DRAFT PENINSULA CLEAN ENERGY CCA TECHNICAL STUDY

9/18/2015

Prepared by Pacific Energy Advisors, Inc.

This Technical Study was prepared for the County of San Mateo for purposes of understanding the potential benefits and liabilities associated with forming a Community Choice Aggregation (CCA) program, which would provide electric generation service to residential and business customers located within San Mateo County. A detailed discussion of the projected operating results related to the CCA program, which has been named Peninsula Clean Energy, are presented herein.

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EXECUTIVE SUMMARY

This Community Choice Aggregation ("CCA") Technical Study ("Study") was prepared by Pacific Energy Advisors, Inc. ("PEA") for purposes of describing the potential benefits and liabilities associated with forming a CCA program, which would provide electric generation service to residential and business customers located within (i) the twenty (20) municipalities in the County of San Mateo ("County"), and (ii) the unincorporated areas of the County (together, the "San Mateo Communities"). The Study evaluated projected operations of such a CCA program, which has been named Peninsula Clean Energy ("PCE"), over a ten-year planning horizon, drawing from best available market intelligence and PEA's direct experience with each of California's operating CCA programs. This information was used to generate a set of anticipated base case assumptions for PCE operations as well as a variety of sensitivities, which were used to demonstrate how certain changes in the base case assumptions would influence anticipated operating results.

For purposes of the Study, PEA and County leadership identified three indicative supply scenarios, which were designed to test the viability of prospective CCA operations under a variety of energy resource compositions. In particular, the three supply scenarios were constructed with the following objectives in mind:

- **Scenario 1**: Maximize PCE rate/cost competitiveness relative to the incumbent investor-owned utility ("IOU"), Pacific Gas & Electric Company ("PG&E"), while ensuring compliance with applicable renewable energy procurement mandates.
- **Scenario 2**: Exceed renewable energy procurement mandates and promote reduced greenhouse gas emissions ("GHGs") within the electric energy sector through the predominant use of non-polluting generating resources.
- **Scenario 3**: Deliver a 100% bundled renewable energy product to all PCE customers based on prevailing market prices.

When considering the prospective supply scenarios evaluated in this Study, it should be understood that PCE would not be limited to any particular scenario assessed in this Study; the Study's supply scenarios were developed in cooperation with San Mateo County leadership for the purpose of demonstrating potential operating outcomes of a new CCA program under a broad range of resource mixes, which generally reflect key objectives of the San Mateo Communities. Prior to the procurement of any particular energy products, PCE would have an opportunity to refine its desired resource mix, which may differ from the prospective scenarios reflected herein.

When developing these supply scenarios, PEA was directed to exclude unbundled renewable energy certificates, nuclear generation, which represents a significant portion of PG&E's energy resource mix[1], and coal generation[2] from the anticipated resource mix.

Based on current market prices and various other operating assumptions, the Study indicates that PCE would be viable under a broad range of market conditions, demonstrating the potential for customer cost savings and significant GHG reductions. In particular, Scenarios 1 and 2 demonstrate the potential for customer cost savings ranging from 2% to 6%, relative to projected PG&E rates, over the ten-year study period. As expected, increased supply costs associated with the Scenario 3 supply portfolio, which specified the exclusive use of

[1] According to PG&E's 2013 Power Content Label, 22% of total electric energy supply was sourced from nuclear generating facilities; in 2014, a similar proportion of PG&E's total electric energy supply was sourced from nuclear generating facilities: 21%, as reflected in PG&E's Power Source Disclosure Report for the 2014 calendar year.

[2] According to the California Energy Commission, approximately 6% of California's total system power mix is comprised of electric energy produced by generators using coal as the primary fuel source: http://energyalmanac.ca.gov/electricity/total_system_power.html.

bundled renewable energy resources for the entirety of PCE's electric supply, resulted in marginally higher customer costs throughout the study period with premiums ranging from 1% to 2% relative to PG&E. As previously noted, none of the prospective supply scenarios include the use of unbundled RECs; renewable energy products will be exclusively limited to "bundled" deliveries produced by generators primarily located within California, the San Mateo Communities and elsewhere in the western United States.

When reviewing the pro forma financial results associated with each of the prospective supply scenarios, as reflected in Appendix A of this Study, line "X" indicates the "Total Change in Customer Electric Charges" during each year of the study period: to the extent that such values are negative, PCE would have the potential to offer comparatively lower customer rates/charges, relative to similar charges imposed by PG&E; to the extent that such values are positive, PCE would need to impose comparatively higher customer charges in order to recover expected costs. Ultimately, the disposition of any projected operating surpluses will be determined by PCE leadership during annual budgeting and ratesetting processes. For example, in the cases of Scenario 1 and Scenario 2, each year of the study period reflects the potential for operating surpluses. Such surpluses could be passed through to PCE customer in the form of comparatively lower electric rates/charges, as reflected in this Study, or PCE leadership could strike a balance between reduced rates and increased funding for complementary energy programs, such as Net Energy Metering, customer rebates (to promote local distributed renewable infrastructure buildout or energy efficiency, for example) as well as other similarly focused programs. PCE leadership would have considerable flexibility in administering the disposition of any projected operating surpluses, subject to any financial covenants that may be entered into by the program.

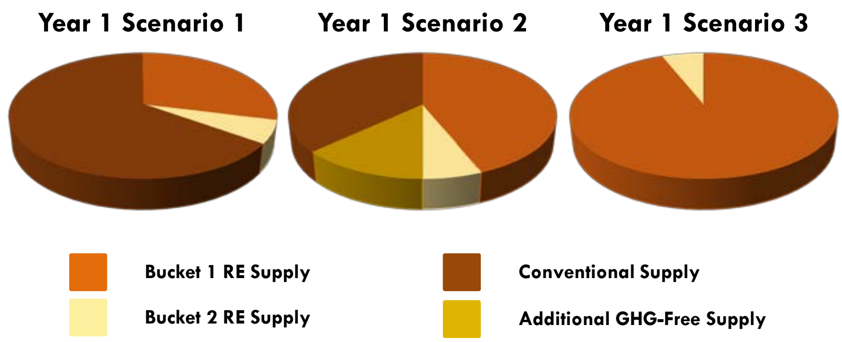
With regard to anticipated clean energy supply and resultant GHG emissions impacts, Scenario 1, which was designed with the primary purpose of minimizing customer costs, resulted in projected emissions *increases* ranging from 136,000 to 488,000 metric tons per year – the noted range of emissions impacts reflects the minimum (occurring in Year 1 of expected PCE operations) and maximum (occurring in Year 10 of expected PCE operations) impacts over the ten-year study period. Conversely, the predominantly carbon-free energy supply associated with Scenario 2 resulted in annual emissions *reductions* ranging from 75,000 (Year 1 impact) to 156,000 (Year 10 impact) metric tons. Scenario 3 yielded the most significant emissions benefits, resulting from a zero portfolio emissions rate – annual projected emissions *reductions* ranged from 130,000 (Year 1 impact) to 266,000 (Year 10 impact) metric tons. With regard to the anticipated GHG emissions impacts reflected under each scenario, it is important to note that such estimates are significantly influenced by PG&E's ongoing use of nuclear generation, which is generally recognized as GHG-free. To the extent that PG&E's use of nuclear generation is curtailed or suspended at some point in the future, PCE's projected emissions reductions would significantly increase.

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

- Conventional Supply (generally electric generation produced through the combustion of fossil fuels, particularly natural gas);
- "Bucket 1" Renewable Energy Supply (generally renewable generation within CA);
- "Bucket 2" Renewable Energy Supply (renewable generation imported into CA); and
- Additional GHG-Free Supply (generally power from large hydro-electric generation facilities, which are not eligible to participate in California's Renewables Portfolio Standard, or "RPS", certification program).

The following exhibit identifies the projected operating results under each supply scenario in Year 1 of anticipated CCA operation. Additional details regarding the composition of each supply scenario are addressed in Chapter 2.

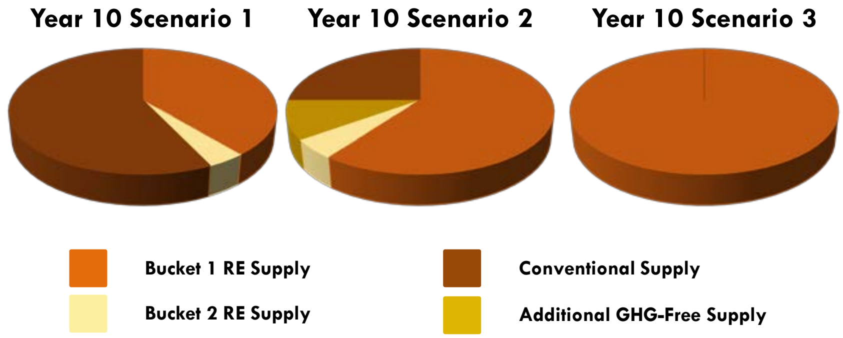
Peninsula Clean Energy Indicative Supply Scenarios: Year 1



Key Considerations	Scenario 1	Scenario 2	Scenario 3
<u>General Environmental Benefits</u> Renewable energy and GHG content	35% Renewable 35% GHG-Free	50% Renewable 63% GHG-Free	100% Renewable 100% GHG-Free
<u>Rate Competitiveness</u> Incremental renewable/clean energy purchases will impose upward pressure on PCE customer rates	Average 6% <u>savings</u> relative to PG&E rate projections	Average 4% <u>savings</u> relative to PG&E rate projections	Average 2% <u>increase</u> relative to PG&E rate projections
<u>Projected Residential Customer Cost Impacts</u>[1] Resource choices will influence monthly energy costs [1]Average monthly usage for PCE res. customers ≈ 450 kWh	Average $5.40 monthly cost <u>savings</u> relative to PG&E rate projections	Average $4.05 monthly cost <u>savings</u> relative to PG&E rate projections	Average $1.80 monthly cost <u>increase</u> relative to PG&E rate projections
<u>Assumed PCE Participation</u> Projected rate savings/increases are assumed to impact customer participation levels; medium and large commercial customers are assumed to be highly cost sensitive	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups	75% customer participation rate assumed for residential and small commercial customer groups; 50% participation for all other customer groups
<u>Comparative GHG Emissions Impacts</u> GHG emissions impact relative to assumed PG&E portfolio	0.278 metric tons CO_2/MWh emissions rate results in <u>additional GHG emissions</u> of ≈136,000 metric tons in Year 1	0.115 metric tons CO_2/MWh emissions rate results in ≈75,000 metric ton <u>GHG emissions reduction</u> in Year 1	Zero emissions rate results in ≈130,000 metric ton <u>GHG emissions reduction</u> in Year 1

The following exhibit identifies the projected operating results under each supply scenario in Year 10 of anticipated CCA operation.

Peninsula Clean Energy Indicative Supply Scenarios: Year 10



Key Considerations	Scenario 1	Scenario 2	Scenario 3
General Environmental Benefits Renewable energy and GHG content	43% Renewable 43% GHG-Free	65% Renewable 75% GHG-Free	100% Renewable 100% GHG-Free
Rate Competitiveness Incremental renewable/clean energy purchases will impose upward pressure on PCE customer rates	Average 4% savings relative to PG&E rate projections	Average 2% savings relative to PG&E rate projections	Average 1% increase relative to PG&E rate projections
Projected Residential Customer Cost Impacts[1] Resource choices will influence monthly energy costs [1]Average monthly usage for PCE res. customers ≈ 450 kWh	Average $4.95 monthly cost savings relative to PG&E rate projections	Average $1.80 monthly cost savings relative to PG&E rate projections	Average $1.35 monthly cost increase relative to PG&E rate projections
Assumed PCE Participation Projected rate savings/increases are assumed to impact customer participation levels; medium and large commercial customers are assumed to be highly cost sensitive	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups	75% customer participation rate assumed for residential and small commercial customer groups; 50% participation for all other customer groups
Comparative GHG Emissions Impacts GHG emissions impact relative to assumed PG&E portfolio	0.243 metric tons CO2/MWh emissions rate results in additional GHG emissions of ≈488,000 metric tons in Year 10	0.066 metric tons CO2/MWh emissions rate results in ≈156,000 metric ton GHG emissions reduction in Year 10	Zero emissions rate results in ≈266,000 metric ton GHG emissions reduction in Year 10

PCE's anticipated long-term power contract portfolio is also expected to generate substantial economic benefits throughout the state as a result of new renewable resource development. The prospective PCE long-term contract portfolio, which is reflected in the anticipated resource mix for each supply scenario, includes approximately 330 MW of new generating capacity (all of which is assumed to be located within California and some of which may be located within the County). Based on widely used industry models, such projects are expected to generate up to 10,000 construction jobs and as much as $1.3 billion in total economic output. Ongoing operation and maintenance ("O&M") jobs associated with such projects are expected to employ as many as 130 full time equivalent positions ("FTEs") with additional annual economic output up to $20 million. PCE would also employ a combination of staff and contractors, resulting in additional ongoing job creation (up to 30 FTEs per year) and related annual economic output ranging from $3 to $9 million.

Based on the results reflected in this Study and PEA's considerable experience with California CCAs, the PCE program has a variety of electric supply options that are projected to yield both customer rate savings and environmental benefits. To the extent that clean energy options, including renewable energy and hydroelectricity, are used in place of conventional power sources, which utilize fossil fuels to produce electric power, anticipated PCE costs and related customer rates would marginally increase. However, Scenario 3 indicates that ratepayer costs associated with a 100% bundled renewable energy supply scenario generally approach parity with the default supply option offered by PG&E over the ten-year study period.

Ultimately, PCE's ability to demonstrate rate competitiveness (while also offering environmental benefits) would hinge on prevailing market prices at the time of power supply contract negotiation and execution. Depending on inevitable changes to market prices and other assumptions, which are substantially addressed through the various sensitivity analyses reflected in this Study, PCE's electric rates may be somewhat lower or higher than similar rates charged by PG&E and would be expected to fall within a competitive range needed for program viability.

As with California's operating CCA programs, PCE's ability to secure requisite customer energy requirements, particularly under long term contracts, will depend on the program's perceived creditworthiness at the time of power procurement. Customer retention and reserve accrual, as well as a successful operating track record, will be viewed favorably by prospective energy suppliers, leading to reduced energy costs and customer rates. As previously noted, it is PEA's opinion that PCE would be operationally viable under a range of resource planning scenarios, demonstrating the potential for customer savings as well as reduced GHG emissions.

SECTION 1: INTRODUCTION

In consideration of its response to the County of San Mateo's ("County") Request for Proposals for Services Developing a Technical Study on CCA, PEA was retained by the County to conduct a technical study focused on the prospective formation of a CCA program serving the San Mateo Communities. This Study reflects the results of a comprehensive analysis, which addresses prospective CCA operations under a range of scenarios, including the identification of anticipated rate/cost impacts, environmental benefits, resource composition and economic development among other considerations. When reviewing this Study, 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.

PEA is an independent consulting firm specializing in providing strategic advice and technical support to various organizations within the California electricity market, particularly aspiring and operating CCA programs. PEA's consultants have been assisting local governments with the evaluation and implementation of CCA programs since 2004, including each of California's operational CCA programs: Marin Clean Energy ("MCE"), Sonoma Clean Power ("SCP") and Lancaster Choice Energy ("LCE"). This Study reflects operating projections that are based on best available information, utilizing transparent, documented assumptions to provide an objective assessment regarding the prospects of CCA operation in the County. However, due to the dynamic nature of California's energy markets, particularly market prices which are subject to frequent changes, the assumptions and projections reflected in this Study should be revisited prior to taking any action(s) or making any decision(s) that may be predicated on information contained in this Study – to the extent that future market price benchmarks materially differ from any of the assumptions noted in this Study, PEA recommends updating pertinent operating projections to ensure well-informed decision making and prudent action.

This Study addresses the projected benefits and liabilities related to the formation, implementation and operation of a potential CCA program, PCE, which would provide electric generation services to residential and business customers currently served by the incumbent investor-owned utility, PG&E, within the following San Mateo Communities:

Town of Atherton	City of Millbrae
City of Belmont	City of Pacifica
City of Brisbane	City of Portola Valley
City of Burlingame	City of Redwood City
Town of Colma	City of San Bruno
City of Daly City	City of San Carlos
City of East Palo Alto	City of San Mateo
City of Foster City	City of South San Francisco
City of Half Moon Bay	Town of Woodside
Town of Hillsborough	Unincorporated San Mateo County
City of Menlo Park	

Under existing rules administered by the California Public Utilities Commission ("CPUC"), PG&E would use its transmission and distribution system to deliver the electricity supplied by PCE in a non-discriminatory manner, as it currently does for its own "bundled service" customers (i.e., customers who receive both electric generation and delivery services from a single provider) and for "direct access" customers who receive electricity provided by competitive retail suppliers. PG&E would continue to provide all metering and billing services, and customers would receive a single electric bill each month from PG&E – each customer's bill would show PCE charges for generation services as well as charges for PG&E delivery services. Money collected by PG&E on behalf of PCE would be electronically transferred each day to PCE's designated bank account. Following enrollment in the CCA program, PCE customers would continue to be eligible for programs funded through distribution rates and operated by PG&E, including rebate/subsidy programs focused on energy efficiency and distributed solar generation.

To fulfill the electric energy requirements of its customers and related compliance obligations, PCE would participate in the electricity market to purchase various energy products from generators, brokers, and/or marketers. In the future, PCE may also produce electricity generated by its own power plants, which could be independently developed or acquired by the CCA. Other programs and services may be offered by PCE as well, such as new programs to promote conservation and/or energy efficiency, locally-situated distributed renewable generation (e.g., photovoltaic solar systems that are installed by a customer "behind the meter" to reduce reliance on offsite energy sources and/or reduce overall energy costs), electric vehicle charging, and customer load shifting (also known as "demand response").

PEA's analysis quantifies the expected benefits and liabilities of the CCA program in terms of overall operating margins, ratepayer costs, reductions in emissions of greenhouse gases ("GHGs", which primarily entail carbon dioxide, or "CO_2") from electric generating resources used to supply customers within the San Mateo Communities, and economic development impacts arising from new job creation and local spending. The remaining sections of this report are organized by subject matter as follows:

Section 2: Study Methodology – describes the methodological approach used to conduct the Study.

Section 3: PCE Technical Parameters – describes the electric consumption patterns and electric resource requirements of prospective PCE customers (i.e., electricity customers located within the San Mateo Communities).

Section 4: Cost of Service Elements – explains the various costs that would be involved in providing electric service through a CCA program.

Section 5: Cost and Benefits Analysis – details the estimated benefits and financial liabilities associated with a variety of potential resource scenarios with regard to ratepayer costs, GHG impacts, and local economic development impacts.

Section 6: Sensitivity Analyses – describes the variables that are expected to have the largest impact on customer rates and shows the range of impacts associated with key variables.

Section 7: Risk Analysis – highlights key risks associated with the formation and operation of a CCA program, including recommended mitigation measures for such risks.

Section 8: Fully Outsourced CCA Model Assessment – PEA previously completed and delivered this Assessment to the County of San Mateo; the Assessment is incorporated by reference in this Study but is not attached hereto.

Section 9: CCA Formation Activities – summarizes the steps involved in forming a CCA program.

Section 10: Evaluation and Recommendations – summarizes Study results and provides recommendations based on PEA's analysis.

Appendix A: PCE Pro Forma Analyses – includes pro forma operating projections for each of the three PCE supply scenarios addressed in this Study.

SECTION 2: STUDY METHODOLOGY

The analytical framework for the Study is a cost-of-service model that estimates all costs and anticipated revenues that would be incurred/received in providing CCA services. The Study examines projected economic impacts over a ten-year study period. As detailed in Section 4 (Cost of Service Elements), CCA program costs include those associated with energy procurement as well as administrative, financing and other costs that would be involved in the program's formation and ongoing operation. Total projected costs over each twelve-month period represent the amounts that must be funded through program rates, also known as the "revenue requirement." Average generation rates of the CCA program, which are calculated by dividing total program costs (dollars) by total program electricity sales (kilowatt hours, kWh; or megawatt hours, MWh), were determined for each year as well as the entirety of PCE's ten-year study period (ten-year averages were calculated on a levelized basis, as further described below) to facilitate comparisons among potential electric supply mixes and against projected PG&E rates.

The CCA program would have myriad choices with regard to the types of resources that may comprise its electric supply portfolio. Such choices typically focus on the following portfolio attributes: 1) the proportion of renewable and non-renewable, or conventional, generation sources; 2) specification of a portfolio GHG emissions rate; 3) selection of specific generating technologies (solar photovoltaic, wind, geothermal, etc.); 4) identification of resource locations (local, in-state, regional); 5) preferred power supply structure (power purchase agreement or, potentially, asset development/acquisition); 6) determination of resource scale (larger "utility-scale" projects and/or smaller distributed generating resources); and 7) duration of supply commitments (short-, mid-, long-term). Each of these choices presents economic and/or environmental tradeoffs. Specification of such preferences, which is a fundamental component of the resource planning process, typically occurs during the implementation and operation stages by those charged with leading and overseeing the CCA program. As the CCA continues to operate over time, resource planning will remain an ongoing obligation, enabling the CCA to adapt its planning principles to changing circumstances while promoting the CCA program's overarching policy objectives.

For purposes of this Study, PEA developed three representative supply portfolios that were evaluated on the basis of ratepayer cost, renewable energy content, GHG emissions, and economic development impacts. The objective of evaluating alternative supply scenarios is to obtain a robust set of analytical results that can be used to inform decision-makers of the inherent trade-offs that exist among various resource choices while also illustrating a reasonable range of outcomes that could be achieved through CCA implementation and operation. It should be understood that PCE would not be limited to any particular supply scenario assessed in this Study; the supply scenarios reflected in this Study have been developed for the sake of example, taking into consideration key objectives of the aspiring CCA program.

Supply Scenarios

The following supply scenarios are representative of different choices that could be made by PCE with regard to overall renewable energy content, fuel sources and generator locations (of the electric resources used to supply PCE's customers). Each scenario embodies unique portfolio attributes and related ratepayer impacts. Subject to compliance with prevailing law and applicable regulations, California CCAs have a broad range of options when assembling a supply portfolio. The three scenarios discussed in this Study also reflect the inclusion of power supply from both existing generating sources, which may supply the majority of PCE's early stage energy requirements, and new renewable generation projects developed as a result of long-term power purchase agreements entered into by the CCA program, which may play an increasingly prominent role in PCE's mid- and long-term resource planning efforts. *With regard to specific sources of supply that may be incorporated by PCE, PEA was directed to exclude potential purchases from coal-fired and nuclear generating resources (utilized* *by the incumbent IOU) as well as the procurement of unbundled renewable energy certificates from all prospective supply portfolios.* In consideration of this direction, such products were omitted during PCE's portfolio analysis. It is also noteworthy that independent development and ownership of generating resources may also be an available supply alternative for the CCA program over the longer-term planning horizon, following years of successful operations, financial reserve accrual and establishment of general creditworthiness. Because the timing of any significant CCA-sponsored resource development and ownership likely falls outside the planning horizon addressed within this Study, PEA has not incorporated CCA-owned resources as a component of the indicative supply scenarios discussed herein.

With regard to the three prospective PCE supply scenarios addressed in this Study, such scenarios were designed to evaluate a broad range of portfolio characteristics for purposes of demonstrating the inherent tradeoffs that exist when deciding between available resource options. The prospective supply portfolios were also constructed in consideration of certain key objectives that were communicated to PEA on behalf of the San Mateo Communities. These objectives generally focused on the achievement of rate competitiveness, GHG emissions reductions and increased use of renewable energy resources relative to the incumbent utility. For purposes of this Study, each scenario was constructed as follows:

PCE Supply Scenario	**Primary Objectives of Supply Portfolio**	**Total Renewable Energy Content[3] as % of Total Supply (Year 1; Year 10)**	**Anticipated GHG Emissions Savings[4] (Year 1; Year 10)**	**Anticipated PCE Customer Cost Impacts[5] (Year 1; Year 10)**
Scenario 1	Cost/rate competitiveness with incumbent utility	YEAR 1 = 35% YEAR 10 = 43%	YEAR 1 = No YEAR 10 = No	YEAR 1 = Moderate Savings YEAR 10 = Moderate Savings
Scenario 2	Above-RPS renewable energy supply plus GHG emissions reductions (relative to incumbent utility)	YEAR 1 = 50% YEAR 10 = 65%	YEAR 1 = Yes (Moderate) YEAR 10 = Yes (Moderate)	YEAR 1 = Minimal Savings YEAR 10 = Minimal Savings
Scenario 3	100% PCC1 (bundled) renewable energy at prevailing market prices	YEAR 1 = 100% YEAR 10 = 100%	YEAR 1 = Yes (Significant) YEAR 10 = Yes (Significant)	YEAR 1 = Increased Costs YEAR 10 = Increased Costs

Under each of the three supply scenarios, the CCA program would cause new renewable generation projects to be developed through long-term power purchase agreements. It should be recognized that developing generation in California is a difficult and time-consuming process, and developing generation within the San

[3] All renewable energy volumes are assumed to be eligible for use in California's Renewables Portfolio Standard ("RPS") program.
[4] Anticipated GHG emissions impacts were determined in consideration of the GHG emissions factor associated with PCE's assumed resource mix as compared to the assumed emissions factor associated with PG&E's supply portfolio, which is expected to decline throughout the ten-year study period.
[5] Anticipated customer cost impacts were determined in consideration of the projected average PCE customer rate to be paid under each of the three prospective supply scenarios relative to the forecasted average PG&E rate.

Mateo Communities and surrounding areas may be even more difficult than in other parts of the state. Major development challenges include siting, permitting, financing and generator interconnection with the transmission system, all of which may take far longer than originally planned. Suitable sites must be identified and placed under control of the developer, and the required land can be quite significant, particularly for photovoltaic solar projects.[6] It is also common for proposed generating projects to draw opposition from local residents and interest groups, who may identify various objections to the project (e.g., habitat destruction/displacement, visual impacts and species mortality). Once a suitable site is secured and the necessary permits are in place, the project must be financed, and that financing will primarily depend upon the perceived creditworthiness of the CCA program, which may take several years to build. As previously noted, PEA has assumed that during the ten year study horizon, generation projects would be developed and financed by third parties under long-term power purchase agreements with PCE.

For purposes of this Study, an indicative long-term renewable energy contract portfolio, which emphasizes resource and delivery profile diversity in consideration of reasonably available project opportunities, was assembled for the PCE program. This indicative long-term contract portfolio was applied when analyzing each of the three supply scenarios for purposes of determining the resource planning and financial impacts associated with long-term power supply commitments that could be reasonably pursued by PCE. As reflected in the following table, the indicative supply portfolio phases in a variety of contracting opportunities over time, allowing the CCA program to incrementally increase long-term renewable supply commitments without unnecessarily exposing PCE to renewable energy price risk at a single point in time – this is both a prudent resource and risk management practice in consideration of recent, ongoing price reductions that have been observed by California's renewable energy buyers. The incremental ramp up in contracted renewable energy volumes will also serve the purpose of mitigating credit concerns that may impact the CCA program during early operations and limit the pace at which new long term resource commitments can be made. Based on PEA's experience, California's three operating CCAs, MCE, SCP and LCE, have been successful in pursuing small- (1 to 5 MWs in size) to mid-sized (5-40 MWs in size) renewable energy contracting opportunities during early operations – the developers/owners for such projects have been able to reconcile credit concerns in consideration of the CCA's projected operating results and/or relatively nominal collateral postings. PEA expects that PCE would have a similar experience when pursuing available renewable project options. For example, prior to commencing operations and in the 24 to 36 months thereafter, it is expected that PCE would be able to secure long-term contract commitments with both small- and mid-sized renewable project opportunities on the basis of PCE's projected operating results. California's other operating CCAs have generally been able to pursue similar opportunities with little to no collateral obligations (utilizing the respective CCA's pro forma operating projections as the basis for creditworthiness). After establishing a successful operating track record, PCE should be effective in pursuing larger-scale project opportunities, which may prove to be more cost competitive. PEA expects that larger-scale projects may be available following the accrual of three or more years of successful operating history, including the accumulation of prudent financial reserves and the demonstration of significant customer retention – in general, the opt-out structure provided for by California's CCA legislation is viewed as a risk by many prospective project developers and energy sellers; however, the successful operating track record of California's existing CCAs and the ongoing compilation of data related to customer participation/retention has provided compelling evidence that CCA customer counts and overall program operations will remain stable over time.

The indicative portfolio of long-term renewable energy contracts also reflects a significant commitment to renewable project development within the County – a total of 20 MWs of anticipated feed-in tariff ("FIT")

[6] Each MW of PV capacity requires approximately five to eight acres, depending upon the location and installation characteristics.

projects has been included in the Study in consideration of the San Mateo Communities' interest in promoting local renewable infrastructure buildout and economic development. FIT projects are typically smaller-scale renewable development opportunities, ranging from 50 kW to 1.5 MW in size, so PEA has assumed that numerous projects will comprise the 20 MW allocation reflected in the indicative resource mix.

For purposes of the Study, PEA has assumed a uniform portfolio of long-term renewable energy contracts for each of the three indicative supply scenarios. In practical terms, this means that each of the prospective supply scenarios reflects the resource mix described below as well as varying amounts of shorter-term renewable energy purchases to fulfill each scenario's specified renewable resource mix. Assumed prices for such long-term transactions as well as associated capacity factors, which reflect the amount of energy produced by each resource relative to its total, potential generating capacity, were also assembled by PEA in consideration of recent renewable energy transactions and typical operating characteristics associated with the noted renewable resource types. It is also noteworthy that PEA's pricing assumptions reflect significant planned reductions in the federal investment tax credit ("ITC"), which is expected to decrease from 30% to 10% for projects with initial delivery dates occurring after December 31, 2016, as well as growing demand for new renewable energy projects resulting from California's RPS procurement mandate increasing to 50% by 2030[7] – both of these considerations may impose upward pressure on renewable energy pricing. PEA has addressed this possibility through relatively conservative price assumptions when compared to the current market for renewable energy products. It is possible, of course, that Congress could extend the ITC at its current level, which would mean prices for solar power would be lower than the assumptions used in this study. It is also possible that increased demand, while applying upward pricing pressure in the near term, may promote expanded supply capabilities, which would have the effect of mitigating such price pressures over time. The specific contracting opportunities, which have been incorporated in PCE's indicative long-term renewable energy supply portfolio, are identified in the following table.

Resource Type	Year of First Delivery	Capacity (MW)	Capacity Factor	Assumed Price ($/MWh)*	Annual Capacity Degradation
Solar PV, utility scale	2019	100	30%	$65	1%
Solar PV, utility scale	2025	100	30%	$65	1%
Wind	2020	100	35%	$70	0%
Landfill Gas to Energy	2020	10	90%	$80	1%
Geothermal	2018	45	100%	$80	0%
Solar PV, multiple FIT (local) projects	2018	5	22%	$100	1%

[7] On September 11, 2015, the California legislature concurred with proposed amendments to Senate Bill 350, the Clean Energy and Pollution Reduction Act of 2015, and recommended this bill for enrolling. If signed, SB 350 would increase California's RPS to 50% by 2030 amongst other clean-energy initiatives. To enact the provisions of SB 350, Governor Brown must sign the bill by October 11, 2015. If signed, many details regarding implementation of SB 350 will be developed over time with oversight by applicable regulatory agencies.

Resource Type	Year of First Delivery	Capacity (MW)	Capacity Factor	Assumed Price ($/MWh)*	Annual Capacity Degradation
Solar PV, multiple FIT (local) projects	2020	5	24%	$90	1%
Solar PV, multiple FIT (local) projects	2021	5	24%	$90	1%
Solar PV, multiple FIT (local) projects	2022	5	24%	$90	1%

*Certain pricing assumptions reflect planned reductions to currently applicable incentives, which may result in increased renewable energy prices during the ten-year planning period. To the extent that such incentives are continued at current levels and/or supply significantly increases, actual prices could be lower than reflected herein. It is important to note that a broad range of considerations, including the assumed increase in California's RPS to 50% by 2030, may influence renewable energy pricing and product availability in future years.

When considering the portfolio composition associated with PCE's prospective supply scenarios, it is important to note that several resource types, including clean (e.g., renewable and GHG-free) and conventional (e.g., fossil-fueled, which typically entails the use of natural gas within California) energy sources, would be available to PCE. With regard to renewable energy product options, California's currently effective RPS program allows for the use of three distinct renewable energy products, which are primarily differentiated by uniquely defined delivery attributes. In particular, certain RPS-eligible renewable energy products are referred to as "bundled renewable energy," meaning that the physical electricity and renewable attributes associated with specified quantities of renewable generation are both sold/delivered to the buyer, whereas other RPS-eligible products are referred to as "unbundled," meaning that the renewable attributes are sold separately from the electric commodity. Under the nomenclature of California's RPS, bundled renewable energy products are categorized as Portfolio Content Category 1 ("PCC1" or "Bucket 1") or Portfolio Content Category 2 ("PCC2" or "Bucket 2"). In general terms, PCC1 products are the most costly, least objectionable and offer the most flexibility when complying with California's RPS procurement mandates. Unbundled renewable energy, or Portfolio Content Category 3 ("PCC3" or "Bucket 3"), has usage limitations under the RPS program and is also the subject of ongoing philosophical debate regarding environmental impacts. For purposes of this Study, PEA was advised to exclude unbundled renewable energy products from PCE's prospective supply portfolios. For purposes of this Study, it was assumed that all additional GHG-free energy (i.e., GHG-free energy obtained from sources that are not RPS-eligible due to size limitations) would be produced/delivered by hydroelectric generators. In consideration of these product options, PCE's three prospective supply scenarios were constructed with the following resource preferences.

PCE Supply Scenario	Primary Objectives of Supply Portfolio	Total Renewable Energy Content[8] as % of Total Supply (Year 1; Year 10)	Total PCC1-Eligible[9] Renewable Energy Content as % of Total Supply (Year 1; year 10)	Total PCC3-Eligible[10] Renewable Energy Content as % of Total Supply (Year 1; year 10)	Total GHG-Free Energy Content[11] as % of Total Supply (Year 1; Year 10)
Scenario 1	Cost/rate competitiveness with incumbent utility	YEAR 1 = 35% YEAR 10 = 43%	YEAR 1 = 29% YEAR 10 = 39%	YEAR 1 = None YEAR 10 = None	YEAR 1 = 35% YEAR 10 = 43%
Scenario 2	Above-RPS renewable energy supply plus GHG emissions reductions (relative to incumbent utility)	YEAR 1 = 50% YEAR 10 = 65%	YEAR 1 = 44% YEAR 10 = 60%	YEAR 1 = None YEAR 10 = None	YEAR 1 = 63% YEAR 10 = 75%
Scenario 3	100% PCC1 (bundled) renewable energy at prevailing market prices	YEAR 1 = 100% YEAR 10 = 100%	YEAR 1 = 94% YEAR 10 = 100%	YEAR 1 = None YEAR 10 = None	YEAR 1 = 100% YEAR 10 = 100%

[8] All renewable energy volumes are assumed to be RPS-eligible for purposes of this Study.
[9] Portfolio Content Category 1, or "Bucket 1" eligible renewable energy resources, are typically located within California but may also be located outside California, delivering power to California delivery points via specified energy scheduling protocols.
[10] Portfolio Content Category 3, or "Bucket 3" eligible renewable energy resources, are typically referred to as "unbundled renewable energy certificates" or "unbundled RECs". Bucket 3 products are produced when metered renewable energy is delivered to the grid and represent the environmental and/or "green attributes" associated with such renewable energy production. However, Bucket 3 products are sold separately from the physical energy commodity without any associated energy delivery obligations for the seller(s) of such products.
[11] Total GHG-free content equals the proportion of total supply produced by renewable energy resources plus the proportion of total supply produced by non-GHG emitting generating resources, namely non-RPS qualifying hydroelectric generators.

Scenario 1: Maximize Rate Competitiveness while Minimally Exceeding RPS Mandates

Scenario 1 was structured for the primary purpose of promoting rate competitiveness with PG&E. With regard to renewable energy procurement, resource preferences within Scenario 1 were generally selected to promote compliance with the legal requirements of California's RPS in advance of applicable deadlines.[12] In particular, Scenario 1 incorporates a 35% RPS-eligible renewable energy supply from day one of CCA program operations, incrementally increasing after the 2020 calendar year in consideration of California's transition to a 50% RPS mandate. For purposes of Scenario 1, PCC3 and nuclear volumes were excluded from the renewable energy supply portfolio, replacing such volumes with additional PCC1 and PCC2 products. This substitution has the effect of increasing total renewable energy supply costs but will likely minimize philosophical objections related to the use of unbundled renewable energy products, which have become more prominent in recent years. Additional clean energy purchases, which would have the effect of reducing overall portfolio GHG emissions, were not considered in an effort to hold down costs, and related customer rates, to the lowest possible levels. A supply portfolio reflecting such a resource mix would be expected to offer among the lowest ratepayer costs during the study period but also the lowest level of environmental benefits. The expected clean energy content associated with Scenario 1 is identified in the following tables, which reflect the proportionate share of purchases relative to PCE's expected energy requirements.

Scenario 1: Proportionate Share of Planned Energy Purchases Relative to PCE's Projected Retail Sales

	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
PCC 1 Supply	26%	26%	26%	33%	32%	32%	31%	31%	38%	38%
PCC 2 Supply	9%	9%	9%	2%	3%	5%	7%	9%	3%	5%
PCC 3 Supply	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total Renewable Energy Supply	**35%**	**35%**	**35%**	**35%**	**35%**	**36%**	**38%**	**40%**	**42%**	**43%**
Additional GHG-Free Energy Supply	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total Clean Energy Supply	**35%**	**35%**	**35%**	**35%**	**35%**	**36%**	**38%**	**40%**	**42%**	**43%**

[12] State law requires PG&E to increase its renewable energy content to 33% by 2020. Based on PG&E's recent Power Source Disclosure Report, which addressed power purchases and sales completed by the utility during the 2014 calendar year, its current renewable energy content is approximately 27%. An equivalent renewable supply percentage should be reflected in PG&E's 2014 Power Content Label, which will be provided to customers of the utility later this year.

	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Conventional Energy Supply (including CAISO* market purchases)	**65%**	**65%**	**65%**	**65%**	**65%**	**64%**	**62%**	**60%**	**59%**	**57%**

*"CAISO" refers to the California Independent System Operator, the organization responsible for overseeing operation of California's wholesale electric transmission system and related energy markets.

As previously noted, each indicative supply scenario reflects a uniform portfolio of long-term renewable energy supply contracts, which incorporates a variety of generating technologies and related energy delivery profiles. In consideration of the expected delivery start dates and energy quantities associated with each prospective contract, PCE's portfolio composition will somewhat change over time, reflecting increased resource diversity.

Snapshots of the Scenario 1, Year 1 resource mix as well as the related Year 10 resource mix are shown in the following figures.

Figure 1: Scenario 1 Resource Mix, Year 1

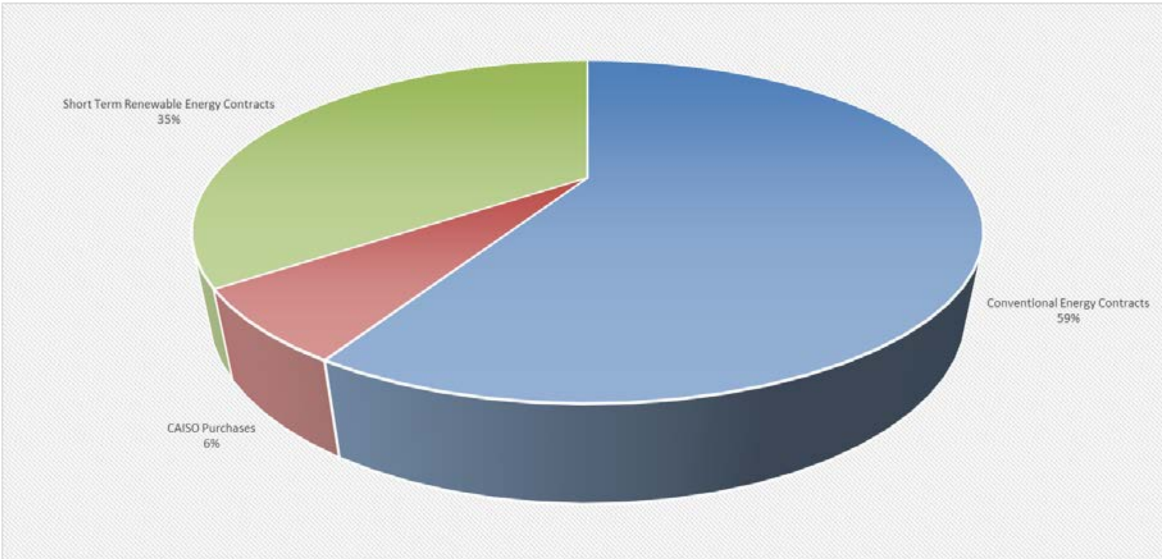


Figure 2: Scenario 1 Resource Mix, Year 10

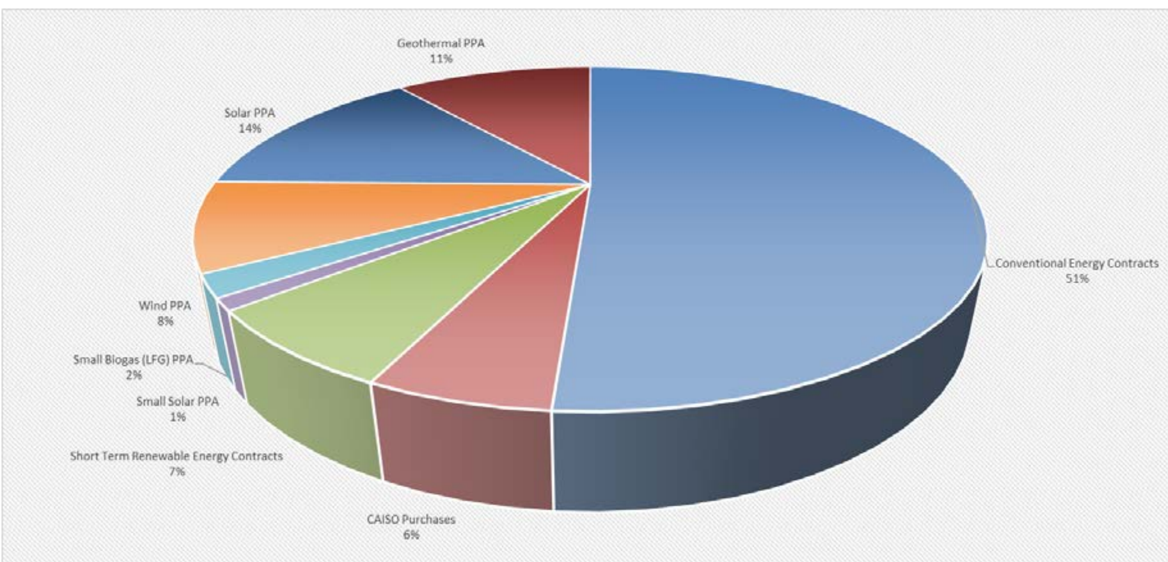
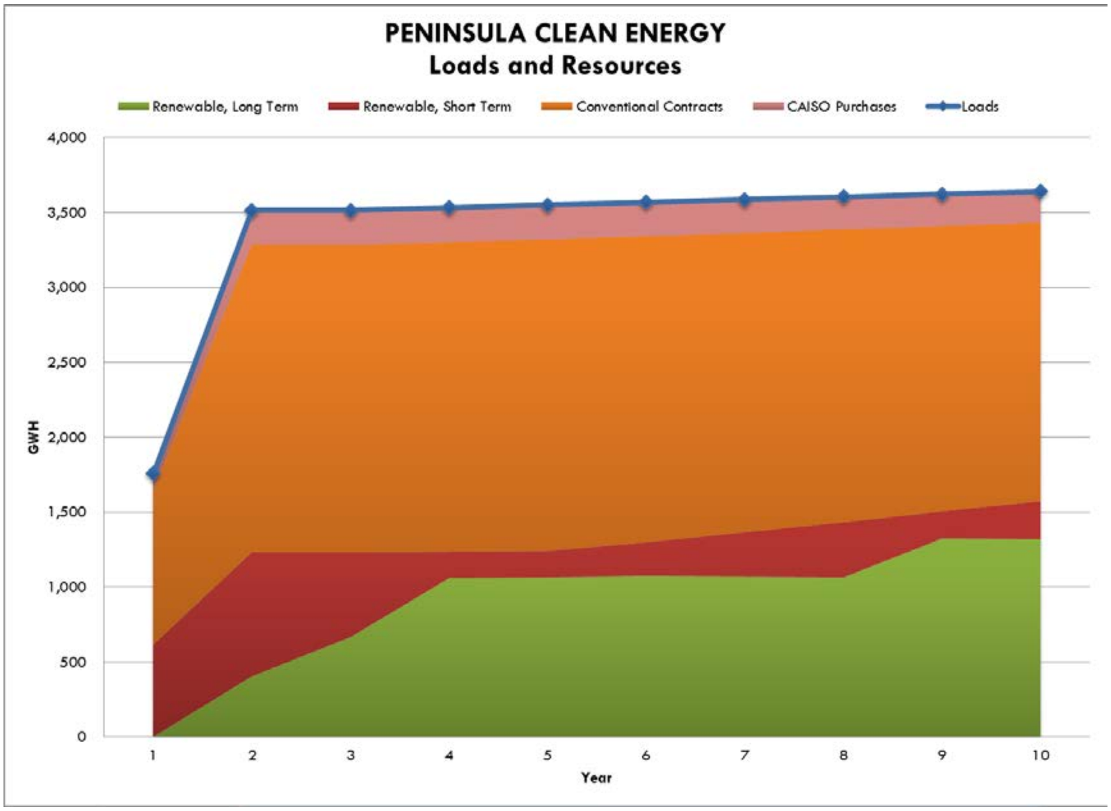


Figure 3 shows how composition of the Scenario 1 supply portfolio changes throughout the study period, reflecting planned diversification of PCE's renewable energy supply portfolio through long-term contracting efforts and local infrastructure build out.

Figure 3: Scenario 1 Load and Resource Projections



Scenario 2: Minimum 50% Renewable Energy Content plus Net GHG Reductions

Scenario 2 reflects more aggressive procurement of renewable energy resources, starting out at a 50% RPS-eligible renewable energy content, increasing to 65% by Year 10 of program operations. This renewable energy procurement strategy ensures that PCE will continually exceed California's RPS mandate, even following recent adoption of the 50% renewable energy procurement requirement. In addition to the noted renewable energy volumes, Scenario 2 assumes that PCE will procure additional GHG-free energy supply to promote the delivery of a resource mix that demonstrates a projected emissions factor that is below PG&E's projected metrics. As with Scenario 1, the Scenario 2 supply portfolio excludes the use of PCC3 products and nuclear power.

Scenario 2: Proportionate Share of Planned Energy Purchases Relative to PCE's Projected Retail Sales

	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
PCC 1 Supply	38%	38%	38%	44%	45%	46%	46%	46%	54%	54%
PCC 2 Supply	13%	13%	13%	6%	8%	9%	11%	14%	8%	11%
PCC 3 Supply	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total Renewable Energy Supply	**50%**	**50%**	**50%**	**50%**	**53%**	**55%**	**58%**	**60%**	**63%**	**65%**

	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
Additional GHG-Free Energy Supply	23%	25%	28%	29%	28%	26%	25%	23%	21%	20%
Total Clean Energy Supply	**73%**	**75%**	**78%**	**79%**	**80%**	**81%**	**82%**	**83%**	**84%**	**85%**
Conventional Energy Supply (including CAISO market purchases)	**27%**	**25%**	**22%**	**21%**	**20%**	**19%**	**18%**	**17%**	**16%**	**15%**

Figure 4: Scenario 2 Resource Mix, Year 1

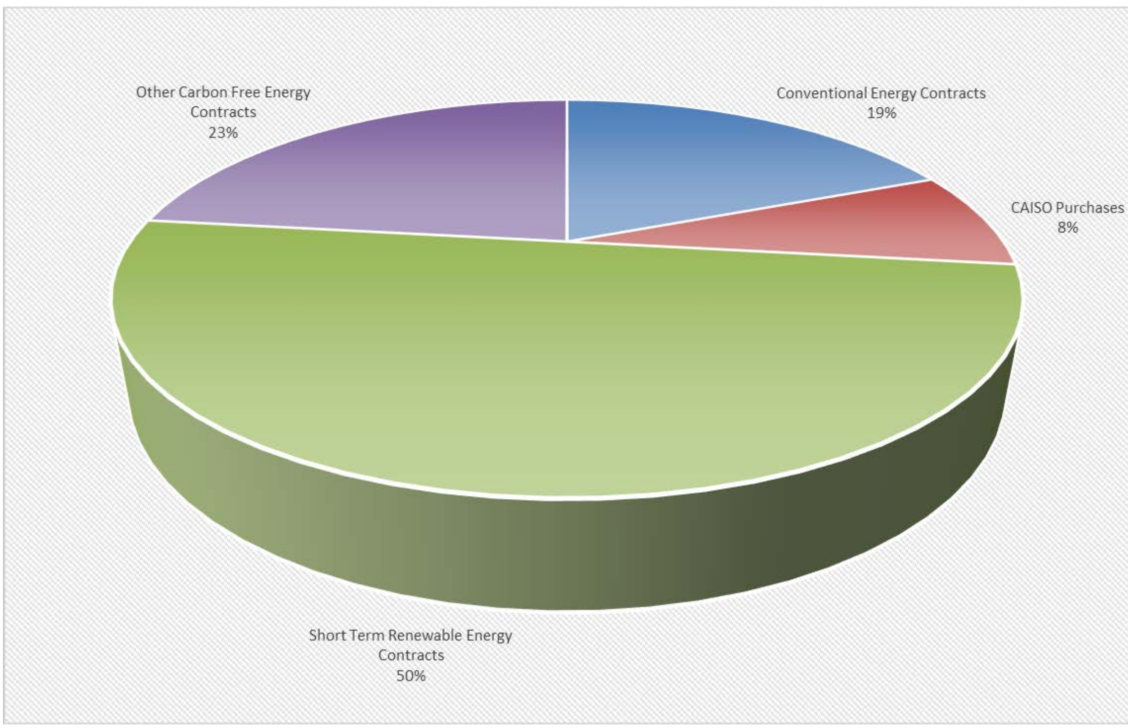


Figure 5: Scenario 2 Resource Mix, Year 10

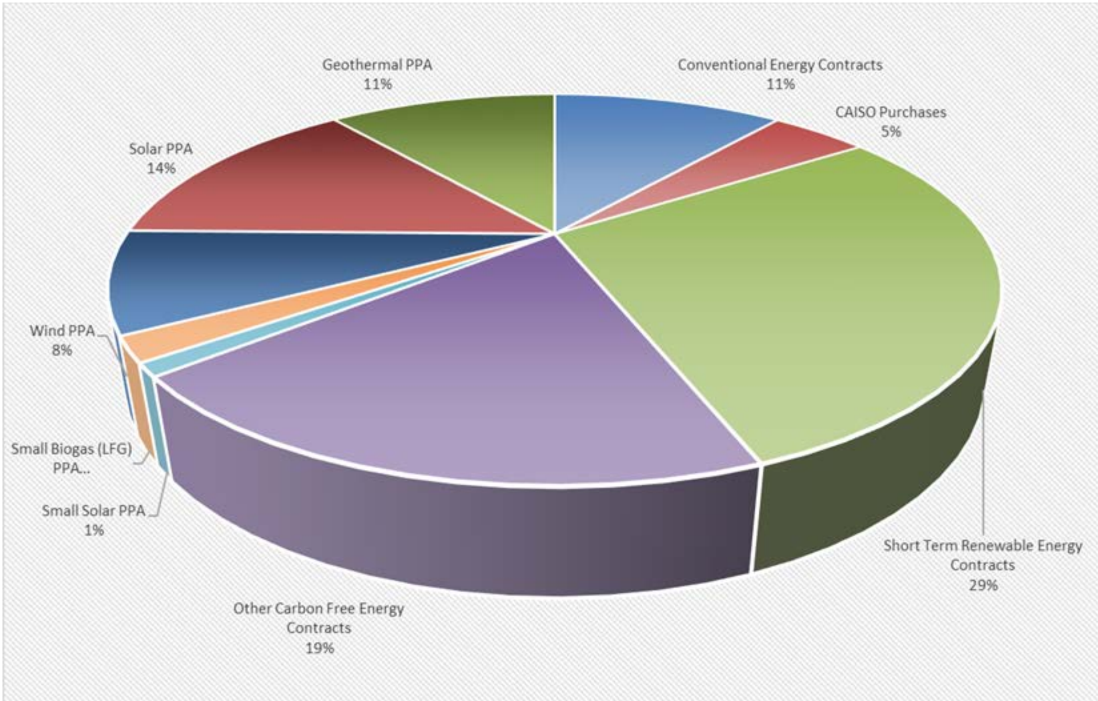
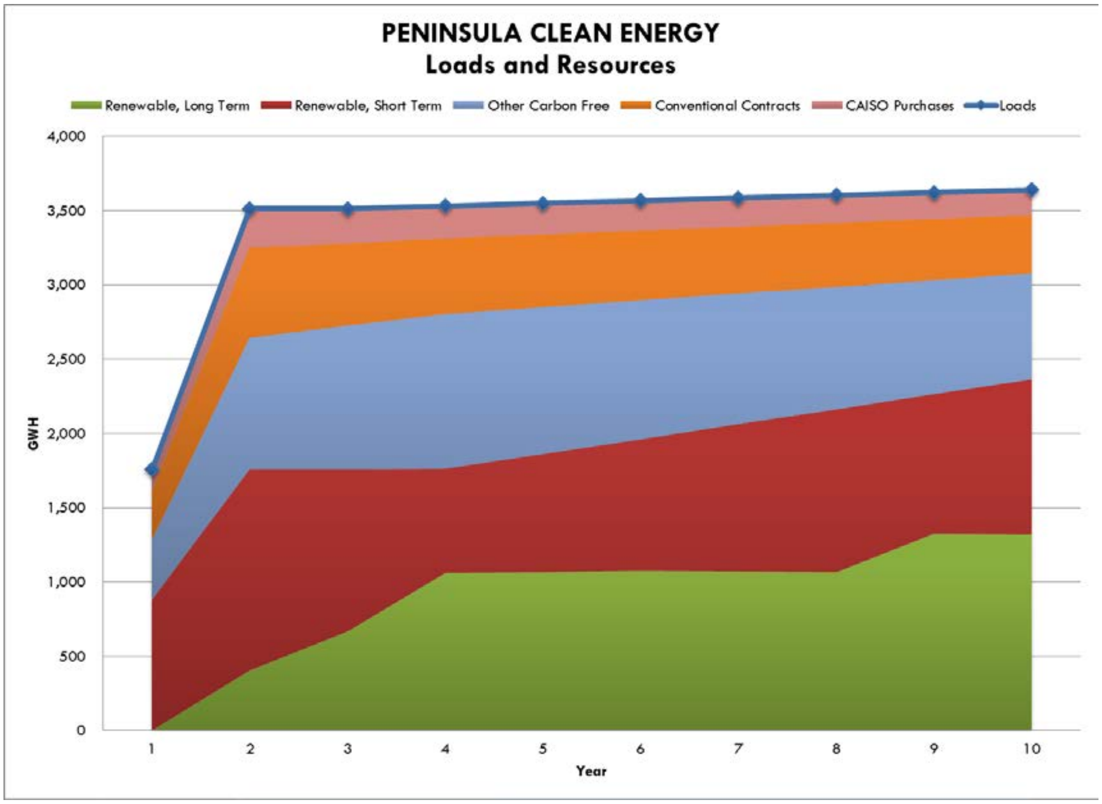


Figure 6 shows how composition of the Scenario 2 supply portfolio changes throughout the study period.

Figure 6: Scenario 2 Load and Resource Projections



Scenario 3: 100% Renewable Energy Content

Scenario 3 represents a supply portfolio that relies entirely on renewable energy throughout the study period, relying on a mix of shorter- and longer-term supply agreements to achieve this objective. PCC3 and nuclear power products are not incorporated in this supply scenario, resulting in the exclusive use of bundled renewable energy products (e.g., PCC1 and PCC2). As a result of this planning strategy, the GHG emissions associated with Scenario 3 are assumed to be zero. It is also noteworthy that the exclusive use of bundled renewable energy products results in comparatively higher costs relative to PG&E, which is expected to reduce customer participation below the assumed levels reflected in Scenario 1 and Scenario 2. As a result of this assumption, annual electric energy requirements of the PCE program fall below similar levels reflected in Scenario 1 and Scenario 2 – in particular, Year 1 energy requirements under Scenario 3 are expected to be approximately 1,000 GWh lower relative to Scenarios 1 and 2; annual energy requirements are also expected to decline over time as customer attrition, following ongoing bill/cost reviews and increased awareness regarding the PCE program, occurs throughout the study period. With regard to Scenario 3, it is also assumed that CARE customers within the San Mateo Communities will continue to receive applicable discounts, as provided through the incumbent utility's distribution rates. However, the basic generation rate under Scenario 3, which will be subject to the aforementioned CARE discount, will be somewhat higher than PG&E's projected generation rate, as described below. Based on this observation, PCE may choose to reset applicable CARE rates under Scenario 3 to avoid the imposition of higher costs on this customer group. To the extent that applicable CARE rates are more heavily discounted under Scenario 3, it is assumed that other, non-CARE rates would marginally increase (above projections reflected in this subsection). This expected outcome is illustrated in the following figures.

Scenario 3: Proportionate Share of Planned Energy Purchases Relative to PCE's Projected Retail Sales

	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10
PCC 1 Supply	75%	75%	79%	86%	86%	86%	86%	86%	89%	89%
PCC 2 Supply	25%	25%	21%	14%	14%	14%	14%	14%	11%	11%
PCC 3 Supply	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total Renewable Energy Supply	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Additional GHG-Free Energy Supply	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total Clean Energy Supply	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
Conventional Energy Supply (including CAISO market purchases)	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**

Figure 7: Scenario 3 Resource Mix, Year 1

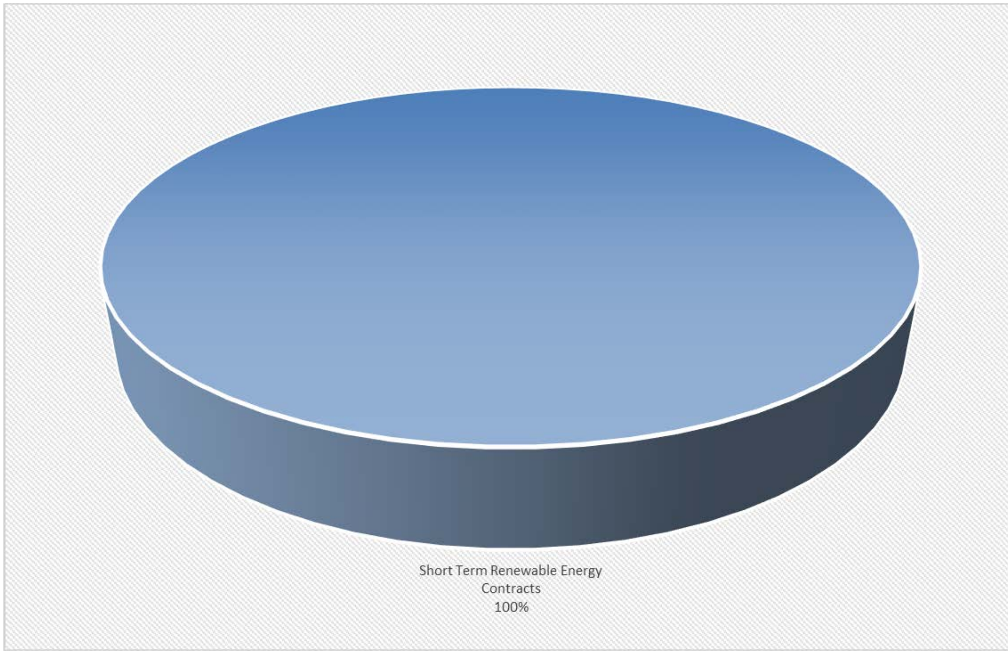


Figure 8: Scenario 3 Resource Mix, Year 10

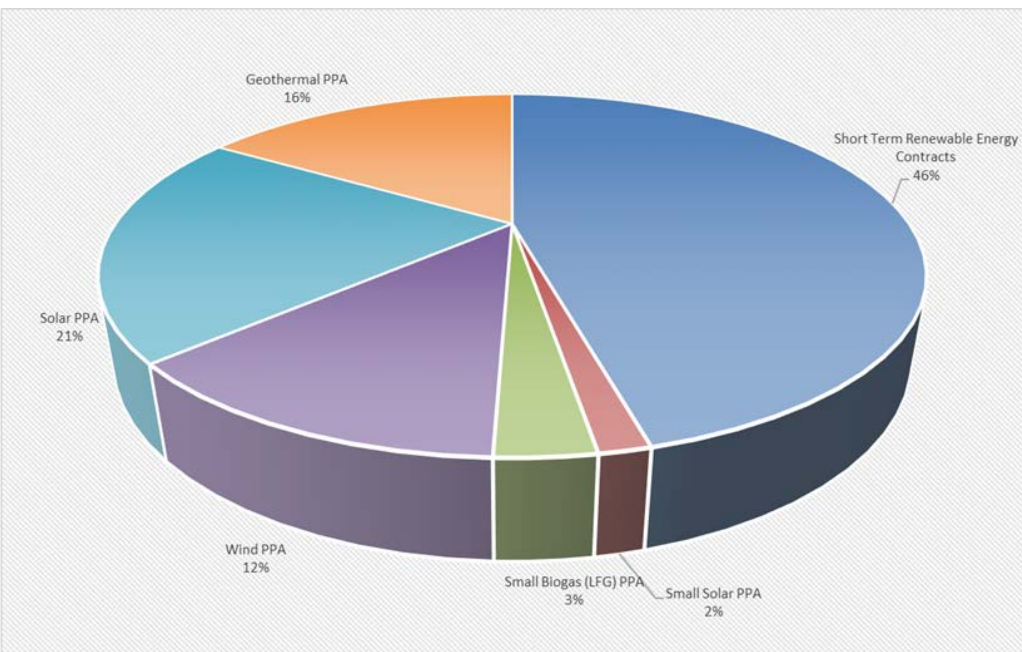
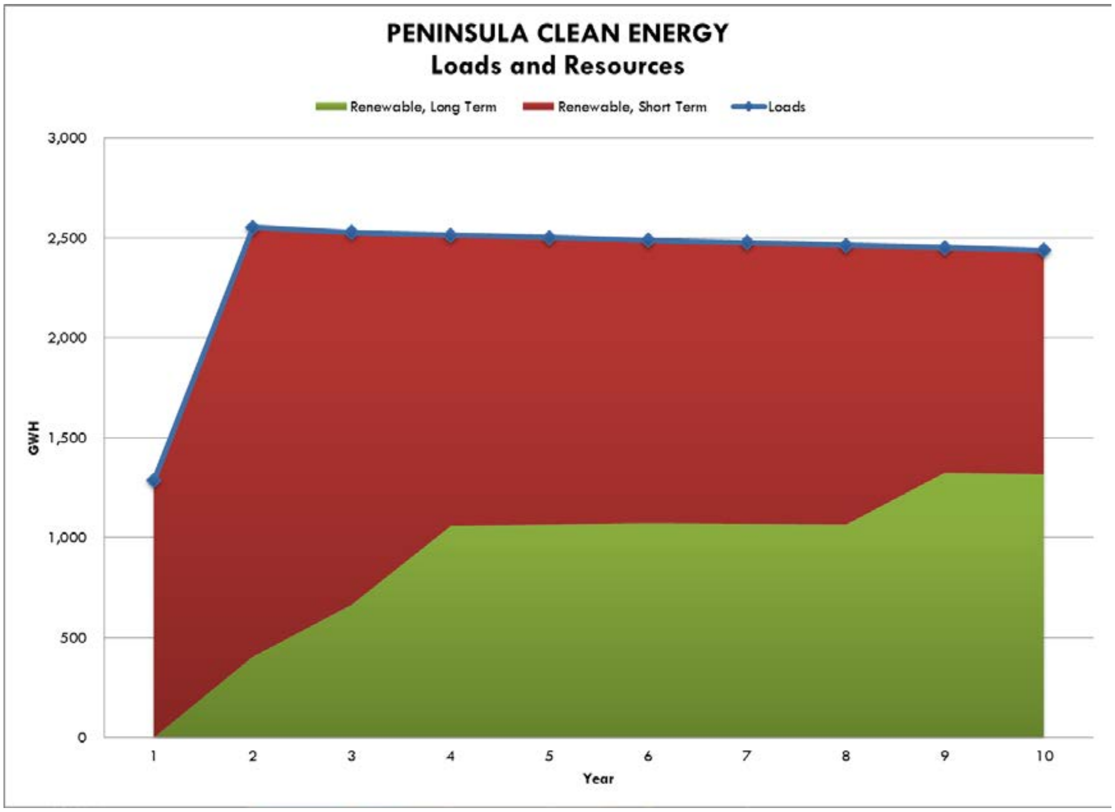


Figure 9 shows how composition of the Scenario 3 supply portfolio changes throughout the study period.

Figure 9: Scenario 3 Load and Resource Projections



Costs and Rates

For each supply scenario, detailed cost estimates were made for the electric power supply costs and all other program costs. Net ratepayer costs or benefits were calculated for each scenario as the difference between the costs ratepayers would pay while taking service under the CCA program and the costs ratepayers would pay under bundled service, as currently provided by PG&E. Competitive rates are a key metric for program feasibility as PCE must offer competitive rates in order to retain customers that are automatically enrolled in the program. Customer retention may also be affected by PCE offering customized rate choices such as voluntary green pricing programs or market based rate options for large end users.[13] Certain communities may be interested in defaulting customers to a 100% renewable energy supply option with the ability to opt down to the prevailing PCE resource mix. As previously discussed, the anticipated higher costs of a 100% renewable service option may affect customer participation rates. In addition, PCE's administrative costs and communication obligations would likely increase as result of administering two default service offerings.

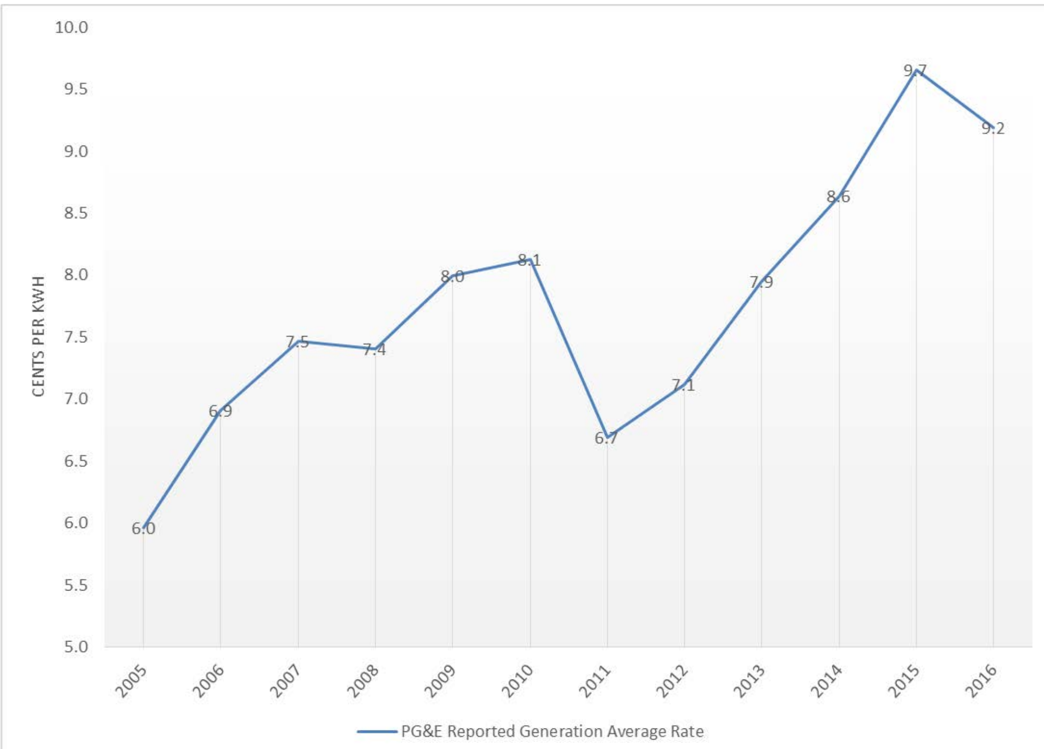
Rate competiveness is particularly important during the first year, when opt out notices are being provided to eligible customers and initial impressions are being formed in the community. Generally speaking, if the net cost to the customer of PCE service is below what the customer would pay for PG&E bundled service, the PCE program can be considered to offer competitive rates and would be feasible. Rates that provide for a modest

[13] Such customized rate options would require PCE design and administration, working collaboratively with customers and interested stakeholders. Green pricing participation may also improve PCE's environmental benefits and overall renewable energy content.

cost increase may also be considered competitive, if the attributes of the electric service being offered are perceived as superior to the electric service offered by PG&E. For instance, a materially higher renewable energy content and/or lower carbon intensity for the electricity sold by PCE may justify a higher price, and PCE rates may be competitive if they are within a defined range of PG&E's.

Historically, PG&E generation rates have trended upwards as shown in Figure 10, but the recent decline in wholesale energy costs are expected to result in lower generation rates beginning in 2016. When reviewing the following figure, it is important to note that myriad factors can influence power prices over time, including weather patterns and natural disasters, infrastructure outages, natural gas storage levels and other considerations. All of these factors contribute to the volatile nature of electric power prices.

Figure 10: PG&E System Average Generation Rates



The primary measure of ratepayer costs calculated for this study is the difference in total electric rates between the CCA program and PG&E. This measure examines the change in customers' total electric bills, including PG&E delivery charges and PG&E surcharges (namely, "exit fees" associated with PG&E's uneconomic generation commitments). In order to compare ratepayer costs over the ten-year study period, during which electric rates change from year-to-year, PEA calculated levelized electric rates on a per kWh basis for each PCE supply scenario and for PG&E bundled service. In simple terms, a levelized rate allows for the comparative evaluation of a multi-year period through the use of a single value or metric, which reflects the year-over-year changes that may occur over such period of time. The development of a levelized electric rate utilizes net present value analysis to consolidate rate-related impacts, which occur over time, in a single number. For purposes of this Study, a levelized rate represent the constant electric rate that would yield equivalent revenues (in present value terms) if charged to customers in place of the projected series of annual rates occurring throughout the ten-year study period. Levelized costs are commonly used in the electric utility industry to provide an apples-to-apples comparative basis for projects that have cash flows occurring at different points in time. Comparing levelized total electric rates for the CCA program against levelized total electric rates for PG&E service provides a simple measure of ratepayer impacts over the entire ten-year study period. Annual impacts are also provided for each scenario and provide a more detailed picture of ratepayer impacts from year to year of program operations.

Greenhouse Gas Emissions

Each supply scenario was evaluated based on the emissions of greenhouse gases associated with electricity production as compared to similar projections prepared by PG&E (for its own supply portfolio). Based on PEA's review of PG&E's projected annual GHG emissions factors, which have been prepared through calendar year 2020, consideration appears to have been given to the impacts of California's increasing RPS procurement mandates. PG&E's projected emissions factor steadily declines through the 2020 calendar year as additional renewable energy purchases and other prospective clean-energy purchases increase with time. PG&E's GHG emissions factor projections for the five-year period beginning in 2016 through 2020 is identified in the following table[14]:

Year	Emission Factor (lbs CO_2/MWh)	Emission Factor (Metric Tons CO_2/MWh)
2016	370	0.168
2017	349	0.158
2018	328	0.149
2019	307	0.139
2020	290	0.131

For the balance of the ten-year study period, PEA assumed incremental emission reductions for the PG&E supply portfolio in consideration of increases to California's RPS procurement mandate and other factors, such as the launch of other California-based CCA programs, which may have the effect of reducing PG&E GHG emissions factor (via reductions in short term conventional energy purchases due to declining retail sales).[15] PEA's assumed annual GHG emissions factors for the PG&E supply portfolio, over the balance of the ten-year study period, are reflected in the following table:

[14] PG&E, Greenhouse Gas Emission Factors: Guidance for PG&E Customers, April 2013.

[15] In practical terms, it is not likely that PG&E would materially adjust renewable energy purchases or reduce carbon-free generation (from its hydroelectric and/or nuclear generators) as a result of customer departure following PCE formation. These carbon-free resources would generally remain in the PG&E supply portfolio without near-term adjustments for departing load. Instead, it is more likely that PG&E would reduce the amount of conventional market purchases with comparatively high emissions intensities, which would have the effect of marginally reducing its portfolio emissions factor following customer departures as the relative proportion of clean energy sources in the PG&E supply portfolio would incrementally increase.

Year	Emission Factor (lbs CO_2/MWh)	Emission Factor (Metric Tons CO_2/MWh)
2021	280	0.127
2022	272	0.123
2023	264	0.120
2024	256	0.116
2025	248	0.112

The PG&E emission profile was selected as the benchmark for comparison to promote a conservative assessment of direct emissions impacts related to CCA operations (on a head-to-head basis with PG&E's anticipated supply portfolio). The GHG impacts associated with PCE's supply portfolio will likely be evaluated (by members of the public and, potentially, through new emissions reporting requirements that may be incorporated in annual Power Content Label, or "PCL", reporting) relative to the PG&E benchmark, which suggests that the aforementioned comparative methodology is appropriate.

For each supply scenario, the difference in GHG emissions produced by the scenario's assumed resource mix and the otherwise applicable PG&E supply portfolio were quantified during each year as well as the entirety of the ten-year study period. The GHG impacts were quantified in terms of total tons of CO_2 emissions.

Economic Development Impacts

A key potential benefit of a CCA program is its ability to promote economic development through investment in and contracts with locally constructed renewable generating infrastructure. Such projects have the potential to stimulate a significant level of new economic activity within California by creating new jobs and spending activities during generator construction, ongoing operation and maintenance. Economic development impacts may also be significant factors when comparing expected operating costs, including generation costs, of the CCA program to electric generation costs under PG&E service, particularly when initial "head-to-head" cost comparisons are comparable. When performing such comparisons, it is important to acknowledge the difficulty in accurately quantifying actual economic benefits related to local project investment, particularly induced economic impacts resulting from the effects of economic multipliers.

In qualitative terms, it is reasonable to assume that new development projects would stimulate new economic activity. However, as with any capital project, quantifying the specific location in which such economic benefits may occur, including job creation, is challenging due to numerous uncertainties affecting the proportion of expenditures and employment that would occur within discretely defined geographic boundaries. Certain tools, which rely on the application of industry-specific economic multipliers, have been developed to assist in completing these projections, but decision makers should be aware of the broad range of outcomes that may actually apply when interpreting analytical results.

To quantify the economic impacts associated with new renewable generation projects that were incorporated in the indicative long-term renewable energy supply portfolio that was applied in each of the three energy supply scenarios, PEA utilized the National Renewable Energy Laboratory's ("NREL") Jobs & Economic Development Impact ("JEDI") models. NREL is the principal research laboratory for the United States Department of Energy ("DOE") Office of Energy Efficiency and Renewable Energy and also provides research expertise for the Office of Science, and the Office of Electricity Delivery and Energy Reliability. NREL is operated for DOE by the Alliance for Sustainable Energy, LLC.[16]

NREL JEDI models are publicly available, spreadsheet-based tools that were specifically designed to "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. Based on user-entered project-specific data or default inputs (derived from industry norms), JEDI estimates the number of jobs and economic impacts to a local area that can reasonably be supported by a power plant, fuel production facility, or other project."[17] Unique JEDI models have been developed for a variety of resource types, including wind, solar, geothermal, biogas and various other generating technologies. Each version of the model may be downloaded free of charge from NREL's website: http://www.nrel.gov/analysis/jedi/download.html.

According to NREL, the JEDI models are peer reviewed and are intended to project gross job estimates. NREL also notes that it "performed extensive interviews with power generation project developers, state tax representatives, and others in the appropriate industries to determine appropriate default values contained within the models." In PEA's opinion, NREL's JEDI models are the appropriate tools to forecast "order of magnitude" local economic development impacts associated with a CCA program serving the San Mateo Communities.

Based on the aforementioned indicative long-term renewable energy contract portfolio that was assumed to exist under each of the three supply scenarios, PEA downloaded, populated and ran the appropriate JEDI models to derive estimates of the anticipated jobs and economic development impacts that could be created in relation to the indicative long-term contract portfolio. PEA utilized each set of economic development projections to assemble an aggregate economic impact analysis for the complete long-term contract portfolio. However, all economic development estimates within this report are presented with the understanding that subtle changes in certain expenditures (and jobs) may result in significant changes to actual economic development impacts.

Key output from the JEDI models is presented within three specific categories: jobs, earnings and economic output. Within each of these broadly defined categories, JEDI models approximate the impacts of economic multipliers by quantifying the "ripple effect" that occurs as a result of new local economic activity. JEDI models initially estimate direct economic impacts at the project site and apply economic multipliers, derived from the U.S. Bureau of Economic Analysis, the U.S. Census Bureau and other sources, to approximate impacts within the supply chain (manufacturing job creation, as an example) as well as induced economic impacts (spending that occurs as a result of activity within the first two categories) related to the project. JEDI models also address job creation and economic impacts on a temporal basis, quantifying related impacts during two specific phases of the project lifecycle: 1) construction; and 2) ongoing operation and maintenance.

Forecasted economic impacts associated with the indicative long-term contract portfolio are presented in aggregate form, inclusive of all anticipated development/contract opportunities, by summing the project-specific impacts calculated by the JEDI models. This approach facilitates a high-level understanding of the prospective economic impacts that could be created through such contracts but does not address temporal nuance related to the timing and receipt of economic benefits associated with specific projects. For example, the unique economic impacts of projects that will begin operation/delivery during the period extending from 2018 through 2025 have been aggregated and presented within a single scenario-specific summary table.

When reviewing economic development projections within this Study, it is important to distinguish between economic impacts related to the construction period and the ongoing operation and maintenance period. All

[16] National Renewable Energy Laboratory website, http://www.nrel.gov/about/, September 2, 2015.
[17] National Renewable Energy Laboratory website: http://www.nrel.gov/analysis/jedi/about_jedi.html, September 2, 2015.

job creation estimates are presented as full time equivalent positions ("FTEs"). Projections related to the construction period are intended to capture annual economic benefits received during the defined construction term (24 months, for example). Economic impacts during the ongoing operation and maintenance period are presented on an annual basis and are projected to persist throughout the project lifecycle. Aggregate jobs and economic development impacts associated with the indicative long-term contract portfolio, which would result in the assumed development and construction of approximately 330 MW of new renewable generating capacity within the state are reflected in the following table.

Economic Development Impacts Summary: Indicative Supply Portfolio (Secured via Long-Term Contract)			
	Jobs	**Earnings**	**Output**
During Construction Period		($ - Millions)	($ - Millions)
Project Development and Onsite Labor Impacts	3,250 - 4,250	210 - 265	375 - 450
Construction and Installation Labor	1,250 - 1,750	85 - 115	
Construction Related Services	2,000 - 2,500	125 - 150	
Power Generation and Supply Chain Impacts	3,250 - 3,750	175 - 225	550 - 600
Induced Impacts	1,500 - 2,000	75 - 100	225 - 275
Total Construction Period Impacts	8,000 - 10,000	460 - 590	1,150 - 1,325
During operating years (Annual)			
Onsite Labor Impacts	50 - 80	3 - 6	3 - 6
Local Revenue and Supply Chain Impacts	20 - 30	1 - 2	5 - 10
Induced Impacts	10 - 20	0 - 1	2 - 4
Total Operating Impacts (Annual)	80 - 130	5 - 10	10 - 20
Peninsula Clean Energy - Internal Staff	10 - 30	1 - 3	3 - 9

Notes: Earnings and Output values are expressed in million dollar increments (2015). Construction period jobs reflect full-time equivalent (FTE) positions during the duration of the construction period (1 FTE = 2,080 hours). For example, if 10,000 construction jobs are expected over a 24-month construction period, an annual equivalent of 5,000 construction jobs would be created through anticipated development activities. Such jobs will not exist following completion of construction activities. Economic impacts "During operating years" represent annual, ongoing impacts that occur as a result of generator operation and related expenditures. With respect to operating jobs, such statistics represent annual, ongoing FTEs during the entire project lifecycle, which may extend up to thirty (30) years in duration. Totals may not add up due to independent rounding.

As reflected in the previous table, the indicative long-term contract supply portfolio, which is assumed to exist in each of the CCA program's three planning scenarios, would result in significant economic benefits throughout the state and, potentially, within the San Mateo Communities.

With respect to the prospective generating facilities that have been incorporated in PCE's indicative long-term contract portfolio, PEA assumed that the significant majority of such facilities would be developed in optimal renewable resource areas throughout California. PEA assumed the development of 20 MW of locally situated renewable generating projects during the study period – such projects are discussed below. With regard to anticipated development projects occurring outside of the San Mateo Communities, PEA assumed that virtually all plant equipment, including turbines and other materials, would be procured outside of the San Mateo Communities. This equipment typically represents the largest single line item expenditure in generator construction. Requisite labor, including general site preparation and ancillary facility construction activities (concrete footings and structures not directly involved in the generation process) would also draw from California's broader regional workforce.

In total, PCE's indicative long-term contract portfolio is projected to result in the creation of approximately 8,000-10,000 new jobs during the aggregate construction period required to complete the assumed 330 MW of new generating projects. During the construction period, individuals working directly on the projects, including electricians, engineers, construction workers and heavy equipment operators, attorneys and permitting specialists, would be responsible for as much as $450 million in new economic output of which as much as $265 million would be collected in the form of salaries and wages. Workers involved with supply chain activities, such as turbine manufacturing and assembly, cement producers and heavy equipment rental companies would be responsible for up to $600 million in new economic activity of which approximately $225 million would be collected in the form of salaries and wages. Furthermore, spending by the aforementioned individuals (as a result of salary and wage collection) would "induce" other local economic impacts at local businesses, including restaurants, grocery stores, gas stations and other providers of goods and services, totaling as much as $275 million of which approximately $100 million would be collected as salaries and wages. In total, the locally developed generation projects identified under PCE's indicative long-term contract portfolio would result in $1.1 to $1.3 billion in new economic output throughout the state and local economy during the construction process.

During ongoing operation of the renewable generators, it is projected that as many as 130 new jobs would be created with a total annual economic impact ranging from $10 to $20 million. It is anticipated that these jobs would remain effective as long as the generating facilities remain operational, resulting in significant, lasting impacts to San Mateo County's local economy.

Local Economic Development Impact Potential

The primary source of local jobs and economic development impacts would be derived through projects developed under PCE's anticipated Feed-In Tariff ("FIT") program, which would promote the construction of locally situated, smaller-scale (i.e., up to 1 MW of total generating capacity, per project) renewable generating projects over time. For purposes of this Study and in consideration of a similar FIT program offered by MCE, PEA assumed that PCE would eventually (by year five of program operation) support the development of approximately 20 MW of locally situated renewable generating capacity, which will likely utilize the photovoltaic solar generating technology.

Based on applicable JEDI modeling results, the prospective PCE FIT program would result in the creation of approximately 370 local jobs during generator construction with an additional 500 jobs induced (during the construction period) through associated economic activity. As previously noted, these construction jobs are temporary, but there is also a nominal level of ongoing job growth associated with generator maintenance and operation, which is projected to be approximately six full-time equivalent employees during each year of facility operation (which may continue for 25-30 years).

Project development would also generate approximately $22 million in earnings for those working on the FIT projects, which is expected to create a total economic stimulus approximating nearly $39 million (in consideration of economic multiplier effects created by the spending of earnings/wages). Supply chain and induced impacts would also be significant totaling approximately $26 million and $71 million, respectively.

It is also anticipated that PCE would employ 10 to 30 internal staff, depending on decisions related to outsourcing/insourcing of requisite activities, during program implementation and ongoing operation. These estimates were derived by PEA in consideration of direct experience working with California's operating CCA programs. Depending on staffing levels, aggregate direct salaries for such staff are estimated to range from \$1 to \$3 million per year with a total of \$3 to \$9 million in total annual local economic activity generated by PCE staff.

These local economic development impacts are subsumed in the aggregate economic development impact totals reflected in the previous table.

SECTION 3: PCE TECHNICAL PARAMETERS (ELECTRICITY CONSUMPTION)

Historical and Projected Electricity Consumption

Total electric consumption for eligible customers within the San Mateo Communities was provided by PG&E for the 2013 and 2014 calendar years. The PG&E historical data was used as the basis for the study's customer and electric load forecast. Based on PEA's review of the PG&E data set, there were 298,435 electric customers within the potential CCA service territory. These customers consumed approximately 4,318 million kilowatt-hours of electricity during the 2014 calendar year. It is noteworthy that the aforementioned customer account and usage statistics include approximately 550 accounts, which are currently served through direct access service arrangements with third party suppliers. These customers account for approximately 10% of the aforementioned energy consumption, or approximately 400 million kWh annually, within the San Mateo Communities. Such usage has been excluded from the projections reflected in this Study – under direct access service arrangements, which are no longer available to California consumers[18], individual customers engage in shorter-term contract arrangements for the provision of electric generation service. By enrolling direct access accounts in the PCE program, such customers would be potentially exposed to duplicate generation charges or may be in violation of existing supply agreements. In consideration of these potential issues, direct access accounts have been excluded from PCE's prospective customer base.

Figure 11 shows how potential electric customers are distributed throughout the San Mateo Communities: the largest customer populations within the potential CCA jurisdiction include the City of San Mateo, Daly City, Redwood City, South San Francisco and the unincorporated areas of the County.

[18] Consideration of Senate Bill 286 (Hertberg), which would have expanded eligibility of direct access service within California, subject to the provision of increased levels of renewable energy supply, was recently suspended by the California legislature and is now a two-year bill. In consideration of this suspension, the participatory cap on direct access service remains capped/fixed at current levels, precluding new customer accounts from enrolling in such service options.

Figure 11: Geographic Distribution of Customers

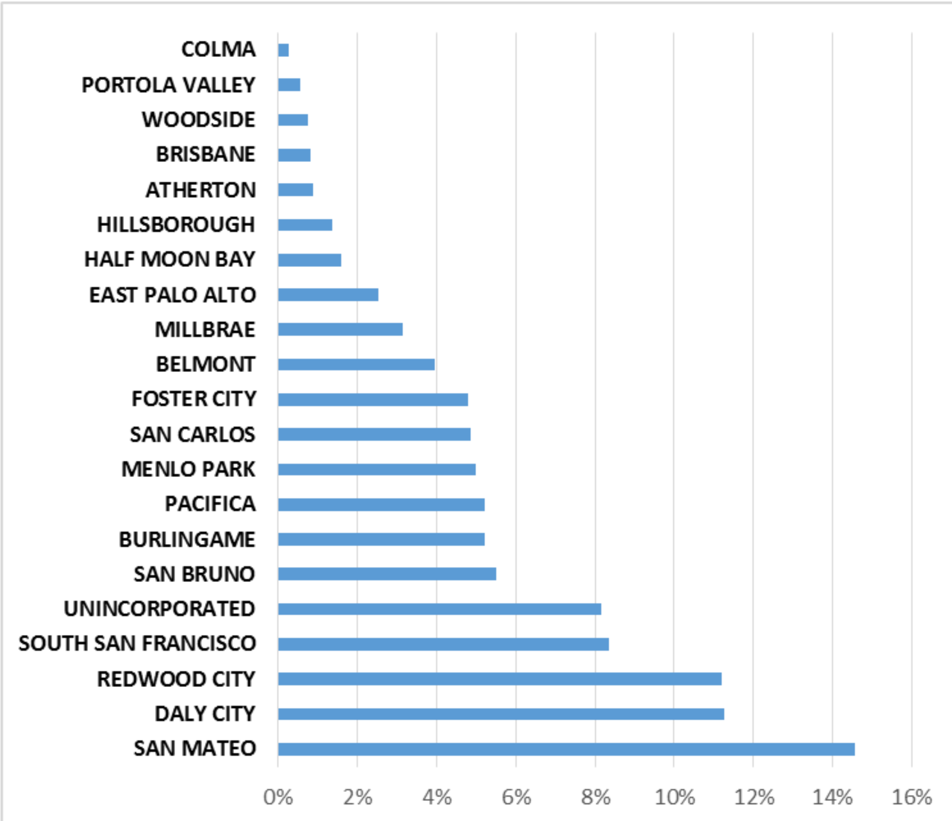
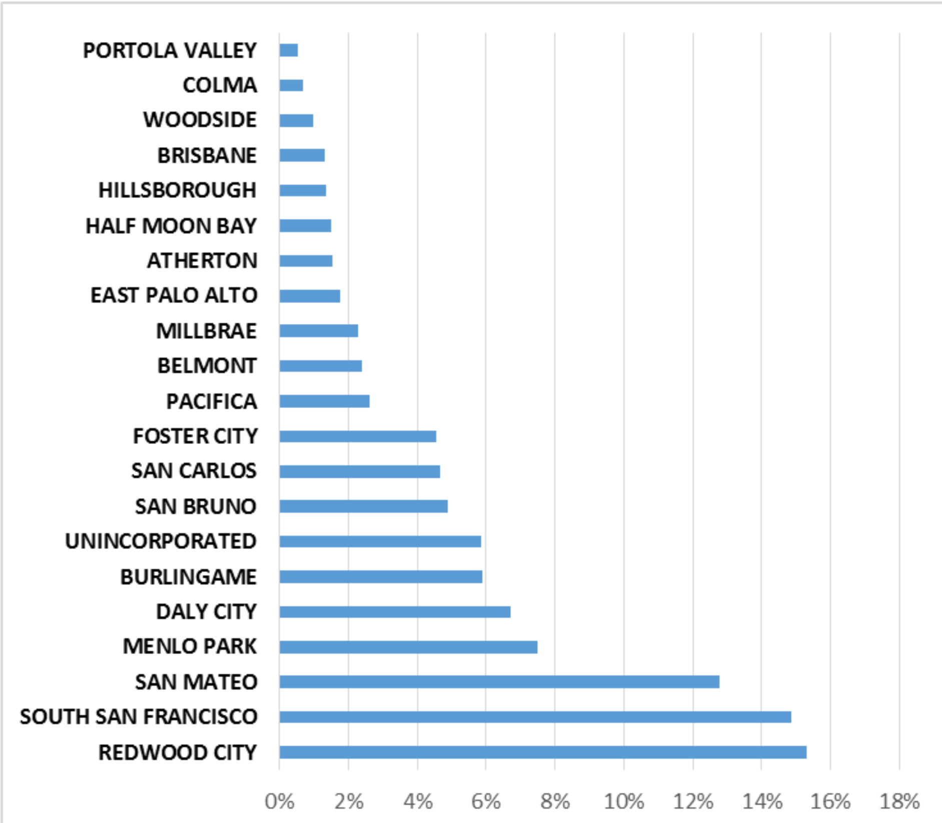


Figure 12 shows the distribution of electric consumption by municipality. The geographic distribution of energy consumption is somewhat different when compared to the service account data in Figure 11 above, indicating disproportionately higher use in certain San Mateo Communities (as a result of differentiated account composition, particularly higher concentrations of larger commercial and/or industrial account types, within such jurisdictions).

Figure 12: Geographic Distribution of Electric Consumption



In deriving the load projections used for the Study, adjustments to the base forecast were made to remove customers identified as taking service under direct access[19] as it was assumed that direct access customers would remain with their current electric service provider. Further adjustments were made to estimate customer opt-out rates during the statutory customer notification period when eligible customers would be offered CCA service and provided with information enabling them to opt out of the program. PEA assumed a 15% customer opt-out rate, which is generally consistent with the reported opt-out rates observed during recent expansions of the Marin Clean Energy program, when evaluating supply Scenario 1 and supply Scenario 2. For supply Scenario 3, which relies exclusively on bundled renewable energy products to serve the electric energy requirements of PCE customers, expected rate increases (when compared to PG&E) are assumed to drive participation levels down relative to Scenarios 1 and 2. For Scenario 3, PEA assumed more conservative participation levels, incorporating a 25% opt-out assumption for all residential and small commercial customers and a 50% opt-out assumption for all other customers groups, including medium commercial, large commercial, industrial and agricultural customers. Additionally, annual customer attrition for Scenario 3 was assumed at 1%. Sensitivities using different opt-out rates are presented in Section 6.

Going forward, potential customers and energy consumption were projected to increase by 0.5% annually, consistent with statewide projections and reflecting impacts from the significant emphasis being placed on energy efficiency in the state.

[19] Direct access allows customers to choose to receive generation service from competitive electricity providers. Currently, direct access service is not available to new customers within California. Proposed legislation may lead to the reopening of this service option at some point in the future.

Projected Customer Mix and Energy Consumption

The projections for enrolled customers (excluding direct access customers) and annual electricity consumption for the major customer classifications are shown in the following table. Hourly electricity consumption and peak demand were estimated using hourly load profiles published by PG&E for each customer classification.

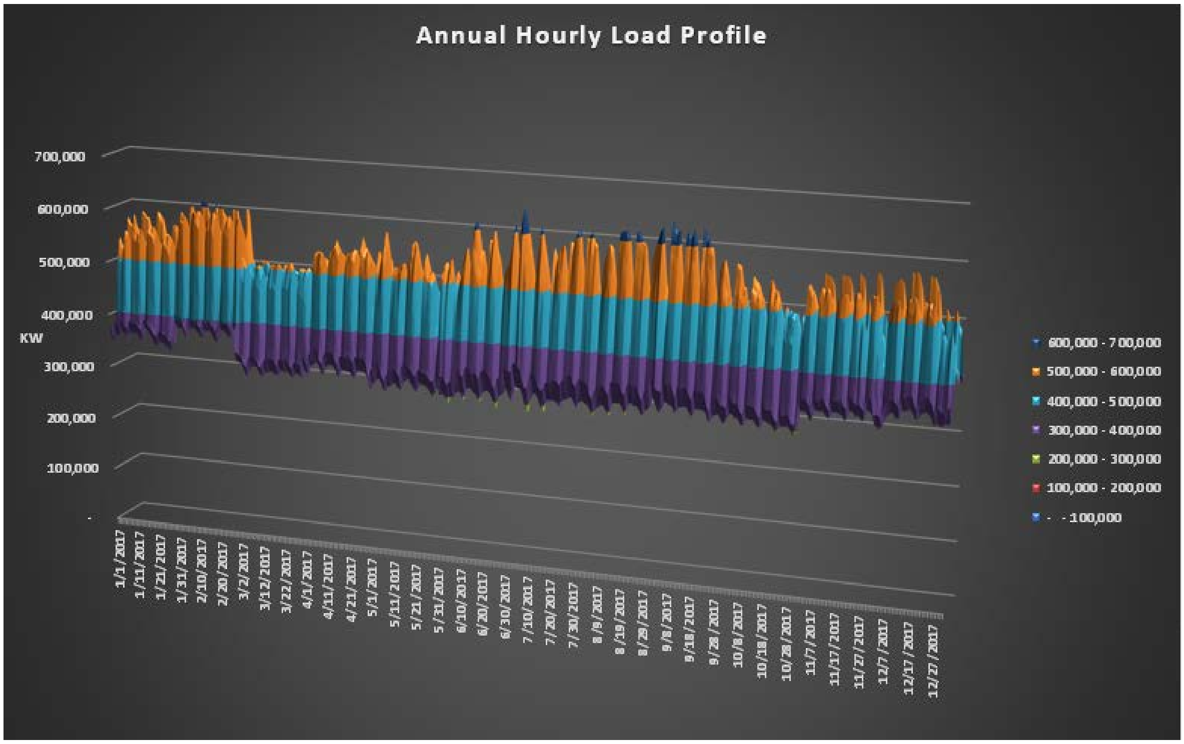
Customer Classification	Customer Accounts	Energy Consumption (MWh)	Share of Energy Consumption (%)
Residential	269,061	1,457,637	37%
Small Commercial	23,072	469,021	12%
Medium Commercial	2,665	613,398	16%
Large Commercial	1,333	933,305	24%
Industrial	43	378,422	10%
Ag and Pumping	275	25,095	1%
Street Lighting	1,432	24,052	1%
TOTAL	297,881*	3,900,930*	100%

*These totals exclude accounts that currently receive generation service under direct access arrangements. As a result, the account totals and annual energy consumption statistics reflected in the "Total" line item are slightly less than the overall account totals and energy usage reported at the beginning of Section 3.

The hourly load forecast indicates a peak demand of approximately 682 MW and a minimum demand of approximately 300 MW. The minimum demand establishes the requirement for baseload energy (constant production level), while the difference between the peak demand and the minimum demand would be met by peaking and dispatchable, load following resources.

Figure 13 shows the hourly load projections for the CCA program in Year 1 of program operations.

Figure 13: Hourly Electric Load Profile for San Mateo County



Renewable Energy Portfolio Requirements

Current law requires that specified percentages of annual retail electricity sales be supplied from qualified renewable energy resources. Senate Bill X1 2 (April, 2011) established a 33% Renewables Portfolio Standard by 2020 with certain interim procurement targets applying in each of three “Compliance Periods”: Compliance Period 1 began on January 1, 2011 and concluded on December 31, 2013 (a three-year period); Compliance Period 2 began on January 1, 2014 and will continue through December 31, 2016 (a three-year period; the current compliance period); and Compliance Period 3 (a four-year period), which will commence on January 1, 2017 and conclude on December 31, 2020.

SBX1 2 also specified additional requirements for the types of renewable energy products that may be used to demonstrate compliance with California’s RPS. According to the currently effective RPS program, there are three Portfolio Content Categories (“PCCs” or “Buckets”) that have been defined in consideration of the unique product attributes associated with typical renewable energy products.

- PCC1, or Bucket 1, renewable products are produced by RPS-certified renewable energy generators located within the state or by out-of-state generators that can meet strict scheduling requirements, ensuring deliverability to California. For purposes of demonstrating RPS compliance, there are no limitations with regard to the use of PCC1 products.

- PCC2, or Bucket 2, renewable products are generally "firmed/shaped" transactions through which the energy produced by an RPS-certified renewable energy generator is not necessarily delivered to California, but an equivalent quantity of energy from a different, non-renewable generating resource is delivered to California and "bundled" (or associated via an electronic transaction tracking system) with the renewable attribute produced by the aforementioned RPS-certified renewable generator. As noted, PCC2 products rely on electronic transaction tracking systems to substantiate the delivery of specified quantities of RPS-eligible renewable energy.
- PCC3, or Bucket 3, renewable products refer to unbundled renewable energy certificates, which are sold separately from the associated electric energy (with no physical energy delivery obligations imposed on the seller of such products).

Under RPS rules, limitations apply with regard to the use of PCC2 and PCC3 products. A more detailed description of the renewable product procurement specifications applicable under the currently effective RPS program are described in the following table.

Compliance Period	Calendar Year	Overall Procurement Target (% of Total Retail Sales)	PCC1 Procurement (% of Total RPS Procurement)	PCC2 Procurement (% of Total RPS Procurement)*	PCC3 Procurement (% of Total RPS Procurement)
CP 1	2011	20.0%	≥50.0%	≤50.0%	≤25.0%
CP 1	2012	20.0%	≥50.0%	≤50.0%	≤25.0%
CP 1	2013	20.0%	≥50.0%	≤50.0%	≤25.0%
CP 2	2014	21.7%	≥65.0%	≤35.0%	≤15.0%
CP 2	2015	23.3%	≥65.0%	≤35.0%	≤15.0%
CP 2	2016	25.0%	≥65.0%	≤35.0%	≤15.0%
CP 3	2017	27.0%	≥75.0%	≤25.0%	≤10.0%
CP 3	2018	29.0%	≥75.0%	≤25.0%	≤10.0%
CP 3	2019	31.0%	≥75.0%	≤25.0%	≤10.0%
CP 3	2020	33.0%	≥75.0%	≤25.0%	≤10.0%

*Note that PCC2 products may be used in place of PCC3 products.

Beyond the 2020 calendar year, California's RPS procurement will likely increase to 50% by 2030, subject to Governor Brown signing SB 350, which is expected to occur no later than October 11, 2015. On September 11, 2015, the California legislature concurred with proposed amendments to Senate Bill 350 (De Leon and Leno), the Clean Energy and Pollution Reduction Act of 2015, and recommended this bill for enrolling. Once signed, there are many details related to SB 350 implementation that will be developed over time with oversight by designated regulatory agencies. However, it is reasonable to assume that interim annual renewable energy procurement targets will be imposed on CCAs and other retail electricity sellers to facilitate progress towards the 50% RPS; PEA also expects that additional detail regarding renewable energy product eligibility, including any restrictions and/or requirements regarding the use of such products, will also become clearer during upcoming implementation efforts.

For purposes of this Study, PEA assumed straight-line progress when moving from the 33% RPS mandate in 2020 to the 50% RPS mandate in 2030, or 1.7% annual increases in California's renewable energy procurement target during the ten-year transition period. With respect to the applicability of various renewable energy products that may be eligible under the prospective 50% RPS, PEA assumed a similar product mix to that which will be allowed under the current RPS program in calendar year 2020: minimum 75% PCC1 content;

maximum 10% PCC3 content. Again, final details related to the implementation of SB 350 will not be certain until implementation of this legislation commences in coordination with assigned regulatory agencies. With regard to any voluntary (above-RPS) renewable energy procurement activities, PEA has assumed that the CCA program would have discretion in how it meets such voluntary, internally imposed targets reflected in the prospective planning scenarios. The following table illustrates PEA's assumed RPS procurement rules as California transitions to a 50% RPS by 2030.

Compliance Period	Calendar Year	Overall Procurement Target (% of Total Retail Sales)	PCC1 Procurement (% of Total RPS Procurement)	PCC2 Procurement (% of Total RPS Procurement)*	PCC3 Procurement (% of Total RPS Procurement)
TBD	2021	34.7%	≥75.0%	≤25.0%	≤10.0%
TBD	2022	36.4%	≥75.0%	≤25.0%	≤10.0%
TBD	2023	38.1%	≥75.0%	≤25.0%	≤10.0%
TBD	2024	39.8%	≥75.0%	≤25.0%	≤10.0%
TBD	2025	41.5%	≥75.0%	≤25.0%	≤10.0%
TBD	2026	43.2%	≥75.0%	≤25.0%	≤10.0%
TBD	2027	44.9%	≥75.0%	≤25.0%	≤10.0%
TBD	2028	46.6%	≥75.0%	≤25.0%	≤10.0%
TBD	2029	48.3%	≥75.0%	≤25.0%	≤10.0%
TBD	2030	50.0%	≥75.0%	≤25.0%	≤10.0%

Capacity Requirements

The CCA program would be required to demonstrate it has sufficient physical generating capacity to meet its projected peak demand (682 MW) plus a 15% planning reserve margin, in accordance with resource adequacy regulations administered by the CPUC and the CEC. A specified portion of generating capacity must be located within certain local reliability areas and the remaining capacity requirement can be met with generating plants anywhere within the CAISO system. Presently, there are two local reliability areas that would apply to the CCA program: the "Greater Bay Area" and the "Other PG&E Areas". Additionally, the CPUC and CAISO have flexible capacity requirement, which must be satisfied by all California load serving entities, including CCAs, to ensure that certain quantities of reserve capacity are capable of increasing generation levels within specified time periods (to promote system reliability when the production from certain grid-connected generators quickly changes as is becoming increasingly common as a result of California's buildout of intermittent renewable energy resources).

Using the most recent data from the 2015 compliance year, the following resource adequacy capacity requirements were assumed to apply to PCE's CCA program to meet the requirements identified above:

Capacity Type	Percentage of Peak Demand
System	75%
Greater Bay Area	14%
Other PG&E Areas	26%
Total	115%

Accordingly, the total resource adequacy requirement for PCE's first year of operations would be approximately 784 MW, with approximately 95 MW of the total procured from the Greater Bay Area region, 177 MW procured from any other local reliability area in the PG&E service area, and 512 MW procured from anywhere within the CAISO footprint. PCE would also have a flexible resource adequacy requirement, which ensures that adequate generation resources connected to the grid can ramp-up and produce power in a short amount of time in response to the intermittency of California renewable resources. Requisite resource adequacy products are typically procured/secured through one or more of the following arrangements: 1) short- to medium-term contract arrangements with the owners or controllers of qualifying generating capacity; 2) capacity attributes conferred through long-term power purchase arrangements with specified generators – such contracts typically provide the buyer with both energy and capacity products from one or more specific generating resources identified in the purchase agreement; or 3) direct ownership of generating facilities, which may be eligible to provide requisite resource adequacy capacity.

SECTION 4: COST OF SERVICE ELEMENTS

This section summarizes the different types of costs that would be incurred by the CCA program in providing electric service to its customers. For each supply scenario, a detailed pro forma was developed that delineates the applicable cost of service elements. These pro forma are shown in Appendix A.

Electricity Purchases

The CCA program would be financially responsible for supplying the net electric demand of all enrolled customers, and it would be able to source that supply from a variety of markets and/or through the program's own generation resources. Energy requirements are ultimately financially settled by the CAISO. The CAISO plays a critical role in balancing supply and demand on a significant portion of California's electric grid and operates short-term markets for energy as well as real-time balancing services to cover inevitable moment-to-moment fluctuations in electricity consumption (resulting from circumstances including but not limited to weather, unexpected changes in customer energy use, unexpected variances in generator operation, infrastructure outages and other situations). The CCA program would interact with the CAISO through an intermediary known as a "Scheduling Coordinator", periodically reporting usage data for its customers and settling with the CAISO for any imbalances (i.e., instances in which the load forecast and/or the planned generator operation differs from expectations, requiring the CAISO to balance any variances through the operation of other system resources) or transactions in the CAISO markets.

Bilateral markets exist for longer term purchases, which allow hedging (i.e., contractual protection via specified/fixed product pricing over a mutually agreed upon delivery term) against the fluctuations in CAISO market prices. Longer term purchases can span many years, with the most active trading being for contracts with terms of less than three years in duration. Contracts for new generation resources typically have contract term lengths of twenty (20) years or more, allowing the project developer/owner to utilize the contract's expected revenue stream to support project financing.

Electric purchase costs were estimated using the projected energy demand during the industry-defined peak and off-peak time periods. Assumed renewable energy contracts of the CCA, as reflected in the previously described indicative long-term contract portfolio, were subtracted from PCE's expected peak and off-peak energy demands, resulting in a residual energy requirements, or "net short", which was assumed to be met with short and mid-term contract purchases of system energy (produced by conventional generating technologies; within California, the majority of system energy is produced by generators using natural gas as a primary fuel source).

Renewable Energy Purchases

Renewable energy purchases may take two forms: 1) physical electric energy bundled with associated renewable/environmental attributes; or 2) unbundled renewable/environmental attributes, which are sold separately from the physical energy commodity. As described in Section 2, unbundled RECs were not incorporated in any of the supply scenarios addressed in this Study; only bundled renewable energy resources, which were assumed to meet the product delivery specifications associated with the PCC1 and PCC2 product designations were incorporated in the indicative PCE supply portfolios.

Purchases of renewable energy from new resources are typically made under bundled, long-term contract arrangements of 20 years or more. Shorter term purchases are common for existing renewable resources and for unbundled renewable energy certificates.

Renewable energy currently sells for a premium relative to the cost of conventional power. However, when compared to the cost of new, natural gas-fueled generation, renewable resources tend to have lower levelized costs.[20]

Renewable energy purchase costs were estimated using predominantly long-term contracts for new renewable energy projects as specified in the indicative long-term contract portfolio. Short term market purchases of bundled renewable energy were assumed to fulfill PCE's remaining renewable energy needs.

With regard to the term renewable energy certificates, or "RECs", it is important to understand that a REC is the only mechanism by which ownership of renewable energy can be demonstrated/substantiated. One REC is created for every whole MWh of metered electricity produced by a registered renewable generating facility. Within the Western United States, a tracking system known as the Western Renewable Energy Generation Information System ("WREGIS") has been developed to facilitate the management of RECs, providing a platform through which RECs can be transferred between buyers and sellers of renewable energy products and also "retired" (meaning, removed from the marketplace) for purposes of demonstrating legal/regulatory compliance or achievement of certain voluntary procurement objectives. All renewable energy production is substantiated via the creation of a REC, which occurs following WREGIS' verification of metered energy production by a registered renewable generating resources. Use of the WREGIS system for purposes of REC accounting serves to minimize concerns regarding double-counting during compliance demonstration and public reporting – in the event that a renewable energy buyer does not possess a REC, it cannot make claims with regard to the associated environmental benefits.

Again, some RECs are bundled with the associated electric energy; other RECs are sold apart from the electric commodity – such RECs are appropriately referred to as "unbundled RECs". The transaction documentation associated with each renewable energy purchase should outline applicable product specifications, including whether or not RECs are being sold with or apart from the electric commodity. In selecting its renewable energy product mix, the CCA program should be aware that California law permits the use of a limited quantity of unbundled RECs, or PCC3 product volumes, for purposes of demonstrating RPS compliance – applicable limitations were previously described in Section 3. Such products currently represent lower-cost options when compared to PCC1 and PCC2 products due to the administrative simplicity associated with such transactions.

In recent years, there has been robust philosophical debate regarding the advantages and pitfalls of unbundled REC use, particularly the environmental benefits associated with such products. Significant research and documentation has been prepared regarding this topic, and PCE is encouraged to review such information prior to engaging in unbundled REC transactions. Organizations including the Center for Resources Solutions (the program administrator for the Green-e Energy program), the United States Environmental Protection Agency, the United States Federal Trade Commission and The Climate Registry, amongst others, have all completed research and/or issued positions regarding the use of unbundled RECs. Furthermore, Assembly Bill 1110 (Ting), which was introduced to the California legislature on February 27, 2015 but is now a two-year bill, was intended to promote the inclusion of GHG emissions intensity reporting by retail electricity suppliers (in annual Power Content Label communications). If AB 1110 moves forward next year, it could impose a retail-level emissions calculation methodology that may eliminate all GHG emissions benefits associated with unbundled RECs. This is also an important consideration as PCE assembles its renewable energy supply portfolio, due to the fact that any GHG benefits conferred through unbundled REC transactions would be excluded from customer reporting, resulting in the reporting of higher than anticipated portfolio emission levels for entities that procured such products. In light of the perceived risks and general controversy associated with the use of unbundled

[20] See for example, Table 62, Estimated Cost of New Renewable and Fossil Generation in California, California Energy Commission, March 2015.

RECs, leadership within the San Mateo Communities advised PEA to exclude Bucket 3 products from each of the prospective supply scenarios.

Electric Generation

Generation projects developed or acquired by the CCA program could also supplement energy purchases. Generation costs would include development costs, capital costs for land, plant and equipment, operations and maintenance costs, and, if applicable, fuel costs. Capital costs for publicly owned utilities such as a CCA are typically financed with long-term debt, and the annual debt service would be an element of annual CCA program costs. For purposes of this Study, PEA's analysis did not contemplate the utilization of CCA-owned/developed generating resources during the ten-year study period for reasons previously described.

Transmission and Grid Services

The CAISO charges market participants, including CCA (via the CCA's selected scheduling coordinator) for a number of transmission and grid management services that it performs. These include costs of managing transmission congestion, acquiring operating reserves and other "ancillary services", and conducting CAISO markets and other grid operations. The CAISO charges are both directly related to PCE's operations, but there are other grid charges that are shared across all load serving entities on a pro rata basis. These costs would be assessed to the Scheduling Coordinator for the CCA program, and are assumed to be directly passed through to the CCA program with no markup.

Financing Costs

The CCA program would need capital to cover start-up costs, working capital, and any generation or other project financing. The analysis assumes short term financing with the exception of generation projects which would be financed with long term debt.

Start-up costs are estimated at $2.7 million, which would fund the program for approximately six months prior to commencement of service to customers. Start-up activities include costs for staffing and professional services, security deposits, the CCA bond/financial security requirement, communications and customer notices, data management, and other activities that must occur before the program begins providing electricity to customers. These costs would be recovered from program revenues after service commences. A breakdown of estimated start-up costs is shown in the following table.

Estimated CCA Program Start-Up Costs

Cost Item	Amount
Staff	$734,000
Consulting and Legal Services	$600,000
Feasibility Study	$150,000
JPA Formation/Development	$50,000
Implementation Plan	$75,000
Power Procurement Solicitation and Contract	$75,000
Marketing and Communications	$337,000
Customer Noticing and Mailers	$335,00
PG&E Service Fees	$37,500
Miscellaneous Administrative and General	$193,000
Financial Security/Bond Carrying Cost	$115,000
Total	$2,700,000

Working capital requirements are estimated at $20 million, which would cover the timing lag between when invoices for power purchases must be paid and other operating expenses incurred prior to when cash is received from customers. Typical invoicing timelines for wholesale power purchase contracts require payment for the prior month's purchases by the 20th of the current month. Customer payments are typically received within sixty to ninety days following electricity delivery. The timing difference between cash outflows and inflows represents the working capital requirement. The possibility exists to negotiate payment timelines with power suppliers in order to reduce the initial working capital requirement. For example, both SCP and LCE have negotiated an additional 30 days in the supplier payment timeline, which would significantly reduce the working capital figure described above.

Billing, Metering and Data Management

PG&E provides billing and metering services for all CCA programs and charges the CCA for such services in accordance with applicable tariffs, which are regulated by the CPUC. PG&E posts the meter data to a data server that the CCA program would be able to access for its power accounting and settlements. PG&E uses systems to exchange billing, payment, and other customer data electronically with competitive retail electric providers such as CCAs. While PG&E issues customer bills and processes customer payments, the CCA program will have a large amount of data to manage and must be able to exchange data with PG&E using automated processes. PEA included costs for third party data management as well as PG&E charges for billing and metering in this cost of service category.

Uncollectible Accounts

CCA rates must account for the small fraction of customers who do not pay their electric bill. PG&E attempts to collect the CCA's charges, but some accounts must be written off as uncollectible. An allowance for uncollectible accounts has been included as a program cost element.

Program Reserves

A reasonable revenue surplus was factored in to estimated CCA program rates to fund a reserve account that would be used for contingencies or as a rate stabilization tool. Financing also requires generation of revenue surpluses that accumulate as reserves, as lenders typically require maintenance of debt service coverage ratios that would necessitate setting rates to yield revenues in excess of program costs.

Bonding and Security Requirements

The CCA program would be required to provide a security deposit to PG&E and post a bond or other form of financial security with the CPUC as part of its registration process. The security deposit covers approximately one month of PG&E charges for billing and metering services. The CCA bond or financial security requirement, which is posted with the CPUC, is intended to cover the potential reentry costs if customers were to be involuntarily returned to PG&E.

The currently effective financial security requirement is $100,000, but PG&E and other investor owned utilities have advocated changes to the methodology that could, under certain market conditions, result in extremely large financial security requirements. PEA's estimate of the CCA Bond amount reflects the currently applicable specification ($100,000). However, the CCA program should actively monitor applicable regulatory proceedings, which may result in changes to this bond amount. Risks associated with such changes are discussed in additional detail within Section 7 of this Study.

PG&E Surcharges

CCA customers will pay the CCA's rates for generation services, PG&E's rates for non-generation services (transmission, distribution, public purpose, etc.), and two surcharges that are currently included in PG&E's generation rates: the Franchise Fee Surcharge and the Power Charge Indifference Adjustment ("PCIA"). These surcharges are not program costs per se, but they do impact how a customer's bill will compare between PG&E bundled service and CCA service.

The franchise fee surcharge is a minor charge that ensures PG&E collects the same amount of franchise fee revenues whether a customer takes generation service from a CCA or from PG&E. The PCIA is a substantial charge that is intended to ensure that generation costs incurred by PG&E before a customer transitions to CCA service are not shifted to remaining PG&E bundled service customers (following a customer's departure from PG&E to CCA service). For purposes of this Study, PEA's assumed surcharges reflect the most recent advice provided by PG&E and assumed changes to the PG&E supply portfolio over time.

SECTION 5: COST AND BENEFITS ANALYSIS

This section contains a quantitative description of the estimated costs and benefits for each representative supply scenario. Each scenario was evaluated using the three criteria described in Section II. Ratepayer costs and benefits are evaluated on the basis of the total electric rates customers would pay under CCA service as compared to PG&E bundled service. Total electric rates include the rates charged by the CCA program plus PG&E's delivery charges and other surcharges. Environmental benefits are evaluated on the basis of reductions in GHG (CO_2) emissions relative to the reference case. Local economic benefits are evaluated on the basis of jobs and economic activity created by the CCA program's investments in local generation resources.

When assessing the comparative environmental impacts associated with each of PCE's prospective supply scenarios, it is important to consider the potential changes that could result from PG&E's reduced or discontinued use of nuclear electricity produced by the Diablo Canyon Power Plant ("DCPP"). DCPP currently produces approximately 18,000 GWh, or more than 20% of PG&E's total power content, per year, but licenses for the facility's two reactor units expire in 2024 and 2025, respectively. At this point in time, there is uncertainty regarding PG&E's ability to successfully relicense these units under the current configuration, which utilizes once-through cooling as part of facility operations. Environmental concerns regarding the use of once-through cooling may present relicensing challenges for PG&E, which could result in temporary or permanent discontinued operation of DCPP. Under this scenario, which falls towards the outer years of the study period, PCE's actual GHG emissions impact would dramatically improve under each of the prospective supply scenarios. It is also noteworthy, that discontinued DCPP operation (without the addition of equivalent generating capacity within the region) may also impose upward pressure on market energy prices and resource adequacy products. PEA recommends that the San Mateo Communities continue to monitor the relicensing status of DCPP as expiration of the existing licenses approaches.

When reviewing PCE's scenario results, it is important to keep in mind the planned phase-in strategy for the prospective CCA customer base, which is expected to occur over a two-year period. Such a strategy will allow the CCA program to "walk before its runs," gaining operational experience while the initial customer base remains relatively small (when compared to the total prospective customer population). This approach will also create an opportunity for the CCA program to debug" potential customer service and billing issues that may arise during initial operations and will also reduce credit/collateral concerns during initial power contracting efforts.

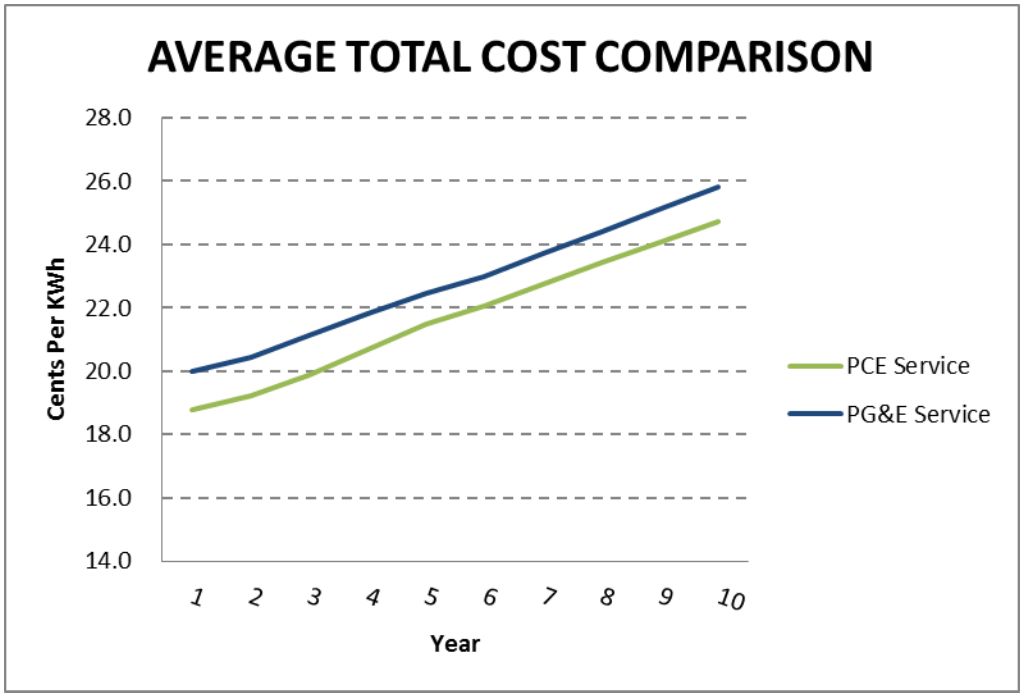
Scenario 1 Study Results

Ratepayer Costs

The primary objective of Scenario 1 is to promote maximum CCA customer savings, if possible, while offering such customers an RPS-compliant resource mix that does not include the use of unbundled RECs. As expected, projected CCA customer rates in Scenario 1 are lower than similar rate projections for PG&E throughout the ten-year study period, with annual comparative benefits ranging from 4% to 6%. Levelized rates over the study period are projected to be 5% lower than projected PG&E rates. For a typical household using 450 kWh per month, a 5% rate difference would result in a cost reduction of approximately $6.18 per month.

Projected average rates for the PCE customer base are shown in the following figure and table, comparing total ratepayer impacts under the PG&E bundled service and CCA service options.

Figure 14: Scenario 1 Annual Ratepayer Costs



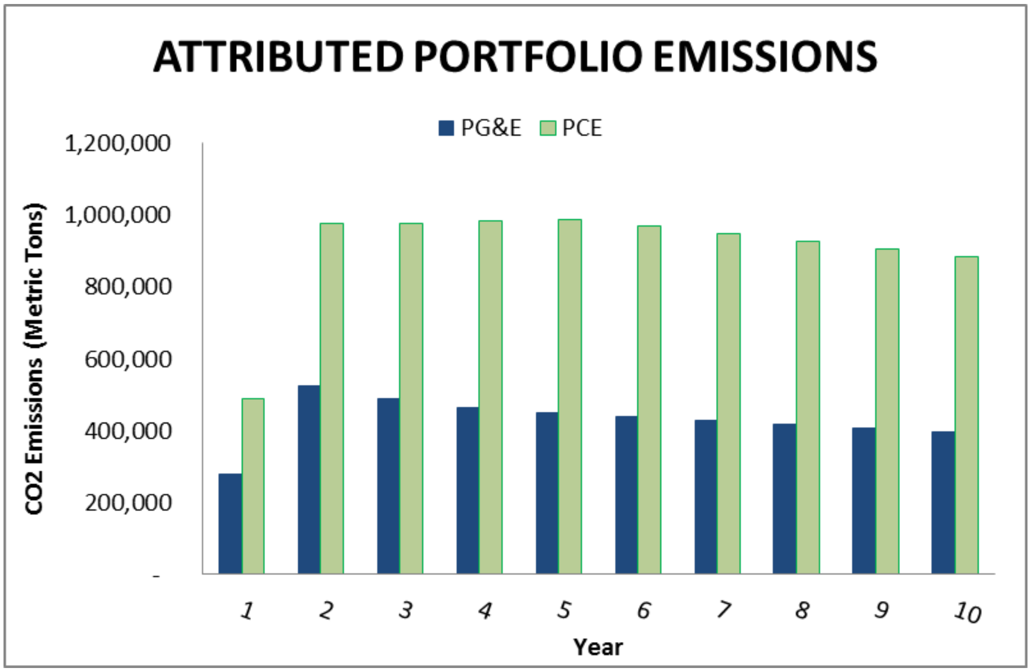
Scenario 1: Annual Total Delivered Rate Comparison

Year	PG&E Total (₵/kWh)	PCE Total (₵/kWh)	Percent Difference
Levelized	22.7	21.6	-5%
1	20.0	18.8	-6%
2	20.4	19.2	-6%
3	21.1	19.9	-6%
4	21.8	20.7	-5%
5	22.5	21.5	-4%
6	23.0	22.0	-4%
7	23.7	22.8	-4%
8	24.4	23.4	-4%
9	25.1	24.1	-4%
10	25.8	24.7	-4%

GHG Impacts

The anticipated GHG impacts associated with Scenario 1 result in relatively significant increases when compared to PG&E's projected emissions profile. Because the assumed Scenario 1 resource mix includes renewable energy purchases that generally track with RPS procurement mandates but no additional GHG-free purchases (i.e., all non-renewable energy purchases would be sourced from the California market with an attributed emissions profile generally equivalent to a typical natural gas generator). The following figure and table provide additional detail regarding the respective GHG emissions profile associated with the assumed PCE and PG&E supply portfolios.

Figure 15: Scenario 1 – Annual GHG Emissions Comparison

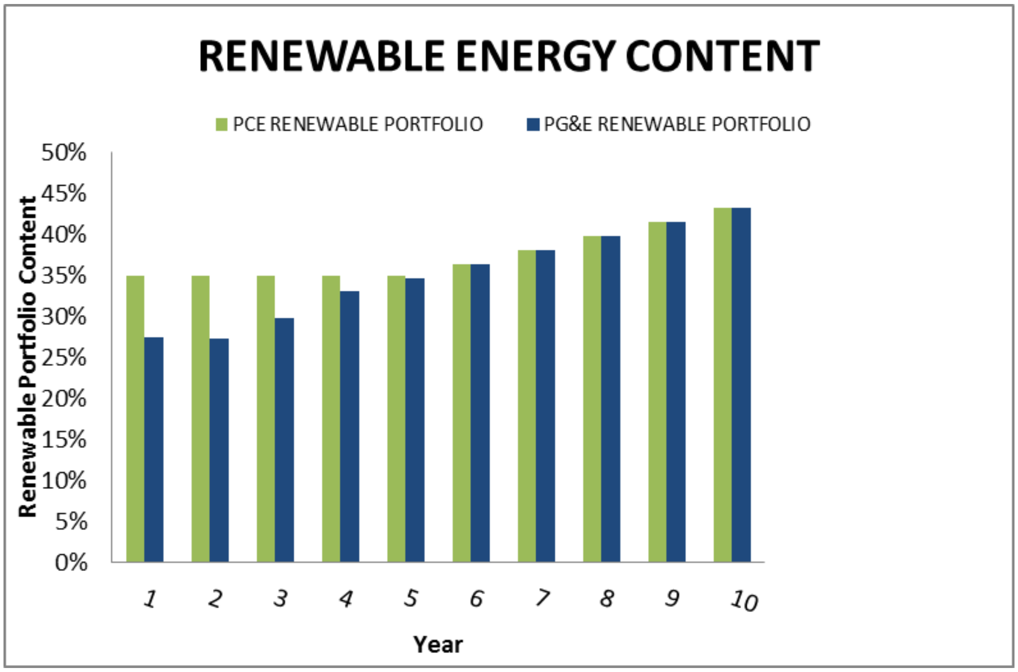


Scenario 1: Annual GHG Emissions Factor Comparison (Metric Tons CO_2/MWh)

Year	PG&E	PCE
1	0.158	0.278
2	0.149	0.278
3	0.139	0.278
4	0.131	0.278
5	0.127	0.278
6	0.123	0.272
7	0.120	0.265
8	0.116	0.258

Year	PG&E	PCE
9	0.112	0.250
10	0.109	0.243

Figure 16: Scenario 1 – Annual Renewable Energy Content Comparison



Scenario 1: Annual Renewable Energy Portfolio Content

Year	PG&E	PCE
1	27%	35%
2	27%	35%
3	30%	35%
4	33%	35%
5	35%	35%
6	36%	36%
7	38%	38%
8	40%	40%
9	42%	42%

Year	PG&E	PCE
10	43%	43%

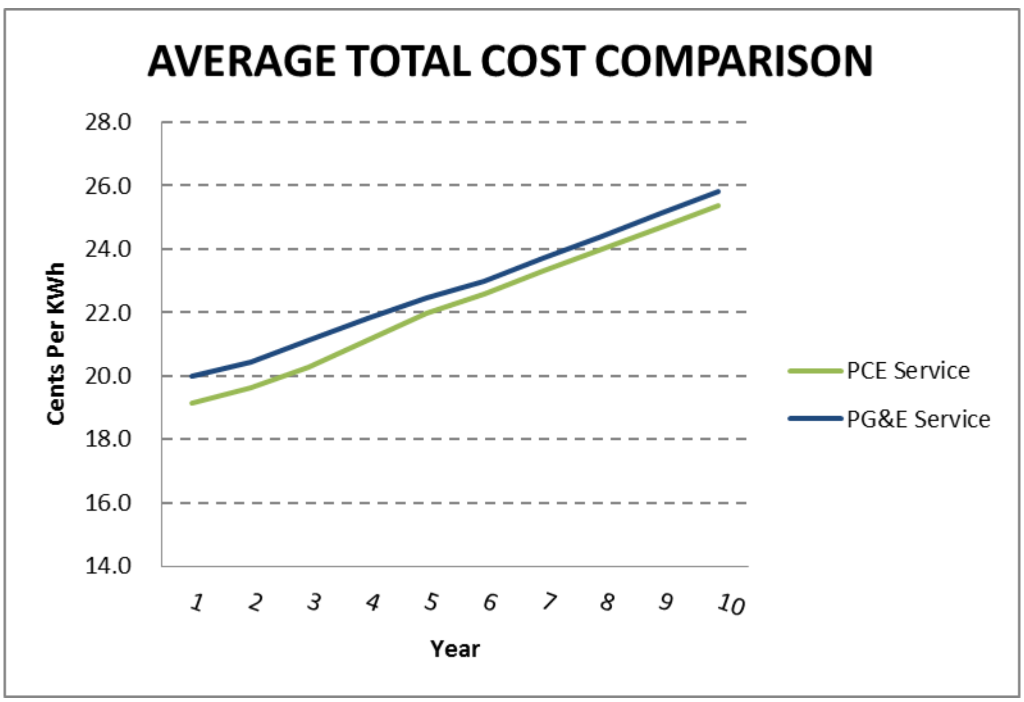
Scenario 2 Study Results

Ratepayer Costs

The primary objective of Scenario 2 is twofold: promote rate competitiveness with PG&E while reducing GHG emissions associated with the CCA program's supply portfolio. For purposes of the Study, this objective is achieved through the inclusion of renewable energy purchases that significantly exceed applicable compliance mandates (doing so without the use of unbundled RECs) as well as additional GHG-free energy purchases, which would be produced by non-RPS-eligible hydroelectric generators located within California and/or the Pacific Northwest. Under Scenario 2, projected CCA customer rates are initially lower than similar rate projections for PG&E and maintain that general relationship throughout the study period – the relationship between PCE and PG&E rates demonstrates marginal customer savings ranging from 2% to 4%. Levelized rates over the study period are projected to be 3% lower than projected PG&E rates. However, in consideration of typical market volatility within the electric power sector and eminent PG&E rate volatility, these results should be reasonably interpreted as reflecting the outcome of general rate parity throughout the study period. For a typical household using 450 kWh per month, a 3% rate difference would result in a cost reduction of approximately $4.36 per month.

Projected average rates for the PCE customer base are shown in the following figure and table, comparing total ratepayer impacts under the PG&E bundled service and CCA service options.

Figure 17: Scenario 2 Annual Ratepayer Costs



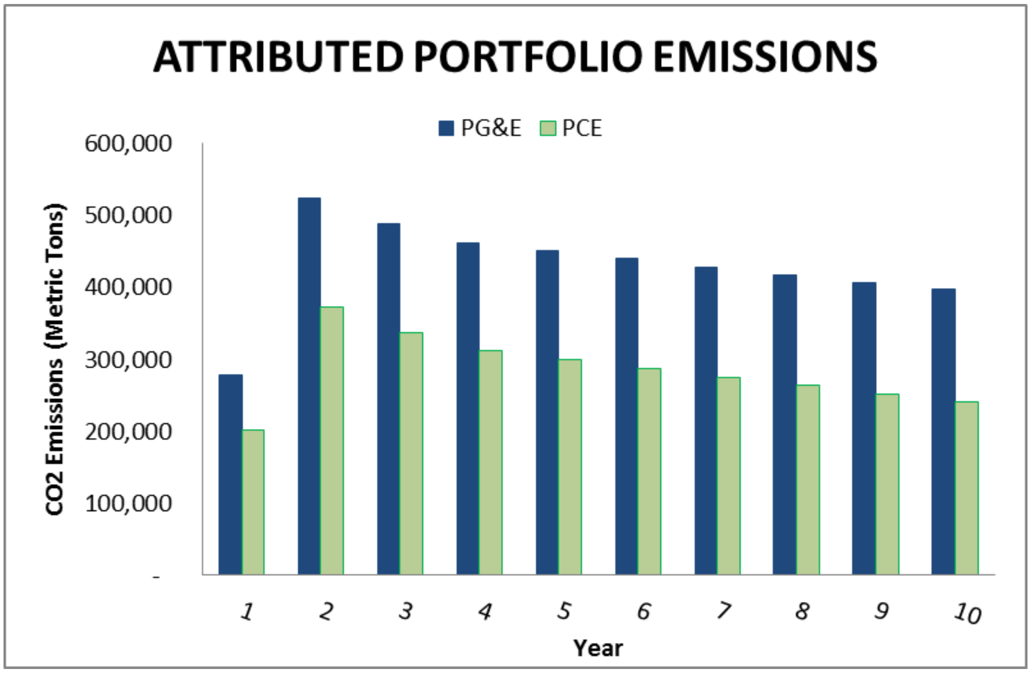
Scenario 2: Annual Total Delivered Rate Comparison

Year	PG&E Total (₵/kWh)	PCE Total (₵/kWh)	Percent Difference
Levelized	22.7	22.1	-3%
1	20.0	19.1	-4%
2	20.4	19.6	-4%
3	21.1	20.3	-4%
4	21.8	21.1	-3%
5	22.5	22.0	-2%
6	23.0	22.6	-2%
7	23.7	23.3	-2%
8	24.4	24.0	-2%
9	25.1	24.7	-2%
10	25.8	25.4	-2%

GHG Impacts

As a result of the significant proportion of GHG-free resources that were incorporated in Scenario 2, the CCA program is able to demonstrate meaningful GHG emissions reductions when compared to PG&E's projected emissions profile. The following figure and table provide additional detail regarding the respective GHG emissions profile associated with the assumed PCE and PG&E supply portfolios.

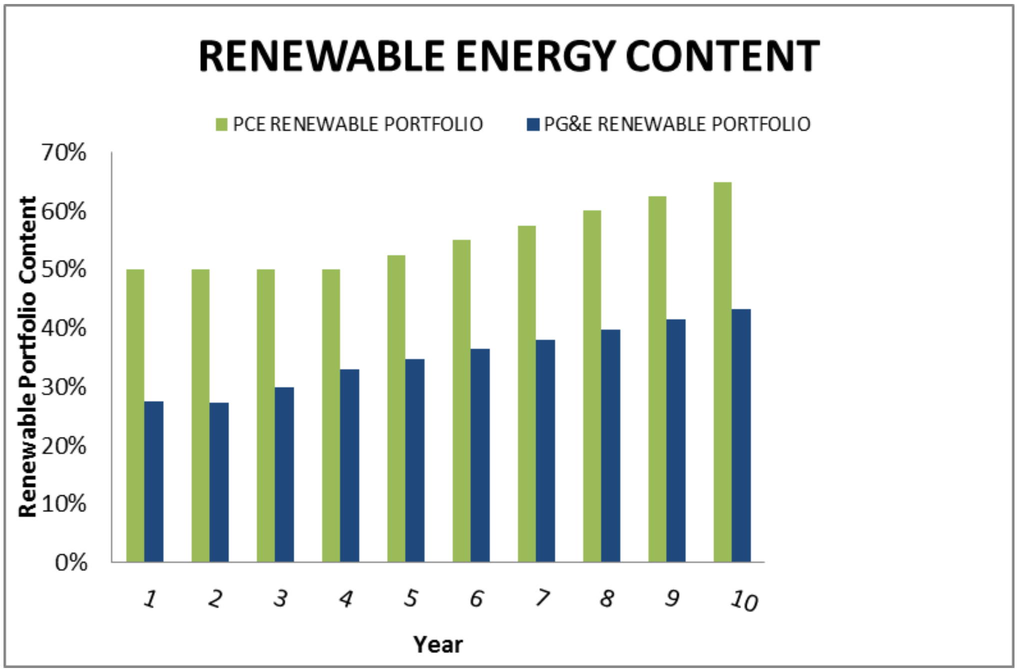
Figure 18: Scenario 2 – Annual GHG Emissions Comparison



Scenario 2: Annual GHG Emissions Factor Comparison (Metric Tons CO_2/MWh)

Year	PG&E	PCE
1	0.158	0.115
2	0.149	0.106
3	0.139	0.096
4	0.131	0.088
5	0.127	0.084
6	0.123	0.080
7	0.120	0.077
8	0.116	0.073
9	0.112	0.070
10	0.109	0.066

Figure 19: Scenario 2 – Annual Renewable Energy Content Comparison



Scenario 2: Annual Renewable Energy Portfolio Content

Year	PG&E	PCE
1	27%	50%
2	27%	50%
3	30%	50%
4	33%	50%
5	35%	53%
6	36%	55%
7	38%	58%
8	40%	60%
9	42%	63%
10	43%	65%

Scenario 3 Study Results

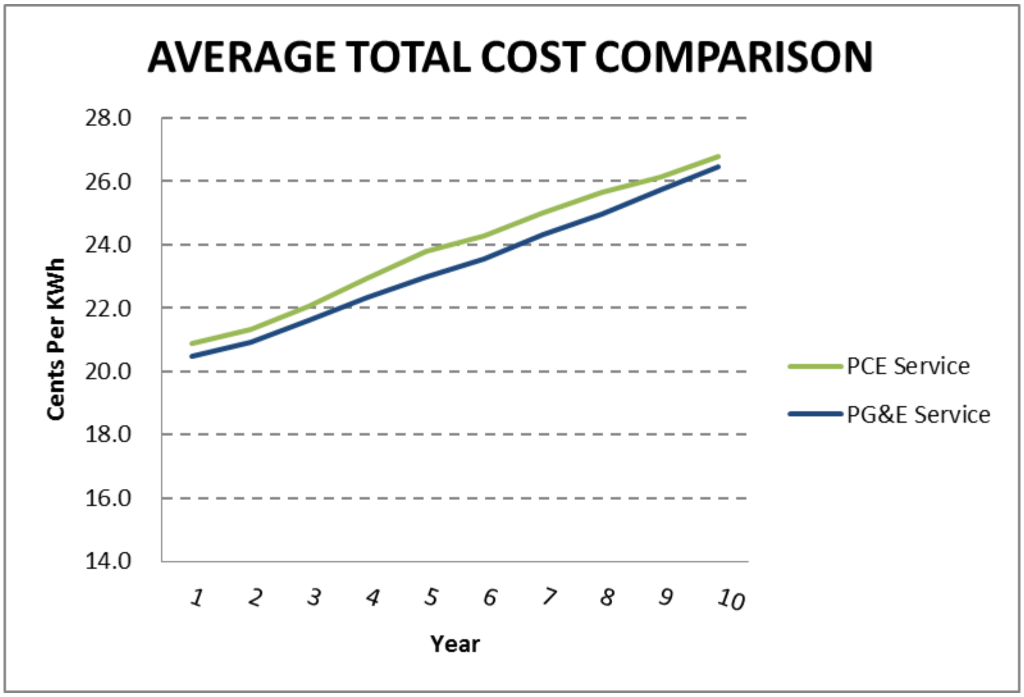
Ratepayer Costs

Scenario 3 is aptly characterized as an aspirational supply scenario under which the entirety of PCE's energy requirements would be sourced from bundled renewable energy resources. As reasonably expected, the relatively high supply costs of bundled renewable energy products would impose incremental rate increases for PCE customers relative to the incumbent utility. Under Scenario 3, projected CCA customer rates remain above similar rate projections for PG&E throughout the study period – the relationship between PCE and PG&E rates demonstrates rate increases ranging from 1% to 3%. Levelized rates over the study period are projected to be 2% higher than projected PG&E rates. For a typical household using 450 kWh per month, a 2% rate difference would result in a cost increase of approximately $1.86 per month. This customer impact is particularly insightful when considering the voluntary, 100% renewable energy option that PCE may offer to its customers. Scenario 3 is also useful when comparing PG&E's anticipated voluntary green option, which has been named Community Solar Choice, to a similar option that may be offered by PCE.

Under PG&E's proposed Community Solar Choice program, bundled customers would have the option to voluntarily purchase up to 100% of their respective electric energy requirements from new and existing solar generating facilities located throughout the PG&E service footprint – PG&E has generically defined the location of such facilities as "local", however there does not appear to be a direct association between individual customers and nearby solar generators. According to PG&E, program launch is anticipated in early 2016 with two available supply variations: 50% solar energy content; and 100% solar energy content. At this point, specific details related to Community Solar Choice pricing have not been posted on PG&E's website, but the utility has generally characterized the cost impact in terms of a "modest monthly premium." PEA recommends that the San Mateo Communities continue to monitor the following PG&E website, http://www.pge.com/en/about/environment/pge/solarchoice/index.page?WT.mc_id=Vanity_greenoption, which indicates that more details will be available soon.

Projected average rates for the PCE customer base are shown in the following figure and table, comparing total ratepayer impacts under the PG&E bundled service and CCA service options.

Figure 20: Scenario 3 Annual Ratepayer Costs



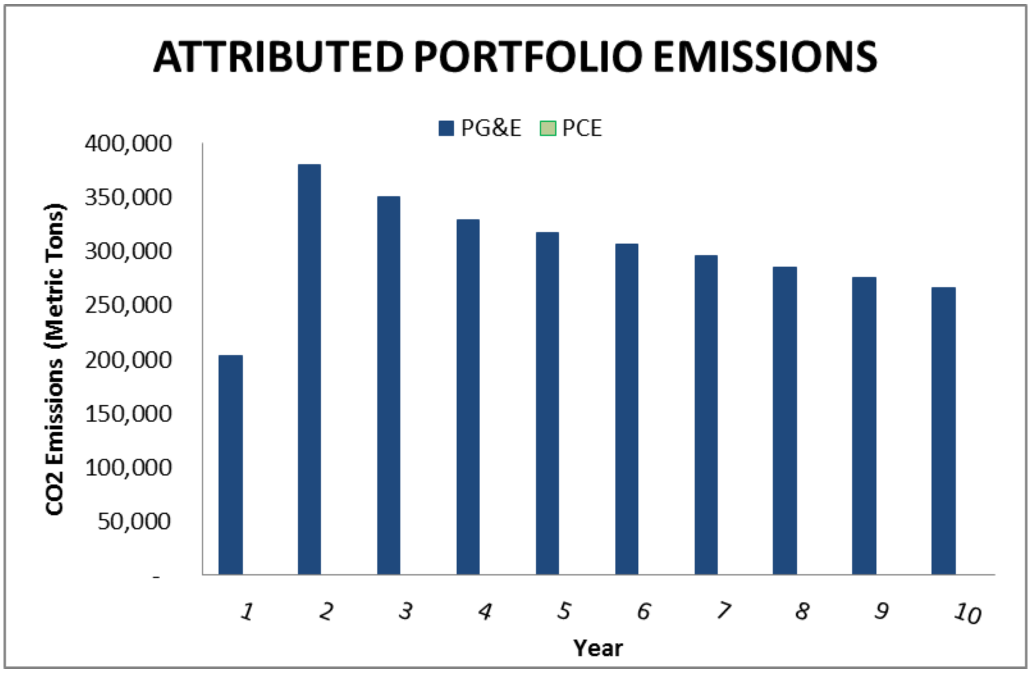
Scenario 3: Annual Total Delivered Rate Comparison

Year	PG&E Total (₵/kWh)	CCA Total (₵/kWh)	Percent Difference
Levelized	23.2	23.7	2%
1	20.5	20.9	2%
2	20.9	21.3	2%
3	21.6	22.0	2%
4	22.3	22.9	3%
5	23.0	23.8	3%
6	23.5	24.3	3%
7	24.3	25.0	3%
8	25.0	25.7	3%
9	25.7	26.2	2%
10	26.5	26.8	1%

GHG Impacts

Through the exclusive use of bundled renewable energy resources, Scenario 3 suggests that the CCA program could achieve substantial GHG emissions reductions when compared to PG&E's projected emissions profile. The following figure and table provide additional detail regarding the respective GHG emissions profile associated with the assumed PCE and PG&E supply portfolios.

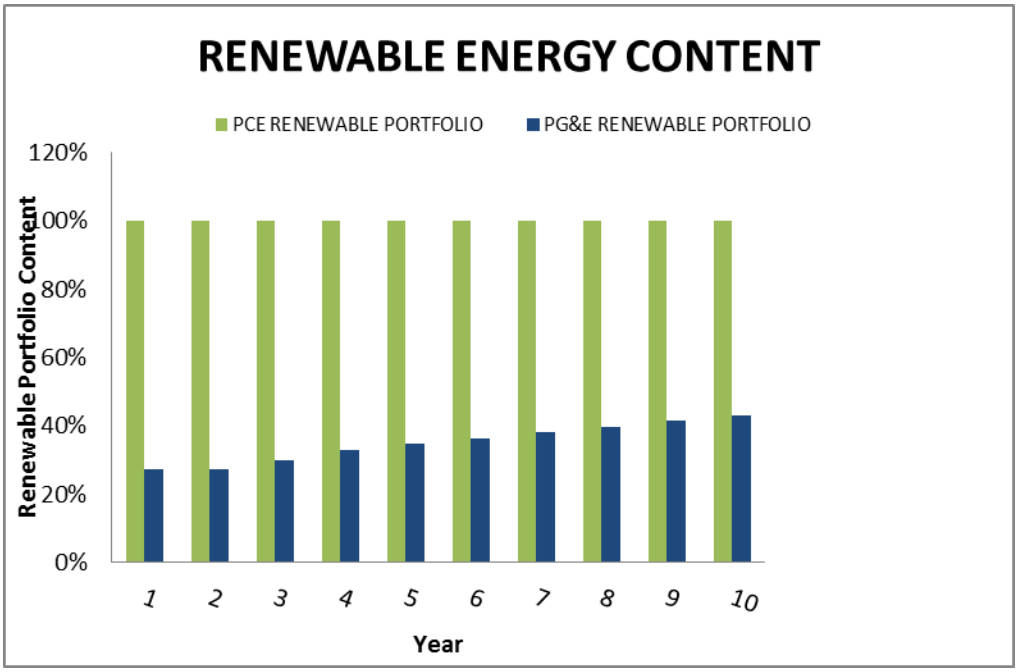
Figure 21: Scenario 3 – Annual GHG Emissions Comparison



Scenario 3: Annual GHG Emissions Factor Comparison (Metric Tons CO_2/MWh)

Year	PG&E	PCE
1	0.158	0.000
2	0.149	0.000
3	0.139	0.000
4	0.131	0.000
5	0.127	0.000
6	0.123	0.000
7	0.120	0.000
8	0.116	0.000
9	0.112	0.000
10	0.109	0.000

Figure 22: Scenario 3 – Annual Renewable Energy Content Comparison



Scenario 3: Annual Renewable Energy Portfolio Content

Year	PG&E	PCE
1	27%	100%
2	27%	100%
3	30%	100%
4	33%	100%
5	35%	100%
6	36%	100%
7	38%	100%
8	40%	100%
9	42%	100%
10	43%	100%

SECTION 6: SENSITIVITY ANALYSES

The economic analysis uses base case input assumptions for many variable factors that influence relative costs of the CCA program. Sensitivity analyses were performed to examine the range of impacts that could result from changes in the most significant variables (relative to base case values). The key variables examined are: 1) power and natural gas prices; 2) renewable energy prices; 3) low carbon energy prices; 4) PG&E rates; 5) PG&E surcharges; and 6) customer participation/opt-out rates.

Power and Natural Gas Prices

Electric power prices in California are substantially influenced by natural gas prices, as natural gas-fired generation is predominantly used as the marginal resource within the state's system dispatch order. Changes in natural gas prices will also tend to change the power purchase costs of the CCA program. To the extent that PCE's selected supply portfolio excludes the use of conventional energy supply, the potential impact related to price volatility within the natural gas market will be minimized. Such changes also influence PG&E's rates, but the relative cost impacts will differ depending upon the proportionate use of conventional resources utilized by the CCA program relative to PG&E.

For the CCA program, the non-renewable portion of the supply portfolio will be influenced by changes in natural gas and wholesale power prices. The PG&E resource mix includes resources that are influenced by natural gas prices such as utility-owned natural gas fueled power plants, so-called "tolling" agreements with independent generators, and certain other contracts that are priced based on an avoided cost formula. The PG&E resource mix also includes energy sources that are not affected by natural gas prices, including renewable resources as well as PG&E's hydro-electric and nuclear assets.

Sensitivity to changes in natural gas and power prices were tested by varying the base case assumptions to create high and low cases. The high case reflects a 50% increase in this input relative to the base case and the low case reflects a 25% decrease relative to the base case.

Renewable Energy Costs

There can be wide variation in renewable energy costs due to locational factors (wind regime, solar insulation, availability of feedstock for biomass and biogas facilities, etc.), transmission costs, technological changes, federal tax policy, and other factors. In fact, the federal investment tax credit, or "ITC", is expected to decrease significantly for projects commencing operations on or after January 1, 2017 – the ITC is expected to drop from 30% to 10%, based on PEA's understanding, which could impose generally proportionate increases to renewable energy pricing following such a change.

Sensitivity to renewable energy cost assumptions was tested by varying the base case costs for renewable power purchase contracts and for the installed costs for renewable generation projects by 25% for the high case and -25% for the low case. The variances were only applied to the CCA's cost structure and not PG&E's in order to test the impact of potential variation in site-specific renewable projects used by the CCA program.

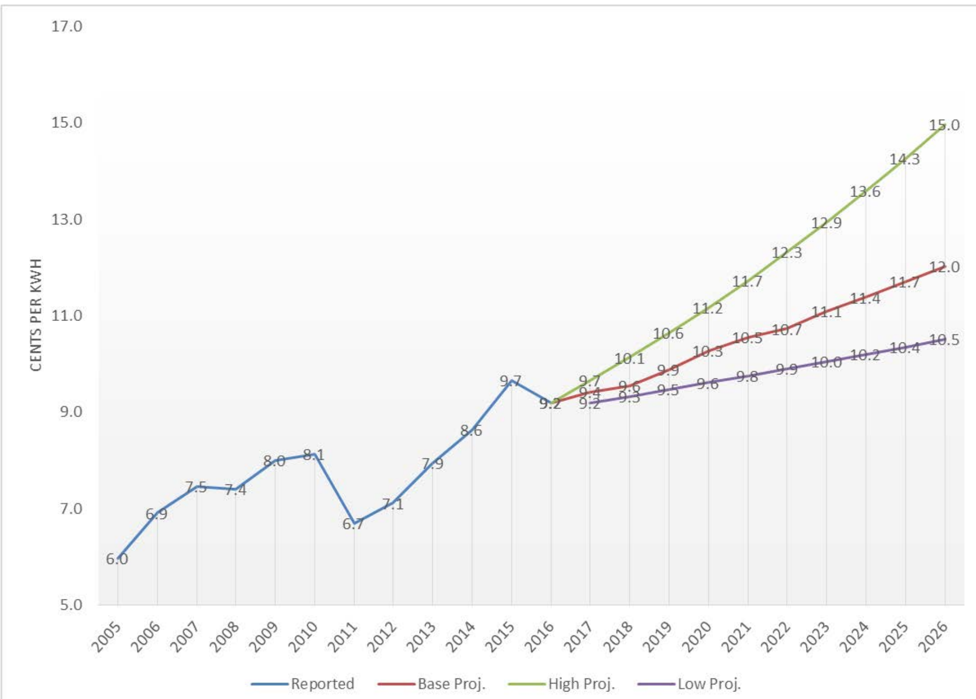
Carbon Free Energy Costs

Specified purchases from carbon free resources or low carbon emissions portfolios generally yields a premium relative to system energy purchases. In consideration of the potential for increased CCA demand for low carbon content energy and the generally fixed supply of the large hydro-electric generation resource base available to California consumers, only a high case was evaluated for this factor. The high carbon free energy cost premium scenario was evaluated at a 300% increase relative to the base case assumption.

PG&E Rates

The base case forecast for PG&E's generation rates yields a projected average annual increase of approximately 2.5%. The forecast relies on resource mix data provided by PG&E in its most recent long-term procurement plan, and incorporates many of the same core market cost assumptions (natural gas prices, power prices, GHG allowance prices, etc.) as used in the forecast of CCA program rates. Numerous factors can cause variances in PG&E's rates, and low and high cases were developed for this variable. One factor that could have a significant increase on PG&E's rates is the potential closure or rebuilding of DCPP, resulting from regulations prohibiting the use of once-through cooling at the plant. A high case was created that reflects an average annual generation rate increase of 5%. The low case assumes 1.5% annual rate increases for PG&E. Figure 23 illustrates the base, high and low case forecasts of PG&E generation rates and how these projections compare with historical trends.

Figure 23: PG&E System Average Generation Rates

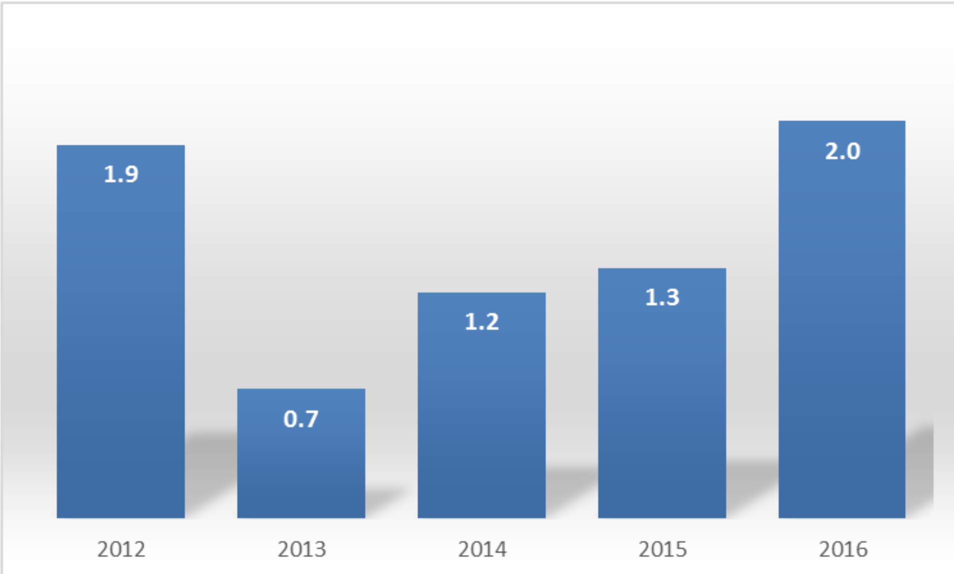


PG&E Surcharges

The PCIA and Franchise Fee surcharges directly impact PCE rate competitiveness, and the PCIA has been volatile. In an August, 2015 filing to the CPUC, PG&E projected PCIA levels for 2016 that are approximately 70% higher than current levels.[21] Figure 24 shows the projected Franchise Fee Surcharge and PCIA applicable to residential customers as well as historical data illustrating the volatility of these surcharges.

[21] PG&E Advice Letter AL-4696-E.

Figure 24: PG&E CCA Surcharges for Residential Customers (Cents Per KWh)



The base case PCIA projections begin with the higher 2016 PCIA charges reported by PG&E and remain relatively flat over the forecast period. High and low cases were run at plus or minus 50% off of the base case.

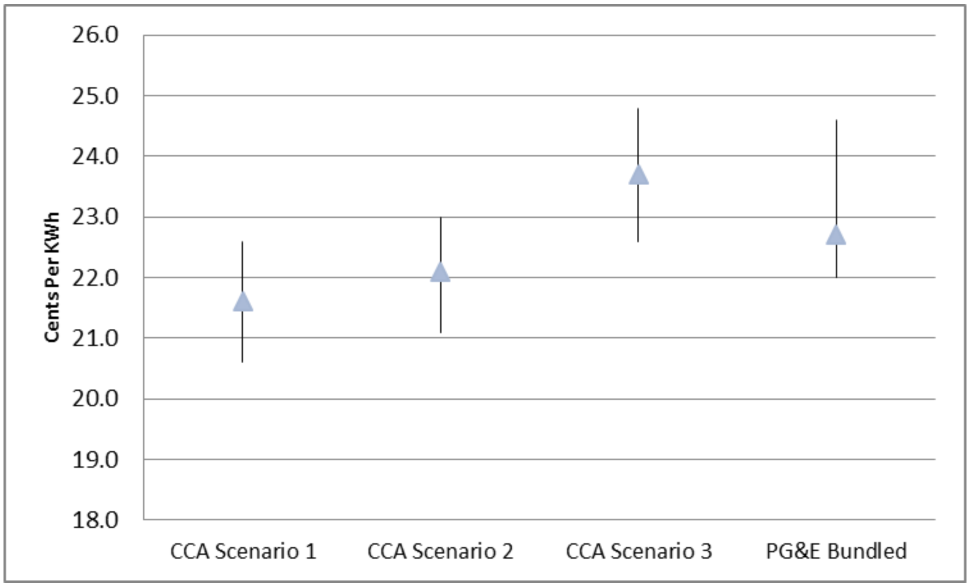
Opt-Out Rates

Sensitivity of ratepayer costs to customer participation in the CCA program was tested by varying the opt-out rate from 25% in the high case to 5% in the low case. For Scenario 3, the high case was set to 35% for residential and small commercial customers and 60% for all other customer groups, while the low case was set to 15% for residential and small commercial and 40% for the other customer groups. A higher opt-out rate would reduce sales volumes relative to base case assumptions, and increase the share of fixed costs paid by each customer, while a lower opt-out rate would have the opposite effect.

Sensitivity Results

The sensitivity analysis produced a range of levelized electric rates for the CCA program and PG&E as shown in the following figure. It should be noted that there is considerable overlap in the range of estimated rates, and while base case estimates show higher rates for the CCA program, any of the CCA Scenarios could potentially result in lower ratepayer costs than under the status quo.

Figure 25: Sensitivity Analysis Range of Levelized Electric Rates



The sensitivity to each tested variable is shown in the following table. Natural Gas/Power prices had the greatest impact on CCA rates in Scenarios 1 and 2, while renewable energy costs were the most significant driver of CCA rates in Scenarios 3.

Sensitivity Analysis: Levelized Ratepayer Costs (Cents Per KWh)

Rate Scenario	Base Case	High Gas/ Power	Low Gas/ Power	High R.E. Costs	Low R.E. Costs	High PG&E Rates	Low PG&E Rates	High PCIA	Low PCIA	High Opt Out	Low Opt Out	High Carbon Free Cost
CCA Scenario 1	21.6	22.5	21.1	22.1	21.1	21.6	21.6	22.6	20.6	21.7	21.5	21.6
CCA Scenario 2	22.1	23.0	21.6	22.7	21.4	22.1	22.1	23.0	21.1	22.1	22.0	22.3
CCA Scenario 3	23.7	24.4	23.4	24.8	22.6	23.7	23.7	24.7	22.7	24.0	23.6	23.7
PG&E Bundled (S1,2)	22.7	23.3	22.3	22.7	22.7	24.1	22.0	22.7	22.7	22.7	22.7	22.7
PG&E Bundled (S3)	23.2	23.8	22.8	23.2	23.2	24.6	22.5	23.2	23.2	23.3	23.1	23.2

The sensitivity results for each PCE supply scenario are depicted graphically in the following figures.

Figure 26: Scenario 1 Sensitivity Impacts on Levelized Electric Rates

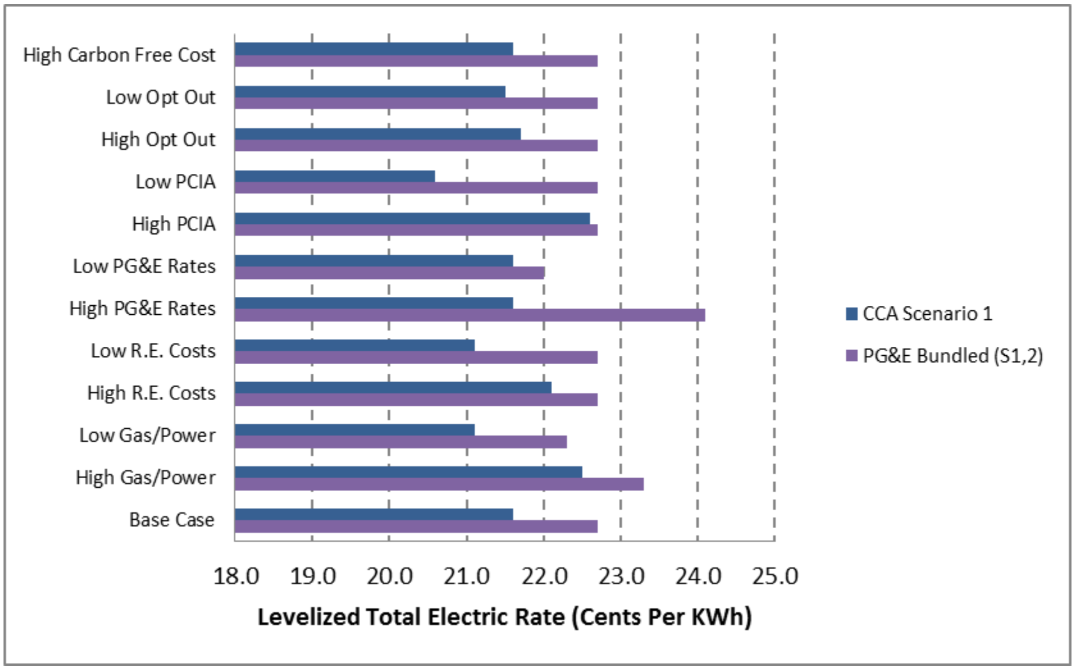


Figure 27: Scenario 2 Sensitivity Impacts on Levelized Electric Rates

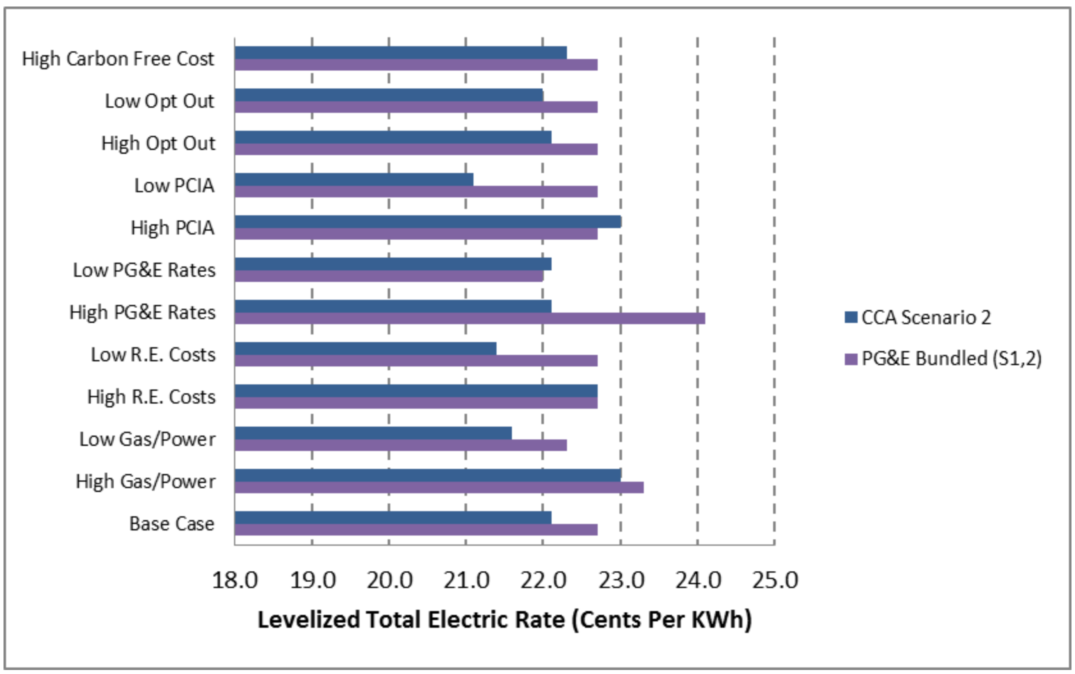
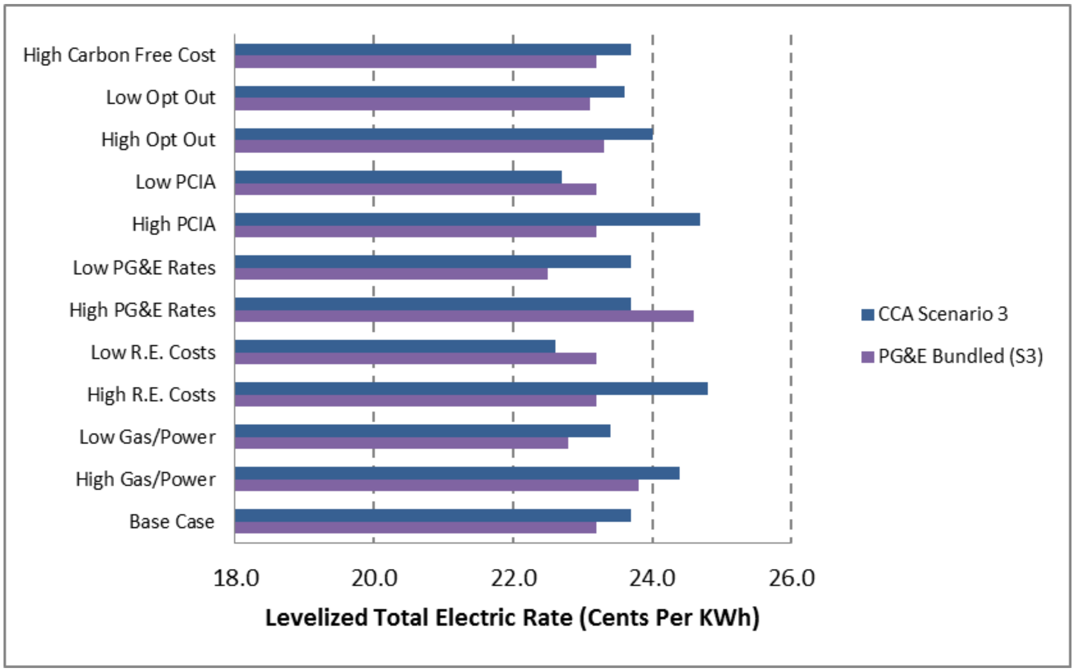


Figure 28: Scenario 3 Sensitivity Impacts on Levelized Electric Rates



SECTION 7: RISK ANALYSIS

CCA formation is not without risk, and a key element of this Study is highlighting key risks that may face the CCA program as well as related risk-mitigation measures. Much of the quantitative impacts associated with key risks has been addressed in Section 6, Sensitivity Analyses, while other risk elements were highlighted in PEA's Alternative CCA Business Model Assessment (the "Assessment"), which was previously provided to San Mateo County. However, there are additional risk elements of which any aspiring CCA program should be aware as well as associated mitigation measures for such risks. In particular, these additional risks include, but are not limited to, the following:

- Financial risks to PCE's member municipalities in the unlikely event of CCA failure;
- Financial risks that may exist in the event that procured energy volumes fall short of or exceed actual customer energy use;
- Reasonably foreseen legislative and regulatory changes, which may limit a CCA's ability to remain competitive with the incumbent utility;
- Availability of renewable and carbon-free energy supplies required to meet compliance mandates, PCE program goals, and customer commitments; and
- General market volatility and price risk.

Financial Risks to PCE Members

In general terms, the prospective financial risks to PCE members will be limited to the extent that the JPA agreement creates separation, also referred to as a "firewall", between the financial assets and obligations of the JPA and those of its individual members. This approach has been effectively employed by both MCE and SCP at the time that each JPA was created, insulating the respective members of each organization from the financial liabilities independently incurred by the JPA (e.g., power purchase agreements, debt, letters of credit and other operating expenditures). For example, if the JPA were to default on a contract obligation, any termination payments would be owed by the JPA and not the individual members, as individual JPA members would not be responsible for the financial commitments of the JPA. From a practical perspective, each member of the JPA would have a relatively small financial exposure, which would be limited to any early-stage contributions and/or expenditures related to the CCA initiative before joining the JPA. After joining the JPA, each participating municipality would be financially insulated via the JPA agreement, and it is anticipated that the JPA would be financially independent during ongoing CCA operations, meaning that the JPA would be responsible for independently demonstrating creditworthiness when entering into power purchase agreements and financial covenants. Based on PEA's understanding, qualified legal counsel was engaged during the formation of each operating, multi-jurisdiction CCA to ensure that the associated JPA agreement created the desired financial protections for its members.

Other than relatively small upfront costs/contributions that may be incurred by the JPA members during CCA evaluation and JPA formation, financial obligations of the participating communities would be limited to individual customer impacts in the event of outright CCA failure. In such a scenario, the $100,000 CCA bond is intended to cover the costs of returning customers to PG&E service. However, following an involuntary return to bundled service, CCA customers would be individually required to pay the transitional bundled commodity cost, as described in PG&E's Electric Schedule TBCC, which imposes a market-based rate on customers who fail to provide PG&E with six-month advance notice prior to reestablishing PG&E electric service.[22] In recent years, the TBCC rate has likely benefited participating customers due to historically low market prices (and the favorable relationship of such prices to PG&E's generation rates). However, inherent price volatility within the

[22] http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_TBCC.pdf

electric power sector could result in relatively high customer costs in the short-term, following an involuntary return to bundled service at a time when market prices are higher than PG&E's prevailing generation rates. In practical terms, the likelihood of this risk materially impacting a PCE customer appears to be quite low.

Deviations between Actual Energy Use and Contracted Purchases

Deviations between actual customer energy use and contracted energy purchases are inevitable. For example, weather variation may impose meaningful day-to-day variances in expected customer energy use, which results in the potential for ongoing imbalances between procured energy volumes and actual electric energy consumption by PCE's customer base. To the extent that such imbalances exist, the CCA may be required to make market purchases during unexpected price spikes and/or sell off excess energy volumes at times when prices are relatively low (when compared to the price paid for such energy), which could impose adverse financial impacts on the CCA program. Again, this is an inevitable risk that is assumed by all energy market participants, but prudent planning and procurement practices can be utilized by the CCA to manage such risk to acceptable levels. In particular, "laddered" procurement strategies can be highly effective in mitigating such risks – this procurement strategy is designed to promote increased cost/rate certainty during the upcoming 12-month operating period by securing 90-100% of the CCA's projected energy requirements during this period of time. Beyond the 12-month operating horizon, an increasing proportion of the CCA's anticipated energy requirements are left "open" (i.e., are not addressed via contractual commitments) to avoid financial commitments based on reduced planning certainty. For example, the CCA program may decide that it is acceptable to take on market price risk associated with 5% of its expected energy requirements over the upcoming 12-month operating period – this strategy would create cost certainty for a significant portion of the CCA's expected energy requirements, allowing the CCA to set rates in consideration of such costs with minimal financial/budgetary risk. For months 13-24, the CCA would reduce forward supply commitments to a level approximating 80-90% of expectations; for months 25-36, the CCA would further reduce forward supply commitments to a level approximating 70-80% of expectations. Forward procurement commitments would continue to "fall down the ladder" in subsequent months, but such open positions are ultimately filled with time. It is also noteworthy that such percentages could always be adjusted in consideration of prevailing market prices and the CCA's overall risk tolerance.

This procurement strategy avoids the prospect of over-procurement and minimizes the prospect of surplus energy sales while also allowing the CCA program to take advantage of favorable procurement opportunities that may come about with time. During early-stage CCA operations, this strategy is particularly useful since the CCA is unlikely to know exact customer participation levels. Over time, as the CCA's customer base becomes more stable/predictable, it will become less challenging to predict customer usage patterns.

Legislative and Regulatory Risk

California's operating CCAs can attest to the challenges presented by anti-CCA legislation – a range of tactics have been employed over time, pre-dating MCE's launch in May, 2010 and resurfacing thereafter in various forms. Ongoing issues continue to arise with regard to proposed legislation designed to assign/shift costs for purposes of competitively disadvantaging CCA programs and/or limit the autonomy of CCA programs, so that such programs appear more similar to their investor-owned counterparts. Recently, SB 350 and AB 1110 have proposed provisions that would be detrimental to existing and aspiring CCA programs.

On September 11, 2015, the California legislature concurred with proposed amendments to Senate Bill 350, the Clean Energy and Pollution Reduction Act of 2015, and recommended this bill for enrolling. If signed, SB 350 would increase California's RPS to 50% by 2030 amongst other clean-energy initiatives. To enact the provisions of SB 350, Governor Brown must sign the bill by October 11, 2015. Many details regarding implementation of SB 350 will be developed over time with oversight by applicable regulatory agencies. With regard to other relevant changes that will be created by SB 350, CCAs should be aware of the following:

- Costs associated with the integration of new renewable infrastructure may be off-set by a CCA if it can demonstrate to the CPUC that it has already provided equivalent resources [Sections 454.51(d) and 454.52(c)];
- CCAs will be required to submit Integrated Resource Plans to the CPUC for certification while retaining the governing authority and procurement autonomy administered by their respective governing boards [Section 454.52(b)(3)];
- The CPUC is now responsible for ensuring that: (1) IOU bundled customers do not incur any cost increases as a result of customers participating in CCA service options, and (2) CCA customers do not experience any cost increases as a result of IOU cost allocation that is not directly related to such CCA customers (Sections 365.2 and 366.3);
- Beginning in 2021, CCAs must have at least 65% of their RPS procurement under long-term contracts of 10 years or more [Section 399.13(b)]; and
- CCA energy efficiency programs will be able to count towards statewide energy efficiency targets [Sections 25310(d)(6) and 25310(d)(8)].

In aggregate, the CCA-specific changes reflected in SB 350 are generally positive, providing for ongoing autonomy with regard to resource planning and procurement. CCAs must be aware, however, of the long-term contracting requirement associated with renewable energy procurement. This is not expected to present issues for PCE, but planning and procurement efforts will need to consider this requirement during ongoing operation of the CCA program.

AB 1110, which is now a two-year bill, was primarily focused on the addition of GHG emission disclosures within the Power Content Label. During discussion in the recent legislative session, CCA interests were generally concerned that the emissions methodology reflected in the bill was designed in a manner that was not necessarily consistent with retail-level emissions reporting conventions used throughout the electric utility industry and also appeared to diminish the environmental value of certain clean energy products. On September 8, 2015, AB 1110 was ordered to the inactive file at the request of Senator Wolk.[23] With this direction in mind, AB 1110 is no longer an issue in the current legislative session. However, PEA recommends that the San Mateo Communities should continue to monitor the legislature's interest in promoting certain reporting changes reflected in AB 1110, as such changes could narrow the potential field of cost-effective supply options that could be pursued by PCE at some point in the future. The AB 1110 GHG emissions reporting methodology may also present methodological conflicts with other programs, such as The Climate Registry, which may be of interest to PCE at some point in the future.

Regulatory risks include the potential for utility generation costs to be shifted to non-bypassable and delivery charges. Examples include: 1) the Cost Allocation Mechanism, under which the costs of certain generation commitments made by the investor owned utilities deemed necessary for grid reliability or to support other state policy, are allocated to non-bundled (CCA and direct access) customers; and 2) the PCIA as previously discussed. Another significant regulatory risk relates to changes that may occur with regard to the CCA Bond amount. Currently, the $100,000 bond amount is quite manageable for aspiring CCA initiatives, but this could change dramatically in the event that a larger bond amount, based on market conditions at the time of an involuntary return of customers to bundled service, is established at some point in the future. PEA recommends that the San

[23] AB 1110 bill history: http://leginfo.legislature.ca.gov/faces/billHistoryClient.xhtml?bill_id=201520160AB1110.

Mateo Communities actively monitor and participate in, as necessary, related regulatory proceedings to ensure that this item does not become a barrier for CCA formation or ongoing operation.

Availability of Requisite Renewable and Carbon-Free Energy Supplies

The prospect of a 50% RPS in California has prompted various questions regarding the sufficiency of renewable generating capacity that may be available to support compliance with such mandates. In particular, both new and existing CCAs, which will be subject to prevailing RPS procurement mandates, represent a growing pool of renewable energy buyers that will be "competing" for requisite in-state resources. While this is certainly a legitimate concern, particularly when considering that the potential for CCA expansion throughout California seems quite significant, it strikes PEA as highly unlikely that any CCA buyer would be unable to meet applicable procurement mandates during the ten-year planning horizon. To date, renewable energy contracting opportunities within California have been abundant, providing interested buyers with cost-competitive procurement opportunities well in excess of compliance mandates and voluntary renewable energy procurement targets that have been established by certain CCAs. Furthermore, to the extent that additional CCA programs continue to form, California's largest buyers of renewable energy, represented by the three investor-owned utilities, will have diminished renewable energy procurement obligations as a result of decreasing retail sales. Certainly, the potential exists for increased supply costs as additional CCA buyers compete for available renewable projects, but the general availability of such projects does not seem to be a significant issue that will face PCE over the ten-year planning horizon.

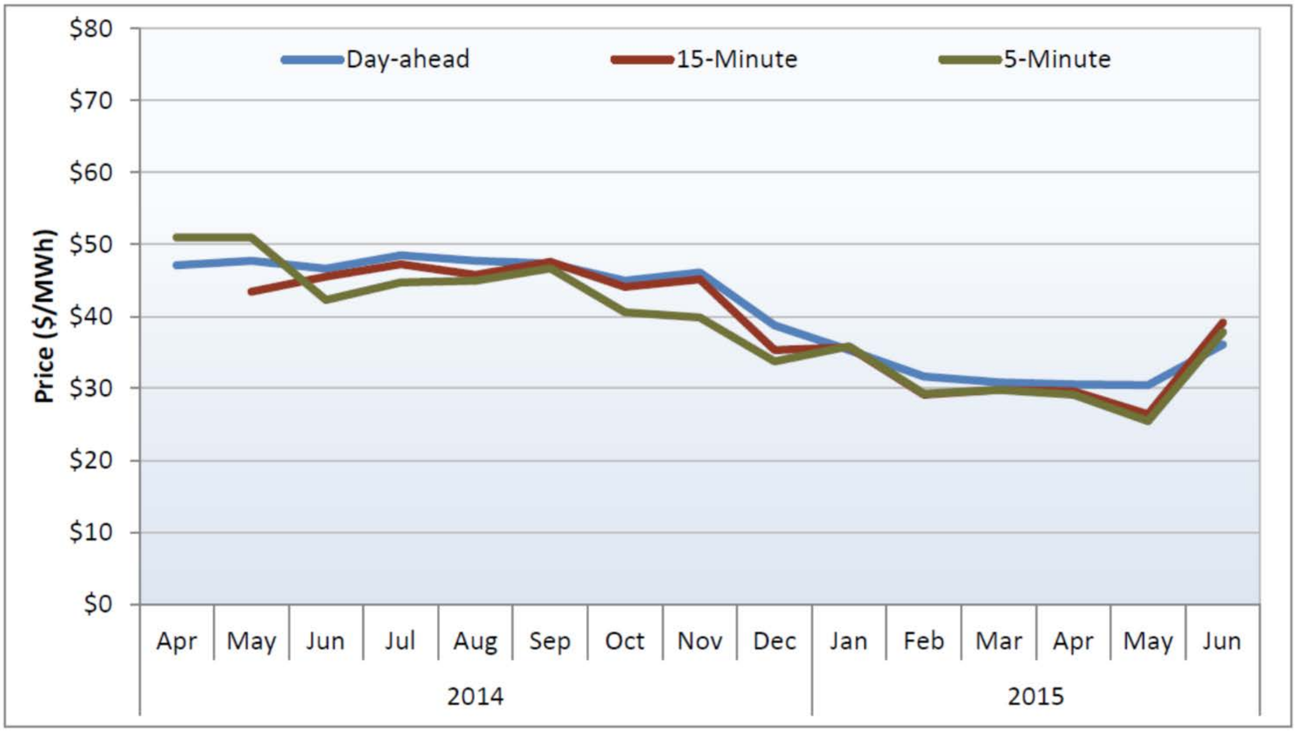
Additionally, as the operational and future CCA's strive to meet high carbon-free energy targets, there is some uncertainty around the availability of hydroelectric generation resources within California and throughout the Pacific Northwest to meet such goals. Outside of renewable energy resources, hydroelectric generation is the lowest cost means of meeting carbon-free objectives (with it in mind that nuclear generation will be excluded from PCE's supply portfolio) but also comes with certain variability in supply. Given the variability of such resources (i.e., wet versus dry year) and unpredictability of the day-to-day energy deliveries, there is risk in achieving carbon content goals. There is also a cost risk associated with the transmission of out-of-state hydroelectric generation into California during certain times of the year when California energy buyers are seeking to import peak hydro season production – this congestion risk could add significant costs to contracted hydroelectric power.

Market Volatility and Price Risk

Wholesale energy markets are subject to sudden and significant volatility, resulting from myriad factors, including but not limited to the following: weather, natural disasters, infrastructure outages, legislation and implementing regulations, and natural gas storage levels. Over the past 24 months (or longer), wholesale energy prices have fallen to near-historic lows, providing a favorable environment for buyers of electric energy. An abundance of domestic natural gas supply, particularly shale gas, and strong storage levels have also suppressed electric energy pricing, which will likely promote the continued trend of relatively low prices for the foreseeable future. However, unexpected circumstances can impose abrupt changes to available pricing, which necessitates a thoughtful, disciplined approach to managing such risk. The following figure, provided by the CAISO, illustrates historic volatility in the wholesale electricity market, including a nearly 40% reduction in such prices over the past 24 months.[24]

[24] California ISO Q2 2015 Report on Market Issues and Performance, August 17, 2015.

Figure 29: Historical Wholesale Electricity Price Curve



As previously described, a laddered procurement strategy will serve to mitigate wholesale pricing impacts at any single point in time. Much like dollar cost averaging in the financial sector, laddered procurement strategies serve to mask the impacts of periodic price spikes and troughs by blending the financial impacts associated with such changes through a temporally diversified supply portfolio. This procurement strategy should also create a certain level of symmetry with market impacts that would also affect incremental procurement completed by the incumbent utility. Ultimately, there is no mitigation tactic that could completely insulate the CCA from market price risk, but a diversified supply portfolio, in terms of transaction timing, fuel sources and contract term lengths, will minimize such risks over time.

SECTION 8: ALTERNATIVE CCA BUSINESS MODEL ASSESSMENT: THIRD-PARTY ADMINISTRATION

In June 2015, PEA prepared and delivered an assessment of the fully outsourced CCA service model at the request of San Mateo County. In general terms, the "fully outsourced model" purported to minimize risks and guarantee benefits typically associated with CCA implementation and operation. This approach differs from the approach taken by California's operating CCAs, which have established internal organizations with the intent of providing CCA as a locally focused/locally situated public service organization for the long term. The existing CCAs have opted for more traditional supplier/service arrangements with longer-standing, highly experienced organizations and/or through the development of internal staff, who have been assigned responsibility for certain operational functions. Based on PEA's research and evaluation, there are certain benefits and risks associated with this approach, which are further articulated in the Assessment, which is incorporated by reference in this Study but not attached hereto.

SECTION 9: CCA FORMATION ACTIVITIES

This section provides a high level summary of the main steps involved in forming a CCA program that culminates in the provision of service to enrolled customers. Key implementation activities include those related to 1) CCA entity formation; 2) regulatory requirements; 3) procurement; 4) financing; 5) organization; and 6) customer noticing. Completion of these activities is reflected in the Study's startup cost estimates.

CCA Entity Formation

Unless the municipal organization that will legally register as the CCA entity already exists, it must be legally established. Municipalities electing to offer or allow others to offer CCA service within their jurisdiction must do so by ordinance. As anticipated for PCE, a joint power authority ("JPA"), the members of which will include certain or all municipal jurisdictions within the San Mateo Communities intending to offer CCA service, will be formed via a related agreement amongst the participating municipalities. Specific examples of applicable JPA agreements are available for currently operating CCA programs, including MCE and SCP, which were formed under this joint structure. Based on PEA's understanding, specific details related to PCE's JPA agreement are currently under development.

Regulatory Requirements

Before aggregating customers, the CCA program must meet certain requirements set forth by the CPUC. In the case of PCE, an Implementation Plan must be adopted by the joint powers authority, and that Implementation Plan must be submitted to the CPUC. The Implementation Plan must include the following:

- An organizational structure of the program, its operations, and its funding;
- Ratesetting and other costs to participants;
- Provisions for disclosure and due process in setting rates and allocating costs among participants;
- The methods for entering and terminating agreements with other entities;
- The rights and responsibilities of program participants, including, but not limited to, consumer protection procedures, credit issues, and shutoff procedures;
- Termination of the program; and
- A description of the third parties that will be supplying electricity under the program, including, but not limited to, information about financial, technical, and operational capabilities.

A Statement of Intent must be included with the Implementation Plan that provides for:

- Universal access
- Reliability
- Equitable treatment of all classes of customers
- Any requirements established by law or the CPUC concerning aggregated service.

The CPUC has ninety days to complete a review and certify the Implementation Plan though previous Implementation Plan reviews completed on behalf of other California CCA programs have required far less time. Following certification of the Implementation Plan, the CCA entity must submit a registration packet to the CPUC, which includes:

- An executed service agreement with PG&E, which may require a security deposit; and

- A bond or evidence of sufficient insurance to cover any reentry fees that may be imposed against it by the CPUC for involuntarily returning customers to PG&E service. As previously noted, the current CCA bond amount is $100,000.

The CCA program would be required to participate in the CPUC's resource adequacy program before commencing service to customers by providing load forecasts and advance demonstration of resource adequacy compliance.

Procurement

Power supplies must be secured several months in advance of commencing service. Power purchase agreements with one or more power suppliers would be negotiated, typically following a competitive selection process. Services that are required include provision of energy, capacity, renewable energy and scheduling coordination.

Financing

Funding must be obtained to cover start-up activities and working capital needs. Start-up funding would be secured early in the implementation process as these funds would be needed to conduct the critical activities leading up to service commencement. Working capital lender commitments should be secured well in advance, but actual funding need not occur until near the time that service begins.

Organization

Initial staff positions would be filled several months in advance of service commencement to conduct the implementation process. Initially, internal staff of the CCA program may be relatively small but this would likely change in the event that the CCA determines to insource various administrative and operational responsibilities and/or develops and administers new programs for its customers. Contracts with other service providers, such as for data management services, would be negotiated and put into effect well in advance of service commencement.

Customer Notices

Customers must be provided notices regarding their pending enrollment in the CCA program. Such notices must contain program terms and conditions as well as opt-out instructions and must be sent to prospective customers at least twice within the sixty-day period immediately preceding automatic enrollment. These notices are referred to as "pre-enrollment" notices. Two additional "post-enrollment" notices must be provided within the sixty-day period following customer enrollment during the statutory opt-out period.

Ratesetting and Preliminary Program Development

As a California CCA, PCE would have independent ratesetting authority with regard to the electric generation charges imposed on its customers. Prior to service commencement, PCE would need to establish initial customer generation rates for each of the customer groups represented in its first operating phase or for all prospective customers within the CCA's prospective service territory. PCE may decide to create a schedule of customer generation rates that generally resembles the current rate options offered by PG&E. This practice would facilitate customer rate comparisons and should avoid confusion that may occur if customers were to be transitioned to dissimilar tariff options. PCE would need to establish a schedule for ongoing rate updates/changes for future customer phases and ongoing operations.

PCE may also choose to offer certain customer-focused programs, such as Net Energy Metering ("NEM"), voluntary green pricing and/or FIT programs, at the time of service commencement. To the extent that PCE intends to offer such programs, specific terms and conditions of service would need to be developed in advance of service commencement.

SECTION 10: EVALUATION AND RECOMMENDATIONS

This section provides an overall assessment of the feasibility for forming a CCA program serving the San Mateo Communities and provides PEA's recommendations in the event a decision is made to proceed with development of the PCE program.

PEA's analysis suggests that PCE could provide significant benefits – both economic and environmental – which could be accomplished under certain prospective operating scenarios with customer rates that are competitive, if not lower than, current rate projections for PG&E. Under a reasonable range of sensitivity assumptions, the analysis shows that customer rates are projected to range from approximately 21 to 25 cents per kWh, on a ten-year levelized cost basis, while PG&E rates are projected to range from 22 to 24 cents per kWh on a levelized basis over this same period of time.

Under base case assumptions, CCA program rates are projected to range from 21.6 cents per kWh to 23.7 cents per kWh, depending upon the ultimate CCA program resource mix. PG&E's generation rate is projected to be 22.7 cents per kWh, creating the potential for customer savings under two of the three supply scenarios. The following table shows projected levelized electric rates and typical residential monthly electric bills under the base case assumptions.

Summary of Ratepayer Impacts

Ratepayer Impact	Scenario 1	Scenario 2	Scenario 3	PG&E
Levelized Electric Rate (Cents/KWh)	21.6	22.1	23.7	22.7
Typical Residential Bill ($/Month)[25]	$97	$99	$107	$102

It should be noted that there is considerable overlap in the range of estimated rates under the various sensitivity scenarios described in this Study, and while base case estimates generally show highly competitive rates for the CCA program, it is anticipated that Scenarios 1 and 2 are most likely to generate customer rate savings while Scenario 3 is most likely to result in increased customer costs relative to the status quo.

With regard to GHG emissions impacts, the ultimate resource mix identified by the CCA program will dictate overall GHG emissions impacts created by PCE operation. Depending upon resource choices made by the CCA program, potential GHG emissions may vary widely relative to PG&E. For example, under Scenario 1, PCE should assume a significant increase in comparative GHG emissions within the San Mateo Communities' electric power sector. Scenarios 2 and 3 are both expected to create significant GHG emissions reductions through the procurement of significant quantities of carbon-free energy. The following table summarizes projected GHG emissions impacts for each of the modeled supply scenarios.

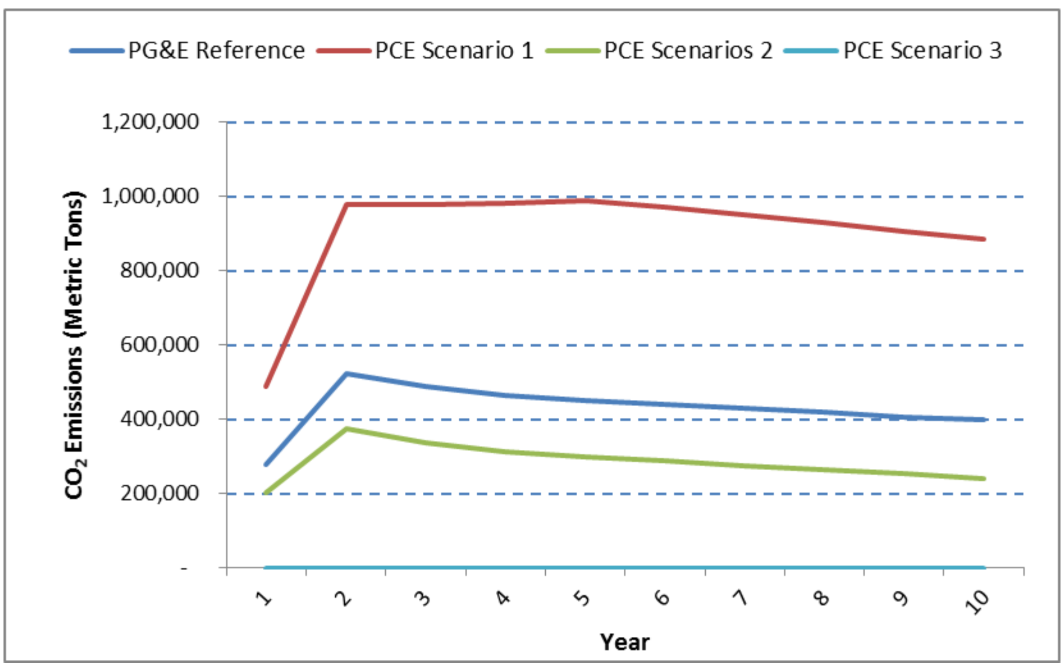
[25] Typical residential monthly consumption in the San Mateo Communities is approximately 450 kWh.

GHG Emissions Impacts (Ten Year Average)

GHG Impact	Scenario 1	Scenario 2	Scenario 3
Annual Change in GHG Emissions (Tons CO_2/Year)	476,125	-145,036	-301,269
Change in Electric Sector CO_2 Emissions in San Mateo County (%)	+111%	-34%	-100%
Projected PCE Portfolio Emissions Factor (metric tons/MWh)	0.268	0.086	0
Projected PG&E Portfolio Emissions Factor (metric tons/MWh)	0.128	0.128	0.128

The following figures illustrate projected GHG emissions under the status quo as well as each of the prospective PCE supply scenarios. Note that the projected GHG emissions trend associated with Scenario 3 coincides with the figure's horizontal access, as there are zero assumed GHG emissions under this planning scenario (resulting from the exclusive use of bundled renewable energy resources).

Figure 30: Projected GHG Emissions



The potential for local generation investment arising from the CCA program appears to offer significant benefits to the local economy. Again, resource decisions will impact the degree to which generation investments yield local benefits as indicated through the analysis of local economic impact associated with the representative supply scenarios. Compared to some other areas in the state, San Mateo County is not the best resource area for solar and wind production, and local projects of this type will tend to have higher costs than projects sited in prime resource areas. Tradeoffs also exist between minimizing ratepayer costs in the short run and expanding use of renewable energy due to the cost premiums that currently exist for renewable energy. Decisions made during the implementation process and during the life of the CCA program will determine how these considerations are balanced. PEA recommends that considerable thought be given upfront to the ultimate goals of the CCA program so that clear objectives are established, giving those responsible for administering the CCA program the opportunity to develop and execute resource management and procurement plans that meet objectives of the San Mateo Communities.

In summary, it is PEA's opinion that, based on currently observed wholesale market conditions, anticipated PG&E electric rates and certain of the supply scenarios evaluated in this Study, amongst various other considerations, a CCA program serving customers within the San Mateo Communities could offer both economic (i.e., positive local economic development impacts and overall cost savings for customers of the CCA program) and environmental benefits during initial program operations and, potentially, throughout the ten-year study period. As previously noted, inherent power market volatility suggests that the San Mateo Communities should affirm the appropriateness of assumptions and projections reflected in this Study before taking any action related to CCA program formation.

APPENDIX A: PCE PRO FORMA ANALYSES

PENINSULA CLEAN ENERGY
FINANCIAL PRO FORMA ANALYSIS
COMMUNITY CHOICE AGGREGATION
SCENARIO 1

CATEGORY	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10
I, CUSTOMER ACCOUNTS:										
RESIDENTIAL (E-1)	114,351	228,702	228,702	229,845	230,995	232,150	233,310	234,477	235,649	236,827
SMALL COMMERCIAL (A-1)	9,080	18,159	18,159	18,250	18,341	18,433	18,525	18,618	18,711	18,805
SMALL COMMERCIAL (A-6)	726	1,452	1,452	1,459	1,466	1,474	1,481	1,488	1,496	1,503
MEDIUM COMMERCIAL (A-10)	1,133	2,265	2,265	2,277	2,288	2,299	2,311	2,322	2,334	2,346
LARGE COMMERCIAL (E-19)	567	1,133	1,133	1,139	1,144	1,150	1,156	1,162	1,167	1,173
INDUSTRIAL (E-20)	18	37	37	37	37	37	37	37	38	38
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	609	1,217	1,217	1,223	1,229	1,236	1,242	1,248	1,254	1,260
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	117	234	234	235	236	237	238	240	241	242
SUBTOTAL - CUSTOMER ACCOUNTS	126,599	253,199	253,199	254,465	255,737	257,016	258,301	259,592	260,890	262,195
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	619,470,827	1,238,966,523	1,238,991,392	1,245,186,349	1,251,412,281	1,257,669,342	1,263,957,689	1,270,277,477	1,276,628,865	1,283,012,009
SMALL COMMERCIAL (A-1)	163,302,073	326,609,557	326,614,968	328,248,043	329,889,283	331,538,730	333,196,424	334,862,406	336,536,718	338,219,401
SMALL COMMERCIAL (A-6)	36,025,089	72,051,506	72,052,834	72,413,098	72,775,164	73,139,039	73,504,735	73,872,258	74,241,620	74,612,828
MEDIUM COMMERCIAL (A-10)	260,685,684	521,379,715	521,388,062	523,995,002	526,614,977	529,248,052	531,894,292	534,553,764	537,226,533	539,912,665
LARGE COMMERCIAL (E-19)	396,641,238	793,295,726	793,308,975	797,275,519	801,261,897	805,268,207	809,294,548	813,341,020	817,407,725	821,494,764
INDUSTRIAL (E-20)	160,824,374	321,653,919	321,659,091	323,267,386	324,883,723	326,508,142	328,140,683	329,781,386	331,430,293	333,087,445
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	10,221,691	20,443,736	20,444,090	20,546,311	20,649,042	20,752,288	20,856,049	20,960,329	21,065,131	21,170,457
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	10,665,003	21,330,429	21,330,852	21,437,506	21,544,694	21,652,417	21,760,679	21,869,483	21,978,830	22,088,724
SUBTOTAL - LOAD REQUIREMENTS	1,657,835,979	3,315,731,111	3,315,790,265	3,332,369,216	3,349,031,062	3,365,776,217	3,382,605,098	3,399,518,124	3,416,515,714	3,433,598,293
III. CCA OPERATING COSTS ($)										
SHORT TERM MARKET PURCHASES	$4,317,715	$9,146,064	$9,447,042	$10,113,129	$10,711,727	$11,179,941	$11,614,587	$12,036,883	$12,152,944	$12,437,741
TERM CONTRACT PURCHASES	$41,968,188	$121,399,342	$141,922,816	$177,540,042	$184,130,035	$189,457,267	$193,504,832	$197,434,581	$215,997,537	$218,419,119
SHORT TERM RENEWABLE MARKET PURCHASES AND RECS	$35,506,512	$48,420,548	$32,533,688	$11,131,853	$10,861,824	$14,256,163	$19,533,378	$25,379,987	$13,422,459	$19,479,769
SHORT TERM CARBON FREE MARKET PURCHASES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANCILLARY SERVICES AND CAISO CHARGES	$5,023,326	$10,384,953	$10,707,528	$11,126,782	$11,553,418	$12,008,301	$12,483,099	$12,974,910	$13,447,977	$13,956,940
RESOURCE ADEQUACY CAPACITY	$8,333,154	$15,125,285	$13,325,313	$13,004,024	$13,384,817	$13,780,229	$14,354,007	$14,952,071	$14,990,346	$15,629,044
STAFF AND OTHER OPERATIONS COSTS	$6,224,813	$8,108,680	$8,270,918	$8,454,641	$8,642,498	$8,834,583	$9,030,992	$9,231,824	$9,437,181	$9,647,164
BILLING AND DATA MANAGEMENT	$2,977,618	$6,133,894	$6,317,911	$6,539,985	$6,769,866	$7,007,827	$7,254,152	$7,509,135	$7,773,081	$8,046,305
UNCOLLECTIBLES EXPENSE	$546,431	$1,118,268	$1,137,300	$1,214,226	$1,254,945	$1,282,622	$1,338,875	$1,397,597	$1,436,108	$1,488,080
STARTUP FINANCING	$4,934,813	$4,934,813	$4,934,813	$4,934,813	$4,934,813	$0	$0	$0	$0	$0
CCA BOND CARRYING COST	$4,498	$9,266	$9,544	$9,879	$10,227	$10,586	$10,958	$11,343	$11,742	$12,155
SUBTOTAL - CCA OPERATING COSTS	$109,837,068	$224,781,113	$228,606,873	$244,069,374	$252,254,169	$257,817,517	$269,124,881	$280,928,332	$288,669,375	$299,116,319
IV. REVENUES FROM GREEN PREMIUM AND MARKET SALES ($)										
GREEN PRICING PREMIUM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MARKET SALES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
V. CONTRIBUTION TO PROGRAM RESERVES ($)	$3,295,112	$6,743,433	$6,858,206	$7,322,081	$7,567,625	$7,734,526	$8,073,746	$8,427,850	$8,660,081	$8,973,490
VI. CCA REVENUE REQUIREMENT ($)	$113,132,180	$231,524,547	$235,465,080	$251,391,455	$259,821,794	$265,552,043	$277,198,627	$289,356,182	$297,329,456	$308,089,808
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	6.8	7.0	7.1	7.5	7.8	7.9	8.2	8.5	8.7	9.0
PG&E AVERAGE GENERATION COST (CENTS/KWH)	9.7	9.8	10.2	10.6	10.8	11.0	11.4	11.7	12.0	12.4
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
POWER CHARGE INDIFFERENCE ADJUSTMENT	$25,915,755	$51,553,829	$57,388,579	$59,734,338	$68,565,139	$71,009,591	$73,095,756	$72,606,186	$75,773,871	$75,292,787
FRANCHISE FEE SURCHARGE	$1,200,075	$2,433,427	$2,518,727	$2,627,661	$2,713,295	$2,773,731	$2,884,199	$2,971,981	$3,073,169	$3,173,136
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 27,115,829	$ 53,987,255	$ 59,907,306	$ 62,361,999	$ 71,278,434	$ 73,783,321	$ 75,979,955	$ 75,578,166	$ 78,847,040	$ 78,465,922
VIII. CCA REVENUE REQUIREMENT PLUS PG&E CCA CUSTOMER SURCHARGES	$140,248,009	$285,511,802	$295,372,386	$313,753,455	$331,100,228	$339,335,364	$353,178,582	$364,934,349	$376,176,496	$386,555,731
IX. REVENUE AT PG&E GENERATION RATES	$160,662,350	$325,779,825	$337,199,584	$351,783,272	$363,247,732	$371,338,653	$386,127,844	$397,879,787	$411,426,593	$424,809,838
X. TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES	**$ (20,414,341)**	**$ (40,268,023)**	**$ (41,827,199)**	**$ (38,029,817)**	**$ (32,147,504)**	**$ (32,003,289)**	**$ (32,949,262)**	**$ (32,945,439)**	**$ (35,250,097)**	**$ (38,254,108)**
CHANGE IN CUSTOMER ELECTRIC CHARGES (%)	**-6%**	**-6%**	**-6%**	**-5%**	**-4%**	**-4%**	**-4%**	**-4%**	**-4%**	**-4%**

PENINSULA CLEAN ENERGY
FINANCIAL PRO FORMA ANALYSIS
COMMUNITY CHOICE AGGREGATION
SCENARIO 2

CATEGORY	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10
I, CUSTOMER ACCOUNTS:										
RESIDENTIAL (E-1)	114,351	228,702	228,702	229,845	230,995	232,150	233,310	234,477	235,649	236,827
SMALL COMMERCIAL (A-1)	9,080	18,159	18,159	18,250	18,341	18,433	18,525	18,618	18,711	18,805
SMALL COMMERCIAL (A-6)	726	1,452	1,452	1,459	1,466	1,474	1,481	1,488	1,496	1,503
MEDIUM COMMERCIAL (A-10)	1,133	2,265	2,265	2,277	2,288	2,299	2,311	2,322	2,334	2,346
LARGE COMMERCIAL (E-19)	567	1,133	1,133	1,139	1,144	1,150	1,156	1,162	1,167	1,173
INDUSTRIAL (E-20)	18	37	37	37	37	37	37	37	38	38
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	609	1,217	1,217	1,223	1,229	1,236	1,242	1,248	1,254	1,260
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	117	234	234	235	236	237	238	240	241	242
SUBTOTAL - CUSTOMER ACCOUNTS	126,599	253,199	253,199	254,465	255,737	257,016	258,301	259,592	260,890	262,195
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	619,470,827	1,238,966,523	1,238,991,392	1,245,186,349	1,251,412,281	1,257,669,342	1,263,957,689	1,270,277,477	1,276,628,865	1,283,012,009
SMALL COMMERCIAL (A-1)	163,302,073	326,609,557	326,614,968	328,248,043	329,889,283	331,538,730	333,196,424	334,862,406	336,536,718	338,219,401
SMALL COMMERCIAL (A-6)	36,025,089	72,051,506	72,052,834	72,413,098	72,775,164	73,139,039	73,504,735	73,872,258	74,241,620	74,612,828
MEDIUM COMMERCIAL (A-10)	260,685,684	521,379,715	521,388,062	523,995,002	526,614,977	529,248,052	531,894,292	534,553,764	537,226,533	539,912,665
LARGE COMMERCIAL (E-19)	396,641,238	793,295,726	793,308,975	797,275,519	801,261,897	805,268,207	809,294,548	813,341,020	817,407,725	821,494,764
INDUSTRIAL (E-20)	160,824,374	321,653,919	321,659,091	323,267,386	324,883,723	326,508,142	328,140,683	329,781,386	331,430,293	333,087,445
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	10,221,691	20,443,736	20,444,090	20,546,311	20,649,042	20,752,288	20,856,049	20,960,329	21,065,131	21,170,457
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	10,665,003	21,330,429	21,330,852	21,437,506	21,544,694	21,652,417	21,760,679	21,869,483	21,978,830	22,088,724
SUBTOTAL - LOAD REQUIREMENTS	1,657,835,979	3,315,731,111	3,315,790,265	3,332,369,216	3,349,031,062	3,365,776,217	3,382,605,098	3,399,518,124	3,416,515,714	3,433,598,293
III. CCA OPERATING COSTS ($)										
SHORT TERM MARKET PURCHASES	$5,484,255	$10,740,437	$9,997,917	$9,920,684	$10,057,485	$10,258,693	$10,468,437	$10,659,214	$10,485,292	$10,558,285
TERM CONTRACT PURCHASES	$13,820,323	$59,565,501	$75,292,315	$104,240,553	$105,356,913	$106,640,147	$106,991,504	$107,297,295	$124,293,855	$124,131,155
SHORT TERM RENEWABLE MARKET PURCHASES AND RECS	$50,723,588	$80,389,117	$65,645,113	$46,132,244	$53,831,801	$62,555,187	$72,833,119	$84,035,886	$76,947,164	$88,633,621
SHORT TERM CARBON FREE MARKET PURCHASES	$17,514,733	$40,463,296	$45,941,285	$52,275,251	$52,383,020	$52,595,382	$52,571,514	$52,173,130	$50,500,177	$48,918,593
ANCILLARY SERVICES AND CAISO CHARGES	$5,023,326	$10,384,953	$10,707,528	$11,126,782	$11,553,418	$12,008,301	$12,483,099	$12,974,910	$13,447,977	$13,956,940
RESOURCE ADEQUACY CAPACITY	$8,333,154	$15,125,285	$13,325,313	$13,004,024	$13,384,817	$13,780,229	$14,354,007	$14,952,071	$14,990,346	$15,629,044
STAFF AND OTHER OPERATIONS COSTS	$6,224,813	$8,108,680	$8,270,918	$8,454,641	$8,642,498	$8,834,583	$9,030,992	$9,231,824	$9,437,181	$9,647,164
BILLING AND DATA MANAGEMENT	$2,977,618	$6,133,894	$6,317,911	$6,539,985	$6,769,866	$7,007,827	$7,254,152	$7,509,135	$7,773,081	$8,046,305
UNCOLLECTIBLES EXPENSE	$575,183	$1,179,230	$1,202,166	$1,283,145	$1,334,573	$1,368,402	$1,429,934	$1,494,167	$1,539,375	$1,597,606
STARTUP FINANCING	$4,934,813	$4,934,813	$4,934,813	$4,934,813	$4,934,813	$0	$0	$0	$0	$0
CCA BOND CARRYING COST	$4,498	$9,266	$9,544	$9,879	$10,227	$10,586	$10,958	$11,343	$11,742	$12,155
SUBTOTAL - CCA OPERATING COSTS	$115,616,305	$237,034,472	$241,644,823	$257,922,002	$268,259,430	$275,059,336	$287,427,716	$300,338,976	$309,426,191	$321,130,868
IV. REVENUES FROM GREEN PREMIUM AND MARKET SALES ($)										
GREEN PRICING PREMIUM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MARKET SALES	$0	$0	$0	$0	$0	$0	$0	$4,562	$151,273	$206,852
V. CONTRIBUTION TO PROGRAM RESERVES ($)	$3,468,489	$7,111,034	$7,249,345	$7,737,660	$8,047,783	$8,251,780	$8,622,831	$9,010,032	$9,278,248	$9,627,720
VI. CCA REVENUE REQUIREMENT ($)	$119,084,794	$244,145,506	$248,894,168	$265,659,662	$276,307,213	$283,311,116	$296,050,547	$309,344,446	$318,553,166	$330,551,736
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	7.2	7.4	7.5	8.0	8.3	8.4	8.8	9.1	9.3	9.6
PG&E AVERAGE GENERATION COST (CENTS/KWH)	9.7	9.8	10.2	10.6	10.8	11.0	11.4	11.7	12.0	12.4
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
POWER CHARGE INDIFFERENCE ADJUSTMENT	$25,915,755	$51,553,829	$57,388,579	$59,734,338	$68,565,139	$71,009,591	$73,095,756	$72,606,186	$75,773,871	$75,292,787
FRANCHISE FEE SURCHARGE	$1,200,075	$2,433,427	$2,518,727	$2,627,661	$2,713,295	$2,773,731	$2,884,199	$2,971,981	$3,073,169	$3,173,136
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 27,115,829	$ 53,987,255	$ 59,907,306	$ 62,361,999	$ 71,278,434	$ 73,783,321	$ 75,979,955	$ 75,578,166	$ 78,847,040	$ 78,465,922
VIII. CCA REVENUE REQUIREMENT PLUS PG&E CCA CUSTOMER SURCHARGES	$146,200,624	$298,132,761	$308,801,474	$328,021,661	$347,585,647	$357,094,437	$372,030,502	$384,922,613	$397,400,206	$409,017,659
IX. REVENUE AT PG&E GENERATION RATES	$160,662,350	$325,779,825	$337,199,584	$351,783,272	$363,247,732	$371,338,653	$386,127,844	$397,879,787	$411,426,593	$424,809,838
X. TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES	**$ (14,461,726)**	**$ (27,647,064)**	**$ (28,398,110)**	**$ (23,761,610)**	**$ (15,662,085)**	**$ (14,244,216)**	**$ (14,097,342)**	**$ (12,957,174)**	**$ (14,026,387)**	**$ (15,792,180)**
CHANGE IN CUSTOMER ELECTRIC CHARGES (%)	**-4%**	**-4%**	**-4%**	**-3%**	**-2%**	**-2%**	**-2%**	**-2%**	**-2%**	**-2%**

PENINSULA CLEAN ENERGY
FINANCIAL PRO FORMA ANALYSIS
COMMUNITY CHOICE AGGREGATION
SCENARIO 3

CATEGORY	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8	YEAR 9	YEAR 10
I, CUSTOMER ACCOUNTS:										
RESIDENTIAL (E-1)	100,898	199,778	197,780	196,781	195,787	194,799	193,815	192,836	191,862	190,894
SMALL COMMERCIAL (A-1)	8,012	15,863	15,704	15,625	15,546	15,467	15,389	15,312	15,234	15,157
SMALL COMMERCIAL (A-6)	641	1,268	1,256	1,249	1,243	1,237	1,230	1,224	1,218	1,212
MEDIUM COMMERCIAL (A-10)	666	1,319	1,306	1,299	1,293	1,286	1,280	1,273	1,267	1,261
LARGE COMMERCIAL (E-19)	333	660	653	650	647	643	640	637	634	630
INDUSTRIAL (E-20)	11	21	21	21	21	21	21	21	20	20
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	358	709	702	698	695	691	688	684	681	677
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	69	136	135	134	133	133	132	131	131	130
SUBTOTAL - CUSTOMER ACCOUNTS	110,987	219,754	217,556	216,458	215,365	214,277	213,195	212,118	211,047	209,981
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	546,588,981	1,082,270,553	1,071,472,468	1,066,061,532	1,060,677,921	1,055,321,498	1,049,992,124	1,044,689,664	1,039,413,981	1,034,164,940
SMALL COMMERCIAL (A-1)	144,089,427	285,302,370	282,454,703	281,028,307	279,609,114	278,197,088	276,792,193	275,394,392	274,003,651	272,619,932
SMALL COMMERCIAL (A-6)	31,786,687	62,938,942	62,310,867	61,996,197	61,683,116	61,371,617	61,061,690	60,753,328	60,446,524	60,141,269
MEDIUM COMMERCIAL (A-10)	153,341,083	303,623,525	300,595,553	299,077,545	297,567,204	296,064,489	294,569,363	293,081,788	291,601,725	290,129,136
LARGE COMMERCIAL (E-19)	233,312,920	461,972,566	457,365,956	455,056,258	452,758,224	450,471,795	448,196,913	445,933,518	443,681,554	441,440,962
INDUSTRIAL (E-20)	94,600,443	187,313,946	185,445,927	184,509,425	183,577,652	182,650,585	181,728,199	180,810,472	179,897,379	178,988,897
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	6,012,613	11,905,322	11,786,619	11,727,097	11,667,875	11,608,952	11,550,327	11,491,998	11,433,963	11,376,222
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	6,273,357	12,421,661	12,297,864	12,235,759	12,173,969	12,112,490	12,051,322	11,990,463	11,929,911	11,869,665
SUBTOTAL - LOAD REQUIREMENTS	1,216,005,512	2,407,748,884	2,383,729,957	2,371,692,121	2,359,715,075	2,347,798,514	2,335,942,132	2,324,145,624	2,312,408,689	2,300,731,025
III. CCA OPERATING COSTS ($)										
SHORT TERM MARKET PURCHASES	$2,385,719	$4,926,973	$4,023,550	$5,433,830	$5,725,297	$6,078,150	$6,424,208	$6,778,524	$8,689,459	$9,043,848
TERM CONTRACT PURCHASES	$0	$32,499,600	$50,097,564	$79,240,428	$80,012,052	$80,788,240	$80,611,042	$80,436,075	$97,870,918	$97,524,276
SHORT TERM RENEWABLE MARKET PURCHASES AND RECS	$74,410,453	$128,589,039	$115,897,016	$96,062,612	$99,237,287	$103,007,382	$107,765,197	$112,620,822	$94,053,514	$97,605,172
SHORT TERM CARBON FREE MARKET PURCHASES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANCILLARY SERVICES AND CAISO CHARGES	$3,684,672	$7,541,370	$7,697,915	$7,919,341	$8,140,769	$8,376,683	$8,620,819	$8,870,866	$9,102,359	$9,352,391
RESOURCE ADEQUACY CAPACITY	$6,241,143	$10,683,118	$8,614,069	$7,987,352	$8,047,796	$8,107,225	$8,328,632	$8,557,143	$8,207,844	$8,440,055
STAFF AND OTHER OPERATIONS COSTS	$5,765,132	$7,145,122	$7,262,026	$7,393,976	$7,528,367	$7,665,246	$7,804,659	$7,946,655	$8,091,281	$8,238,586
BILLING AND DATA MANAGEMENT	$2,610,411	$5,323,673	$5,428,549	$5,563,169	$5,701,127	$5,842,507	$5,987,392	$6,135,870	$6,288,031	$6,443,965
UNCOLLECTIBLES EXPENSE	$500,162	$1,008,219	$1,019,778	$1,072,678	$1,096,638	$1,099,327	$1,127,710	$1,156,730	$1,161,517	$1,183,241
STARTUP FINANCING	$4,934,813	$4,934,813	$4,934,813	$4,934,813	$4,934,813	$0	$0	$0	$0	$0
CCA BOND CARRYING COST	$3,943	$8,042	$8,200	$8,404	$8,612	$8,826	$9,045	$9,269	$9,499	$9,734
SUBTOTAL - CCA OPERATING COSTS	$100,536,449	$202,659,969	$204,983,481	$215,616,603	$220,432,758	$220,973,585	$226,678,704	$232,511,954	$233,474,421	$237,841,269
IV. REVENUES FROM GREEN PREMIUM AND MARKET SALES ($)										
GREEN PRICING PREMIUM	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
MARKET SALES	$1,472,215	$3,039,958	$2,678,323	$3,461,136	$3,664,151	$3,909,273	$4,127,826	$4,351,267	$6,374,506	$6,625,092
V. CONTRIBUTION TO PROGRAM RESERVES ($)	$2,971,927	$5,988,600	$6,069,155	$6,364,664	$6,503,058	$6,511,929	$6,676,526	$6,844,821	$6,812,997	$6,936,485
VI. CCA REVENUE REQUIREMENT ($)	$102,036,160	$205,608,611	$208,374,313	$218,520,131	$223,271,665	$223,576,241	$229,227,405	$235,005,508	$233,912,913	$238,152,662
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	8.4	8.5	8.7	9.2	9.5	9.5	9.8	10.1	10.1	10.4
PG&E AVERAGE GENERATION COST (CENTS/KWH)	9.7	9.8	10.2	10.6	10.8	11.0	11.4	11.7	12.0	12.4
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
POWER CHARGE INDIFFERENCE ADJUSTMENT	$19,557,655	$38,516,914	$42,447,673	$43,740,896	$49,705,239	$50,962,534	$51,935,146	$51,071,430	$52,766,594	$51,907,266
FRANCHISE FEE SURCHARGE	$878,739	$1,764,038	$1,807,627	$1,866,948	$1,908,513	$1,931,513	$1,988,354	$2,028,382	$2,076,469	$2,122,574
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 20,436,394	$ 40,280,952	$ 44,255,301	$ 45,607,844	$ 51,613,753	$ 52,894,047	$ 53,923,501	$ 53,099,812	$ 54,843,063	$ 54,029,840
VIII. CCA REVENUE REQUIREMENT PLUS PG&E CCA CUSTOMER SURCHARGES	$122,472,554	$245,889,563	$252,629,613	$264,127,975	$274,885,418	$276,470,288	$283,150,905	$288,105,320	$288,755,975	$292,182,502
IX. REVENUE AT PG&E GENERATION RATES	$117,856,580	$236,592,953	$242,439,155	$250,395,263	$255,969,977	$259,054,698	$266,678,270	$272,046,774	$278,496,189	$284,679,804
X. TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES	**$ 4,615,974**	**$ 9,296,610**	**$ 10,190,459**	**$ 13,732,712**	**$ 18,915,440**	**$ 17,415,590**	**$ 16,472,635**	**$ 16,058,546**	**$ 10,259,786**	**$ 7,502,697**
CHANGE IN CUSTOMER ELECTRIC CHARGES (%)	**2%**	**2%**	**2%**	**3%**	**3%**	**3%**	**3%**	**3%**	**2%**	**1%**