thereof. The City Council hereby declares that it would have passed each section, subsection, subdivision, paragraph, sentence, clause, or phrase thereof irrespective of the fact that any one or more subsections, subdivisions, paragraphs, sentences, clauses, or phrases be declared unconstitutional, or invalid, or ineffective.

SECTION FIVE

Effective Date. This ordinance shall take effect on the later of (a) the date the MCE Board of Directors adopts a resolution adding the City of Calistoga as a member of MCE, or (b) 30 days after its passage. Before the expiration of fifteen (15) days after its passage, the ordinance shall be published in accordance with law in a newspaper of general circulation published and circulated in the city of Calistoga.

THIS ORDINANCE was introduced with the first reading waived at the City of Calistoga City Council meeting of the **20th day of October, 2015,** and was passed and adopted at a regular meeting of the Calistoga City Council **on November 3, 2015**, by the following vote:

AYES:	**Councilmember Kraus, Councilmember Lopez-Ortega, Councilmember Barnes and Mayor Canning**
NOES:	**None**
ABSENT:	**Vice Mayor Dunsford**
ABSTAIN:	**None**

Chris Canning, Mayor

ATTEST:

Melissa Velasquez, Deputy City Clerk

ORDINANCE O2016-3

ORDINANCE OF THE CITY COUNCIL OF THE CITY OF NAPA, STATE OF CALIFORNIA, APPROVING THE MARIN CLEAN ENERGY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

WHEREAS, the City of Napa has been actively investigating options to provide electric services to constituents within its service area with the intent of promoting use of renewable energy and reducing energy related greenhouse gas emissions; and

WHEREAS, on September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation; and

WHEREAS, the Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and on December 19, 2008, the Marin Clean Energy (MCE) was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time; and

WHEREAS, on February 2, 2010, the California Public Utilities Commission certified the "Implementation Plan" of the MCE, confirming the MCE's compliance with the requirements of the Act; and

WHEREAS, in order to become a member of the MCE, the Act requires the City of Napa to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the MCE; and

WHEREAS, the City Council has considered all information related to this matter, as presented at the public meeting of the City Council identified herein, including any supporting reports by City Staff, and any information provided during public meetings.

NOW, THEREFORE, BE IT ORDAINED, by the City Council of the City of Napa as follows:

SECTION 1: Based upon all of the above, the City Council elects to implement a Community Choice Aggregation program within the City of Napa's jurisdiction by and through the City of Napa's participation in Marin Clean Energy. The City Manager is hereby authorized to execute the MCE Joint Powers Agreement.

SECTION 2: Severability. If any section, sub-section, subdivision, paragraph, clause or phrase in this Ordinance, or any part thereof, is for any reason held to be invalid or unconstitutional, such decision shall not affect the validity of the remaining sections or portions of this Ordinance or any part thereof. The City Council hereby declares that it would have passed each section, sub-section, subdivision, paragraph, sentence, clause or phrase of this Ordinance, irrespective of the fact that any one or more sections, sub-sections, subdivisions, paragraphs, sentences, clauses or phrases may be declared invalid or unconstitutional.

SECTION 3: Effective Date. This Ordinance shall become effective on the later of (a) the date the Board of Directors of MCE adopts a Resolution adding the City of Napa as a member of MCE, or (b) 30 days after the adoption of this ordinance.

City of Napa, a municipal corporation

MAYOR: Jill Techel

ATTEST: Lisa Blackmon

FOR CITY CLERK OF THE CITY OF NAPA
Lisa Blackmon, Deputy City Clerk

STATE OF CALIFORNIA
COUNTY OF NAPA } SS:
CITY OF NAPA

I, Dorothy Roberts, City Clerk of the City of Napa, do hereby certify that the foregoing Ordinance had its first reading and was introduced during the regular meeting of the City Council on the 19th day of January, 2016, and had its second reading and was adopted and passed during the regular meeting of the City Council on the 2nd day of February, 2016, by the following vote:

AYES:	Inman, Luros, Mott. Sedgley, Techel
NOES:	None
ABSENT:	None
ABSTAIN:	None

ATTEST: Lisa Blackmon
Lisa Blackmon, Deputy City Clerk

FOR Dorothy Roberts
City Clerk

Approved as to Form:

Michael W. Barrett
City Attorney

BEFORE THE CITY COUNCIL OF THE CITY OF LAFAYETTE

IN THE MATTER OF:

An Ordinance of the City Council of the City of Lafayette approving the Marin Clean Energy Joint Powers Agreement and authorizing the Implementation of a Community Choice Aggregation Program	)))))	Ordinance 644

WHEREAS, the City of Lafayette of has been actively investigating options to provide electric services to constituents within its service area since June 2014 with the intent of promoting use of renewable energy, reducing energy related greenhouse gas emissions, and providing Lafayette residents and businesses with alternatives to Pacific Gas & Electric Company; and

WHEREAS, on September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, Ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation (CCA); and

WHEREAS, on September 27, 2006, AB32 was signed into law establishing the goal of reducing the state's greenhouse gas emissions to 1990 levels by 2020; and

WHEREAS, on November 13, 2006, the Lafayette City Council adopted the Environmental Strategy which recognizes the importance of environmental sustainability and encourages community awareness, responsibility, participation, and education to promote an environmentally sustainable community; and

WHEREAS, the Act expressly authorizes participation in a CCA program through a joint powers agency, and on December 19, 2008, Marin Clean Energy (MCE) was established as a joint powers authority pursuant to a Joint Powers Agreement, as amended from time to time; and

WHEREAS, on February 2, 2010, the California Public Utilities Commission certified the "Implementation Plan" of MCE, confirming MCE's compliance with the requirements of the Act; and

WHEREAS, the City of Lafayette is committed to the development of renewable energy generation and energy efficiency improvements, reduction of greenhouse gases, protection of the environment, and fully supports MCE's current electricity procurement plan, which targets more than 50% renewable energy content; and

WHEREAS, approximately 89-percent of housing in the City of Lafayette was built prior to Title 24 standards and is less energy efficient than newer construction; and

WHEREAS, in 2010, 22-percent of overall community wide greenhouse gas emissions in Lafayette was caused by energy use and Lafayette has a considerable opportunity to impact emissions through energy conservation, energy efficiency, and the use of renewable energy sources; and

WHEREAS, electricity in Lafayette is generated and provided by Pacific Gas and Electric Company (PG&E) and there is not presently an alternative provider in the City. PG&E is currently working to add more renewable energy to its power mix under California's renewable portfolio standard and is on track to have 33-percent renewables by the end of 2020; and

WHEREAS, the City finds it important that its customers- residents, businesses, and public facilities- have alternative choices to energy procurement beyond PG&E; and

WHEREAS, the City of Lafayette finds that joining MCE will offer Lafayette customers choice in their power provider and will help Lafayette meet the state goal set out in AB32 and the goals outlined in the City's Environmental Strategy; and

WHEREAS, on August 10, 2015 the Lafayette City Council authorized a Letter of Intent to be sent to Marin Clean Energy requesting that they conduct a membership analysis for Lafayette; and

WHEREAS, in order to become a member of MCE, the MCE Joint Powers Agreement requires the City to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in MCE.

THE CITY COUNCIL OF THE CITY OF LAFAYETTE DOES ORDAIN AS FOLLOWS:

Section 1. The City of Lafayette has been actively investigating options to provide electric services to constituents within its service area with the intent of promoting use of renewable energy, reducing energy related greenhouse gas emissions, and providing Lafayette residents and businesses with alternatives to Pacific Gas & Electric Company.

Section 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch . 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation (CCA).

Section 3. The Act expressly authorizes participation in CCA program through a joint powers agency, and on December 19, 2008, Marin Clean Energy (MCE) was established as a joint powers authority pursuant to a Joint Powers Agreement, as amended from time to time.

Section 4. On February 2, 2010 the California Public Utilities Commission certified the "Implementation Plan" of the MCE, confirming the MCE's compliance with the requirements of the Act.

Section 5. In order to become a member of MCE, the Act requires the City of Lafayette to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the MCE.

Section 6. Based upon all of the above, the City of Lafayette Council elects to implement a Community Choice Aggregation program within the City of Lafayette's jurisdiction by and through the City of Lafayette's participation in Marin Clean Energy. The Mayor is hereby authorized to execute the MCE Joint Powers Agreement.

Section 7. If any section, subsection, subdivision, sentence, clause, phrase, or portion of this Ordinance for any reason is held to be invalid or unconstitutional by the decision of any court of competent jurisdiction, such decision shall not affect the validity of the remaining portions of this Ordinance. The City Council hereby declares that it would have adopted this Ordinance, and each section, subsection, subdivision, sentence, clause, phrase, or portion thereof, irrespective of the fact that any one or more sections, subsections, subdivisions, sentences, clauses, phrases, or portions thereof be declared invalid or unconstitutional.

Section 8. This ordinance shall take effect on the later of (a) the date the - Board of Directors of MCE adopts a Resolution adding the City/Town as a member of MCE, or (b) 30 days after its adoption and, before the expiration of 30 days after its passage.

Section 9. The City Clerk shall either (a) have this Ordinance published in a newspaper of general circulation once within fifteen (15) days after its adoption, or (b) have a summary of this Ordinance published twice in a newspaper of general circulation, once five (5) days before its adoption and again within fifteen (15) days after adoption.

The foregoing Ordinance was introduced at a meeting of the City Council of the City of Lafayette held on January 25, 2016, and adopted and ordered published at a meeting of the City Council held on March 14, 2016, by the following vote:

AYES: **Mitchell, B. Andersson, Reilly and Tatzin**
NOES: **None**
ABSTAIN: **None**
ABSENT: **M. Anderson**

ATTEST:

Joanne Robbins

Joanne Robbins, City Clerk

APPROVED:

Mark Mitchell, Mayor

CITY OF ST. HELENA

ORDINANCE NO. 2016-1

ORDINANCE OF CITY OF ST. HELENA APPROVING THE MARIN CLEAN ENERGY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

The City Council of the City of St. Helena ordains as follows:

SECTION 1. The City of St. Helena has been actively investigating options to provide electric services to constituents within its service area with the intent of promoting use of renewable energy and reducing energy related greenhouse gas emissions.

SECTION 2. On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation.

SECTION 3. The Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and on December 19, 2008, the Marin Clean Energy (MCE) was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time.

SECTION 4. On February 2, 2010 the California Public Utilities Commission certified the "Implementation Plan" of the MCE, confirming the MCE's compliance with the requirements of the Act.

SECTION 5. In order to become a member of the MCE, the Act requires the City of St. Helena to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the MCE.

SECTION 6. Based upon all of the above, the City Council elects to implement a Community Choice Aggregation program within the City of St. Helena's jurisdiction by and through the City of St. Helena's participation in the Marin Clean Energy. The Mayor is hereby authorized to execute the MCE Joint Powers Agreement.

SECTION 7. This ordinance shall take effect on the later of (a) the date the Board of Directors of MCE adopts a Resolution adding the City as a member of MCE, or (b) 30 days after its adoption and, before the expiration of 30 days after its passage, a summary of this ordinance shall be published once with the names of the members of the Council voting for and against the same in the St. Helena Star, a newspaper of general circulation published in the City of. St. Helena.

The foregoing ordinance was introduced at a meeting of the City Council of the City of St. Helena held on November 24, 2015, and adopted at a meeting held on January 12, 2016, by the following vote:

Mayor Galbraith:	yes
Vice Mayor White:	yes
Councilmember Crull:	absent
Councilmember Dohring:	yes
Councilmember Pitts:	yes

APPROVED:

Alan Galbraith
Alan Galbraith, Mayor

ATTEST:

Cindy Black
Cindy Black, City Clerk

CITY OF ST HELENA
Incorporated March 24, 1876
Re-incorporated May 14, 1889
STATE OF CALIFORNIA

THE CITY OF WALNUT CREEK
ORDINANCE NO. 2149

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF WALNUT CREEK APPROVING THE MARIN CLEAN ENERGY JOINT POWERS AGREEMENT AND AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION PROGRAM

The City Council of the City of Walnut Creek ordains as follows:

__Section 1.__ The City of Walnut Creek has been actively investigating options to provide electric services to constituents within its service area with the intent of promoting use of renewable energy and reducing energy related greenhouse gas emissions.

__Section 2.__ On September 24, 2002, the Governor signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and businesses in a community-wide electricity aggregation program known as Community Choice Aggregation.

__Section 3.__ The Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and on December 19, 2008, the Marin Clean Energy (MCE) was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time.

__Section 4.__ On February 2, 2010 the California Public Utilities Commission certified the "Implementation Plan" of the MCE, confirming the MCE's compliance with the requirements of the Act.

__Section 5.__ In order to become a member of the MCE, the Act requires the City of Walnut Creek to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the MCE.

__Section 6.__ Based upon all of the above, the City Council elects to implement a Community Choice Aggregation program within the City of Walnut Creek's jurisdiction by and through the City of Walnut Creek's participation in the Marin Clean Energy. The Mayor is hereby authorized to execute the MCE Joint Powers Agreement.

__Section 7.__ Pursuant to the provisions of Government Code Section 36933, a summary of this Ordinance shall be prepared by the City Attorney. At least five (5) days prior to the Council meeting at which this Ordinance is scheduled to be adopted, the City Clerk shall (1) publish the summary, and (2) post in the City Clerk's Office a certified copy of this Ordinance. Within fifteen (15) days after the adoption of this Ordinance, the City Clerk shall (1) publish the summary, and (2) post in the City Clerk's Office a certified copy of the full text of this Ordinance along with the names of those City Council members voting for and against this Ordinance or otherwise voting. This Ordinance shall become effective on the 31st day after its adoption.

PASSED AND ADOPTED by the City Council of the City of Walnut Creek at a regular meeting thereof held on the 15th day of March, 2016 by the following called vote:

AYES: Councilmembers: Simmons, Carlston, Mayor Haskew

NOES:	Councilmembers:	Wedel
ABSTAIN:	Councilmembers:	Silva
ABSENT:	Councilmembers:	None

Loella Haskew
Mayor of the City of Walnut Creek

Attest:

Suzie Martinez, CMC
City Clerk of the City of Walnut Creek

I HEREBY CERTIFY the foregoing to be a true and correct copy of Ordinance No. 2149 duly passed and adopted by the City Council of Walnut Creek, County of Contra Costa, State of California, at a regular meeting of said Council held on the 15th day of March, 2016.

Suzie Martinez, CMC
City Clerk of the City of Walnut Creek

Town of Yountville
Ordinance Number 16-448

Approving the Marin Clean Energy Joint Powers Agreement and Authorizing the Implementation of a Community Choice Aggregation Program

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Recitals

Whereas,

A. The Town of Yountville has been actively investigating options to provide electric services to constituents within its service areas with the intent of promoting use of renewable energy and reducing energy related greenhouse gas emissions.

B. On September 24, 2002, the Governor of California signed into law Assembly Bill 117 (Stat. 2002, ch. 838; see California Public Utilities Code section 366.2; hereinafter referred to as the "Act"), which authorizes any California city or county, whose governing body so elects, to combine the electricity load of its residents and business in a community-wide electricity aggregation program known as Community Choice Aggregation.

C. The Act expressly authorizes participation in a Community Choice Aggregation (CCA) program through a joint powers agency, and on December 19, 2008, the Marin Clean Energy (MCE) was established as a joint power authority pursuant to a Joint Powers Agreement, as amended from time to time.

D. On February 2, 2010, the California Public Utilities Commission certified the "Implementation Plan" of the MCE, confirming the MCE's compliance with the requirements of the Act.

E. During its January 26 regular meeting, the Yountville Go Green Team received presentations from representatives of MCE and unanimously recommended to the Town Council that the Town become a member of MCE.

F. In order to become a member of the MCE, the Act requires the Town of Yountville to individually adopt an ordinance electing to implement a Community Choice Aggregation program within its jurisdiction by and through its participation in the MCE.

Now therefore, the Town Council of the Town of Yountville does ordain as follows:

1. Implement a Community Choice Aggregation program within the Town of Yountville's jurisdiction by and through the Town of Yountville's participation in the Marin Clean Energy.

2. The Mayor is hereby authorized to execute the MCE Joint Powers Agreement.

3. Effective Date. This ordinance shall take effect on the later of (a) the date the Board of Directors of MCE adopts a Resolution adding the Town of Yountville as a member of MCE, or (b) 30 days after its adoption and, before the expiration of 30 days after its passage, a summary of this ordinance shall be published once with the names of the members of the Council voting for and against the same in the Yountville Sun, a newspaper of general circulation published in the Town of Yountville.

4. Posting. Within 15 days from the date of passage of this ordinance, the Town Clerk shall post a copy of the ordinance in accordance with California Government Code in at least three public places in the Town.

INTRODUCED by the Town Council on the first day of March 2016; and

PASSED AND ADOPTED at a regular meeting of the Town Council on the fifteenth day of March 2016 by the following vote:

AYES: DORENBECHER, HALL, DURHAM AND DUNBAR
NOES: MOHLER
ABSENT: NONE
ABSTAIN: NONE

John F. Dunbar, Mayor

ATTEST:

TOWN OF YOUNTVILLE

Julie Baldia, Deputy Town Clerk

I, JULIE BALDIA, DEPUTY TOWN CLERK of the Town of Yountville, California, do hereby certify that the foregoing Ordinance was regularly introduced and placed upon its first reading at a regular meeting of the Town Council on the first day of March, 2016. That thereafter said Ordinance was duly adopted and passed at a regular meeting of the Town Council on the fifteenth day of March, 2016 by the following vote:

AYES: HALL, DORENBECHER, DURHAM AND DUNBAR
NOES: MOHLER
ABSENT:
ABSTAIN:

Julie Baldia, Deputy Town Clerk

APPROVED AS TO FORM:

Michael Cobden, Town Attorney

East Bay Community Energy Authority

- Joint Powers Agreement –

Effective ______________

Among The Following Parties:

EAST BAY COMMUNITY ENERGY AUTHORITY

JOINT POWERS AGREEMENT

This Joint Powers Agreement ("Agreement"), effective as of _________, is made and entered into pursuant to the provisions of Title 1, Division 7, Chapter 5, Article 1 (Section 6500 *et seq*.) of the California Government Code relating to the joint exercise of powers among the parties set forth in Exhibit A ("Parties"). The term "Parties" shall also include an incorporated municipality or county added to this Agreement in accordance with Section 3.1.

RECITALS

1. The Parties are either incorporated municipalities or counties sharing various powers under California law, including but not limited to the power to purchase, supply, and aggregate electricity for themselves and their inhabitants.

2. In 2006, the State Legislature adopted AB 32, the Global Warming Solutions Act, which mandates a reduction in greenhouse gas emissions in 2020 to 1990 levels. The California Air Resources Board is promulgating regulations to implement AB 32 which will require local government to develop programs to reduce greenhouse gas emissions.

3. The purposes for the Initial Participants (as such term is defined in Section 1.1.16 below) entering into this Agreement include securing electrical energy supply for customers in participating jurisdictions, addressing climate change by reducing energy related greenhouse gas emissions, promoting electrical rate price stability, and fostering local economic benefits such as jobs creation, community energy programs and local power development. It is the intent of this Agreement to promote the development and use of a wide range of renewable energy sources and energy efficiency programs, including but not limited to State, regional and local solar and wind energy production.

4. The Parties desire to establish a separate public agency, known as the East Bay Community Energy Authority ("Authority"), under the provisions of the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 *et seq*.) ("Act") in order to collectively study, promote, develop, conduct, operate, and manage energy programs.

5. The Initial Participants have each adopted an ordinance electing to implement through the Authority a Community Choice Aggregation program pursuant to California Public Utilities Code Section 366.2 ("CCA Program"). The first priority of the Authority will be the consideration of those actions necessary to implement the CCA Program.

6. By establishing the Authority, the Parties seek to:

   (a) Provide electricity rates that are lower or competitive with those offered by PG&E for similar products;

(b) Offer differentiated energy options (e.g. 33% or 50% qualified renewable) for default service, and a 100% renewable content option in which customers may "opt-up" and voluntarily participate;

(c) Develop an electric supply portfolio with a lower greenhouse gas (GHG) intensity than PG&E, and one that supports the achievement of the parties' greenhouse gas reduction goals and the comparable goals of all participating jurisdictions;

(d) Establish an energy portfolio that prioritizes the use and development of local renewable resources and minimizes the use of unbundled renewable energy credits;

(e) Promote an energy portfolio that incorporates energy efficiency and demand response programs and has aggressive reduced consumption goals;

(f) Demonstrate quantifiable economic benefits to the region (e.g. union and prevailing wage jobs, local workforce development, new energy programs, and increased local energy investments);

(g) Recognize the value of workers in existing jobs that support the energy infrastructure of Alameda County and Northern California. The Authority, as a leader in the shift to a clean energy, commits to ensuring it will take steps to minimize any adverse impacts to these workers to ensure a "just transition" to the new clean energy economy;

(h) Deliver clean energy programs and projects using a stable, skilled workforce through such mechanisms as project labor agreements, or other workforce programs that are cost effective, designed to avoid work stoppages, and ensure quality;

(i) Promote personal and community ownership of renewable resources, spurring equitable economic development and increased resilience, especially in low income communities;

(j) Provide and manage lower cost energy supplies in a manner that provides cost savings to low-income households and promotes public health in areas impacted by energy production; and

(k) Create an administering agency that is financially sustainable, responsive to regional priorities, well managed, and a leader in fair and equitable treatment of employees through adopting appropriate best practices employment policies, including, but not limited to, promoting efficient consideration of petitions to unionize, and providing appropriate wages and benefits.

AGREEMENT

NOW, THEREFORE, in consideration of the mutual promises, covenants, and conditions hereinafter set forth, it is agreed by and among the Parties as follows:

ARTICLE 1
CONTRACT DOCUMENTS

1.1 Definitions. Capitalized terms used in the Agreement shall have the meanings specified below, unless the context requires otherwise.

1.1.1 "AB 117" means Assembly Bill 117 (Stat. 2002, ch. 838, codified at Public Utilities Code Section 366.2), which created CCA.

1.1.2 "Act" means the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 *et seq*.)

1.1.3 "Agreement" means this Joint Powers Agreement.

1.1.4 "Annual Energy Use" has the meaning given in Section 1.1.23.

1.1.5 "Authority" means the East Bay Community Energy Authority established pursuant to this Joint Powers Agreement.

1.1.6 "Authority Document(s)" means document(s) duly adopted by the Board by resolution or motion implementing the powers, functions and activities of the Authority, including but not limited to the Operating Rules and Regulations, the annual budget, and plans and policies.

1.1.7 "Board" means the Board of Directors of the Authority.

1.1.8 "Community Choice Aggregation" or "CCA" means an electric service option available to cities and counties pursuant to Public Utilities Code Section 366.2.

1.1.9 "CCA Program" means the Authority's program relating to CCA that is principally described in Sections 2.4 and 5.1.

1.1.10 "Days" shall mean calendar days unless otherwise specified by this Agreement.

1.1.11 "Director" means a member of the Board of Directors representing a Party, including an alternate Director.

1.1.12 "Effective Date" means the date on which this Agreement shall become effective and the East Bay Community Energy Authority shall exist as a separate public agency, as further described in Section 2.1.

1.1.13 "Ex Officio Board Member" means a non-voting member of the Board of Directors as described in Section 4.2.2. The Ex Officio Board Member may not serve on the Executive Committee of the Board or participate in closed session meetings of the Board.

1.1.14 "Implementation Plan" means the plan generally described in Section 5.1.2 of this Agreement that is required under Public Utilities Code Section 366.2 to be filed with the California Public Utilities Commission for the purpose of describing a proposed CCA Program.

1.1.15 "Initial Costs" means all costs incurred by the Authority relating to the establishment and initial operation of the Authority, such as the hiring of a Chief Executive Officer and any administrative staff, any required accounting, administrative, technical and legal services in support of the Authority's initial formation activities or in support of the negotiation, preparation and approval of power purchase agreements. The Board shall determine the termination date for Initial Costs.

1.1.16 "Initial Participants" means, for the purpose of this Agreement the County of Alameda, the Cities of Albany, Berkeley, Emeryville, Oakland, Piedmont, San Leandro, Hayward, Union City, Newark, Fremont, Dublin, Pleasanton and Livermore.

1.1.17 "Operating Rules and Regulations" means the rules, regulations, policies, bylaws and procedures governing the operation of the Authority.

1.1.18 "Parties" means, collectively, the signatories to this Agreement that have satisfied the conditions in Sections 2.2 or 3.1 such that it is considered a member of the Authority.

1.1.19 "Party" means, singularly, a signatory to this Agreement that has satisfied the conditions in Sections 2.2 or 3.1 such that it is considered a member of the Authority.

1.1.20 "Percentage Vote" means a vote taken by the Board pursuant to Section 4.12.1 that is based on each Party having one equal vote.

1.1.21 "Total Annual Energy" has the meaning given in Section 1.1.23.

1.1.22 "Voting Shares Vote" means a vote taken by the Board pursuant to Section 4.12.2 that is based on the voting shares of each Party described in Section 1.1.23 and set forth in Exhibit C to this Agreement. A Voting Shares vote cannot take place on a matter unless the matter first receives an affirmative or tie Percentage Vote in the manner required by Section 4.12.1 and three or more Directors immediately thereafter request such vote.

1.1.23 "Voting Shares Formula" means the weight applied to a Voting Shares Vote and is determined by the following formula:

(Annual Energy Use/Total Annual Energy) multiplied by 100, where (a) "Annual Energy Use" means (i) with respect to the first two years following the Effective Date, the annual electricity usage, expressed in kilowatt hours ("kWh"), within the Party's respective jurisdiction and (ii) with respect to the period after the second anniversary of the Effective Date, the annual electricity usage, expressed in kWh, of accounts within a Party's respective jurisdiction that are served by the Authority and (b) "Total Annual Energy" means the sum of all Parties' Annual Energy Use. The initial values for Annual Energy use are designated in Exhibit B and the initial voting shares are designated in Exhibit C. Both Exhibits B and C shall be adjusted annually as soon as reasonably practicable after January 1, but no later than March 1 of each year subject to the approval of the Board.

1.2 **Documents Included**. This Agreement consists of this document and the following exhibits, all of which are hereby incorporated into this Agreement.

Exhibit A: List of the Parties

Exhibit B: Annual Energy Use

Exhibit C: Voting Shares

1.3 **Revision of Exhibits**. The Parties agree that Exhibits A, B and C to this Agreement describe certain administrative matters that may be revised upon the approval of the Board, without such revision constituting an amendment to this Agreement, as described in Section 8.4. The Authority shall provide written notice to the Parties of the revision of any such exhibit.

ARTICLE 2
FORMATION OF EAST BAY COMMUNITY ENERGY AUTHORITY

2.1 **Effective Date and Term**. This Agreement shall become effective and East Bay Community Energy Authority shall exist as a separate public agency on December 1, 2016, provided that this Agreement is executed on or prior to such date by at least three Initial Participants after the adoption of the ordinances required by Public Utilities Code Section 366.2(c)(12). The Authority shall provide notice to the Parties of the Effective Date. The Authority shall continue to exist, and this Agreement shall be effective, until this Agreement is terminated in accordance with Section 7.3, subject to the rights of the Parties to withdraw from the Authority.

2.2 **Initial Participants**. Until December 31, 2016, all other Initial Participants may become a Party by executing this Agreement and delivering an executed copy of this Agreement and a copy of the adopted ordinance required by Public Utilities Code Section 366.2(c)(12) to the Authority. Additional conditions, described in Section 3.1, may apply (i) to either an incorporated municipality or county desiring to become a Party that is not an Initial Participant and (ii) to Initial Participants that have not executed and delivered this Agreement within the time period described above.

2.3 **Formation**. There is formed as of the Effective Date a public agency named the East Bay Community Energy Authority. Pursuant to Sections 6506 and 6507 of the Act, the Authority is a public agency separate from the Parties. The debts, liabilities or obligations of the Authority shall not be debts, liabilities or obligations of the individual Parties unless the governing board of a Party agrees in writing to assume any of the debts, liabilities or obligations of the Authority. A Party who has not agreed to assume an Authority debt, liability or obligation shall not be responsible in any way for such debt, liability or obligation even if a majority of the Parties agree to assume the debt, liability or obligation of the Authority. Notwithstanding Section 8.4 of this Agreement, this Section 2.3 may not be amended unless such amendment is approved by the governing boards of all Parties.

2.4 **Purpose**. The purpose of this Agreement is to establish an independent public agency in order to exercise powers common to each Party and any other powers granted to the Authority under state law to participate as a group in the CCA Program pursuant to Public Utilities Code Section 366.2(c)(12); to study, promote, develop, conduct, operate, and manage energy and energy-related climate change programs; and, to exercise all other powers necessary and incidental to accomplishing this purpose.

2.5 **Powers**. The Authority shall have all powers common to the Parties and such additional powers accorded to it by law. The Authority is authorized, in its own name, to exercise all powers and do all acts necessary and proper to carry out the provisions of this Agreement and fulfill its purposes, including, but not limited to, each of the following:

2.5.1 to make and enter into contracts, including those relating to the purchase or sale of electrical energy or attributes thereof;

2.5.2 to employ agents and employees, including but not limited to a Chief Executive Officer and General Counsel;

2.5.3 to acquire, contract, manage, maintain, and operate any buildings, works or improvements, including electric generating facilities;

2.5.4 to acquire property by eminent domain, or otherwise, except as limited under Section 6508 of the Act, and to hold or dispose of any property;

2.5.5 to lease any property;

2.5.6 to sue and be sued in its own name;

2.5.7 to incur debts, liabilities, and obligations, including but not limited to loans from private lending sources pursuant to its temporary borrowing powers such as Government Code Section 53850 *et seq*. and authority under the Act;

2.5.8 to form subsidiary or independent corporations or entities, if appropriate, to carry out energy supply and energy conservation programs at the lowest possible cost consistent with the Authority's CCA Program implementation plan, risk management policies, or to take advantage of legislative or regulatory changes;

2.5.9 to issue revenue bonds and other forms of indebtedness;

2.5.10 to apply for, accept, and receive all licenses, permits, grants, loans or other assistance from any federal, state or local public agency;

2.5.11 to submit documentation and notices, register, and comply with orders, tariffs and agreements for the establishment and implementation of the CCA Program and other energy programs;

2.5.12 to adopt rules, regulations, policies, bylaws and procedures governing the operation of the Authority ("Operating Rules and Regulations");

2.5.13 to make and enter into service, energy and any other agreements necessary to plan, implement, operate and administer the CCA Program and other energy programs, including the acquisition of electric power supply and the provision of retail and regulatory support services; and

2.5.14 to negotiate project labor agreements, community benefits agreements and collective bargaining agreements with the local building trades council and other interested parties.

2.6 **Limitation on Powers**. As required by Government Code Section 6509, the power of the Authority is subject to the restrictions upon the manner of exercising power possessed by the City of Emeryville and any other restrictions on exercising the powers of the Authority that may be adopted by the Board.

2.7 **Compliance with Local Zoning and Building Laws**. Notwithstanding any other provisions of this Agreement or state law, any facilities, buildings or structures located, constructed or caused to be constructed by the Authority within the territory of the Authority shall comply with the General Plan, zoning and building laws of the local jurisdiction within which the facilities, buildings or structures are constructed and comply with the California Environmental Quality Act ("CEQA").

2.8 Compliance with the Brown Act. The Authority and its officers and employees shall comply with the provisions of the Ralph M. Brown Act, Government Code Section 54950 *et seq*.

2.9 Compliance with the Political Reform Act and Government Code Section 1090. The Authority and its officers and employees shall comply with the Political Reform Act (Government Code Section 81000 *et seq.*) and Government Code Section 1090 *et seq*, and shall adopt a Conflict of Interest Code pursuant to Government Code Section 87300. The Board of Directors may adopt additional conflict of interest regulations in the Operating Rules and Regulations.

ARTICLE 3
AUTHORITY PARTICIPATION

3.1 Addition of Parties. Subject to Section 2.2, relating to certain rights of Initial Participants, other incorporated municipalities and counties may become Parties upon (a) the adoption of a resolution by the governing body of such incorporated municipality or county requesting that the incorporated municipality or county, as the case may be, become a member of the Authority, (b) the adoption by an affirmative vote of a majority of all Directors of the entire Board satisfying the requirements described in Section 4.12, of a resolution authorizing membership of the additional incorporated municipality or county, specifying the membership payment, if any, to be made by the additional incorporated municipality or county to reflect its pro rata share of organizational, planning and other pre-existing expenditures, and describing additional conditions, if any, associated with membership, (c) the adoption of an ordinance required by Public Utilities Code Section 366.2(c)(12) and execution of this Agreement and other necessary program agreements by the incorporated municipality or county, (d) payment of the membership fee, if any, and (e) satisfaction of any conditions established by the Board.

3.2 Continuing Participation. The Parties acknowledge that membership in the Authority may change by the addition and/or withdrawal or termination of Parties. The Parties agree to participate with such other Parties as may later be added, as described in Section 3.1. The Parties also agree that the withdrawal or termination of a Party shall not affect this Agreement or the remaining Parties' continuing obligations under this Agreement.

ARTICLE 4
GOVERNANCE AND INTERNAL ORGANIZATION

4.1 Board of Directors. The governing body of the Authority shall be a Board of Directors ("Board") consisting of one director for each Party appointed in accordance with Section 4.2.

4.2 Appointment of Directors. The Directors shall be appointed as follows:

4.2.1 The governing body of each Party shall appoint and designate in writing one regular Director who shall be authorized to act for and on behalf of the Party on matters within the powers of the Authority. The governing body of each Party also shall appoint and designate in writing one alternate Director who may vote on matters when the regular Director is absent from a Board meeting. The person appointed and designated as the regular Director shall be a member of the governing body of the Party. The person appointed and designated as the alternate Director shall also be a member of the governing body of the Party.

4.2.2 The Board shall also include one non-voting ex officio member as defined in Section 1.1.13 ("Ex Officio Board Member"). The Chair of the Community Advisory Committee, as described in Section 4.9 below, shall serve as the Ex Officio Board Member. The Vice Chair of the Community Advisory Committee shall serve as an alternate Ex Officio Board Member when the regular Ex Officio Board Member is absent from a Board meeting.

4.2.3 The Operating Rules and Regulations, to be developed and approved by the Board in accordance with Section 2.5.12 may include rules regarding Directors, such as meeting attendance requirements. No Party shall be deprived of its right to seat a Director on the Board.

4.3 **<u>Terms of Office</u>**. Each regular and alternate Director shall serve at the pleasure of the governing body of the Party that the Director represents, and may be removed as Director by such governing body at any time. If at any time a vacancy occurs on the Board, a replacement shall be appointed to fill the position of the previous Director in accordance with the provisions of Section 4.2 within 90 days of the date that such position becomes vacant.

4.4 **<u>Quorum</u>**. A majority of the Directors of the entire Board shall constitute a quorum, except that less than a quorum may adjourn a meeting from time to time in accordance with law.

4.5 **<u>Powers and Function of the Board</u>**. The Board shall conduct or authorize to be conducted all business and activities of the Authority, consistent with this Agreement, the Authority Documents, the Operating Rules and Regulations, and applicable law. Board approval shall be required for any of the following actions, which are defined as "Essential Functions":

4.5.1 The issuance of bonds or any other financing even if program revenues are expected to pay for such financing.

4.5.2 The hiring of a Chief Executive Officer and General Counsel.

4.5.3 The appointment or removal of an officer.

4.5.4 The adoption of the Annual Budget.

4.5.5 The adoption of an ordinance.

4.5.6 The initiation of resolution of claims and litigation where the Authority will be the defendant, plaintiff, petitioner, respondent, cross complainant or cross petitioner, or intervenor; provided, however, that the Chief Executive Officer or General Counsel, on behalf of the Authority, may intervene in, become party to, or file comments with respect to any proceeding pending at the California Public Utilities Commission, the Federal Energy Regulatory Commission, or any other administrative agency, without approval of the Board. The Board shall adopt Operating Rules and Regulations governing the Chief Executive Officer and General Counsel's exercise of authority under this Section 4.5.6.

4.5.7 The setting of rates for power sold by the Authority and the setting of charges for any other category of service provided by the Authority.

4.5.8 Termination of the CCA Program.

4.6 **Executive Committee**. The Board shall establish an Executive Committee consisting of a smaller number of Directors. The Board may delegate to the Executive Committee such authority as the Board might otherwise exercise, subject to limitations placed on the Board's authority to delegate certain Essential Functions, as described in Section 4.5 and the Operating Rules and Regulations. The Board may not delegate to the Executive Committee or any other committee its authority under Section 2.5.12 to adopt and amend the Operating Rules and Regulations or its Essential Functions listed in Section 4.5. After the Executive Committee meets or otherwise takes action, it shall, as soon as practicable, make a report of its activities at a meeting of the Board.

4.7 **Director Compensation**. Directors shall receive a stipend of $100 per meeting, as adjusted to account for inflation, as provided for in the Authority's Operating Rules and Regulations.

4.8 **Commissions, Boards and Committees**. The Board may establish any advisory commissions, boards and committees as the Board deems appropriate to assist the Board in carrying out its functions and implementing the CCA Program, other energy programs and the provisions of this Agreement. The Board may establish rules, regulations, policies, bylaws or procedures to govern any such commissions, boards, or committees and shall determine whether members shall be compensated or entitled to reimbursement for expenses.

4.9 **Community Advisory Committee**. The Board shall establish a Community Advisory Committee consisting of nine members, none of whom may be voting members of the Board. The function of the Community Advisory Committee shall be to advise the Board of Directors on all subjects related to the operation of the CCA Program as set forth in a work plan adopted by the Board of Directors from time to time, with the exception of personnel and litigation decisions. The Community Advisory Committee is advisory only, and shall not have decision-making authority, or receive any delegation of authority from the Board of Directors. The Board shall publicize the opportunity to serve on the Community Advisory Committee, and shall appoint members of the Community Advisory Committee from those individuals expressing interest in serving, and who represent a diverse cross-section of interests, skill sets and geographic regions. Members of the Community Advisory Committee shall serve staggered four-year terms (the first term of three of the members shall be two years, and four years thereafter), which may be renewed. A member of the Community Advisory Committee may be removed by the Board of Directors by majority vote. The Board of Directors shall determine whether the Community Advisory Committee members will receive a stipend and/or be entitled to reimbursement for expenses.

4.10 <u>Chief Executive Officer</u>. The Board of Directors shall appoint a Chief Executive Officer for the Authority, who shall be responsible for the day-to-day operation and management of the Authority and the CCA Program. The Chief Executive Officer may exercise all powers of the Authority, including the power to hire, discipline and terminate employees as well as the power to approve any agreement, if the expenditure is authorized in the Authority's approved budget, except the powers specifically set forth in Section 4.5 or those powers which by law must be exercised by the Board of Directors. The Board of Directors shall provide procedures and guidelines for the Chief Executive Officer exercising the powers of the Authority in the Operating Rules and Regulations.

4.11 <u>General Counsel.</u> The Board of Directors shall appoint a General Counsel for the Authority, who shall be responsible for providing legal advice to the Board of Directors and overseeing all legal work for the Authority.

4.12 <u>Board Voting</u>.

4.12.1 Percentage Vote. Except when a supermajority vote is expressly required by this Agreement or the Operating Rules and Regulations, action of the Board on all matters shall require an affirmative vote of a majority of all Directors on the entire Board (a "Percentage Vote" as defined in Section 1.1.20). A supermajority vote is required by this Agreement for the matters addressed by Section 8.4. When a supermajority vote is required by this Agreement or the Operating Rules and Regulations, action of the Board shall require an affirmative Percentage Vote of the specified supermajority of all Directors on the entire Board. No action can be taken by the Board without an affirmative Percentage Vote. Notwithstanding the foregoing, in the event of a tie in the Percentage Vote, an action may be approved by an affirmative "Voting Shares Vote," as defined in Section 1.1.22, if three or more Directors immediately request such vote.

4.12.2 Voting Shares Vote. In addition to and immediately after an affirmative percentage vote, three or more Directors may request that, a vote of the voting shares shall be held (a "Voting Shares Vote" as defined in Section 1.1.22). To approve an action by a Voting Shares Vote, the corresponding voting shares (as defined in Section 1.1.23 and Exhibit C) of all Directors voting in the affirmative shall exceed 50% of the voting share of all Directors on the entire Board, or such other higher voting shares percentage expressly required by this Agreement or the Operating Rules and Regulations. In the event that any one Director has a voting share that equals or exceeds that which is necessary to disapprove the matter being voted on by the Board, at least one other Director shall be required to vote in the negative in order to disapprove such matter. When a voting shares vote is held, action by the Board requires both an affirmative Percentage Vote and an affirmative Voting Shares Vote. Notwithstanding the foregoing, in the event of a tie in the Percentage Vote, an action may be approved on an affirmative Voting Shares Vote. When a supermajority vote is required by this Agreement or the Operating Rules and Regulations, the supermajority vote is subject to the Voting Share Vote provisions of this Section 4.12.2, and the specified supermajority of all Voting Shares is required for approval of the action, if the provision of this Section 4.12.2 are triggered.

4.13 **Meetings and Special Meetings of the Board**. The Board shall hold at least four regular meetings per year, but the Board may provide for the holding of regular meetings at more frequent intervals. The date, hour and place of each regular meeting shall be fixed by resolution or ordinance of the Board. Regular meetings may be adjourned to another meeting time. Special and Emergency meetings of the Board may be called in accordance with the provisions of California Government Code Section 54956 and 54956.5. Directors may participate in meetings telephonically, with full voting rights, only to the extent permitted by law.

4.14 **Officers**.

4.14.1 **Chair and Vice Chair**. At the first meeting held by the Board in each calendar year, the Directors shall elect, from among themselves, a Chair, who shall be the presiding officer of all Board meetings, and a Vice Chair, who shall serve in the absence of the Chair. The Chair and Vice Chair shall hold office for one year and serve no more than two consecutive terms, however, the total number of terms a Director may serve as Chair or Vice Chair is not limited. The office of either the Chair or Vice Chair shall be declared vacant and the Board shall make a new selection if: (a) the person serving dies, resigns, or ceases to be a member of the governing body of the Party that the person represents; (b) the Party that the person represents removes the person as its representative on the Board, or (c) the Party that he or she represents withdraws from the Authority pursuant to the provisions of this Agreement.

4.14.2 **Secretary**. The Board shall appoint a Secretary, who need not be a member of the Board, who shall be responsible for keeping the minutes of all meetings of the Board and all other official records of the Authority.

4.14.3 **Treasurer and Auditor**. The Board shall appoint a qualified person to act as the Treasurer and a qualified person to act as the Auditor, neither of whom needs to be a member of the Board. The same person may not simultaneously hold both the office of Treasurer and the office of the Auditor of the Authority. Unless otherwise exempted from such requirement, the Authority shall cause an independent audit to be made annually by a certified public accountant, or public accountant, in compliance with Section 6505 of the Act. The Treasurer shall act as the depositary of the Authority and have custody of all the money of the Authority, from whatever source, and as such, shall have all of the duties and responsibilities specified in Section 6505.5 of the Act. The Board may require the Treasurer and/or Auditor to file with the Authority an official bond in an amount to be fixed by the Board, and if so requested, the Authority shall pay the cost of premiums associated with the bond. The Treasurer shall report directly to the Board and shall comply with the requirements of treasurers of incorporated municipalities. The Board may transfer the responsibilities of Treasurer to any person or entity as the law may provide at the time.

4.15 Administrative Services Provider. The Board may appoint one or more administrative services providers to serve as the Authority's agent for planning, implementing, operating and administering the CCA Program, and any other program approved by the Board, in accordance with the provisions of an Administrative Services Agreement. The appointed administrative services provider may be one of the Parties. The Administrative Services Agreement shall set forth the terms and conditions by which the appointed administrative services provider shall perform or cause to be performed all tasks necessary for planning, implementing, operating and administering the CCA Program and other approved programs. The Administrative Services Agreement shall set forth the term of the Agreement and the circumstances under which the Administrative Services Agreement may be terminated by the Authority. This section shall not in any way be construed to limit the discretion of the Authority to hire its own employees to administer the CCA Program or any other program.

4.16 Operational Audit. The Authority shall commission an independent agent to conduct and deliver at a public meeting of the Board an evaluation of the performance of the CCA Program relative to goals for renewable energy and carbon reductions. The Authority shall approve a budget for such evaluation and shall hire a firm or individual that has no other direct or indirect business relationship with the Authority. The evaluation shall be conducted at least once every two years.

ARTICLE 5
IMPLEMENTATION ACTION AND AUTHORITY DOCUMENTS

5.1 Implementation of the CCA Program.

5.1.1 Enabling Ordinance. Prior to the execution of this Agreement, each Party shall adopt an ordinance in accordance with Public Utilities Code Section 366.2(c)(12) for the purpose of specifying that the Party intends to implement a CCA Program by and through its participation in the Authority.

5.1.2 Implementation Plan. The Authority shall cause to be prepared an Implementation Plan meeting the requirements of Public Utilities Code Section 366.2 and any applicable Public Utilities Commission regulations as soon after the Effective Date as reasonably practicable. The Implementation Plan shall not be filed with the Public Utilities Commission until it is approved by the Board in the manner provided by Section 4.12.

5.1.3 Termination of CCA Program. Nothing contained in this Article or this Agreement shall be construed to limit the discretion of the Authority to terminate the implementation or operation of the CCA Program at any time in accordance with any applicable requirements of state law.

5.2 **Other Authority Documents**. The Parties acknowledge and agree that the operations of the Authority will be implemented through various documents duly adopted by the Board through Board resolution or minute action, including but not necessarily limited to the Operating Rules and Regulations, the annual budget, and specified plans and policies defined as the Authority Documents by this Agreement. The Parties agree to abide by and comply with the terms and conditions of all such Authority Documents that may be adopted by the Board, subject to the Parties' right to withdraw from the Authority as described in Article 7.

5.3 **Integrated Resource Plan.** The Authority shall cause to be prepared an Integrated Resource Plan in accordance with CPUC regulations that will ensure the long-term development and administration of a variety of energy programs that promote local renewable resources, conservation, demand response, and energy efficiency, while maintaining compliance with the State Renewable Portfolio standard and customer rate competitiveness. The Authority shall prioritize the development of energy projects in Alameda and adjacent counties. Principal aspects of its planned operations shall be in a Business Plan as outlined in Section 5.4 of this Agreement.

5.4 **Business Plan.** The Authority shall cause to be prepared a Business Plan, which will include a roadmap for the development, procurement, and integration of local renewable energy resources as outlined in Section 5.3 of this Agreement. The Business Plan shall include a description of how the CCA Program will contribute to fostering local economic benefits, such as job creation and community energy programs. The Business Plan shall identify opportunities for local power development and how the CCA Program can achieve the goals outlined in Recitals 3 and 6 of this Agreement. The Business Plan shall include specific language detailing employment and labor standards that relate to the execution of the CCA Program as referenced in this Agreement. The Business Plan shall identify clear and transparent marketing practices to be followed by the CCA Program, including the identification of the sources of its electricity and explanation of the various types of electricity procured by the Authority. The Business Plan shall cover the first five (5) years of the operation of the CCA Program. The Business Plan shall be completed by the Authority no later than eight (8) months after the seating of the Authority Board of Directors. Progress on the implementation of the Business Plan shall be subject to annual public review.

5.5 **Labor Organization Neutrality.** The Authority shall remain neutral in the event its employees, and the employees of its subcontractors, if any, wish to unionize.

5.6 **Renewable Portfolio Standards.** The Authority shall provide its customers energy primarily from Category 1 eligible renewable resources, as defined under the California RPS and consistent with the goals of the CCA Program. The Authority shall not procure energy from Category 3 eligible renewable resources (unbundled Renewable Energy Credits or RECs) exceeding 50% of the State law requirements, to achieve its renewable portfolio goals. However, for Category 3 RECs associated with generation facilities located within its service jurisdiction, the limitation set forth in the preceding sentence shall not apply.

ARTICLE 6
FINANCIAL PROVISIONS

6.1 **Fiscal Year**. The Authority's fiscal year shall be 12 months commencing July 1 and ending June 30. The fiscal year may be changed by Board resolution.

6.2 **Depository**.

6.2.1 All funds of the Authority shall be held in separate accounts in the name of the Authority and not commingled with funds of any Party or any other person or entity.

6.2.2 All funds of the Authority shall be strictly and separately accounted for, and regular reports shall be rendered of all receipts and disbursements, at least quarterly during the fiscal year. The books and records of the Authority shall be open to inspection by the Parties at all reasonable times.

6.2.3 All expenditures shall be made in accordance with the approved budget and upon the approval of any officer so authorized by the Board in accordance with its Operating Rules and Regulations. The Treasurer shall draw checks or warrants or make payments by other means for claims or disbursements not within an applicable budget only upon the prior approval of the Board.

6.3 **Budget and Recovery Costs**.

6.3.1 **Budget**. The initial budget shall be approved by the Board. The Board may revise the budget from time to time through an Authority Document as may be reasonably necessary to address contingencies and unexpected expenses. All subsequent budgets of the Authority shall be prepared and approved by the Board in accordance with the Operating Rules and Regulations.

6.3.2 **Funding of Initial Costs**. The County shall fund the Initial Costs of establishing and implementing the CCA Program. In the event that the

CCA Program becomes operational, these Initial Costs paid by the County and any specified interest shall be included in the customer charges for electric services to the extent permitted by law, and the County shall be reimbursed from the payment of such charges by customers of the Authority. The Authority may establish a reasonable time period over which such costs are recovered. In the event that the CCA Program does not become operational, the County shall not be entitled to any reimbursement of the Initial Costs.

6.3.4 **Additional Contributions and Advances**. Pursuant to Government Code Section 6504, the Parties may in their sole discretion make financial contributions, loans or advances to the Authority for the purposes of the Authority set forth in this Agreement. The repayment of such contributions, loans or advances will be on the written terms agreed to by the Party making the contribution, loan or advance and the Authority.

ARTICLE 7
WITHDRAWAL AND TERMINATION

7.1 **Withdrawal**.

7.1.1 **General Right to Withdraw**. A Party may withdraw its membership in the Authority, effective as of the beginning of the Authority's fiscal year, by giving no less than 180 days advance written notice of its election to do so, which notice shall be given to the Authority and each Party. Withdrawal of a Party shall require an affirmative vote of the Party's governing board.

7.1.2 **Withdrawal Following Amendment**. Notwithstanding Section 7.1.1, a Party may withdraw its membership in the Authority following an amendment to this Agreement provided that the requirements of this Section 7.1.2 are strictly followed. A Party shall be deemed to have withdrawn its membership in the Authority effective 180 days after the Board approves an amendment to this Agreement if the Director representing such Party has provided notice to the other Directors immediately preceding the Board's vote of the Party's intention to withdraw its membership in the Authority should the amendment be approved by the Board.

7.1.3 **The Right to Withdraw Prior to Program Launch**. After receiving bids from power suppliers for the CCA Program, the Authority must provide to the Parties a report from the electrical utility consultant retained by the Authority comparing the Authority's total estimated electrical rates, the estimated greenhouse gas emissions rate and the amount of estimated renewable energy to be used with that of the incumbent utility. Within 30 days after receiving this report, through its City Manager or a person expressly authorized by the Party, any Party may immediately withdraw its membership in the Authority by providing written notice of withdrawal to the Authority if the report determines that any one of the following conditions exists: (1) the Authority is unable to provide total electrical rates, as part of its baseline offering to customers, that are equal to or lower than the incumbent utility, (2) the Authority is unable to provide electricity in a manner that has a lower greenhouse gas emissions rate than the incumbent utility, or (3) the Authority will use less qualified renewable energy than the incumbent utility. Any Party who withdraws from the Authority pursuant to this Section 7.1.3 shall not be entitled to any refund of the Initial Costs it has paid to the Authority prior to the date of withdrawal unless the Authority is later terminated pursuant to Section 7.3. In such event, any Initial Costs not expended by the Authority shall be returned to all Parties, including any Party that has withdrawn pursuant to this section, in proportion to the contribution that each made. Notwithstanding anything to the contrary in this Agreement, any Party who withdraws pursuant to this section shall not be responsible for any liabilities or obligations of the Authority after the date of withdrawal, including without limitation any liability arising from power purchase agreements entered into by the Authority.

7.2 **Continuing Liability After Withdrawal; Further Assurances; Refund.** A Party that withdraws its membership in the Authority under either Section 7.1.1 or 7.1.2 shall be responsible for paying its fair share of costs incurred by the Authority resulting from the Party's withdrawal, including costs from the resale of power contracts by the Authority to serve the Party's load and any similar costs directly attributable to the Party's withdrawal, such costs being limited to those contracts executed while the withdrawing Party was a member, and administrative costs associated thereto. The Parties agree that such costs shall not constitute a debt of the withdrawing Party, accruing interest, or having a maturity date. The Authority may withhold funds otherwise owing to the Party or may require the Party to deposit sufficient funds with the Authority, as reasonably determined by the Authority, to cover the Party's costs described above. Any amount of the Party's funds held by the Authority for the benefit of the Party that are not required to pay the Party's costs described above shall be returned to the Party. The withdrawing party and the Authority shall execute and deliver all further instruments and documents, and take any further action that may be reasonably necessary, as determined by the Board, to effectuate the orderly withdrawal of such Party from membership in the Authority. A withdrawing party has the right to continue to participate in Board discussions and decisions affecting customers of the CCA Program that reside or do business within the jurisdiction of the Party until the withdrawal's effective date.

7.3 **Mutual Termination**. This Agreement may be terminated by mutual agreement of all the Parties; provided, however, the foregoing shall not be construed as limiting the rights of a Party to withdraw its membership in the Authority, and thus terminate this Agreement with respect to such withdrawing Party, as described in Section 7.1.

7.4 **Disposition of Property upon Termination of Authority**. Upon termination of this Agreement as to all Parties, any surplus money or assets in possession of the Authority for use under this Agreement, after payment of all liabilities, costs, expenses, and charges incurred under this Agreement and under any Authority Documents, shall be returned to the then-existing Parties in proportion to the contributions made by each.

ARTICLE 8
MISCELLANEOUS PROVISIONS

8.1 Dispute Resolution. The Parties and the Authority shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. Before exercising any remedy provided by law, a Party or the Parties and the Authority shall engage in nonbinding mediation in the manner agreed upon by the Party or Parties and the Authority. The Parties agree that each Party may specifically enforce this section 8.1. In the event that nonbinding mediation is not initiated or does not result in the settlement of a dispute within 120 days after the demand for mediation is made, any Party and the Authority may pursue any remedies provided by law.

8.2 Liability of Directors, Officers, and Employees. The Directors, officers, and employees of the Authority shall use ordinary care and reasonable diligence in the exercise of their powers and in the performance of their duties pursuant to this Agreement. No current or former Director, officer, or employee will be responsible for any act or omission by another Director, officer, or employee. The Authority shall defend, indemnify and hold harmless the individual current and former Directors, officers, and employees for any acts or omissions in the scope of their employment or duties in the manner provided by Government Code Section 995 *et seq*. Nothing in this section shall be construed to limit the defenses available under the law, to the Parties, the Authority, or its Directors, officers, or employees.

8.3 Indemnification of Parties. The Authority shall acquire such insurance coverage as the Board deems necessary to protect the interests of the Authority, the Parties and the public. Such insurance coverage shall name the Parties and their respective Board or Council members, officers, agents and employees as additional insureds. The Authority shall defend, indemnify and hold harmless the Parties and each of their respective Board or Council members, officers, agents and employees, from any and all claims, losses, damages, costs, injuries and liabilities of every kind arising directly or indirectly from the conduct, activities, operations, acts, and omissions of the Authority under this Agreement.

8.4 Amendment of this Agreement. This Agreement may be amended in writing by a two-thirds affirmative vote of the entire Board satisfying the requirements described in Section 4.12. Except that, any amendment to the voting provisions in Section 4.12 may only be made by a three-quarters affirmative vote of the entire Board. The Authority shall provide written notice to the Parties at least 30 days in advance of any proposed amendment being considered by the Board. If the proposed amendment is adopted by the Board, the Authority shall provide prompt written notice to all Parties of the effective date of such amendment along with a copy of the amendment.

8.5 **Assignment**. Except as otherwise expressly provided in this Agreement, the rights and duties of the Parties may not be assigned or delegated without the advance written consent of all of the other Parties, and any attempt to assign or delegate such rights or duties in contravention of this Section 8.5 shall be null and void. This Agreement shall inure to the benefit of, and be binding upon, the successors and assigns of the Parties. This Section 8.5 does not prohibit a Party from entering into an independent agreement with another agency, person, or entity regarding the financing of that Party's contributions to the Authority, or the disposition of proceeds which that Party receives under this Agreement, so long as such independent agreement does not affect, or purport to affect, the rights and duties of the Authority or the Parties under this Agreement.

8.6 **Severability**. If one or more clauses, sentences, paragraphs or provisions of this Agreement shall be held to be unlawful, invalid or unenforceable, it is hereby agreed by the Parties, that the remainder of the Agreement shall not be affected thereby. Such clauses, sentences, paragraphs or provision shall be deemed reformed so as to be lawful, valid and enforced to the maximum extent possible.

8.7 **Further Assurances**. Each Party agrees to execute and deliver all further instruments and documents, and take any further action that may be reasonably necessary, to effectuate the purposes and intent of this Agreement.

8.8 **Execution by Counterparts**. This Agreement may be executed in any number of counterparts, and upon execution by all Parties, each executed counterpart shall have the same force and effect as an original instrument and as if all Parties had signed the same instrument. Any signature page of this Agreement may be detached from any counterpart of this Agreement without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of this Agreement identical in form hereto but having attached to it one or more signature pages.

8.9 **Parties to be Served Notice**. Any notice authorized or required to be given pursuant to this Agreement shall be validly given if served in writing either personally, by deposit in the United States mail, first class postage prepaid with return receipt requested, or by a recognized courier service. Notices given (a) personally or by courier service shall be conclusively deemed received at the time of delivery and receipt and (b) by mail shall be conclusively deemed given 72 hours after the deposit thereof (excluding Saturdays, Sundays and holidays) if the sender receives the return receipt. All notices shall be addressed to the office of the clerk or secretary of the Authority or Party, as the case may be, or such other person designated in writing by the Authority or Party. In addition, a duplicate copy of all notices provided pursuant to this section shall be provided to the Director and alternate Director for each Party. Notices given to one Party shall be copied to all other Parties. Notices given to the Authority shall be copied to all Parties. All notices required hereunder shall be delivered to:

The County of Alameda

Director, Community Development Agency

224 West Winton Ave.
Hayward, CA 94612

With a copy to:

Office of the County Counsel
1221 Oak Street, Suite 450
Oakland, CA 94612

if to [PARTY No. ____]

Office of the City Clerk
____
____

Office of the City Manager/Administrator
____
____

Office of the City Attorney
____
____

if to [PARTY No._____]

Office of the City Clerk
____
____

Office of the City Manager/Administrator
____
____

Office of the City Attorney
____
____

ARTICLE 9
<u>SIGNATURE</u>

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

By: ______________________________

Name: ____________________________

Title: _____________________________

Date: _____________________________

Party: ____________________________

EXHIBIT A

-LIST OF THE PARTIES

(This draft exhibit is based on the assumption that all of the Initial Participants will become Parties. On the Effective Date, this exhibit will be revised to reflect the Parties to this Agreement at that time.)-

-

DRAFT EXHIBIT B

-ANNUAL ENERGY USE

(This draft exhibit is based on the assumption that <u>all</u> of the Initial Participants will become Parties. On the Effective Date, this exhibit will be revised to reflect the Parties to this Agreement at that time.)

This Exhibit B is effective as of ________________.

Party	kWh ([YEAR]*)

*Data provided by PG&E

<u>DRAFT EXHIBIT C</u>

- VOTING SHARES

(This draft exhibit is based on the assumption that <u>all</u> of the Initial Participants will become Parties. On the Effective Date, this exhibit will be revised to reflect the Parties to this Agreement at that time.)

This Exhibit C is effective as of ____________________.

Party	kWh ([YEAR]*)	Voting Share Section 4.11.2
Total		

*Data provided by PG&E

Appendix I. MCE's approval for inclusion of Contra Costa

MCE Clean Energy
My community. My choice.

1125 Tamalpais Avenue
San Rafael, CA 94901

1 (888) 632-3674
mceCleanEnergy.org

November 8, 2016

John Kopchik, Director of Conservation and Development
Contra Costa County
30 Muir Road
Martinez, CA 94553

Dear Mr. Kopchik:

As you may be aware, MCE is currently serving customers in many jurisdictions of Contra Costa County with clean electricity choices at competitive rates for customers. We have been in touch with staff representatives from the County and we are familiar with the technical study currently underway to consider community choice options in other parts of the county not currently served. As part of this process MCE has been asked to clarify what the cost and process would be for new jurisdictions interested in joining MCE.

To respond to this request the MCE Board recently held a Special Meeting to discuss the inclusion process and costs for new jurisdictions within the borders of Contra Costa County. We are pleased to inform you that our Board has approved a six-month "inclusion period" that would allow no-cost membership consideration if your membership application is completed between December 1, 2016 and May 31, 2017.

Membership application requirements are attached here and include the following:

- Adoption of a resolution requesting membership
- Adoption of the ordinance required by the Public Utilities Code Section 366.2(c) (10)
- Executed Memorandum of Understanding
- Signed request for load data from PG&E
- County assessor data for all building stock in jurisdiction
- Designation of a staff person from your county to serve as a liaison to MCE

If you are interested in submitting a membership application please notify Alex DiGiorgio, MCE's Community Development Manager, and he will assist you with any questions you may have as you complete the checklist. You can reach Alex by email at: adiorgio@mcecleanenergy.org or by phone at: 415-464-6031.

Please note that (1) adoption of your Ordinance to join MCE will be subject to approval by the MCE Board, and (2) MCE will conduct an economic feasibility analysis prior to approving membership. Also, if membership is approved, timing of procurement and customer enrollment would be determined by the MCE Board. We will remain in close contact with your county about the most likely target dates for each process.

To streamline communications and policy setting, participating jurisdictions may consolidate voting representation on the MCE Board. If you choose this option, the selected representative would have a weighted vote based on the combined customer load of all the jurisdictions which voted to consolidate.

We are happy to meet with you or your council to answer questions or provide additional information. We look forward to the opportunity to work with you on your membership application for MCE service. Please let me know if we can be of any further assistance.

Sincerely,

Dawn Weisz
CEO