Table of Contents

REVISED 5/13/16

VI. Appendices

APPENDIX 1: Additional Acknowledgements

APPENDIX 2: Glossary of Terms

APPENDIX 3: CCE Frequently Asked Questions

APPENDIX 4: a. MBCP Complete DRAFT Technical Study

b. Proformas

c. Independent Peer Review

d. PEA Response to Peer Review

APPENDIX 5: MBCP Formation Work Plan

APPENDIX 6: a. Sample JPA Ordinance – Silicon Valley Community CE Partnership

b. Sample JPA Agreement – Peninsula Clean Energy (PCE)

c. Sample JPA Resolution – (PCE)

APPENDIX 7: Sample Business Implementation Plan- (PCE)

APPENDIX 8: a. Sample Budget 2016/17 – Marin Energy Authority (MEA)

b. Sample Budget 2015/16 – Sonoma Clean Power (SCP)

APPENDIX 9: Sample Service Agreement with PG&E – (MEA)

APPENDIX 10: Sample Customer Power Bill from PG&E with CCE included- (MEA)

APPENDIX 11: Sample of Customer Opt Out Notification (MEA)

SECTION I

REGIONAL PROJECT DEVELOPMENT ADVISORY COMMITTEE

Summary Report & Recommendations

Background

Formed in 2013, the Monterey Bay Community Power project is a region-wide collaborative partnership comprised of all 21 local governments within the greater Monterey Bay area, including the Counties of Santa Cruz, Monterey, San Benito and all 18 cities located within. The partnership also includes Monterey Bay Unified Air Pollution Control District, Salinas Valley Solid Waste Authority, and Monterey Regional Waste Management District. The purpose of the project has been to investigate the viability of establishing a local community choice energy (CCE) joint powers agency (JPA) within the region. Authorized by California legislation (AB 117 in 2001, amended by SB 790 in 2011), CCE allows counties and cities to pool their electricity load in order to purchase electricity or invest in energy projects and programs for local residents and businesses as an alternative to the existing utility provider, (PG&E.) Formal resolutions to participate in the project were passed by every jurisdiction during 2013, with each given the option of appointing a representative to the Project Development Advisory Committee overseeing the investigation.

Regional Project Development Advisory Committee (PDAC) Work and Process

After initial formation, the PDAC approved the County of Santa Cruz as the lead agency on behalf of the partnership to raise the funds and provide staffing. The 15-member PDAC hosted 26 public meetings from December 2012 through June 2016, providing guidance and making key decisions with input from the Project Team and consultants. To ensure that the entire region had access to PDAC deliberations, the meetings have been rotated between the Monterey Regional Waste Management District Board Chambers in Marina and the Santa Cruz County Board of Supervisors Chambers in Santa Cruz, with one special session in San Benito County. A project website was established in early 2013 to provide information, answers to frequently asked questions and post PDAC meeting materials and updates, MBCommunityPower.org.

By the middle of 2014, $404,846 had been raised to conduct a Phase 1 Technical Feasibility Study, an analysis of the benefits and risks associated with creating a local CCE agency and a comparison of that information with the current rates and services provided by PGE. The study and an independent peer review were completed by April, 2016 and are included here in Section III and Appendix 4 of this information packet. The study reveals several favorable environmental and economic outcomes. These include local control over electricity rates and complimentary programs, a significant increase in procuring and generating renewable electricity for the region and the potential value of redirected revenue to benefit the local economy and create green jobs.

It is worth noting that the project funds raised were from private community and state resources, not from local government general budgets. The project's non-profit partner, the Community Foundation of Santa Cruz County (CFSCC), graciously accepted private donations for the project totaling $25,607. The PDAC worked collaboratively with the CFSCC to provide oversight and accountability regarding how these funds have been spent. The remaining funds came from grants procured and managed by Santa Cruz County as the lead project partner. The grants awarded were from the California Strategic Growth Council ($344,239), the World Wildlife Fund ($30,000), and the UC Santa Cruz Carbon Fund ($5,000).

The PDAC has collaborated with the Project Team on all elements of Phase 1 investigative work as outlined below. Members of the PDAC and Project Team and their affiliations are listed under "Acknowledgements" at the end of this report.

- Provided regular public meeting opportunities for community members to learn about CCE and have input into PDAC discussions and decisions;
- Developed a Phase 1 work and Project Team plan with goals and objectives;
- Assisted with the development of grant proposals and oversaw the CFSCC budget and expenditures;
- Tracked State legislative and regulatory activities affecting CCE investigation;
- Created the content, goals and objectives of the project website, community group educational presentations and regular update reports to county and city partners;
- Developed the scope and assumptions of the Technical Feasibility Study, the independent peer review and the qualifications and criteria for hiring the appropriate consultants;
- Gathered expert information, options and best practices regarding the phased formation work tasks, governance, executive staffing, and start-up financing;

- Scoped the qualifications and criteria for a professional consultant to develop a region-wide outreach communications program and designed the plan with the firm hired;

- Reviewed the contents of the Technical Feasibility Study and all other information and recommendations contained in this packet; and

- Guided the next steps to complete Phase 1 work and assisted the MBCP county and city partners in their deliberations regarding CCE-JPA formation.

This comprehensive information packet has been assembled as a culmination of the PDAC's work over the past few years, providing each county and city partner the information needed to decide whether to participate with partners in the next steps toward forming a regional CCE-JPA. The PDAC has assembled a complete public record of all committee deliberations, which are posted on the website, MBCommunityPower.org. The PDAC will continue to meet during 2016 until Phase 1 work is concluded and a CCE ordinance has been considered or approved by interested county and city partners.

Phase 1 Project Status, Next Steps and Phase 2 Formation Work

Phase 1 Project Status and Next Steps:

To recap, in this first phase, the PDAC has conducted an initial exploration of CCE program viability and has overseen the development of a technical study and assembled related resource information. Community engagement strategies have been implemented, and will continue, to educate the affected energy customers and lay the foundation for Phase 2 formation work. Over the next 6 months, the PDAC will steer completion of Phase 1 that will include hosting a series of public workshops and special study sessions to be attended by PDAC representatives, elected officials, county and city executive staff, project staff and CCE experts from around the State. The PDAC has also formed two subcommittees that will meet on an ad hoc basis to discuss governance, executive staff and start-up financing options. The end result of Phase 1 will be the decision to form a CCE-JPA governing Board after start-up financing has been determined and recruitment has begun to hire a chief executive to manage Phase 2 work. The next steps and timeframe to complete Phase 1 work are:

- May 13, 2016: All MBCP county and city partners will receive this information packet with PDAC recommendations regarding best practices and next steps.

- May 24 and June 9th: The PDAC will host three special public study sessions for county and city electeds and executive staff to review and discuss the technical study with the consultants as well as options regarding governance, start-up financing, and formation:
  - May 24- 9:30 am to noon – Monterey County Board Chambers- Salinas
  - June 9- 9:30am to noon – Santa Cruz County Board Chambers – Santa Cruz
  - June 9- 3:00 pm to 5:30pm- San Benito County Board Chambers- Hollister

- County and cities interested in forming a CCE-JPA may join an ad hoc subcommittee comprised of executive staff who will develop a formation proposal for Board of

Supervisors and City Councils' consideration on or before September 15, 2016, (target date.) Professionals who have experience in retail electricity services, program design, finance, wholesale purchasing and renewable resource development will assist this work.

- May through October: A comprehensive regional outreach and communications program to engage and educate the community at large will be implemented by a professional consulting firm.

- August through October: County and city governing Boards will consider the ad hoc subcommittee formation proposal and adopt ordinances and agreements with other early adoptive partners.

- October 31, 2016: A regional CCE agency joint powers governing Board will be seated and a final selection for the CEO position is made. The CEO hires staff and Phase 2 begins.

Phase 2 Formation Work:
This phase involves program design, soliciting energy procurement services, seeking CPUC approval of an implementation plan, executing a service agreement with PG&E, and expanding community engagement. Agency staff will also complete all remaining legal requirements, enroll customers and prepare to launch an independent operation. Appendix 5 has a more detailed proposed formation work plan for the Monterey Bay Community Power partnership. The end result of Phase 2 work will be to launch (i.e., provide power to customers) no later than September/October, 2017. Note that all start-up costs are reimbursable with interest after program launch through ratepayer revenues.

PDAC Recommendations- Feasibility, Formation and CCE Best Practices

Feasibility Recommendation:
The prospects for CCE programs in California have improved significantly in recent years as a result of many factors:

- The success of Marin Clean Energy and Sonoma Clean Power in providing their communities with greener power at prices competitive with PG&E while investing considerable surplus funds into local renewable energy and energy efficiency projects that created local jobs;

- Favorable wholesale energy market conditions, resulting in relatively low cost power;

- Recognition that a CCE program can be self-supporting for meeting climate action plan objectives and other local public policy goals;

- The reduced market costs of renewable power and improvements in renewable technologies; and

- The development of expertise, best practices and an expanded vendor base to serve CCE programs.

The Monterey Bay Community Power (MBCP) partnership formed in 2013 as the first tri-county/18 city effort in the State. Since then, two CCE agencies have launched (Sonoma Clean Power and the City of Lancaster) and many more communities are actively pursuing CCE formation, including the counties of Alameda, Butte, Contra Costa, Humboldt, Lake, Los Angeles, Mendocino, San Bernardino, San Diego, San Luis Obispo, San Francisco, San Mateo, Santa Barbara, Santa Clara, Venture and Yolo, as well as the cities of Davis and San Diego.

The analysis and outcomes from the technical feasibility study as well as all of the Phase 1 investigative work undertaken for the past three years indicate that establishing a successful CCE agency within the Monterey Bay Region is highly feasible with a wide range of options.

Formation Recommendations:

(1) Next Steps – All MBCP counties and cities are strongly encouraged to participate in one or more of these next steps to determine their interest in becoming an early adoptive partner in forming a regional CCE-JPA agency:

- Attend the public special study sessions hosted by the PDAC starting in May and continuing through June that will focus on the technical study results, governance, executive staffing and start-up financing options and best practices. At these meetings, executive staff from successful CCE agencies and other experts will be in attendance to assist interested county and city representatives. (See page 3 of this report for the schedule.)

- Request a Board or Council general presentation to determine further interest. For more information or to schedule a meeting, contact Gine Johnson, Office of Santa Cruz Supervisor Bruce McPherson, at (831) 454-2200, gine.johnson@santacruzcounty.us.

- Send a Board representative and/or executive staff member to the PDAC's ad hoc subcommittee meetings. Two subcommittees, Governance and Finance, will meet in parallel with the public special study sessions to develop a formation proposal. Recommendations to the governing Boards of early adoptive county and city partners will be forwarded on or before September 15. To attend these meetings, contact the PDAC Chair, Nancy Gordon at (831) 454-2714, nancy.gordon@santacruzcounty.us.

(2) Decision Deadline: Once a formation determination has been made, the PDAC recommends that the CCE-JPA agency be established on or before October 31, 2016 for several important reasons:

- The best window of opportunity to launch a CCE agency (i.e., actually provide power to customers) has proven to be between April and October as a "best practice." Even after a CCE-JPA is established, additional formation tasks must ensue which may take up to 12 months, so to make the recommended "launch window", interested partners should form no later than one year in advance.

- Efforts to undermine the ability of local governments to justify forming CCE agencies are continual through the legislative and regulatory processes. Even though these efforts have not succeeded so far, it may just be a matter of time. If these efforts are eventually successful, CCE agencies that have already been formed will be able to continue unimpeded.

- In order to form a CCE agency, county and city partners must first agree on governance, start-up financing and executive staff recruitment. This process typically took California's established CCE agencies three to four months to accomplish. The deadline of October 31 gives early adoptive partners up to six months to make a final decision. County and city partners that do not make a decision by October will still have the option to join the CCE-JPA at a later date.

<u>CCE Best Practices Recommendations:</u> New CCEs can mitigate risk and ensure best practices by learning from the experiences of operational CCE agencies. In addition to the technical study, Section lll of this information packet includes an overview of regulations as well as information and lessons learned from other multi-jurisdictional CCE agencies regarding structure, governance, financing and program phasing. The PDAC spent countless hours reviewing and discussing this information with statewide CCE experts and recommends the following best practices be considered by MBCP county and city partners as they contemplate formation:

- Structure – The PDAC recommends a regional agency that includes as many of the MBCP county and city partners as possible. The economy of scale relative to procurement buying power, start-up and long-term financing and other operational considerations makes a compelling case for a regional agency. Given the nature and technical complexity of running the business of a CCE program, the PDAC also recommends that the agency not be embedded in an existing government entity, but be formed as a stand-alone joint powers agency. Further, the PDAC does <u>not</u> recommended that an existing CCE-JPA be joined for a fee as the economic and job creation benefits to the Monterey region would be considerably diminished. However, "back-end" turn- key administrative services that have a proven operational track record are readily available to newly formed CCEs and should be accessed to streamline start-up and operational tasks and costs.

- Governance – To meet the diverse needs of the Monterey Bay region, the PDAC recommends a governance structure that aligns with these principles:

    - Consistent with the best practices learned from the success and challenges of established CCE governing boards as outlined in Section lll of the information packet.

    - Equitably representative and aligned with population density and electricity usage within the region;

    - A manageable number of board members with the ability to scale to accommodate later members;

    - Primary members and alternates should be elected officials;

    - Industry technical experts without a conflict of interest should be advisory to the Board;

    - Structured similarly to an existing and well-accepted Monterey regional JPA board that has been serving the same partner counties and cities successfully for many years, the Monterey Bay Air Resources District.

    - Section lll, page 20 of the information packet outlines the specific governance board and technical expert advisory committee structure recommendation.

- Start-up Financing & Payback Period – There are many options to providing the capital for Phase 2 formation work, but the most straight forward path is for one of the main partners to provide all of the funding, or guarantee a private loan, which can be paid back with interest once the CCE agency begins to generate revenue from ratepayers. Although a cost-share strategy is often used in starting a joint powers agency, this requires additional time and contractual work in what is already a complex formation process. However the start-up is financed, the CCE governing Board should aim to pay it back as soon as it is financially feasible.

- Guiding Principles– The PDAC recommends strategic and operational alignment with these principles:

    - Serve community goals and local policy objectives, including greenhouse gas reductions and increased statewide and local renewable energy supply.

    - Control and safeguard customer revenues to ensure long-term financial viability and local government ownership, even when power supply costs fluctuate.

- Offer competitive rates and choice in customer electricity services that does not include the use of unbundled renewable energy credits, coal or nuclear resources and prioritizes in-state renewable contracts as is financially viable and available.

- Support the rapid investment in local renewable energy generation to the maximum extent feasible while ensuring fiscal stability, rate parity and carbon reduction goals are met.

- Pursue long-term power procurement strategies and local power ownerships that hedge future market risk and incorporate diversity of energy suppliers, technologies and products.

- Plan for long-term financial viability through integrated resource planning, in-house fiscal management, transparent rate setting and policies that build program reserves. Building robust reserves enhances the agency's credit rating, lowers the cost of procurement and increases the viability of issuing future bonds for projects.

- Maintain a firewall between the assets and liabilities of the CCE agency and those of municipal general funds.

- Adhere to applicable statutory and regulatory compliance requirements.

- Implement effective risk management practices and ensure transparency and accountability to the local community and oversight agencies.

- Offer complementary programs that serve community interests such as feed and tariff, net-metering, comprehensive energy efficiency retrofits, demand response, community solar, electric vehicle charging, battery storage, as well as support for local training programs in both the private and public sectors and research/development of emerging technologies.

- Establish criteria for the use of surplus revenues that ensures geographic equity and adheres to economic justice principles.

- Define criteria for selecting energy procurement vendor(s) that aligns with the region's sustainability and economic vitality goals.

- Develop a long-term strategic goal of regional energy self-sufficiency by building out local renewable generation projects using local workers making prevailing wages with benefits. Establish a definition of "the use of local workers" and adhere to established local government definitions of "prevailing wages."

ACKNOWLEDGEMENTS

The Project Development Advisory Committee would like express tremendous gratitude to the respective County Boards, City Councils and Joint Powers Agencies within the Monterey tri-county region for participating in this project and embracing regional collaboration on an initiative that holds such significant potential for meeting economic and environmental goals.

Thank you to the PDAC members, lead partner Santa Cruz County, the Project Team and Ambassadors as well as the professional consultants who worked tirelessly for more than three years to investigate community choice energy and provide education to stakeholder groups. We express our thanks and appreciation as well to the two working groups of local volunteer experts and stakeholders who assisted the Project Team (see Appendix 1.)

This project would not have been possible without the fiscal sponsorship of the Community Foundation of Santa Cruz County (CFSCC) accepting donations from generous members of the community. Our sincere thanks to the CFSCC Board and executive staff, and especially to all of the *Monterey Bay CCA Fund* donors (see Appendix 1.)

Grant support from the California Strategic Growth Council, the World Wildlife Fund, and the UC Santa Cruz Carbon Fund was critical to completing this project, for which the committee is sincerely appreciative.

Finally, to the staff of Marin Clean Energy and Sonoma Clean Power, thank you for your technical assistance, generosity and for paving the way for the rest of the California to follow in your footsteps.

Project Development Advisory Committee Members

Nancy Gordon, Chair, Santa Cruz County
Richard Stedman, Vice-Chair, Monterey Bay Unified Air Pollution Control District
Daniel Bertoldi, Monterey County
Ross Clark, City of Santa Cruz
Tim Flanagan, Monterey Regional Waste Management District
Rich Grunow, City of Capitola
Chris Khan, City of Salinas
Nancy Lockwood, City of Watsonville
Patrick Mathews, Salinas Valley Solid Waste Authority
Larry Pearson, Pacific Cookie Company, Business Sector Representative
Adam Goldstone, San Benito County
Taylor Bateman, City of Scotts Valley
Ray Friend, City of Hollister
Roger Grimsley, City of San Juan Bautista

Project Team Members and Ambassadors
Gine Johnson, Office of Santa Cruz Supervisor Bruce McPherson
David Carlson, Santa Cruz County Planning Department
Carol Johnson, Santa Cruz County General Services Department
Julia Holl, Office of Assembly Member Mark Stone
Kris Damhorst, Volunteer Project Team Member/Ambassador
Matt Farrell, Volunteer Project Team Member/Ambassador
Brennen Jensen, Volunteer Project Team Member/Ambassador
Joel Kauffman, Volunteer Project Team Member/Ambassador
Martin Carver, Volunteer Project Team Member/Ambassador
Marc Adato, Volunteer Project Team Member/Ambassador
Abby Young, Volunteer Project Team Member
Laurie Talcott, Volunteer Ambassador
Beverly DesChaux, Volunteer Ambassador
Jackson Damhorst, Volunteer Ambassador

Consultants
Local Energy Aggregation Network (LEAN) – General Strategy & Assistance
Miller Maxfield – Communications and Outreach
Pacific Energy Advisors - Technical Feasibility Study
MRW Associates - Independent Peer Reviewer

SECTION ll
INTRODUCTION TO COMMUNITY CHOICE ENERGY

How Local Energy Aggregation Works

Enabled by California legislation (AB 117 and SB 790), community choice energy (CCE) allows cities and counties to pool their residential, business and municipal electricity loads, and to purchase power (or generate it) on their behalf. In this model, the current investor owned utility, PG&E, remains an essential partner. Energy transmission, distribution, repair, and customer service functions remain with PG&E, which also continues to provide customer billing. CCE customers are automatically enrolled over time unless they wish to opt out and continue to buy their electricity from PG&E.
CCE charges appear as a new section on the current PG&E customer bill (see APPENDIX 10.) All other charges are the same and beneficial programs continue (i.e., CARE, Medical Baseline, and other low-income programs.)

A regional CCE joint powers agency (CCE-JPA) leverages the market power of group purchasing and local control. It can be designed to achieve a number of economic vitality and environmental public policy and program objectives, such as contributing millions of dollars to the local economy, creating local jobs, increasing renewable resources in the community's energy portfolio, reducing greenhouse gas emissions, promoting local development of renewable energy installations and offering comprehensive energy efficiency programs.

In short, a regional CCE-JPA purchases green electricity on the open market and PG&E delivers the energy, maintains the lines and bills the customers. The customers benefit from affordable rates, local control and cleaner energy. CCE offers a choice of service providers, where no choice exists now. By establishing a CCE-JPA, local governments choose to give choice to their constituents.

Why Investigate Community Choice Energy?

<u>Local Control:</u> Community choice energy puts control of electricity purchasing and pricing into local hands and allows the community to determine what type of energy mix best serves the needs of the region. Right now, consumers do not have these choices. The CCE's local governing Board significantly increases transparent accountability because consumers have direct access to the decision makers as well as the deliberation process. CCE agencies are funded through CCE customers paying their electricity bills, not by taxes. Creating and maintaining a local public agency that is well managed, financially self-sustaining and provides clean locally produced energy strengthens the capacity and resilience of the entire region.

Economic Vitality: Local ratepayer money stays local. Surplus revenues that would normally flow to the investor owned utility will stay in the community to help fund renewable energy projects, create jobs, and stimulate the local economy. The value of redirected revenue over time is millions of dollars. The opportunity to use that revenue to build local renewable energy generation facilities, EV charging stations, energy storage capacity as well as increase the energy efficiency of our buildings is significant and key to the success of a local CCE agency. Surplus revenues may also be used to stabilize or lower consumer rates.

Meeting Local Climate Action Plan Goals: Establishing a regional CCE agency is the single most impactful strategy for meeting state and regional climate goals. In the Monterey Bay Region, roughly half of the greenhouse gas emissions are caused by energy use. Of all the beneficial initiatives identified in the region's 21 climate action plans, CCE is the one that will result in the highest reduction of emissions within just a few years of establishing the agency. It is the one program that we can implement that will make the biggest difference before the "tipping point" of carbon emissions is reached worldwide.

Creating Market Competition: Market competition drives down costs, which has happened in two other regions within California.

Providing Cleaner Energy with the Same Rates: Community choice energy agencies can deliver more renewable energy than the investor owned utility at the same rate. Supply autonomy allows for the greater use of renewable sources (solar, wind, wave, biomass) The two well-established CCEs in California have significantly increased the renewables in their portfolios without charging more than PG&E and, in some cases, are offering meaningful rate savings. The Monterey Bay Community Power technical study indicates we can more than double the renewables in the regional portfolio at the same rate charged by the investor owned utility. That increase could result in a portfolio with 59% renewable energy as compared to the current 27% provided by PG&E.

Maintaining the Same Reliable Service from PG&E: Energy transmission, line maintenance and customer service remains the responsibility of PG&E. PG&E will continue to handle all customer service and support of the grid. Current low-income programs remain available to customers, (i.e., CARE, Medical Baseline, etc.)

Stimulating Private Sector Innovation and Workforce Development:
A regional CCE agency has the ability to create policy and financial incentives that support private sector entities as well as work force development initiatives. Private sector businesses and non-profits focused on developing innovative energy technologies, products and services could be incentivized to locate or expand their business here. The region's educational institutions, apprenticeship programs and job placement programs already provide green jobs training and careers which could receive significant support from a regional CCE-JPA.

Basic Risks and Mitigations

Establishing a regional CCE-JPA offers many opportunities for the Monterey Bay region but presents some risk. Building solid governance and operational capacity as an organization within the first few years is the first and foremost strategy in mitigating those risks. Following the best practices and principles as recommended by the regional Project Development Advisory Committee and outlined in the cover report can ensure that appropriate capacity is built and a strong foundation is established to serve the region for many successful years.

The other main risks relate to market price fluctuations and regulatory uncertainty. California's energy markets have been stable for several years and prices for electricity from renewable and conventional energy resources are low. The current buyer's market is expected to continue for the next several years because of the excess energy supplies. A local CCE agency can protect itself from future market shifts by forecasting with conservative rates as well as using diverse portfolios that include longer-term energy supplies and investments in local power projects and programs that lower the load needed and help fix the cost of the region's supply. A long-term goal of regional self-sufficiency that aims to provide 100% of our electricity supply from local renewable sources is a highly effective mitigation strategy that addresses future market fluctuations and ensures an abundant supply of clean, affordable energy for future generations. By partnering with other CCEs from around the State and proactively engaging in proceedings with the State legislature and regulatory Boards, regulatory issues may be effectively managed. Here is an outline of short-term and long-term risks:

Governance and Operational Risks:

- Governing Board with too many members without the appropriate expertise, lowering flexibility and timeliness in decision making
- Not aligning with best practices based on other CCE experiences
- Opt-out rate uncertainty
- Credit availability for power supply

Market Risks:

- PG&E rate uncertainty (generation rates and exit fees)
- Length of current favorable wholesale energy prices
- Availability of large hydro resources to meet carbon-free content goals

Political and Regulatory Uncertainties:

- Future CCE-specific State legislation
- Regulatory changes around renewable and capacity mandates
- Rulings that adversely affect the establishment and operations of CCEs from the California Public Utilities Commission (CPUC) in response to requests from the investor owned utilities

Snapshots of Success - Marin Clean Energy & Sonoma Clean Power

The Project Development Advisory Committee and Project Team have been inspired and guided by the proven models of the two established multi-jurisdictional CCE programs in California. Marina Clean Energy and Sonoma Clean Power are offering their customers greener power with a mix that features more renewable sources at competitive rates, and for some plans, lower rates. Both are offering enhanced programs for energy efficiency and locally sourced solar while performing well financially and operationally.

<u>Marin Clean Energy – Results after six years of full operations</u>

- Serving 170,500 customers, 80% of the total customer meters
- Annual Budget - $145,993,097
- Reserves- Forecasted to increase to $16,696,319 by the end of the current fiscal year (March 31, 2016)
- Regular customer plan – 50% renewable portfolio at comparable rates versus 27% renewables from PG&E
- 100% renewable energy customer plan- $5/more per month than PG&E rates
- 100% Local Solar customer plan- 20% more than PG&E rates
- Key accomplishments - Has created 2400 jobs and has 10 renewable projects completed are under way
- Start-up costs completely paid off

<u>Sonoma Clean Power – Results after two years of full operations</u>

- Serving 196,206 customers, 89% of the total customer meters
- Annual Budget - $165,495,000
- Reserves - Forecasted to increase to $30,000,000 by the end of the current fiscal year (March 31, 2016).
- Regular customer plan – 80% Carbon Free with 36% renewables, 44% hydro energy and 8% less than PG&E rates, versus 27% renewables from PG&E
- EverGreen customer plan - 100 % local renewable energy at 12% more than PG&E rates
- Key Accomplishments - Saved customers $13 million in its first year of operations and has met California's 2020 renewable energy targets
- $1.3 million remaining of start-up costs to pay off

Elements of the Technical Feasibility Study

The technical study was conducted for the purpose of describing the potential benefits and liabilities with forming a CCE agency, including the overall size of the program, forecasted future demand, resource availability, and the ability to be rate competitive. The study analyzed different possible power supply scenarios and the impact on greenhouse gas emissions, as well as the potential for local job creation and surplus revenues. Estimated CCE-JPA start-up costs were identified and a risk assessment completed. For the Monterey Bay Community Power partnership, the analysis was conducted two ways:

- For the entire tri-county region inclusive of all 18 cities; and
- Each individual county inclusive of the cities within its boundaries.

The executive summary of the technical study (Section lV) describes in greater detail each of these elements. The full study is in APPENDIX 4 with proformas for each scenario for the entire tri-county region as well as for the individual counties. Also included in APPENDIX 4 is an independent peer evaluation of the technical study as well as responses to the peer's comments. The final version of the technical study will incorporate input from the PDAC and will address issues identified by the peer reviewer.

SECTION lll
OVERVIEW & LESSONS LEARNED
MULTI-JURISDICTIONAL CCE AGENCIES

Structure & Governance

Per statute, CCE programs may be initiated and administered by a single municipality (i.e. city or county) or a group of them on a cooperative, inter-jurisdictional basis. Like similar municipally sponsored services, such as municipal power or water agencies, program governance typically remains in the public domain whether through elected or appointed representation of the communities served. This section will focus on governance, financing and program phasing options and best practices for a potentially large regional program that could eventually include all 21 of the Monterey Bay Community Power county and city partners.

<u>Legal Structure:</u>
AB 117 does not specify a required legal structure for multi-jurisdictional CCE programs. However, established CCE programs and many of those currently in progress are operating under California's Joint Powers Authority (JPA) Act, which allows for inter-agency cooperation and the provision of common services while maintaining legal and financial separation between the operations, assets and liabilities of the JPA and its county and city members. This latter issue of financial and legal separation has been especially important to cities and counties interested in offering the benefits and choice inherent in a CCE program without burdening municipal staff with program administration or in any way putting their government's general funds at risk through program participation.

It should be noted that there is a new, as yet untested, operational structure for CCEs that relies on commercially outsourced services offered to multiple jurisdictions under private contract. This commercially outsourced model does not use the JPA structure and it is unclear to what extent program operations, revenues, and governance remain within local, municipal control. It is also unknown how the "legal and financial firewall" protections afforded by the JPA structure are offered in privately managed models, and how those are supported (or not) by existing case law. Still, it is a model that is garnering some interest, especially in areas that are remote, financially burdened or lacking in available professional talent to run a local or regional CCE program.

Joint Powers Agencies in California are established by a joint powers agreement ("the constitution") that defines, codifies and governs the way the JPA will operate on behalf of its member jurisdictions (or agencies). The JPA Agreement is passed by resolution of its member agencies and may also be augmented by operating guidelines, bylaws and/or program policies if the Board of the JPA so chooses. While the JPA as a legal structure has many different applications in the State of California (transportation, housing, planning, public policy, etc.), CCEs serve a utility function and are considered "load serving entities." Thus, they are more similar to a municipal utility providing a commodity service rather than a regional planning or policy setting association – think "Solid Waste Management Authority" rather than an "Association of Local Governments", for example. This utility business and customer-serving focus will be an important consideration in both the staffing and leadership composition of the MBCP CCE agency.

The Project Development Advisory Committee (PDAC) reviewed several governance options including those of current CCE programs, large regional JPAs operating in California and existing JPAs currently serving the Monterey Bay region. Three models were identified:

1. Traditional CCE- JPA Approach:
    - 1 Board seat per member jurisdiction (primary plus alternate).
    - All elected representatives.
    - Alternate can be elected or appointee.
    - Meetings are monthly.
    - Examples include the two well-established CCEs in California, Marin Clean Energy and Sonoma Clean Power.

2. Multi-County/Regional Approach:
    - Combines elected officials with appointed representatives with technical/functional industry expertise.
    - Allocates a certain number of seats by category: county, cities and "at large" technical/function experts.
    - Assumes a primary and alternate for each seat.
    - County and city reps assumed to be elected representatives; their alternates can be municipal staff or technical/functional experts without a conflict of interest.

- At large technical/functional expert seats are selected by application per criteria established by the governing Board.

- Meetings are usually monthly, but can also be every-other-month or even quarterly if there is a robust committee structure.

- Examples include Metropolitan Transportation Commission, Golden Gate Bridge District, CalTrain, Monterey Bay Unified Air Pollution Control District, Central CA Alliance for Health, and the recently formed Santa Cruz Mid-County Groundwater Management Agency.

3. Existing JPA Approach:
   - Adopt/use an existing JPA's governance structure and administrative capacity, either one within the Monterey Bay region or an established CCE outside the Monterey region.

   - Joining an existing JPA within the region means that the CCE program would not be the primary focus of the agency as it would be a business line within a broader scope and mission. The complexity of running the business of a CCE program does not make this the best option.

   - Joining an existing CCE-JPA outside the region is a simple path, but it significantly dilutes the economic benefits of keeping the program local. Local decision-making and interaction with the region's ratepayers would also be greatly diminished. This is the least attractive option.

After extensive discussion, the PDAC recommends option two – forming a multi-county JPA as a stand alone agency- as the governance structure that makes the most sense for the MBCP partnership.

<u>CCE JPA Agreements:</u>
The CCE programs that include multiple jurisdictions and operate under a JPA structure are governed by intergovernmental agreements that have evolved over the last few years. New CCEs in the process of formation in San Mateo and Santa Clara counties have been the most recent to draft these agreements, (see APPENDIX 6 for examples.)

In addition to standard JPA language, there are several elements that need to be considered by the MBCP partners. These elements are outlined on the following pages, 19 and 20, with a description of current practices from successfully established CCEs within California and the PDAC's recommendations. On page 21 is the specific board and technical advisory committee structure recommended by the PDAC.

Governance Element	Currently practices of CCEs	PDAC Recommendation
Agency Purpose	CCE and energy related programs only.	CCE and energy related programs only.
Municipal Membership	Municipalities as full members. (Marin Clean Energy-MCE) Municipalities as participants. (Sonoma Clean Power-SCP)	Investigate further the pros and cons of each approach.
Board Composition	1 member per jurisdiction. (MCE & SCP) Primary Board member is an elected official. (MCE & SCP) Alternate is elected (MCE) or may be appointed (SCP).	Board of 11 to 15 members that combines elected officials and/or "at large" technical/functional experts *with no conflict of interest*. Recommended structure on page 21 is automatically "scalable" to accommodate county & city members who do not initially join the CCE/JPA.
Board Voting	Majority vote with an option to call for a weighted vote (SCP). Majority and weighted vote combined (MCE).	Majority vote. Recommended structure is already weighted based on load size and population.
Joint Powers	Power to contract, employ, acquire and maintain public works, incur debt and issue bonds, invoke eminent domain under certain conditions, adopt rules and regulations.	Power to contract, employ, acquire and maintain public works, incur debt and issue bonds, invoke eminent domain under certain conditions, adopt rules and regulations.
Withdrawal of Membership	MCE – Municipal accounts only; may be a fee for departing load due to stranded costs. SCP- Option to remove all accounts with negotiated timing and payout agreement to cover stranded costs.	Option to remove all accounts with negotiated timing and payout agreement to cover stranded costs.

JPA Administration: Self-administered or outsourced?	MCP & SCP: Self-administered with option to contract for certain JPA functions.	Self-administered with outsourcing for certain "turn key" administrative functions that are readily available within the industry.
New county/city members joining the JPA after initial launch	Modest cost or no cost at the discretion of the JPA Board.	Modest cost or no cost at the discretion of the JPA Board.
JPA Committees: Permissive or Required? Technical Advisory Committee to the Board	MCE- Permissive at discretion of the Board. SCP – Operations and Rate Setting Committees included in JPA agreement.	Permissive at the discretion of the Board after the need is identified and each committee's function is defined. *Do not specify committee structure in the JPA agreement.* *However, a technical advisory committee of experts with no conflict of interest to assist the Board is highly recommended. Possible technical expert categories: energy procurement/industry experience; utility background; finance; environmental, clean tech or related policy and/or operational experience.*
Cost Recovery for Advanced Start-Up Funds	Full cost recovery of start-up costs.	Full cost recovery of start-up costs, including all *unfunded* remaining Phase 1 activities as well as all Phase 2 formation work.
Board meeting frequency and location	Monthly meetings in one central location.	At the discretion of the governing board.

Recommended Governing Board Structure & Technical Advisory Committee Structure

Local Government Entity	# Members*	Appointed By
Monterey County	3	Monterey County Board
City of Salinas	1	Salinas City Council
Monterey Peninsula Cities	2	Monterey City Select Com
Salinas Valley Cities	1	Monterey City Select Com
Santa Cruz County	2	Santa Cruz County
Santa Cruz County Cities	2	Santa Cruz City Select Com
San Benito County Supervisors	1	San Benito Board
San Benito County Cities	1	San Benito City Select Com
Total:	**13**	

* Each primary member should have an appointed alternate*

Weighted Representation:

	Votes	Population (2015)	Loads (year 3)
Monterey County:	7 (53.8%)	433,898 (56.6%)	1,998 MWh (62.0%)
Santa Cruz County:	4 (30.8%)	274,146 (35.8%)	941 MWh (29.2%)
San Benito County:	2 (15.4%)	58,792 (7.7%)	283 MWh (8.8%)
Totals:	**13**	**766,836**	**3,222 MWh**

Technical Advisory Committee Structure:

- Comprised of technical and industry experts without a conflict of interest.
- One appointment per each County and City CCE-JPA member.
- Advises on all aspects of the agency operations.
- Criteria for membership to be developed by the Governing Board.
- Possible representative expertise: energy procurement & industry experience; utility background; finance; environmental, clean tech or related policy and/or operational experience.

Financing

Financing for multi-jurisdictional CCEs generally falls into three categories that cover initial planning and implementation (seed capital), program launch/initial energy contract (short term working capital), and longer-term agency operations (term debt/line of credit). To date, financing for CCE programs has come from a variety of sources including grants, private investors, municipalities and banks. More recent offerings have included vendor financing and deferred compensation in exchange for multi-year contracts that typically carry a five-year term. Types of capital required are:

<u>Start-Up/Seed Capital:</u> Seed capital covers early start-up costs prior to program revenue, (i.e. before paying customers.) The amount of seed capital needed to launch a new CCE program will be influenced by the size and complexity of the program. However, there are a number of fixed costs associated with program implementation as well. Seed capital requirements for existing and soon-to-launch CCE programs have ranged from \$1.5M -\$2.5M and cover the period from initial planning and study to program design, implementation and launch. Depending on how much seed capital is available, it may also cover initial JPA staffing and the utility bond requirement, although these expenses are often covered through the initial working capital loan. (See Section IV- Technical Study Executive Summary for a more detailed estimate of start-up costs for the MBCP CCE-JPA.)

To date, start-up capital has come from a combination of grants and municipal loans. Banks have traditionally not provided seed capital as it is considered high-risk capital until JPA commitments are made, ordinances are passed, and the program is closer to having revenue-generating customers. The exception to this rule is a loan that has a credit backing from a municipality, or vendor sponsored financing that will carry minimum contract terms in exchange for the credit.

A few notes regarding seed capital:

- All start up costs may be repaid through the early operating customer revenues of the CCE program.
- A municipality may lend funds to cover start-up, as a zero-interest loan or for a small fee.
- Seed capital may also be privately funded through grants or private investors. The key is to use the least cost financing available so as not to burden the JPA with high debt at launch.

<u>Working Capital:</u> CCE's will typically require working capital approximately six months prior to program launch, depending on how much seed capital remains in the coffers. This type of credit covers negative cash flow in the early stages of program launch and is intended to get the CCE "over the hump" from pre-launch to early operations until it reaches more stable revenues and operations. The amount of early working capital

needed is entirely dependent on the CCE's phasing plans, early staffing/operations expenses, and the size and cost of the energy contract. It can range from a low of $2M to a high of $15M or more depending on the program size at initial launch. This debt is usually short term and is often provided by a lender, although it can be municipally or vendor financed as well. It also requires a credit guaranty, which is usually provided by the sponsoring municipality(s) of the CCE program. The guaranty is released soon after revenues begin flowing (usually within 12-24 months) and the CCE-JPA is ready for longer-term debt and larger lines of credit.

Some notes regarding early working capital:

- This type of finance requires a guaranty that will be released when the CCE is stable and generating solid revenues.
- This debt will provide the credit backing required for the initial energy supply contract and early operating expenses.
- During the time the CCE is seeking working capital, it will also want to consider other banking services such as deposit accounts, lockbox services and the like. Generally, these services are provided by the lender as a bundled package with the loan.

<u>Longer Term Debt/Lines of Credit:</u> Once the program is launched and revenues have commenced, the CCE will want to consider longer-term debt and lines of credit to support agency operations and an expanded portfolio of energy contracts. Typically, this debt is used to refinance early working capital and pay off any start-up loans. It often carries a stable, fixed rate that can be repaid over time and may be accompanied by a separate line of credit to serve as backing for power contracts.

When it comes to a CCE banking partner, size matters. Make sure the bank is large enough to finance your program over the long term. CCE's can be very large with significant capital requirements, especially as the program matures. Banks need to live within their loan-deposit caps so make sure it has enough credit capacity for long-term needs of the CCE-JPA.

<u>Underwriting Considerations:</u> When a bank considers lending to a new CCE, it will consider a number of factors including the management team. Examples:

- Does the Chairman, CEO, and other management team members demonstrate political savvy?
- Does the team have a combination of experience and entrepreneurship?
- Does it have knowledge of energy markets and energy contracting?
- Does it have a robust marketing program?
- Does the team understand the complexities of operating a customer-service focused utility service along with the complimentary energy programs?

The bank will also consider the program's financial modeling which provides a detailed forecast of program expenses and revenues over a period of years. The knowledge and credibility of the author of the financial proforma will be important as well. Finally, the bank will also consider community support, level of local government commitments, and Board/governance structure.

Program Phasing

In the world of CCE, program phasing is part of the program planning process and is influenced by a number of factors including availability of credit and capital, seasonal economics, and level of operational capacity to run the program. There are generally three elements to the phasing discussion, all of which will need to be reviewed with the governing Board and articulated in the CCE's implementation plan that must be certified by the California Public Utilities Commission:

- Program size (energy usage and customer count)
- Municipal/geographic representation
- Customer classes (e.g. residential, municipal, commercial)

Program Size: The first element that will be considered is the overall program size in terms of energy usage, load size/shape, and number of customer accounts. To date, the operational CCE's have all started service with only a small portion of their load and customer base (as little as 10-20%), enrolling customers and adding load over a period of time (~ 8 months – 2 years). A few things influence the size of initial enrollment:

- Organizational capacity and level of readiness to enroll customers;
- Utility capacity to switch customers over in batches; and
- Availability of credit to cover the cost of the initial energy contract and staffing to service the initial customers.

Municipal and Geographic Representation:
This element of phasing has to do with which municipalities join the JPA as founding members and those that choose to join later. In order to commence service, local governments must pass a CCE ordinance and in the case of MBCP, pass a JPA resolution to approve their participation in the agency. Once the CCE knows "who's in" it will be able to better ascertain overall program size, credit needs and appropriate phasing strategy. It should be noted that second and third round cities that join later are subject to the approval of the JPA Board and may have to wait until all initial customers are enrolled before joining the agency. This could be a year or even two after the initial program launch.

Customer Classes: This element of phasing refers to the types of customers that will be enrolled at each phase. Although there are hundreds of rate classes and corresponding tariffs, typical customer classes include residential, small and large commercial, municipal and agricultural. Large commercial customers served by Direct Access will not be enrolled in a CCE program unless they choose to do so.

Phasing Strategy: Once the size, municipal representation and credit needs are known, the technical team can design a phasing strategy that will best serve the MBCP program. As noted above, the phasing strategy will be articulated in the Implementation Plan that must be submitted and certified by the CPUC prior to launch. Phasing in of customers can occur in several phases (usually three) over a period of 12-24 months depending on the desire of the CCE Board to build up slowly or quickly.

To date, it has been a common practice among CCEs to launch with their commercial load sometime in the summer tariff season with a small percentage of residential accounts if desired. This is because of the strong economics and lower customer count that allows the agency to build revenues and stabilize operations before rolling out to the larger customer base of municipal and residential customers. While this strategy is not required, it is now considered a best practice relative to program launch.

In conclusion, there are a number of steps and factors to be considered prior to determining the program phasing strategy. The first is to understand which counties and cities want to participate as initial JPA members and the size of their load and number of accounts. Once that is determined, a clearer sense of credit needs will emerge and more precise modeling can be done to inform customer phasing.

MONTEREY BAY COMMUNITY POWER TECHNICAL STUDY

5/4/2016

Prepared by Pacific Energy Advisors, Inc.

This Technical Study was prepared for the Monterey Bay Community Power initiative (MBCP) for purposes of forming a Community Choice Energy (CCE) program, which would provide electric generation service to residential and business customers located within the counties of Monterey, San Benito and Santa Cruz. A detailed discussion of the projected operating results related to the MBCP program, including anticipated costs and benefits, is presented herein.

Monterey Bay Community Power Technical Study

PREPARED BY PACIFIC ENERGY ADVISORS, INC.

Table of Contents

EXECUTIVE SUMMARY

This Community Choice Energy ("CCE") Technical Study ("Study") was prepared for the Monterey Bay Community Power initiative ("MBCP"), by Pacific Energy Advisors, Inc. ("PEA") under contract with the County of Santa Cruz, for purposes of describing the potential benefits and liabilities associated with forming a CCE program within the counties of Monterey, San Benito and Santa Cruz (the "MBCP Partnership"). Such a program would provide electric generation service to residential and business customers located within the unincorporated areas of the MBCP Partnership as well as the incorporated cities therein. In aggregate, there are twenty one (21) municipalities located within the MBCP Partnership, which include the aforementioned counties as well as the following cities located therein: Capitola, Carmel, Del Rey Oaks, Gonzales, Greenfield, Hollister, King City, Marina, Monterey, Pacific Grove, Salinas, San Juan Bautista, Sand City, Santa Cruz, Scotts Valley, Seaside, Soledad and Watsonville (together, the "MBCP Communities").

This Study addresses the potential benefits and liabilities associated with forming a CCE program over a ten-year planning horizon, drawing from the best available market intelligence and PEA's direct experience with each of California's operating CCE programs – PEA has unique experience with regard to California CCE program evaluation, development and operation, having provided broad functional support to each operating CCE, which include Marin Clean Energy ("MCE"), Sonoma Clean Power ("SCP"), Lancaster Choice Energy ("LCE"), and CleanPowerSF, which will commence service to its first phase of residential and business customers located within the City and County of San Francisco during Spring 2016. PEA utilized this direct experience to generate a set of anticipated scenarios for MBCP operations as well as a variety of sensitivity analyses, which were framed to demonstrate how certain changes in the base case scenarios would influence anticipated operating results for the MBCP program. At the request of the MBCP Partnership, PEA also completed stand-alone analyses for each of the three participating counties to facilitate each entity's understanding of the costs and benefits associated with independent CCE formation (as opposed to CCE formation as part of a multi-county partnership). The results associated with these stand-alone, county-specific analyses are further discussed in Appendix A, County-Specific Scenario Analyses.

MBCP's Prospective Customers

Currently, Pacific Gas & Electric ("PG&E") serves approximately 285,000 customer accounts within communities of the MBCP Partnership, representing a mix of residential (≈86%), commercial (≈12%) and agricultural (≈2%) accounts. These customers consume nearly 3.7 billion kilowatt hours ("kWh") of electric energy each year. While the majority of customers fall under the residential classification, such accounts historically consume only 36% of the total electricity delivered by PG&E while commercial and agricultural accounts consumed the remaining 64% (comprised of ≈48% commercial consumption and ≈18% agricultural consumption). Peak customer demand within the MBCP Communities, which represents the highest level of instantaneous energy consumption throughout the year, occurs during the month of September, totaling 661 megawatts ("MW"). Under CCE service, each of these accounts would be enrolled in the MBCP program over a three-phase implementation schedule commencing in 2017, as later discussed in this Study. Consistent with California law, customers may elect to take service from the CCE provider or remain with PG&E, a process known as "opting-out." For purposes of the Study, PEA utilized current participatory statistics compiled by the operating CCE programs to derive an assumed participation rate of 85% for the MBCP program; the remaining 15% of regional customers are assumed to opt-out of the MBCP program and would continue receiving generation service from PG&E. Customer and energy usage projections referenced throughout this Study reflect such adjustment.

MBCP Indicative Supply Scenarios

For purposes of the Study, PEA and the MBCP Partnership identified three indicative supply scenarios, which were designed to test the viability of prospective CCE operations under a variety of energy resource compositions, emphasizing the MBCP Partnership's interest in significantly reducing greenhouse gas emissions ("GHGs") through increased use of carbon-free electric energy sources – it is important to note that, according to the United States Environmental Protection Agency, the main GHGs include carbon dioxide (in 2014, carbon dioxide accounted for 80.9% of all human-activity created GHGs within the U.S.; electric power sector carbon dioxide emissions also accounted for 30% of total U.S. GHGs in 2014), methane, nitrous oxide and fluorinated gases[1]; however, during the combustion of fossil fuels, not only are carbon dioxide and nitrous oxide emitted but also carbon monoxide, volatile organic compounds, sulfur dioxide and particulate matter; to the extent that the MBCP program is successful in reducing the use of fossil fuels within the electric power sector, a broad spectrum of pollutants, including GHGs, would also be reduced. With these considerations in mind, the following supply scenarios were constructed for purposes of completing this CCE Study:

- **Scenario 1**: Maximize renewable energy and greenhouse gas emission ("GHG") reductions while not exceeding the incumbent investor-owned utility's ("IOU"), Pacific Gas & Electric Company ("PG&E"), projected generation rates. Under Scenario 1, clean energy sources would be generally limited to California-based, bundled renewable energy products and a minimal amount of regionally produced hydroelectricity.[2, 3]
- **Scenario 2**: Maximize renewable energy and GHG reductions while not exceeding PG&E's projected generation rates. Under Scenario 2, clean energy sources would be limited to California-based and regionally produced, bundled renewable energy products.
- **Scenario 3**: Maximize MBCP rate competitiveness while achieving a 25% annual reduction in GHG emissions relative to PG&E's projected resource mix. Under Scenario 3, clean energy sources would include California-based and regionally produced, bundled renewable energy products as well as regionally produced hydroelectricity.[4]

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

When developing MBCP's indicative supply scenarios, PEA was directed to include additional assumptions. In particular, all scenarios include the provision of a voluntary retail service option that would provide

[1] U.S. Environmental Protection Agency: https://www3.epa.gov/climatechange/ghgemissions/gases.html.
[2] Consistent with California's Renewables Portfolio Standard ("RPS") laws, retail sellers of electric energy, including CCEs, must procure a minimum 33% of all electricity from eligible renewable energy sources by 2020; with the recent enrollment of Senate Bill 350, California's RPS procurement mandate has been increased to 50% by 2030. All MBCP supply scenarios addressed in this Study were attentive to such minimum requirements, ensuring MBCP compliance with California's RPS on a projected basis.
[3] Industry accepted GHG accounting practices generally recognize eligible renewable energy sources as GHG-free. Under the Scenario 1 and 3 portfolio compositions, incremental purchases of non-RPS-eligible GHG-free sources, specifically electricity produced by larger hydroelectric resources (with nameplate generating capacity in excess of 30 megawatts) would be procured by MBCP to achieve targeted GHG emissions reductions.
[4] Under Scenario 3, the proportion of RPS-eligible renewable energy is projected to minimally exceed specified RPS procurement mandates throughout the Study period.

participating customers with 100% renewable energy (presumably for a price premium); for purposes of this Study, it was assumed that only a small percentage of MBCP customers would select this service option (≈2% of the projected MBCP customer base), which is generally consistent with customer participation in other operating CCE programs. In addition, all scenarios assume the availability of current solar development incentives as well as an MBCP-administered net energy metering ("NEM") service option, which could be used to further promote the development of local, customer-sited renewable resources. PEA was also directed to exclude the use of: 1) unbundled renewable energy certificates (due to ongoing controversy focused on environmental benefit accounting for such products); 2) specified purchases from nuclear generation, which is generally unavailable to wholesale energy buyers, including CCE programs, but represents a significant portion of PG&E's energy resource mix[5]; and 3) coal generation,[6] which is a cost-effective but highly polluting domestic power source.

Projected Cost Impacts to MBCP Customers

Based on current market prices and various operating assumptions, as detailed in Section 2: Study Methodology, this Study indicates that MBCP 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 general rate parity, relative to projected PG&E rates, over the ten-year study period while providing the region with significant electric power sector GHG emissions reductions through the predominant use of bundled renewable energy resources. Scenario 3, which was designed to maximize rate competitiveness with PG&E while also reducing annual electric power sector GHG emissions by 25%, demonstrated the potential for meaningful MBCP cost reductions (ranging from 3% in Year 1 to 5% in Year 10 of projected operations) while also achieving significant environmental benefits. As previously noted, none of the prospective supply scenarios include the use of unbundled renewable energy certificates; renewable energy products will be exclusively limited to "bundled" deliveries produced by generators primarily located within: 1) California; 2) the MBCP Communities; and 3) elsewhere in the western United States. As described above, each prospective supply scenario incorporates differing proportions of clean energy resources to achieve MBCP's desired objectives.

General Operating Projections

When reviewing the pro forma financial results associated with each of the prospective supply scenarios, as reflected in Appendix B of this Study, the "Total Change in Customer Electric Charges" during each year of the study period reflects the projected net revenues (or deficits) that would be realized by MBCP in the event that the program decided to offer customer electric rates that were equivalent to similar rates charged by PG&E. To the extent that the Total Change in Customer Electric Charges is negative, MBCP 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, MBCP would need to impose comparatively higher customer charges in order to recover expected costs. Ultimately, the disposition of any projected net revenues will be determined by MBCP leadership during periodic budgeting and rate-setting processes. For example, in the cases of Scenario 3, each year of the study period reflects the potential for net revenues. Such net revenues could be passed through to MBCP customers in the form of comparatively lower electric rates/charges, as contemplated in this Study, utilized as working capital for program operations in an attempt to reduce

[5] 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.

[6] According to the California Energy Commission, approximately 6% of California's 2014 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.

program financing requirements, or MBCP 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. MBCP leadership would have considerable flexibility in administering the disposition of any projected net revenues, subject to any financial covenants that may be entered into by the program.

Environmental Impacts

With regard to MBCP's anticipated clean energy supply and resultant GHG emissions impacts, each prospective supply scenario yielded different environmental benefits, resulting from the diverse composition of clean energy sources within each supply scenario. Such benefits were generally quantified in consideration of the anticipated carbon intensity of PG&E's prospective supply portfolio relative to similar projections for MBCP. To the extent that each of MBCP's indicative supply portfolios incorporated higher proportions of non-carbon-emitting generating technologies than PG&E, GHG emission reductions are expected to occur following MBCP implementation. For example, Scenario 1, which was specifically designed to maximize GHG emission reductions through the exclusive use of California-based renewable energy supply and a small amount of additional, regionally produced hydroelectricity (which was only incorporated in Year 1 of projected MBCP operations for purposes of achieving general rate parity with the incumbent utility), resulted in annual GHG emissions *reductions* ranging from approximately 36,000 (or 20%, Year 1 impact) to 164,000 (or 42%, Year 10 impact) metric tons. Supply Scenario 2, which was similarly constructed to Scenario 1, utilizing both California-based and regionally produced renewable energy products to achieve MBCP's desired environmental objectives (without additional hydroelectricity), resulted in annual emissions *reductions* ranging from approximately 36,000 (or 20%, Year 1 impact) to 238,000 (or 62%, Year 10 impact) metric tons. Supply Scenario 3 yielded slightly different emissions benefits through the use of a more diverse portfolio of clean energy resources, including California-based and regionally produced renewable energy as well as hydroelectricity, creating a projected annual GHG emissions reduction of 25% during each year of the Study period. This level of projected GHG emissions reductions equates to 45,000 metric tons in Year 1, increasing to 97,000 metric tons in Year 10.

When considering MBCP's projected environmental benefits, it is noteworthy that current market pricing for renewable and GHG-free power sources is becoming increasingly cost competitive when compared to conventional generating technologies. This trend has allowed for the inclusion of significant proportions of GHG-free electricity within each of MBCP's prospective supply scenarios while retaining cost competitiveness. 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. In particular, the Diablo Canyon Power Plant ("DCPP") produces approximately 20% of the utility's total annual electric energy requirements. During the latter portion of the Study period, DCPP will need to relicense the facility's two reactor units (in 2024 and 2025, respectively) and there is some 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 – use of once-through cooling is no longer permissible within California, and affected generators must reconfigure requisite cooling systems or face discontinued operation. To the extent that PG&E's use of nuclear generation is curtailed or suspended at some point in the future, MBCP's projected emissions reductions would significantly increase under each operating scenario. However, due to the timing of the relicensing issue facing DCPP, substantive increases to projected environmental benefits (resulting from prospective changes to PG&E's nuclear power supply) should not be assumed during the Study period.

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

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

For the sake of comparison, Table 1 displays PG&E's proportionate use of various power sources during the most recent reporting year (2014) as well as the aggregate resource mix within the state of California, as reported by the California Energy Commission ("CEC"). During the Study period, planned increases in California's RPS procurement mandate and various other factors will contribute to periodic changes in PG&E's noted resource mix. Such changes will affect projected GHG emissions comparisons between MBCP and PG&E.

Table 1: 2014 PG&E and California Power Mix

Energy Resource	2014 PG&E Power Mix[1]	2014 California Power Mix[2]
Eligible Renewable	**27%**	**20%**
--Biomass & Waste	5%	3%
--Geothermal	5%	4%
--Small Hydroelectric	1%	1%
--Solar	9%	4%
--Wind	7%	8%
Coal	0%	6%
Large Hydroelectric	8%	6%
Natural Gas	24%	45%
Nuclear	21%	9%
Unspecified Sources of Power	21%	14%
Total[3]	**100%**	**100%**

[1]*Source: PG&E 2014 Power Source Disclosure Report;*
[2]*Source: California Energy Commission - http://energyalmanac.ca.gov/electricity/total_system_power.html; and*
[3]*Numbers may not add due to rounding.*

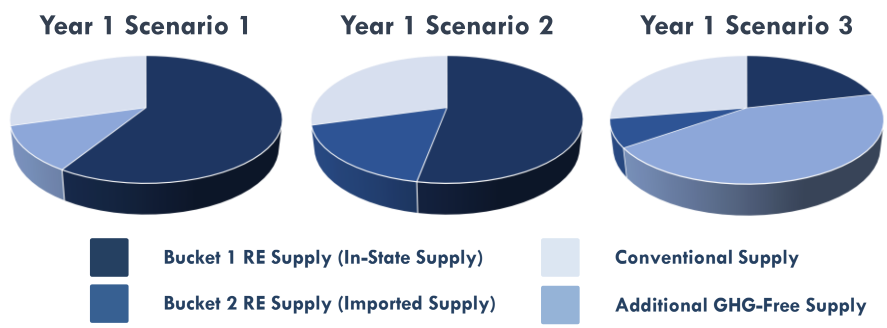
Projected Economic Development Benefits

MBCP's projected long-term power contract portfolio is also expected to have the potential to generate substantial economic benefits throughout the state as a result of new renewable resource development. A moderate component of this impact is expected to occur within the local economy as a direct result of renewable infrastructure buildout to be supported by a MBCP-administered Feed-In Tariff program, which could be designed to promote the development of smaller-scale renewable generating projects that would supply a modest portion of MBCP's total energy requirements. The prospective MBCP long-term contract portfolio, which is reflected in the anticipated resource mix for each supply scenario, includes approximately 340 MW of new generating capacity (all of which is assumed to be located within California and some of which may be located within certain of the MBCP Communities). Based on widely used industry models, such projects are expected to generate up to 11,000 construction jobs and nearly $1.4 billion in total economic output. Ongoing operation and maintenance ("O&M") jobs associated with such projects are expected to employ as many as 185 full time equivalent positions ("FTEs") with additional annual economic output approximating $28 million. MBCP would also employ a combination of staff and contractors, resulting in additional ongoing job creation (up to 29 FTEs per year) and related annual economic output ranging from $3 to $9 million.

Consolidated Scenario Highlights

The following exhibit identifies the projected operating results under each indicative supply scenario in Year 1 of anticipated MBCP operations. Additional details regarding the composition of each supply scenario are addressed in Section 2.

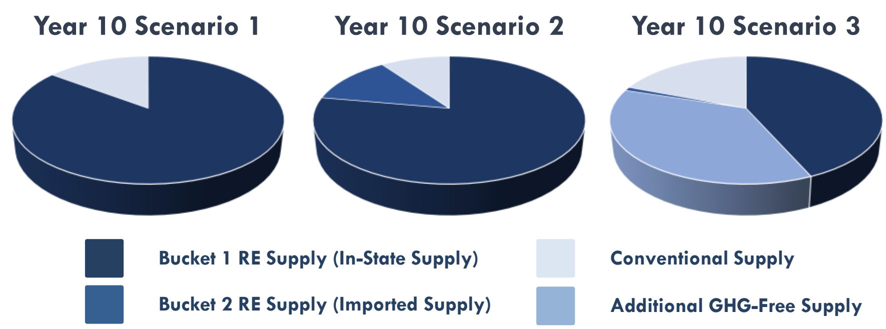
Monterey Bay Community Power Indicative Supply Scenarios: Year 1



Key Considerations	Scenario 1	Scenario 2	Scenario 3
General Environmental Benefits	59% Renewable 70% GHG-Free	71% Renewable 71% GHG-Free	28% Renewable 72% GHG-Free
Rate Competitiveness	≈rate parity relative to PG&E projections	≈rate parity relative to PG&E projections	Average 3% savings relative to PG&E rate projections
Projected Residential Customer Cost Impacts[1] [1]Average monthly usage for MBCP residential customers ≈ 446 kWh	Projected MBCP & PG&E costs are equivalent	Projected MBCP & PG&E costs are equivalent	Average $3.01 monthly cost savings relative to PG&E projections
Assumed MBCP Participation	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups
Comparative GHG Emissions Impacts	0.126 metric tons CO2/MWh emissions rate; ≈35,660 metric ton GHG emissions reduction in Year 1 (≈20% reduction)	0.126 metric tons CO2/MWh emissions rate; ≈36,301 metric ton GHG emissions reduction in Year 1 (≈20% reduction)	0.119 metric tons CO2/MWh emissions rate; ≈44,573 metric ton GHG emissions reduction in Year 1 (≈25% reduction)

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

Monterey Bay Community Power Indicative Supply Scenarios: Year 10



Key Considerations	Scenario 1	Scenario 2	Scenario 3
General Environmental Benefits	85% Renewable 85% GHG-Free	90% Renewable 90% GHG-Free	44% Renewable 81% GHG-Free
Rate Competitiveness	Average 1% savings relative to PG&E rate projections	Average 1% savings relative to PG&E rate projections	Average 5% savings relative to PG&E rate projections
Projected Residential Customer Cost Impacts[1] [1]Average monthly usage for MBCP residential customers ≈ 446 kWh	Average $1.57 monthly cost savings relative to PG&E rate projections	Average $1.79 monthly cost savings relative to PG&E rate projections	Average $6.23 monthly cost savings relative to PG&E projections
Assumed MBCP Participation	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups
Comparative GHG Emissions Impacts	0.063 metric tons CO_2/MWh emissions rate; ≈163,559 metric ton GHG emissions reduction in Year 10 (≈42% reduction)	0.042 metric tons CO_2/MWh emissions rate; ≈237,857 metric ton GHG emissions reduction in Year 10 (≈62% reduction)	0.082 metric tons CO_2/MWh emissions rate; ≈96,594 metric ton GHG emissions reduction in Year 10 (≈25% reduction)

Findings and Conclusions

Based on the results reflected in this Study and PEA's considerable experience with California CCEs, the MBCP program has a variety of electric supply options that are projected to yield both competitive customer rates and significant environmental benefits. To the extent that clean energy options, including renewable energy and hydroelectricity, are used in place of anticipated conventional power sources, which utilize fossil fuels to produce electric power, anticipated MBCP costs and related customer rates would be marginally higher. However, Scenario 3 indicates that the potential exists for significant GHG emissions reductions and marginally increased renewable energy deliveries under a scenario in which MBCP rates are meaningfully below similar rates charged by the incumbent utility. In general terms, each of the indicative supply scenarios discussed in this Study reflects the potential for MBCP to promote meaningful reductions in electric-sector GHG emissions while offering competitive electric generation rates.

Ultimately, MBCP'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, MBCP's actual 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 CCE programs, MBCP'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. Operational viability is also based on the assumption that MBCP would be able to secure the necessary startup funding as well as additional financing to satisfy program working capital estimates. As previously noted, it is PEA's opinion that MBCP would be operationally viable under a relatively broad range of resource planning scenarios, demonstrating the potential for customer savings as well as reduced electric-sector GHG emissions throughout the region.

Monterey Bay Community Power

COMMUNITY OUTREACH PLAN

APRIL 2016

Miller Maxfield, Inc.
Strategic Communications & Public Affairs

Monterey Bay Community Power

TABLE OF CONTENTS

COMMUNITY OUTREACH PLAN • APRIL 2016

INTRODUCTION

Following the passage of AB 117, which enabled local governments to aggregate the residential, business and municipal electricity loads within their jurisdictions, Monterey Bay Community Power formed for the purposes of exploring the feasibility for generating electricity as an alternative for customers to PG&E. The top benefits of an eventual formation of a Community Choice Energy agency include establishing local control over rates, creating rate parity with PG&E, reducing greenhouse gasses by sourcing green energy, and redirecting revenue from PG&E to the local economy through projects and initiatives to be developed by the new agency, with input and direction from the community.

Organized by the County of Santa Cruz as the lead partner, and with support from the Community Foundation of Santa Cruz County, the project is managed by a Project Development Advisory Committee (PDAC) with representation from three counties and 18 cities, all of whose governing bodies passed resolutions to investigate the feasibility of creating a Community Choice Energy project.

They are:

- Santa Cruz County
- Monterey County
- San Benito County
- City of Santa Cruz
- City of Scotts Valley
- City of Capitola
- City of Watsonville
- City of Salinas
- City of Monterey
- City of Carmel
- City of Sand City
- City of Soledad
- City of Seaside
- City of Greenfield
- City of Pacific Grove
- City of Marina
- City of King City
- City of Del Ray Oaks
- City of Hollister
- City of San Juan Bautista
- City of Gonzales

Key partner agencies include:

- Monterey Regional Waste Management District
- Salinas Valley Solid Waste Authority
- Monterey Bay Unified Air Pollution Control Board

The PDAC has met since 2013 to oversee the exploration of a Community Choice Energy agency, including the impact on the local economy, the ability to produce energy, and the ability to provide that energy at rates that are similar to PG&E's. The Technical Feasibility Study, which will undergo peer review, identified three supply scenarios that seek rate parity or cost savings with PG&E under various combinations of renewable and regionally produced energy products.

From April-September 2016, the Outreach Plan will be implemented across the region with the goal of early adoptive county and city partners taking action by the end of September toward formation of a Community Choice Energy agency. The agency could begin providing energy to residential and commercial customers within the early adopter jurisdictions by October 2017.

TRI-COUNTY REGION & DEMOGRAPHICS

The region covered by the Monterey Bay Community Power Project includes Santa Cruz, Monterey and San Benito counties, which represent a total estimated population of about 761,415 people and 285,000 PG&E customer accounts. About a third (36%) of the total electricity delivered by PG&E in the project area is consumed by the residential sector, whereas 48% and 18 %, respectively, represent commercial and agricultural consumption.

The three counties span a combined 5,100 square miles on the Central Coast of California, and reflect great diversity in their individual populations, top sectors of industry, urban and rural geography, and political landscape. Each county, and including the communities within each county, will require customized public outreach designed to address unique sets of interests and questions.

MONTEREY COUNTY

Monterey County covers 3,280 square miles with an estimated population of 431,344 people, which is estimated to have grown 4 percent since 2010. The largest city in Monterey County is the city of Salinas, which is the county seat and the largest city in the tri-county region. The largest ethnic group in Monterey County is Hispanic/Latino at 57.4%, followed by whites at 31.2%. Asians make up 6.9% of the population, while African-Americans make up 3.5%. More than half of residents, or 52.8%, speak a language other than English at home and nearly a third of residents, or 30.1%, were born outside the U.S. About a quarter of the population (26.4%) is made up of people under the age of 18, while 12% of residents are 65 or older.

There are more than 125,000 households in Monterey County and about 140,000 housing units, with nearly 50% being owner occupied. The median household income is the lowest in the three-county region, at $58,582 and Monterey County has the highest poverty rate at 17%.

Nearly three-quarters of residents (71.2%) 25 years or older have a high school degree and nearly a quarter (23.1%) of those residents have a bachelor's degree or higher.

Top industries in Monterey County include agriculture, tourism and government.

SAN BENITO COUNTY

San Benito County covers 1,388 square miles. San Benito County has the smallest population of the tri-county area, with 58,267 residents and a growth rate of 5.4% since 2010. The largest city in San Benito County is Hollister, which serves as the county seat. Hispanic/Latino residents represent the largest ethnic group (58.3%), followed by whites (36%), Asians (2.6%) and African-Americans (1.3%). A language other than English is spoken at home by 39.2% of residents age 5 or older, and a fifth of the population (20.5%) was born outside the U.S.

Compared to its overall population, San Benito County has the highest percentage of children in the tri-county area (26.8%) and the smallest percentage (11.4%) of people over 65. There are more than 17,000 households in the county with about 18,000 housing units. The median household income is the highest in the tri-county area at $67,874 and the poverty rate is the lowest (14.1%). More than three-quarters of residents age 25 and older (77.9%) have high school degrees or higher, but the county has the lowest percentage within that age group in the region for having bachelor's degrees or higher.

Top industries include agriculture and health care.

SANTA CRUZ COUNTY

Santa Cruz County covers 590 square miles with an estimated population of about 271,804 people, a figure that has estimated to have grown 3.6% since 2010. The largest city in Santa Cruz County is Santa Cruz, which is the county seat.

The ethnic makeup of Santa Cruz County is 58.2% white, 33.2% Hispanic or Latino, 4.8% Asian and 1.4% African-American. About a third of residents (31.6%) speak a language other than English at home. Nearly one-fifth (18.2%) of the population is foreign born. The percentage of the population under age 18 is 20.1%, while residents over 65 represent 13.5%.

There are more than 94,000 households in Santa Cruz County and about 105,000 housing units, nearly 60% of which are owner occupied. The median household income is $66,923. Most residents over the age of 25 have high school degrees or higher (85.5%) and about a third, or 37.5%, have bachelor's degrees or higher. About 16% of residents are estimated to live in poverty.

Top industries in Santa Cruz County include tourism, agriculture and education.

OUTREACH PLAN

Development and implementation of a communications outreach plan that reaches a three-county region in a relatively short time frame requires excellent research, strategy, planning and execution. The most effective and compelling communication channels must be prioritized in order to maximize communication and education goals to reach audiences.

It will be imperative that the MBCP narrative, and its value proposition including features and benefits, be compelling, understandable and attractive to residents.

To reach target audiences where they live, work and play, MBCP outreach must be tailored to resonate in the various cultural/political "microclimates" that exist throughout the region.

TARGET AUDIENCES

For Phase 2 (April 15-October 31), which represents implementation of the plan, a two-track approach will be implemented:

1. Education and consensus-building among elected officials, public sector staff and key community leaders through presentations and one-on-one meetings, backed by essential support materials that will tell the MBCP story, features and benefits.
2. Awareness-building with the general public across the region through compelling collateral materials, social media, earned media coverage and participation in community events.

Direct engagement coupled with outreach to community members and constituents will help position the project for future success.

In addition to the public at large, the following audiences have been identified as key targets:

- Elected Officials & Senior Staff
- Business Groups
- Environmental Groups
- Agriculture-Related Organizations
- Community Service Groups
- Neighborhood Groups
- Congregations
- Latino Organizations
- Senior Groups

COMMUNICATION STRATEGY

SURVEY OF KEY STAKEHOLDERS

- Survey to target a well-balanced group of 30-50 key influencers representing various constituencies, organizations and sectors across the region.
- Input to be requested from city managers.
- Survey instrument to be electronic and based on a "Survey Monkey" model, with targets to be secured via email and phone before receiving the survey via email.
- Will fulfill grant requirement.
- Results will inform messaging and strategy.

DEVELOPMENT OF MESSAGING

Messaging serves as the framework around which all public outreach and communication activities are built. Identifying MBCP key messages is an essential component of the Community Outreach Plan.

- The MBCP narrative and messaging must be compelling and accessible to a wide range of target audiences.
- Messaging will be able to be tailored to resonate in the various cultural/political "microclimates" that exist throughout the region.
- Existing messaging will be evaluated and evolved for use moving forward.
- Messaging will reflect input from Stakeholder Surveys.
- A standardized "boilerplate" description of MBCP will be developed for use in press releases, etc. in order to ensure consistency in how MBCP is described.

OUTREACH TOOLS

MBCP BRANDING

The existing MBCP name and logo will be retained for the outreach project. Other branding strategies include:

Tagline

A tagline will be developed to succinctly describe MBCP. The tagline will complement the logo and will be included on all external communications.

Identity Package

A MBCP identity package will be developed, including business cards for five people, digital letterhead and Word templates for a press release, backgrounder and fact sheet.

Presentations

Two existing PowerPoint presentations will be updated.

Brochure

A brochure will be produced to be used as a leave behind at one-on-one meetings, community events and tabling opportunities. Content may include elements such as key messages, background, timeline, infographics, quotes from key influences and early adopters, timeline, contact info, photos. Proposed design is an accordion-fold brochure that includes English and Spanish content – six panels for each language.

Signage

Banners: Two vertical pull-up banners and two horizontal vinyl banners will be produced for use at events.

Tablecloth Banners: Two tablecloth banners will be produced for use a tabling events.

Poster Boards: To be produced as needed for events for use at entrance areas, etc.

Information Kit

Information kits will be produced in English and Spanish for use as a leave-behind for one-on-one meetings, as well as other meetings (such as with reporters) as needed. Recommended kit components include: fact sheet, backgrounder, Q&A/FAQ, list of supporters, brochure, sample of a customer bill and press releases.

Website

The MBCP current website will be updated, including redirection to a more intuitive URL, layout and content. The goal for the website is to provide the public and decision makers with essential news and information about the past, present and future of the CCE project. Additional CCE agency names will be proposed and related URLs reserved for the future JPA's consideration.

OUTREACH ACTIVITIES

MBCP-HOSTED EVENTS

Community Meetings/Study Sessions/Workshops

The study sessions will provide attendees with an in-depth look at Monterey Bay's proposed Community Choice Energy program. The study sessions will be presentation format and be approximately 2.5 hours long. The events will provide an overview of the project and will cover the mechanics of CCE, how it would work in the Monterey Bay region, results from the recently completed technical study and plans for moving forward. In addition to promotional activities targeting the general public, direct outreach will take place with senior staff from relevant local jurisdictions. Presenters will include CCE experts and staff.

The following dates, which are aligned with currently scheduled PDAC meetings, are proposed:

- May 24, 9:30 to 12 p.m. at the Monterey County Board Chambers
- June 9, 9:30 to 12 p.m. at the Santa Cruz County Board Chambers
- June 9, 3 to 5:30 p.m. at the San Benito County Board Chambers
- July 14, 1:30 to 4 p.m. at the Santa Cruz County Board Chambers

For the May 24 event, Monterey County-based AMP Media will be asked to record the event in English and Spanish (including translation services) for use on community TV and other potential outlets, as well as online. Video content may be segmented for use as shorter, downloadable videos.

Two additional, smaller community study sessions are envisioned for western and southern Monterey County. Dates are to be determined.

DRAFT PROGRAM

Welcome – Identify who for each meeting (15 minutes)
Monterey Bay Community Power regional collaborative process and program goals.
Introduce elected officials & Project Development Advisory Committee members.

Community Choice Energy – Shawn Marshall, Director, Local Energy Aggregation Network
Board member TBD – SCP or MCE (20 minutes)
How Community Choice Energy works.
Successes of existing California CCEs.

Results of the Technical Study – Pacific Energy Advisors (45 minutes)

Next Steps – MBCP Team (30 minutes)
Key Elements of CCE start up and Operations.
Monterey Bay Community Power partnership - Planning Timeline.
How to participate/stay informed.

Networking with Presenters (30 minutes)

2016 Monterey Bay Regional Climate Action Compact Annual Summit

In partnership with the Monterey Bay Climate Action Compact, the Summit will focus on the recent activities of the Compact, with special emphasis on the MBCP. MBCP-specific content will include a keynote speech on CCE, as well as materials, displays and other information about MBCP. Event will be ½-day, beginning in the morning. Tentative date: September 1 (location TBD)

Presentations To Community Organizations

Presentations about MBCP will be made to community organizations throughout the region. Lead presenters will include Brennen Jensen, Margaret Bruce and Marc Adato, each of whom is an expert on CCE. MBCP ad hoc committee members will provide perspective and consultation for specific organizations. Target organizations will be contacted to determine if an opportunity to present exists. Presentation formats and content will be adapted to each organization and may include PowerPoint and information kits. Goals for this strategy are to make presentations to 10 organizations in Monterey County, 5 in San Benito County and 10 in Santa Cruz County.

Monterey County Sample Targets

Carmel Chamber of Commerce
Marina Chamber of Commerce
Monterey Peninsula Chamber of Commerce
Pebble Beach Company
Moss Landing Chamber of Commerce
North Monterey County Chamber of Commerce
Pacific Grove Chamber of Commerce
Salinas Chamber of Commerce
Grower-Shipper Association
Rotary Club of Cannery Row
Rotary Club of Carmel
Rotary Club of Carmel Valley
Rotary Club of King City
Rotary Club of Monterey
Rotary Club of Salinas
Rotary Club of Seaside
Transition Aromas
Monterey County Democrats
Sustainable Monterey County
Monterey County Business Council

Santa Benito County Sample Targets

San Benito County Business Council
San Benito County Chamber of Commerce and Visitors Bureau
Hollister Elks Lodge
Hollister Lions Club
Rotary Club of Hollister
Rotary Club of San Juan Bautista
Sierra Club – Loma Prieta Chapter
San Benito County Democratic Central Committee

Santa Cruz County Sample Targets

Pajaro Valley Chamber of Commerce and Agriculture
Farm Bureau
Capitola/Soquel Chamber of Commerce
Santa Cruz Chamber of Commerce
Sunrise Santa Cruz Rotary
Santa Cruz Neighbors
Santa Cruz County Democratic Women's Club
COPA (Tri-County)

Tabling Opportunities

Tabling opportunities provide a chance for MBCP representatives to engage directly with the public at events hosted by other organizations. MBCP materials will be available for the public and the table/booth will have MBCP branding (banner).

Target Events

- Monterey Bay Economic Partnership Regional Summit (April 26, 2016)
- Santa Cruz County Fair (Sept. 14-18, 2016)
- San Benito County Fair (Sept. 29-Oct. 2)
- Monterey County Fair (Aug. 31-Sept. 5)

Others events such as Farmer's Markets, Open Streets events, etc. may be considered.

EARNED MEDIA (PRESS)

Media relations, publicity or "earned media" is an essential vehicle by which to deliver MBCP's key messages because it provides third-party validation of MBCP mission and goals, and establishes confidence by the public. A primary strategy will to engage with local and regional media to tell the MBCP story. Initially we recommend one-on-one meetings to (re)introduce the concept of CCE, MBCP and answer questions.

Press Releases

Press releases will be written, distributed and pitched to the media to generate press coverage of events, milestones, etc. Earned media opportunities supported by press releases include news and feature stories (print & online); radio and TV interviews; and calendar listings.

Media Protocol & Response

A media protocol will be created for use by PDAC members and associated staff and leadership in order to ensure message consistency, responsiveness and to prevent confusion. Elements of the media relations protocol will include:

- Identification of primary and secondary spokespersons
- A rapid response policy for incoming reporter calls
- Commitment to relationship-building and honest dealing with reporters
- Monitoring of comments for online stories

Letter to the Editor

Individuals who have a positive view of MBCP may be asked to submit a letter-to-the-editor as a low-cost, high-impact way to deliver key messages in a personalized way. Goal will be at least two letters per month. Letter-writers will be supported with access to MBCP information as needed, as well as instructions for how to submit letters.

Op-Eds & Editorial Boards

Op-eds authored by MBCP representatives and experts will be pursued with local news outlets. Editorials boards present a unique opportunity to meet with news editors to increase understanding and clarifies key issues, with the goal of securing a positive editorial about MBCP. These opportunities will be pursued.

PSAs (Public Service Announcements)

PSAs offer an opportunity to deliver messages primarily via radio, and to some degree TV, per FCC requirements. PSAs will be written and submitted to stations. Stations are not obligated to run the PSA, but may choose to do so.

Media Outlets

The following news outlets, as well as others, will be the focus of news, letters-to-the-editor, op-ed, editorial board and PSA strategies:

<u>Monterey County-Based</u>

Monterey County Herald
Monterey County Weekly
Salinas Californian
Salinas Valley Chamber Business Journal
Regional Small Biz Monterey Bay
Carmel Pine Cone
Cedar Street Times
KION TV
KSBW TV
Carmel Magazine
Gonzales Tribune
Greenfield News
KDRH-FM
King City Rustler
KRKC-FM
Soledad Bee
South County Newspapers
KCDC-FM/The Beach
KHIP-FM/The Hippo
KKHK-FM/BOB
KLOK-FM
KWAV-FM
KDON-FM
KSEA-FM
KTOM-FM
El Sol
KAZU-FM
KRAY La Buena
KTGE Radio Tigre
KMJV Radio Lobo
KSE La Campesina
Univision

<u>San Benito County-Based</u>

Hollister Freelance/San Benito Today
BenitoLink

<u>Santa Cruz County-Based</u>

Aptos Times, Capitola/Soquel, Scotts Valley Times
Aptos Community News
Boulder Creek Insider
Cabrillo Voice
City on a Hill Press
Good Times
Growing Up in Santa Cruz
Hilltromper
KZSC-FM
KSCO-AM
KUSP-FM
KPIG-FM
My Scotts Valley
Santa Cruz Life
Santa Cruz Mountain Bulletin
Santa Cruz Parent
Scott Valley Press Banner
Santa Cruz Sentinel
TechBeat
La Ganga
Register Pajaronian

SOCIAL MEDIA

Social media platforms will be utilized to raise awareness and visibility for MBCP and support the goal to reach residents in the tri-county region. Platforms will include:

Facebook

Task 1: Optimize Page

- Work with graphic designer to re-size cover photos to fit dimensions
- Ensure consistent “likes” with like-minded organizations, media etc.
- Update all content (including “About” section with updated MBCP messages).
- Refresh photos.
- Connect Facebook page to Twitter and YouTube accounts

Task 2: Monthly Content Calendar

- Create ongoing content plan/pattern of posts (upcoming events, relevant news coverage, factoids, etc.)
- Research MBCP materials for 3 posts per week
- Identify photos to accompany posts (possibly from existing MBCP resources)
- Coordinate edits/approvals from MBCP for scheduled posts using Google docs or other platform

Task 3: Facebook Cross-Promotion with Affinity/Partner Facebook pages

- Direct outreach with MBCP partner sites for sharing posts/links (essential for building support).

Topics for Facebook posts will include: news, facts, events and content from other MBCP social media platforms.

YouTube

Videos will be posted as available and can be shared on Facebook, Twitter, Google+ and in an email newsletter. Appropriate videos for posting could include community media, educations/explanatory videos and MBCP promotional videos.

Twitter

- Auto-populate Facebook posts to Twitter account.
- Live tweet from community meetings.
- Provide login credentials to interested MBCP team members who would like to participate in sharing information on Twitter.
- Topics for Twitter posts could include news, facts, events and retweeted posts from like-minded organizations.

Google+

- Content can be sourced from all other MBCP social media channel.
- Topics may include news, facts and event information.

Nextdoor

- Content to focus on news and information of interest at a neighborhood level.

Social Media Protocol & Additional Strategies

A monthly content calendar will be created, with posts to be scheduled primarily between 9am-12pm Monday thru Friday. User comments will receive a same-day response whenever possible. Controversial comments that require a response from MBCP will be subject to a collaborative process involving the project team. MBCP will like pages and posts by like-minded/affinity/stakeholder organizations including other non-profits, government, media, for-profit partners.

Additional Strategies

- MBCP will invite participation on website and through e-news
- MBCP will include Facebook icon on all digital and printed materials
- A budget of $75/month will be used to promote the page, boost posts and promote event pages
- Video will be featured in posts, i.e. English and Spanish recordings of the May 12 MBCP event to be held in Monterey County

EMAIL NEWSLETTERS (E-NEWS)

Based on the existing platform and distribution list, a monthly email newsletter will include news, factoids, event details, commitments of support, upcoming events/news, policy updates, etc. Sign-ups for the newsletter can be promoted and gathered from a variety of sources including community events in order to build the distribution list.

Task 1: Optimize Newsletter

- Create a template for the newsletter that fits with the look and feel of other MBCP materials.
- Encourage newsletter signups via the website, Facebook, events and other outreach.

Task 2: Newsletter Publication Calendar

- Create an ongoing content plan for the email newsletter, including proposed publication dates and suggested content.
- Identify topics and content for newsletter articles, and photos to accompany the articles.

VIDEO

A video will be produced to bring MBCP to life in an engaging, compelling way. The video will be 2-3 minutes long, with two shorter "snippet" versions produce for use on social media. An additional mobile phone-based strategy will be explored, through which short (15-30 seconds), simple vignettes would be created to present testimonials about renewable energy. Intended uses for the videos, in addition to social media, include presentations, website content and public television. The lead video is envisioned to include a simplified and clear explanation of CCE and a humanized approach to explaining the benefits of CCE, while featuring footage shot in the MBCP region.

ADVERTISING

A modest investment in advertising is planned as a strategy to supplement other outreach strategies and deliver messages to a broader audience of the general public. Advertising will consist of two investments:

- Facebook advertising to promote the page and "boost" specific posts. Facebook advertising allows targeting based on geography and Facebook user interests (i.e. environmental causes, etc.).
- KAZU underwriting to promote the summit that is tentatively scheduled for September 1. KAZU is the public radio NPR affiliate for the Monterey Bay Area and includes a listening audience that will likely be interested in and receptive to the MBCP project.

WEBINAR

A webinar will be conducted to cover best practices from the outreach effort. Target audiences will include interested parties from throughout California, as well as local government staff and members of the public. The webinar will be offered as a "brown bag," 1-hour online program and will include two speakers.

OUTREACH TIMELINE

April

- Finalize outreach plan
- Stakeholder surveys
- Messaging
- Video start

May

- Collateral materials and information kits produced
- Social media, website and email optimized
- Monterey County community meeting/ study session (May 24)
- Community presentations
- Media/press outreach

June

- Santa Cruz County community meeting/ study session (June 9)
- San Benito County community meeting/ study session (June 9)
- Additional Monterey County study sessions
- Community presentations
- Media/press outreach
- Social media push
- Video completion

July

- Santa Cruz community meeting/ study session (July 14)
- Community presentations
- Media/press outreach
- Social media push

August

- Community presentations
- Media/press outreach
- Social media push
- KAZU underwriting

September

- Offset Project Annual Summit (Sept. 1)
- Media/press outreach
- Social media push

October

- Community presentations
- Media/press outreach
- Social media push

November

- Best practices webinar

ESTIMATED BUDGET

Total Budget: $91,000.00

Activity	% of Budget
MBCP-hosted events	18%
Branding and collateral materials	17%
Earned media	16%
Tabling opportunities	9%
Video	9%
Presentations to community groups	8%
Social media and email outreach	6%
Stakeholder survey and messaging	5%
Advertising	4%
Website	2%
Webinar	2%
Contingency	4%
	100%

Monterey Bay
Community Power

APPENDIX 1 - Additional Acknowledgements

The Project Development Advisory Committee would like to additionally acknowledge the Santa Cruz County staff who were involved with the project on various levels and/or served on the Technical Working Group and the Communications Working Group with the volunteer experts listed below. Thanks to each County staff member and volunteer expert for your hard work and contributions to this project:

Allyson Violante, Office of Supervisor Zach Friend
David Reid, Office of Supervisor John Leopold
Allison Endert, Office of Supervisor Ryan Coonerty
Andy Schiffrin, Office of Supervisor Ryan Coonerty
Paia Levine, Santa Cruz County Planning Department
Nancy McCollum, Santa Cruz County Planning Department
Kevin Bratcher, Santa Cruz County General Services Department
James Allen, Allterra Solar
Mary Cunov, Cross-cultural Teacher
Andy Hartmann, IBEW Local 234
Joe Jordan, Educator/Solar Consultant
Mike Keller, Anaerobics Technology
Angela Lipanovich, Estriatus Law
Jim Weisenstein, Day One Solar
Kurt Yeager, Galvin Electricity Initiative

Several community groups and individuals donated to the Monterey Bay CCA Fund at the Community Foundation of Santa Cruz County. Their support provided the seed funding that became the basis for successful grants from the *California Strategic Growth Council*, the *World Wildlife Fund*, and the *UC Santa Cruz Carbon Fund*, allowing the project to expand to the entire region and move forward. To each, the PDAC extends its sincerest thanks:

The Holland Family Trust and the Weisenstein Family
Cruzio Internet - Peggy Dolgenos and Chris Neklason
Redwood Nonviolence Community
Matt and Connie Farrell
Tim Flanagan
Eileen Balian and Alexander Gaguine
Brett Garrett
Valley Women's Club
Gine Johnson and Bill Holl
Greg Pepping
Tiffany Wise-West
Joel and Sara Kauffman
Jeff Larkey

APPENDIX 2: Glossary of Terms

Term	**Meaning**
Behind-the-meter	Refers to energy efficiency or electricity generation that takes place on the customer side of the electricity meter rather than on the utility/grid side.
California Public Utilities Commission (CPUC)	California's State agency in charge of regulating investor-owned utilities.
Community Choice Aggregation	The legal term used in AB 117 and by the CPUC for programs herein referred to as Community Choice Energy. As authorized by statute, CCA allows local governments to pool the municipal, residential and commercial electrical load within their municipalit(ies) for the purpose of procuring and developing power on their behalf.
Demand response	Technology that lowers electricity demand (or consumption) in response to shortages in the available supply of electricity.
Direct Access	A program that permits utility customers to purchase power supplies from a provider other than the incumbent utility; CCE programs are not considered direct access
Feed-in tariff	A standard power contract, usually for small projects 1MW or less, that requires the utility to pay a set amount for generated renewable electricity for a set number of years, depending on technology.
Greenhouse gas (GHG)	A gas that causes the atmosphere to trap heat radiating from the earth. The most common GHG is Carbon Dioxide, though Methane and others have this effect.
MWH (megawatt-hour)	A unit of electrical energy that is produced or consumed= to 1,000 kilowatt hours. Thus, 8,000 kwh = 8 MWh.
Implementation Plan	A plan CCAs must present to the CPUC for its certification and review for consistency with state law and CPUC rules
Investor-owned utility	A privately-owned power distribution company, such as Pacific Gas and Electric (PG&E), that in California is regulated by the CPUC.
Joint powers authority (JPA)	An entity permitted under the laws of some states, whereby two or more public authorities (for example, local governments, or special districts) can operate collectively.
Electric Load	The amount of electricity a customer or group of customers uses; also referred to as "demand."
Load-serving entity	A firm or organization that purchases electricity on behalf of any customer or group of customers. Once formed, a CCA is considered a load serving entity.
MW (megawatt)	A unit of electrical power equal to 1 million watts that expresses the capacity (or power rating) of power plants or consuming devices. As a unit of capacity, a MW is distinct from a MWH, which is a unit of electricity. For example, a solar plant with a *capacity* of 1 *MW* will – running at fully capacity – produce a *MWH* of *electricity* in one hour.

Microgrid	A local, small scale power grid that can operate independently of or in conjunction with the central utility system.
Net metering	A state-mandated program through which utility customers with behind-the-meter renewable generating facilities smaller than 1 MW can receive bill credit for power not used on-site and delivered to the grid (causing the meter to run backwards).
PCIA or “exit fee”	Power Charge Indifference Adjustment (PCIA) is an “exit fee” based on stranded costs of utility generation set by the California Public Utilities Commission. It is calculated annually and assessed to customers who take service from an electric generation provider (e.g. CCE) other than the incumbent utility.
Peak load	The electrical power demand at that time, over the course of a year and during the day, when electricity consumption is greatest.
Power Purchase Agreement (PPA)	Term for energy supply contract
Renewable energy certificate (REC)	A certificate of proof that one MWh of electricity was generated and delivered to the grid by an eligible renewable energy resource. A REC can be sold together with the underlying energy or “unbundled,” and sold separately.
Renewable portfolio standard (RPS)	Law that requires CA utilities and other load serving entities (including CCAs) to provide an escalating percentage of CA qualified renewable power (culminating at 33% by 2020) in their annual energy portfolio.
Community shared solar	An arrangement by which many electricity customers in a community may each own a portion of a solar PV generating facility, and therefore receive a share of the electricity and/or revenue it generates.
Smart grid	An electricity supply network that uses electronic communications and management systems to respond to changes in system requirements.
Solar PV	A solar electricity generating technology in which solar energy is transformed into electricity through a photovoltaic (PV) effect.
Unbundled RECs	Renewable energy certificates that verify a purchase of a MWH unit of renewable power where the actual power and the certificate are “unbundled” and sold to different buyers.

APPENDIX 3

CCE (aka CCA) Frequently Asked Questions

Renewable Energy Questions

Q: What are fossil fuels?
A: Energy sources formed by the decay of plants, dinosaurs, and other animals over millions of years; coal, oil, and natural gas are fossil fuels. These energy reserves form so slowly in comparison to our rate of energy use that they are regarded as a finite resource.

Q: Can municipal solid waste generate energy?
A: Yes. Trash or garbage is used to produce heat or electricity by burning it or by capturing the gases it gives off and using them as fuel.

Q: What is nonrenewable energy?
A: Fuels that are not naturally replaced as we use them. This includes fossil fuels, nuclear fuels, and municipal solid waste.

Q: What is renewable energy?
A: Sources of energy that are either continuously resupplied by the sun or tap inexhaustible resources. In California, qualified renewable energy sources include wind, solar, biomass, small hydropower, and geothermal energy.

Q: What types of renewable energy can a CCA purchase?
A: CCA's purchase or develop renewable energy sources that are compliant with the State's renewable portfolio standard (RPS) including solar, wind, small hydro, geothermal, biomass and biogas.

Q: How does solar energy produce electricity?
A: Solar panels contain photovoltaics – a technology that uses semiconductors to directly convert light into electricity.

Q: How is energy generated from wind?
A: Wind is used to turn a turbine to generate electricity which is connected to the grid. A wind farm is another name for a wind power plant where multiple turbines are usually spread out over a relatively large area of land.

Q: What is geothermal energy?
A: Heat energy stored in the Earth's crust, which can be harnessed to produce electricity or heat water and living spaces.

Q: What is hydropower energy?
A: The energy of flowing water, which can be harnessed to make electricity or to do mechanical work. Note that hydropower is considered a greenhouse gas free resource, but only "small hydro" generated from power plants smaller than 30MW qualifies as a CA renewable resource.

Q. What about nuclear -- is that considered a clean power resource?
A. Nuclear energy is considered a greenhouse gas free resource but it does not qualify as a renewable resource. Operational CCAs in California have not used nuclear in their power portfolios and have instead relied on hydropower to boost their GHG free energy content.

Q: What is renewable energy from biomass?
A: In the renewable energy industry, biomass usually refers to the wood, wood-processing residues, agricultural residues, and energy crops that are used to create electricity, generate heat, or produce liquid transportation fuels.

Q: Doesn't biogas contain methane and pollute more than natural gas or coal?
A: Natural gas produces half the CO2 as coal. Biomass digestion systems do create methane (biogas), but the systems are closed-loop so the
methane can be recovered as a fuel. Biogas systems require much less energy input to create methane than natural gas or coal production. Biogas systems use more efficient natural processes. Natural gas and coal use energy intensive methods to; extract, transport, and covert these raw products even before they can be processed into usable fuel. The primary difference between the greenhouse gas effects from biogas versus natural gas is in the extraction, production and transportation of natural gas which adds more CO2 than just the utilization of the fuel.

Q: What are energy crops?
A: Crops grown specifically for their fuel value, including food crops such as corn and sugarcane, and nonfood crops such as willow trees and switch grass.

Q: What is renewable energy from biogas?
A: Biogas is a fuel gas, composed of a mixture consisting of 65% methane (CH4) and of 35% CO2. It is a *renewable source of energy* resulting from biomass. *Biogas* is produced by the breakdown of organic matter in the absence of oxygen (anaerobic digestion). *Biogas* can come from animal manure or from organic solid waste that is processed at a local resource recovery center in a bio-digester.

Q: Could biomass be generated in the Monterey Bay Region?
A: Yes. The Salinas Valley Solid Waste Authority and the Monterey Regional Waste Management District have both expressed interest in selling renewable energy generated from the production of biogas. Other local resource recovery centers could also be potential candidates for producing biogas. CCAs are a potential buyer of biogas electricity that would be generated and consumed close to the source of production.

Q: Why is more renewable energy beneficial?
A: The investment in renewable energy provides economic, environmental and national security benefits.

- More jobs are created from the development of renewable energy than fossil fuel energy.
- Buildings consume 42% of America's energy (and 72% of its electricity). Transportation consumes 71% of U.S. oil – (13 million barrels/day). Eliminating waste in the built environment and transportation sectors will make America stronger and safer by keeping that $1 billion/day oil-import cost at home. The U.S. would be less buffeted by volatile oil prices and less anxious to defend access to oil.
- The reduction of harmful greenhouse gas emissions is critical to combat the devastating and costly challenges of global warming and pollution.

Q: Why doesn't PG&E buy more renewable energy?
A: Renewable energy is currently more expensive than fossil based resources, PG&E has many long-standing power contracts, and their business model requires shareholder profits. The extra cost of renewable energy, combined with PG&E's profit margin, makes it more difficult for PG&E to rapidly shift to clean energy and keep their electricity rates from rising.

Q: How much renewable energy does PG&E provide?
A: As of 2015, PG&E reported 27% renewable energy sources in their electricity portfolio. As per the State's renewable portfolio standard (RPS), PG&E and all utilities are required to provide a minimum 33% renewable energy in their electricity portfolio by 2020. PG&E is now offering a voluntary 100% clean energy option at a rate premium price to boost their renewable energy performance.

Q: How much renewable energy can a CCA provide?
A: When local communities have control over electricity purchasing they can determine how much clean electrical energy they want to offer their customers and at what price, subject to compliance with the State Renewable Portfolio Standard (RPS) requirement. To date, all operational CCAs have significantly exceeded the utility portfolio and State RPS requirements.

- For example, in 2010, Marin Clean Energy (MCE) began service with 26% clean energy at comparable rates to PG&E at a time when the utility was providing only 17% clean energy. MCE is now delivering 56% clean energy in its default "Light Green" product and is and also offering a 100% clean energy option for a slight premium.

Q. What is a Renewable Energy Certificate (REC)?
A. Similar in concept to carbon credits, RECs were established by the US-EPA in the early 1990s to serve as a market stimulus for new renewable power generation, regardless of production location. A REC is a certificate of proof that one MWh of electricity was generated and delivered to the grid by an eligible renewable energy resource. A REC can be sold together with the underlying electrons (bundled) or decoupled from the electrons and sold separately, creating an "unbundled" REC. Legally speaking, it is the REC (not the electron) that confers the

environmental attribute of the power that was developed. RECs are tracked by registries and may not be double counted; they may however, be transferred and sold if not already used for compliance and thus retired. Most states do not recognize the difference between bundled and unbundled RECs for compliance purposes. The California renewable portfolio standard, however, uses a compliance scale which gives category 1 (in-state bundled RECs) greatest value, category 2 bundled RECs (primarily from neighboring states) next level of value, and least compliance value to “category 3” unbundled RECs. The costs of each REC product correlate similarly from highest to lowest cost. Most operational CCAs in California use category 1 and 2 RECs and are either phasing out or limiting their use of category 3 RECs in their power portfolios.

Cost Questions

Q: Will my electricity rates go up?
A: The goal of a local CCA is to provide more clean energy at competitive generation rates to the utility, either at the same price or slightly lower. CCAs procure and design their own energy portfolios and set their own electricity rates.

Q: Will a local CCA result in rate parity?
A: A technical feasibility study published in March 2016 indicates that Monterey Bay Community Power will be able to achieve rate parity or perhaps slightly lower rates than PG&E depending on its power mix and percentage of renewables in its portfolio.

Q. What is the Power Charge Indifference Adjustment (PCIA) and how does it affect my bill?
A. The Power Charge Indifference Adjustment (PCIA) is an “exit fee” charged by the utility to cover its stranded energy costs resulting from departing customer load. It is calculated annually by the CPUC based on market price benchmarks and assessed to customers who take service from an electric generation provider (e.g. a CCA) other than the incumbent utility. The PCIA shows as a surcharge on a customer’s bill but is taken into account when a CCA sets rates in order to remain cost competitive or cost neutral with the utility. Operational CCAs have called for PCIA reforms to improve transparency of the methodology and calculations, require third party audits of utility contracts used in the PCIA calculations, find other solutions to avoid costs and over procurement, and a sun setting of the PCIA over a fixed period of time.

Q: How do CCAs generate profit?
A: CCAs are run by a not-for-profit local public agency and operate as a market driven social enterprise that generates its own revenue. Ratepayers provide revenue, and this revenue provides the local CCA with a surplus that can be used to fund local electricity generation, lower electricity rates, and pay off debt.

Q: How do CCAs fund the construction of the Distributed Generation + Intelligent Grid?
A: CCAs can provide funding for renewable energy projects and energy efficiency programs. CCAs can be a catalyst for local build-out of the DG + IG system of the 21^{st} Century by providing funding to implement new technology.

Q: How would solar be financed?
A: Currently, it is difficult for customers to sell excess solar energy back to PG&E. Those that do make an arrangement to sell power to PG&E are offered less than what their power is worth. Under a locally designed net energy metering program, CCAs can provide an incentive by paying property owners fair market rates for the excess energy that their solar systems produce. Or, a CCA can include a Feed in Tariff program that allows the customer to sell all its solar generation to the CCA through a power purchase agreement with favorable terms and pricing. In addition, CCAs could provide 0% loans to leverage expansion of roof-top solar generation.

Q: How does a CCA procure electricity?
A: A CCA must submit a plan to the California Public Utilities commission that specifies how it will purchase 115% of the estimated electricity demand for its area for a period of one year. CCAs negotiate the purchase of electricity (renewable and otherwise) on the open market by entering into power purchase agreements with energy providers. All energy that is generated is identified by certificates that guarantee the type of energy and location of production. CCAs must also enter into a contract with PG&E to transmit the electricity that the CCA buys over PG&E's transmission lines. The latter is part of the CCA/utility service agreement that is codified before program launch.

Q: How does a CCA affect the Investor Owned Utility (PG&E)?
A: The CCA takes control of the procurement of electricity, decides what mix of renewable energy will be delivered to its customers and sets the electricity rates. PG&E continues to provide natural gas and other energy sources, maintain the transmission and power distribution system ("the grid"), provide consolidated customer billing and customer service in the event of a power outage or delivery problem.

Q: Where does the start-up money for a CCA come from?
A: The Phase I Technical Feasibility Study is estimated to cost $150,000, which was paid through private donations. If a CCA proves feasible in the Monterey Bay Region, then a Phase II Implementation Plan and other elements of program start-up will be required. The cost of Phase II implementation steps will be identified as part of the Phase 1 Study. Program implementation can be funded with a combination of borrowed revenues, private capital, and public/private grant sources. Borrowed funds would be repaid with interest from the revenue generated by the CCA once it is operational and generating a positive cash flow.

Economic Questions

Q: Is there an economic benefit to having a CCA in the local region?
A: Yes. CCAs allow a local region to capture the electrical generation revenue that has been going out of the area to PG&E. Once the cost of program operations and power is covered, CCAs may use a portion of their surplus revenue (formerly PG&E profit) to fund local renewable energy projects, energy efficiency and other energy related programs. This is a new source of

local revenue that will help achieve local climate goals, stabilize customer rates and generate new jobs.

Q: What is an economic multiplier?
A: An economic a multiplier effect occurs when a change in spending causes a disproportionate change in total demand.

Q: Do CCAs help provide a local economic multiplier?
A: Yes. CCAs may redirect their surplus revenue to fund clean energy projects and programs. This creates new jobs and new income for people in the region. As people spend money in their communities, these dollars create new demand for goods and services. The multiplier effect represents both the new income from clean energy jobs, and the jobs created to support this additional spending.

Q: Does the formation of a CCA cost PG&E jobs?
A: No. One of the tertiary goals of a CCA is to help stimulate new jobs in the energy sector. The jobs currently serving the PG&E power generation, transmission, grid maintenance and customer billing functions will be retained. Large utility scale energy projects will be constructed by PG&E and their workforce. In addition, smaller scale, locally distributed renewable energy projects may be facilitated by local CCAs in partnership with independent power producers, creating net new jobs for the region and its local communities.

Q: Has Marin Clean Energy developed renewable energy projects?
A: The first obligation for MCE (and any new CCA) is to repay their start-up loans and establish a healthy reserve fund before using surplus revenue to fund local projects. Having now done that, MCE has several local renewable projects in the works, including a 10.5 MW solar facility in the city of Richmond which has provided both local and union jobs. MCE is also pursuing a variety of other programs to increase the percentage of new clean energy as well as energy storage and demand reduction technologies.

Q: How can a CCA be cost competitive with PG&E?
A: CCAs have lower costs because they: can procure power in favorable power market conditions, do not pay shareholder profits or corporate salaries, operate as not-for-profit public agencies with lower overhead and borrowing costs.

Governance Questions

Q: Who is going to buy the electrical power for the cities and counties?
A: Energy procurement would be done by a locally managed CCA with energy procurement specialists to assist in the structuring and terms of energy supply contracts. The agency would be managed as a Joint Powers Authority governed by a local board appointed by participating

cities and counties. All agency activities would be transparent to rate payers via regular local public meetings and deliberations.

Q: Aren't CCAs replicating the California Public Utilities Commission (CPUC)?
A: No. The CPUC regulates the State's investor-owned utilities (including PG&E) and has jurisdiction over some operational elements and procurement requirements of CCA programs. However, CCAs bring the process of energy procurement and energy choice to the local region. This gives residents and business owners more opportunity to participate in the energy procurement and investment process.

Q: Would CCA customers still pay for energy transmission and distribution?
A: Yes. CCAs only provide the electric generation and procurement piece of the energy puzzle. Transmission, grid/power-line maintenance and customer service in the event of a power outage is still provided by PG&E. Customers continue to pay for those services through their PG&E bills just as they always have.

Customer Service Questions

Q: As a customer, will I still get a bill from PG&E?
A: Yes, your consolidated utility bill will still come from PG&E and PG&E will continue to provide you with customer service. PG&E will continue to bill you for your natural gas and will indicate that you are buying electricity from your local CCA. The customer billing and payment process is exactly the same under a CCA as it is with PG&E.

Q: Who do I call when my power goes out?
A: PG&E is responsible for the transmission of gas and electricity. PG&E will still maintain the utility grid. Any issues with power delivery will continue to be handled by PG&E.

Q: Can I opt in or out of a CCA program?
A: Per state law, CCA programs are designed as "opt-out" programs which means that customers are automatically enrolled with the option to opt-out at any time and remain with bundled utility service. Customers are notified a minimum of 4 times over 120 days and may opt-out at any time. Customers may also opt back in to the CCA program after a 12-month hold period at PG&E.

Q: Can I get rid of PG&E smart meter?
A: Customer related PG&E service issues, including smart meters, are still handled by PG&E.

Q: If we installed solar panels on our building would we need a Power Purchase Agreement to sell our excess energy to a CCA?
A: No. Under a net energy metering program, the CCA would be able to offer property owners fair market rates for their excess energy production without a PPA. A longer-term PPA for small-

distributed solar projects (usually below 1 MW) could be contemplated under a feed-in-tariff program.

Q: Would the Monterey Bay CCA propose an unaffordable clean energy program?
A: No. The program is focused on delivering more clean energy with fewer greenhouse gas emissions at rates that are equal to or below PG&E rates. The program will also offer other product options with higher or 100% renewable energy which could carry a small price premium. These options would be offered to customers on a voluntary basis.

Phase I Technical Study - Process Questions

Q: What role does the Community Foundation Santa Cruz County (CFSCC) have in this project?
A: The CFSSC is the fiscal sponsor for the Monterey Bay CCA Phase I Technical Feasibility Study.

Q: Who paid for the Phase I Technical Feasibility Study?
A: Private donors and grants covered the costs of the Phase I Technical Study through charitable contributions. There have been no general fund impacts to participating cities and counties.

Q: What is the Project Development Advisory Committee (PDAC)?
A: The PDAC is the project oversight group comprised of one representative from each participating city, county or joint powers authority. The PDAC directed the Phase I Technical Feasibility Study and prepared a work plan and recommendations to carry the project forward into implementation.

Q: Can the public come to PDAC meetings?
A: Yes. All PDAC meetings are open to the public. Public notice will be given on the website in advance of all PDAC meetings.

Q: What does the Phase I Technical Feasibility Study focus on?
A: The Technical Study was published in March 2016 and focused on the following program elements: 1) cost/benefit/risk analysis, 2) procurement/power supply options, 3) rate/price modeling, 4) employment projections, 5) potential for greenhouse gas emissions/reductions, and 6) program start-up and early operations costs.

Environmental Compliance Questions

Q: If a CCA is created for the Monterey Bay Region, who would get credit for the greenhouse gas reductions?
A: CCA's have proven to be an effective method for rapidly achieving greenhouse gas reduction targets in municipal climate action plans. Participating communities are able to "claim" their pro-rata share of GHG reductions for compliance with CAP goals. It should be noted, however,

that GHG reductions are not formally credited or allocated to any one entity other than the CCA agency itself.

Q: Have CCAs proven to improve air quality?
A: Yes. Marin Clean Energy and Sonoma Clean Power have dramatically reduced their County's greenhouse gas emissions. MCE met the State's AB32 Global Warming Solutions Act targets after only 3 years of operation (several years ahead of schedule), and SCP experienced a 40% reduction in GHG emissions after only a year of operation, due primarily to the large percentage of hydropower in their supply portfolio. Reduced GHGs means cleaner air.

Policy Questions

Q: Are there advantages to including jurisdictions from the Tri-county Area?
A: Yes. There are economies of scale associated with power procurement and the ability to spread costs across a larger customer base. It is possible to phase in cities and customers over a period of time and for jurisdictions to join the JPA even after the initial program has launched.

Q: Is there a connection between CCA and various Desalinization Plant Proposals?
A: No, there is not a direct connection. CCAs offer a variety of community benefits independent from any desalinization plant proposals. However, CCAs would provide an additional source of local clean energy that could help reduce or off-set the increased energy demand and greenhouse gas emissions of any proposed desalinization plant.

Q: Could a CCA offer 100% clean energy?
A: Yes, CCAs can have different power products and rate structures to offer customers a choice in how green they want to go. The Joint Powers Authority would determine how much clean energy would be offered to local customers based on policy goals, customer needs, and the need to maintain rate competition with PG&E.

Q: Does PG&E offer a 100% clean energy option?
A: Yes, PG&E recently launched a new 'solar choice' option program offered to customers on a voluntary, cost-premium basis of 3.58 cents/kwh.

Q: What is Property Assessed Clean Energy (PACE) program?
A: Based on AB811, several counties in the State of California are piloting various approaches to set up the California First Program which is designed to significantly reduce greenhouse gas emissions. This program allows property owners to purchase renewable energy technologies through reimbursable grants to significantly reduce costs through energy savings.

Q: Would a CCA be beneficial to a community if they are already pursing a Property Assessed Clean Energy (PACE) program:
A: Yes. Forming a CCA in the Monterey Bay Region would create a revenue generating partner for local PACE programs. This would help to:

- Provide additional an additional funding source to support the marketing and installation of solar, wind or thermal renewable generation systems for businesses and residences.
- Pay property owners fair market rates for their excess energy.
- Ensure that rates remain low and stable so that customers can realize the cost savings of their renewable energy generation.

MONTEREY BAY COMMUNITY POWER TECHNICAL STUDY

5/4/2016

Prepared by Pacific Energy Advisors, Inc.

This Technical Study was prepared for the Monterey Bay Community Power initiative (MBCP) for purposes of forming a Community Choice Energy (CCE) program, which would provide electric generation service to residential and business customers located within the counties of Monterey, San Benito and Santa Cruz. A detailed discussion of the projected operating results related to the MBCP program, including anticipated costs and benefits, is presented herein.

Monterey Bay Community Power Technical Study

PREPARED BY PACIFIC ENERGY ADVISORS, INC.

Table of Contents

EXECUTIVE SUMMARY

This Community Choice Energy ("CCE") Technical Study ("Study") was prepared for the Monterey Bay Community Power initiative ("MBCP"), by Pacific Energy Advisors, Inc. ("PEA") under contract with the County of Santa Cruz, for purposes of describing the potential benefits and liabilities associated with forming a CCE program within the counties of Monterey, San Benito and Santa Cruz (the "MBCP Partnership"). Such a program would provide electric generation service to residential and business customers located within the unincorporated areas of the MBCP Partnership as well as the incorporated cities therein. In aggregate, there are twenty one (21) municipalities located within the MBCP Partnership, which include the aforementioned counties as well as the following cities located therein: Capitola, Carmel, Del Rey Oaks, Gonzales, Greenfield, Hollister, King City, Marina, Monterey, Pacific Grove, Salinas, San Juan Bautista, Sand City, Santa Cruz, Scotts Valley, Seaside, Soledad and Watsonville (together, the "MBCP Communities").

This Study addresses the potential benefits and liabilities associated with forming a CCE program over a ten-year planning horizon, drawing from the best available market intelligence and PEA's direct experience with each of California's operating CCE programs – PEA has unique experience with regard to California CCE program evaluation, development and operation, having provided broad functional support to each operating CCE, which include Marin Clean Energy ("MCE"), Sonoma Clean Power ("SCP"), Lancaster Choice Energy ("LCE"), and CleanPowerSF, which will commence service to its first phase of residential and business customers located within the City and County of San Francisco during Spring 2016. PEA utilized this direct experience to generate a set of anticipated scenarios for MBCP operations as well as a variety of sensitivity analyses, which were framed to demonstrate how certain changes in the base case scenarios would influence anticipated operating results for the MBCP program. At the request of the MBCP Partnership, PEA also completed stand-alone analyses for each of the three participating counties to facilitate each entity's understanding of the costs and benefits associated with independent CCE formation (as opposed to CCE formation as part of a multi-county partnership). The results associated with these stand-alone, county-specific analyses are further discussed in Appendix A, County-Specific Scenario Analyses.

MBCP's Prospective Customers

Currently, Pacific Gas & Electric ("PG&E") serves approximately 285,000 customer accounts within communities of the MBCP Partnership, representing a mix of residential (≈86%), commercial (≈12%) and agricultural (≈2%) accounts. These customers consume nearly 3.7 billion kilowatt hours ("kWh") of electric energy each year. While the majority of customers fall under the residential classification, such accounts historically consume only 36% of the total electricity delivered by PG&E while commercial and agricultural accounts consumed the remaining 64% (comprised of ≈48% commercial consumption and ≈18% agricultural consumption). Peak customer demand within the MBCP Communities, which represents the highest level of instantaneous energy consumption throughout the year, occurs during the month of September, totaling 661 megawatts ("MW"). Under CCE service, each of these accounts would be enrolled in the MBCP program over a three-phase implementation schedule commencing in 2017, as later discussed in this Study. Consistent with California law, customers may elect to take service from the CCE provider or remain with PG&E, a process known as "opting-out." For purposes of the Study, PEA utilized current participatory statistics compiled by the operating CCE programs to derive an assumed participation rate of 85% for the MBCP program; the remaining 15% of regional customers are assumed to opt-out of the MBCP program and would continue receiving generation service from PG&E. Customer and energy usage projections referenced throughout this Study reflect such adjustment.

MBCP Indicative Supply Scenarios

For purposes of the Study, PEA and the MBCP Partnership identified three indicative supply scenarios, which were designed to test the viability of prospective CCE operations under a variety of energy resource compositions, emphasizing the MBCP Partnership's interest in significantly reducing greenhouse gas emissions ("GHGs") through increased use of carbon-free electric energy sources – it is important to note that, according to the United States Environmental Protection Agency, the main GHGs include carbon dioxide (in 2014, carbon dioxide accounted for 80.9% of all human-activity created GHGs within the U.S.; electric power sector carbon dioxide emissions also accounted for 30% of total U.S. GHGs in 2014), methane, nitrous oxide and fluorinated gases[1]; however, during the combustion of fossil fuels, not only are carbon dioxide and nitrous oxide emitted but also carbon monoxide, volatile organic compounds, sulfur dioxide and particulate matter; to the extent that the MBCP program is successful in reducing the use of fossil fuels within the electric power sector, a broad spectrum of pollutants, including GHGs, would also be reduced. With these considerations in mind, the following supply scenarios were constructed for purposes of completing this CCE Study:

- **Scenario 1**: Maximize renewable energy and greenhouse gas emission ("GHG") reductions while not exceeding the incumbent investor-owned utility's ("IOU"), Pacific Gas & Electric Company ("PG&E"), projected generation rates. Under Scenario 1, clean energy sources would be generally limited to California-based, bundled renewable energy products and a minimal amount of regionally produced hydroelectricity.[2, 3]
- **Scenario 2**: Maximize renewable energy and GHG reductions while not exceeding PG&E's projected generation rates. Under Scenario 2, clean energy sources would be limited to California-based and regionally produced, bundled renewable energy products.
- **Scenario 3**: Maximize MBCP rate competitiveness while achieving a 25% annual reduction in GHG emissions relative to PG&E's projected resource mix. Under Scenario 3, clean energy sources would include California-based and regionally produced, bundled renewable energy products as well as regionally produced hydroelectricity.[4]

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

When developing MBCP's indicative supply scenarios, PEA was directed to include additional assumptions. In particular, all scenarios include the provision of a voluntary retail service option that would provide

[1] U.S. Environmental Protection Agency: https://www3.epa.gov/climatechange/ghgemissions/gases.html.

[2] Consistent with California's Renewables Portfolio Standard ("RPS") laws, retail sellers of electric energy, including CCEs, must procure a minimum 33% of all electricity from eligible renewable energy sources by 2020; with the recent enrollment of Senate Bill 350, California's RPS procurement mandate has been increased to 50% by 2030. All MBCP supply scenarios addressed in this Study were attentive to such minimum requirements, ensuring MBCP compliance with California's RPS on a projected basis.

[3] Industry accepted GHG accounting practices generally recognize eligible renewable energy sources as GHG-free. Under the Scenario 1 and 3 portfolio compositions, incremental purchases of non-RPS-eligible GHG-free sources, specifically electricity produced by larger hydroelectric resources (with nameplate generating capacity in excess of 30 megawatts) would be procured by MBCP to achieve targeted GHG emissions reductions.

[4] Under Scenario 3, the proportion of RPS-eligible renewable energy is projected to minimally exceed specified RPS procurement mandates throughout the Study period.

participating customers with 100% renewable energy (presumably for a price premium); for purposes of this Study, it was assumed that only a small percentage of MBCP customers would select this service option (≈2% of the projected MBCP customer base), which is generally consistent with customer participation in other operating CCE programs. In addition, all scenarios assume the availability of current solar development incentives as well as an MBCP-administered net energy metering ("NEM") service option, which could be used to further promote the development of local, customer-sited renewable resources. PEA was also directed to exclude the use of: 1) unbundled renewable energy certificates (due to ongoing controversy focused on environmental benefit accounting for such products); 2) specified purchases from nuclear generation, which is generally unavailable to wholesale energy buyers, including CCE programs, but represents a significant portion of PG&E's energy resource mix[5]; and 3) coal generation,[6] which is a cost-effective but highly polluting domestic power source.

Projected Cost Impacts to MBCP Customers

Based on current market prices and various operating assumptions, as detailed in Section 2: Study Methodology, this Study indicates that MBCP 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 general rate parity, relative to projected PG&E rates, over the ten-year study period while providing the region with significant electric power sector GHG emissions reductions through the predominant use of bundled renewable energy resources. Scenario 3, which was designed to maximize rate competitiveness with PG&E while also reducing annual electric power sector GHG emissions by 25%, demonstrated the potential for meaningful MBCP cost reductions (ranging from 3% in Year 1 to 5% in Year 10 of projected operations) while also achieving significant environmental benefits. As previously noted, none of the prospective supply scenarios include the use of unbundled renewable energy certificates; renewable energy products will be exclusively limited to "bundled" deliveries produced by generators primarily located within: 1) California; 2) the MBCP Communities; and 3) elsewhere in the western United States. As described above, each prospective supply scenario incorporates differing proportions of clean energy resources to achieve MBCP's desired objectives.

General Operating Projections

When reviewing the pro forma financial results associated with each of the prospective supply scenarios, as reflected in Appendix B of this Study, the "Total Change in Customer Electric Charges" during each year of the study period reflects the projected net revenues (or deficits) that would be realized by MBCP in the event that the program decided to offer customer electric rates that were equivalent to similar rates charged by PG&E. To the extent that the Total Change in Customer Electric Charges is negative, MBCP 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, MBCP would need to impose comparatively higher customer charges in order to recover expected costs. Ultimately, the disposition of any projected net revenues will be determined by MBCP leadership during periodic budgeting and rate-setting processes. For example, in the cases of Scenario 3, each year of the study period reflects the potential for net revenues. Such net revenues could be passed through to MBCP customers in the form of comparatively lower electric rates/charges, as contemplated in this Study, utilized as working capital for program operations in an attempt to reduce

[5] 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.

[6] According to the California Energy Commission, approximately 6% of California's 2014 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.

program financing requirements, or MBCP 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. MBCP leadership would have considerable flexibility in administering the disposition of any projected net revenues, subject to any financial covenants that may be entered into by the program.

Environmental Impacts

With regard to MBCP's anticipated clean energy supply and resultant GHG emissions impacts, each prospective supply scenario yielded different environmental benefits, resulting from the diverse composition of clean energy sources within each supply scenario. Such benefits were generally quantified in consideration of the anticipated carbon intensity of PG&E's prospective supply portfolio relative to similar projections for MBCP. To the extent that each of MBCP's indicative supply portfolios incorporated higher proportions of non-carbon-emitting generating technologies than PG&E, GHG emission reductions are expected to occur following MBCP implementation. For example, Scenario 1, which was specifically designed to maximize GHG emission reductions through the exclusive use of California-based renewable energy supply and a small amount of additional, regionally produced hydroelectricity (which was only incorporated in Year 1 of projected MBCP operations for purposes of achieving general rate parity with the incumbent utility), resulted in annual GHG emissions *reductions* ranging from approximately 36,000 (or 20%, Year 1 impact) to 164,000 (or 42%, Year 10 impact) metric tons. Supply Scenario 2, which was similarly constructed to Scenario 1, utilizing both California-based and regionally produced renewable energy products to achieve MBCP's desired environmental objectives (without additional hydroelectricity), resulted in annual emissions *reductions* ranging from approximately 36,000 (or 20%, Year 1 impact) to 238,000 (or 62%, Year 10 impact) metric tons. Supply Scenario 3 yielded slightly different emissions benefits through the use of a more diverse portfolio of clean energy resources, including California-based and regionally produced renewable energy as well as hydroelectricity, creating a projected annual GHG emissions reduction of 25% during each year of the Study period. This level of projected GHG emissions reductions equates to 45,000 metric tons in Year 1, increasing to 97,000 metric tons in Year 10.

When considering MBCP's projected environmental benefits, it is noteworthy that current market pricing for renewable and GHG-free power sources is becoming increasingly cost competitive when compared to conventional generating technologies. This trend has allowed for the inclusion of significant proportions of GHG-free electricity within each of MBCP's prospective supply scenarios while retaining cost competitiveness. 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. In particular, the Diablo Canyon Power Plant ("DCPP") produces approximately 20% of the utility's total annual electric energy requirements. During the latter portion of the Study period, DCPP will need to relicense the facility's two reactor units (in 2024 and 2025, respectively) and there is some 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 – use of once-through cooling is no longer permissible within California, and affected generators must reconfigure requisite cooling systems or face discontinued operation. To the extent that PG&E's use of nuclear generation is curtailed or suspended at some point in the future, MBCP's projected emissions reductions would significantly increase under each operating scenario. However, due to the timing of the relicensing issue facing DCPP, substantive increases to projected environmental benefits (resulting from prospective changes to PG&E's nuclear power supply) should not be assumed during the Study period.

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

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

For the sake of comparison, Table 1 displays PG&E's proportionate use of various power sources during the most recent reporting year (2014) as well as the aggregate resource mix within the state of California, as reported by the California Energy Commission ("CEC"). During the Study period, planned increases in California's RPS procurement mandate and various other factors will contribute to periodic changes in PG&E's noted resource mix. Such changes will affect projected GHG emissions comparisons between MBCP and PG&E.

Table 1: 2014 PG&E and California Power Mix

Energy Resource	2014 PG&E Power Mix[1]	2014 California Power Mix[2]
Eligible Renewable	**27%**	**20%**
--Biomass & Waste	5%	3%
--Geothermal	5%	4%
--Small Hydroelectric	1%	1%
--Solar	9%	4%
--Wind	7%	8%
Coal	0%	6%
Large Hydroelectric	8%	6%
Natural Gas	24%	45%
Nuclear	21%	9%
Unspecified Sources of Power	21%	14%
Total[3]	**100%**	**100%**

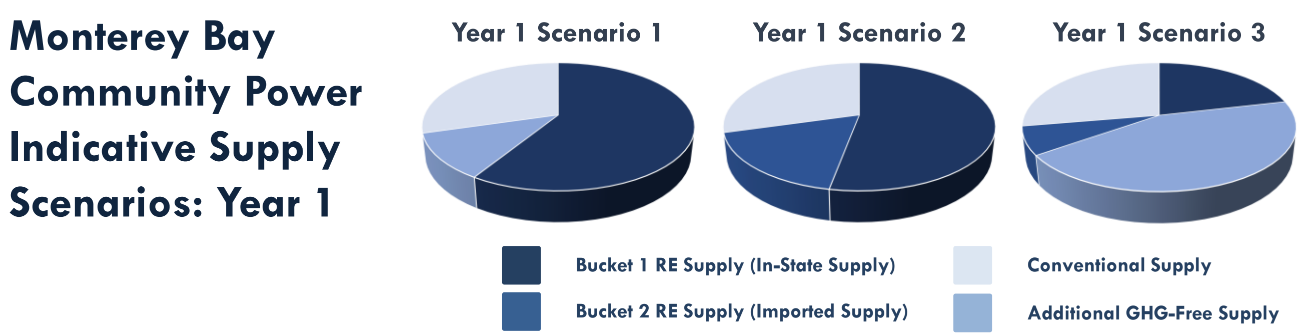
[1]*Source: PG&E 2014 Power Source Disclosure Report;*
[2]*Source: California Energy Commission - http://energyalmanac.ca.gov/electricity/total_system_power.html; and*
[3]*Numbers may not add due to rounding.*

Projected Economic Development Benefits

MBCP's projected long-term power contract portfolio is also expected to have the potential to generate substantial economic benefits throughout the state as a result of new renewable resource development. A moderate component of this impact is expected to occur within the local economy as a direct result of renewable infrastructure buildout to be supported by a MBCP-administered Feed-In Tariff program, which could be designed to promote the development of smaller-scale renewable generating projects that would supply a modest portion of MBCP's total energy requirements. The prospective MBCP long-term contract portfolio, which is reflected in the anticipated resource mix for each supply scenario, includes approximately 340 MW of new generating capacity (all of which is assumed to be located within California and some of which may be located within certain of the MBCP Communities). Based on widely used industry models, such projects are expected to generate up to 11,000 construction jobs and nearly $1.4 billion in total economic output. Ongoing operation and maintenance ("O&M") jobs associated with such projects are expected to employ as many as 185 full time equivalent positions ("FTEs") with additional annual economic output approximating $28 million. MBCP would also employ a combination of staff and contractors, resulting in additional ongoing job creation (up to 29 FTEs per year) and related annual economic output ranging from $3 to $9 million.

Consolidated Scenario Highlights

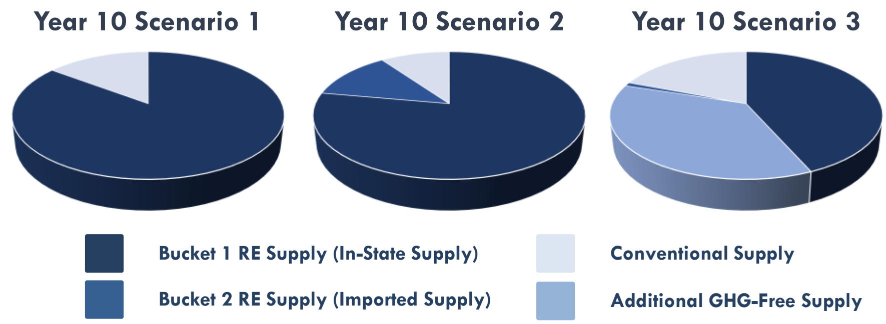
The following exhibit identifies the projected operating results under each indicative supply scenario in Year 1 of anticipated MBCP operations. Additional details regarding the composition of each supply scenario are addressed in Section 2.



Key Considerations	Scenario 1	Scenario 2	Scenario 3
General Environmental Benefits	59% Renewable 70% GHG-Free	71% Renewable 71% GHG-Free	28% Renewable 72% GHG-Free
Rate Competitiveness	≈rate parity relative to PG&E projections	≈rate parity relative to PG&E projections	Average 3% savings relative to PG&E rate projections
Projected Residential Customer Cost Impacts[1] [1]Average monthly usage for MBCP residential customers ≈ 446 kWh	Projected MBCP & PG&E costs are equivalent	Projected MBCP & PG&E costs are equivalent	Average $3.01 monthly cost savings relative to PG&E projections
Assumed MBCP Participation	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups
Comparative GHG Emissions Impacts	0.126 metric tons CO_2/MWh emissions rate; ≈35,660 metric ton GHG emissions reduction in Year 1 (≈20% reduction)	0.126 metric tons CO_2/MWh emissions rate; ≈36,301 metric ton GHG emissions reduction in Year 1 (≈20% reduction)	0.119 metric tons CO_2/MWh emissions rate; ≈44,573 metric ton GHG emissions reduction in Year 1 (≈25% reduction)

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

Monterey Bay Community Power Indicative Supply Scenarios: Year 10



Key Considerations	Scenario 1	Scenario 2	Scenario 3
General Environmental Benefits	85% Renewable 85% GHG-Free	90% Renewable 90% GHG-Free	44% Renewable 81% GHG-Free
Rate Competitiveness	Average 1% savings relative to PG&E rate projections	Average 1% savings relative to PG&E rate projections	Average 5% savings relative to PG&E rate projections
Projected Residential Customer Cost Impacts[1] [1]Average monthly usage for MBCP residential customers ≈ 446 kWh	Average \$1.57 monthly cost savings relative to PG&E rate projections	Average \$1.79 monthly cost savings relative to PG&E rate projections	Average \$6.23 monthly cost savings relative to PG&E projections
Assumed MBCP Participation	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups
Comparative GHG Emissions Impacts	0.063 metric tons CO_2/MWh emissions rate; ≈163,559 metric ton GHG emissions reduction in Year 10 (≈42% reduction)	0.042 metric tons CO_2/MWh emissions rate; ≈237,857 metric ton GHG emissions reduction in Year 10 (≈62% reduction)	0.082 metric tons CO_2/MWh emissions rate; ≈96,594 metric ton GHG emissions reduction in Year 10 (≈25% reduction)

Findings and Conclusions

Based on the results reflected in this Study and PEA's considerable experience with California CCEs, the MBCP program has a variety of electric supply options that are projected to yield both competitive customer rates and significant environmental benefits. To the extent that clean energy options, including renewable energy and hydroelectricity, are used in place of anticipated conventional power sources, which utilize fossil fuels to produce electric power, anticipated MBCP costs and related customer rates would be marginally higher. However, Scenario 3 indicates that the potential exists for significant GHG emissions reductions and marginally increased renewable energy deliveries under a scenario in which MBCP rates are meaningfully below similar rates charged by the incumbent utility. In general terms, each of the indicative supply scenarios discussed in this Study reflects the potential for MBCP to promote meaningful reductions in electric-sector GHG emissions while offering competitive electric generation rates.

Ultimately, MBCP'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, MBCP's actual 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 CCE programs, MBCP'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. Operational viability is also based on the assumption that MBCP would be able to secure the necessary startup funding as well as additional financing to satisfy program working capital estimates. As previously noted, it is PEA's opinion that MBCP would be operationally viable under a relatively broad range of resource planning scenarios, demonstrating the potential for customer savings as well as reduced electric-sector GHG emissions throughout the region.

SECTION 1: INTRODUCTION

This Community Choice Energy ("CCE") Technical Study ("Study") was prepared for the Monterey Bay Community Power initiative ("MBCP"), by Pacific Energy Advisors, Inc. ("PEA") under contract with the County of Santa Cruz, for purposes of describing the potential benefits and liabilities associated with forming a CCE program within the counties of Monterey, San Benito and Santa Cruz (the "MBCP Partnership"). Such a program would provide electric generation service to residential and business customers located within the unincorporated areas of the MBCP Partnership as well as the incorporated cities therein. In aggregate, there are twenty one (21) municipalities located within the MBCP Partnership, each of which is identified below in Table 2 (with each associated county identified in parenthesis). Together, these communities comprise the "MBCP Communities."

Table 2: Prospective MBCP Member Communities

City of Capitola (Santa Cruz)	City of San Juan Bautista (San Benito)
City of Carmel (Monterey)	Sand City (Monterey)
City of Del Rey Oaks (Monterey)	City of Santa Cruz (Santa Cruz)
City of Gonzales (Monterey)	City of Scotts Valley (Santa Cruz)
City of Greenfield (Monterey)	City of Seaside (Monterey)
City of Hollister (San Benito)	City of Soledad (Monterey)
King City (Monterey)	City of Watsonville (Santa Cruz)
City of Marina (Monterey)	County of Monterey (unincorporated areas)
City of Monterey (Monterey)	County of San Benito (unincorporated areas)
City of Pacific Grove (Monterey)	County of Santa Cruz (unincorporated areas)
City of Salinas (Monterey)	

In consideration of its response to the County of Santa Cruz's Request for Proposal #14P1-004 for a Technical Study to Determine Feasibility of Community Choice Aggregation, which was issued on February 10, 2015, PEA was retained by the County of Santa Cruz to conduct a technical study focused on the prospective formation of a CCE program serving the MBCP Communities. This Study reflects the results of a comprehensive analysis, which addresses prospective CCE operations under a range of scenarios, including the identification of anticipated rate/cost impacts, environmental benefits, resource composition and economic development amongst 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 CCE programs. PEA's consultants have been assisting local governments with the evaluation and implementation of CCE programs since 2004, including each of California's operational CCE programs, which include Marin Clean Energy ("MCE"), Sonoma Clean Power ("SCP"), Lancaster Choice Energy ("LCE") and CleanPowerSF, which will commence service to its first phase of residential and business customers located within the City and County of San Francisco during Spring 2016. This Study reflects operating projections that are based on the best available information, utilizing transparent, documented assumptions to provide an objective assessment regarding the prospects of CCE operation within the MBCP Communities. Such assumptions are later discussed in Section 2. However, due to the dynamic nature of California's energy markets, particularly market prices which are subject to frequent changes, MBCP should confirm that the assumptions reflected in this Study generally align with future market conditions (observed at the time of any decision by the MBCP Partnership to move forward) to promote the achievement of early-stage MBCP operations that generally align with the operating projections reflected in this Study. To the extent that future market price benchmarks materially differ from any of the assumptions noted in Section 2 of this Study, PEA recommends updating pertinent operating projections to ensure well-informed decision-making and prudent action.

When reviewing this Study, note that the term Community Choice Aggregation ("CCA"), which is referenced within applicable legislation and related regulations, is currently being used interchangeably with the term Community Choice Energy ("CCE")[7], a term of art that has been adopted by the MBCP Partnership to identify its aggregation initiative. Use of the CCE acronym is becoming increasingly common when referring to similar customer aggregation programs throughout the state. For purposes of this Study, the term Community Choice Energy or "CCE" is used when referring to such aggregation programs.

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 MBCP 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 MBCP charges for generation services as well as charges for PG&E delivery services. Money collected by PG&E on behalf of MBCP would be electronically transferred each day to MBCP's designated bank account. Following enrollment in the CCE program, MBCP customers would continue to be eligible for PG&E-administered programs funded through distribution rates and public goods charges, including rebate and subsidy programs focused on energy efficiency and distributed solar generation.

To fulfill the electric energy requirements of its customers and related compliance obligations, MBCP would participate in the electricity market to purchase various energy products from qualified generators, brokers, and/or marketers. In the future, MBCP may also produce electricity generated by its own power plants, which could be independently developed or acquired by the CCE. Other programs and services may be offered by MBCP 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 CCE program in terms of overall operating margins, ratepayer costs, reductions in emissions of GHGs, which primarily entail carbon dioxide ("CO_2") from electric generating resources used to supply customers within the MBCP 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 approach used to conduct the Study.
>
> ***Section 3:*** *MBCP Technical Parameters* – describes the electric consumption patterns and electric resource requirements of prospective MBCP customers (i.e., electricity customers located within the MBCP Communities).

[7] While it is generally understood that both terms refer to the same type of load serving entity, as provided for under the California Public Utilities Code, PEA is not aware of any current references to the term "Community Choice Energy" or "CCE" in such Code or applicable regulations. In consideration of this observation, MBCP should remain aware of this terminology when communicating with jurisdictional regulatory entities or legislators regarding its prospective aggregation program to ensure that naming conventions conform with currently applicable laws and regulations which address such programs.

Section 4: *Cost of Service Elements* – explains the various costs that would be involved in providing electric service through a CCE 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 CCE program, including recommended mitigation measures for such risks.

Section 8: *CCE Formation Activities* – summarizes the steps involved in forming a CCE program.

Section 9: *Evaluation and Recommendations* – summarizes Study results and provides recommendations based on PEA's analysis.

Appendix A: *County-Specific Analyses* – addresses county-specific costs and benefits for purposes of understanding the impacts of single-county CCE formation, as opposed to multi-county implementation (as discussed in the body of this Study).

Appendix B: *MBCP Pro Forma Analyses* – includes pro forma operating projections for each of the three MBCP 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 CCE services. The Study examines projected CCE operations over a ten-year study period, including the expected economic/financial impacts related thereto. As detailed in Section 4, Cost of Service Elements, CCE 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 CCE 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 MBCP'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 CCE 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 or a combination thereof);
5) Preferred power supply structure (power purchase agreement or, potentially, asset development/ acquisition);
6) Determination of resource scale (for example, larger "utility-scale" projects and/or smaller distributed generating resources); and
7) Duration of supply commitments (short-, mid-, long-term).[8]

Each of these choices presents economic and/or environmental tradeoffs. Specification of initial supply 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 CCE program. As the CCE continues to operate over time, resource planning will remain an ongoing obligation, enabling the CCE to adapt its planning principles to changing circumstances while promoting the CCE 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 CCE implementation and operation. It should be understood that MBCP 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 CCE program.

[8] For purposes of this Study, a "short-term" supply commitment generally refers to a contract term of one to three years in duration; a "mid-term" supply commitment generally refers to a contract term of three to ten years in duration; and a "long-term" supply commitment generally refers to a contract term of ten or more years in duration.

Supply Scenario Overview

The following supply scenarios are representative of different choices that could be made by MBCP with regard to overall renewable energy content, fuel sources and generator locations (of the electric resources used to supply MBCP's customers). Each scenario embodies unique portfolio attributes and related ratepayer impacts. Subject to compliance with prevailing law and applicable regulations, California CCEs have a broad range of options when assembling supply portfolios. 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 MBCP's early stage energy requirements, and new renewable generation projects developed as a result of long-term power purchase agreements entered into by the CCE program, which may play an increasingly prominent role in MBCP's mid- and long-term resource planning efforts.

With regard to the specific sources of power supply that were considered as part of this Study, PEA was directed to exclude the use of: 1) unbundled renewable energy certificates (due to ongoing controversy focused on environmental benefit accounting for such products); 2) specified purchases from nuclear generation, which is generally unavailable to wholesale energy buyers, including CCE programs, but represents a significant portion of PG&E's energy resource mix; and 3) coal generation, which is a cost-effective but highly polluting domestic power source. Exclusion of the aforementioned energy products will not only avoid potential controversy regarding the use of generally objectionable and/or environmentally damaging power sources, but it will also promote consistency between MBCP's future portfolio emissions reporting and potential changes in California law.[9] In consideration of this direction, such products were omitted during MBCP's portfolio analysis.

It is also noteworthy that independent development and ownership of generating resources may also be an available supply alternative for the CCE 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 CCE-sponsored resource development and ownership likely falls outside the planning horizon addressed within this Study, PEA has not incorporated MBCP-owned resources as a component of the indicative supply scenarios discussed herein. This assumption is largely based on observations related to California's operating CCE programs, which have yet to pursue direct investment in generating resources[10]; the timeline for investment in such resources is likely consistent with PEA's related assumptions reflected in this Study.

With regard to the three prospective MBCP 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 MBCP Partnership. 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. Table 3 identifies key planning elements of each scenario addressed in this Study.

---

[9] Assembly Bill 1110 (Ting), which has become a two-year bill, is intended to require the disclosure of portfolio emissions intensity to California's retail electricity customers. The proposed methodology for such disclosures would not allow the inclusion of environmental benefits associated with unbundled renewable energy certificates. Specific details regarding AB 1110 are not yet finalized and should be monitored by MBCP to ensure that its intended resource mix will result in reported GHG metrics that align with its expectations.

[10] While MCE has participated in early-stage development funding for a locally situated photovoltaic solar project (within the City of Richmond, California), it does not yet have an ownership share of this project.

Table 3: Key Planning Elements of Each MBCP Indicative Supply Scenario

MBCP Supply Scenario	Primary Objectives of Supply Portfolio	Total Renewable Energy Content[11] as % of Total Supply (Year 1; Year 10)	Anticipated GHG Emissions Savings[12] (Year 1; Year 10)	Anticipated MBCP Customer Cost Impacts[13] (Year 1; Year 10)
Scenario 1	Achieve significant GHG emissions reductions (relative to PG&E) while not exceeding PG&E's projected generation rates; clean energy sources generally limited to CA renewables and minimal hydroelectricity	YEAR 1 = 59% YEAR 10 = 85%	YEAR 1 = 20% reduction YEAR 10 = 42% reduction	YEAR 1 = "Zero" impact YEAR 10 = 1% average savings
Scenario 2	Achieve significant GHG emissions reductions (relative to PG&E) while not exceeding PG&E's projected generation rates; clean energy sources generally limited to CA and regional renewables	YEAR 1 = 71% YEAR 10 = 90%	YEAR 1 = 20% reduction YEAR 10 = 62% reduction	YEAR 1 = "Zero" impact YEAR 10 = 1% average savings
Scenario 3	Maximize MBCP rate competitiveness while achieving a projected 25% annual GHG emissions reductions (relative to PG&E); clean energy sources to include CA and regional renewables and well as hydroelectricity	YEAR 1 = 28% YEAR 10 = 44%	YEAR 1 = 25% reduction YEAR 10 = 25% reduction	YEAR 1 = 3% average savings YEAR 10 = 5% average savings

Under each of the three supply scenarios, the CCE 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 MBCP Communities and surrounding areas may be even more difficult than in other parts of the state, such as California's Central Valley. Major development challenges include siting, permitting, financing and generator interconnection with the transmission system, all of which may take far longer (and result in higher costs) 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.[14] 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).

[11] All renewable energy volumes are assumed to be eligible for use in California's Renewables Portfolio Standard ("RPS") program.

[12] Anticipated GHG emissions impacts were determined in consideration of the GHG emissions factor associated with MBCP'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.

[13] Anticipated customer cost impacts were determined in consideration of the projected average MBCP customer rate to be paid under each of the three prospective supply scenarios relative to the forecasted average PG&E rate.

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

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 CCE 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 MBCP without direct ownership of such projects by the CCE program.

Key Assumptions

When preparing the Study, it was necessary for PEA to incorporate a variety of assumptions, which were primarily based on current market observations and PEA's direct experience with California's operating CCE programs. Such assumptions were instrumental in deriving MBCP's projected operating results, as many actual data points, such as final contract energy pricing and future customer participation in the MBCP program, will not be known until immediately prior to or after service commencement. For purposes of this Study, the key assumptions identified in Table 4 were incorporated to facilitate the development of MBCP operating projections:

Table 4: Key Assumptions Underlying the MBCP Technical Study

Key Assumption	Description
Power Supply Costs	Prices for renewable energy and resource adequacy capacity are based on prices observed for recent transactions and escalated for future periods. Prices for conventional power supply utilize forward curves based on exchange quoted futures prices for power, natural gas and GHG emissions allowances. Fees associated with wholesale scheduling, balancing and settlement with the California Independent System Operator are based on similar costs experienced by existing CCE programs. Capacity requirements and shaped energy requirements were estimated using monthly customer load data by rate classification as adjusted by PG&E's hourly class load profiles.
PG&E Rates	PG&E actual 2016 rates (December 30, 2015 Annual Electric True-up for rates effective January 1, 2016) and surcharges (e.g., PCIA) were applied to customer load data aggregated by major rate schedule to form the basis for the PG&E rate forecast. For future years, the forecast was derived using PG&E's most recent resource plan, adjusted for changes to renewable energy content mandated by SB 350. Forecast of PCIA is based on projected PG&E power portfolio cost and forward market prices. It is assumed that CCE would provide similar rate designs and options as PG&E.
Community Participation	All twenty one (21) municipalities are assumed to participate.
Customer Participation	Service is assumed to be offered to all customers except those taking direct access and standby service. Based on average customer retention experienced by operating CCE programs, 85% of customers offered service across all customer classes are assumed to enroll.
CCE Rates & Reserve	CCE rates would be set to recover all program costs including power supply, administration, and debt service as well as funding a reserve equivalent to 4% of annual program costs.
CCE Operations	Staffing and other operating costs were estimated by benchmarking to the three currently operating CCE programs, with adjustment for differences in the number of customers served. Costs associated with administering net energy metering, demand response and energy efficiency programs were included at $1,275,000 per year.

Key Assumption	Description
Bonds and Other Deposits	CPUC Bond: $100,000 (Included in Startup Cost) PG&E Deposit: $22,500 (Included in Startup Cost) CAISO Deposit: $500,000 (Included in Working Capital) Supplier Reserve: $2,250,000 (Included in Working Capital) Startup Costs: $2,251,250 Working Capital: $10,700,000
Rate Comparisons	Rate comparisons are based on the total delivered rate between CCE service and PG&E service, with the CCE program offering a rate structure that generally parallels that of PG&E including time-of-use rate differentials that may be applicable under certain rate schedules (e.g., certain Net Energy Metered customers, which may take service under rate schedules with time-of-use rate variants). For CCE service, the total delivered rate includes the CCE charges, PG&E delivery charges, and PG&E surcharges (e.g., PCIA). For PG&E service, the total delivered rate includes PG&E generation charges and PG&E delivery charges.
Renewable Portfolio Standards	Study assumes the currently applicable renewable energy requirements are maintained through 2020 and increased to 50% renewable portfolio content by 2030 as mandated by SB 350.
Greenhouse gas emissions rates	For PG&E, used its most recent forecast of portfolio emissions rates and adjusted the rate downwards for future years for the effects of anticipated increase in renewable energy content. Assumed continued operation of Diablo Canyon Nuclear Power Plant throughout study period. For CCE, used the CARB default emissions rate applied to power purchases other than purchases from renewable and hydro-electric sources.
Voluntary 100% Renewable Energy Program	Assumed 2% of enrolled customers elect this option.

Multi-Phase Customer Enrollment

For purposes of this Study, PEA assumed a three-phase customer implementation strategy that would result in the enrollment of prospective MBCP customers in the following manner: 1) one-third of prospective MBCP customers would be enrolled during the first month of service, drawing from a broad, representative cross section of the entire MBCP customer base; 2) another third of the original customer population (i.e., half of the remaining customer population which had yet to be enrolled) would be transitioned to CCE service during the thirteenth month of operation, reflecting similar characteristics when compared with the first phase; and 3) all remaining customers not previously enrolled would be transitioned to CCE service during the twenty fifth month of program operations. Such a strategy would allow the CCE 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 CCE 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. Furthermore, a multi-year phase-in strategy will serve to minimize initial working capital requirements of the MBCP program by reducing power contract payment obligations during early operations, allowing the CCE program to build reserves for purposes of self-funding future phase-in activities. It is worth noting that each of California's operating CCE programs has used a similar approach when implementing its prospective customer base; CleanPowerSF will also commence CCE program operations with a relatively small subset of its prospective customer base (during Spring 2016).

Indicative Renewable Energy Contract Portfolio

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 MBCP program. For example, a contract portfolio exclusively focused on solar resources would not provide for requisite energy requirements during the night; similarly, a portfolio focused on the exclusive use of wind resources would not adequately address MBCP customer energy requirements during times of day when wind levels are low. In consideration of the unique generating characteristics associated with various renewable energy technologies, PEA assembled MBCP's indicative renewable energy contract portfolio for purposes of creating a composite energy delivery profile that would reasonably match the manner in which MBCP customers use electric energy. Considerable amounts of solar capacity were incorporated in the indicative supply portfolio in consideration of robust resource availability throughout California and MBCP's need for considerable amounts of electricity during peak times of day. Geothermal and biogas[15] generating technologies were also incorporated in the supply portfolio, as such resources have been successfully secured by other CCE programs and provide a stable ("basesload") energy delivery profile that only marginally varies over time. Wind generating capacity was also included due to its availability and general cost effectiveness in serving CCE renewable energy requirements.

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 MBCP. As reflected in the following table, the indicative supply portfolio phases in a variety of contracting opportunities over time, allowing the CCE program to incrementally increase long-term renewable supply commitments without unnecessarily exposing MBCP to renewable energy price risk at a single point in time – this is 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 CCE 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 operating CCEs, MCE, SCP, LCE and CleanPowerSF, 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 of such projects have been able to reconcile credit concerns in consideration of the CCE's projected operating results and/or relatively nominal collateral postings. PEA expects that MBCP would have similar experiences when pursuing available renewable project options. For example, prior to commencing operations and in the 24 to 36 months thereafter, it is expected that MBCP would be able to secure long-term contract commitments with both small- and mid-sized renewable project opportunities on the basis of MBCP's projected operating results. California's other operating CCEs have generally been able to pursue similar opportunities with little to no collateral obligations, utilizing the respective CCE's pro forma operating projections as the basis for demonstrating creditworthiness.

After establishing a successful operating track record, MBCP 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 CCE legislation is viewed as a risk by many prospective project developers and energy sellers; however, the successful operating track record of California's existing CCEs and the ongoing compilation of data related to customer participation/retention has provided compelling evidence that CCE customer counts and overall program operations will remain stable over time – in general, MCE, SCP and LCE have each experienced customer retention rates in excess of

[15] Biogas generating technologies may include landfill gas-to-energy projects, digester gas generating technologies or other technologies that rely on the diversion of organic materials for purposes of contributing to the production of electric power.

80% with each successive CCE program observing increased retention rates relative to its predecessors. This trend seems to suggest that improved familiarity with the CCE business model, a growing track record of success amongst California's operating CCE programs, and effective marketing campaigns have contributed to higher levels of customer retention over time.

The indicative portfolio of long-term renewable energy contracts also reflects a significant commitment to renewable project development within the MBCP Communities – a total of 20 MWs of anticipated feed-in tariff ("FIT") projects has been included in the Study in consideration of the MBCP Partnership's 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. Ultimately, it will be the decision of MBCP's leadership to determine the appropriate level of FIT participation that is desirable for this program.

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 additional renewable and GHG-free energy procured under shorter-term contract arrangements. Such additional energy volumes will be procured/applied 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 the recent extension of the federal investment tax credit ("ITC"), which will continue at the current 30% level through December 31, 2018, decreasing thereafter until the ITC remains constant at 10% in 2022. PEA's pricing assumptions also reflect growing demand for new renewable energy projects resulting from California's RPS procurement mandate increasing to 50% by 2030.[16] However, it is 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 MBCP's indicative long-term renewable energy supply portfolio, are identified below in Table 5.

[16] On October 7, 2015, Governor Brown signed Senate Bill 350, the Clean Energy and Pollution Reduction Act of 2015. SB 350 increases California's RPS to 50% by 2030 amongst other clean-energy initiatives. Many details regarding implementation of SB 350 will be developed over time with oversight by applicable regulatory agencies.

Table 5: MBCP's Indicative Long-Term Renewable Energy Contract Portfolio

Resource Type	Year of First Delivery	Capacity (MW)	Capacity Factor**	Assumed Price ($/MWh)***
Solar PV, utility scale	2020	100*	30%	$55
Solar PV, utility scale	2024	100*	30%	$65
Wind	2021	100*	35%	$60
Biogas (RPS-eligible)	2021	10*	90%	$80
Biogas (RPS-eligible)	2026	10*	90%	$80
Geothermal	2019	50	100%	$75
Solar PV, multiple FIT (local) projects	2019	5*	22%	$100
Solar PV, multiple FIT (local) projects	2021	5*	24%	$90
Solar PV, multiple FIT (local) projects	2022	5*	24%	$90
Solar PV, multiple FIT (local) projects	2023	5*	24%	$90
Total		390 MW		

**Denotes assumed new generating capacity to be developed as a result of long-term contracts between MBCP and qualified renewable project developers. 340 MW of potential new, California-based renewable generating capacity has been assumed in this Study.*

***Capacity factors quantify the proportionate amount of energy produced by each resource relative to its total, potential generating capacity. For example, if a 10 MW biogas generator, such as a landfill gas-to-energy project, produced 78,840 MWh per year (relative to its total generating potential of 87,600 MWhs), its capacity factor would be 90%. By comparison, solar generators have relatively low capacity factors (ranging from 20% - 30%, generally), as such generators produce no power at night and very little power during the early morning and late afternoon hours.*

****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 California's recently increased RPS (to 50% by 2030), may influence renewable energy pricing and product availability in future years.*

Regarding the referenced local solar projects, which are assumed to be developed under an MBCP-administered FIT program, the pricing assumptions for such projects were set in consideration of three key factors:

1) Prices currently available under PG&E's Electric-Renewable Market Adjusting Tariff ("ReMAT"), which represents the current construct of PG&E's FIT program – local project developers would be evaluating MBCP's FIT in consideration of other available alternatives, so it is assumed that MBCP would want to offer comparatively higher prices to attract such developers;
2) The assumption that project development costs within MBCP's participating jurisdictions generally exceed project development costs in other locations; and
3) The general interest of the MBCP Partnership in providing meaningful price incentives to promote local renewable infrastructure buildout.

If such a program is administered by MBCP, FIT energy prices will need to be sufficiently high to compel project sponsors to focus development efforts on locally situated project sites – this is the primary purpose of locally-focused FIT programs. More specifically, PG&E's ReMAT currently offers eligible, smaller-scale solar projects a base energy price of $61.23 per MWh.[17] This price is adjusted according to a schedule of Time of Delivery, or "TOD", factors which generally increase the annual average price paid to participating solar generators, depending on the quantity of energy produced and delivered during peak times of day (e.g. weekdays between the hours of 3:00 and 8:00 P.M.). In general terms, the aforementioned base energy price may translate to a TOD-adjusted average price of more than $70 per MWh, depending on actual power production. PEA also assumed that project development costs, particularly land costs within the MBCP service territory, would generally be higher than average development costs throughout PG&E's service territory. With these observations in mind, as well as the general concept that FIT programs are intended to incentivize local renewable infrastructure buildout, the prices associated with FIT energy productions were set at comparatively high levels, ranging from $90-$100 per MWh. Such prices reflect a premium ranging from $25-$35 per MWh relative to larger projects within optimal development locations.[18] While such prices seem sufficient to promote local FIT interest, it is noteworthy that MBCP could independently adjust such prices in the event that actual FIT participation is below (or above) desired levels. In the event that the MBCP FIT program generates more interest and participation than originally anticipated, MBCP could cap the program by implementing a total capacity ceiling. The cap could always be modified, but implementing a participatory ceiling would provide an additional layer of financial certainty for the FIT program.

Energy Production Options & Scenario Composition

When considering the portfolio composition associated with MBCP's prospective supply scenarios, 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 supply the electric energy requirements of MBCP customers. 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 unique 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 (i.e., Renewable Energy Certificates, or "RECs") are both delivered to the buyer, whereas other RPS-eligible products are referred to as "unbundled," meaning that the renewable attributes, or RECs, 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 MBCP'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, MBCP's three prospective supply scenarios were constructed with the resource preferences reflected in Table 6.

---

[17] PG&E's Program Period 15 price for As-Available Peaking products, as noted on PG&E's ReMAT website on March 3, 2016: http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/ReMAT/index.page.

[18] Note that MCE's FIT tariff offers similar price incentives to attract local developers. According to MCE's FIT tariff, applicable prices are scheduled to incrementally decrease over time (as successive FIT projects enter the project development queue).

Table 6: MBCP's Scenario-Specific Energy Resource Preferences

MBCP Supply Scenario	Primary Objectives of Supply Portfolio	Total Renewable Energy Content[19] as % of Total Supply (Year 1; Year 10)	Total PCC1-Eligible[20] Renewable Energy Content as % of Total Supply (Year 1; year 10)	Total PCC2-Eligible[21] Renewable Energy Content as % of Total Supply (Year 1; year 10)	Total GHG-Free Energy Content[22] as % of Total Supply (Year 1; Year 10)
Scenario 1	Achieve significant GHG emissions reductions (relative to PG&E) while not exceeding PG&E's projected generation rates; clean energy sources generally limited to CA renewables and minimal hydroelectricity	YEAR 1 = 59% YEAR 10 = 85%	YEAR 1 = 59% YEAR 10 = 85%	YEAR 1 = None YEAR 10 = None	YEAR 1 = 70% YEAR 10 = 85%
Scenario 2	Achieve significant GHG emissions reductions (relative to PG&E) while not exceeding PG&E's projected generation rates; clean energy sources generally limited to CA and regional renewables	YEAR 1 = 71% YEAR 10 = 90%	YEAR 1 = 53% YEAR 10 = 78%	YEAR 1 = 18% YEAR 10 = 12%	YEAR 1 = 71% YEAR 10 = 90%

[19] All renewable energy volumes are assumed to be RPS-eligible for purposes of this Study.

[20] 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.

[21] Portfolio Content Category 2, or "Bucket 2" eligible renewable energy resources, are typically located outside of California but are subject to specific energy delivery requirements articulated in applicable RPS regulations.

[22] 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 3	Maximize MBCP rate competitiveness while achieving a projected 25% annual GHG emissions reductions (relative to PG&E); clean energy sources to include CA and regional renewables and well as hydroelectricity	YEAR 1 = 28% YEAR 10 = 44%	YEAR 1 = 21% YEAR 10 = 43%	YEAR 1 = 7% YEAR 10 = 1%	YEAR 1 = 72% YEAR 10 = 81%

Scenario 1: Maximize GHG Emissions Reductions while Maintaining Rate Parity with PG&E – Bucket 1 Renewables & Hydroelectricity as Designated Clean Energy Sources

Scenario 1 was structured for the primary purpose of maximizing projected GHG emissions reductions while maintaining general rate parity with PG&E. Under Scenario 1, clean energy resources were generally limited to Bucket 1-eligible renewables with only a small amount of regionally produced hydroelectricity included in the Year 1 resource mix. This decision generally has the effect of increasing total renewable energy supply costs within the MBCP portfolio but should reduce the prospect of future RPS compliance issues in the post-2020 framework – while many of the details related to SB 350 compliance have yet to be identified, it seems reasonable to assume that limitations related to the use of California-based renewables will not be imposed. Additional clean energy purchases, which would have the effect of reducing overall GHG emissions associated with the MBCP supply portfolio, were also incorporated in Year 1, yielding a 70% GHG-free resource mix in Year 1, increasing to 85% in Year 10. Beginning in Year 2 of projected Scenario 2 operations, Bucket 1 renewables were incorporated as the exclusive source of MBCP's clean energy supply. The expected clean energy content associated with Scenario 1 is identified in Table 7, which reflects the proportionate share of purchases relative to MBCP's expected energy requirements.

Table 7: Scenario 1 - Proportionate Share of Planned Energy Purchases Relative to MBCP'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	59%	76%	76%	80%	80%	80%	85%	85%	85%	85%
PCC 2 Supply	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
PCC 3 Supply	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total Renewable Energy Supply	**59%**	**76%**	**76%**	**80%**	**80%**	**80%**	**85%**	**85%**	**85%**	**85%**
Additional GHG-Free Energy Supply	12%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total Clean Energy Supply	**70%**	**76%**	**76%**	**80%**	**80%**	**80%**	**85%**	**85%**	**85%**	**85%**

	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)	30%	25%	24%	20%	20%	20%	15%	15%	15%	15%

**"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. Energy purchases from the CAISO market are not associated with specific generating resources. As such, CAISO purchases are also commonly referred to as "Unspecified Sources of Power" or "Market Purchases" due to the fact that these purchases are made from a pool of generating resources administered by the CAISO. Note that it is very common for CCEs to incorporate considerable quantities of Market Purchases in their respective supply portfolios (20% to 40%, for example). As previously indicated, PG&E's power supply portfolio included 21% Market Purchases in 2014. Note that numbers may not add due to rounding.*

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, MBCP'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

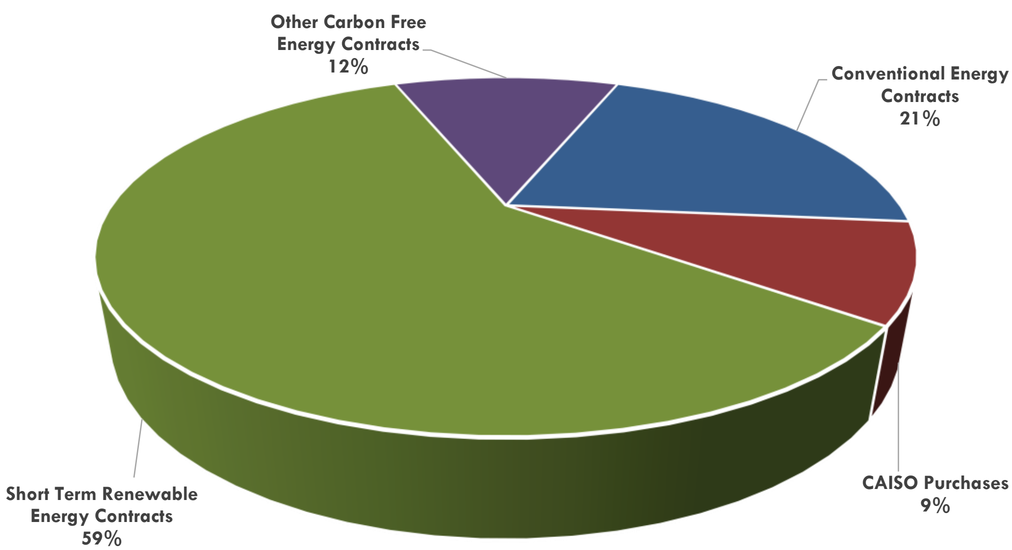


Figure 2: Scenario 1 Resource Mix, Year 10

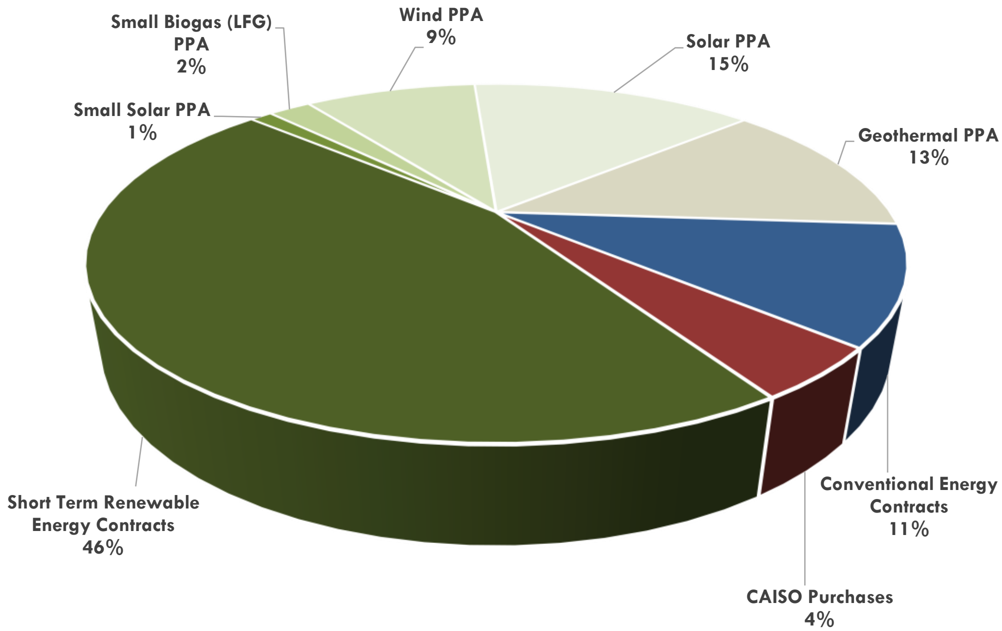
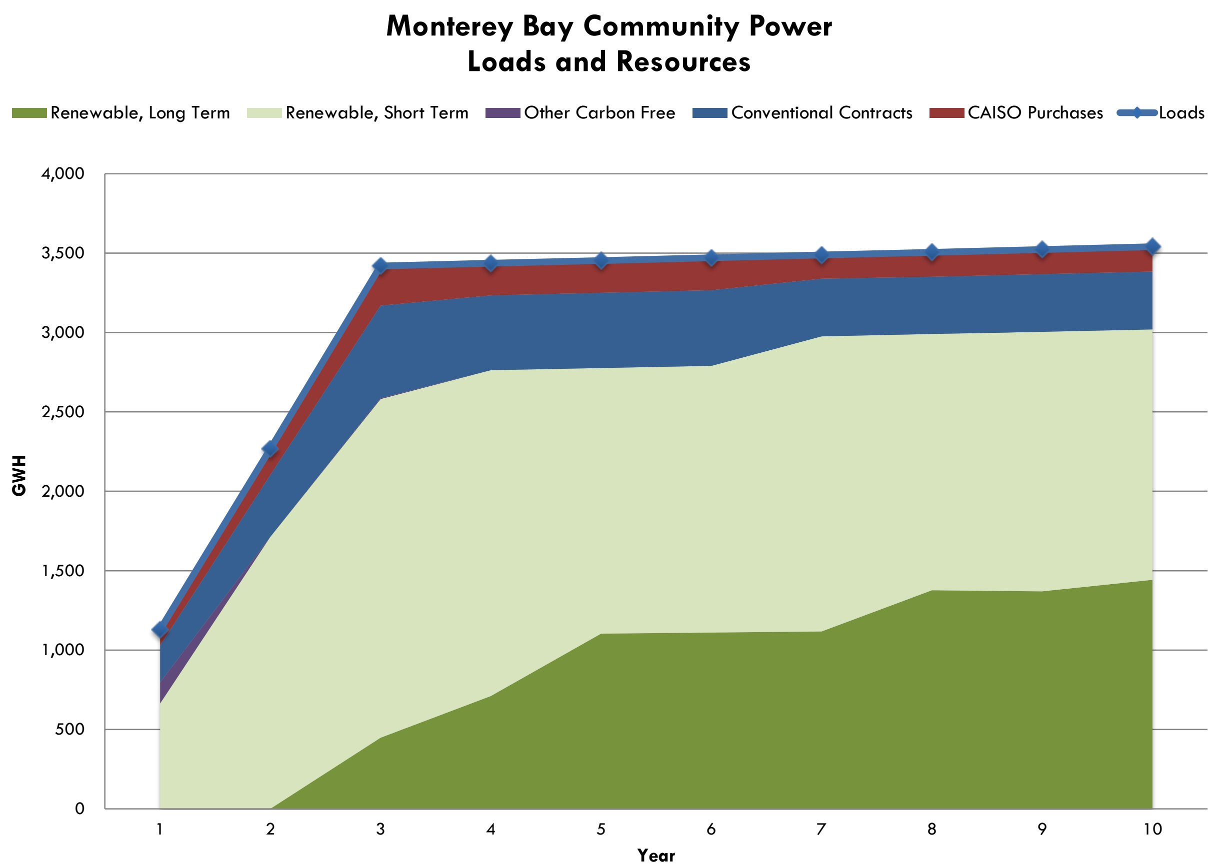


Figure 3 shows how composition of the Scenario 1 supply portfolio changes throughout the study period, reflecting planned diversification of MBCP's renewable energy supply portfolio through long-term contracting efforts and local infrastructure build out.

Figure 3: Scenario 1 Load and Resource Projections



Scenario 2: Maximize GHG Emissions Reductions while Maintaining Rate Parity with PG&E – Bucket 1 & Bucket 2 Renewables as Designated Clean Energy Sources

Scenario 2 is similar in design to Scenario 1, framed for the primary purpose of maximizing projected GHG emissions reductions while maintaining general rate parity with PG&E. However, under Scenario 2, MBCP would expand the use of RPS-eligible renewable energy products to include both Bucket 1- and Bucket 2-eligible resources. As previously noted, Bucket 1 and Bucket 2 products are generally recognized as "bundled" renewable energy, as the buyer receives both electric energy and associated environmental attributes (conveyed via renewable energy certificates) when contracting for related supply; Bucket 1 resources are generally located within California, while Bucket 2 resources are generally located outside of California but within the western United States. The renewable energy supply portfolio associated with Scenario 2 is lower in cost when compared to Scenario 1, as Bucket 2 renewable energy premiums tend to be significantly less expensive (less than half) than premiums associated with Bucket 1 products.

Under Scenario 2, MBCP's projected renewable energy content begins at 71% in Year 1 of program operations, increasing to 90% in Year 10. This renewable energy procurement strategy ensures that MBCP will continually exceed California's RPS mandate, even following recent adoption of the 50% renewable energy procurement requirement. As with Scenario 1, the Scenario 2 supply portfolio excludes the use of PCC3 products and nuclear power. Table 8 details the annual resource composition for Scenario 2 during the 10-year planning period.

Table 8: Scenario 2 - Proportionate Share of Planned Energy Purchases Relative to MBCP'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	53%	64%	64%	64%	71%	74%	73%	77%	77%	78%
PCC 2 Supply	18%	21%	21%	21%	14%	16%	17%	13%	13%	12%
PCC 3 Supply	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total Renewable Energy Supply	**71%**	**85%**	**85%**	**85%**	**85%**	**90%**	**90%**	**90%**	**90%**	**90%**
Additional GHG-Free Energy Supply	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total Clean Energy Supply	**71%**	**85%**	**85%**	**85%**	**85%**	**90%**	**90%**	**90%**	**90%**	**90%**
Conventional Energy Supply (including CAISO market purchases)	**29%**	**15%**	**15%**	**15%**	**15%**	**10%**	**10%**	**10%**	**10%**	**10%**

Figure 4: Scenario 2 Resource Mix, Year 1

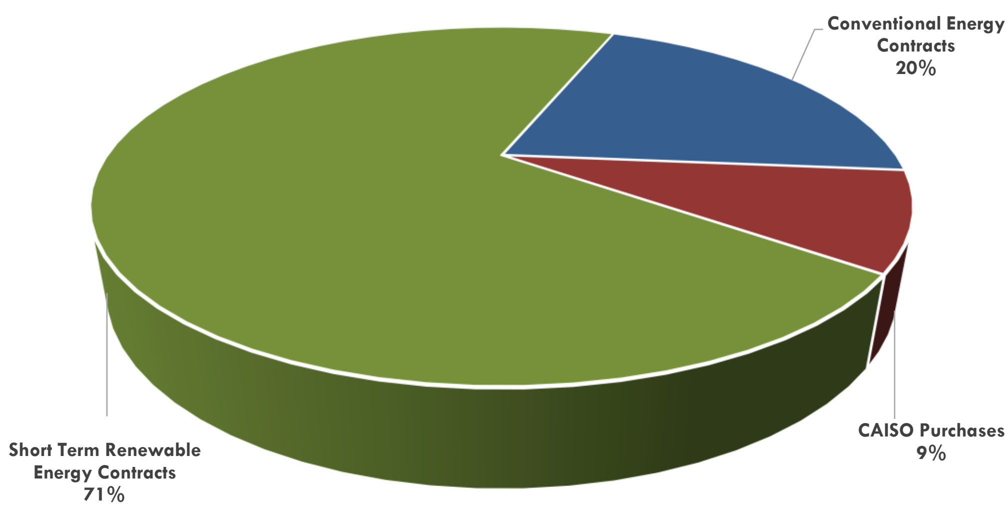


Figure 5: Scenario 2 Resource Mix, Year 10

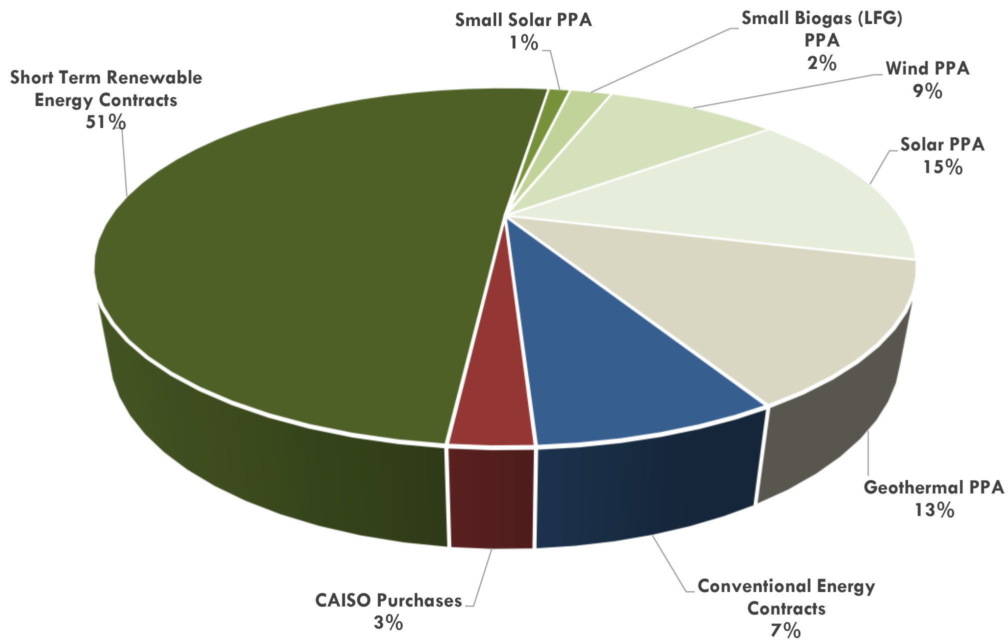
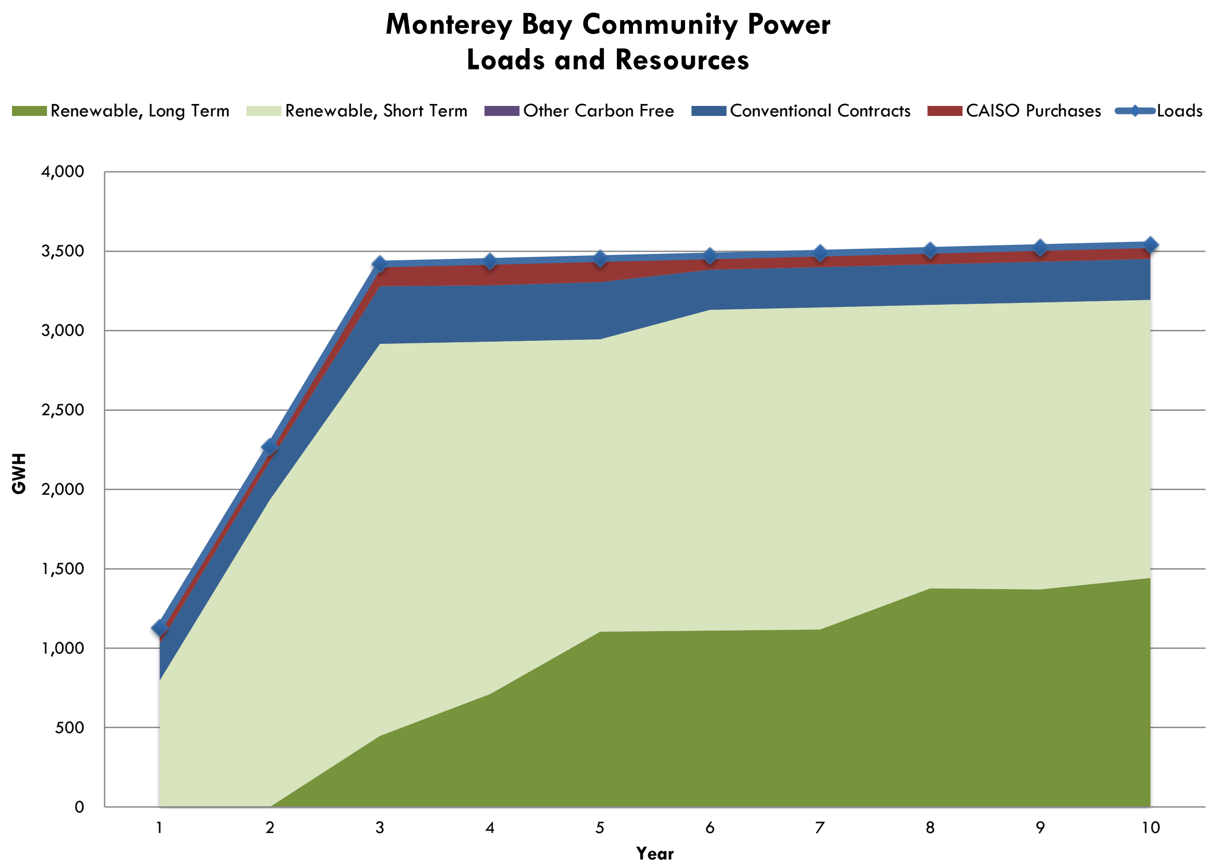


Figure 6 shows how composition of the Scenario 2 supply portfolio changes throughout the study period.

Figure 6: Scenario 2 Load and Resource Projections



Scenario 3: Maximize Rate Competitiveness while Maintaining 25% Annual GHG Emissions Reductions

Scenario 3 represents a supply portfolio that is designed to maximize rate competitiveness while maintaining 25% annual GHG emissions reductions (relative to PG&E) throughout the Study period. This objective of maximizing rate competitiveness was achieved through the use of a diversified portfolio of clean energy resources, including Bucket 1, Bucket 2 and hydroelectric energy products. With regard to renewable energy procurement, resource preferences within Scenario 3 were generally selected to promote the achievement of an overall renewable resource percentage that would marginally exceed specified (and anticipated) RPS compliance mandates. In particular, Scenario 3 incorporates a 28% RPS-eligible renewable energy supply from day one of CCE program operations, incrementally increasing after the 2020 calendar year in consideration of California's transition to a 50% RPS mandate. The Scenario 3 resource mix contributes to the achievement of this objective by incorporating a diversified mix of shorter- and longer-term supply agreements with a variety of generating technologies. Similar to Scenarios 1 and 2, PCC3 and nuclear power products are not incorporated in this supply scenario.

Additional GHG-free power sources are layered on top of planned renewable energy purchases, resulting in proportionate GHG-free supply that begins at 72% in Year 1 and gradually increases to 81% in Year 10 of projected MBCP operations. The GHG emissions profile associated with Scenario 3 reflects average annual reductions (relative to PG&E) of 25% throughout the 10-year Study period. Table 9 provides additional detail regarding the indicative resource mix for Scenario 3.

Table 9: Scenario 3 - Proportionate Share of Planned Energy Purchases Relative to MBCP'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	21%	23%	24%	26%	34%	34%	35%	41%	42%	43%
PCC 2 Supply	7%	8%	8%	9%	2%	3%	5%	0%	1%	1%
PCC 3 Supply	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total Renewable Energy Supply	**28%**	**30%**	**32%**	**34%**	**36%**	**38%**	**39%**	**41%**	**43%**	**44%**
Additional GHG-Free Energy Supply	44%	43%	43%	43%	42%	41%	40%	39%	38%	37%
Total Clean Energy Supply	**72%**	**74%**	**76%**	**77%**	**78%**	**78%**	**79%**	**80%**	**80%**	**81%**
Conventional Energy Supply (including CAISO market purchases)	**28%**	**26%**	**24%**	**23%**	**22%**	**22%**	**21%**	**20%**	**20%**	**19%**

Figure 7: Scenario 3 Resource Mix, Year 1

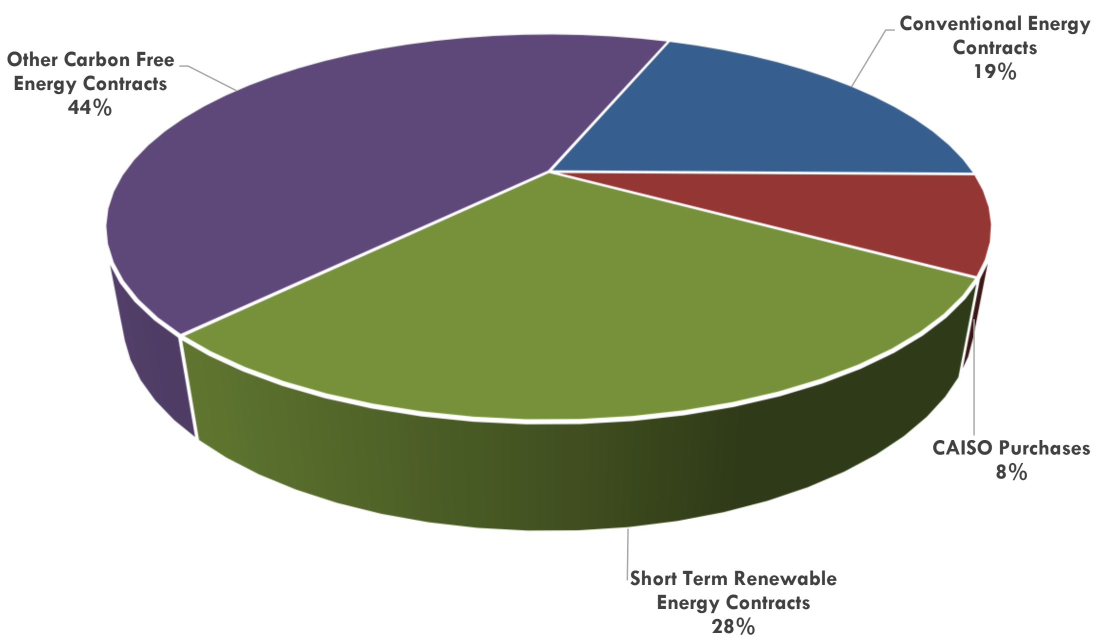


Figure 8: Scenario 3 Resource Mix, Year 10

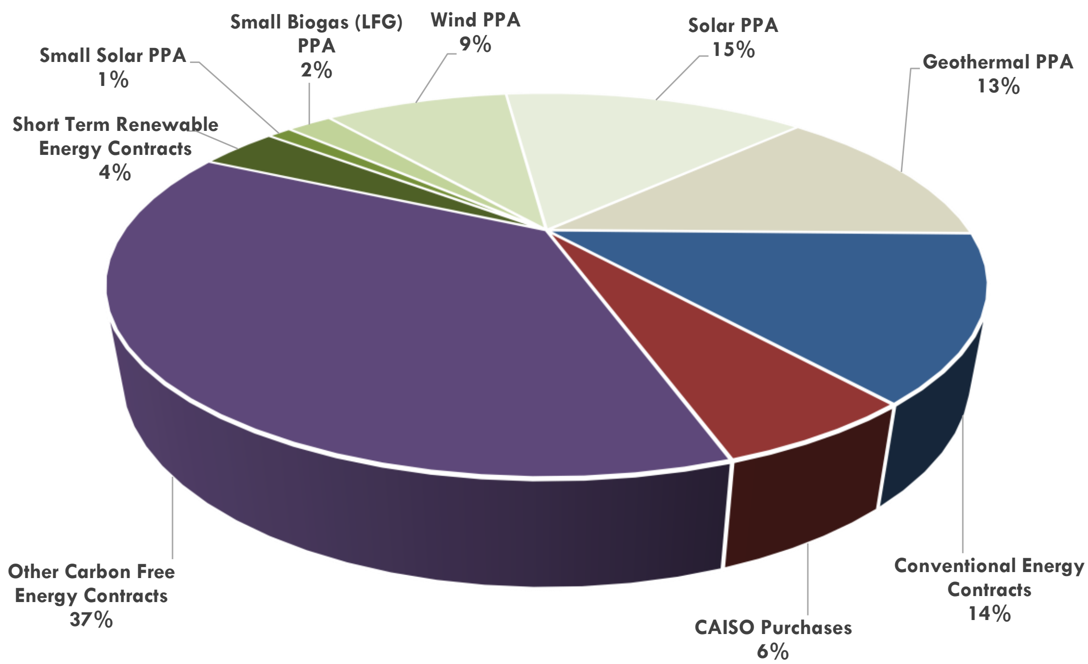
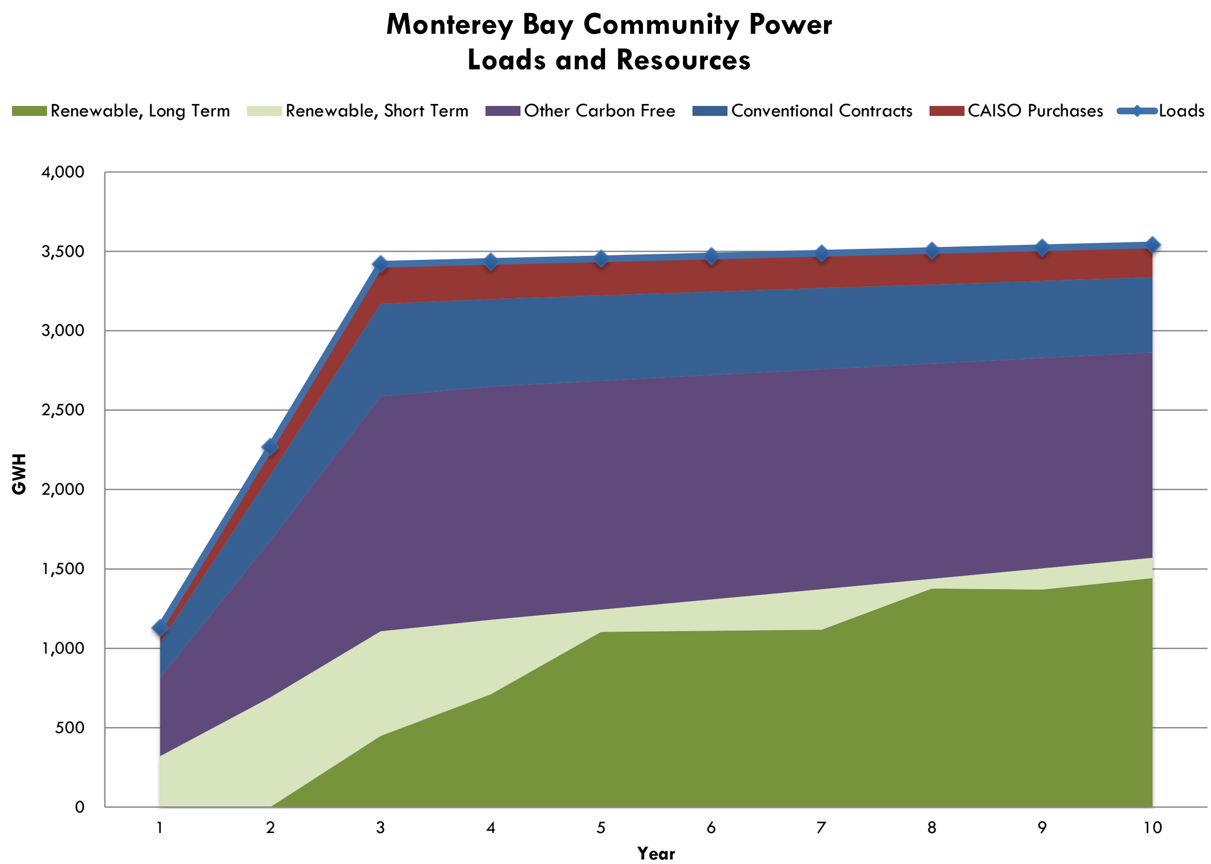


Figure 9 shows how composition of the Scenario 3 supply portfolio changes throughout the study period.

Figure 9: Scenario 3 Load and Resource Projections



Costs and Rates

For each supply scenario, detailed estimates were made for 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 CCE 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 MBCP must offer competitive rates in order to retain customers that are automatically enrolled in the program. Customer retention may also be affected by MBCP offering customized rate choices, such as voluntary green pricing programs or market based rate options for large end users.[23]

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 customer cost of MBCP service is equivalent to or below what the customer would otherwise pay for PG&E bundled service, the MBCP program could be considered to offer competitive rates and would be viable with regard to this important metric. Rates that provide for a modest cost increase may also be considered competitive, if the "quality" of the retail electricity product offered by MBCP is viewed as meaningfully higher

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

than existing option(s) provided by the incumbent utility – in this context, the term "quality" generally refers to specific attributes of an electric supply portfolio, including renewable energy content, GHG emissions impacts and complimentary customer programs, that create measurable distinctions between two available service alternatives. To the extent that the attributes associated with MBCP service are perceived as superior to the attributes associated with PG&E service, then certain cost increases may not impose significant impacts to the overall level of customer participation in the CCE program. More specifically, a materially higher renewable energy content and/or lower carbon intensity for the electricity sold by MBCP may justify a higher price, and MBCP rates may be viewed as competitive so long as such rates do not deviate substantially from the PG&E benchmark.

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. When reviewing Figure 10 note that PG&E's "System Average Generation Rate" represents the average power price paid by the composite of all customer groups (e.g., residential, commercial, etc.).

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 CCE 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 MBCP 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 represents 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 CCE 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 are identified in the Table 10[24]:

Table 10: PG&E GHG Emission Factor Projections (2016 through 2020)

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 CCE programs, which may have the effect of reducing PG&E's GHG emissions factor (via reductions in short-term conventional energy purchases due to declining retail sales).[25] 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 Table 11:

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

[25] 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 MBCP 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.

Table 11: PEA's Projected GHG Emission Factors for the PG&E Supply Portfolio (2021 through 2025)

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 emissions profile was selected as the benchmark for comparison to promote a conservative assessment of direct emissions impacts related to CCE operations (on a head-to-head basis with PG&E's anticipated supply portfolio). The GHG impacts associated with MBCP'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 CCE 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 valuable 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 CCE 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.[26]

[26] National Renewable Energy Laboratory website, http://www.nrel.gov/about/, September 2, 2015.

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."[27] 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 CCE program serving the MBCP 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 creation 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 2019 through 2026 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 job creation estimates are presented as full time equivalent positions ("FTEs"). Projections related to the

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

construction period are intended to capture annual economic benefits received during the defined construction term (24 months, for example; note that actual construction periods may vary from project to project). 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 340 MW (as previously reflected in Table 5, above) of new renewable generating capacity within the state are reflected in Table 12.

Table 12: MBCP Economic Development Benefits Potential

Economic Development Benefits Potential: Indicative Supply Portfolio (Secured via Long-Term Contract)			
During Construction Period	**Jobs (FTEs)**	**Earnings** ($ - Millions)	**Output** ($ - Millions)
Project Development and Onsite Labor Impacts	3,750 - 4,750	240 - 290	425 - 475
Construction and Installation Labor	*1,500 - 2,000*	*110 - 130*	
Construction Related Services	*2,250 - 2,750*	*130 - 160*	
Power Generation and Supply Chain Impacts	3,500 - 4,000	200 - 250	575 - 600
Induced Impacts	1,750 - 2,250	80 - 110	260 - 300
Total Construction Period Impacts	9,000 - 11,000	520 - 650	1,260 - 1,375
During Operating Years (Annual)			
Onsite Labor Impacts	80 - 110	5 - 8	5 - 8
Local Revenue and Supply Chain Impacts	40 - 50	2 - 4	10 - 14
Induced Impacts	15 - 25	1 - 2	3 - 6
Total Operating Impacts (Annual)	135 - 185	8 - 14	18 - 28
MBCP - Internal Staff	8 - 29	1 - 3	3 - 9

Notes: Earnings and Output values are expressed in million dollar increments (2016). Construction period jobs reflect full-time equivalent (FTE) positions that will be maintained during 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 as a result of anticipated development activities. Such jobs will not exist following completion of the construction period. Economic impacts "During Operating Years" represent annual, ongoing impacts that occur as a result of generator operation and related expenditures. With respect to estimated jobs occurring during operating years, such statistics represent annual, ongoing FTEs during the entire project lifecycle, which may extend up to thirty (30) years or more 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 CCE program's three planning scenarios, would result in valuable economic benefits throughout the state and, to a lesser extent, within the MBCP Communities, as explained below. It is also noteworthy that all jobs reflected in the previous table are assumed to be additive relative to the status quo. More specifically, PEA assumes that jobs created through new generator development and construction as well as ongoing maintenance activities will not displace existing jobs. Furthermore, it is also reasonable to assume that MBCP would have little impact on the current PG&E workforce, including those individuals employed to operate and maintain the utility's distribution infrastructure, provide customer service, operate existing generating facilities and myriad other responsibilities within the utility. To date, PEA is not aware of any specific evidence linking CCE formation and operation to diminished utility employment. In practical terms, the significant majority of utility functions remain unchanged following CCE formation while the responsibilities associated with a very small subset of utility positions may change somewhat in consideration of the coordination required between the incumbent utility and CCE suppliers.

With respect to the prospective generating facilities that have been incorporated in MBCP'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 also assumed the development of 20 MW of locally situated renewable generating projects, which would be developed during the study period under long-term contract arrangements between MBCP and third-party project developers (under an assumed MBCP-administered FIT program) – such projects are discussed below. With regard to anticipated development projects located in areas outside of the MBCP Communities, PEA assumed that virtually all plant equipment, including turbines and other materials, would be procured outside of the MBCP 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. *When considering the following economic development benefits potential, note that virtually all impacts – other than those associated with the Local Economic Development Benefits Potential, discussed in the similarly named subsection (below) – are assumed to accrue in areas outside of the MBCP Communities.* With this in mind, only a relatively small portion of the total potential economic development benefits are assumed to accrue within the MBCP Communities.

In total, MBCP's indicative long-term contract portfolio is projected to result in the creation of approximately 9,000-11,000 new jobs during the aggregate construction period required to complete the assumed 340 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 $475 million in new economic output of which as much as $290 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 $250 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 $300 million of which approximately $110 million would be collected as salaries and wages. In total, the locally developed generation projects identified under MBCP's indicative long-term contract portfolio would result in approximately $1.26 to $1.38 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 185 new jobs would be created with a total annual economic impact ranging from $18 to $28 million. It is anticipated that these jobs would remain effective as long as the generating facilities remain operational, resulting in valuable, lasting impacts throughout the state.

Local Economic Development Benefits Potential

The primary source of local jobs and economic development impacts would be derived through projects developed under MBCP's anticipated 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 a period of five to seven years (and beyond, should MBCP choose to expand this program after initial participatory limitations are achieved). Note that the 1 MW capacity limitation has been referenced in consideration of the FIT programs currently administered by MCE and SCP. To the extent that MBCP's governing board determines to specify different project limitations for its FIT program, this would be permissible. However, MBCP should be aware that projects in excess of 1 MW may result in additional administrative complexities due to generator registration and scheduling requirements (with the CAISO) imposed on projects in excess of the 1 MW capacity threshold. For purposes of this Study and in consideration of a similar FIT program offered by MCE, PEA assumed that MBCP 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. PEA acknowledges that a fairly aggressive FIT buildout schedule has been incorporated in the Study. However, growing familiarity with the CCE business model and an increasing appreciation amongst project developers for the financial viability of operating CCEs, as well as decreasing prices to be paid under PG&E's ReMAT program, have catalyzed recent interest in CCE-administered FIT programs. In fact, interest in MCE's FIT has jumped over the past year with more than 6 MW of locally situated renewable generating capacity (out of MCE's total FIT participatory cap of 15 MW) actively operating or under development (with related FIT contracts in place between the developers of such projects and MCE). Ultimately, many factors may affect MBCP's FIT buildout schedule, including the availability of project financing to interested project developers, actual project interconnection timelines (for most projects, interconnection will be pursued under a PG&E-administered process, which is subject to delays), price competitiveness and other factors. To the extent that MBCP's FIT buildout schedule is delayed, noted economic development benefits will be deferred until such projects can be completed.

Based on applicable JEDI modeling results, the prospective MBCP FIT program would result in the potential creation of more than 370 jobs within the MBCP Communities and/or surrounding areas during generator construction with as many as 500 additional jobs created through supply chain and induced (during the construction period) economic activity over a period ranging from five to seven years, depending on the actual period of time required to complete construction activities. As previously noted, these construction jobs are temporary, but there is also a nominal level of ongoing support for jobs supporting requisite operation and maintenance activity, which is projected to be approximately six full-time equivalent employees during each year of facility operation (which may continue for 25-30 or more, depending on the actual period of time that such FIT projects remain in service).

Project development would also generate nearly $23 million in earnings for those working on the FIT projects, which is expected to create a total economic stimulus approximating nearly $40 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 MBCP would employ 8 to 29 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 CCE 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 MBCP staff.

These local economic development impacts are subsumed in the aggregate economic development impact totals reflected in the previous table. It is also noteworthy that PEA previously attempted to contact NREL regarding certain wage-related assumptions that are included in the various JEDI models, specifically whether or not prevailing wages are reflected in such assumptions. In spite of PEA's efforts, NREL has not yet responded. To the extent that prevailing wage requirements are imposed in any project-specific power purchase agreement, it is reasonable to assume that earnings and related economic development impacts may somewhat increase to the extent that NREL's wage assumptions are lower than applicable prevailing wages.

SECTION 3: MBCP TECHNICAL PARAMETERS (ELECTRICITY CONSUMPTION)

Historical and Projected Electricity Consumption

Total electric consumption for eligible customers within the MBCP Communities was provided by PG&E for the 2014 calendar year. 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 285,509 electric accounts within the potential CCE service territory. These customers consumed approximately 3,998 million kilowatt-hours of electricity during the 2014 calendar year. It is noteworthy that the aforementioned customer account and usage statistics include approximately 565 accounts, which are currently served through direct access service arrangements with third party suppliers. These customers account for approximately 7% of the aforementioned energy consumption, or approximately 297 million kWh annually, within the MBCP 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[28], individual customers typically engage in shorter-term contract arrangements for the provision of electric generation service. By enrolling direct access accounts in the MBCP program, such customers would be potentially exposed to duplicate generation charges and/or may be in violation of existing supply agreements. In consideration of these potential issues, direct access accounts have been excluded from MBCP's prospective customer base. Table 13 summarizes customer account totals and historical annual energy use within the MBCP Communities. When reviewing the statistics reflected in Table 13, note that the historical annual electricity usage within the MBCP Communities is more than double MCE's total annual energy use (which approximates 1.8 million MWh per year) and approximately 1.5 times the size of SCP's annual sales volume.

Table 13: MBCP – Electric Energy Overview

Current Service Provider	Customer Accounts	Customer Accounts (% of Total)	Energy Use (MWh)	Energy Use (% of Total)
PG&E ("Bundled" electric accounts)	284,944	99.8%	3,701,593	92.6%
Direct Access electric accounts	565	0.2%	296,708	7.4%
Total – MBCP	**285,509**	**100.0%**	**3,998,301**	**100.0%**

Figure 11 shows how potential electric customers are distributed throughout the MBCP Communities: the largest customer populations within the potential CCE jurisdiction include the unincorporated areas of Santa Cruz County, the City of Salinas, unincorporated areas of Monterey County, the City of Santa Cruz and the City of Monterey.

[28] Consideration of Senate Bill 286 (Hertzberg), 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

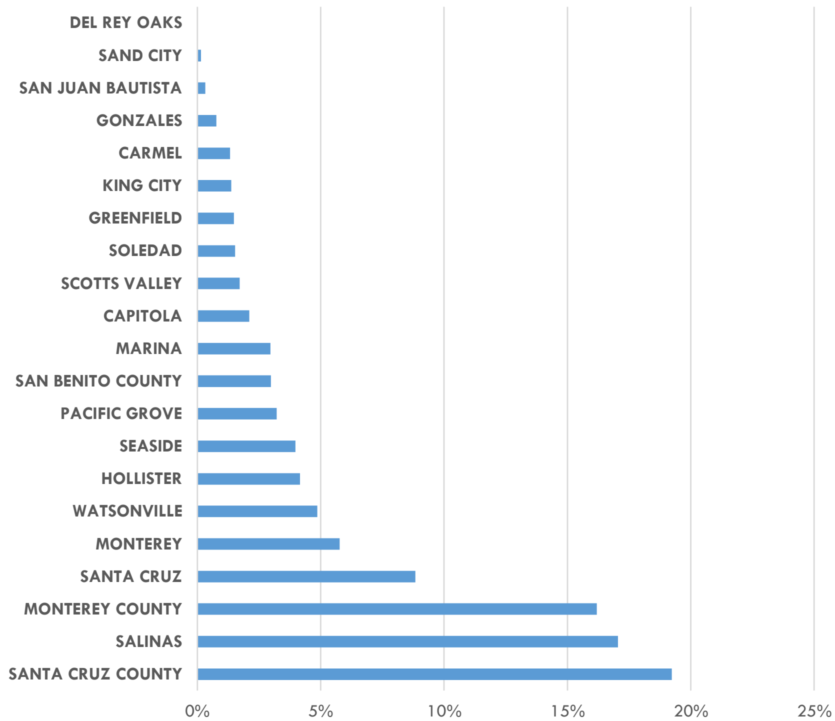
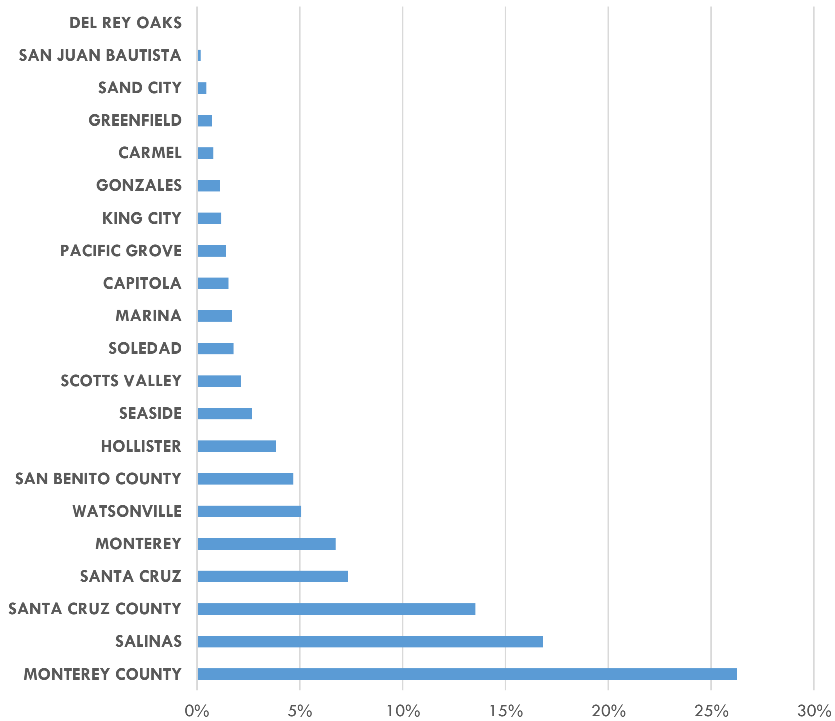


Figure 12 shows the distribution of electric consumption by municipality. The geographic distribution of energy consumption is somewhat different when compared to the service account data in Figure 11 above, indicating disproportionately higher use in certain communities (as a result of differentiated 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[29] 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 CCE 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 MCE program, when evaluating each of MBCP's prospective supply scenarios. 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 within the state. The most recent baseline sales forecast for the PG&E planning area projects an average growth in energy consumption of 1.29% between 2013 and 2025.[30] Adjusting the long-term growth rate for estimates of incremental self-generation (e.g., rooftop photovoltaic systems) and achievable energy efficiency yields an annual net energy consumption increase of approximately 0.3% for the PG&E planning area.[31] A slightly higher growth rate (0.5%) was used for the MBCP sales forecast in consideration of the above average growth expected within the region.

---

[29] 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.

[30] Kavalec, Chris, 2015. California Energy Demand Updated Forecast, 2015-2025. California Energy Commission, Electricity Supply Analysis Division. Publication Number: CEC-2002014-009-CMF, Table 6.

[31] *Ibid*., Table 26

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 Table 14. Hourly electricity consumption and peak demand were estimated using hourly load profiles published by PG&E for each customer classification.

Table 14: Projected Accounts Totals and Energy Use for the MBCP Customer Base

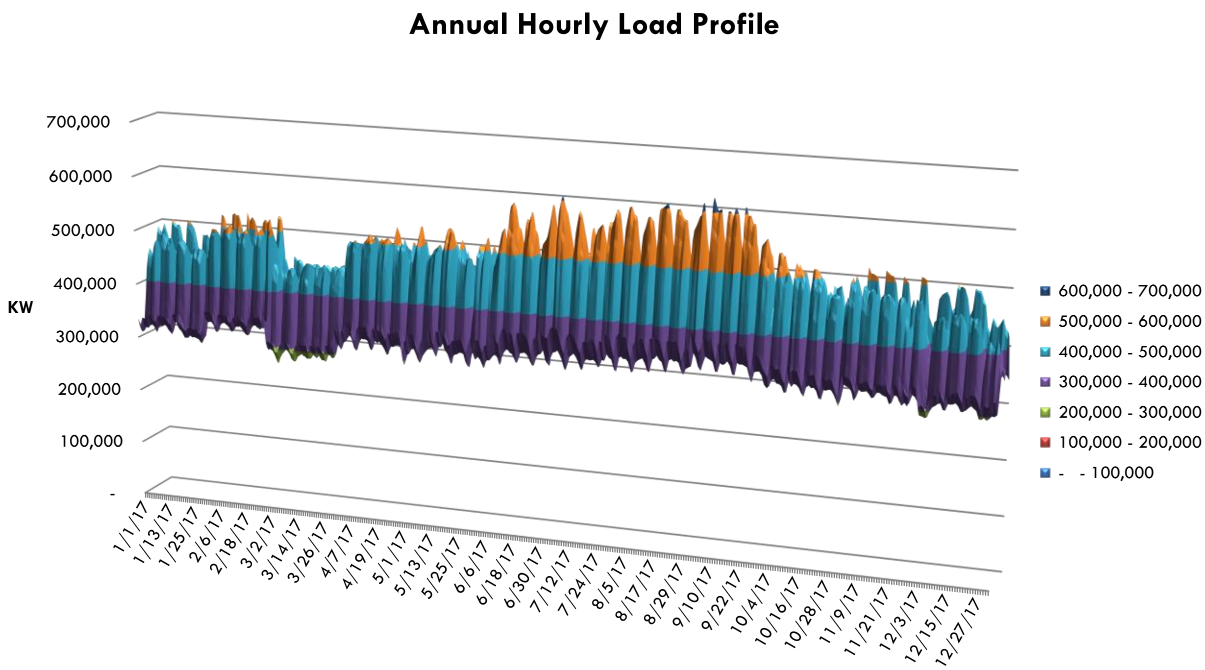
Customer Classification	Customer Accounts	Customer Accounts (% of Total)	Energy Use (MWh)	Share of Energy Use (%)
Residential	245,638	86%	1,315,876	36%
Small Commercial	28,795	10%	457,547	12%
Medium Commercial	2,374	1%	391,890	11%
Large Commercial	1,096	<1%	481,004	13%
Industrial	41	<1%	388,677	11%
Ag and Pumping	4,940	2%	648,468	18%
Street Lighting	2,060	1%	18,129	<1%
TOTAL*	**284,944**	**100.0%**	**3,701,593**	**100%**
Peak Demand	**661 MW (September)**			

Numbers may not add due to rounding.

The hourly load forecast indicates a peak demand of approximately 661 MW (occurring during the month of September), a minimum demand of approximately 288 MW (occurring during the month of March), and an average demand of about 423 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 CCE program in Year 1 of program operations.

Figure 13: MBCP Hourly Electric Load Profile



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 Table 15.

Table 15: Renewable Energy Procurement Requirements of California's RPS Program

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 target was recently increased to 50% by 2030 – Governor Brown signed SB 350 (De Leon and Leno), the Clean Energy and Pollution Reduction Act of 2015, on October 7, 2015; SB 350 increases California's RPS procurement target to 50% by 2030 amongst other clean-energy initiatives. Many details related to SB 350 implementation 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 CCEs 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. For example, the delivery specifications associated with certain RPS products may be altered or eliminated in relation to post-2020 compliance. To the extent that such changes occur, market pricing for RPS-eligible products is likely to change, which could have the effect of increasing or decreasing power procurement costs associated with each of MBCP's indicative supply scenarios. In PEA's opinion, it is unlikely that the use of California-based renewable projects will be restricted for the foreseeable future. However, changes to current rules regarding the use of out-of-state renewable energy resources could increase costs associated with in-state supply in the event that additional restrictions/specifications are imposed on renewable energy imports. PEA recommends that the MBCP Partnership continue to monitor SB 350 implementation should it determine to move forward with MBCP implementation. With regard to any voluntary (above-RPS) renewable energy procurement activities, PEA has assumed that the CCE program would have discretion in how it meets such voluntary, internally imposed targets reflected in the prospective planning scenarios. Table 16 illustrates PEA's assumed RPS procurement rules as California transitions to a 50% RPS by 2030.

Table 16: Projected Renewable Energy Procurement Requirements Following SB350 Implementation

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%

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

Capacity Requirements

The CCE program would be required to demonstrate it has sufficient physical generating capacity to meet its projected peak demand (661 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 (as defined in the CPUC's annual Resource Adequacy Guide) that would apply to the CCE program: the "Greater Bay Area" and the "Other PG&E Areas." Additionally, the CPUC and CAISO impose a flexible capacity requirement, which must be satisfied by all California load serving entities, including CCEs, 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).

Based on PEA's experience in managing resource adequacy portfolios and compliance activities, the following resource adequacy capacity requirements were assumed to apply to MBCP's CCE program to meet the requirements identified above. Such resource adequacy capacity requirements are identified in Table 17.

Table 17: MBCP's Projected Resource Adequacy Capacity Requirements

Capacity Type	Percentage of Peak Demand
CAISO System	79%
Greater Bay Area	13%
Other PG&E Areas	23%
Total	115%

Accordingly, the total resource adequacy requirement for MBCP's first year of full operations would be approximately 643 MW per month, with approximately 85 MW of the total procured from the Greater Bay Area region, 147 MW procured from any other local reliability area in the PG&E service area, and 411 MW procured from anywhere within the CAISO northern region (NP15). 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 CCE 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 B.

Electricity Purchases

The CCE 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 CCE 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 CCE program, as reflected in the previously described indicative long-term contract portfolio, were subtracted from MBCP'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 MBCP 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.[32]

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 MBCP'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 resource. 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 CCE 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 MBCP 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 within California. In consideration of the MBCP Partnership's preliminary planning decision to exclude the use of unbundled RECs from all prospective supply scenarios, the potential change in GHG reporting conventions contemplated under AB 1110 would not

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

necessarily present any issues for MBCP.[33] However, if MBCP chooses to reconsider the use of unbundled RECs at some point in the future, it should be aware that such a practice may result in the reporting of higher than anticipated portfolio emission levels. As previously discussed and in light of the perceived risks and general controversy associated with the use of unbundled RECs, MBCP program management advised PEA to exclude Bucket 3 products from each of the prospective supply scenarios.

Hydroelectric Energy Purchases

Certain of MBCP's indicative supply scenarios include prospective energy purchases from larger hydroelectric generators located throughout the western United States. Larger hydroelectric generators are not eligible for California RPS certification (due to capacity limitations imposed on such resources) but are considered GHG-free for purposes of emissions accounting. Such purchases are typically arranged through transactions with power marketers, which may have access to hydroelectric energy supply under various contracts with one or more generators, or through direct transactions with asset owners. Regional hydroelectric purchases generally reflect a modest price premium ($1-$3/MWh) relative to conventional energy alternatives.

Despite recent drought conditions, operating CCE programs have been successful in securing desired quantities of hydroelectric power, supplementing contracted renewable energy with additional hydroelectric energy to decrease the overall emissions intensity of the CCE program's total supply portfolio. However, as additional CCE programs throughout California continue to pursue implementation, it is reasonable to assume that competition for available hydroelectric energy supply will increase, which may impose upward pressure on this resource type, particularly if subsequent CCE initiatives share similar environmental objectives to those expressed by the MBCP Partnership. PEA's projected price premium for hydroelectric energy reflects assumed competition amongst CCE buyers and other market participants, resulting in increased price premiums (above those previously noted) over the ten-year Study period. To the extent that hydroelectric energy supplies are not available to MBCP, additional renewable energy resources could be procured as an alternative GHG-reduction strategy; this strategy would likely increase expected power supply costs for the MBCP program to the extent that renewable energy is substituted for hydroelectric power.

Electric Generation

Generation projects developed or acquired by the CCE 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 CCE are typically financed with long-term debt, and the annual debt service would be an element of annual CCE program costs. For purposes of this Study, PEA's analysis did not contemplate the utilization of CCE-owned/developed generating resources during the ten-year study period for reasons previously described.

Transmission and Grid Services

The CAISO charges market participants, including CCEs (via the CCE'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 MBCP's operations, but there are other grid charges that are shared across all load serving entities on a pro rata basis. These costs

[33] Note that continued discussions focused on AB1110 may result in further changes to this proposed legislation, some of which may affect GHG accounting for other clean energy products. The MBCP Partnership should continue to monitor AB1110 progress prior to selecting its preferred resource mix.

would be assessed to the Scheduling Coordinator for the CCE program, and are assumed to be directly passed through to the CCE program with no markup.

Start-Up Costs

Start-up costs are estimated to be approximately $2.25 million, which would provide necessary program funding during the approximate twelve-month period immediately preceding service commencement to MBCP customers. Start-up costs include MBCP staffing and requisite professional services, security deposits, the CCE bond/financial security requirement, communications and customer notices, data management, and other activities that must occur before the program begins providing electricity to its customers. These costs would be recovered through MBCP rates after service commences. A breakdown of estimated start-up costs is shown in Table 18.

Table 18: Estimated MBCP Program Start-Up Costs

Startup Cost Category	Projected Cost ($)
Technical Study	$150,000
JPA Formation/Development	$50,000
Implementation Plan Development	$50,000
Power Supplier Solicitation & Contracting	$75,000
Staffing	$708,750
Consultants and Legal Counsel	$600,000
Marketing & Communications	$270,000
Security Deposits	$22,500
Service Fees	$37,500
CCA Bond	$100,000
Miscellaneous Administrative & General	$187,500
Total	**$2,251,250**

MBCP start-up cost estimates are based on expenses incurred during the pre-launch activities of California's operating CCE programs. More specifically, PEA developed a start-up cost profile in consideration of the actual experiences of California's operating CCE programs, then scaled MBCP start-up cost estimates based on relative size (electric energy requirements) and customer composition when compared to the representative start-up cost profile. A detailed description of each cost item is provided below.

<u>Internal Staffing</u>: As an independently operating JPA, it is assumed that the MBCP program will begin to hire its own staff (on an interim or full-time basis, depending on specific job responsibilities) twelve months prior to service commencement.

<u>Technical Consulting and Legal Services</u>: Includes services provided by experienced firms and/or individuals to support the following pre-launch activities: contract negotiations (with data management providers and energy suppliers), regulatory and compliance reporting, load forecasting, rate design and ratesetting, customer rate analysis, joint mailer content development, pro forma and budget development, and other portfolio management services. Costs also include discussions, technical analysis, and negotiations (with banking and financial institutions) related to securing financing for Program operations. This line item generally addresses related costs that will be incurred during the twelve-month period immediately preceding MBCP launch.

Marketing and Communications: Includes costs specific to marketing, communications and customer outreach, which are assumed to be outsourced services for purposes of this Study. Additional costs include the design and printing of marketing materials, advertising across various media, and sponsorship of community events.

Customer Noticing and Mailers: Includes costs associated with the first two customer mailers (printing and postage), which will be sent to prospective customers prior to service commencement – these notices are also commonly referred to as "opt-out notices." Estimates are based on costs incurred by existing CCE programs.

Security Deposits: Includes amounts required to satisfy the PG&E security deposit, which equates to the monthly average PG&E service fee to be incurred by MBCP during its first year of operation. The security deposit is typically posted around the same time as the CCE Bond (which will be posted with the CPUC).

Miscellaneous Administrative and General: Includes additional overhead during the twelve-month period immediately preceding service commencement. Some of these costs include travel, office supplies, and rent for office space.

CCE Bond: An amount equal to $100,000, which MBCP would be required to post with the CPUC prior to launching the Program. For purposes of this Study, it is assumed that the CCE Bond is posted upon certification of the Implementation Plan.

Debt Service: Includes interest and principal payments associated with initial program financing. Such payment obligations are expected to commence four months prior to service commencement. Depending on SVCEE's final credit structure, MBCP could potentially negotiate terms that are more closely aligned with the anticipated timing of rate revenue receipt. MBCP's "bridge-financing", which is required to ensure that the Program has adequate working capital at the time of launch and during the months immediately thereafter, is the basis for assumed debt service payments.

Other Pre-Launch Activities: Includes costs related to Implementation Plan development, product and portfolio design (i.e., the compilation and description of default and voluntary retail service options as well as requisite portfolio accounting activities to ensure that all customer commitments are satisfactorily addressed), and Request for Proposal development and administration (to secure requisite data manager services, energy products and scheduling coordinator services). Costs would be incurred by MBCP during the twelve-month period immediately preceding service commencement.

Financing Costs

MBCP would need access to capital for the primary purposes of covering anticipated start-up costs and working capital requirements as well as any other project financing needs that may arise. Working capital requirements are estimated at $10.7 million, which would cover cash flow needs, primarily arising from the timing lag between power purchase payment deadlines and the receipt of customer revenues. The noted working capital requirement is additive to the $2.25 million in start-up costs (discussed above in the "Start-Up Costs" sub-section). Typical invoicing timelines for wholesale power purchase contracts require payment (for the prior month's energy deliveries) by the 20th of each month. Customer payments (revenues) are typically received within sixty to ninety days following electricity delivery. The timing difference between cash outflows and inflows represents MBCP's working capital requirement. The possibility exists to negotiate payment timelines with power suppliers in order to reduce MBCP's initial working capital requirement. For example, both SCP and LCE have negotiated an additional 30 days in the supplier payment timeline, which significantly reduces each organization's working capital need.

Billing, Metering and Data Management

PG&E provides billing and metering services for all CCE programs and charges the CCE 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 CCE 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 CCEs. While PG&E issues customer bills and processes customer payments, the CCE 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.

Staff and Other Operating Costs

Internal staffing and/or contractors would be required to manage MBCP's day-to-day operations. These activities include program management, financial administration, resource planning, marketing and communications, regulatory compliance and advocacy, and other general administration. Such costs were estimated for MBCP based on a review of the publicly available budgets adopted by the currently operating CCE programs: Marin Clean Energy, Sonoma Clean Power, and Lancaster Choice Energy. Additional costs were included for administration of certain demand side programs anticipated to be offered by MBCP. These programs may include customer self-generation (net energy metering) program incentives, electric vehicle charging programs, energy efficiency and demand response programs. Included in the pro forma projections for this cost element is an assumed $1,275,000 annual budget to support the administration of such programs, which is assumed to include the funding of various customer incentives that may be offered by MBCP. MBCP may also qualify for additional funding for administration of energy efficiency programs through application to the CPUC.

Uncollectible Accounts

CCE rates must account for the small fraction of customers who do not pay their electric bill. PG&E attempts to collect the CCE'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 MBCP rates to fund a reserve account that would be used for contingencies or as a rate stabilization tool. Financing also requires generation of net revenues 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

MBCP 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 CCE 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 CCE Bond amount reflects the currently applicable specification ($100,000). However, the CCE 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

MBCP customers will pay the CCE'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 CCE 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 CCE 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 CCE service are not shifted to remaining PG&E bundled service customers (following a customer's departure from PG&E to CCE service). For purposes of this Study, PEA's assumed surcharges reflect PG&E's current tariff rates 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 2. Ratepayer costs and benefits are evaluated on the basis of the total electric rates customers would pay under CCE service as compared to PG&E bundled service. Total electric rates include the rates charged by the CCE 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 CCE program's investments in local generation resources.

When assessing the comparative environmental impacts associated with each of MBCP'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, MBCP'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 MBCP Partnership continue to monitor the relicensing status of DCPP as expiration of the existing licenses approaches.

As previously discussed (in Section 2), it is important to keep in mind the planned phase-in strategy for the prospective MBCP customer base, which is expected to occur over a 25-month period. The projected operating results reflected in the Study demonstrate the impacts of a phase-in strategy that would enroll customers in the following manner: 1) one-third of prospective MBCP customers would be enrolled during the first month of service, drawing from a broad, representative cross section of the entire MBCP customer base; 2) another third of the original customer population (i.e., half of the remaining customer population which had yet to be enrolled) would be transitioned to CCE service during the thirteenth month of operation, reflecting similar characteristics when compared with the first phase; and 3) all remaining customers not previously enrolled would be transitioned to CCE service during the twenty fifth month of program operations.

Scenario 1 Study Results

Ratepayer Costs

It is generally appropriate to characterize Scenario 1 as an "optimized" supply scenario under which MBCP's projected clean energy purchases are maximized subject to the imposition of a rate constraint, which required that MBCP's rates did not exceed projected PG&E rates throughout the Study period. This objective was achieved through the predominant use of Bucket 1-eligible renewable energy supply, minimal hydroelectric supply (in Year 1 only) and no unbundled RECs. Consistent with PEA's expectations, significant GHG emissions reductions were projected to occur throughout the ten-year Study period while maintaining general rate parity with PG&E. Levelized MBCP rates over the Study period are generally projected to be equivalent to similar PG&E rate projections. For example, a typical household using 446 kWh per month, would receive a very modest monthly cost savings averaging $0.42 over the ten-year Study term – as previously noted, projected MBCP rates are generally equivalent to projected PG&E rates.

Projected average rates for the MBCP customer base are shown in Figure 14 and Table 19, comparing total ratepayer impacts under the PG&E bundled service and CCE service options.

Figure 14: Scenario 1 Annual Ratepayer Costs

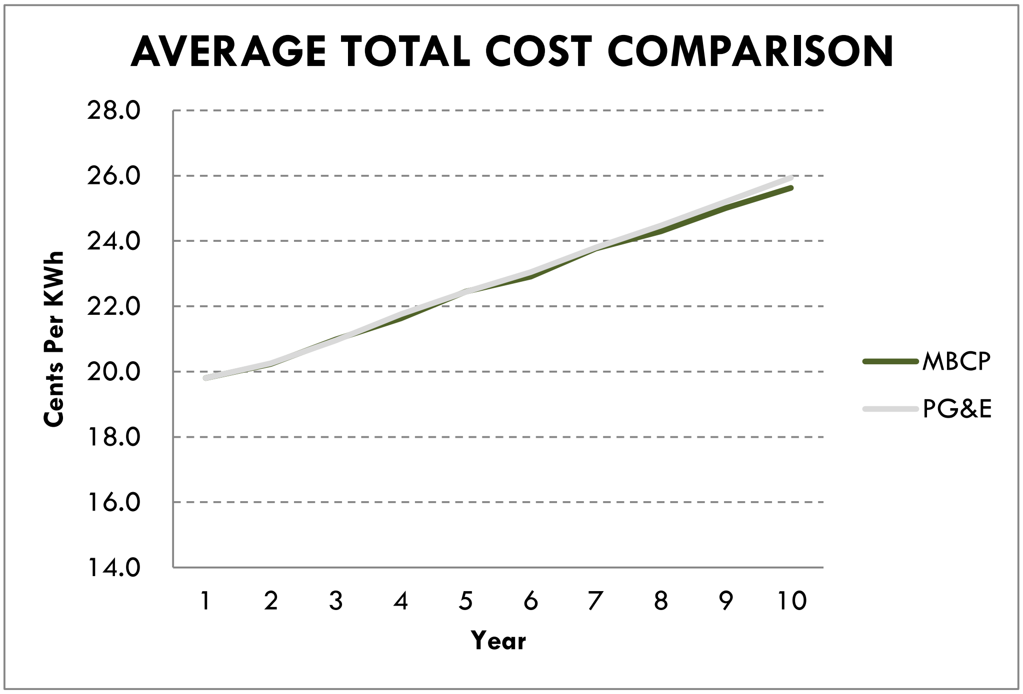


Table 19: Scenario 1 - Annual Total Delivered Rate Comparison

Year	PG&E Total (₵/kWh)	MBCP Total (₵/kWh)	Percent Difference
Levelized	22.82	22.73	0%
1	19.80	19.80	0%
2	20.25	20.23	0%
3	20.96	20.99	0%
4	21.75	21.63	-1%
5	22.44	22.45	0%
6	23.05	22.91	-1%
7	23.80	23.77	0%
8	24.48	24.30	-1%
9	25.21	25.01	-1%
10	25.94	25.63	-1%

GHG Impacts

Consistent with the primary Scenario 1 planning objective, MBCP's anticipated GHG emissions reductions are significant when compared to projected GHG emissions of the PG&E supply portfolio. Predominant use of Bucket 1-eligible renewable energy supply, coupled with a modest amount of hydroelectric energy supply in Year 1, was assumed when framing the Scenario 1 supply portfolio. The following figures and tables provide additional detail regarding the respective GHG emissions profile associated with the assumed MBCP and PG&E supply portfolios.

Figure 15: Scenario 1 – Annual GHG Emissions Comparison

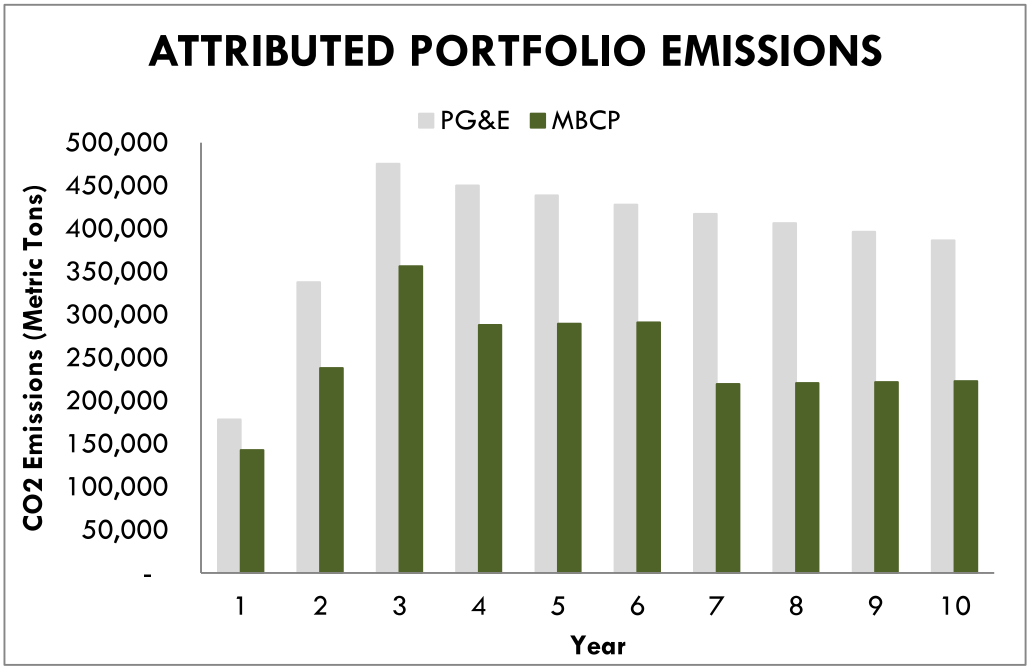


Table 20: Scenario 1 - Annual GHG Emissions Factor Comparison (Metric Tons CO_2/MWh)

Year	PG&E	MBCP
1	0.158	0.126
2	0.149	0.105
3	0.139	0.104
4	0.131	0.084
5	0.127	0.084
6	0.123	0.084
7	0.120	0.063
8	0.116	0.063
9	0.112	0.063
10	0.109	0.063

Figure 16: Scenario 1 – Annual Renewable Energy Content Comparison

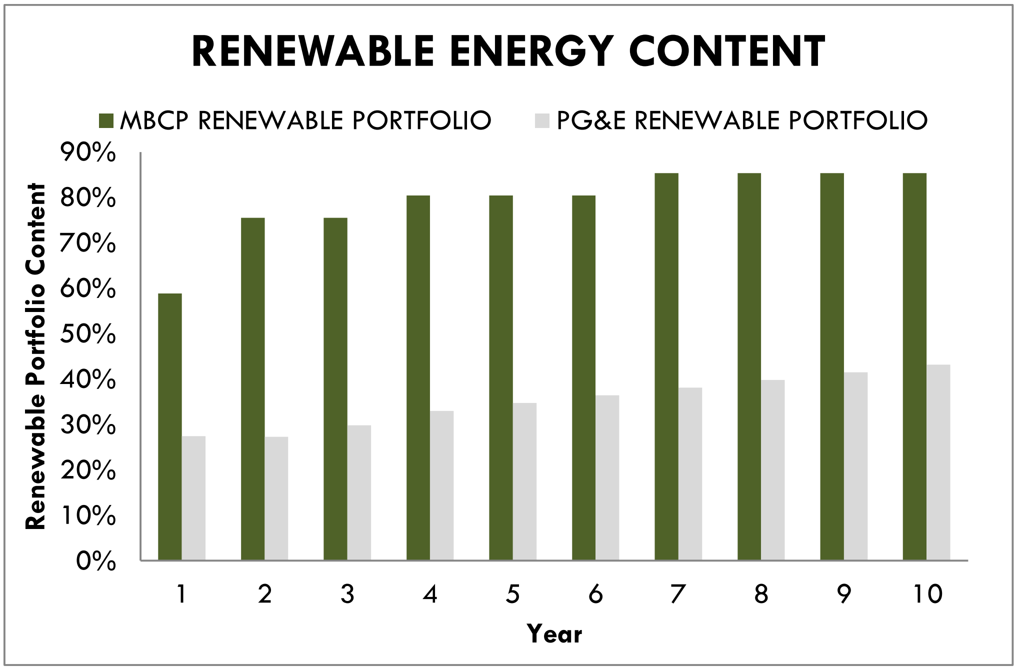


Table 21: Scenario 1 - Annual Renewable Energy Portfolio Content

Year	PG&E	MBCP
1	27%	59%
2	27%	76%
3	30%	76%
4	33%	80%
5	35%	80%
6	36%	80%
7	38%	85%
8	40%	85%
9	42%	85%
10	43%	85%

Scenario 2 Study Results

Ratepayer Costs

Similar to Scenario 1, the primary objective of Scenario 2 was to maximize GHG emissions reductions while maintaining projected generation rates that were generally equivalent to similar rate projections for PG&E. However, a different resource mix was utilized to achieve MBCP's desired objective under Scenario 2: only Bucket 1- and Bucket 2-eligible renewable energy resources were used to promote the achievement of MBCP's clean energy objectives; similar to MBCP's other indicative supply scenarios, no unbundled RECs were included in Scenario 2. Consistent with PEA's expectations, significant GHG emissions reductions were projected to occur throughout the ten-year Study period while maintaining general rate parity with PG&E. Levelized MBCP rates over the Study period are generally projected to be at or slightly below similar PG&E rate projections. For example, a typical MBCP household using 446 kWh per month, would receive a very modest monthly cost savings averaging $0.68 during the ten-year Study period – as previously noted, projected MBCP rates are generally equivalent to projected PG&E rates.

Projected average rates for the MBCP customer base are shown in Figure 17 and Table 22, comparing total ratepayer impacts under the PG&E bundled service and CCE service options.

Figure 17: Scenario 2 Annual Ratepayer Costs

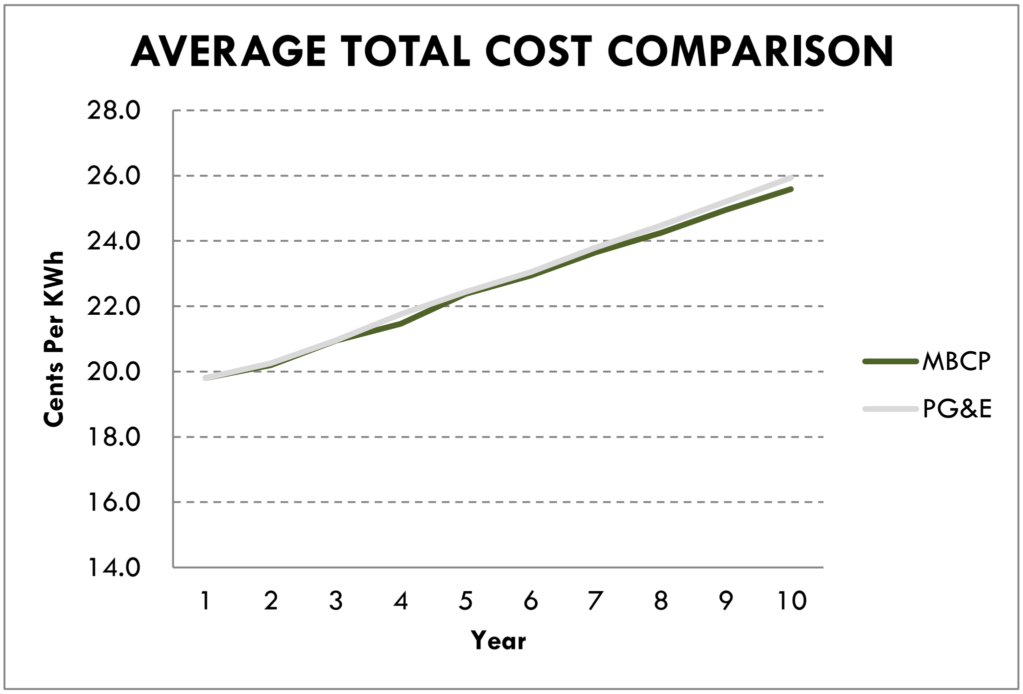


Table 22: Scenario 2 - Annual Total Delivered Rate Comparison

Year	PG&E Total (₵/kWh)	MBCP Total (₵/kWh)	Percent Difference
Levelized	22.82	22.67	-1%
1	19.80	19.80	0%
2	20.25	20.19	0%
3	20.96	20.95	0%
4	21.75	21.47	-1%
5	22.44	22.38	0%
6	23.05	22.94	0%
7	23.80	23.65	-1%
8	24.48	24.25	-1%
9	25.21	24.96	-1%
10	25.94	25.58	-1%

GHG Impacts

As a result of the significant proportion of renewable resources that were incorporated in Scenario 2, the CCE program is able to demonstrate considerable GHG emissions reductions when compared to PG&E's projected emissions profile. The following figures and tables provide additional detail regarding the respective GHG emissions profile associated with the assumed MBCP and PG&E supply portfolios.

Figure 18: Scenario 2 – Annual GHG Emissions Comparison

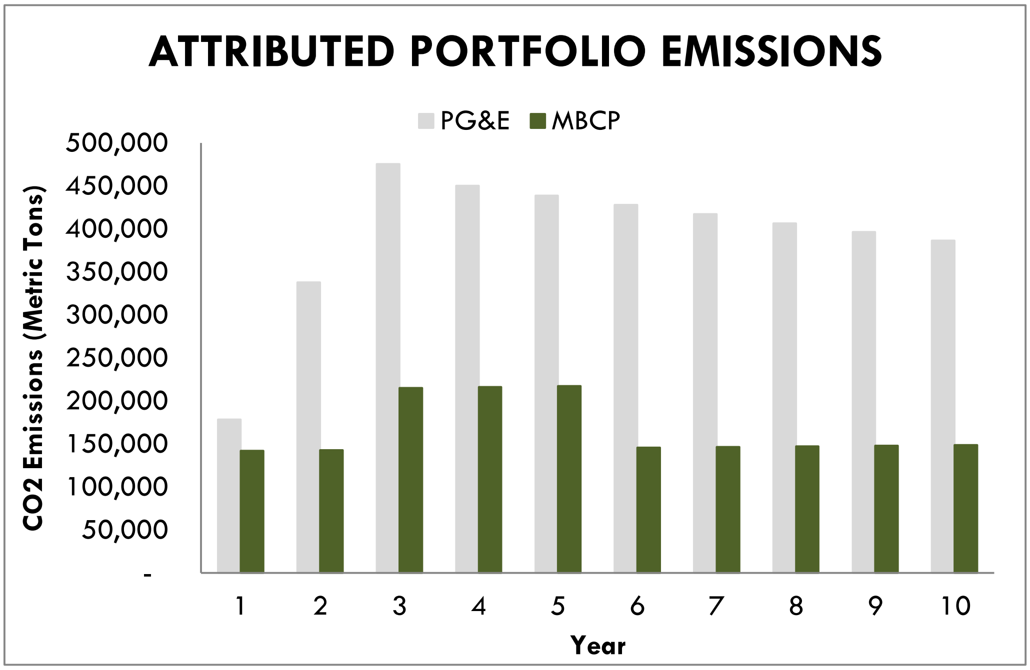


Table 23: Scenario 2 - Annual GHG Emissions Factor Comparison (Metric Tons CO_2/MWh)

Year	PG&E	MBCP
1	0.158	0.126
2	0.149	0.063
3	0.139	0.063
4	0.131	0.063
5	0.127	0.063
6	0.123	0.042
7	0.120	0.042
8	0.116	0.042
9	0.112	0.042
10	0.109	0.042

Figure 19: Scenario 2 – Annual Renewable Energy Content Comparison

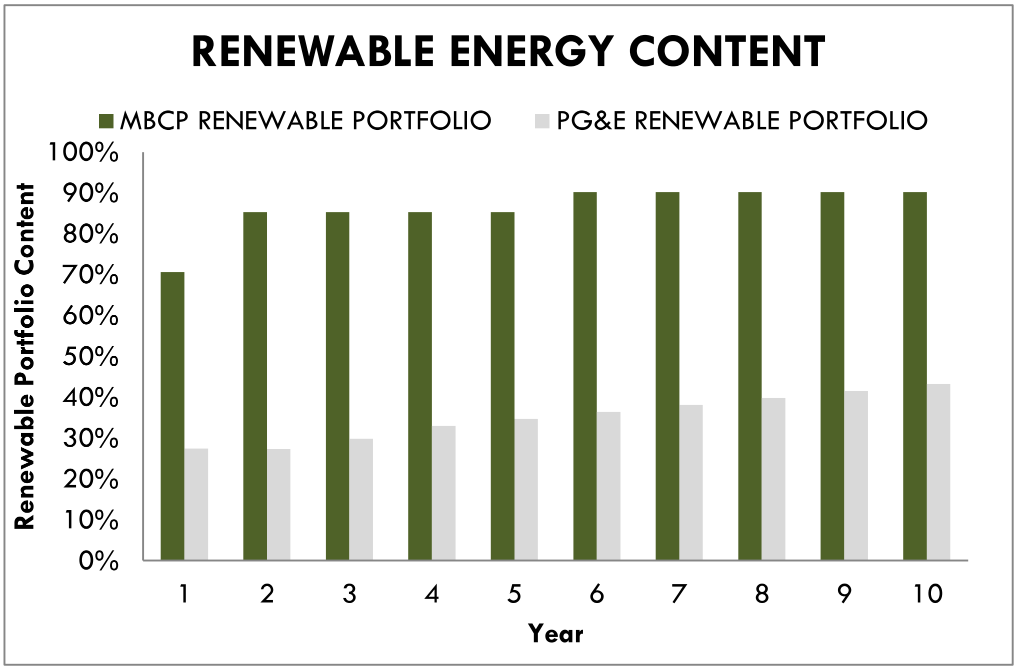


Table 24: Scenario 2 - Annual Renewable Energy Portfolio Content

Year	PG&E	MBCP
1	27%	71%
2	27%	85%
3	30%	85%
4	33%	85%
5	35%	85%
6	36%	90%
7	38%	90%
8	40%	90%
9	42%	90%
10	43%	90%

Scenario 3 Study Results

Ratepayer Costs

Scenario 3 was constructed for the primary purposes of maximizing MBCP rate competitiveness while also achieving annual 25% emissions reductions (relative to PG&E projections) throughout the ten-year Study period. To achieve these objectives, Scenario 3 incorporated a diverse portfolio of clean energy resources, utilizing Bucket 1- and Bucket 2-eligible renewable energy as well as significant amounts of hydroelectricity. The indicative supply portfolio reflected in Scenario 3 resulted in levelized MBCP cost savings approximating 4% of total electricity charges during the ten-month Study period (during this period, projected annual cost savings range from 3% to 5%). For a typical MBCP household using 446 kWh per month, this equates to an average monthly cost savings of $4.50 during the ten-year Study period.

Projected average rates for the MBCP customer base are shown in Figure 20 and Table 25, comparing total ratepayer impacts under the PG&E bundled service and CCE service options.

Figure 20: Scenario 3 Annual Ratepayer Costs

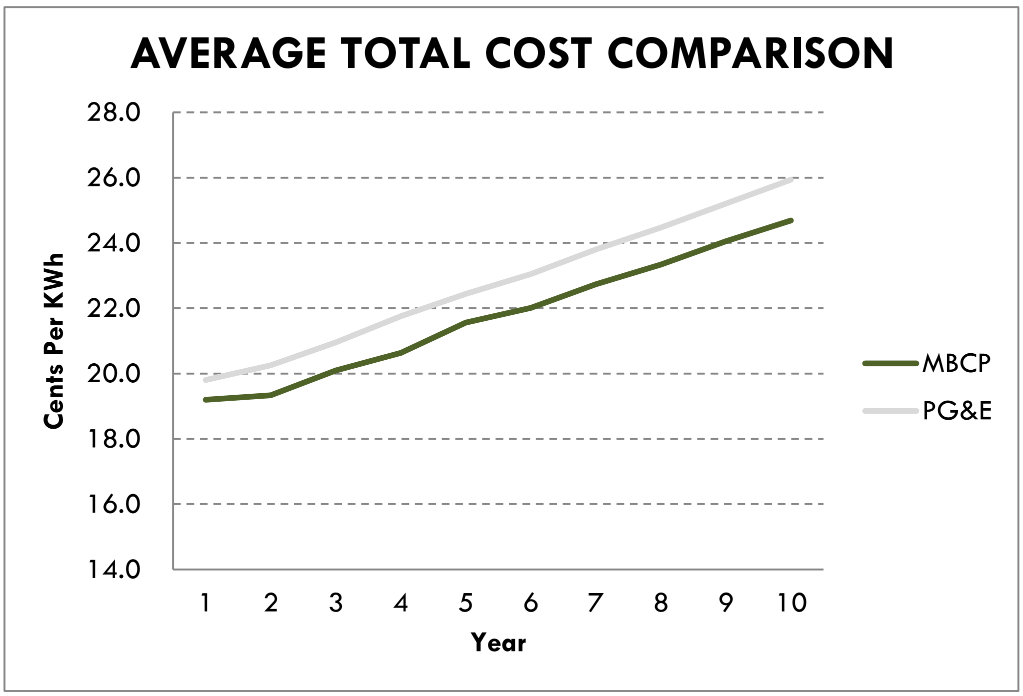


Table 25: Scenario 3 - Annual Total Delivered Rate Comparison

Year	PG&E Total (₵/kWh)	CCE Total (₵/kWh)	Percent Difference
Levelized	22.82	21.80	-4%
1	19.80	19.20	-3%
2	20.25	19.33	-5%
3	20.96	20.10	-4%
4	21.75	20.64	-5%
5	22.44	21.56	-4%
6	23.05	22.01	-4%
7	23.80	22.73	-4%
8	24.48	23.34	-5%
9	25.21	24.05	-5%
10	25.94	24.69	-5%

GHG Impacts

Through the use of a diverse portfolio of clean energy resources, Scenario 3 reflects 25% annual GHG emissions reductions when compared to PG&E's projected emissions profile. The following figures and tables provide additional detail regarding the respective GHG emissions profile associated with the assumed MBCP and PG&E supply portfolios.

Figure 21: Scenario 3 – Annual GHG Emissions Comparison

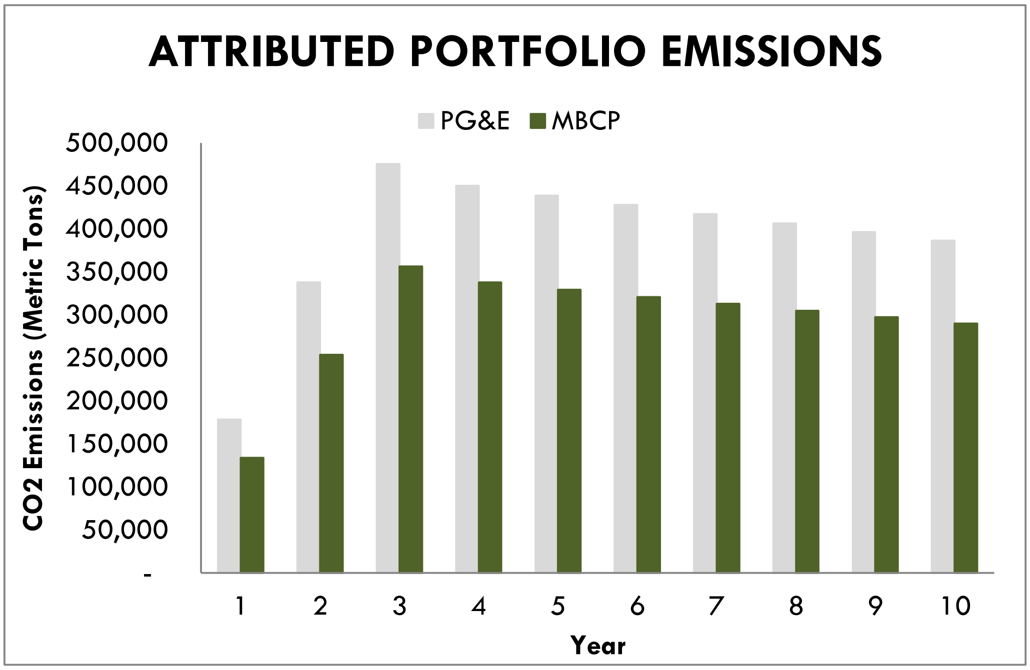


Table 26: Scenario 3 - Annual GHG Emissions Factor Comparison (Metric Tons CO_2/MWh)

Year	PG&E	MBCP
1	0.158	0.119
2	0.149	0.112
3	0.139	0.104
4	0.131	0.098
5	0.127	0.095
6	0.123	0.092
7	0.120	0.090
8	0.116	0.087
9	0.112	0.084
10	0.109	0.082

Figure 22: Scenario 3 – Annual Renewable Energy Content Comparison

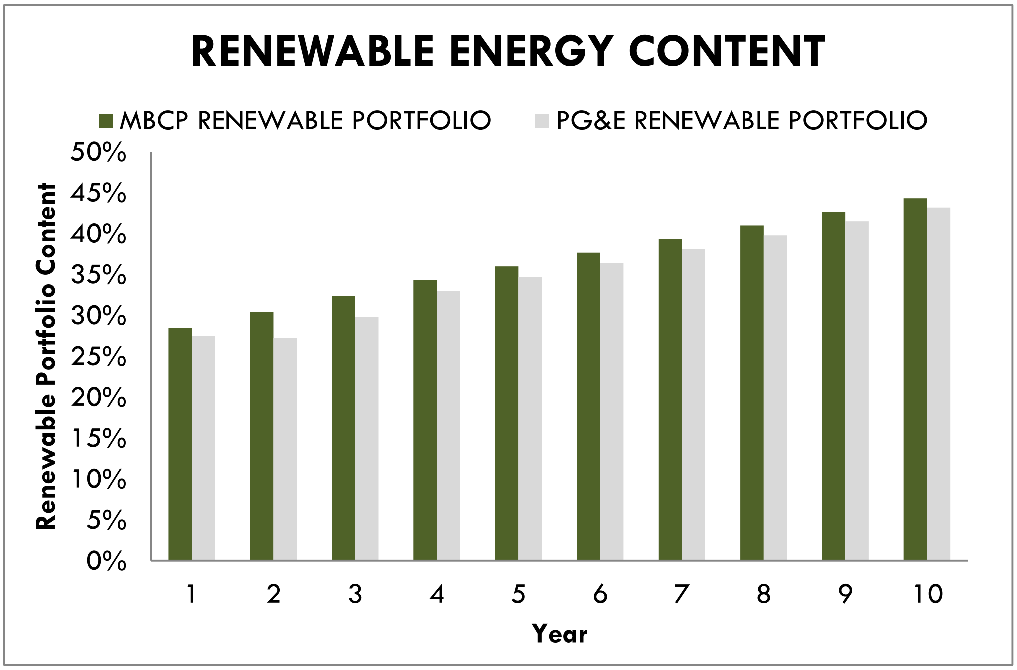


Table 27: Scenario 3 - Annual Renewable Energy Portfolio Content

Year	PG&E	MBCP
1	27%	28%
2	27%	30%
3	30%	32%
4	33%	34%
5	35%	36%
6	36%	38%
7	38%	39%
8	40%	41%
9	42%	43%
10	43%	44%

SECTION 6: SENSITIVITY ANALYSES

The economic analysis uses base case input assumptions for many variable factors that influence relative costs of the CCE 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. Additionally, a “small JPA” sensitivity case was run reflective of minimal community participation in the MBCP joint powers agency to test the viability of a much smaller CCE program, and a “perfect storm” sensitivity was run to examine the cumulative impacts of adverse changes to the key variables.

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. This fact is consistent with how PEA developed the ten-year power price forecast in which a detailed natural gas forecast was assembled and then converted to power prices using factors consistent with industry standards. Changes in natural gas prices will also tend to change the power purchase costs of the CCE program. To the extent that MBCP’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 CCE program relative to PG&E.

For the CCE 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. 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 MBCP’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 CCE program.

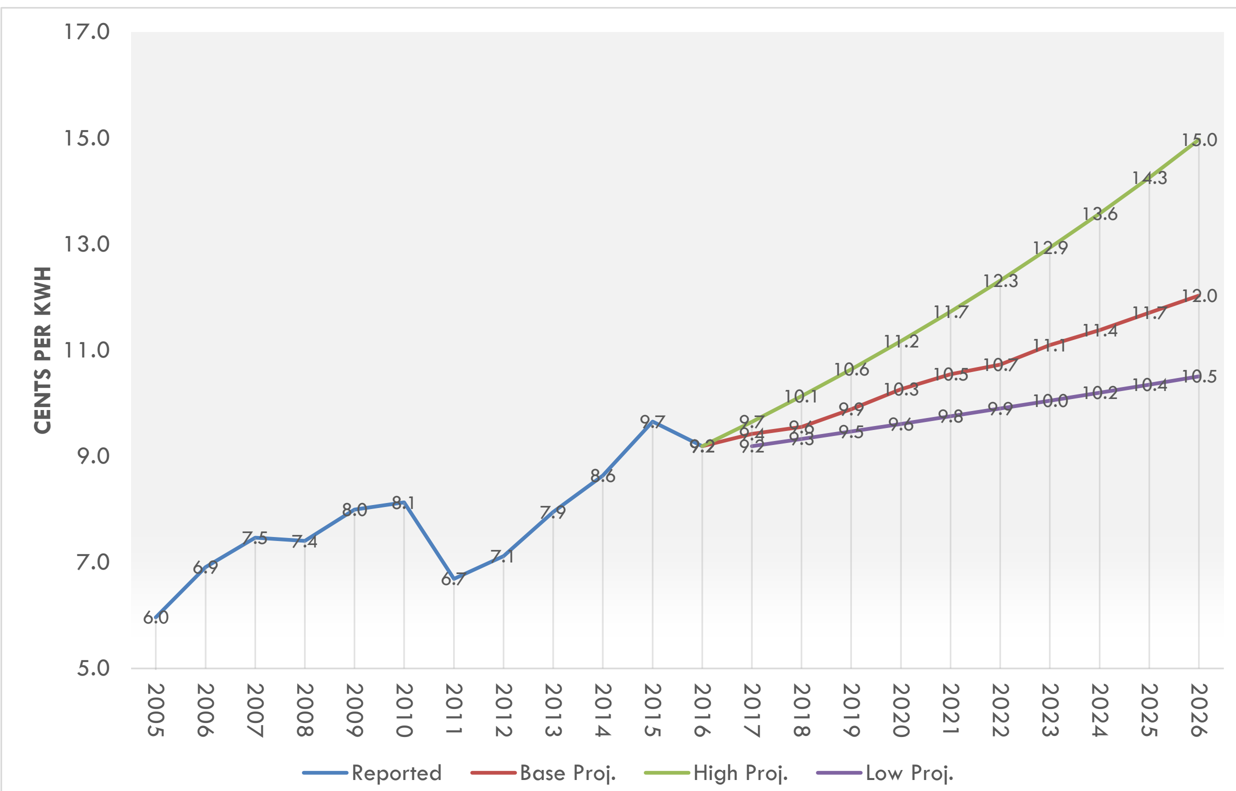
Carbon-Free Energy Costs

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 CCE demand for low carbon energy content 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 CCE 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.

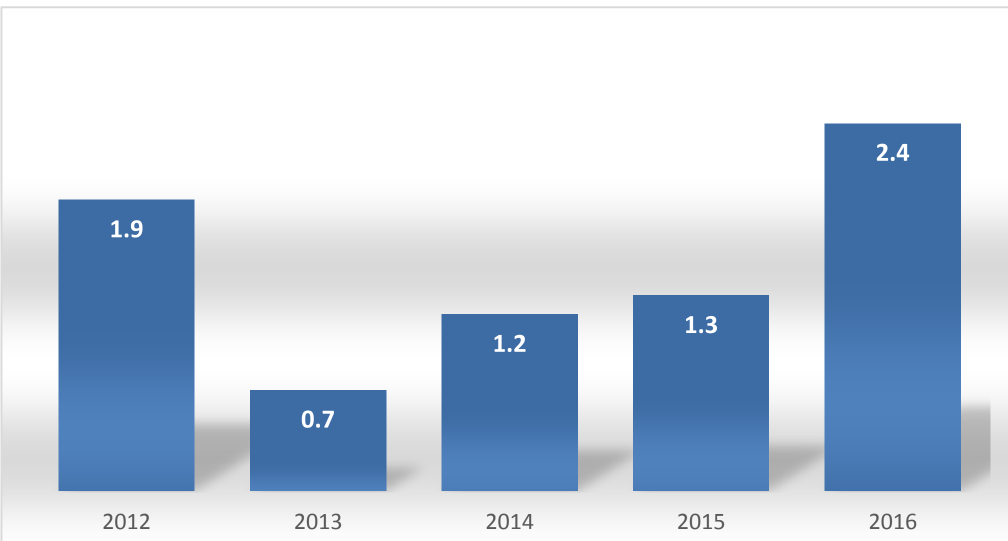
Figure 23: PG&E System Average Generation Rates



PG&E Surcharges

The PCIA and Franchise Fee surcharges directly impact MBCP rate competitiveness, and the PCIA has been volatile. On January 1, 2016, the PCIA rate applicable to all customers within the PG&E service territory increase substantially. For example, PG&E's average residential PCIA rate increased approximately 95% relative to similar charges that were effective in 2015.[34] In general terms, the PCIA is set on an annual basis in consideration of a specified methodology that takes into consideration the difference in costs associated with PG&E's supply portfolio and a market benchmark – to the extent that costs associated with the PG&E supply portfolio exceed the market benchmark, departing customers, including CCE customers, are subject to a PCIA surcharge. The specific methodology that is employed when determining the PCIA is subject to CPUC oversight, and PG&E must perform related PCIA calculations consistent with such methodology. Over time, PCIA charges will change based on the relationship between PG&E's power portfolio costs and current market pricing. In concept, the PCIA should diminish (and eventually expire) over time, as PCIA charges are directly associated with PG&E power contracts, all of which should have finite term lengths. Once such contracts expire, any related PCIA impacts should fall to zero. However, because PG&E engages in ongoing contracting efforts, PCIA charges may persist for 20 years or more (but should diminish over time). 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.

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



The base case PCIA projections begin with the currently effective 2016 PCIA charges and remain relatively flat throughout 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 CCE program was tested by varying the opt-out rate from 25% in the high case to 5% in the low case. 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.

[34] PG&E Advice Letter AL-4696-E-A.

Community Participation (Small JPA)

While the base case includes all municipalities as participants in the JPA, a sensitivity was run to examine the impacts of a much smaller program being formed in the region. For purposes of this sensitivity, it was assumed that 25% of the total potential customers are offered service in the CCE and that 15% of these customers elect to opt-out. Adjustments were made to assumed staffing costs to reflect the smaller scale of operations. The long term renewable contract portfolio was adjusted downward on a pro rata basis to reflect the reduced energy requirements. The results of this sensitivity indicate that a viable program could be operated with significantly less than 100% participation of the prospective communities.

Perfect Storm

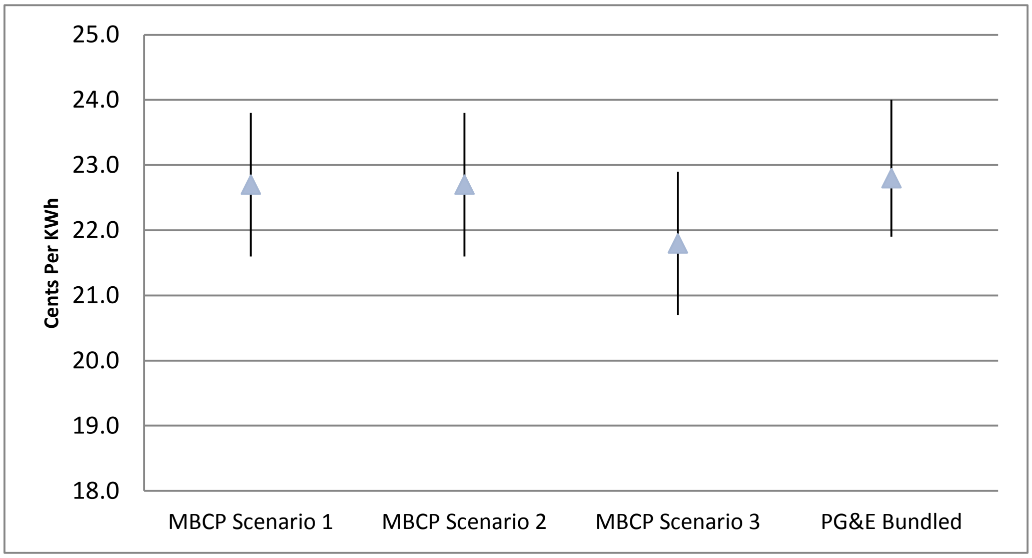
This sensitivity examines the cumulative effects of adverse changes to all of the key variables to present what could be considered a worst case. The likelihood that all of these variables change in unison is remote; many of the key variables are negatively correlated meaning that increases in one variable would normally be associated with decreases in another. For example, increases in market prices for power should result in decreases in the PG&E surcharges, but for purposes of this sensitivity it was assumed that the PG&E surcharges would also increase. This sensitivity was constructed with the following assumptions: high natural gas/power prices, high renewable energy and low carbon energy costs, high PG&E surcharges, high customer opt-out rates, and low PG&E rates.

Sensitivity Results

The sensitivity analysis produced a range of levelized electric rates for the CCE program and PG&E as shown in the Figure 25.[35] When reviewing this figure, the base case outcomes associated with each scenario are represented by the "arrowheads" that are positioned along each vertical line – to the extent each line extends above (or below) the arrowhead, this represents the potential for customer rates to be higher (or lower) than the base case outcomes. 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 CCE program, any of the CCE Scenarios could potentially result in lower ratepayer costs than under the status quo. The sensitivity analysis for the Perfect Storm scenario is discussed above but not included in Figure 25 as it is very unlikely to occur and would distort the results presented in the figure. Rate outcomes for all conditions analyzed are included in Table 28 and Figures 26 and 27.

[35] The ranges shown in Figure 25 do not include the Small JPA and Perfect Storm sensitivities.

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 and PG&E Surcharges had the greatest impact on MBCP rates in Scenario3, while renewable energy costs were an increasingly important driver of MBCP rates in Scenarios 1 and 2. Table 28 provides additional detail regarding potential impacts to MBCP and PG&E rates that could result under each sensitivity variable. Note: within Table 28, yellow highlighted cells indicate sensitivity scenarios in which MBCP rates are projected to exceed similar rates charged by PG&E; stated somewhat differently, the yellow highlighted cells draw attention to market conditions that are expected to impose larger rate changes on MBCP than PG&E.

Table 28: 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	Perfect Storm
MBCP Scenario 1	22.7	23.4	22.4	23.5	21.9	22.7	22.7	23.8	21.6	22.7	22.7	22.7	24.9
MBCP Scenario 2	22.7	23.3	22.3	23.4	21.9	22.7	22.7	23.8	21.6	22.7	22.6	22.7	24.8
MBCP Scenario 3	21.8	22.5	21.5	22.3	21.3	21.8	21.8	22.9	20.7	21.8	21.8	22.1	24.1
PG&E Bundled	22.8	23.5	22.5	22.8	22.8	24.0	21.9	22.8	22.8	22.8	22.8	22.8	22.8

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

Figure 26: Scenario 1 Sensitivity Impacts on Levelized Electric Rates

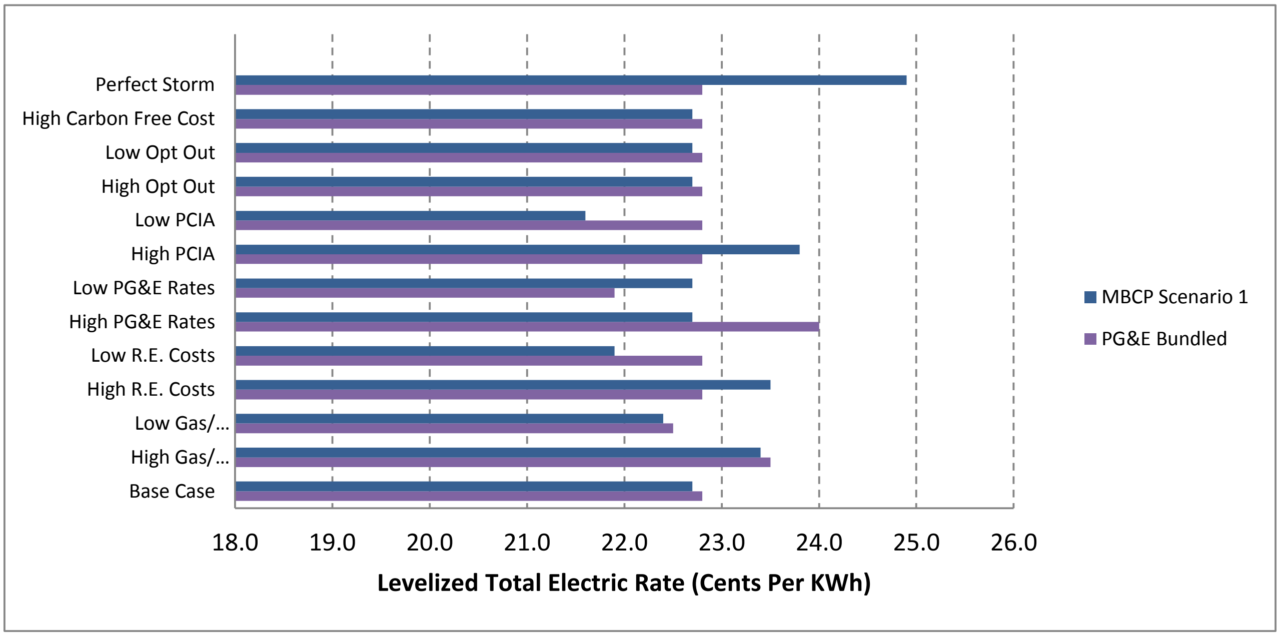


Figure 27: Scenario 2 Sensitivity Impacts on Levelized Electric Rates

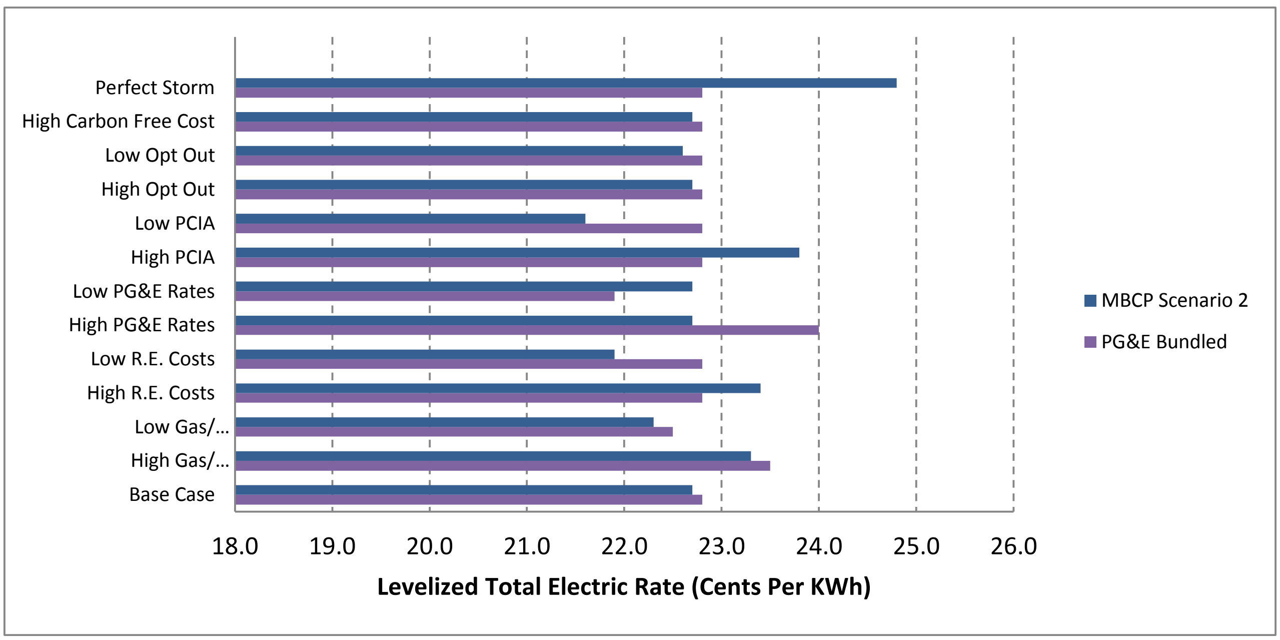
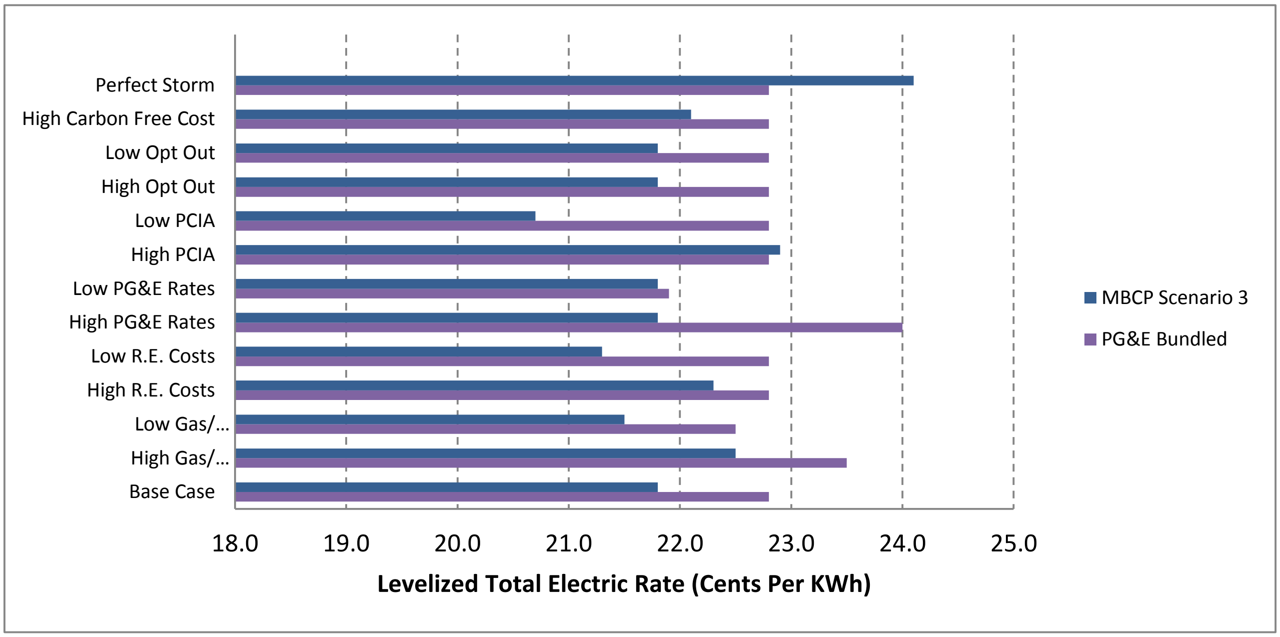


Figure 28: Scenario 3 Sensitivity Impacts on Levelized Electric Rates



Additional Operating Sensitivity: High Local Renewable Infrastructure Buildout

During an April 2016 meeting of MBCP's Project Development Advisory Committee ("PDAC"), PEA was asked to complete an additional sensitivity analysis addressing the prospect of increased local renewable infrastructure buildout under an expanded Feed-In Tariff program (relative to the base case supply portfolio assumptions reflected throughout this Study). In particular, the "High FIT Sensitivity" was completed to address the prospect of an MBCP administered FIT program with an overall participatory cap of 100 MW (relative to the base case assumption of 20 MW) and increased pricing levels (relative to the base case) designed to promote additional project participation/development throughout the prospective MBCP service territory. At the PDAC's request, PEA completed this analysis, the results of which have been summarized in Appendix C.

SECTION 7: RISK ANALYSIS

CCE formation is not without risk, and a key element of this Study is highlighting risks that may be faced by the CCE program as well as related risk-mitigation measures. Several of the quantitative impacts associated with key risks have been addressed in Section 6, Sensitivity Analyses. However, there are additional risk elements of which any aspiring CCE 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 MBCP's member municipalities in the unlikely event of CCE 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 CCE's ability to remain competitive with the incumbent utility;
- Availability of renewable and carbon-free energy supplies required to meet compliance mandates, MBCP program goals, and customer commitments; and
- General market volatility and price risk.

Financial Risks to MBCP Members

In general terms, the prospective financial risks to MBCP 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 was 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 CCE 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 CCE 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 CCE 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 CCE evaluation and JPA formation as well as any financial guarantees that may be offered to support startup, financial obligations of the participating communities would be limited to individual customer impacts in the event of outright CCE failure. In such a scenario, the $100,000 CCE bond is intended to cover the costs of returning customers to PG&E service. However, following an involuntary return to bundled service, CCE customers would be individually required to pay the PG&E Transitional Bundled Commodity Cost (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.[36] 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 electric power sector could result in relatively high customer costs in the short-term, following an involuntary return to bundled service at a time

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

when market prices are higher than PG&E's prevailing generation rates. Depending on future market conditions during a time of involuntary customer return to PG&E service, cost impacts during the six-month transition period could be +/-25% (or more, depending on actual market prices) relative to otherwise applicable PG&E rate schedules. In practical terms, the likelihood of this risk materially impacting a MBCP customer appears to be quite low.

PEA also assumes that one or more of the MBCP Communities may choose to make financial contributions for purposes of completing MBCP's formative and start-up activities. At the time of JPA formation, PEA also assumes that such MBCP Communities would likely request repayment of any contributions following successful launch of the MBCP program and a yet-to-be-defined period of successful operations thereafter. Clearly, the repayment of such funding is dependent upon the successful launch and operation of the MBCP program.

For example, if MBCP fails to launch or discontinues business operations prior to repaying any funding contributed by certain of the MBCP Communities, then such community runs the risk of financial losses equivalent to any amounts expended in advance of such circumstances. Once MBCP has launched and is serving customers, it is reasonable to assume that the financial contributions that were previously made by certain MBCP Communities would be paid back within the first five years of MBCP operation.

From a practical perspective, current operating projections provide considerable safety margins for MBCP, allowing for a range of market conditions and/or rate changes before rate competitiveness would be compromised. In the event that future PG&E rate changes and/or wholesale power prices fall outside of the aforementioned safety margins, MBCP would likely defer program launch and cease incurring startup expenses until projected operations improve, potentially jeopardizing or delaying the reimbursement of any funding provided by certain of the MBCP Communities.

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 MBCP's customer base. To the extent that such imbalances exist, the CCE 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 CCE 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 CCE 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 CCE's projected energy requirements during this period of time. Beyond the 12-month operating horizon, an increasing proportion of the CCE'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 CCE 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 CCE's expected energy requirements, allowing the CCE to set rates in consideration of such costs with minimal financial/budgetary risk. For months 13-24, the CCE would reduce forward supply commitments to a level approximating 80-90% of expectations; for months 25-36, the CCE 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 CCE'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 CCE program to take advantage of favorable procurement opportunities that may come about with time. During early-stage CCE operations, this strategy is particularly useful since the CCE is unlikely to know exact customer participation levels. Over time, as the CCE's customer base becomes more stable/predictable, it will become less challenging to predict customer usage patterns. Furthermore, a laddered procurement strategy allows the CCE's portfolio composition to evolve over time as opposed to committing to a specific resource mix that would only be minimally adjustable (subject to potential adverse economic consequences) until related power supply agreements had expired.

Legislative and Regulatory Risk

California's operating CCEs can attest to the challenges presented by anti-CCE 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 CCE programs and/or limit the autonomy of CCE programs, so that such programs appear more similar to their investor-owned counterparts. Recently, SB 350 and AB 1110 presented such issues. However, California's operating CCEs were able to address many of the potentially detrimental changes included within these bills through effective lobbying and technical support. California's IOUs regularly rely on professional lobbyists to promote their respective interests within the California legislature, and CCEs have successfully employed similar tactics to represent their own interests, which often differ from those of their investor-owned counterparts. Use of lobbyists within proximity to the State Capitol also mitigates logistical challenges that may be encountered when addressing time-sensitive issues that require on-site meeting participation and collaboration.

CCEs have also enjoyed similar success in California's regulatory arena by utilizing the expertise of specialized regulatory support, including qualified regulatory counsel and analysts, who have deep and long-standing familiarity with a broad range of regulatory proceedings, assigned commissioners, judges and support staff within jurisdictional agencies. Because certain proceedings have the potential to directly affect the formation and ongoing operation of CCE programs, it is critically important to retain such expertise for purposes of representing the CCEs interests, particularly if the CCE has not yet hired internal regulatory counsel and/or staff. Over time, the CCE program may choose to scale its internal regulatory staffing in consideration of the level of work required to achieve successful regulatory representation and desired outcomes.

Regarding recent legislation, on October 7, 2015, Governor Brown signed Senate Bill 350, the Clean Energy and Pollution Reduction Act of 2015, enacting pertinent clean energy mandates reflected in this legislation. In particular, SB 350 increases California's RPS to 50% by 2030 amongst other clean-energy initiatives. 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 have been created by SB 350, CCEs should be aware of the following:

- Costs associated with the integration of new renewable infrastructure may be off-set by a CCE if it can demonstrate to the CPUC that it has already provided equivalent resources [Sections 454.51(d) and 454.52(c)];

- CCEs 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)]. Note that the CPUC recently (on February 11, 2016) adopted an Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning and to Coordinate and Refine Long-Term Procurement Planning Requirements, which will begin the process of addressing the Integrated Resource Plans of CCEs;

- 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 CCE service options, and (2) CCE customers do not experience any cost increases as a result of IOU cost allocation that is not directly related to such CCE customers (Sections 365.2 and 366.3);

- Beginning in 2021, CCEs must have at least 65% of their RPS procurement under long-term contracts of 10 years or more [Section 399.13(b)]; and

- CCE energy efficiency programs will be able to count towards statewide energy efficiency targets [Sections 25310(d)(6) and 25310(d)(8)].

In aggregate, the CCE-specific changes reflected in SB 350 are generally positive, providing for ongoing autonomy with regard to resource planning and procurement. CCEs must be aware, however, of the long-term contracting requirement associated with renewable energy procurement. This is not expected to present issues for MBCP, but planning and procurement efforts will need to consider this requirement during ongoing operation of the CCE 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 2015 legislative session, CCE 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.[37] With this direction in mind, AB 1110 is no longer an issue in the current legislative session. However, PEA recommends that the MBCP Partnership continue monitoring 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 MBCP 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 MBCP at some point in the future.

Another piece of pending legislation that could pose direct and indirect impacts on CCE programs is SB 286 (Hertzberg). SB 286 was originally introduced during the 2015 legislative session (has now been converted into a two-year bill) with the goal of increasing the direct access participatory cap by approximately 33%. In its current form, SB 286 suggests that new direct access customers would be required to contract for 100% renewable energy. If passed during the 2016 legislative session, SB 286 could either spark additional renewable development, which could keep prices stable, or push renewable prices upward due to the increased demand. Additionally, raising the direct access cap could put more pressure on CCE programs to offer even more price competitive products to retain large commercial and industrial customers.

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 ("CAM"), 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 (CCE and direct access) customers; and 2) the PCIA as previously discussed.

CAM is a mechanism that allows investor owned utilities to impose a portion of the costs associated with their power purchases onto CCE customers, even though these purchases are for fossil fuel resources with prices that are often above current market levels. In theory, the goal of CAM is to promote grid reliability and should only be applied to resources that contribute in that regard; in practical terms, the investor owned utilities have

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

obtained CPUC-approved CAM treatment for many types of generating resources. Bundled, CCE, and direct access customers pay for CAM in the form of the New System Generation Charge ("NSGC"). The NSGC imposes costs on CCE customers that often seem to be duplicative in light of long-term capacity commitments that have already been made by CCEs in the form of various power purchase agreements (which can include capacity attributes as an element of the purchased product). In other words, the present CAM methodology does not appear to adequately reflect the contribution being made by CCEs in terms of promoting capacity buildout within California's energy market and generally undermines CCE procurement autonomy through the imposition of costs that are not associated with contracts voluntarily entered into by the CCE.

One of the only tangible benefits realized by CCE's under the current CAM rules is an offsetting capacity allocation, which slightly reduces monthly resource adequacy requirements of the CCE entity. As previously noted, the passage of SB 350 requires that CCEs have at least 65% of applicable RPS procurement under long-term contracts, and existing CCEs have already demonstrated a track record of long term contracting notwithstanding the pending requirements of SB 350. Such contracts typically confer capacity benefits associated with the contracted resources, which could result in diminished value of CAM capacity allocations, as many CCEs would have already procured a significant portion of applicable capacity requirements through requisite renewable energy contracting efforts – stated somewhat differently, the CAM charges imposed on CCE customers would result in little capacity value for CCE customers due to the fact that many CCEs would have already arranged for such capacity under requisite long-term contract arrangements.

Another significant regulatory risk relates to changes that may occur with regard to the CCE Bond amount. Currently, the $100,000 bond amount is quite manageable for aspiring CCE 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 MBCP Partnership actively monitor and participate in, as necessary, related regulatory proceedings to ensure that this item does not become a barrier for CCE formation or ongoing operation. As previously noted, retention of an experienced lobbyist and qualified regulatory expertise will serve to manage and mitigate the aforementioned risks.

Availability of Requisite Renewable and Carbon-Free Energy Supplies

California's recent adoption of a 50% RPS 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 CCEs, 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 CCE expansion throughout California seems quite significant, it is highly unlikely that any CCE 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 CCEs. Furthermore, to the extent that additional CCE 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 CCE buyers compete for available renewable projects, but the general availability of such projects does not seem to be a significant issue that will face MBCP over the ten-year planning horizon. It is also reasonable to assume that California-based project developers will be competing for buyers in the sense that prospective renewable development opportunities (i.e., potential renewable generating capacity) may actually exceed statewide demand. This circumstance has occurred in the past, particularly when California's largest renewable energy buyers, the IOUs, have met applicable renewable energy procurement targets – in these instances, project developers are forced to "compete" for other buyers, including CCEs, which have benefited from very favorable pricing for both short- and long-term transactions.

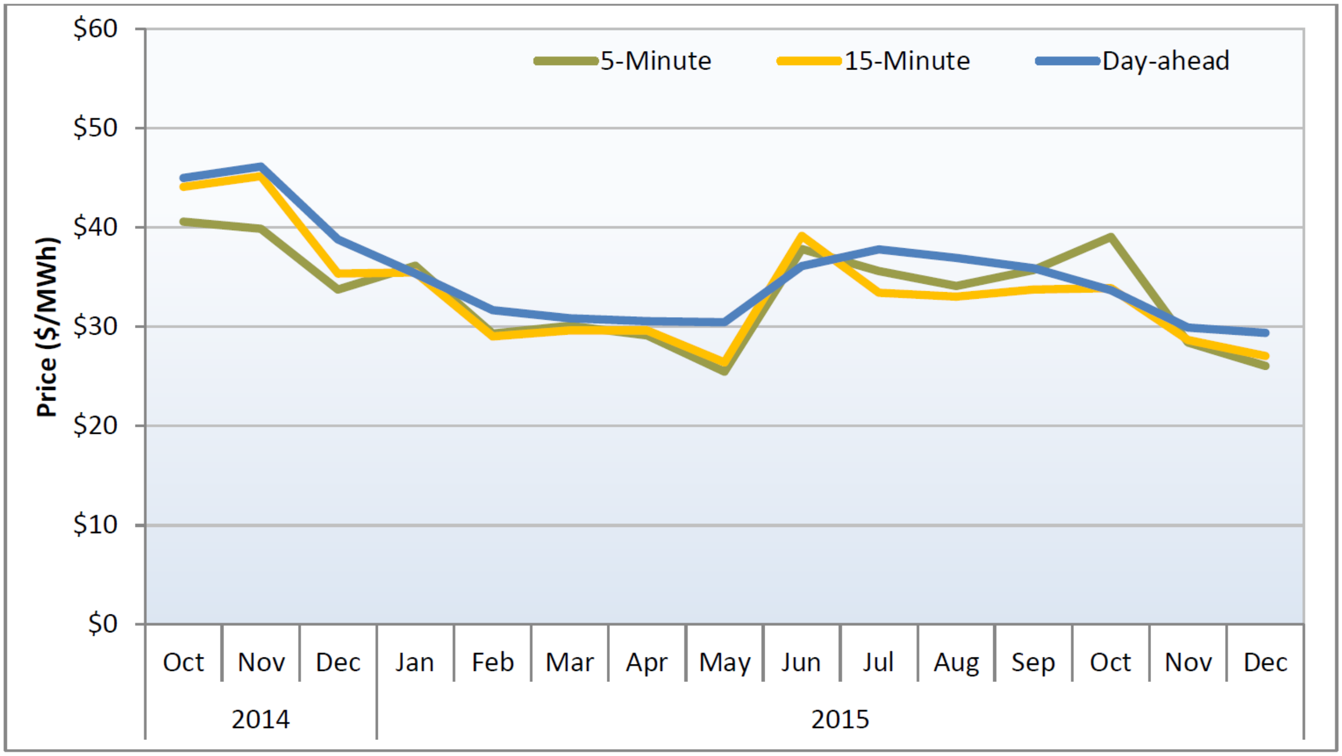
Additionally, as the operational and future CCE's strive to meet high carbon-free energy targets, there is some uncertainty around the availability of hydroelectric generation resources within California and throughout the Pacific Northwest to meet such goals. Outside of renewable energy resources, hydroelectric generation is the lowest cost means of meeting carbon-free objectives (keeping in mind that nuclear generation will be excluded from MBCP'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. To the extent that necessary hydroelectric power supply is not available, the CCE program may choose to incorporate additional renewable energy supply, likely at an increased cost, to ensure that emission reduction commitments can be satisfied.

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 30 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 a recent 15-month period.[38]

[38] California ISO Q4 2015 Report on Market Issues and Performance, February 24, 2016.

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. For example, Table 29 reflects typical guidelines associated with a laddered procurement strategy – such strategies generally attempt to balance the interests of near-term planning and budgetary certainty while moderating market price risks at any single point in time. Based on the declining percentages reflected in Table 29, this balance could be reasonably achieved while allowing for the inclusion of other, future contracting opportunities as well as planned efficiency and demand-side impacts. Such strategies have been successfully implemented by other CCE programs and are generally recognized as a prudent planning/procurement strategy. Note that the percentages reflected in Table 29 may vary in consideration of the buyer's unique preferences and tolerance for risk.

Table 29: Indicative Contracting Guidelines under a Laddered Procurement Strategy

Time Horizon	Contracting Guideline (Contractual Commitments/Total Energy Need)
Current Year	80% to 100%
Year 2	70% to 100%
Year 3	60% to 95%
Year 4 and Beyond	Up to 70%

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 CCE 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: CCE FORMATION ACTIVITIES

This section provides a high level summary of the main steps involved in forming a CCE program that culminates in the provision of service to enrolled customers. Key implementation activities include those related to 1) CCE 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.

CCE Entity Formation

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

Regulatory Requirements

Before aggregating customers, the CCE program must meet certain requirements set forth by the CPUC. In the case of MBCP, 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 CCE programs have required far less time. Following certification of the Implementation Plan, the CCE 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 CCE bond amount is $100,000.

The CCE 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. More specifically, a start-up CCE program would be required to file a formal load forecast with the CEC upon execution of a primary supply contract, which triggers a 100% commitment to program launch.

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. Once a firm commitment to offering CCE service is made, typically through execution of power supply contracts, the CCE should provide its inaugural load forecast to the California Energy Commission to initiate determination of the applicable resource adequacy requirements (i.e., capacity) for the first year of operation.

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 CCE program may be relatively small but this would likely change in the event that the CCE 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 CCE 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 CCE, MBCP would have independent ratesetting authority with regard to the electric generation charges imposed on its customers. Prior to service commencement, MBCP 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 CCE's prospective service territory. MBCP 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. MBCP would need to establish a schedule for ongoing rate updates/changes for future customer phases and ongoing operations.

MBCP 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 MBCP intends to offer such programs, specific terms and conditions of service would need to be developed in advance of service commencement.

SECTION 9: EVALUATION AND RECOMMENDATIONS

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

PEA's analysis suggests that MBCP 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, CCE program rates are projected to range from 21.8 cents per kWh to 22.7 cents per kWh, depending upon the ultimate CCE program resource mix. PG&E's generation rate is projected to be 22.8 cents per kWh, creating the potential for customer savings under each of the three supply scenarios. Table 30 shows projected levelized electric rates and typical residential monthly electric bills under the base case assumptions.

Table 30: Summary of Ratepayer Impacts

Ratepayer Impact	Scenario 1	Scenario 2	Scenario 3	PG&E
Levelized Electric Rate (Cents/KWh)	22.7	22.7	21.8	22.8
Typical Residential Bill ($/Month)[39]	$101	$100	$96	$101

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 CCE program, it is anticipated that Scenario 3 is most likely to generate customer rate savings while Scenarios 1 and 3 are most likely to result in general cost equivalency over time.

With regard to GHG emissions impacts, the ultimate resource mix identified by the CCE program will dictate actual GHG emissions impacts created by MBCP operation. Depending upon resource choices made by the CCE program, potential GHG emissions may vary widely relative to PG&E. For example, under Scenarios 1 and 2, MBCP should assume significant electric power sector GHG emissions impacts within the MBCP Communities. The GHG emissions impact associated with Scenario 3, while not as high as those projected for Scenarios 1 and 2, still results in projected 25% annual GHG emissions reductions relative to the incumbent utility (based on the procurement of significant quantities of renewable and additional carbon-free energy). Table 31 summarizes projected GHG emissions impacts for each of the modeled supply scenarios.

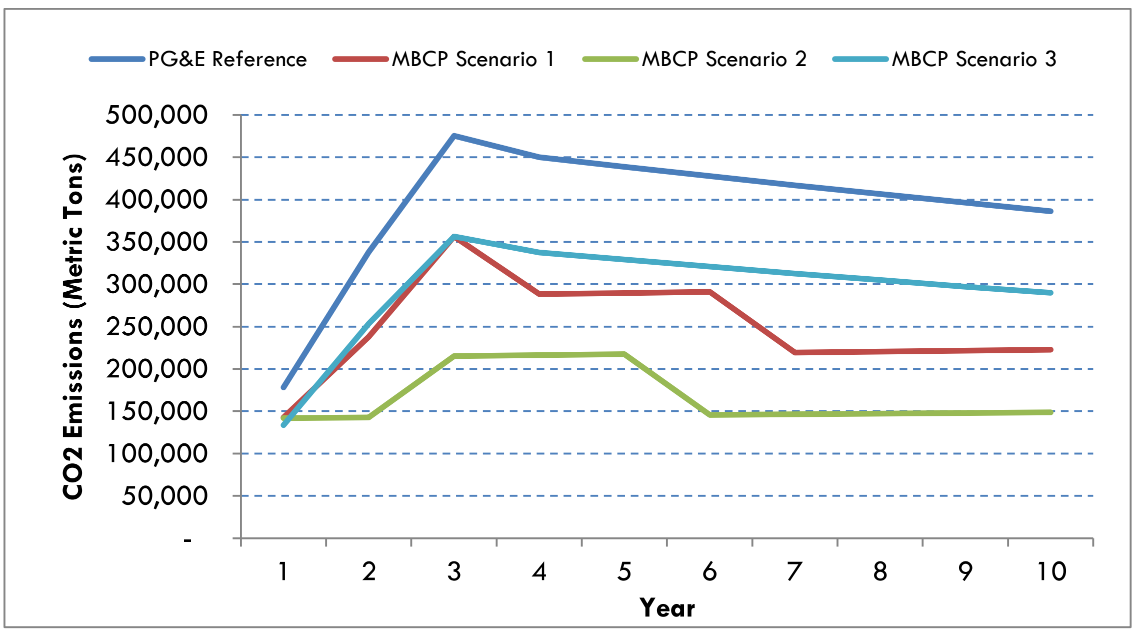
[39] Average monthly residential electricity consumption within the MBCP Communities is approximately 446 kWh.

Table 31: GHG Emissions Impacts (Ten Year Average)

GHG Impact	Scenario 1	Scenario 2	Scenario 3
Annual Change in GHG Emissions (Tons CO_2/Year)	-142,415	-224,617	-97,869
GHG Equivalency Impact (EPA)	-29,982 cars/year	-47,288 cars/year	-20,604 cars/year
Change in Electric Sector CO_2 Emissions within the MBCP Communities (%)	-36%	-57%	-25%
Projected MBCP Portfolio Emissions Factor (metric tons/MWh)	0.084	0.059	0.096
Projected PG&E Portfolio Emissions Factor (metric tons/MWh)	0.128	0.128	0.128

Figure 30 illustrate projected GHG emissions from CCE program customer under the status quo as well as each of the prospective MBCP supply scenarios. When reviewing Figure 30, note that the sharp increase in emissions between year one and year three is directly related to MBCP's phased customer enrollment schedule – during this twenty-five month period, total emissions are expected to increase as customers are added to the MBCP program. Following full enrollment in year three, MBCP portfolio emissions gradually decline over time as increased quantities of carbon-free energy sources are increasingly reflected in the overall MBCP resource mix. Note that the projected GHG emissions trend associated with Scenario 1 coincides with the PG&E reference line, as there are zero assumed GHG emissions reductions under this planning scenario.

Figure 30: Projected GHG Emissions



The potential for local generation investment arising from the CCE program may also 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, the MBCP Communities are not the best resource areas 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 CCE program will determine how these considerations are balanced. PEA recommends that considerable thought be given upfront to the ultimate goals of the CCE program so that clear objectives are established, giving those responsible for administering the CCE program the opportunity to develop and execute resource management and procurement plans that meet objectives of the MBCP program.

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 CCE program serving customers within the MBCP Communities could offer both economic (i.e., positive economic development impacts and overall cost savings for customers of the CCE program) and environmental benefits during initial program operations and, potentially, throughout the ten-year study period. As previously noted, due to the dynamic nature of California's energy markets, particularly market prices which are subject to frequent changes, the MBCP Partnership should confirm that the assumptions reflected in this Study generally align with future market conditions (observed at the time of any decision by the MBCP Partnership to move forward) to promote the achievement of early-stage MBCP operations that generally align with the operating projections reflected 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 related to MBCP program formation.

APPENDIX A: COUNTY-SPECIFIC SCENARIO ANALYSES

Overview

At the request of the MBCP Partnership, PEA completed a stand-alone CCE evaluation for each participating county (including both unincorporated areas of each county as well as the cities located therein) for purposes of determining the projected costs and benefits associated with independent CCE formation. Through these stand-alone analyses, the MBCP Partnership will have a more thorough understanding of the expected rate impacts on local electric customers, startup costs and environmental benefits that may occur in the event that one or more of the participating counties were to independently pursue CCE implementation. As reflected below, the expected costs and benefits under single-county CCE implementation may differ significantly from the aggregate operating projections associated with a multi-county program.

As displayed in Figures 31 and 32, proportionate electricity use and customer accounts vary widely throughout the tri-county region with Monterey County representing both the largest proportion of energy consumption (62%) and customer accounts (56%); San Benito County represents the smallest proportion of energy consumption (9%) and customer accounts (7%).

Figure 31: Proportion of MBCP Electricity Consumption by County

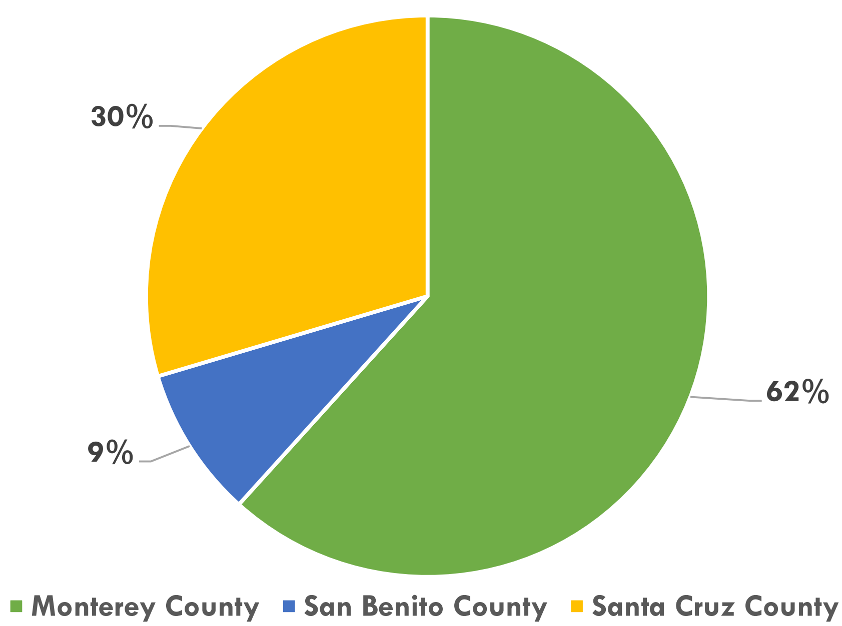
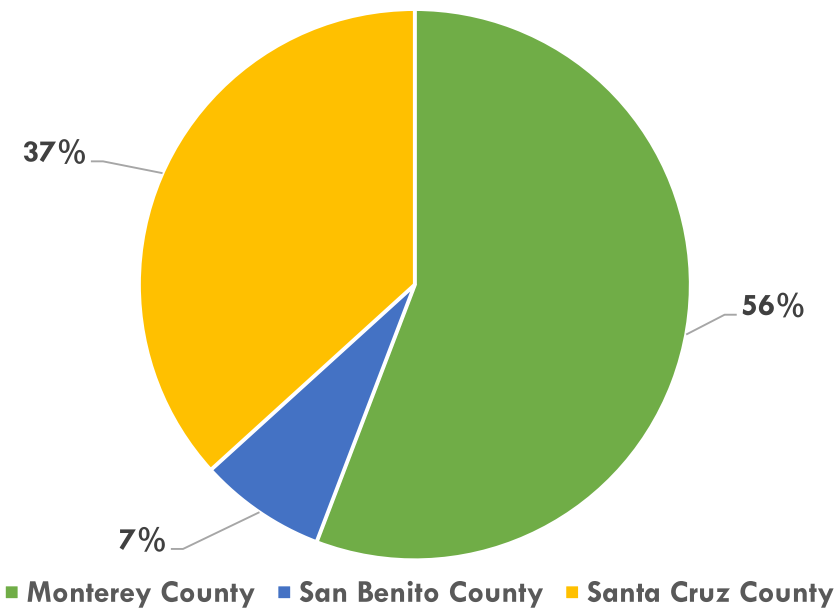


Figure 32: Proportion of MBCP Total Accounts by County



For purposes of the county-specific analyses, PEA assumed that each of the three indicative supply scenarios would be implemented without modification. However, certain changes to anticipated phase-in assumptions were made in consideration of the overall reduction in total customer accounts within each county relative to the aggregated customer base. For example, because San Benito County has approximately 19,000 total electric accounts, there was no need to pursue multi-phase implementation – California's operating CCA programs have each successfully completed implementation phases with accounts totals that exceed this threshold. A single-phase implementation strategy was also assumed in Santa Cruz County, which has approximately 90,000 electric accounts – this would represent a relatively large enrollment phase, but such an approach results in improved operating results during Year 1 of program operations. Due to its larger customer base (approximating 140,000 accounts), it was assumed that Monterey County would pursue a two-phase implementation approach.

With regard to the indicative supply portfolio that was assumed for the tri-county program, this portfolio was proportionately divided when completing the single-county analyses, reflecting reduced long-term power purchase commitments with California-based renewable resources (in consideration of each county's reduced renewable energy requirement). For example, if a 100 MW PV solar contract was assumed for the MBCP program, a 62 MW PV solar project was assumed for Monterey County, as this county represents 62% of total electric energy requirements within the tri-county region. Similarly, Santa Cruz County would be allocated a 30 MW PV solar project in place of the 100 MW project that was planned for the tri-county program.

Changes to the indicative supply portfolio assumptions in each county-specific analysis proportionately affected related economic development benefit expectations as well. In the case of Santa Cruz County, for example, 30% of the anticipated aggregate economic development benefits are generally expected to occur in the event that Santa Cruz pursues single-county CCE implementation (as a direct result of Santa Cruz representing 30% of total electric energy use within the tri-county region). Such economic benefits expectations are not further discussed within this Appendix.

Additional detail related to single-county CCE implementations is provided below, including an identification of independent startup costs, expected rate/cost impacts, environmental benefits and other key details. PEA also provides high-level findings and conclusions related to each prospective single-county CCE implementation.

Monterey County

Consolidated Scenario Highlights, Monterey County

Table 32 identifies the projected operating results for Monterey County under each indicative supply scenario in Year 1 of anticipated MBCP operations.

Table 32: Projected Year 1 Operating Results, Monterey County

Key Considerations	Scenario 1	Scenario 2	Scenario 3
General Environmental Benefits	59% Renewable 70% GHG-Free	71% Renewable 71% GHG-Free	28% Renewable 72% GHG-Free
Rate Competitiveness	Average 1% savings relative to PG&E rate projections	Average 1% savings relative to PG&E rate projections	Average 4% savings relative to PG&E rate projections
Projected Residential Customer Cost Impacts[1] [1]Average monthly usage for Monterey residential customers ≈ 414 kWh	Average $0.58 monthly cost savings relative to PG&E projections	Average $0.60 monthly cost savings relative to PG&E projections	Average $3.44 monthly cost savings relative to PG&E projections
Assumed Monterey Participation	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups
Comparative GHG Emissions Impacts	0.126 metric tons CO2/MWh emissions rate; ≈33,130 metric ton GHG emissions reduction in Year 1 (≈20% reduction)	0.126 metric tons CO2/MWh emissions rate; ≈33,726 metric ton GHG emissions reduction in Year 1 (≈20% reduction)	0.119 metric tons CO2/MWh emissions rate; ≈41,413 metric ton GHG emissions reduction in Year 1 (≈25% reduction)

Table 33 identifies the projected operating results for Monterey County under each indicative supply scenario in Year 10 of anticipated MBCP operations.

Table 33: Projected Year 10 Operating Results, Monterey County

Key Considerations	Scenario 1	Scenario 2	Scenario 3
General Environmental Benefits	85% Renewable 85% GHG-Free	90% Renewable 90% GHG-Free	44% Renewable 81% GHG-Free
Rate Competitiveness	Average 1% savings relative to PG&E rate projections	Average 1% savings relative to PG&E rate projections	Average 5% savings relative to PG&E rate projections
Projected Residential Customer Cost Impacts[1] [1]Average monthly usage for Monterey residential customers ≈ 414 kWh	Average $1.00 monthly cost savings relative to PG&E rate projections	Average $1.20 monthly cost savings relative to PG&E rate projections	Average $5.45 monthly cost savings relative to PG&E projections
Assumed Monterey Participation	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups
Comparative GHG Emissions Impacts	0.063 metric tons CO2/MWh emissions rate; ≈101,330 metric ton GHG emissions reduction in Year 10 (≈42% reduction)	0.042 metric tons CO2/MWh emissions rate; ≈147,325 metric ton GHG emissions reduction in Year 10 (≈62% reduction)	0.082 metric tons CO2/MWh emissions rate; ≈59,828 metric ton GHG emissions reduction in Year 10 (≈25% reduction)

Start-Up Costs, Monterey County

In the event that Monterey County determined to pursue independent CCE formation, start-up costs are estimated to be approximately $1.96 million, which would provide necessary program funding during the approximate twelve-month period immediately preceding service commencement to Monterey County customers. In general terms, the estimated start-up costs for Monterey County are relatively similar to those of the broader MBCP program (which are estimated at $2.25 million) – because Monterey County represents the majority of MBCP customer accounts as well as annual energy use, there are only minor reductions due to scale; other cost categories, including the CCA Bond, service fees and the security deposit remained fixed, regardless of size. A breakdown of estimated start-up costs for Monterey County is shown in Table 34.

Table 34: Estimated Start-Up Costs, Monterey County

Start-Up Cost Category	Projected Cost ($)
Technical Study	$25,000
JPA Formation/Development	$50,000
Implementation Plan Development	$50,000
Power Supplier Solicitation & Contracting	$75,000
Staffing	$590,625
Consultants and Legal Counsel	$600,000
Marketing & Communications	$225,000
Security Deposits	$22,500
Service Fees	$37,500
CCA Bond	$100,000
Miscellaneous Administrative & General	$187,500
Total	**$1,963,125**

Scenario Results, Monterey County

The following section summarizes scenario-specific operating results for Monterey County. To the extent that previously discussed tables and figures do not change under this county-specific analysis, such information has not been repeated.

Figure 33: Scenario 1 Annual Ratepayer Costs

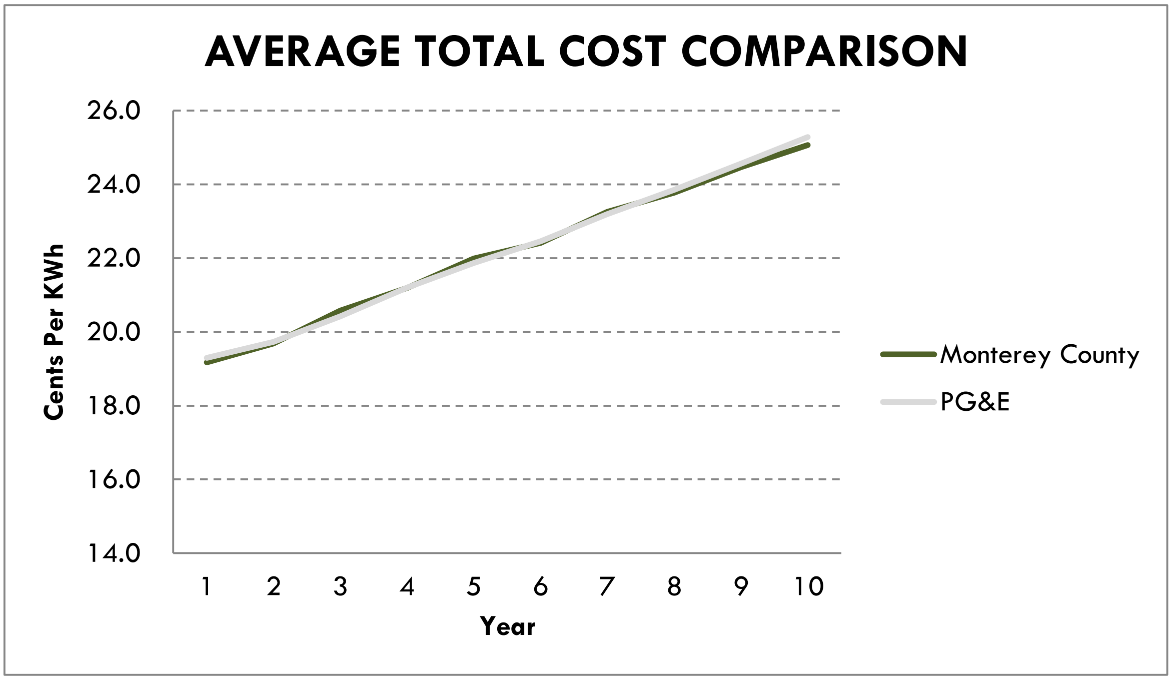


Table 35: Scenario 1 - Annual Total Delivered Rate Comparison

Year	PG&E Total (₵/kWh)	CCE Total (₵/kWh)	Percent Difference
Levelized	22.07	22.05	0%
1	19.30	19.18	-1%
2	19.73	19.68	0%
3	20.42	20.58	1%
4	21.20	21.19	0%
5	21.87	21.99	1%
6	22.46	22.41	0%
7	23.20	23.26	0%
8	23.85	23.77	0%
9	24.57	24.47	0%
10	25.28	25.07	-1%

Figure 34: Scenario 1 – Annual GHG Emissions Comparison

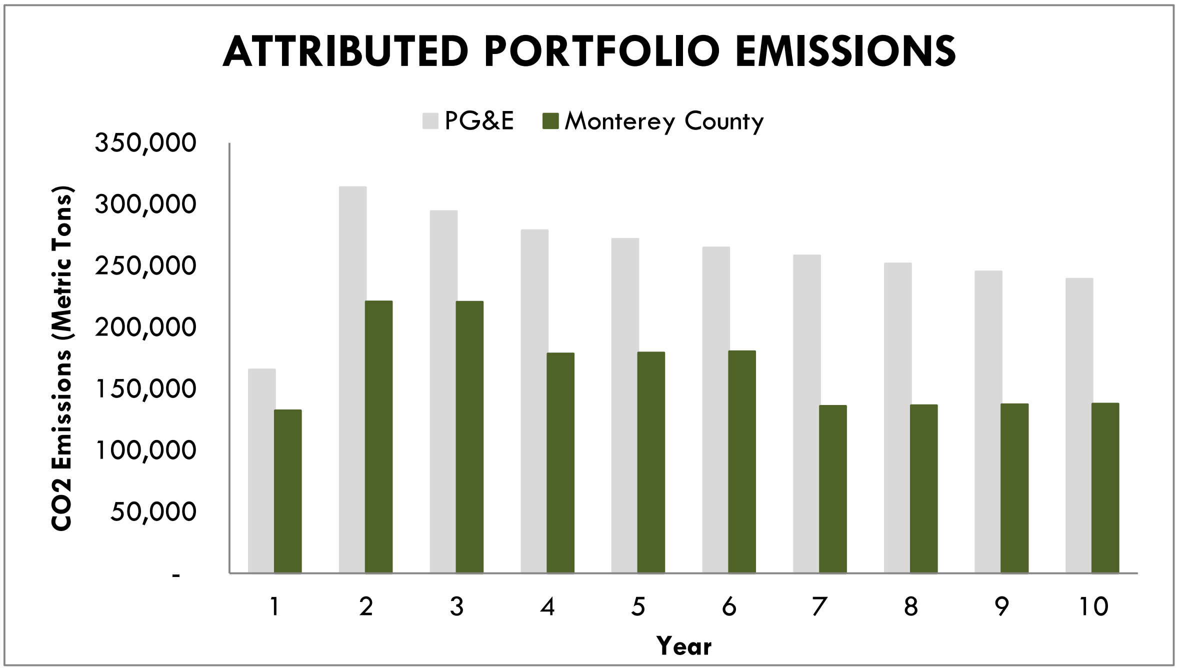


Figure 35: Scenario 2 Annual Ratepayer Costs

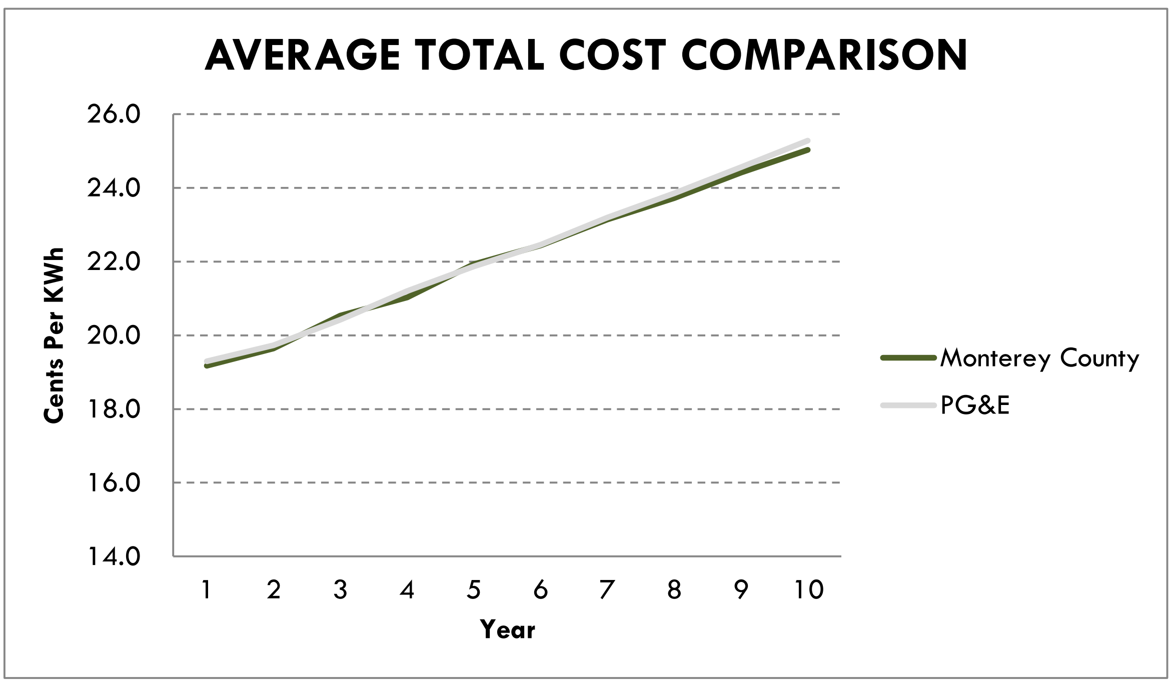


Table 36: Scenario 2 - Annual Total Delivered Rate Comparison

Year	PG&E Total (₵/kWh)	CCE Total (₵/kWh)	Percent Difference
Levelized	22.07	21.99	-4%
1	19.30	19.17	-1%
2	19.73	19.65	0%
3	20.42	20.54	1%
4	21.20	21.03	-1%
5	21.87	21.93	0%
6	22.46	22.44	0%
7	23.20	23.14	0%
8	23.85	23.73	-1%
9	24.57	24.42	-1%
10	25.28	25.03	-1%

Figure 36: Scenario 2 – Annual GHG Emissions Comparison

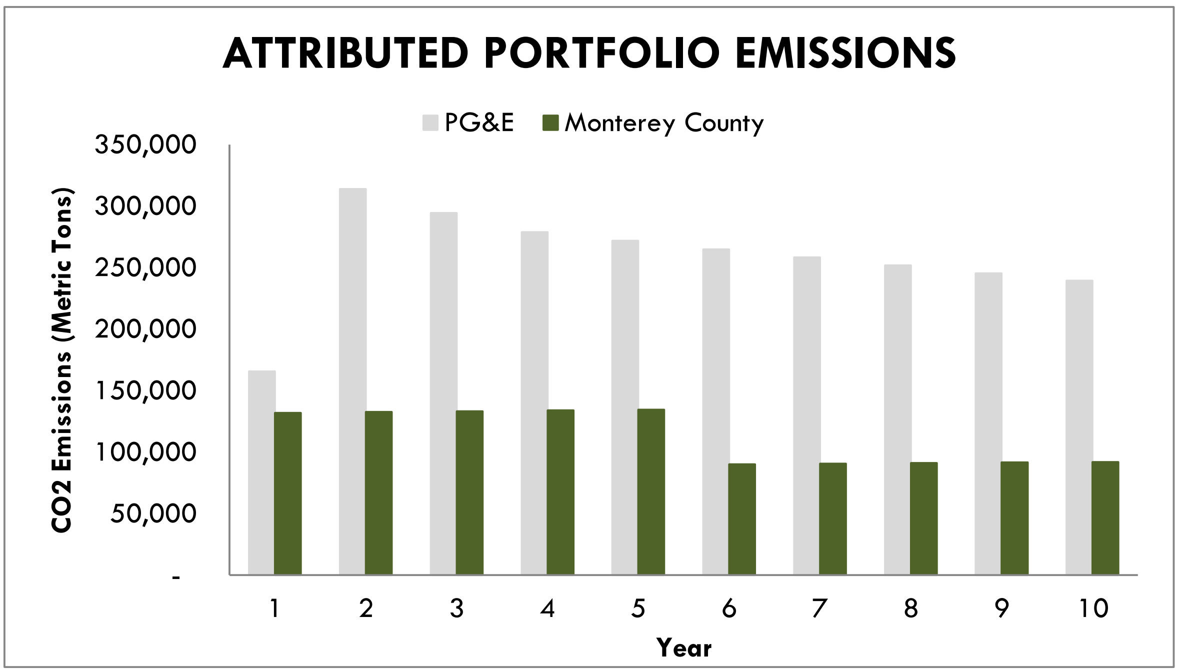


Figure 37: Scenario 3 Annual Ratepayer Costs

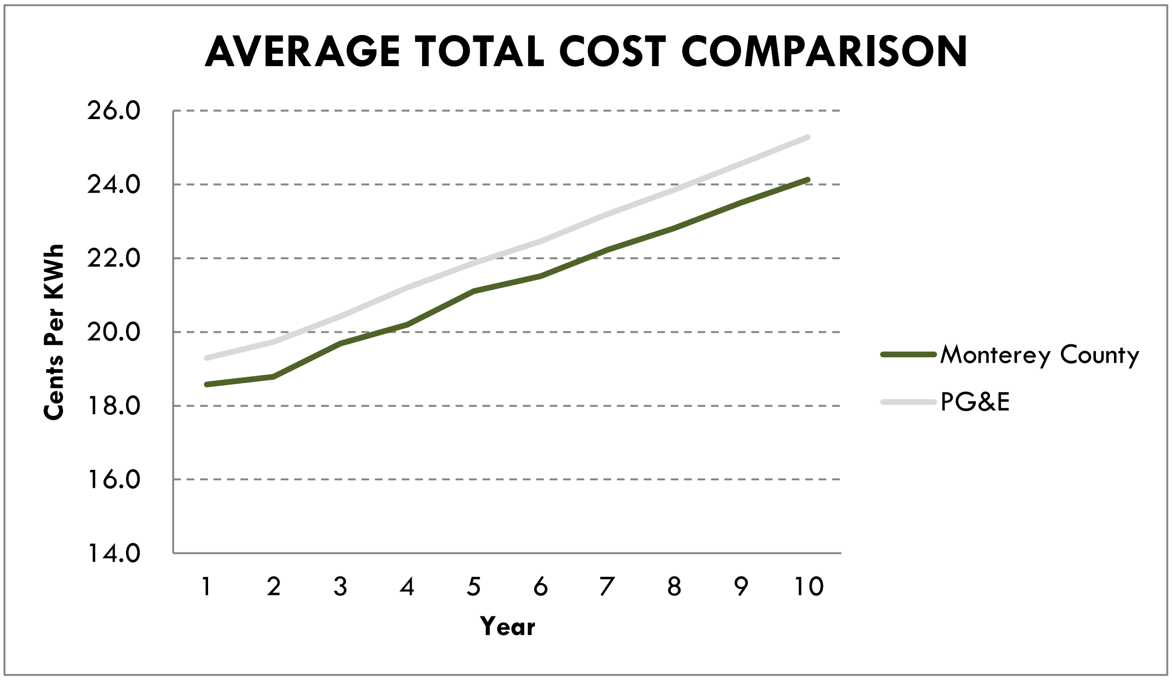
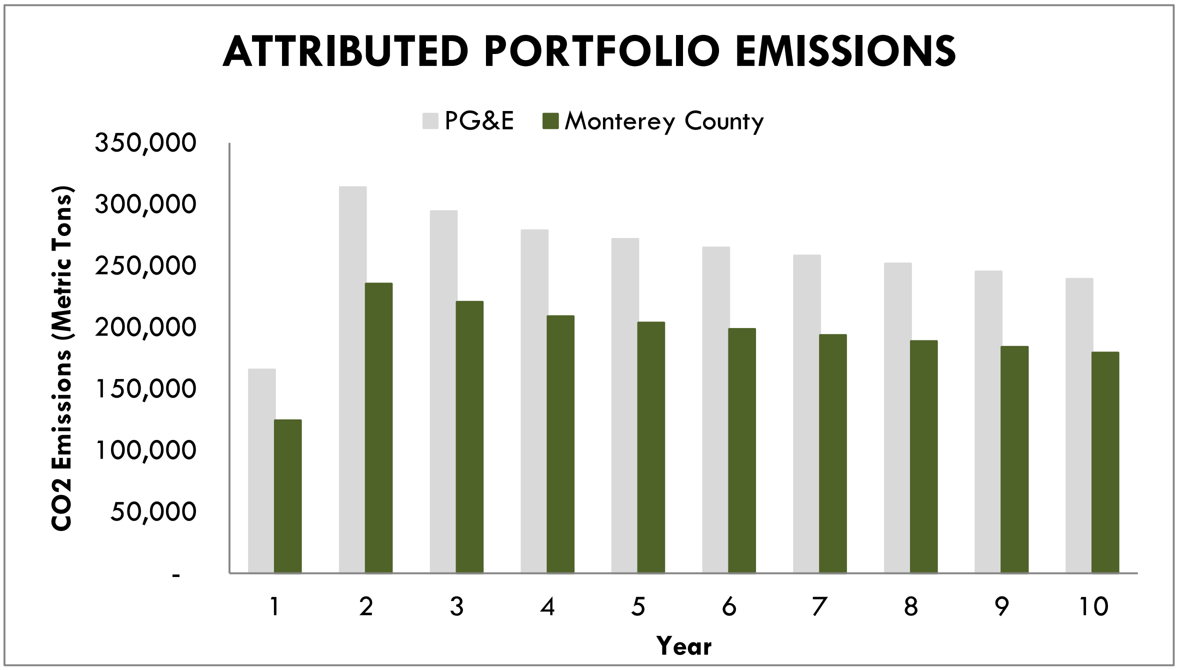


Table 37: Scenario 3 - Annual Total Delivered Rate Comparison

Year	PG&E Total (₵/kWh)	CCE Total (₵/kWh)	Percent Difference
Levelized	22.07	21.14	-4%
1	19.30	18.57	-4%
2	19.73	18.78	-5%
3	20.42	19.69	-4%
4	21.20	20.20	-5%
5	21.87	21.10	-4%
6	22.46	21.51	-4%
7	23.20	22.22	-4%
8	23.85	22.81	-4%
9	24.57	23.51	-4%
10	25.28	24.13	-5%

Figure 38: Scenario 3 – Annual GHG Emissions Comparison



Findings and Conclusions, Monterey County

Based on the results reflected in Monterey County's individual analysis, rate-related impacts are very similar to those reflected in the broader MBCP study, indicating levelized savings under each indicative supply scenario that generally approximates projected savings for the tri-county region. With regard to GHG emissions reductions, proportionate impacts are generally equivalent (with absolute impacts – measured in metric tons – reduced in consideration of the smaller subset of customers within Monterey County relative to the entire MBCP customer base). Based on PEA's observations, Monterey County appears to be a viable candidate for independent CCE implementation, demonstrating the potential for significant environmental benefits and rate competitiveness.

San Benito County

Consolidated Scenario Highlights, San Benito County

Table 38 identifies the projected operating results for San Benito County under each indicative supply scenario in Year 1 of anticipated MBCP operations.

Table 38: Projected Year 1 Operating Results, San Benito County

Key Considerations	Scenario 1	Scenario 2	Scenario 3
General Environmental Benefits	59% Renewable 70% GHG-Free	71% Renewable 71% GHG-Free	28% Renewable 72% GHG-Free
Rate Competitiveness	Average 2% increase relative to PG&E rate projections	Average 2% increase relative to PG&E rate projections	Average 1% savings relative to PG&E rate projections
Projected Residential Customer Cost Impacts[1] [1]Average monthly usage for San Benito residential customers ≈ 519 kWh	Average \$1.76 monthly cost increase relative to PG&E projections	Average \$1.74 monthly cost increase relative to PG&E projections	Average \$1.71 monthly cost savings relative to PG&E projections
Assumed San Benito Participation	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups
Comparative GHG Emissions Impacts	0.126 metric tons CO2/MWh emissions rate; ≈9,399 metric ton GHG emissions reduction in Year 1 (≈20% reduction)	0.126 metric tons CO2/MWh emissions rate; ≈9,568 metric ton GHG emissions reduction in Year 1 (≈20% reduction)	0.119 metric tons CO2/MWh emissions rate; ≈11,749 metric ton GHG emissions reduction in Year 1 (≈25% reduction)

Table 39 identifies the projected operating results for San Benito County under each indicative supply scenario in Year 10 of anticipated MBCP operations.

Table 39: Projected Year 10 Operating Results, San Benito County

Key Considerations	Scenario 1	Scenario 2	Scenario 3
General Environmental Benefits	85% Renewable 85% GHG-Free	90% Renewable 90% GHG-Free	44% Renewable 81% GHG-Free
Rate Competitiveness	Average 2% increase relative to PG&E rate projections	Average 1% increase relative to PG&E rate projections	Average 2% savings relative to PG&E rate projections
Projected Residential Customer Cost Impacts[1] [1]Average monthly usage for San Benito residential customers ≈ 519 kWh	Average $2.33 monthly cost increase relative to PG&E rate projections	Average $2.09 monthly cost increase relative to PG&E rate projections	Average $3.08 monthly cost savings relative to PG&E projections
Assumed San Benito Participation	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups
Comparative GHG Emissions Impacts	0.063 metric tons CO2/MWh emissions rate; ≈14,373 metric ton GHG emissions reduction in Year 10 (≈42% reduction)	0.042 metric tons CO2/MWh emissions rate; ≈20,898 metric ton GHG emissions reduction in Year 10 (≈62% reduction)	0.082 metric tons CO2/MWh emissions rate; ≈8,487 metric ton GHG emissions reduction in Year 10 (≈25% reduction)

Start-Up Costs – San Benito County

In the event that San Benito County determined to pursue independent CCE formation, start-up costs are estimated to be approximately $1.00 million, which would provide necessary program funding during the approximate twelve-month period immediately preceding service commencement to San Benito County customers. In general terms, the estimated start-up costs for San Benito County are comparatively lower than those of the broader MBCP program (which are estimated at $2.25 million) – because San Benito County represents the smallest portion of MBCP customer accounts as well as annual energy use, there are significant reductions due to scale; other cost categories, including the CCA Bond, service fees and the security deposit remained fixed, regardless of size. A breakdown of estimated start-up costs for San Benito County is shown in Table 40.

Table 40: Estimated Start-Up Costs, San Benito County

Start-Up Cost Category	Projected Cost ($)
Technical Study	$25,000
JPA Formation/Development	$50,000
Implementation Plan Development	$50,000
Power Supplier Solicitation & Contracting	$75,000
Staffing	$236,250
Consultants and Legal Counsel	$240,000
Marketing & Communications	$90,000
Security Deposits	$22,500
Service Fees	$37,500
CCA Bond	$100,000
Miscellaneous Administrative & General	$75,000
Total	**$1,001,250**

Scenario Results – San Benito County

The following section summarizes scenario-specific operating results for San Benito County. To the extent that previously discussed tables and figures do not change under this county-specific analysis, such information has not been repeated.

Figure 39: Scenario 1 Annual Ratepayer Costs

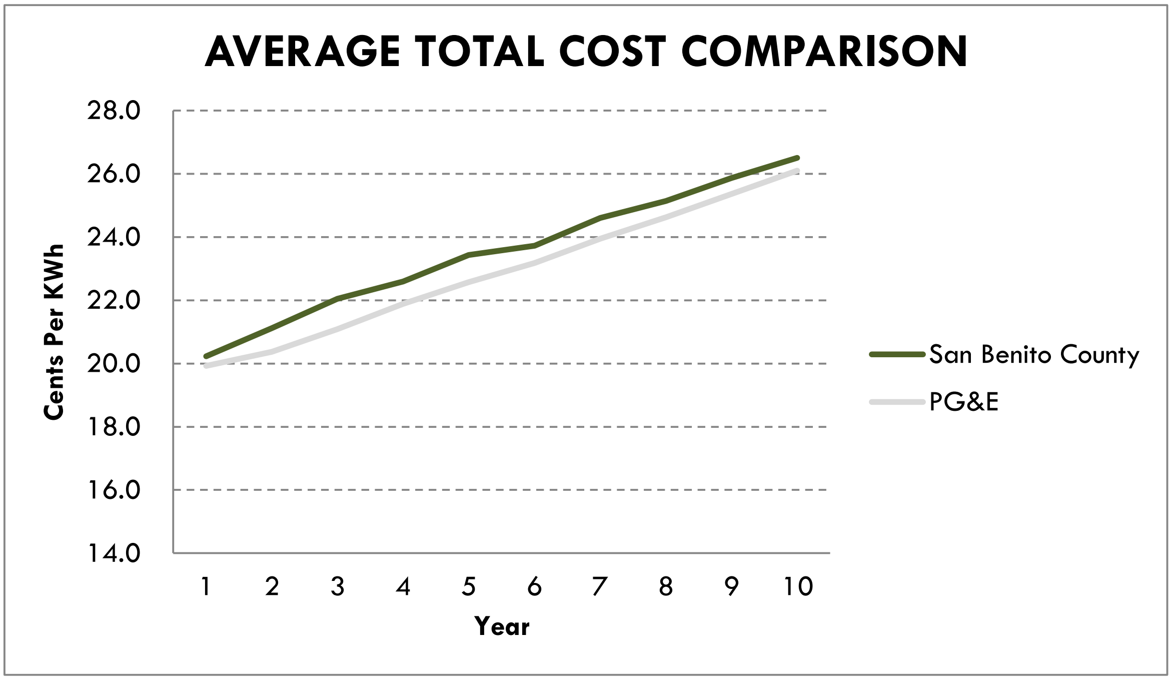


Table 41: Scenario 1 - Annual Total Delivered Rate Comparison

Year	PG&E Total (₵/kWh)	CCE Total (₵/kWh)	Percent Difference
Levelized	22.60	23.23	3%
1	19.93	20.23	2%
2	20.37	21.12	4%
3	21.09	22.05	5%
4	21.88	22.59	3%
5	22.58	23.43	4%
6	23.19	23.73	2%
7	23.95	24.60	3%
8	24.62	25.14	2%
9	25.36	25.87	2%
10	26.10	26.50	2%

Figure 40: Scenario 1 – Annual GHG Emissions Comparison

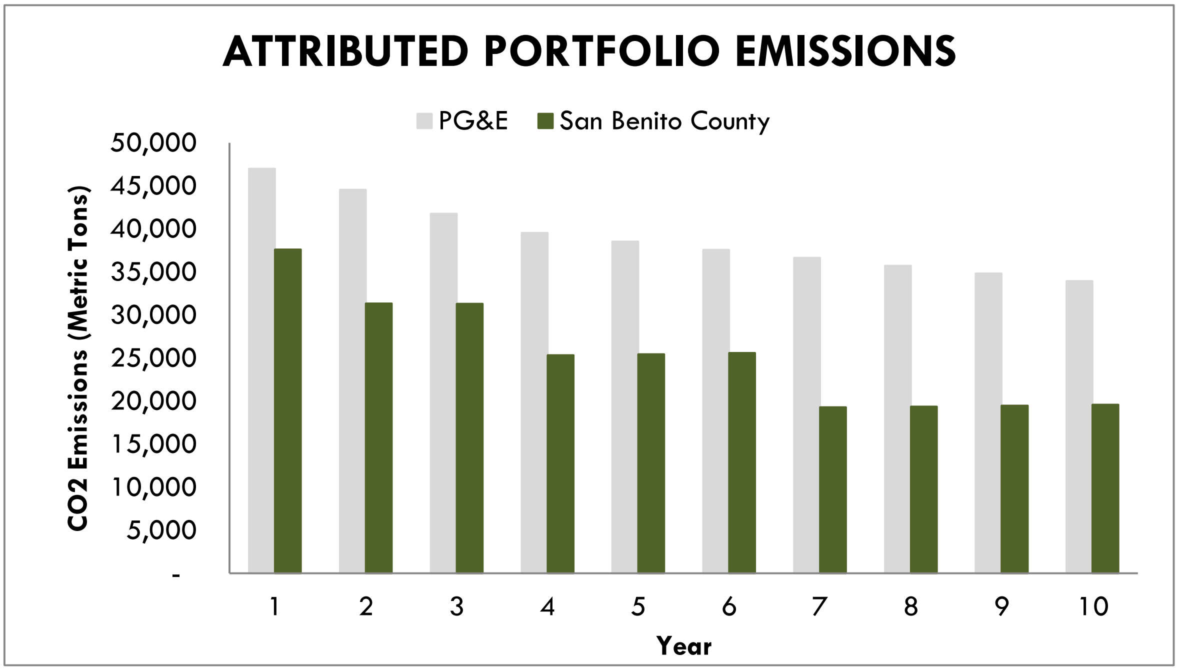


Figure 41: Scenario 2 Annual Ratepayer Costs

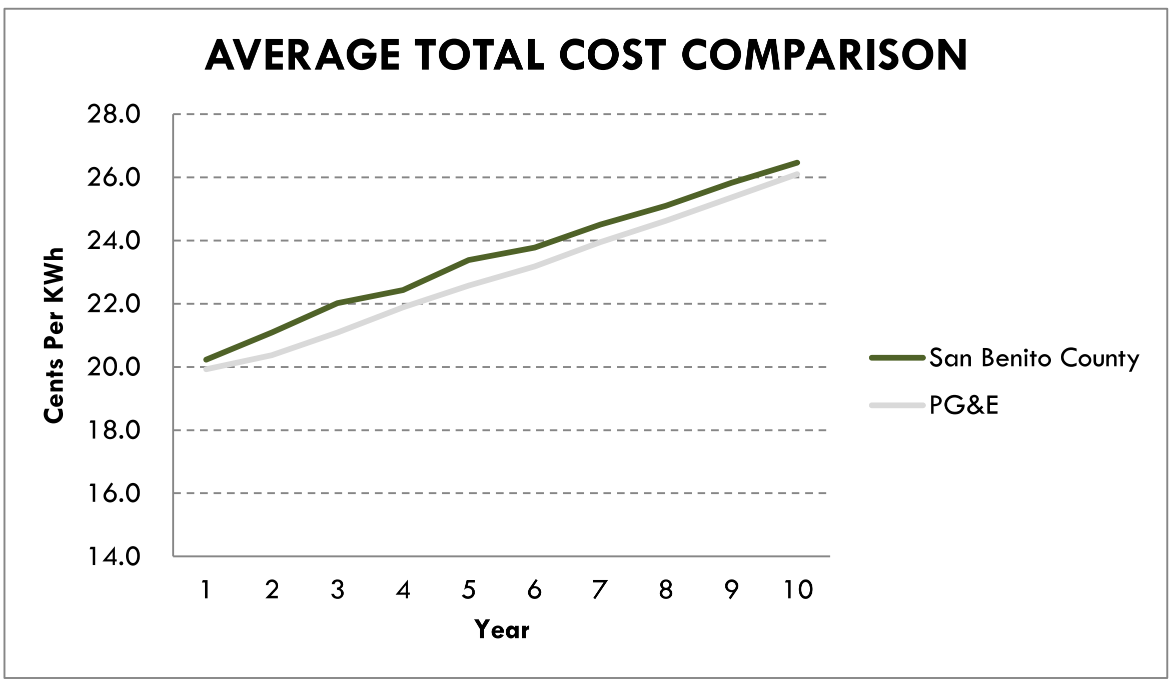


Table 42: Scenario 2 - Annual Total Delivered Rate Comparison

Year	PG&E Total (₵/kWh)	CCE Total (₵/kWh)	Percent Difference
Levelized	22.60	23.19	3%
1	19.93	20.23	2%
2	20.37	21.09	4%
3	21.09	22.02	4%
4	21.88	22.44	3%
5	22.58	23.38	4%
6	23.19	23.77	3%
7	23.95	24.50	2%
8	24.62	25.10	2%
9	25.36	25.83	2%
10	26.10	26.46	1%

Figure 42: Scenario 2 – Annual GHG Emissions Comparison

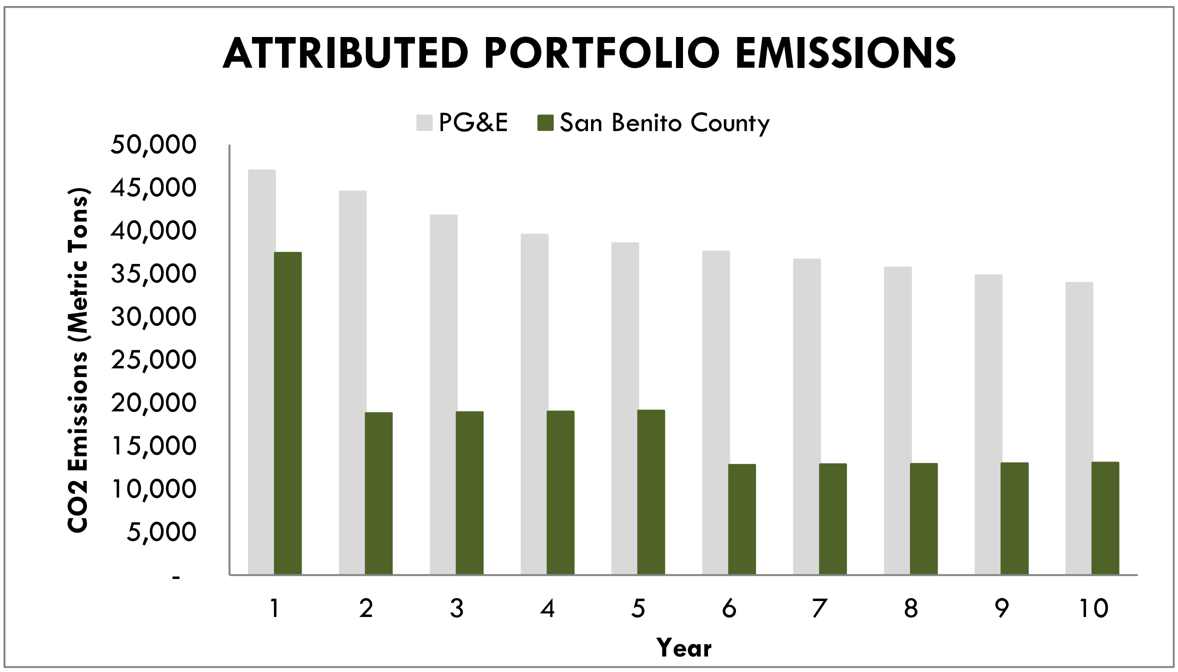


Figure 43: Scenario 3 Annual Ratepayer Costs

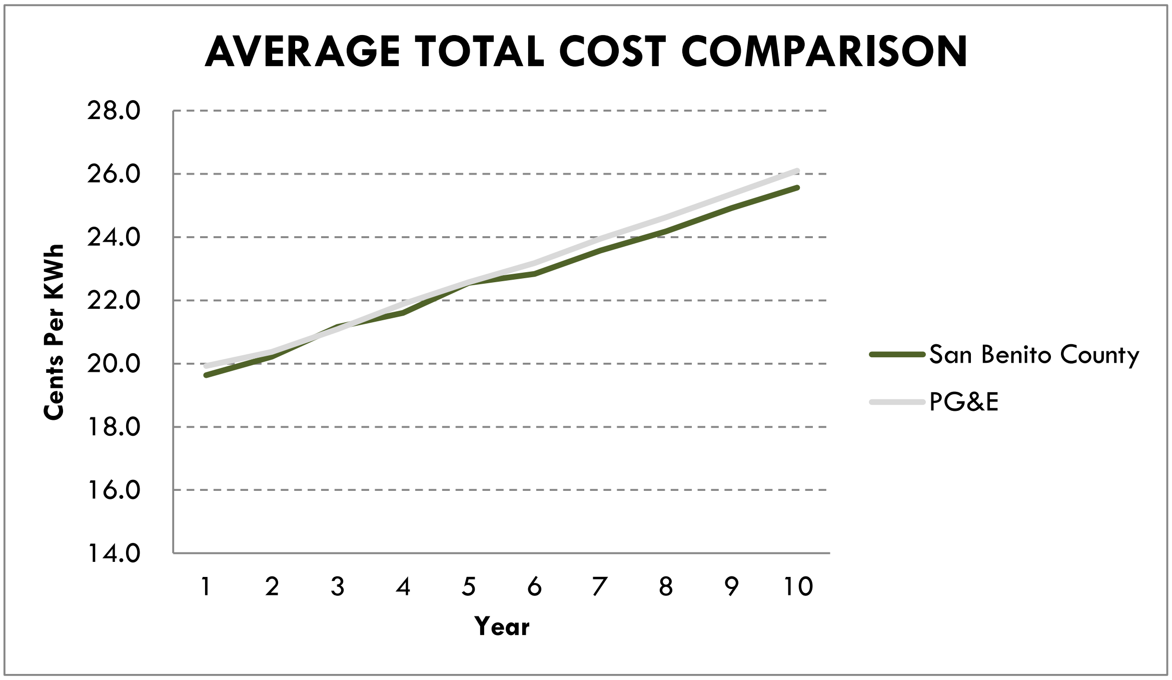
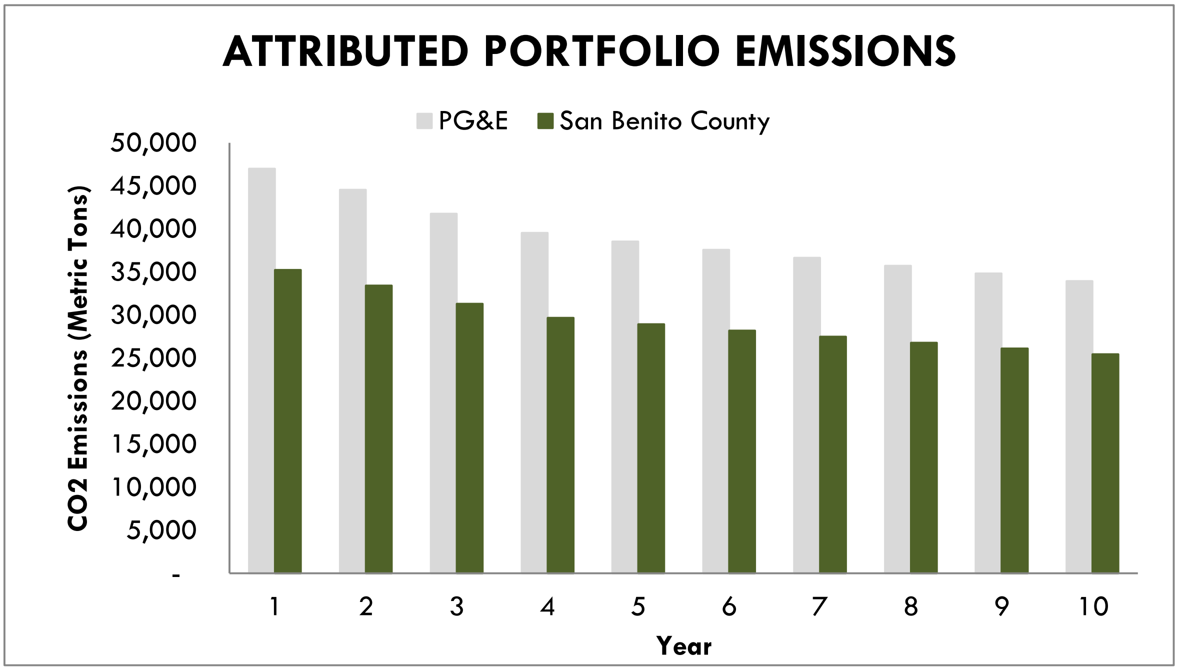


Table 43: Scenario 3 - Annual Total Delivered Rate Comparison

Year	PG&E Total (₵/kWh)	CCE Total (₵/kWh)	Percent Difference
Levelized	22.60	22.34	-1%
1	19.93	19.63	-1%
2	20.37	20.22	-1%
3	21.09	21.16	0%
4	21.88	21.60	-1%
5	22.58	22.55	0%
6	23.19	22.84	-1%
7	23.95	23.57	-2%
8	24.62	24.18	-2%
9	25.36	24.92	-2%
10	26.10	25.56	-2%

Figure 44: Scenario 3 – Annual GHG Emissions Comparison



Findings and Conclusions, San Benito County

Based on the results reflected in San Benito County's individual analysis, rate-related impacts are meaningfully different than those reflected in the broader MBCP study. In particular, Scenarios 1 and 2 suggest that San Benito County customers would experience levelized cost *increases* approximating 3% during the ten-year Study period. Under Scenario 3, nominal savings is achieved (at 1%, levelized over the ten-year Study period), but this is well below the 4% levelized savings that was projected for the broader MBCP program under the Scenario 3 portfolio composition. With regard to GHG emissions reductions, proportionate impacts are generally equivalent (with absolute impacts – measured in metric tons – reduced in consideration of the smaller subset of customers within San Benito County relative to the entire MBCP customer base). Based on PEA's observations, independent CCE program implementation by San Benito County would likely promote measurable environmental benefits while imposing *increased* costs on participating customers.

Santa Cruz County

Consolidated Scenario Highlights, Santa Cruz County

Table 44 identifies the projected operating results for Santa Cruz County under each indicative supply scenario in Year 1 of anticipated MBCP operations.

Table 44: Projected Year 1 Operating Results, Santa Cruz County

Key Considerations	Scenario 1	Scenario 2	Scenario 3
General Environmental Benefits	59% Renewable 70% GHG-Free	71% Renewable 71% GHG-Free	28% Renewable 72% GHG-Free
Rate Competitiveness	Average 2% savings relative to PG&E rate projections	Average 2% savings relative to PG&E rate projections	Average 4% savings relative to PG&E rate projections
Projected Residential Customer Cost Impacts[1] [1]Average monthly usage for Santa Cruz residential customers ≈ 479 kWh	Average $1.68 monthly cost savings relative to PG&E projections	Average $1.70 monthly cost savings relative to PG&E projections	Average $4.73 monthly cost savings relative to PG&E projections
Assumed Santa Cruz Participation	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups
Comparative GHG Emissions Impacts	0.126 metric tons CO2/MWh emissions rate; ≈31,213 metric ton GHG emissions reduction in Year 1 (≈20% reduction)	0.126 metric tons CO2/MWh emissions rate; ≈31,744 metric ton GHG emissions reduction in Year 1 (≈20% reduction)	0.119 metric tons CO2/MWh emissions rate; ≈39,016 metric ton GHG emissions reduction in Year 1 (≈25% reduction)

Table 45 identifies the projected operating results for Santa Cruz County under each indicative supply scenario in Year 10 of anticipated MBCP operations.

Table 45: Projected Year 10 Operating Results, Santa Cruz County

Key Considerations	Scenario 1	Scenario 2	Scenario 3
General Environmental Benefits	59% Renewable 70% GHG-Free	71% Renewable 71% GHG-Free	28% Renewable 72% GHG-Free
Rate Competitiveness	Average 1% savings relative to PG&E rate projections	Average 1% savings relative to PG&E rate projections	Average 4% savings relative to PG&E rate projections
Projected Residential Customer Cost Impacts[1] [1]Average monthly usage for Santa Cruz residential customers ≈ 479 kWh	Average $1.39 monthly cost savings relative to PG&E rate projections	Average $1.65 monthly cost savings relative to PG&E rate projections	Average $6.17 monthly cost savings relative to PG&E projections
Assumed Santa Cruz Participation	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups	85% customer participation rate assumed across all customer groups
Comparative GHG Emissions Impacts	0.063 metric tons CO2/MWh emissions rate; ≈47,733 metric ton GHG emissions reduction in Year 10 (≈42% reduction)	0.042 metric tons CO2/MWh emissions rate; ≈69,399 metric ton GHG emissions reduction in Year 10 (≈62% reduction)	0.082 metric tons CO2/MWh emissions rate; ≈28,183 metric ton GHG emissions reduction in Year 10 (≈25% reduction)

Start-Up Costs, Santa Cruz County

In the event that Santa Cruz County determined to pursue independent CCE formation, start-up costs are estimated to be approximately $1.64 million, which would provide necessary program funding during the approximate twelve-month period immediately preceding service commencement to Santa Cruz County customers. In general terms, the estimated start-up costs for Santa Cruz County are somewhat lower than those of the broader MBCP program (which are estimated at $2.25 million) – because Santa Cruz County represents the second largest portion of MBCP customer accounts as well as annual energy use, there are certain proportionate cost reductions due to scale; other cost categories, including the CCA Bond, service fees and the security deposit remained fixed, regardless of size. A breakdown of estimated start-up costs for Santa Cruz County is shown in Table 46.

Table 46: Estimated Start-Up Costs, Santa Cruz County

Start-Up Cost Category	Projected Cost ($)
Technical Study	$25,000
JPA Formation/Development	$50,000
Implementation Plan Development	$50,000
Power Supplier Solicitation & Contracting	$75,000
Staffing	$472,500
Consultants and Legal Counsel	$480,000
Marketing & Communications	$180,000
Security Deposits	$22,500
Service Fees	$37,500
CCA Bond	$100,000
Miscellaneous Administrative & General	$150,000
Total	**$1,642,500**

Scenario Results, Santa Cruz County

The following section summarizes scenario-specific operating results for Santa Cruz County. To the extent that previously discussed tables and figures do not change under this county-specific analysis, such information has not been repeated.

Figure 45: Scenario 1 Annual Ratepayer Costs

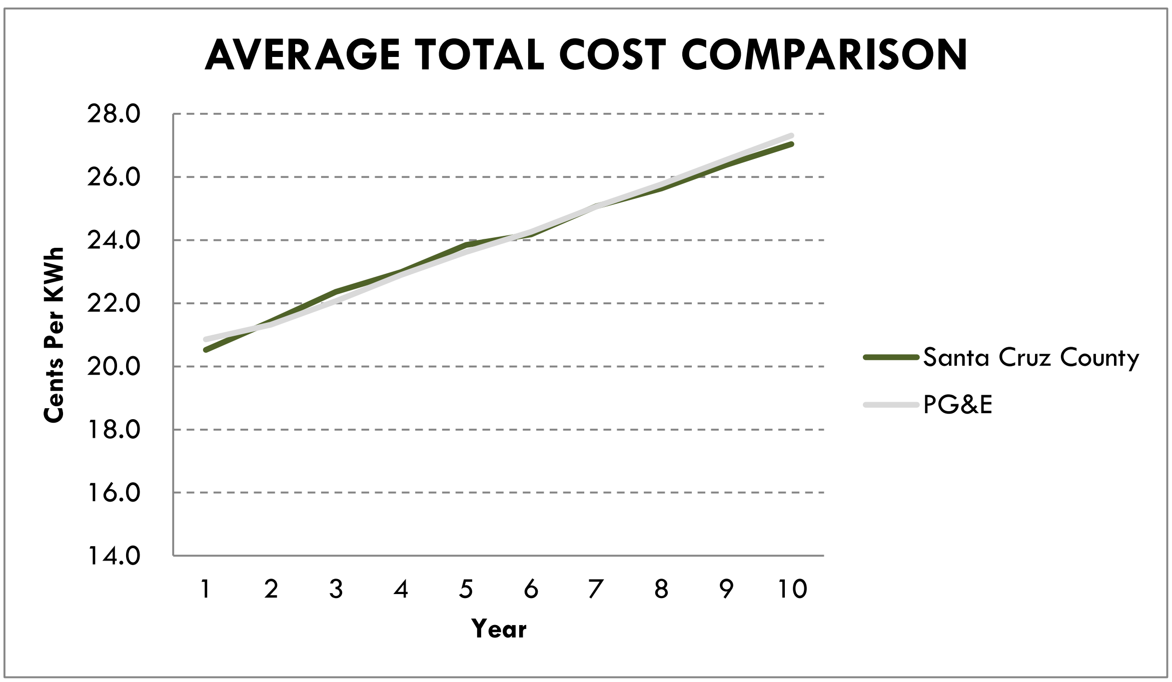


Table 47: Scenario 1 - Annual Total Delivered Rate Comparison

Year	PG&E Total (₵/kWh)	CCE Total (₵/kWh)	Percent Difference

Year	PG&E Total (₵/kWh)	CCE Total (₵/kWh)	Percent Difference
Levelized	23.65	23.64	0%
1	20.85	20.52	-2%
2	21.32	21.42	0%
3	22.07	22.36	1%
4	22.90	22.99	0%
5	23.63	23.85	1%
6	24.26	24.18	0%
7	25.06	25.07	0%
8	25.77	25.64	-1%
9	26.54	26.39	-1%
10	27.31	27.04	-1%

Figure 46: Scenario 1 – Annual GHG Emissions Comparison

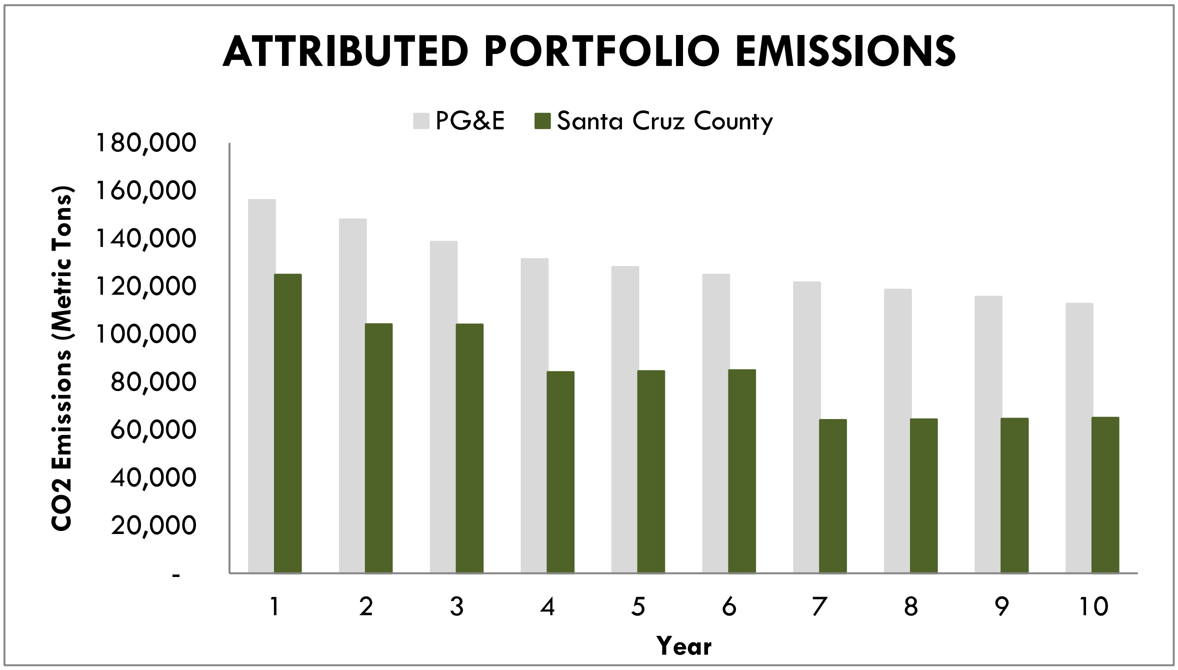


Figure 47: Scenario 2 Annual Ratepayer Costs

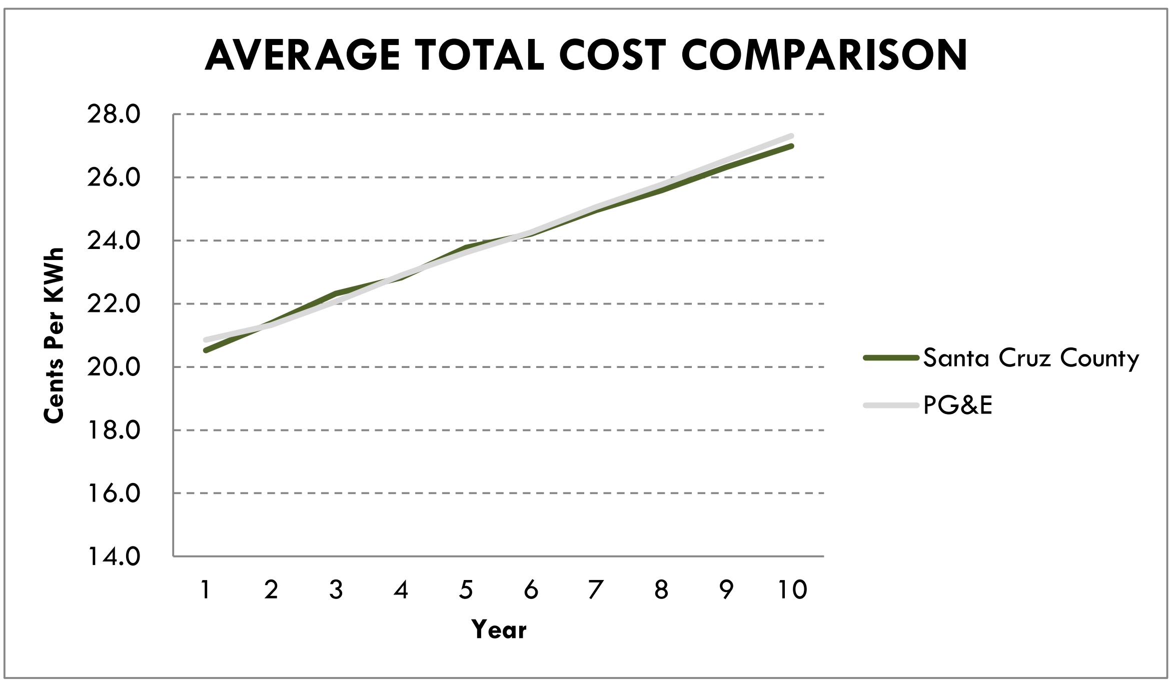


Table 48: Scenario 2 - Annual Total Delivered Rate Comparison

Year	PG&E Total (₵/kWh)	CCE Total (₵/kWh)	Percent Difference
Levelized	23.65	23.58	0%
1	20.85	20.52	-2%
2	21.32	21.38	0%
3	22.07	22.32	1%
4	22.90	22.83	0%
5	23.63	23.78	1%
6	24.26	24.21	0%
7	25.06	24.96	0%
8	25.77	25.59	-1%
9	26.54	26.33	-1%
10	27.31	26.99	-1%

Figure 48: Scenario 2 – Annual GHG Emissions Comparison

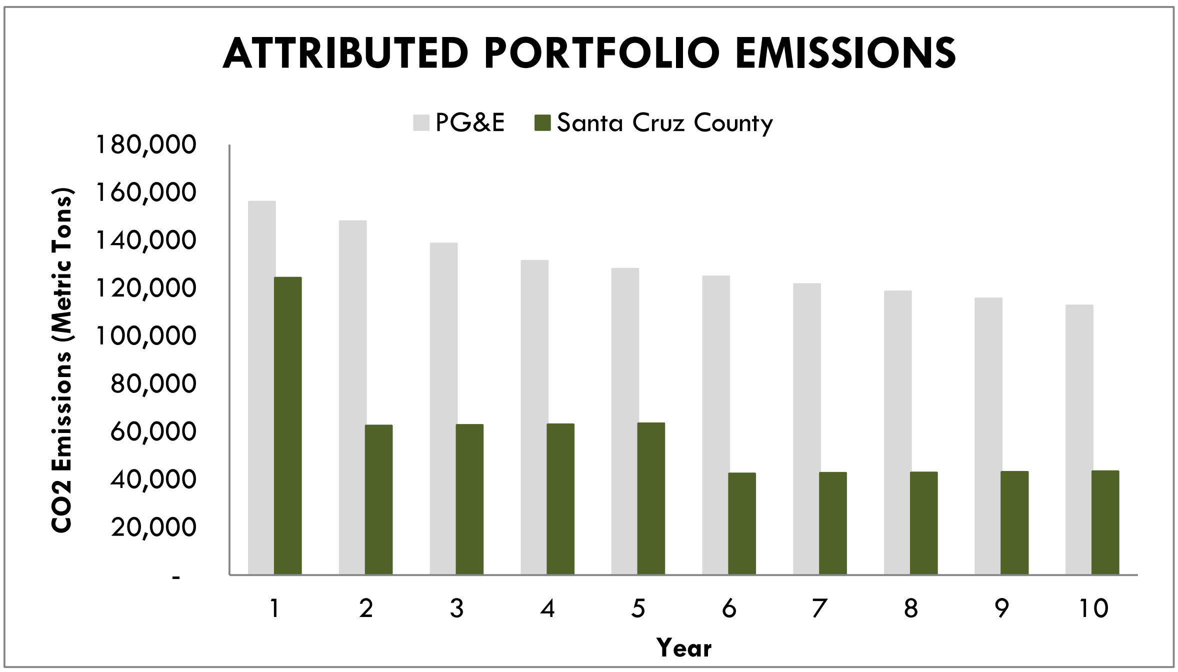


Figure 49: Scenario 3 Annual Ratepayer Costs

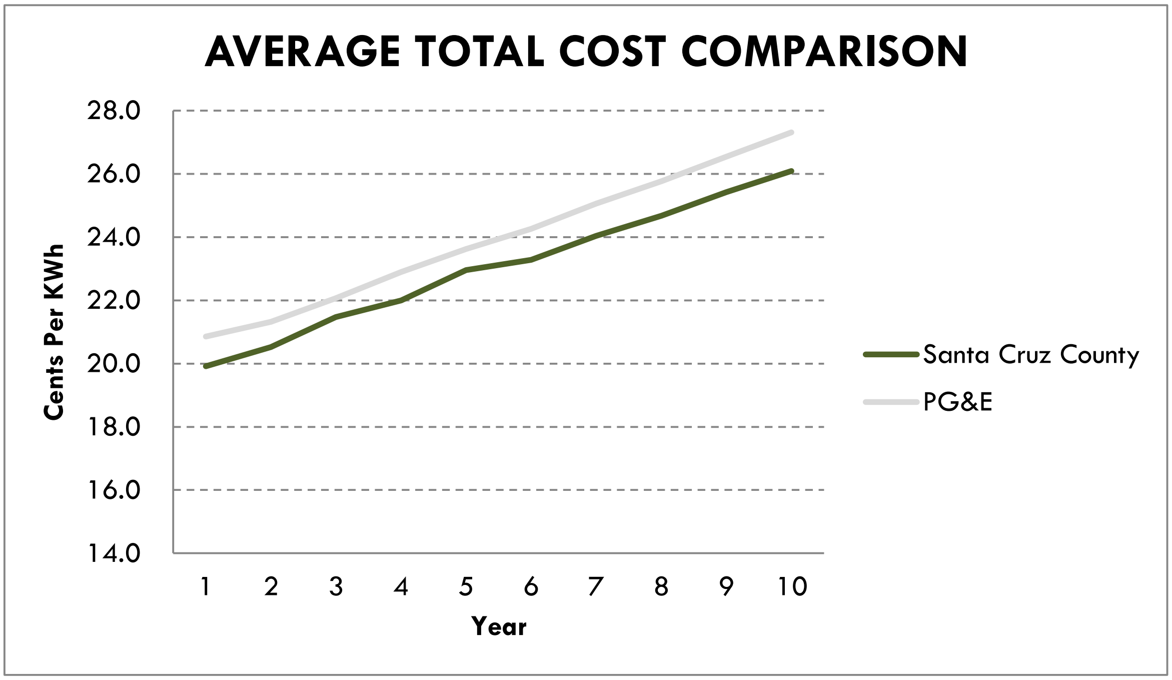
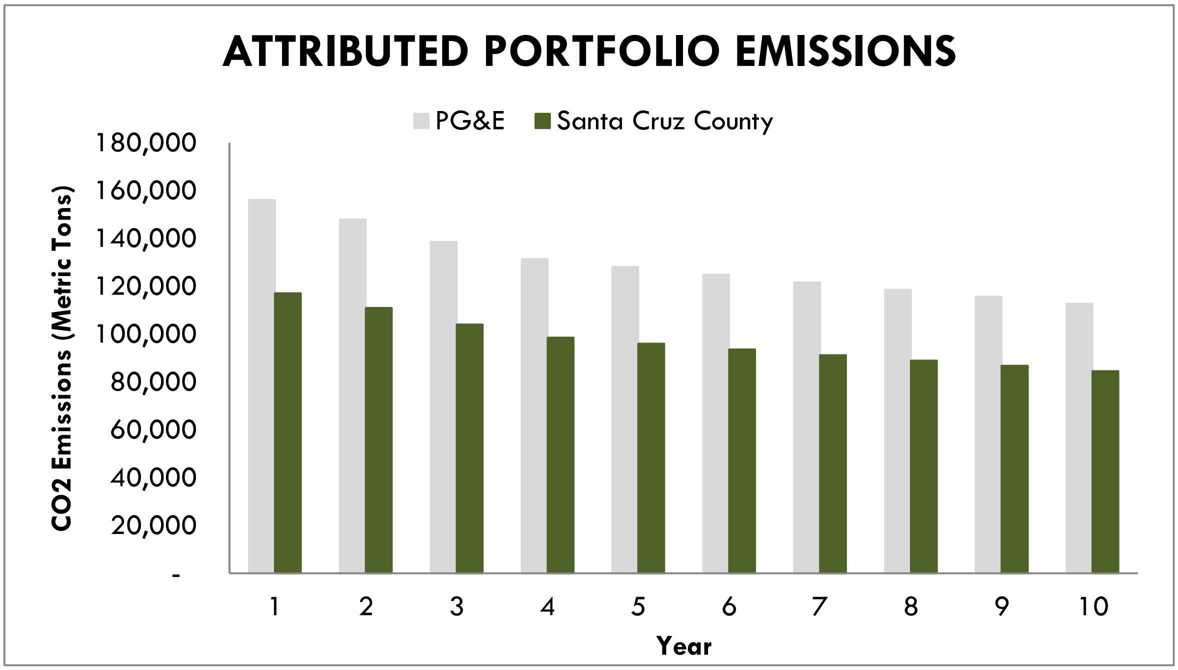


Table 49: Scenario 3 - Annual Total Delivered Rate Comparison

Year	PG&E Total (₵/kWh)	CCE Total (₵/kWh)	Percent Difference
Levelized	23.65	22.74	-4%
1	20.85	19.92	-4%
2	21.32	20.52	-4%
3	22.07	21.47	-3%
4	22.90	22.00	-4%
5	23.63	22.96	-3%
6	24.26	23.28	-4%
7	25.06	24.04	-4%
8	25.77	24.68	-4%
9	26.54	25.43	-4%
10	27.31	26.10	-4%

Figure 50: Scenario 3 – Annual GHG Emissions Comparison



Findings and Conclusions, Santa Cruz County

Based on the results reflected in Santa Cruz County's individual analysis, rate-related impacts are very similar to those reflected in the broader MBCP study, indicating levelized savings under each indicative supply scenario that generally approximates projected savings for the tri-county region. With regard to GHG emissions reductions, proportionate impacts are generally equivalent (with absolute impacts – measured in metric tons – reduced in consideration of the smaller subset of customers within Santa Cruz County relative to the entire MBCP customer base). Based on PEA's observations, Santa Cruz County appears to be a viable candidate for independent CCE implementation, demonstrating the potential for significant environmental benefits and rate competitiveness.

APPENDIX B: MBCP PRO FORMA ANALYSES

When reviewing MBCP's Pro Forma Analyses, there are certain line items that require further explanation/definition in order to appropriately understand the scope of inputs and outcomes reflected therein. These line items include the following:

Short Term Market Purchases: Electric energy purchases from the CAISO spot market. Such energy purchases are not directly associated with specific generating resources and will be characterized as "unspecified purchases" within MBCP's annual Power Content Label. Such purchases have been attributed the California Air Resource Board-designated emissions factor for unspecified purchases, which generally reflects the emissions intensity of a moderately efficient natural gas generator.

Conventional and Renewable Power Purchase Agreements: Electric energy purchases arranged with generator owners, power marketers or other suppliers with term lengths ranging from approximately one month to 25-years in duration. Such transactions may designate specific generating sources or generic energy purchases from the CAISO market, depending on MBCP's preferences. For example, purchases associated with the indicative long-term contract portfolio reflected in this Study will be included in this category and will designate specific renewable generating sources within applicable transaction documents. This category may also include term purchases of electric energy from unspecified sources to fulfill a portion of MBCP's non-GHG-free energy requirements.

Short Term Renewable Energy Purchases: Electric energy purchases from RPS-eligible renewable generating sources with term lengths ranging from approximately one month to 5-years in duration. Specified generating sources may be identified in applicable transaction documents. However, short-term renewable energy suppliers may source applicable renewable energy quantities from a pool of multiple generating resources meeting the eligibility requirements of California's RPS program.

Short Term Carbon Free Energy Purchases: Electric energy purchases from regionally located hydroelectric generating sources with term lengths ranging from approximately one month to 5-years in duration. Specified generating sources may be identified in applicable transaction documents. However, short-term carbon-free energy suppliers may source applicable energy quantities from a pool of multiple hydroelectric generating resources.

Ancillary Services and CAISO Charges: Costs imposed by the CAISO on all market participants, including Community Choice Energy providers, for purposes of ensuring grid reliability and management of CAISO power markets.

Resource Adequacy Capacity: Charges incurred by all load serving entities, including Community Choice Energy providers, for purposes of ensuring that sufficient reserve capacity remains available during periods of unexpectedly high demand, infrastructure outages, weather variations and other contingencies. Resource Adequacy procurement is the subject of various regulatory compliance obligations, including periodic reporting. Currently, the reserve capacity requirement is based on a reserve margin of 115% of forecasted monthly peak demands.

Staff and Other Operating Costs: Costs incurred by MBCP to administer the CCE program, including staff, consultants, overhead, program management and other ancillary expenses.

Billing and Data Management: Costs incurred by MBCP to procure the services of a qualified vendor that will interface with PG&E (to ensure the accurate and timely transfer of customer billing data) and the CAISO (for *purposes of communicating settlement quality meter data that will be used during the CAISO settlement process). Customer service functions are also subsumed in this vendor relationship, including the administration of a MBCP call center that will staffed for purposes of addressing various customer inquiries.*

Uncollectible Expense: In any utility operation, certain customers will not pay some/all of billed charges. For purposes of the Study, an assumed uncollectible rate of 0.5% was applied (as a percentage of total MBCP operating costs). This assumption is based on observations related to California's currently operating CCAs as well as prior discussions with PG&E.

Startup Financing: Repayment of principal and interest for amounts required by MBCP to effectively implement the CCE program, including administrative costs incurred prior to the receipt of customer revenues, timing lags between supplier payments and customer revenue collection, and seasonal variations in revenue collection (relative to costs) during early-stage operations. Such financing is assumed to be secured through bank loans, letters of credit, MBCP member contributions or a combination of these potential sources.

CCA Bond Carry Cost: Assumed interest payment associated with the requisite $100,000 CCA bond that must be posted with the CPUC.

Green Pricing Premium: Incremental revenues associated with the collection of rate premiums (in excess of the participating customer's default generation rate) to be paid by participants in MBCP's voluntary 100% renewable energy service option.

Market Sales: Revenues received during isolated instances when energy supplied under MBCP's anticipated energy supply agreements may marginally exceed customer usage. In such instances, excess electric power will be sold in the CAISO market with revenues accruing to MBCP.

Contribution to Program Reserves: Planned operating reserve contribution, which has been assumed at a level of 4% of annual MBCP operating costs.

CCA Revenue Requirement: The total amount, inclusive of all MBCP operating costs and reserves, less Green Pricing Premium and Market Sales Revenues, which must be collected via MBCP customer rates.

Power Charge Indifference Adjustment: For purposes of promoting an accurate total cost comparison of MBCP and PG&E service, the Power Charge Indifference Adjustment is reflected in the Pro Forma. The Power Charge Indifference Adjustment is the primary component of CCE exit fees. This lines indicates the total amount to be collected from MBCP customer by PG&E during each year of program operation.

Franchise Fee Surcharge: A surcharge applied by PG&E to MBCP customers to ensure full collection of franchise fee amounts that are remitted to local governments.

CCA Revenue Requirement Plus PG&E CCA Customer Surcharges: The sum of similarly named line items.

Revenue at PG&E Generation Rates: Projected revenues to be collected by MBCP if PG&E generation rates were applied, without discount, to MBCP customers.

Total Change in Customer Electric Charge or Surplus: The calculated difference between the following line items: CCA Revenue Requirement Plus PG&E CCA Customer Surcharges less Revenue at PG&E Generation Rates. To the extent that a negative value results from this calculation, MBCP would have the opportunity to reduce customer rates (relative to PG&E), contribute additional amounts to program reserves, fund additional complementary energy programs or incentives, or a combination of these discretionary fund uses. To the extent that a positive *value results from the calculation, MBCP would be required to charge rates in excess of PG&E to collect the noted revenue requirement.*

Total Change in Customer Electric Charge or Surplus (%): The ratio represented by Total Change in Customer Electric Charge or Surplus divided by Revenue that would be collected at PG&E Total Rates.

APPENDIX C: ADDITIONAL OPERATING SENSITIVITY – HIGH LOCAL RENEWABLE INFRASTRUCTURE BUILDOUT

As noted in Section 6, MBCP's PDAC requested completion of an alternative sensitivity analysis to address prospective operating impacts related to the administration of an expanded MBCP Feed-In Tariff program. For reference, the base case assumptions reflected in this Study include an assumed FIT program with overall participatory limitations set at 20 MW, which would be implemented in four phases over a five-year period (with 5 MW of assumed small-scale renewable project development included within each phase). Base case assumptions also reflected FIT pricing ranging from $90/MWh to $100/MWh, reflecting above-market incentives that are assumed to be necessary for purposes of addressing regional development costs and attracting developer interest. In PEA's opinion, the base case FIT assumptions were quite aggressive, particularly with regard to the timing of project development. For example, MCE, which has been serving customers since May 2010 and released its FIT program contemporaneous with service commencement, has secured FIT contracts approximating 5-6 MW; of this contract capacity, 1 MW of local solar generation is currently operational (and serving as a wholesale supplier to MCE). This case study highlights the challenges of local infrastructure buildout even when supported by comparatively favorable pricing structures.

For purposes of the "High FIT" sensitivity, PEA was advised to increase the overall participatory cap of MBCP's FIT program to 100 MW (an increase of 80 MW) with associated pricing increases to promote additional participation (ranging from $110/MWh to $120/MWh; up from the base case FIT price range of $90/MWh to $100/MWh) – it is noteworthy that PG&E's current ReMAT program offers a base price for solar energy deliveries of $61.23/MWh, as of May 2, 2016; this price is subject to time-of-delivery adjustments, which may increase the price paid to project owners by approximately 10-20% relative to the aforementioned base price. These sensitivity parameters were applied to indicative Scenario 3, as previously described in this Study. No other assumptions were altered (other than the aforementioned FIT capacity increase and related price increases) when completing this analysis.

From a practical perspective, the specified parameters for the High FIT sensitivity are *very aggressive*, reflecting prospective outcomes that have not yet been achieved by California's operating CCA programs or by the incumbent utility (within the prospective MBCP service territory during any five-year period). With this in mind, it is important to view the High Fit sensitivity as aspirational, reflecting goals that may not be realized for the foreseeable future. Regardless, the economic impacts resulting from this sensitivity, including anticipated rate changes resulting from additional above-market renewable energy purchases, were quite modest, largely due to the relatively small volumes of renewable energy produced by incremental FIT capacity relative to MBCP's total energy requirement. Table 50 (below) provides a comparison of expected PG&E rates over the ten-year Study period to rates resulting from the High Fit analysis; base case rates associated with indicative supply scenario 3 are also provided for context.

Table 50: High FIT Sensitivity – Customer Rate Comparison

Year	PG&E Total (₵/kWh)	CCE Total, Scenario 3 (Base Case, ₵/kWh)	CCE Total, Scenario 3 (High FIT, ₵/kWh)	Percent Difference Scenario 3 Base Case vs. High FIT	Percent Difference High FIT vs. PG&E
Levelized	22.82	21.80	21.91	1%	-3%
1	19.80	19.20	19.20	0%	-5%
2	20.25	19.33	19.33	0%	-4%
3	20.96	20.10	20.17	0%	-5%
4	21.75	20.64	20.69	0%	-3%
5	22.44	21.56	21.67	1%	-4%
6	23.05	22.01	22.17	1%	-4%
7	23.80	22.73	22.93	1%	-4%
8	24.48	23.34	23.52	1%	-4%
9	25.21	24.05	24.18	1%	-4%
10	25.94	24.69	24.79	0%	-3%

PEA also completed a stand-alone pro forma analysis for the High Fit sensitivity, which is reflected below in Table 51. Despite the economic feasibility of such a program, technical limitations associated with local renewable infrastructure buildout at this scale would likely compromise the achievement of desired objectives. For this reason, MBCP may choose to administer a high-capacity FIT program but would not likely be successful in achieving full participation without significantly increasing associated pricing.

Table 51: High FIT Sensitivity – Pro Forma Analysis

Monterey Bay Community Power
FINANCIAL PRO FORMA ANALYSIS
COMMUNITY CHOICE AGGREGATION
SCENARIO 3 - HIGH FIT SENSITIVITY

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)	70,647	142,000	214,065	215,135	216,211	217,292	218,378	219,470	220,567	221,670
SMALL COMMERCIAL (A-1)	7,808	15,694	23,658	23,777	23,896	24,015	24,135	24,256	24,377	24,499
SMALL COMMERCIAL (A-6)	474	952	1,435	1,442	1,450	1,457	1,464	1,472	1,479	1,486
MEDIUM COMMERCIAL (A-10)	683	1,372	2,069	2,079	2,090	2,100	2,111	2,121	2,132	2,142
LARGE COMMERCIAL (E-19)	315	634	955	960	965	970	974	979	984	989
INDUSTRIAL (E-20)	12	24	36	36	36	36	36	37	37	37
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	592	1,191	1,795	1,804	1,813	1,822	1,831	1,841	1,850	1,859
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	1,421	2,856	4,305	4,327	4,348	4,370	4,392	4,414	4,436	4,458
SUBTOTAL - CUSTOMER ACCOUNTS	81,951	164,722	248,318	249,560	250,808	252,062	253,322	254,589	255,862	257,141
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	378,452,127	760,688,775	1,146,738,328	1,152,472,020	1,158,234,380	1,164,025,552	1,169,845,680	1,175,694,908	1,181,573,383	1,187,481,250
SMALL COMMERCIAL (A-1)	107,600,535	216,277,075	326,037,690	327,667,879	329,306,218	330,952,749	332,607,513	334,270,550	335,941,903	337,621,613
SMALL COMMERCIAL (A-6)	23,992,135	48,224,192	72,697,970	73,061,460	73,426,767	73,793,901	74,162,870	74,533,685	74,906,353	75,280,885
MEDIUM COMMERCIAL (A-10)	112,709,496	226,546,087	341,518,226	343,225,817	344,941,946	346,666,656	348,399,989	350,141,989	351,892,699	353,652,163
LARGE COMMERCIAL (E-19)	138,338,987	278,061,364	419,177,506	421,273,394	423,379,761	425,496,659	427,624,143	429,762,263	431,911,075	434,070,630
INDUSTRIAL (E-20)	111,785,418	224,688,690	338,718,201	340,411,792	342,113,851	343,824,420	345,543,542	347,271,260	349,007,616	350,752,654
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	5,213,992	10,480,124	15,798,787	15,877,781	15,957,170	16,036,956	16,117,141	16,197,727	16,278,715	16,360,109
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	186,503,659	374,872,355	565,120,075	567,945,675	570,785,404	573,639,331	576,507,527	579,390,065	582,287,015	585,198,450
SUBTOTAL - LOAD REQUIREMENTS	1,064,596,349	2,139,838,662	3,225,806,783	3,241,935,817	3,258,145,496	3,274,436,224	3,290,808,405	3,307,262,447	3,323,798,759	3,340,417,753
III. CCA OPERATING COSTS ($)										
SHORT TERM MARKET PURCHASES	$3,205,663	$6,437,658	$9,534,902	$9,648,953	$10,140,539	$10,500,237	$10,866,927	$11,083,393	$11,268,481	$11,521,395
CONVENTIONAL AND RENEWABLE POWER PURCHASE AGREEMENTS	$8,078,272	$16,222,898	$62,659,553	$77,868,745	$109,998,507	$116,382,087	$122,801,241	$140,613,334	$140,566,547	$147,003,475
SHORT TERM RENEWABLE ENERGY PURCHASES	$16,504,308	$37,196,705	$33,633,255	$23,751,380	$3,821,578	$5,138,202	$6,616,860	$0	$0	$0
SHORT TERM CARBON FREE ENERGY PURCHASES	$19,164,684	$40,353,482	$63,747,875	$68,253,286	$71,452,158	$74,509,137	$77,582,798	$74,716,292	$80,571,328	$82,094,108
ANCILLARY SERVICES AND CAISO CHARGES	$3,180,910	$6,605,095	$10,282,450	$10,706,535	$11,132,077	$11,571,491	$12,029,037	$12,503,534	$12,963,429	$13,450,998
RESOURCE ADEQUACY CAPACITY	$5,541,703	$11,483,478	$15,052,075	$13,280,014	$12,461,216	$12,205,413	$11,933,193	$11,915,362	$12,479,090	$12,788,896
STAFF AND OTHER OPERATING COSTS	$7,107,606	$8,390,814	$9,734,117	$9,946,607	$10,163,794	$10,385,783	$10,612,681	$10,844,599	$11,081,648	$11,323,945
BILLING AND DATA MANAGEMENT	$1,927,492	$3,990,488	$6,196,130	$6,413,924	$6,639,373	$6,872,747	$7,114,324	$7,364,393	$7,623,251	$7,891,209
UNCOLLECTIBLES EXPENSE	$339,301	$669,151	$1,069,949	$1,111,029	$1,190,728	$1,237,825	$1,297,785	$1,345,205	$1,382,769	$1,430,370
STARTUP FINANCING	$3,149,514	$3,149,514	$3,149,514	$2,336,394	$2,336,394	$0	$0	$0	$0	$0
CCA BOND CARRYING COST	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
SUBTOTAL - CCA OPERATING COSTS	$68,200,953	$134,500,782	$215,061,320	$223,318,367	$239,337,866	$248,804,423	$260,856,348	$270,387,611	$277,938,044	$287,505,897
IV. REVENUES FROM 100% GREEN PREMIUM AND MARKET SALES ($)										
GREEN PRICING PREMIUM	$258,009	$519,522	$783,952	$787,986	$794,987	$801,507	$807,503	$812,930	$817,741	$821,886
MARKET SALES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
V. CONTRIBUTION TO PROGRAM RESERVES ($)	$2,728,038	$5,380,031	$8,602,453	$8,932,735	$9,573,515	$9,952,177	$10,434,254	$10,815,504	$11,117,522	$11,500,236
VI. CCA REVENUE REQUIREMENT ($)	$70,670,982	$139,361,290	$222,879,820	$231,463,115	$248,116,393	$257,955,093	$270,483,098	$280,390,185	$288,237,824	$298,184,246
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	6.6	6.5	6.9	7.1	7.6	7.9	8.2	8.5	8.7	8.9
PG&E AVERAGE GENERATION COST (CENTS/KWH)	9.4	9.6	10.0	10.4	10.8	11.0	11.4	11.7	12.1	12.4
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
POWER CHARGE INDIFFERENCE ADJUSTMENT	$22,881,655	$44,795,597	$71,250,517	$70,492,889	$76,151,611	$72,816,712	$74,910,927	$73,705,727	$76,944,078	$76,156,930
FRANCHISE FEE SURCHARGE	$615,036	$1,253,628	$1,967,254	$2,068,756	$2,149,075	$2,210,287	$2,301,334	$2,373,965	$2,457,238	$2,538,592
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 23,496,690	$ 46,049,225	$ 73,217,771	$ 72,561,645	$ 78,300,686	$ 75,027,000	$ 77,212,261	$ 76,079,692	$ 79,401,317	$ 78,695,522
VIII. CCA REVENUE REQUIREMENT PLUS PG&E CCA CUSTOMER SURCHARGES	$94,167,672	$185,410,516	$296,097,592	$304,024,760	$326,417,079	$332,982,093	$347,695,360	$356,469,877	$367,639,141	$376,879,768
IX. REVENUE AT PG&E GENERATION RATES	$100,592,316	$205,037,491	$321,754,786	$338,355,876	$351,492,517	$361,504,104	$376,395,220	$388,274,459	$401,894,256	$415,200,069
X. TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS	$ (6,424,644)	$ (19,626,975)	$ (25,657,195)	$ (34,331,116)	$ (25,075,438)	$ (28,522,011)	$ (28,699,860)	$ (31,804,582)	$ (34,255,115)	$ (38,320,300)
CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS (%)	-3%	-5%	-4%	-5%	-3%	-4%	-4%	-4%	-4%	-4%

Monterey Bay Community Power
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)	70,647	142,000	214,065	215,135	216,211	217,292	218,378	219,470	220,567	221,670
SMALL COMMERCIAL (A-1)	7,808	15,694	23,658	23,777	23,896	24,015	24,135	24,256	24,377	24,499
SMALL COMMERCIAL (A-6)	474	952	1,435	1,442	1,450	1,457	1,464	1,472	1,479	1,486
MEDIUM COMMERCIAL (A-10)	683	1,372	2,069	2,079	2,090	2,100	2,111	2,121	2,132	2,142
LARGE COMMERCIAL (E-19)	315	634	955	960	965	970	974	979	984	989
INDUSTRIAL (E-20)	12	24	36	36	36	36	36	37	37	37
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	592	1,191	1,795	1,804	1,813	1,822	1,831	1,841	1,850	1,859
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	1,421	2,856	4,305	4,327	4,348	4,370	4,392	4,414	4,436	4,458
SUBTOTAL - CUSTOMER ACCOUNTS	81,951	164,722	248,318	249,560	250,808	252,062	253,322	254,589	255,862	257,141
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	378,452,127	760,688,775	1,146,738,328	1,152,472,020	1,158,234,380	1,164,025,552	1,169,845,680	1,175,694,908	1,181,573,383	1,187,481,250
SMALL COMMERCIAL (A-1)	107,600,535	216,277,075	326,037,690	327,667,879	329,306,218	330,952,749	332,607,513	334,270,550	335,941,903	337,621,613
SMALL COMMERCIAL (A-6)	23,992,135	48,224,192	72,697,970	73,061,460	73,426,767	73,793,901	74,162,870	74,533,685	74,906,353	75,280,885
MEDIUM COMMERCIAL (A-10)	112,709,496	226,546,087	341,518,226	343,225,817	344,941,946	346,666,656	348,399,989	350,141,989	351,892,699	353,652,163
LARGE COMMERCIAL (E-19)	138,338,987	278,061,364	419,177,506	421,273,394	423,379,761	425,496,659	427,624,143	429,762,263	431,911,075	434,070,630
INDUSTRIAL (E-20)	111,785,418	224,688,690	338,718,201	340,411,792	342,113,851	343,824,420	345,543,542	347,271,260	349,007,616	350,752,654
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	5,213,992	10,480,124	15,798,787	15,877,781	15,957,170	16,036,956	16,117,141	16,197,727	16,278,715	16,360,109
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	186,503,659	374,872,355	565,120,075	567,945,675	570,785,404	573,639,331	576,507,527	579,390,065	582,287,015	585,198,450
SUBTOTAL - LOAD REQUIREMENTS	1,064,596,349	2,139,838,662	3,225,806,783	3,241,935,817	3,258,145,496	3,274,436,224	3,290,808,405	3,307,262,447	3,323,798,759	3,340,417,753
III. CCA OPERATING COSTS ($)										
SHORT TERM MARKET PURCHASES	$3,412,375	$6,054,499	$9,554,028	$8,290,905	$9,011,015	$9,631,733	$7,892,640	$8,170,585	$8,560,139	$9,018,484
CONVENTIONAL AND RENEWABLE POWER PURCHASE AGREEMENTS	$8,599,185	$15,257,337	$57,889,750	$69,676,644	$97,594,467	$99,956,316	$96,375,746	$114,532,071	$115,187,947	$122,328,096
SHORT TERM RENEWABLE ENERGY PURCHASES	$35,915,111	$97,082,482	$126,474,349	$129,521,407	$111,436,615	$117,894,613	$137,351,005	$125,565,064	$132,104,327	$132,882,265
SHORT TERM CARBON FREE ENERGY PURCHASES	$5,081,361	$0	$210,010	$0	$0	$0	$0	$0	$0	$0
ANCILLARY SERVICES AND CAISO CHARGES	$3,180,910	$6,605,095	$10,282,450	$10,706,535	$11,132,077	$11,571,491	$12,029,037	$12,503,534	$12,963,429	$13,450,998
RESOURCE ADEQUACY CAPACITY	$5,541,703	$11,483,478	$15,506,564	$13,743,457	$13,415,957	$13,811,926	$14,223,307	$14,250,591	$14,860,323	$15,217,039
STAFF AND OTHER OPERATING COSTS	$7,107,606	$8,390,814	$9,734,117	$9,946,607	$10,163,794	$10,385,783	$10,612,681	$10,844,599	$11,081,648	$11,323,945
BILLING AND DATA MANAGEMENT	$1,927,492	$3,990,488	$6,196,130	$6,413,924	$6,639,373	$6,872,747	$7,114,324	$7,364,393	$7,623,251	$7,891,209
UNCOLLECTIBLES EXPENSE	$369,576	$760,069	$1,194,985	$1,253,179	$1,308,648	$1,350,623	$1,427,994	$1,466,154	$1,511,905	$1,560,560
STARTUP FINANCING	$3,149,514	$3,149,514	$3,149,514	$2,336,394	$2,336,394	$0	$0	$0	$0	$0
CCA BOND CARRYING COST	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
SUBTOTAL - CCA OPERATING COSTS	$74,286,332	$152,775,274	$240,193,396	$251,890,552	$263,039,840	$271,476,733	$287,028,234	$294,698,490	$303,894,469	$313,674,096
IV. REVENUES FROM 100% GREEN PREMIUM AND MARKET SALES ($)										
GREEN PRICING PREMIUM	$174,037	$214,470	$333,013	$275,775	$285,468	$295,503	$229,417	$237,481	$245,829	$254,469
MARKET SALES	$0	$0	$0	$0	$0	$0	$186,392	$0	$0	$0
V. CONTRIBUTION TO PROGRAM RESERVES ($)	$2,971,453	$6,111,011	$9,607,736	$10,075,622	$10,521,594	$10,859,069	$11,473,674	$11,787,940	$12,155,779	$12,546,964
VI. CCA REVENUE REQUIREMENT ($)	$77,083,748	$158,671,815	$249,468,119	$261,690,399	$273,275,966	$282,040,300	$298,086,098	$306,248,949	$315,804,420	$325,966,590
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	7.2	7.4	7.7	8.1	8.4	8.6	9.1	9.3	9.5	9.8
PG&E AVERAGE GENERATION COST (CENTS/KWH)	9.4	9.6	10.0	10.4	10.8	11.0	11.4	11.7	12.1	12.4
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
POWER CHARGE INDIFFERENCE ADJUSTMENT	$22,881,655	$44,795,597	$71,250,517	$70,492,889	$76,151,611	$72,816,712	$74,910,927	$73,705,727	$76,944,078	$76,156,930
FRANCHISE FEE SURCHARGE	$615,036	$1,253,628	$1,967,254	$2,068,756	$2,149,075	$2,210,287	$2,301,334	$2,373,965	$2,457,238	$2,538,592
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 23,496,690	$ 46,049,225	$ 73,217,771	$ 72,561,645	$ 78,300,686	$ 75,027,000	$ 77,212,261	$ 76,079,692	$ 79,401,317	$ 78,695,522
VIII. CCA REVENUE REQUIREMENT PLUS PG&E CCA CUSTOMER SURCHARGES	$100,580,438	$204,721,040	$322,685,890	$334,252,044	$351,576,652	$357,067,299	$375,298,359	$382,328,641	$395,205,736	$404,662,112
IX. REVENUE AT PG&E GENERATION RATES	$100,592,316	$205,037,491	$321,754,786	$338,355,876	$351,492,517	$361,504,104	$376,395,220	$388,274,459	$401,894,256	$415,200,069
X. TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS	$ (11,878)	$ (316,451)	$ 931,103	$ (4,103,832)	$ 84,135	$ (4,436,805)	$ (1,096,861)	$ (5,945,819)	$ (6,688,519)	$ (10,537,956)
CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS (%)	0%	0%	0%	-1%	0%	-1%	0%	-1%	-1%	-1%

Monterey Bay Community Power
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)	70,647	142,000	214,065	215,135	216,211	217,292	218,378	219,470	220,567	221,670
SMALL COMMERCIAL (A-1)	7,808	15,694	23,658	23,777	23,896	24,015	24,135	24,256	24,377	24,499
SMALL COMMERCIAL (A-6)	474	952	1,435	1,442	1,450	1,457	1,464	1,472	1,479	1,486
MEDIUM COMMERCIAL (A-10)	683	1,372	2,069	2,079	2,090	2,100	2,111	2,121	2,132	2,142
LARGE COMMERCIAL (E-19)	315	634	955	960	965	970	974	979	984	989
INDUSTRIAL (E-20)	12	24	36	36	36	36	36	37	37	37
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	592	1,191	1,795	1,804	1,813	1,822	1,831	1,841	1,850	1,859
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	1,421	2,856	4,305	4,327	4,348	4,370	4,392	4,414	4,436	4,458
SUBTOTAL - CUSTOMER ACCOUNTS	81,951	164,722	248,318	249,560	250,808	252,062	253,322	254,589	255,862	257,141
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	378,452,127	760,688,775	1,146,738,328	1,152,472,020	1,158,234,380	1,164,025,552	1,169,845,680	1,175,694,908	1,181,573,383	1,187,481,250
SMALL COMMERCIAL (A-1)	107,600,535	216,277,075	326,037,690	327,667,879	329,306,218	330,952,749	332,607,513	334,270,550	335,941,903	337,621,613
SMALL COMMERCIAL (A-6)	23,992,135	48,224,192	72,697,970	73,061,460	73,426,767	73,793,901	74,162,870	74,533,685	74,906,353	75,280,885
MEDIUM COMMERCIAL (A-10)	112,709,496	226,546,087	341,518,226	343,225,817	344,941,946	346,666,656	348,399,989	350,141,989	351,892,699	353,652,163
LARGE COMMERCIAL (E-19)	138,338,987	278,061,364	419,177,506	421,273,394	423,379,761	425,496,659	427,624,143	429,762,263	431,911,075	434,070,630
INDUSTRIAL (E-20)	111,785,418	224,688,690	338,718,201	340,411,792	342,113,851	343,824,420	345,543,542	347,271,260	349,007,616	350,752,654
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	5,213,992	10,480,124	15,798,787	15,877,781	15,957,170	16,036,956	16,117,141	16,197,727	16,278,715	16,360,109
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	186,503,659	374,872,355	565,120,075	567,945,675	570,785,404	573,639,331	576,507,527	579,390,065	582,287,015	585,198,450
SUBTOTAL - LOAD REQUIREMENTS	1,064,596,349	2,139,838,662	3,225,806,783	3,241,935,817	3,258,145,496	3,274,436,224	3,290,808,405	3,307,262,447	3,323,798,759	3,340,417,753
III. CCA OPERATING COSTS ($)										
SHORT TERM MARKET PURCHASES	$3,397,513	$3,828,246	$6,064,268	$6,294,935	$6,918,819	$5,236,332	$5,587,142	$5,842,370	$6,116,790	$6,440,016
CONVENTIONAL AND RENEWABLE POWER PURCHASE AGREEMENTS	$8,561,732	$9,647,181	$49,095,556	$64,646,800	$92,322,133	$88,879,907	$90,565,891	$108,664,969	$109,030,708	$115,830,357
SHORT TERM RENEWABLE ENERGY PURCHASES	$40,941,819	$104,302,397	$137,978,500	$131,497,198	$116,861,763	$134,670,498	$142,120,366	$132,997,304	$139,768,890	$141,318,840
SHORT TERM CARBON FREE ENERGY PURCHASES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANCILLARY SERVICES AND CAISO CHARGES	$3,180,910	$6,605,095	$10,282,450	$10,706,535	$11,132,077	$11,571,491	$12,029,037	$12,503,534	$12,963,429	$13,450,998
RESOURCE ADEQUACY CAPACITY	$5,541,703	$11,483,478	$15,506,564	$13,743,457	$13,415,957	$13,811,926	$14,223,307	$14,250,591	$14,860,323	$15,217,039
STAFF AND OTHER OPERATING COSTS	$7,107,606	$8,390,814	$9,734,117	$9,946,607	$10,163,794	$10,385,783	$10,612,681	$10,844,599	$11,081,648	$11,323,945
BILLING AND DATA MANAGEMENT	$1,927,492	$3,990,488	$6,196,130	$6,413,924	$6,639,373	$6,872,747	$7,114,324	$7,364,393	$7,623,251	$7,891,209
UNCOLLECTIBLES EXPENSE	$369,041	$756,986	$1,190,035	$1,227,929	$1,298,952	$1,357,143	$1,411,264	$1,462,339	$1,507,225	$1,557,362
STARTUP FINANCING	$3,149,514	$3,149,514	$3,149,514	$2,336,394	$2,336,394	$0	$0	$0	$0	$0
CCA BOND CARRYING COST	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
SUBTOTAL - CCA OPERATING COSTS	$74,178,830	$152,155,698	$239,198,634	$246,815,279	$261,090,762	$272,787,328	$283,665,511	$293,931,598	$302,953,764	$313,031,266
IV. REVENUES FROM 100% GREEN PREMIUM AND MARKET SALES ($)										
GREEN PRICING PREMIUM	$106,031	$109,758	$170,424	$176,415	$182,616	$126,023	$130,453	$135,038	$139,785	$144,698
MARKET SALES	$0	$283,447	$425,974	$45,380	$178,973	$594,187	$620,533	$816,546	$839,978	$868,867
V. CONTRIBUTION TO PROGRAM RESERVES ($)	$2,967,153	$6,074,890	$9,550,906	$9,870,796	$10,436,472	$10,887,726	$11,321,799	$11,724,602	$12,084,551	$12,486,496
VI. CCA REVENUE REQUIREMENT ($)	$77,039,952	$157,837,383	$248,153,141	$256,464,280	$271,165,645	$282,954,843	$294,236,324	$304,704,616	$314,058,552	$324,504,197
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	7.2	7.4	7.7	7.9	8.3	8.6	8.9	9.2	9.4	9.7
PG&E AVERAGE GENERATION COST (CENTS/KWH)	9.4	9.6	10.0	10.4	10.8	11.0	11.4	11.7	12.1	12.4
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
POWER CHARGE INDIFFERENCE ADJUSTMENT	$22,881,655	$44,795,597	$71,250,517	$70,492,889	$76,151,611	$72,816,712	$74,910,927	$73,705,727	$76,944,078	$76,156,930
FRANCHISE FEE SURCHARGE	$615,036	$1,253,628	$1,967,254	$2,068,756	$2,149,075	$2,210,287	$2,301,334	$2,373,965	$2,457,238	$2,538,592
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 23,496,690	$ 46,049,225	$ 73,217,771	$ 72,561,645	$ 78,300,686	$ 75,027,000	$ 77,212,261	$ 76,079,692	$ 79,401,317	$ 78,695,522
VIII. CCA REVENUE REQUIREMENT PLUS PG&E CCA CUSTOMER SURCHARGES	$100,536,642	$203,886,608	$321,370,913	$329,025,925	$349,466,331	$357,981,842	$371,448,586	$380,784,308	$393,459,869	$403,199,719
IX. REVENUE AT PG&E GENERATION RATES	$100,592,316	$205,037,491	$321,754,786	$338,355,876	$351,492,517	$361,504,104	$376,395,220	$388,274,459	$401,894,256	$415,200,069
X. TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS	$ (55,674)	$ (1,150,882)	$ (383,874)	$ (9,329,951)	$ (2,026,186)	$ (3,522,262)	$ (4,946,634)	$ (7,490,151)	$ (8,434,387)	$ (12,000,349)
CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS (%)	0%	0%	0%	-1%	0%	0%	-1%	-1%	-1%	-1%

Monterey Bay Community Power
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)	70,647	142,000	214,065	215,135	216,211	217,292	218,378	219,470	220,567	221,670
SMALL COMMERCIAL (A-1)	7,808	15,694	23,658	23,777	23,896	24,015	24,135	24,256	24,377	24,499
SMALL COMMERCIAL (A-6)	474	952	1,435	1,442	1,450	1,457	1,464	1,472	1,479	1,486
MEDIUM COMMERCIAL (A-10)	683	1,372	2,069	2,079	2,090	2,100	2,111	2,121	2,132	2,142
LARGE COMMERCIAL (E-19)	315	634	955	960	965	970	974	979	984	989
INDUSTRIAL (E-20)	12	24	36	36	36	36	36	37	37	37
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	592	1,191	1,795	1,804	1,813	1,822	1,831	1,841	1,850	1,859
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	1,421	2,856	4,305	4,327	4,348	4,370	4,392	4,414	4,436	4,458
SUBTOTAL - CUSTOMER ACCOUNTS	81,951	164,722	248,318	249,560	250,808	252,062	253,322	254,589	255,862	257,141
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	378,452,127	760,688,775	1,146,738,328	1,152,472,020	1,158,234,380	1,164,025,552	1,169,845,680	1,175,694,908	1,181,573,383	1,187,481,250
SMALL COMMERCIAL (A-1)	107,600,535	216,277,075	326,037,690	327,667,879	329,306,218	330,952,749	332,607,513	334,270,550	335,941,903	337,621,613
SMALL COMMERCIAL (A-6)	23,992,135	48,224,192	72,697,970	73,061,460	73,426,767	73,793,901	74,162,870	74,533,685	74,906,353	75,280,885
MEDIUM COMMERCIAL (A-10)	112,709,496	226,546,087	341,518,226	343,225,817	344,941,946	346,666,656	348,399,989	350,141,989	351,892,699	353,652,163
LARGE COMMERCIAL (E-19)	138,338,987	278,061,364	419,177,506	421,273,394	423,379,761	425,496,659	427,624,143	429,762,263	431,911,075	434,070,630
INDUSTRIAL (E-20)	111,785,418	224,688,690	338,718,201	340,411,792	342,113,851	343,824,420	345,543,542	347,271,260	349,007,616	350,752,654
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	5,213,992	10,480,124	15,798,787	15,877,781	15,957,170	16,036,956	16,117,141	16,197,727	16,278,715	16,360,109
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	186,503,659	374,872,355	565,120,075	567,945,675	570,785,404	573,639,331	576,507,527	579,390,065	582,287,015	585,198,450
SUBTOTAL - LOAD REQUIREMENTS	1,064,596,349	2,139,838,662	3,225,806,783	3,241,935,817	3,258,145,496	3,274,436,224	3,290,808,405	3,307,262,447	3,323,798,759	3,340,417,753
III. CCA OPERATING COSTS ($)										
SHORT TERM MARKET PURCHASES	$3,205,663	$6,437,658	$9,554,028	$9,669,434	$10,186,270	$10,573,723	$10,971,571	$11,193,412	$11,381,956	$11,639,091
CONVENTIONAL AND RENEWABLE POWER PURCHASE AGREEMENTS	$8,078,272	$16,222,898	$57,889,750	$73,150,538	$100,556,110	$102,330,132	$104,134,652	$122,149,595	$122,298,927	$128,932,028
SHORT TERM RENEWABLE ENERGY PURCHASES	$16,504,308	$37,196,705	$35,917,641	$26,159,266	$8,649,262	$12,453,409	$16,704,237	$4,556,916	$10,222,550	$10,268,372
SHORT TERM CARBON FREE ENERGY PURCHASES	$19,164,684	$40,353,482	$63,747,875	$68,253,286	$71,452,158	$74,509,137	$77,582,798	$80,575,533	$82,107,091	$83,995,283
ANCILLARY SERVICES AND CAISO CHARGES	$3,180,910	$6,605,095	$10,282,450	$10,706,535	$11,132,077	$11,571,491	$12,029,037	$12,503,534	$12,963,429	$13,450,998
RESOURCE ADEQUACY CAPACITY	$5,541,703	$11,483,478	$15,506,564	$13,743,457	$13,415,957	$13,811,926	$14,223,307	$14,250,591	$14,860,323	$15,217,039
STAFF AND OTHER OPERATING COSTS	$7,107,606	$8,390,814	$9,734,117	$9,946,607	$10,163,794	$10,385,783	$10,612,681	$10,844,599	$11,081,648	$11,323,945
BILLING AND DATA MANAGEMENT	$1,927,492	$3,990,488	$6,196,130	$6,413,924	$6,639,373	$6,872,747	$7,114,324	$7,364,393	$7,623,251	$7,891,209
UNCOLLECTIBLES EXPENSE	$339,301	$669,151	$1,059,890	$1,101,897	$1,172,657	$1,212,542	$1,266,863	$1,317,193	$1,362,696	$1,413,590
STARTUP FINANCING	$3,149,514	$3,149,514	$3,149,514	$2,336,394	$2,336,394	$0	$0	$0	$0	$0
CCA BOND CARRYING COST	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
SUBTOTAL - CCA OPERATING COSTS	$68,200,953	$134,500,782	$213,039,459	$221,482,840	$235,705,553	$243,722,390	$254,640,971	$264,757,266	$273,903,370	$284,133,055
IV. REVENUES FROM 100% GREEN PREMIUM AND MARKET SALES ($)										
GREEN PRICING PREMIUM	$258,009	$519,522	$783,952	$787,986	$794,987	$801,507	$807,503	$812,930	$817,741	$821,886
MARKET SALES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
V. CONTRIBUTION TO PROGRAM RESERVES ($)	$2,728,038	$5,380,031	$8,521,578	$8,859,314	$9,428,222	$9,748,896	$10,185,639	$10,590,291	$10,956,135	$11,365,322
VI. CCA REVENUE REQUIREMENT ($)	$70,670,982	$139,361,290	$220,777,085	$229,554,167	$244,338,788	$252,669,778	$264,019,106	$274,534,627	$284,041,764	$294,676,491
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	6.6	6.5	6.8	7.1	7.5	7.7	8.0	8.3	8.5	8.8
PG&E AVERAGE GENERATION COST (CENTS/KWH)	9.4	9.6	10.0	10.4	10.8	11.0	11.4	11.7	12.1	12.4
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
POWER CHARGE INDIFFERENCE ADJUSTMENT	$22,881,655	$44,795,597	$71,250,517	$70,492,889	$76,151,611	$72,816,712	$74,910,927	$73,705,727	$76,944,078	$76,156,930
FRANCHISE FEE SURCHARGE	$615,036	$1,253,628	$1,967,254	$2,068,756	$2,149,075	$2,210,287	$2,301,334	$2,373,965	$2,457,238	$2,538,592
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 23,496,690	$ 46,049,225	$ 73,217,771	$ 72,561,645	$ 78,300,686	$ 75,027,000	$ 77,212,261	$ 76,079,692	$ 79,401,317	$ 78,695,522
VIII. CCA REVENUE REQUIREMENT PLUS PG&E CCA CUSTOMER SURCHARGES	$94,167,672	$185,410,516	$293,994,856	$302,115,812	$322,639,474	$327,696,778	$341,231,368	$350,614,319	$363,443,081	$373,372,014
IX. REVENUE AT PG&E GENERATION RATES	$100,592,316	$205,037,491	$321,754,786	$338,355,876	$351,492,517	$361,504,104	$376,395,220	$388,274,459	$401,894,256	$415,200,069
X. TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS	$ (6,424,644)	$ (19,626,975)	$ (27,759,930)	$ (36,240,064)	$ (28,853,044)	$ (33,807,326)	$ (35,163,852)	$ (37,660,141)	$ (38,451,175)	$ (41,828,055)
CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS (%)	-3%	-5%	-4%	-5%	-4%	-4%	-4%	-5%	-5%	-5%

Monterey County (Single County)
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)	58,111	116,803	117,387	117,974	118,564	119,157	119,752	120,351	120,953	121,558
SMALL COMMERCIAL (A-1)	6,610	13,286	13,353	13,419	13,486	13,554	13,622	13,690	13,758	13,827
SMALL COMMERCIAL (A-6)	396	795	799	803	807	811	815	819	823	828
MEDIUM COMMERCIAL (A-10)	605	1,216	1,222	1,228	1,234	1,240	1,246	1,253	1,259	1,265
LARGE COMMERCIAL (E-19)	295	593	596	599	602	605	608	611	614	617
INDUSTRIAL (E-20)	12	24	24	25	25	25	25	25	25	25
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	524	1,053	1,058	1,063	1,069	1,074	1,079	1,085	1,090	1,096
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	1,513	3,042	3,057	3,072	3,088	3,103	3,119	3,134	3,150	3,166
SUBTOTAL - CUSTOMER ACCOUNTS	68,066	136,812	137,496	138,184	138,874	139,569	140,267	140,968	141,673	142,381
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	288,852,912	580,594,353	583,497,325	586,414,812	589,346,886	592,293,620	595,255,088	598,231,364	601,222,521	604,228,633
SMALL COMMERCIAL (A-1)	90,881,123	182,671,057	183,584,413	184,502,335	185,424,846	186,351,971	187,283,731	188,220,149	189,161,250	190,107,056
SMALL COMMERCIAL (A-6)	19,940,621	40,080,649	40,281,052	40,482,457	40,684,870	40,888,294	41,092,735	41,298,199	41,504,690	41,712,214
MEDIUM COMMERCIAL (A-10)	99,504,021	200,003,082	201,003,097	202,008,113	203,018,153	204,033,244	205,053,410	206,078,678	207,109,071	208,144,616
LARGE COMMERCIAL (E-19)	130,425,547	262,155,350	263,466,127	264,783,458	266,107,375	267,437,912	268,775,101	270,118,977	271,469,572	272,826,920
INDUSTRIAL (E-20)	136,417,799	274,199,775	275,570,774	276,948,628	278,333,371	279,725,038	281,123,663	282,529,282	283,941,928	285,361,638
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	5,049,460	10,149,415	10,200,162	10,251,163	10,302,419	10,353,931	10,405,700	10,457,729	10,510,018	10,562,568
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	218,016,199	438,212,560	440,403,623	442,605,641	444,818,669	447,042,763	449,277,976	451,524,366	453,781,988	456,050,898
SUBTOTAL - LOAD REQUIREMENTS	989,087,683	1,988,066,242	1,998,006,573	2,007,996,606	2,018,036,589	2,028,126,772	2,038,267,406	2,048,458,743	2,058,701,037	2,068,994,542
III. CCA OPERATING COSTS ($)										
SHORT TERM MARKET PURCHASES	$3,160,437	$5,604,014	$5,895,301	$5,110,917	$5,563,585	$5,945,818	$4,884,869	$5,071,042	$5,311,792	$5,595,143
CONVENTIONAL AND RENEWABLE POWER PURCHASE AGREEMENTS	$7,964,302	$14,122,115	$35,820,591	$43,125,319	$60,449,993	$61,907,759	$59,731,371	$71,023,188	$71,427,882	$75,852,700
SHORT TERM RENEWABLE ENERGY PURCHASES	$33,367,758	$90,196,709	$78,319,536	$80,195,523	$68,976,405	$72,973,649	$85,021,702	$77,706,567	$81,754,643	$82,229,793
SHORT TERM CARBON FREE ENERGY PURCHASES	$4,720,955	$0	$130,076	$0	$0	$0	$0	$0	$0	$0
ANCILLARY SERVICES AND CAISO CHARGES	$2,955,167	$6,136,337	$6,368,470	$6,631,115	$6,894,665	$7,166,806	$7,450,177	$7,744,045	$8,028,876	$8,330,845
RESOURCE ADEQUACY CAPACITY	$5,197,904	$10,771,059	$9,708,801	$8,619,106	$8,419,619	$8,668,820	$8,927,720	$8,948,629	$9,330,813	$9,556,291
STAFF AND OTHER OPERATING COSTS	$5,029,047	$6,189,752	$6,324,307	$6,461,823	$6,602,366	$6,746,003	$6,892,805	$7,042,840	$7,196,183	$7,352,905
BILLING AND DATA MANAGEMENT	$1,600,904	$3,314,352	$3,430,852	$3,551,446	$3,676,279	$3,805,501	$3,939,264	$4,077,729	$4,221,061	$4,369,432
UNCOLLECTIBLES EXPENSE	$334,031	$695,721	$744,039	$778,990	$813,428	$836,072	$884,240	$908,070	$936,356	$966,436
STARTUP FINANCING	$2,809,815	$2,809,815	$2,809,815	$2,102,755	$2,102,755	$0	$0	$0	$0	$0
CCA BOND CARRYING COST	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
SUBTOTAL - CCA OPERATING COSTS	$67,141,821	$139,841,374	$149,553,288	$156,578,493	$163,500,594	$168,051,928	$177,733,646	$182,523,611	$188,209,107	$194,255,043
IV. REVENUES FROM 100% GREEN PREMIUM AND MARKET SALES ($)										
GREEN PRICING PREMIUM	$161,694	$199,258	$206,262	$170,810	$176,814	$183,029	$142,097	$147,092	$152,262	$157,614
MARKET SALES	$0	$0	$0	$0	$22,240	$21,119	$184,925	$112,494	$115,061	$118,318
V. CONTRIBUTION TO PROGRAM RESERVES ($)	$2,685,673	$5,593,655	$5,982,132	$6,263,140	$6,539,134	$6,721,232	$7,101,949	$7,296,445	$7,523,762	$7,765,469
VI. CCA REVENUE REQUIREMENT ($)	$69,665,800	$145,235,770	$155,329,157	$162,670,823	$169,840,675	$174,569,013	$184,508,574	$189,560,471	$195,465,546	$201,744,580
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	7.0	7.3	7.8	8.1	8.4	8.6	9.1	9.3	9.5	9.8
PG&E AVERAGE GENERATION COST (CENTS/KWH)	9.3	9.5	9.8	10.3	10.6	10.9	11.3	11.6	11.9	12.3
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
POWER CHARGE INDIFFERENCE ADJUSTMENT	$20,764,882	$40,651,574	$43,106,107	$42,647,747	$46,071,237	$44,053,645	$45,320,632	$44,591,493	$46,550,675	$46,074,456
FRANCHISE FEE SURCHARGE	$564,580	$1,150,784	$1,203,911	$1,266,028	$1,315,181	$1,352,641	$1,408,360	$1,452,808	$1,503,769	$1,553,556
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 21,329,462	$ 41,802,359	$ 44,310,018	$ 43,913,774	$ 47,386,418	$ 45,406,286	$ 46,728,991	$ 46,044,301	$ 48,054,444	$ 47,628,011
VIII. CCA REVENUE REQUIREMENT PLUS PG&E CCA CUSTOMER SURCHARGES	$90,995,262	$187,038,129	$199,639,175	$206,584,597	$217,227,094	$219,975,299	$231,237,565	$235,604,772	$243,519,990	$249,372,592
IX. REVENUE AT PG&E GENERATION RATES	$92,204,839	$187,941,282	$196,617,724	$206,762,308	$214,789,839	$220,907,714	$230,007,368	$237,266,526	$245,589,304	$253,720,212
X. TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS	$ (1,209,578)	$ (903,153)	$ 3,021,451	$ (177,711)	$ 2,437,254	$ (932,414)	$ 1,230,197	$ (1,661,755)	$ (2,069,313)	$ (4,347,620)
CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS (%)	-1%	0%	1%	0%	1%	0%	0%	0%	0%	-1%

Monterey County (Single County)
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)	58,111	116,803	117,387	117,974	118,564	119,157	119,752	120,351	120,953	121,558
SMALL COMMERCIAL (A-1)	6,610	13,286	13,353	13,419	13,486	13,554	13,622	13,690	13,758	13,827
SMALL COMMERCIAL (A-6)	396	795	799	803	807	811	815	819	823	828
MEDIUM COMMERCIAL (A-10)	605	1,216	1,222	1,228	1,234	1,240	1,246	1,253	1,259	1,265
LARGE COMMERCIAL (E-19)	295	593	596	599	602	605	608	611	614	617
INDUSTRIAL (E-20)	12	24	24	25	25	25	25	25	25	25
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	524	1,053	1,058	1,063	1,069	1,074	1,079	1,085	1,090	1,096
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	1,513	3,042	3,057	3,072	3,088	3,103	3,119	3,134	3,150	3,166
SUBTOTAL - CUSTOMER ACCOUNTS	68,066	136,812	137,496	138,184	138,874	139,569	140,267	140,968	141,673	142,381
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	288,852,912	580,594,353	583,497,325	586,414,812	589,346,886	592,293,620	595,255,088	598,231,364	601,222,521	604,228,633
SMALL COMMERCIAL (A-1)	90,881,123	182,671,057	183,584,413	184,502,335	185,424,846	186,351,971	187,283,731	188,220,149	189,161,250	190,107,056
SMALL COMMERCIAL (A-6)	19,940,621	40,080,649	40,281,052	40,482,457	40,684,870	40,888,294	41,092,735	41,298,199	41,504,690	41,712,214
MEDIUM COMMERCIAL (A-10)	99,504,021	200,003,082	201,003,097	202,008,113	203,018,153	204,033,244	205,053,410	206,078,678	207,109,071	208,144,616
LARGE COMMERCIAL (E-19)	130,425,547	262,155,350	263,466,127	264,783,458	266,107,375	267,437,912	268,775,101	270,118,977	271,469,572	272,826,920
INDUSTRIAL (E-20)	136,417,799	274,199,775	275,570,774	276,948,628	278,333,371	279,725,038	281,123,663	282,529,282	283,941,928	285,361,638
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	5,049,460	10,149,415	10,200,162	10,251,163	10,302,419	10,353,931	10,405,700	10,457,729	10,510,018	10,562,568
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	218,016,199	438,212,560	440,403,623	442,605,641	444,818,669	447,042,763	449,277,976	451,524,366	453,781,988	456,050,898
SUBTOTAL - LOAD REQUIREMENTS	989,087,683	1,988,066,242	1,998,006,573	2,007,996,606	2,018,036,589	2,028,126,772	2,038,267,406	2,048,458,743	2,058,701,037	2,068,994,542
III. CCA OPERATING COSTS ($)										
SHORT TERM MARKET PURCHASES	$3,146,629	$3,561,642	$3,759,760	$3,893,462	$4,282,172	$3,284,910	$3,506,326	$3,641,493	$3,812,537	$4,014,002
CONVENTIONAL AND RENEWABLE POWER PURCHASE AGREEMENTS	$7,929,506	$8,975,339	$30,439,028	$40,057,334	$57,220,834	$55,202,271	$56,257,444	$67,420,724	$67,649,760	$71,868,227
SHORT TERM RENEWABLE ENERGY PURCHASES	$38,037,937	$96,904,537	$85,444,999	$81,419,292	$72,344,936	$83,372,922	$87,984,663	$82,312,788	$86,513,521	$87,461,695
SHORT TERM CARBON FREE ENERGY PURCHASES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANCILLARY SERVICES AND CAISO CHARGES	$2,955,167	$6,136,337	$6,368,470	$6,631,115	$6,894,665	$7,166,806	$7,450,177	$7,744,045	$8,028,876	$8,330,845
RESOURCE ADEQUACY CAPACITY	$5,197,904	$10,771,059	$9,708,801	$8,619,106	$8,419,619	$8,668,820	$8,927,720	$8,948,629	$9,330,813	$9,556,291
STAFF AND OTHER OPERATING COSTS	$5,029,047	$6,189,752	$6,324,307	$6,461,823	$6,602,366	$6,746,003	$6,892,805	$7,042,840	$7,196,183	$7,352,905
BILLING AND DATA MANAGEMENT	$1,600,904	$3,314,352	$3,430,852	$3,551,446	$3,676,279	$3,805,501	$3,939,264	$4,077,729	$4,221,061	$4,369,432
UNCOLLECTIBLES EXPENSE	$333,535	$693,314	$741,430	$763,682	$807,718	$841,236	$874,792	$905,941	$933,764	$964,767
STARTUP FINANCING	$2,809,815	$2,809,815	$2,809,815	$2,102,755	$2,102,755	$0	$0	$0	$0	$0
CCA BOND CARRYING COST	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
SUBTOTAL - CCA OPERATING COSTS	$67,041,943	$139,357,648	$149,028,962	$153,501,514	$162,352,844	$169,089,970	$175,834,692	$182,095,690	$187,688,015	$193,919,662
IV. REVENUES FROM 100% GREEN PREMIUM AND MARKET SALES ($)										
GREEN PRICING PREMIUM	$98,511	$101,973	$105,558	$109,268	$113,109	$78,056	$80,800	$83,640	$86,580	$89,624
MARKET SALES	$0	$332,622	$333,050	$78,276	$171,642	$553,212	$585,668	$651,595	$672,959	$698,922
V. CONTRIBUTION TO PROGRAM RESERVES ($)	$2,681,678	$5,561,001	$5,947,836	$6,136,930	$6,487,248	$6,741,470	$7,009,961	$7,257,764	$7,480,602	$7,728,830
VI. CCA REVENUE REQUIREMENT ($)	$69,625,110	$144,484,054	$154,538,191	$159,450,899	$168,555,341	$175,200,172	$182,178,184	$188,618,218	$194,409,078	$200,859,946
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	7.0	7.3	7.7	7.9	8.4	8.6	8.9	9.2	9.4	9.7
PG&E AVERAGE GENERATION COST (CENTS/KWH)	9.3	9.5	9.8	10.3	10.6	10.9	11.3	11.6	11.9	12.3
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
POWER CHARGE INDIFFERENCE ADJUSTMENT	$20,764,882	$40,651,574	$43,106,107	$42,647,747	$46,071,237	$44,053,645	$45,320,632	$44,591,493	$46,550,675	$46,074,456
FRANCHISE FEE SURCHARGE	$564,580	$1,150,784	$1,203,911	$1,266,028	$1,315,181	$1,352,641	$1,408,360	$1,452,808	$1,503,769	$1,553,556
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 21,329,462	$ 41,802,359	$ 44,310,018	$ 43,913,774	$ 47,386,418	$ 45,406,286	$ 46,728,991	$ 46,044,301	$ 48,054,444	$ 47,628,011
VIII. CCA REVENUE REQUIREMENT PLUS PG&E CCA CUSTOMER SURCHARGES	$90,954,572	$186,286,413	$198,848,209	$203,364,674	$215,941,759	$220,606,459	$228,907,175	$234,662,519	$242,463,522	$248,487,957
IX. REVENUE AT PG&E GENERATION RATES	$92,204,839	$187,941,282	$196,617,724	$206,762,308	$214,789,839	$220,907,714	$230,007,368	$237,266,526	$245,589,304	$253,720,212
X. TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS	$ (1,250,267)	$ (1,654,870)	$ 2,230,485	$ (3,397,634)	$ 1,151,920	$ (301,255)	$ (1,100,192)	$ (2,604,007)	$ (3,125,781)	$ (5,232,254)
CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS (%)	-1%	0%	1%	-1%	0%	0%	0%	-1%	-1%	-1%

Monterey County (Single County)
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)	58,111	116,803	117,387	117,974	118,564	119,157	119,752	120,351	120,953	121,558
SMALL COMMERCIAL (A-1)	6,610	13,286	13,353	13,419	13,486	13,554	13,622	13,690	13,758	13,827
SMALL COMMERCIAL (A-6)	396	795	799	803	807	811	815	819	823	828
MEDIUM COMMERCIAL (A-10)	605	1,216	1,222	1,228	1,234	1,240	1,246	1,253	1,259	1,265
LARGE COMMERCIAL (E-19)	295	593	596	599	602	605	608	611	614	617
INDUSTRIAL (E-20)	12	24	24	25	25	25	25	25	25	25
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	524	1,053	1,058	1,063	1,069	1,074	1,079	1,085	1,090	1,096
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	1,513	3,042	3,057	3,072	3,088	3,103	3,119	3,134	3,150	3,166
SUBTOTAL - CUSTOMER ACCOUNTS	68,066	136,812	137,496	138,184	138,874	139,569	140,267	140,968	141,673	142,381
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	288,852,912	580,594,353	583,497,325	586,414,812	589,346,886	592,293,620	595,255,088	598,231,364	601,222,521	604,228,633
SMALL COMMERCIAL (A-1)	90,881,123	182,671,057	183,584,413	184,502,335	185,424,846	186,351,971	187,283,731	188,220,149	189,161,250	190,107,056
SMALL COMMERCIAL (A-6)	19,940,621	40,080,649	40,281,052	40,482,457	40,684,870	40,888,294	41,092,735	41,298,199	41,504,690	41,712,214
MEDIUM COMMERCIAL (A-10)	99,504,021	200,003,082	201,003,097	202,008,113	203,018,153	204,033,244	205,053,410	206,078,678	207,109,071	208,144,616
LARGE COMMERCIAL (E-19)	130,425,547	262,155,350	263,466,127	264,783,458	266,107,375	267,437,912	268,775,101	270,118,977	271,469,572	272,826,920
INDUSTRIAL (E-20)	136,417,799	274,199,775	275,570,774	276,948,628	278,333,371	279,725,038	281,123,663	282,529,282	283,941,928	285,361,638
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	5,049,460	10,149,415	10,200,162	10,251,163	10,302,419	10,353,931	10,405,700	10,457,729	10,510,018	10,562,568
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	218,016,199	438,212,560	440,403,623	442,605,641	444,818,669	447,042,763	449,277,976	451,524,366	453,781,988	456,050,898
SUBTOTAL - LOAD REQUIREMENTS	989,087,683	1,988,066,242	1,998,006,573	2,007,996,606	2,018,036,589	2,028,126,772	2,038,267,406	2,048,458,743	2,058,701,037	2,068,994,542
III. CCA OPERATING COSTS ($)										
SHORT TERM MARKET PURCHASES	$2,968,387	$5,959,997	$5,895,301	$5,964,753	$6,283,177	$6,521,351	$6,765,849	$6,901,142	$7,016,427	$7,173,931
CONVENTIONAL AND RENEWABLE POWER PURCHASE AGREEMENTS	$7,480,336	$15,019,192	$35,820,591	$45,276,987	$62,263,365	$63,358,100	$64,471,442	$75,635,038	$75,723,562	$79,831,246
SHORT TERM RENEWABLE ENERGY PURCHASES	$15,333,707	$34,558,453	$22,230,343	$16,174,876	$5,320,063	$7,673,861	$10,304,174	$2,759,127	$6,274,853	$6,291,397
SHORT TERM CARBON FREE ENERGY PURCHASES	$17,805,390	$37,491,329	$39,484,285	$42,274,855	$44,256,179	$46,149,616	$48,053,387	$49,907,033	$50,855,652	$52,025,164
ANCILLARY SERVICES AND CAISO CHARGES	$2,955,167	$6,136,337	$6,368,470	$6,631,115	$6,894,665	$7,166,806	$7,450,177	$7,744,045	$8,028,876	$8,330,845
RESOURCE ADEQUACY CAPACITY	$5,197,904	$10,771,059	$9,708,801	$8,619,106	$8,419,619	$8,668,820	$8,927,720	$8,948,629	$9,330,813	$9,556,291
STAFF AND OTHER OPERATING COSTS	$5,029,047	$6,189,752	$6,324,307	$6,461,823	$6,602,366	$6,746,003	$6,892,805	$7,042,840	$7,196,183	$7,352,905
BILLING AND DATA MANAGEMENT	$1,600,904	$3,314,352	$3,430,852	$3,551,446	$3,676,279	$3,805,501	$3,939,264	$4,077,729	$4,221,061	$4,369,432
UNCOLLECTIBLES EXPENSE	$305,903	$611,251	$660,364	$685,289	$729,092	$750,450	$784,024	$815,078	$843,237	$874,656
STARTUP FINANCING	$2,809,815	$2,809,815	$2,809,815	$2,102,755	$2,102,755	$0	$0	$0	$0	$0
CCA BOND CARRYING COST	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
SUBTOTAL - CCA OPERATING COSTS	$61,488,059	$122,863,037	$132,734,628	$137,744,504	$146,549,060	$150,842,008	$157,590,341	$163,832,161	$169,492,164	$175,807,365
IV. REVENUES FROM 100% GREEN PREMIUM AND MARKET SALES ($)										
GREEN PRICING PREMIUM	$239,710	$482,674	$485,566	$488,064	$492,401	$496,439	$500,153	$503,514	$506,494	$509,062
MARKET SALES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
V. CONTRIBUTION TO PROGRAM RESERVES ($)	$2,459,522	$4,914,521	$5,309,385	$5,509,780	$5,861,962	$6,033,680	$6,303,614	$6,553,286	$6,779,687	$7,032,295
VI. CCA REVENUE REQUIREMENT ($)	$63,707,872	$127,294,884	$137,558,448	$142,766,220	$151,918,621	$156,379,250	$163,393,802	$169,881,933	$175,765,356	$182,330,598
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	6.4	6.4	6.9	7.1	7.5	7.7	8.0	8.3	8.5	8.8
PG&E AVERAGE GENERATION COST (CENTS/KWH)	9.3	9.5	9.8	10.3	10.6	10.9	11.3	11.6	11.9	12.3
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
POWER CHARGE INDIFFERENCE ADJUSTMENT	$20,764,882	$40,651,574	$43,106,107	$42,647,747	$46,071,237	$44,053,645	$45,320,632	$44,591,493	$46,550,675	$46,074,456
FRANCHISE FEE SURCHARGE	$564,580	$1,150,784	$1,203,911	$1,266,028	$1,315,181	$1,352,641	$1,408,360	$1,452,808	$1,503,769	$1,553,556
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 21,329,462	$ 41,802,359	$ 44,310,018	$ 43,913,774	$ 47,386,418	$ 45,406,286	$ 46,728,991	$ 46,044,301	$ 48,054,444	$ 47,628,011
VIII. CCA REVENUE REQUIREMENT PLUS PG&E CCA CUSTOMER SURCHARGES	$85,037,334	$169,097,243	$181,868,466	$186,679,994	$199,305,040	$201,785,536	$210,122,794	$215,926,235	$223,819,801	$229,958,609
IX. REVENUE AT PG&E GENERATION RATES	$92,204,839	$187,941,282	$196,617,724	$206,762,308	$214,789,839	$220,907,714	$230,007,368	$237,266,526	$245,589,304	$253,720,212
X. TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS	$ (7,167,505)	$ (18,844,039)	$ (14,749,258)	$ (20,082,314)	$ (15,484,799)	$ (19,122,178)	$ (19,884,574)	$ (21,340,292)	$ (21,769,503)	$ (23,761,602)
CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS (%)	-4%	-5%	-4%	-5%	-4%	-4%	-4%	-4%	-4%	-5%

San Benito County (Single County)
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)	15,620	15,698	15,777	15,856	15,935	16,015	16,095	16,175	16,256	16,338
SMALL COMMERCIAL (A-1)	2,064	2,074	2,085	2,095	2,105	2,116	2,127	2,137	2,148	2,159
SMALL COMMERCIAL (A-6)	103	103	104	104	105	105	106	106	107	107
MEDIUM COMMERCIAL (A-10)	145	146	146	147	148	149	149	150	151	152
LARGE COMMERCIAL (E-19)	54	55	55	55	55	56	56	56	57	57
INDUSTRIAL (E-20)	4	4	4	4	4	4	4	4	4	5
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	192	193	193	194	195	196	197	198	199	200
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	566	569	572	575	577	580	583	586	589	592
SUBTOTAL - CUSTOMER ACCOUNTS	18,748	18,842	18,936	19,031	19,126	19,221	19,318	19,414	19,511	19,609
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	97,362,187	97,848,998	98,338,243	98,829,934	99,324,084	99,820,705	100,319,808	100,821,407	101,325,514	101,832,142
SMALL COMMERCIAL (A-1)	24,425,674	24,547,802	24,670,541	24,793,894	24,917,863	25,042,452	25,167,665	25,293,503	25,419,971	25,547,070
SMALL COMMERCIAL (A-6)	6,079,994	6,110,394	6,140,946	6,171,651	6,202,509	6,233,521	6,264,689	6,296,012	6,327,492	6,359,130
MEDIUM COMMERCIAL (A-10)	29,195,509	29,341,486	29,488,194	29,635,635	29,783,813	29,932,732	30,082,396	30,232,808	30,383,972	30,535,891
LARGE COMMERCIAL (E-19)	27,304,663	27,441,186	27,578,392	27,716,284	27,854,865	27,994,139	28,134,110	28,274,781	28,416,155	28,558,235
INDUSTRIAL (E-20)	20,869,901	20,974,251	21,079,122	21,184,518	21,290,440	21,396,892	21,503,877	21,611,396	21,719,453	21,828,050
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	1,389,231	1,396,177	1,403,158	1,410,174	1,417,225	1,424,311	1,431,433	1,438,590	1,445,783	1,453,012
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	73,973,142	74,343,008	74,714,723	75,088,297	75,463,738	75,841,057	76,220,262	76,601,363	76,984,370	77,369,292
SUBTOTAL - LOAD REQUIREMENTS	280,600,301	282,003,302	283,413,319	284,830,385	286,254,537	287,685,810	289,124,239	290,569,860	292,022,710	293,482,823
III. CCA OPERATING COSTS ($)										
SHORT TERM MARKET PURCHASES	$910,613	$813,948	$856,340	$756,775	$832,683	$890,163	$751,373	$792,106	$829,511	$873,552
CONVENTIONAL AND RENEWABLE POWER PURCHASE AGREEMENTS	$2,294,746	$2,051,149	$5,201,202	$6,297,595	$8,838,165	$9,054,802	$8,777,227	$10,450,904	$10,515,843	$11,165,488
SHORT TERM RENEWABLE ENERGY PURCHASES	$9,466,302	$12,794,227	$11,054,974	$11,283,500	$9,633,182	$10,191,129	$11,890,531	$10,802,586	$11,369,401	$11,414,561
SHORT TERM CARBON FREE ENERGY PURCHASES	$1,339,316	$0	$18,451	$0	$0	$0	$0	$0	$0	$0
ANCILLARY SERVICES AND CAISO CHARGES	$838,637	$870,712	$903,656	$940,938	$978,346	$1,016,973	$1,057,194	$1,098,906	$1,139,329	$1,182,186
RESOURCE ADEQUACY CAPACITY	$1,578,013	$1,634,974	$1,483,358	$1,327,858	$1,301,685	$1,340,750	$1,381,335	$1,387,491	$1,446,211	$1,482,312
STAFF AND OTHER OPERATING COSTS	$2,091,937	$2,135,264	$2,179,496	$2,224,650	$2,270,747	$2,317,806	$2,365,847	$2,414,892	$2,464,961	$2,516,076
BILLING AND DATA MANAGEMENT	$440,955	$456,454	$472,499	$489,107	$506,299	$524,096	$542,518	$561,587	$581,327	$601,761
UNCOLLECTIBLES EXPENSE	$100,075	$109,056	$116,122	$120,107	$125,310	$126,679	$133,830	$137,542	$141,733	$146,180
STARTUP FINANCING	$1,054,449	$1,054,449	$1,054,449	$700,918	$700,918	$0	$0	$0	$0	$0
CCA BOND CARRYING COST	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
SUBTOTAL - CCA OPERATING COSTS	$20,116,543	$21,921,733	$23,342,047	$24,142,948	$25,188,835	$25,463,896	$26,901,355	$27,647,515	$28,489,817	$29,383,615
IV. REVENUES FROM 100% GREEN PREMIUM AND MARKET SALES ($)										
GREEN PRICING PREMIUM	$45,872	$28,264	$29,258	$24,229	$25,081	$25,962	$20,156	$20,865	$21,598	$22,357
MARKET SALES	$17,391	$29,526	$31,175	$61,189	$93,177	$99,935	$152,493	$179,401	$186,975	$195,970
V. CONTRIBUTION TO PROGRAM RESERVES ($)	$803,966	$875,688	$932,435	$963,270	$1,003,826	$1,014,558	$1,069,954	$1,098,725	$1,132,114	$1,167,506
VI. CCA REVENUE REQUIREMENT ($)	$20,857,247	$22,739,631	$24,214,049	$25,020,801	$26,074,403	$26,352,557	$27,798,660	$28,545,973	$29,413,357	$30,332,794
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	7.4	8.1	8.5	8.8	9.1	9.2	9.6	9.8	10.1	10.3
PG&E AVERAGE GENERATION COST (CENTS/KWH)	9.4	9.5	9.9	10.3	10.7	10.9	11.3	11.6	12.0	12.3
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
POWER CHARGE INDIFFERENCE ADJUSTMENT	$6,123,042	$5,993,564	$6,355,454	$6,287,875	$6,792,626	$6,495,157	$6,681,958	$6,574,456	$6,863,313	$6,793,100
FRANCHISE FEE SURCHARGE	$159,716	$162,775	$170,289	$179,076	$186,028	$191,327	$199,208	$205,495	$212,703	$219,745
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 6,282,758	$ 6,156,339	$ 6,525,744	$ 6,466,950	$ 6,978,654	$ 6,686,484	$ 6,881,166	$ 6,779,951	$ 7,076,016	$ 7,012,846
VIII. CCA REVENUE REQUIREMENT PLUS PG&E CCA CUSTOMER SURCHARGES	$27,140,005	$28,895,970	$30,739,793	$31,487,751	$33,053,057	$33,039,041	$34,679,826	$35,325,924	$36,489,373	$37,345,639
IX. REVENUE AT PG&E GENERATION RATES	$26,282,756	$26,786,094	$28,022,692	$29,468,536	$30,612,650	$31,484,592	$32,781,509	$33,816,112	$35,002,305	$36,161,152
X. TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS	$ 857,249	$ 2,109,876	$ 2,717,100	$ 2,019,215	$ 2,440,407	$ 1,554,448	$ 1,898,317	$ 1,509,812	$ 1,487,068	$ 1,184,487
CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS (%)	2%	4%	5%	3%	4%	2%	3%	2%	2%	2%

San Benito County (Single County)
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)	15,620	15,698	15,777	15,856	15,935	16,015	16,095	16,175	16,256	16,338
SMALL COMMERCIAL (A-1)	2,064	2,074	2,085	2,095	2,105	2,116	2,127	2,137	2,148	2,159
SMALL COMMERCIAL (A-6)	103	103	104	104	105	105	106	106	107	107
MEDIUM COMMERCIAL (A-10)	145	146	146	147	148	149	149	150	151	152
LARGE COMMERCIAL (E-19)	54	55	55	55	55	56	56	56	57	57
INDUSTRIAL (E-20)	4	4	4	4	4	4	4	4	4	5
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	192	193	193	194	195	196	197	198	199	200
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	566	569	572	575	577	580	583	586	589	592
SUBTOTAL - CUSTOMER ACCOUNTS	18,748	18,842	18,936	19,031	19,126	19,221	19,318	19,414	19,511	19,609
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	97,362,187	97,848,998	98,338,243	98,829,934	99,324,084	99,820,705	100,319,808	100,821,407	101,325,514	101,832,142
SMALL COMMERCIAL (A-1)	24,425,674	24,547,802	24,670,541	24,793,894	24,917,863	25,042,452	25,167,665	25,293,503	25,419,971	25,547,070
SMALL COMMERCIAL (A-6)	6,079,994	6,110,394	6,140,946	6,171,651	6,202,509	6,233,521	6,264,689	6,296,012	6,327,492	6,359,130
MEDIUM COMMERCIAL (A-10)	29,195,509	29,341,486	29,488,194	29,635,635	29,783,813	29,932,732	30,082,396	30,232,808	30,383,972	30,535,891
LARGE COMMERCIAL (E-19)	27,304,663	27,441,186	27,578,392	27,716,284	27,854,865	27,994,139	28,134,110	28,274,781	28,416,155	28,558,235
INDUSTRIAL (E-20)	20,869,901	20,974,251	21,079,122	21,184,518	21,290,440	21,396,892	21,503,877	21,611,396	21,719,453	21,828,050
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	1,389,231	1,396,177	1,403,158	1,410,174	1,417,225	1,424,311	1,431,433	1,438,590	1,445,783	1,453,012
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	73,973,142	74,343,008	74,714,723	75,088,297	75,463,738	75,841,057	76,220,262	76,601,363	76,984,370	77,369,292
SUBTOTAL - LOAD REQUIREMENTS	280,600,301	282,003,302	283,413,319	284,830,385	286,254,537	287,685,810	289,124,239	290,569,860	292,022,710	293,482,823
III. CCA OPERATING COSTS ($)										
SHORT TERM MARKET PURCHASES	$906,799	$542,116	$572,698	$595,172	$658,229	$534,657	$570,465	$585,216	$612,366	$644,375
CONVENTIONAL AND RENEWABLE POWER PURCHASE AGREEMENTS	$2,285,133	$1,366,132	$4,486,423	$5,890,354	$8,398,541	$8,158,926	$8,321,337	$9,929,542	$9,968,638	$10,587,961
SHORT TERM RENEWABLE ENERGY PURCHASES	$10,791,214	$13,745,719	$12,065,707	$11,457,089	$10,138,562	$11,694,807	$12,340,422	$11,465,359	$12,061,314	$12,167,138
SHORT TERM CARBON FREE ENERGY PURCHASES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANCILLARY SERVICES AND CAISO CHARGES	$838,637	$870,712	$903,656	$940,938	$978,346	$1,016,973	$1,057,194	$1,098,906	$1,139,329	$1,182,186
RESOURCE ADEQUACY CAPACITY	$1,578,013	$1,634,974	$1,483,358	$1,327,858	$1,301,685	$1,340,750	$1,381,335	$1,387,491	$1,446,211	$1,482,312
STAFF AND OTHER OPERATING COSTS	$2,091,937	$2,135,264	$2,179,496	$2,224,650	$2,270,747	$2,317,806	$2,365,847	$2,414,892	$2,464,961	$2,516,076
BILLING AND DATA MANAGEMENT	$440,955	$456,454	$472,499	$489,107	$506,299	$524,096	$542,518	$561,587	$581,327	$601,761
UNCOLLECTIBLES EXPENSE	$99,936	$109,029	$116,091	$118,130	$124,767	$127,940	$132,896	$137,215	$141,371	$145,909
STARTUP FINANCING	$1,054,449	$1,054,449	$1,054,449	$700,918	$700,918	$0	$0	$0	$0	$0
CCA BOND CARRYING COST	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
SUBTOTAL - CCA OPERATING COSTS	$20,088,572	$21,916,348	$23,335,878	$23,745,717	$25,079,593	$25,717,454	$26,713,514	$27,581,707	$28,417,017	$29,329,217
IV. REVENUES FROM 100% GREEN PREMIUM AND MARKET SALES ($)										
GREEN PRICING PREMIUM	$27,947	$14,465	$14,973	$15,499	$16,044	$11,072	$11,461	$11,864	$12,281	$12,713
MARKET SALES	$17,665	$124,372	$129,831	$101,866	$133,868	$233,914	$248,365	$244,908	$254,169	$265,272
V. CONTRIBUTION TO PROGRAM RESERVES ($)	$802,836	$871,679	$928,242	$945,754	$997,829	$1,019,342	$1,058,606	$1,093,472	$1,126,514	$1,162,558
VI. CCA REVENUE REQUIREMENT ($)	$20,845,796	$22,649,191	$24,119,315	$24,574,106	$25,927,510	$26,491,810	$27,512,293	$28,418,407	$29,277,080	$30,213,789
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	7.4	8.0	8.5	8.6	9.1	9.2	9.5	9.8	10.0	10.3
PG&E AVERAGE GENERATION COST (CENTS/KWH)	9.4	9.5	9.9	10.3	10.7	10.9	11.3	11.6	12.0	12.3
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
POWER CHARGE INDIFFERENCE ADJUSTMENT	$6,123,042	$5,993,564	$6,355,454	$6,287,875	$6,792,626	$6,495,157	$6,681,958	$6,574,456	$6,863,313	$6,793,100
FRANCHISE FEE SURCHARGE	$159,716	$162,775	$170,289	$179,076	$186,028	$191,327	$199,208	$205,495	$212,703	$219,745
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 6,282,758	$ 6,156,339	$ 6,525,744	$ 6,466,950	$ 6,978,654	$ 6,686,484	$ 6,881,166	$ 6,779,951	$ 7,076,016	$ 7,012,846
VIII. CCA REVENUE REQUIREMENT PLUS PG&E CCA CUSTOMER SURCHARGES	$27,128,555	$28,805,530	$30,645,059	$31,041,056	$32,906,164	$33,178,294	$34,393,460	$35,198,358	$36,353,096	$37,226,634
IX. REVENUE AT PG&E GENERATION RATES	$26,282,756	$26,786,094	$28,022,692	$29,468,536	$30,612,650	$31,484,592	$32,781,509	$33,816,112	$35,002,305	$36,161,152
X. TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS	$ 845,798	$ 2,019,436	$ 2,622,367	$ 1,572,520	$ 2,293,514	$ 1,693,701	$ 1,611,950	$ 1,382,246	$ 1,350,791	$ 1,065,482
CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS (%)	2%	4%	4%	3%	4%	3%	2%	2%	2%	1%

San Benito County (Single County)
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)	15,620	15,698	15,777	15,856	15,935	16,015	16,095	16,175	16,256	16,338
SMALL COMMERCIAL (A-1)	2,064	2,074	2,085	2,095	2,105	2,116	2,127	2,137	2,148	2,159
SMALL COMMERCIAL (A-6)	103	103	104	104	105	105	106	106	107	107
MEDIUM COMMERCIAL (A-10)	145	146	146	147	148	149	149	150	151	152
LARGE COMMERCIAL (E-19)	54	55	55	55	55	56	56	56	57	57
INDUSTRIAL (E-20)	4	4	4	4	4	4	4	4	4	5
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	192	193	193	194	195	196	197	198	199	200
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	566	569	572	575	577	580	583	586	589	592
SUBTOTAL - CUSTOMER ACCOUNTS	18,748	18,842	18,936	19,031	19,126	19,221	19,318	19,414	19,511	19,609
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	97,362,187	97,848,998	98,338,243	98,829,934	99,324,084	99,820,705	100,319,808	100,821,407	101,325,514	101,832,142
SMALL COMMERCIAL (A-1)	24,425,674	24,547,802	24,670,541	24,793,894	24,917,863	25,042,452	25,167,665	25,293,503	25,419,971	25,547,070
SMALL COMMERCIAL (A-6)	6,079,994	6,110,394	6,140,946	6,171,651	6,202,509	6,233,521	6,264,689	6,296,012	6,327,492	6,359,130
MEDIUM COMMERCIAL (A-10)	29,195,509	29,341,486	29,488,194	29,635,635	29,783,813	29,932,732	30,082,396	30,232,808	30,383,972	30,535,891
LARGE COMMERCIAL (E-19)	27,304,663	27,441,186	27,578,392	27,716,284	27,854,865	27,994,139	28,134,110	28,274,781	28,416,155	28,558,235
INDUSTRIAL (E-20)	20,869,901	20,974,251	21,079,122	21,184,518	21,290,440	21,396,892	21,503,877	21,611,396	21,719,453	21,828,050
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	1,389,231	1,396,177	1,403,158	1,410,174	1,417,225	1,424,311	1,431,433	1,438,590	1,445,783	1,453,012
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	73,973,142	74,343,008	74,714,723	75,088,297	75,463,738	75,841,057	76,220,262	76,601,363	76,984,370	77,369,292
SUBTOTAL - LOAD REQUIREMENTS	280,600,301	282,003,302	283,413,319	284,830,385	286,254,537	287,685,810	289,124,239	290,569,860	292,022,710	293,482,823
III. CCA OPERATING COSTS ($)										
SHORT TERM MARKET PURCHASES	$857,559	$863,119	$856,340	$869,156	$928,492	$966,955	$1,006,703	$1,038,532	$1,059,550	$1,087,188
CONVENTIONAL AND RENEWABLE POWER PURCHASE AGREEMENTS	$2,161,049	$2,175,059	$5,201,202	$6,580,793	$9,079,603	$9,248,319	$9,420,658	$11,071,898	$11,095,543	$11,703,851
SHORT TERM RENEWABLE ENERGY PURCHASES	$4,350,113	$4,902,049	$3,098,832	$2,202,296	$631,215	$957,043	$1,321,596	$180,828	$679,616	$653,290
SHORT TERM CARBON FREE ENERGY PURCHASES	$5,051,319	$5,318,072	$5,600,768	$5,996,605	$6,277,652	$6,546,233	$6,816,279	$7,079,215	$7,213,775	$7,379,668
ANCILLARY SERVICES AND CAISO CHARGES	$838,637	$870,712	$903,656	$940,938	$978,346	$1,016,973	$1,057,194	$1,098,906	$1,139,329	$1,182,186
RESOURCE ADEQUACY CAPACITY	$1,578,013	$1,634,974	$1,483,358	$1,327,858	$1,301,685	$1,340,750	$1,381,335	$1,387,491	$1,446,211	$1,482,312
STAFF AND OTHER OPERATING COSTS	$2,091,937	$2,135,264	$2,179,496	$2,224,650	$2,270,747	$2,317,806	$2,365,847	$2,414,892	$2,464,961	$2,516,076
BILLING AND DATA MANAGEMENT	$440,955	$456,454	$472,499	$489,107	$506,299	$524,096	$542,518	$561,587	$581,327	$601,761
UNCOLLECTIBLES EXPENSE	$92,120	$97,051	$104,253	$106,662	$113,375	$114,591	$119,561	$124,167	$128,402	$133,032
STARTUP FINANCING	$1,054,449	$1,054,449	$1,054,449	$700,918	$700,918	$0	$0	$0	$0	$0
CCA BOND CARRYING COST	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
SUBTOTAL - CCA OPERATING COSTS	$18,517,650	$19,508,702	$20,956,353	$21,440,483	$22,789,832	$23,034,266	$24,033,192	$24,959,015	$25,810,213	$26,740,863
IV. REVENUES FROM 100% GREEN PREMIUM AND MARKET SALES ($)										
GREEN PRICING PREMIUM	$68,005	$68,466	$68,877	$69,231	$69,846	$70,419	$70,946	$71,423	$71,845	$72,209
MARKET SALES	$21,203	$25,993	$31,175	$37,896	$73,319	$84,018	$95,640	$128,324	$139,295	$151,689
V. CONTRIBUTION TO PROGRAM RESERVES ($)	$739,858	$779,308	$837,007	$856,104	$908,661	$918,010	$957,502	$993,228	$1,026,837	$1,063,567
VI. CCA REVENUE REQUIREMENT ($)	$19,168,301	$20,193,551	$21,693,309	$22,189,460	$23,555,328	$23,797,839	$24,824,108	$25,752,496	$26,625,910	$27,580,532
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	6.8	7.2	7.7	7.8	8.2	8.3	8.6	8.9	9.1	9.4
PG&E AVERAGE GENERATION COST (CENTS/KWH)	9.4	9.5	9.9	10.3	10.7	10.9	11.3	11.6	12.0	12.3
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
POWER CHARGE INDIFFERENCE ADJUSTMENT	$6,123,042	$5,993,564	$6,355,454	$6,287,875	$6,792,626	$6,495,157	$6,681,958	$6,574,456	$6,863,313	$6,793,100
FRANCHISE FEE SURCHARGE	$159,716	$162,775	$170,289	$179,076	$186,028	$191,327	$199,208	$205,495	$212,703	$219,745
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 6,282,758	$ 6,156,339	$ 6,525,744	$ 6,466,950	$ 6,978,654	$ 6,686,484	$ 6,881,166	$ 6,779,951	$ 7,076,016	$ 7,012,846
VIII. CCA REVENUE REQUIREMENT PLUS PG&E CCA CUSTOMER SURCHARGES	$25,451,059	$26,349,890	$28,219,052	$28,656,410	$30,533,981	$30,484,323	$31,705,274	$32,532,447	$33,701,926	$34,593,377
IX. REVENUE AT PG&E GENERATION RATES	$26,282,756	$26,786,094	$28,022,692	$29,468,536	$30,612,650	$31,484,592	$32,781,509	$33,816,112	$35,002,305	$36,161,152
X. TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS	$ (831,697)	$ (436,204)	$ 196,360	$ (812,126)	$ (78,669)	$ (1,000,270)	$ (1,076,235)	$ (1,283,664)	$ (1,300,379)	$ (1,567,775)
CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS (%)	-1%	-1%	0%	-1%	0%	-1%	-2%	-2%	-2%	-2%

Santa Cruz County (Single County)
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)	80,098	80,498	80,901	81,305	81,712	82,120	82,531	82,943	83,358	83,775
SMALL COMMERCIAL (A-1)	8,140	8,180	8,221	8,262	8,304	8,345	8,387	8,429	8,471	8,513
SMALL COMMERCIAL (A-6)	527	530	532	535	538	540	543	546	549	551
MEDIUM COMMERCIAL (A-10)	694	697	701	704	708	711	715	718	722	726
LARGE COMMERCIAL (E-19)	301	303	304	306	307	309	310	312	313	315
INDUSTRIAL (E-20)	7	7	7	7	7	7	7	7	7	7
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	538	541	544	547	549	552	555	558	560	563
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	670	674	677	681	684	687	691	694	698	701
SUBTOTAL - CUSTOMER ACCOUNTS	90,975	91,430	91,887	92,347	92,808	93,272	93,739	94,207	94,678	95,152
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	460,022,517	462,322,630	464,634,243	466,957,414	469,292,201	471,638,662	473,996,856	476,366,840	478,748,674	481,142,417
SMALL COMMERCIAL (A-1)	116,634,992	117,218,167	117,804,258	118,393,280	118,985,246	119,580,172	120,178,073	120,778,963	121,382,858	121,989,772
SMALL COMMERCIAL (A-6)	26,025,786	26,155,915	26,286,695	26,418,128	26,550,219	26,682,970	26,816,385	26,950,466	27,085,219	27,220,645
MEDIUM COMMERCIAL (A-10)	109,866,496	110,415,828	110,967,907	111,522,747	112,080,360	112,640,762	113,203,966	113,769,986	114,338,836	114,910,530
LARGE COMMERCIAL (E-19)	126,534,990	127,167,665	127,803,504	128,442,521	129,084,734	129,730,157	130,378,808	131,030,702	131,685,856	132,344,285
INDUSTRIAL (E-20)	41,817,632	42,026,721	42,236,854	42,448,039	42,660,279	42,873,580	43,087,948	43,303,388	43,519,905	43,737,504
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	4,156,808	4,177,592	4,198,480	4,219,472	4,240,569	4,261,772	4,283,081	4,304,497	4,326,019	4,347,649
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	46,780,878	47,014,782	47,249,856	47,486,105	47,723,536	47,962,154	48,201,964	48,442,974	48,685,189	48,928,615
SUBTOTAL - LOAD REQUIREMENTS	931,840,099	936,499,300	941,181,796	945,887,705	950,617,144	955,370,230	960,147,081	964,947,816	969,772,555	974,621,418
III. CCA OPERATING COSTS ($)										
SHORT TERM MARKET PURCHASES	$3,004,893	$2,668,924	$2,807,849	$2,441,330	$2,652,849	$2,835,608	$2,314,418	$2,439,527	$2,554,108	$2,689,072
CONVENTIONAL AND RENEWABLE POWER PURCHASE AGREEMENTS	$7,572,331	$6,725,688	$16,881,723	$20,299,385	$28,402,325	$29,094,194	$28,013,360	$33,390,845	$33,585,108	$35,660,901
SHORT TERM RENEWABLE ENERGY PURCHASES	$31,436,460	$42,488,099	$36,947,817	$37,869,159	$32,643,278	$34,535,290	$40,220,256	$36,824,772	$38,739,069	$38,985,167
SHORT TERM CARBON FREE ENERGY PURCHASES	$4,447,710	$0	$61,274	$0	$0	$0	$0	$0	$0	$0
ANCILLARY SERVICES AND CAISO CHARGES	$2,784,480	$2,890,964	$3,000,334	$3,124,091	$3,248,270	$3,376,498	$3,510,017	$3,648,482	$3,782,682	$3,924,959
RESOURCE ADEQUACY CAPACITY	$4,800,292	$4,973,565	$4,474,370	$3,962,252	$3,866,430	$3,980,380	$4,098,767	$4,105,729	$4,281,564	$4,383,986
STAFF AND OTHER OPERATING COSTS	$4,669,486	$4,767,821	$4,868,245	$4,970,806	$5,075,548	$5,182,519	$5,291,766	$5,403,339	$5,517,287	$5,633,662
BILLING AND DATA MANAGEMENT	$2,139,734	$2,214,946	$2,292,801	$2,373,393	$2,456,818	$2,543,175	$2,632,568	$2,725,102	$2,820,890	$2,920,044
UNCOLLECTIBLES EXPENSE	$317,707	$347,080	$370,102	$385,716	$402,241	$407,738	$430,406	$442,689	$456,404	$470,989
STARTUP FINANCING	$2,686,080	$2,686,080	$2,686,080	$2,102,755	$2,102,755	$0	$0	$0	$0	$0
CCA BOND CARRYING COST	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
SUBTOTAL - CCA OPERATING COSTS	$63,860,673	$69,764,666	$74,392,095	$77,530,386	$80,852,014	$81,956,903	$86,513,058	$88,981,986	$91,738,611	$94,670,280
IV. REVENUES FROM 100% GREEN PREMIUM AND MARKET SALES ($)										
GREEN PRICING PREMIUM	$152,335	$93,863	$97,162	$80,462	$83,290	$86,218	$66,936	$69,289	$71,724	$74,246
MARKET SALES	$0	$0	$0	$0	$0	$0	$12,944	$70,215	$69,025	$68,015
V. CONTRIBUTION TO PROGRAM RESERVES ($)	$2,554,427	$2,790,587	$2,975,684	$3,101,215	$3,234,081	$3,278,276	$3,460,005	$3,556,471	$3,666,783	$3,784,091
VI. CCA REVENUE REQUIREMENT ($)	$66,262,765	$72,461,390	$77,270,617	$80,551,140	$84,002,805	$85,148,961	$89,893,182	$92,398,953	$95,264,645	$98,312,110
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	7.1	7.7	8.2	8.5	8.8	8.9	9.4	9.6	9.8	10.1
PG&E AVERAGE GENERATION COST (CENTS/KWH)	9.7	9.9	10.3	10.8	11.1	11.4	11.8	12.1	12.5	12.8
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
POWER CHARGE INDIFFERENCE ADJUSTMENT	$20,924,230	$20,481,766	$21,718,450	$21,487,511	$23,212,392	$22,195,855	$22,834,210	$22,466,843	$23,453,951	$23,214,014
FRANCHISE FEE SURCHARGE	$554,648	$565,270	$591,366	$621,878	$646,023	$664,423	$691,792	$713,626	$738,658	$763,113
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 21,478,878	$ 21,047,036	$ 22,309,816	$ 22,109,389	$ 23,858,415	$ 22,860,278	$ 23,526,002	$ 23,180,468	$ 24,192,609	$ 23,977,127
VIII. CCA REVENUE REQUIREMENT PLUS PG&E CCA CUSTOMER SURCHARGES	$87,741,644	$93,508,427	$99,580,433	$102,660,530	$107,861,220	$108,009,239	$113,419,184	$115,579,421	$119,457,254	$122,289,237
IX. REVENUE AT PG&E GENERATION RATES	$90,825,060	$92,564,438	$96,837,741	$101,834,129	$105,787,832	$108,800,994	$113,282,736	$116,858,002	$120,957,118	$124,961,736
X. TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS	$ (3,083,416)	$ 943,989	$ 2,742,693	$ 826,400	$ 2,073,388	$ (791,755)	$ 136,448	$ (1,278,581)	$ (1,499,864)	$ (2,672,499)
CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS (%)	-2%	0%	1%	0%	1%	0%	0%	-1%	-1%	-1%

Santa Cruz County (Single County)
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)	80,098	80,498	80,901	81,305	81,712	82,120	82,531	82,943	83,358	83,775
SMALL COMMERCIAL (A-1)	8,140	8,180	8,221	8,262	8,304	8,345	8,387	8,429	8,471	8,513
SMALL COMMERCIAL (A-6)	527	530	532	535	538	540	543	546	549	551
MEDIUM COMMERCIAL (A-10)	694	697	701	704	708	711	715	718	722	726
LARGE COMMERCIAL (E-19)	301	303	304	306	307	309	310	312	313	315
INDUSTRIAL (E-20)	7	7	7	7	7	7	7	7	7	7
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	538	541	544	547	549	552	555	558	560	563
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	670	674	677	681	684	687	691	694	698	701
SUBTOTAL - CUSTOMER ACCOUNTS	90,975	91,430	91,887	92,347	92,808	93,272	93,739	94,207	94,678	95,152
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	460,022,517	462,322,630	464,634,243	466,957,414	469,292,201	471,638,662	473,996,856	476,366,840	478,748,674	481,142,417
SMALL COMMERCIAL (A-1)	116,634,992	117,218,167	117,804,258	118,393,280	118,985,246	119,580,172	120,178,073	120,778,963	121,382,858	121,989,772
SMALL COMMERCIAL (A-6)	26,025,786	26,155,915	26,286,695	26,418,128	26,550,219	26,682,970	26,816,385	26,950,466	27,085,219	27,220,645
MEDIUM COMMERCIAL (A-10)	109,866,496	110,415,828	110,967,907	111,522,747	112,080,360	112,640,762	113,203,966	113,769,986	114,338,836	114,910,530
LARGE COMMERCIAL (E-19)	126,534,990	127,167,665	127,803,504	128,442,521	129,084,734	129,730,157	130,378,808	131,030,702	131,685,856	132,344,285
INDUSTRIAL (E-20)	41,817,632	42,026,721	42,236,854	42,448,039	42,660,279	42,873,580	43,087,948	43,303,388	43,519,905	43,737,504
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	4,156,808	4,177,592	4,198,480	4,219,472	4,240,569	4,261,772	4,283,081	4,304,497	4,326,019	4,347,649
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	46,780,878	47,014,782	47,249,856	47,486,105	47,723,536	47,962,154	48,201,964	48,442,974	48,685,189	48,928,615
SUBTOTAL - LOAD REQUIREMENTS	931,840,099	936,499,300	941,181,796	945,887,705	950,617,144	955,370,230	960,147,081	964,947,816	969,772,555	974,621,418
III. CCA OPERATING COSTS ($)										
SHORT TERM MARKET PURCHASES	$2,991,884	$1,680,539	$1,775,633	$1,860,249	$2,029,746	$1,577,702	$1,683,799	$1,718,158	$1,800,647	$1,897,650
CONVENTIONAL AND RENEWABLE POWER PURCHASE AGREEMENTS	$7,539,549	$4,234,957	$14,280,538	$18,835,061	$26,832,106	$25,924,271	$26,424,199	$31,572,996	$31,686,386	$33,666,518
SHORT TERM RENEWABLE ENERGY PURCHASES	$35,836,333	$45,647,891	$40,304,341	$38,445,628	$34,202,455	$39,405,369	$41,586,343	$38,985,176	$40,942,220	$41,410,765
SHORT TERM CARBON FREE ENERGY PURCHASES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ANCILLARY SERVICES AND CAISO CHARGES	$2,784,480	$2,890,964	$3,000,334	$3,124,091	$3,248,270	$3,376,498	$3,510,017	$3,648,482	$3,782,682	$3,924,959
RESOURCE ADEQUACY CAPACITY	$4,800,292	$4,973,565	$4,474,370	$3,962,252	$3,866,430	$3,980,380	$4,098,767	$4,105,729	$4,281,564	$4,383,986
STAFF AND OTHER OPERATING COSTS	$4,669,486	$4,767,821	$4,868,245	$4,970,806	$5,075,548	$5,182,519	$5,291,766	$5,403,339	$5,517,287	$5,633,662
BILLING AND DATA MANAGEMENT	$2,139,734	$2,214,946	$2,292,801	$2,373,393	$2,456,818	$2,543,175	$2,632,568	$2,725,102	$2,820,890	$2,920,044
UNCOLLECTIBLES EXPENSE	$317,239	$345,484	$368,412	$378,371	$399,071	$409,950	$426,137	$440,795	$454,158	$469,188
STARTUP FINANCING	$2,686,080	$2,686,080	$2,686,080	$2,102,755	$2,102,755	$0	$0	$0	$0	$0
CCA BOND CARRYING COST	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
SUBTOTAL - CCA OPERATING COSTS	$63,766,577	$69,443,746	$74,052,253	$76,054,106	$80,214,699	$82,401,364	$85,655,096	$88,601,278	$91,287,334	$94,308,272
IV. REVENUES FROM 100% GREEN PREMIUM AND MARKET SALES ($)										
GREEN PRICING PREMIUM	$92,809	$48,036	$49,724	$51,472	$53,281	$36,769	$38,062	$39,400	$40,785	$42,218
MARKET SALES	$0	$86,538	$86,893	$16,643	$18,430	$238,761	$251,738	$196,259	$205,905	$217,223
V. CONTRIBUTION TO PROGRAM RESERVES ($)	$2,550,663	$2,774,288	$2,958,614	$3,041,499	$3,207,851	$3,286,504	$3,416,134	$3,536,201	$3,643,257	$3,763,642
VI. CCA REVENUE REQUIREMENT ($)	$66,224,431	$72,083,460	$76,874,250	$79,027,490	$83,350,839	$85,412,338	$88,781,431	$91,901,821	$94,683,901	$97,812,472
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	7.1	7.7	8.2	8.4	8.8	8.9	9.2	9.5	9.8	10.0
PG&E AVERAGE GENERATION COST (CENTS/KWH)	9.7	9.9	10.3	10.8	11.1	11.4	11.8	12.1	12.5	12.8
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
POWER CHARGE INDIFFERENCE ADJUSTMENT	$20,924,230	$20,481,766	$21,718,450	$21,487,511	$23,212,392	$22,195,855	$22,834,210	$22,466,843	$23,453,951	$23,214,014
FRANCHISE FEE SURCHARGE	$554,648	$565,270	$591,366	$621,878	$646,023	$664,423	$691,792	$713,626	$738,658	$763,113
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 21,478,878	$ 21,047,036	$ 22,309,816	$ 22,109,389	$ 23,858,415	$ 22,860,278	$ 23,526,002	$ 23,180,468	$ 24,192,609	$ 23,977,127
VIII. CCA REVENUE REQUIREMENT PLUS PG&E CCA CUSTOMER SURCHARGES	$87,703,309	$93,130,496	$99,184,067	$101,136,880	$107,209,254	$108,272,616	$112,307,433	$115,082,289	$118,876,510	$121,789,599
IX. REVENUE AT PG&E GENERATION RATES	$90,825,060	$92,564,438	$96,837,741	$101,834,129	$105,787,832	$108,800,994	$113,282,736	$116,858,002	$120,957,118	$124,961,736
X. TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS	$ (3,121,751)	$ 566,058	$ 2,346,326	$ (697,250)	$ 1,421,422	$ (528,378)	$ (975,303)	$ (1,775,713)	$ (2,080,608)	$ (3,172,136)
CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS (%)	-2%	0%	1%	0%	1%	0%	0%	-1%	-1%	-1%

Santa Cruz County (Single County)
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)	80,098	80,498	80,901	81,305	81,712	82,120	82,531	82,943	83,358	83,775
SMALL COMMERCIAL (A-1)	8,140	8,180	8,221	8,262	8,304	8,345	8,387	8,429	8,471	8,513
SMALL COMMERCIAL (A-6)	527	530	532	535	538	540	543	546	549	551
MEDIUM COMMERCIAL (A-10)	694	697	701	704	708	711	715	718	722	726
LARGE COMMERCIAL (E-19)	301	303	304	306	307	309	310	312	313	315
INDUSTRIAL (E-20)	7	7	7	7	7	7	7	7	7	7
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	538	541	544	547	549	552	555	558	560	563
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	670	674	677	681	684	687	691	694	698	701
SUBTOTAL - CUSTOMER ACCOUNTS	90,975	91,430	91,887	92,347	92,808	93,272	93,739	94,207	94,678	95,152
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	460,022,517	462,322,630	464,634,243	466,957,414	469,292,201	471,638,662	473,996,856	476,366,840	478,748,674	481,142,417
SMALL COMMERCIAL (A-1)	116,634,992	117,218,167	117,804,258	118,393,280	118,985,246	119,580,172	120,178,073	120,778,963	121,382,858	121,989,772
SMALL COMMERCIAL (A-6)	26,025,786	26,155,915	26,286,695	26,418,128	26,550,219	26,682,970	26,816,385	26,950,466	27,085,219	27,220,645
MEDIUM COMMERCIAL (A-10)	109,866,496	110,415,828	110,967,907	111,522,747	112,080,360	112,640,762	113,203,966	113,769,986	114,338,836	114,910,530
LARGE COMMERCIAL (E-19)	126,534,990	127,167,665	127,803,504	128,442,521	129,084,734	129,730,157	130,378,808	131,030,702	131,685,856	132,344,285
INDUSTRIAL (E-20)	41,817,632	42,026,721	42,236,854	42,448,039	42,660,279	42,873,580	43,087,948	43,303,388	43,519,905	43,737,504
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	4,156,808	4,177,592	4,198,480	4,219,472	4,240,569	4,261,772	4,283,081	4,304,497	4,326,019	4,347,649
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	46,780,878	47,014,782	47,249,856	47,486,105	47,723,536	47,962,154	48,201,964	48,442,974	48,685,189	48,928,615
SUBTOTAL - LOAD REQUIREMENTS	931,840,099	936,499,300	941,181,796	945,887,705	950,617,144	955,370,230	960,147,081	964,947,816	969,772,555	974,621,418
III. CCA OPERATING COSTS ($)										
SHORT TERM MARKET PURCHASES	$2,823,959	$2,836,613	$2,807,849	$2,843,538	$2,995,749	$3,110,449	$3,228,287	$3,295,155	$3,351,535	$3,428,171
CONVENTIONAL AND RENEWABLE POWER PURCHASE AGREEMENTS	$7,116,376	$7,148,266	$16,881,723	$21,312,950	$29,266,433	$29,786,794	$30,316,308	$35,547,029	$35,594,623	$37,523,432
SHORT TERM RENEWABLE ENERGY PURCHASES	$14,446,204	$16,279,119	$10,526,419	$7,711,567	$2,629,692	$3,746,538	$4,994,140	$1,510,596	$3,144,960	$3,174,651
SHORT TERM CARBON FREE ENERGY PURCHASES	$16,774,828	$17,660,681	$18,599,483	$19,914,011	$20,847,334	$21,739,257	$22,636,048	$23,509,227	$23,956,084	$24,506,995
ANCILLARY SERVICES AND CAISO CHARGES	$2,784,480	$2,890,964	$3,000,334	$3,124,091	$3,248,270	$3,376,498	$3,510,017	$3,648,482	$3,782,682	$3,924,959
RESOURCE ADEQUACY CAPACITY	$4,800,292	$4,973,565	$4,474,370	$3,962,252	$3,866,430	$3,980,380	$4,098,767	$4,105,729	$4,281,564	$4,383,986
STAFF AND OTHER OPERATING COSTS	$4,669,486	$4,767,821	$4,868,245	$4,970,806	$5,075,548	$5,182,519	$5,291,766	$5,403,339	$5,517,287	$5,633,662
BILLING AND DATA MANAGEMENT	$2,139,734	$2,214,946	$2,292,801	$2,373,393	$2,456,818	$2,543,175	$2,632,568	$2,725,102	$2,820,890	$2,920,044
UNCOLLECTIBLES EXPENSE	$291,207	$307,290	$330,687	$341,577	$362,445	$367,328	$383,539	$398,723	$412,248	$427,480
STARTUP FINANCING	$2,686,080	$2,686,080	$2,686,080	$2,102,755	$2,102,755	$0	$0	$0	$0	$0
CCA BOND CARRYING COST	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
SUBTOTAL - CCA OPERATING COSTS	$58,534,147	$61,766,844	$66,469,491	$68,658,440	$72,852,973	$73,834,438	$77,092,939	$80,144,884	$82,863,373	$85,924,880
IV. REVENUES FROM 100% GREEN PREMIUM AND MARKET SALES ($)										
GREEN PRICING PREMIUM	$225,835	$227,369	$228,731	$229,908	$231,951	$233,853	$235,602	$237,186	$238,589	$239,799
MARKET SALES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
V. CONTRIBUTION TO PROGRAM RESERVES ($)	$2,341,366	$2,470,674	$2,658,780	$2,746,338	$2,914,119	$2,953,378	$3,083,718	$3,205,795	$3,314,535	$3,436,995
VI. CCA REVENUE REQUIREMENT ($)	$60,649,678	$64,010,149	$68,899,540	$71,174,870	$75,535,142	$76,553,963	$79,941,055	$83,113,493	$85,939,319	$89,122,076
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	6.5	6.8	7.3	7.5	7.9	8.0	8.3	8.6	8.9	9.1
PG&E AVERAGE GENERATION COST (CENTS/KWH)	9.7	9.9	10.3	10.8	11.1	11.4	11.8	12.1	12.5	12.8
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
POWER CHARGE INDIFFERENCE ADJUSTMENT	$20,924,230	$20,481,766	$21,718,450	$21,487,511	$23,212,392	$22,195,855	$22,834,210	$22,466,843	$23,453,951	$23,214,014
FRANCHISE FEE SURCHARGE	$554,648	$565,270	$591,366	$621,878	$646,023	$664,423	$691,792	$713,626	$738,658	$763,113
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 21,478,878	$ 21,047,036	$ 22,309,816	$ 22,109,389	$ 23,858,415	$ 22,860,278	$ 23,526,002	$ 23,180,468	$ 24,192,609	$ 23,977,127
VIII. CCA REVENUE REQUIREMENT PLUS PG&E CCA CUSTOMER SURCHARGES	$82,128,556	$85,057,185	$91,209,356	$93,284,259	$99,393,557	$99,414,241	$103,467,056	$106,293,961	$110,131,927	$113,099,203
IX. REVENUE AT PG&E GENERATION RATES	$90,825,060	$92,564,438	$96,837,741	$101,834,129	$105,787,832	$108,800,994	$113,282,736	$116,858,002	$120,957,118	$124,961,736
X. TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS	$ (8,696,504)	$ (7,507,253)	$ (5,628,385)	$ (8,549,870)	$ (6,394,275)	$ (9,386,753)	$ (9,815,680)	$ (10,564,040)	$ (10,825,191)	$ (11,862,532)
CHANGE IN CUSTOMER ELECTRIC CHARGES OR SURPLUS (%)	-4%	-4%	-3%	-4%	-3%	-4%	-4%	-4%	-4%	-4%

Peer Review of the Monterey Bay Community Power CCA Technical Study

On Behalf of the County of Santa Cruz

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

March 31, 2016

Table of Contents

Executive Summary

In 2016, Pacific Energy Advisors, Inc. (PEA) released a Community Choice Aggregation (CCA) Technical Study (Study), describing the potential benefits and liabilities associated with the formation of Monterey Bay Community Power (MBCP), which would provide electric generation service to residential and business customers located within the municipalities in the Monterey, San Benito and Santa Cruz counties, as well as unincorporated areas of the counties. The Study evaluated projected operations of MBCP, over a ten-year planning horizon, considering such factors as MBCP's ability to offer rates competitive with Pacific Gas & Electric (PG&E); increased use of renewable energy sources; reduced emissions of greenhouse gases (GHG) and local and statewide employment and economic impacts.

In early 2016, the Santa Cruz County retained MRW & Associates, LLC (MRW) to conduct a peer review to assess the soundness and thoroughness of the technical analysis, as well as the reasonableness of the underlying assumptions. MRW was also asked to provide any additional information that might be useful to the County and MBCP member decision makers. The following is MRW's professional review of the Study.

Overall, MRW finds that the Study was thorough and professionally performed. We found no "fatal flaws" or major assumptions that require revision. As noted here, there are a few areas that may benefit from clarification, expansion or revision, but overall the Study is sound.

Even though the Study finds that the CCA would be cost-competitive under a wide range of assumptions over the 10-year period, given ratemaking in California, it is likely that in an isolated year, PG&E's rates will be less than the MBCP's average cost of service. This would be more likely under the Scenarios 1 or 2, where costs are designed for parity with PG&E's rates, leaving a minimal buffer between the MBCP rates and PG&E's.

The remainder of the executive summary presents MRW's responses to the specific questions listed in the County's request for proposals.

1. **Does the study consider all pertinent factors to determine current and future electric energy requirements of the CCA?**

Yes. Overall, MRW found that the Study was thorough and considered all the necessary parts to evaluate the energy requirements of MBCP.

2. **Does the study incorporate current power market conditions and reasonable projections of expected future conditions?**

In general, the power market assumptions are reasonable. As discussed in more detail under Question 6, MRW found that the timing of the long-term renewable contracts assumed in Study may be optimistic. Nonetheless, MRW does not believe that this would impact the overall results of the Study.

3. **Considering the difficulty in accurately estimating greenhouse gas (GHG) emissions attributable to a given electricity supply portfolio, are the estimates of the GHG emissions intensity of the CCA scenarios relative to PG&E reasonable and adequate?**

Yes, MRW finds estimates of the GHG emissions intensity of the CCA scenarios and PG&E reasonable and adequate.

4. **Does the study consider all pertinent factors in projecting future PG&E rates for comparison to CCA costs/payment projections?**

While MRW did not have access to PEA's PG&E rate forecasting model, its outputs were reasonable and its results are generally consistent with recent forecasts performed by MRW.

5. **Does the study consider all pertinent factors in presenting a reasonably accurate investor-owned utility (IOU) vs. CCA cost/payment comparison?**

Yes. The input variables into the PG&E rates and CCA costs are complete and generally reasonable.

6. **Do the pro forma analyses consider all pertinent factors in projecting CCA's operating results? Do the pro form analyses include reasonable cost-of-service variables?**

Yes, the pro forma analysis includes all pertinent factors in projecting CCA's operating results as well as generally reasonable cost-of-service variables.

The schedule for the implementation of new renewable resources may be optimistic and not met. For example, acquiring 100 MW of utility scale solar PV by 2019 may be challenging. The facility or facilities underlying the 100 MW would have to be associated with projects that already have all their requisite permits in place and a place in the CAISO interconnection queue. (This is in fact what PEA was considering in its projection.) A contract would need to be signed quickly, once the CCA is established, so that the developer(s) can begin construction and deliver power by 2019. Even this might be challenging, given that banks that could fund the project(s) for the developer might find the counterparty risk associated with a brand-new entity to be too great.

7. **Do you have any other suggestions for reducing CCA costs under a traditional California CCA formation scenario?**

MRW has no suggestions. The Study identified the key cost components, their underlying activities and functions, and provided reasonable estimates for those components.

8. Does the study present an adequate analysis of potential economic benefits and challenges of various supply scenarios? Does the study present a reasonable assessment of job creation, both total jobs created and local jobs created?

The Study used a reasonable tool, the Jobs and Economic Development Impact ("JEDI") model, to estimate the employment and economic impacts of the assumed MBCP-sponsored renewable energy projects. MRW finds the results to be reasonable to an order of magnitude. Nonetheless, the way that the Study characterized the economic and job impacts was misleading. In multiple places in the Study, the economic impacts were characterized as "significant," both statewide and for the Monterey Bay region. While the impacts are undoubtedly positive, they are better described as "modest."

MRW concurs with the Study that MBCP would have little to no impact on the PG&E workforce.

9. Should any additional benefits or challenges be considered?

MRW does not believe that any major additional benefits or challenges need be considered. As discussed in more detail below, a few additional rate sensitivity runs should be conducted to explore the likely challenge of meeting the schedule set for new renewable project development and variations in greenhouse gas allowance prices.

10. Does the study provide a thorough evaluation of the prospective CCA's ability to achieve rate competitiveness with PG&E? What other factors, if any, should be considered?

The Study is thorough in evaluating the CCA's ability to achieve rate competitiveness. The variables tested in the sensitivity analysis, along with the assumed values for those variables, were all appropriate. Nonetheless, it would be useful to see the year-by-year results for the sensitivities. By presenting the sensitivity results solely as a 10-year levelized cost, one cannot see pertinent trends. These might include CCA average costs exceeding PG&E rates in early years but being low enough in later years so as to generate a positive levelized value. Or the PG&E and CCA rate projections could cross each other in a later year, so that if a longer time-frame was considered the results would be different.

MRW recommends that PEA identify any sensitivity cases where the PG&E and CCA rate lines "cross," present those results, discuss the likelihood of that case coming to fruition, and describe how the CCA might address that risk.

11. Does the study consider all pertinent factors to assess the overall cost-benefit potential of CCA?

The Study addressed all the pertinent factors needed to assess the overall cost-benefit potential of MBCP. MRW recommends that PEA conduct an additional set of rate sensitivity runs exploring higher and lower greenhouse gas allowance costs and a more conservative timeline for the implementation of power purchase agreements (PPAs) associated with new renewable project development.

12. Does the study consider all pertinent risk factors involved with establishment and operation of the CCA program, and are such factors properly weighted and analyzed?

Overall, the risk analysis was thorough and provided appropriate responses to the risks identified. Please see response to Question 9 above for a recommendation for an additional risk factor to consider.

Introduction and Background

In 2016, Pacific Energy Advisors, Inc. (PEA) prepared a technical study (Study), considering the potential benefits and liabilities associated with the formation of Monterey Bay Community Power (MBCP). MBCP would provide electric generation service to residential and business customers in the twenty municipalities in the Monterey Bay region, including the Counties of Santa Cruz, Monterey and San Benito, as well as the incorporated cities and towns within those counties. The Study evaluated projected operations of MBCP, over a ten-year planning horizon, considering such factors as MBCP's ability to offer rates competitive with Pacific Gas & Electric (PG&E); increased use of renewable energy sources; emissions of greenhouse gases (GHG), and local and statewide employment and economic impacts.

In late 2015, the County retained MRW & Associates, LLC (MRW) to conduct a peer review to assess the soundness and thoroughness of the technical analysis, as well as the reasonableness of the underlying assumptions. MRW was also asked to provide any additional information that might be useful to the County and MBCP decision makers. The following is MRW's professional review of the Study.

Overall, MRW finds that the Study was thorough and professionally performed. We found no "fatal flaws" or major assumptions that require revision. As noted here, there are a few areas that may benefit from clarification, expansion or revision, but overall the Study is sound.

Even though the Study finds that the CCA would be cost-competitive under a wide range of assumptions over the 10-year period, given ratemaking in California, it is likely that there would be years when PG&E's rates would be less than the MBCP's average cost of service. This can be addressed both through sufficient rate stabilization reserves and good communications with its customers.

The remainder of the report is organized by topic: demand forecast, supply assumptions, other operating costs, PG&E fees, sensitivity analysis, economic and employment analysis, and risk assessment.

Demand Forecast

PEA based its demand forecast upon the baseline consumption from the 2014 PG&E load data and the California Energy Commission's forecast of load for 2015 to 2025.[1] From that forecast, the Study assumed a 0.5% annual growth rate, which is lower than the CEC base forecast (1.29%) so as to account for additional self-generation (e.g., rooftop solar PV) and energy efficiency. This is a credible source for forecasting purposes, and PEA's energy efficiency adjustment is reasonable.

---

[1] Kavalec, Chris, 2015. California Energy Demand Updated Forecast, 2015-2025. California Energy Commission, Electricity Supply Analysis Division. Publication Number: CEC-2002014-009-CMF, Table 6.

PEA also removed the Direct Access load from the forecast, assuming that those customers would remain on DA service and not join the CCA. PEA further assumed a 15% customer opt-out rate for its Supply Scenarios 1 and 2. This opt-out rate is consistent with the reported opt-out rates observed during recent expansions of the Marin Clean Energy program as well as that for Sonoma Clean Power. Sensitivities using different opt-out rates were also explored.

In combination with the sensitivities, these overall opt-out and load forecast assumptions are reasonable for the pro-forma analysis.

The Study notes that the hourly electricity consumption and peak demand were estimated using hourly load profiles published by PG&E for each customer classification. This is a reasonable source. However, these profiles are system-wide, and as such would likely overstate the peak demand for the Monterey Bay region, as its air conditioning load is low relative to the PG&E territory overall. Overestimating the peak demand would result in conservative (i.e., high) cost estimates for meeting resource adequacy requirements.

Supply Assumptions

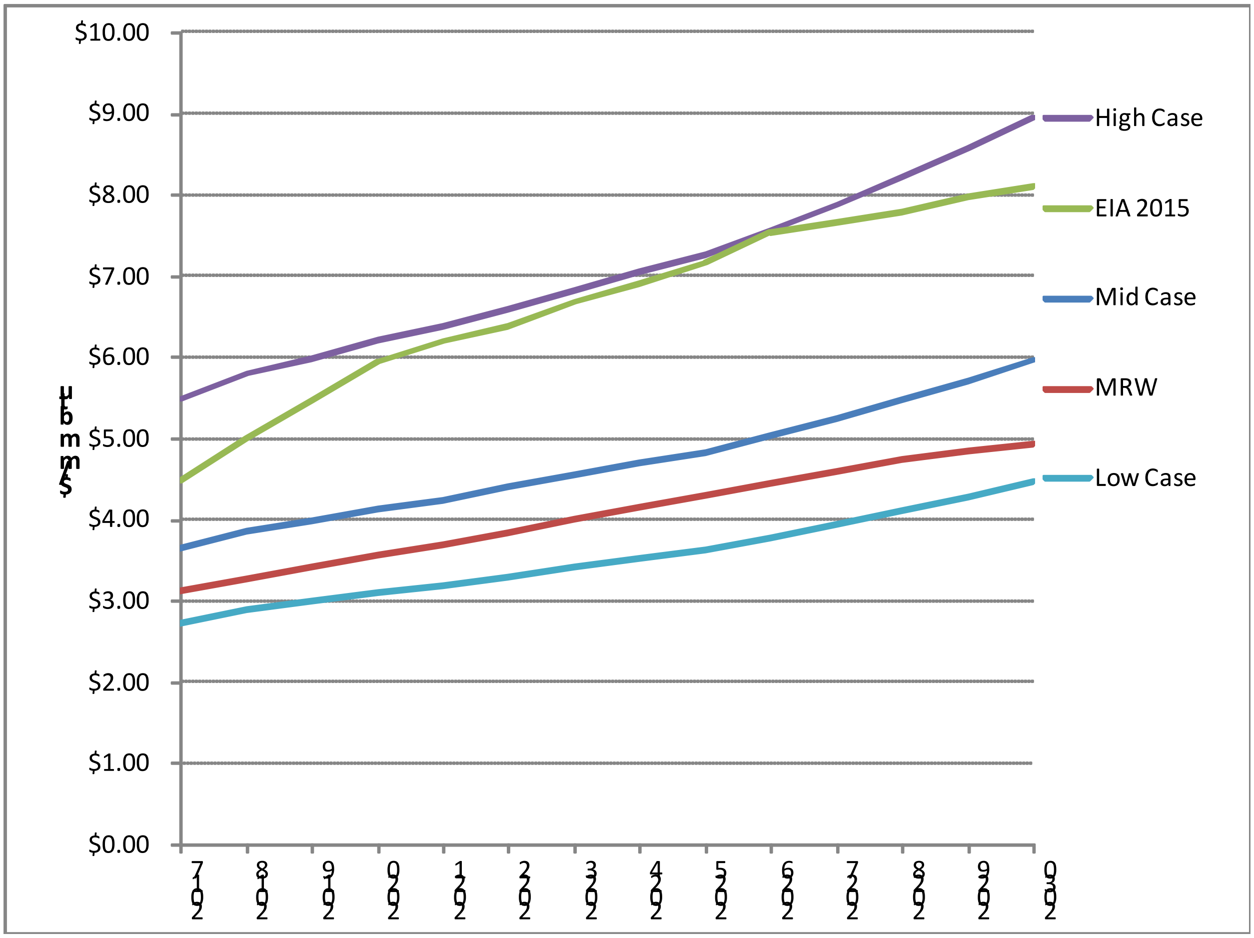
This section presents MRW's comments on the key elements of the supply forecast: renewable and non-renewable power prices, resource adequacy prices, associated greenhouse gas (GHG) costs, and the phasing in of MBCP power purchase agreements with specific renewable assets.

Non-Renewable Power and Underlying Gas Prices

Consistent with prior PEA evaluations, the Study assumes that the market cost of power equals the annual average price of gas times a "market heat rate" plus any associated GHG compliance costs. Given that natural gas generators are on the margin in the CAISO system a majority of hours and thus set market prices, this method is reasonable.

Figure 1 below shows the natural gas price forecast underlying the Study's power price forecasts, along with two benchmarks: the average prices to electric generators from the Energy Information Administration's 2015 Annual Energy Outlook, and the 2017 and 2018 futures prices for natural gas at PG&E's city gate. As the figure shows, both the benchmarks are within the sensitivity range used by PEA. Note that the EIA 2015 data is significantly higher than the Study's Mid Case (although still lower than the Study High Case), due in all likelihood to the continued fall of natural gas prices since the EIA forecast was produced in late 2014/early 2015.

Figure 1. Natural Gas Price Forecasts



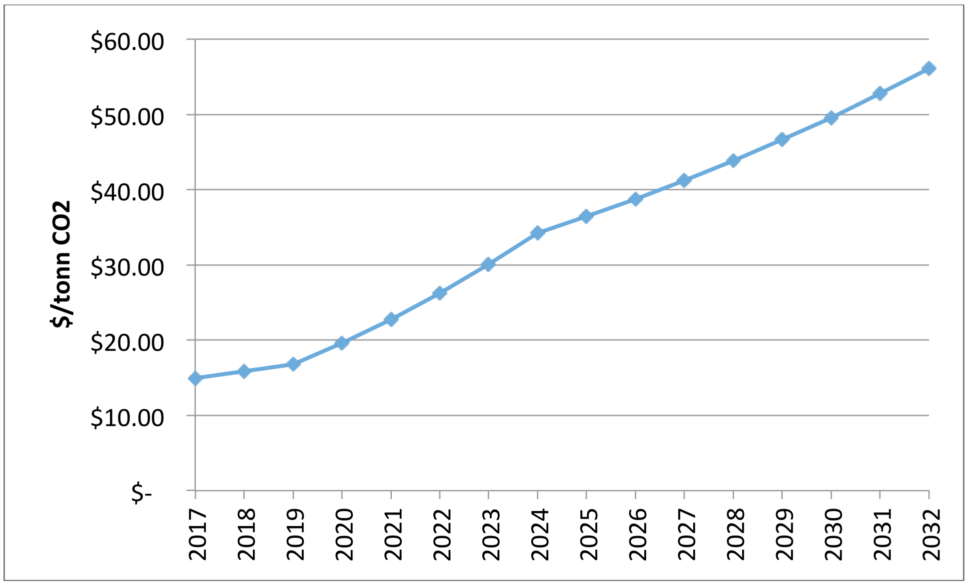
The Study uses a market heat rate of 8,000 Btu/kWh. This rate falls between that of a combustion turbine, which would set the wholesale power market price at times of higher demand, and a newer combined cycle power plant, which would set the wholesale market price most other hours. MRW finds the 8,000 Btu/kWh to be a bit high, given that the continuing large influx of renewables that is occurring (and will continue to occur through 2030) will pull down the market heat rate—i.e., more efficient plants will be on the margin. This means that for the given gas price forecast, the Study's market price forecast may be on the order of 5-10% too high. Nonetheless, given the uncertainty of gas prices, along with the sensitivity analyses conducted, this difference does not affect the overall conclusions of the Study.

The Study assumed a GHG emissions rate of 0.428 ton/MWh for market power. This emissions rate falls between that of a gas-fired combined cycle (0.38 ton/MWh) and a combustion turbine (0.50 ton/MWh) and is reasonable.

GHG Prices

Figure 2 shows the Study's projected cost of GHG allowances. The Study assumes that allowance price begins at $14.96 per metric ton ($/ton) and escalates at around 6% per year, with the exception of 2020 through 2025, where it escalates at 14%-17% per year. The Study's implicit forecast for 2016, $14.16/ton is higher than the actual January 2016 California carbon allowance price, of $13.20/ton.

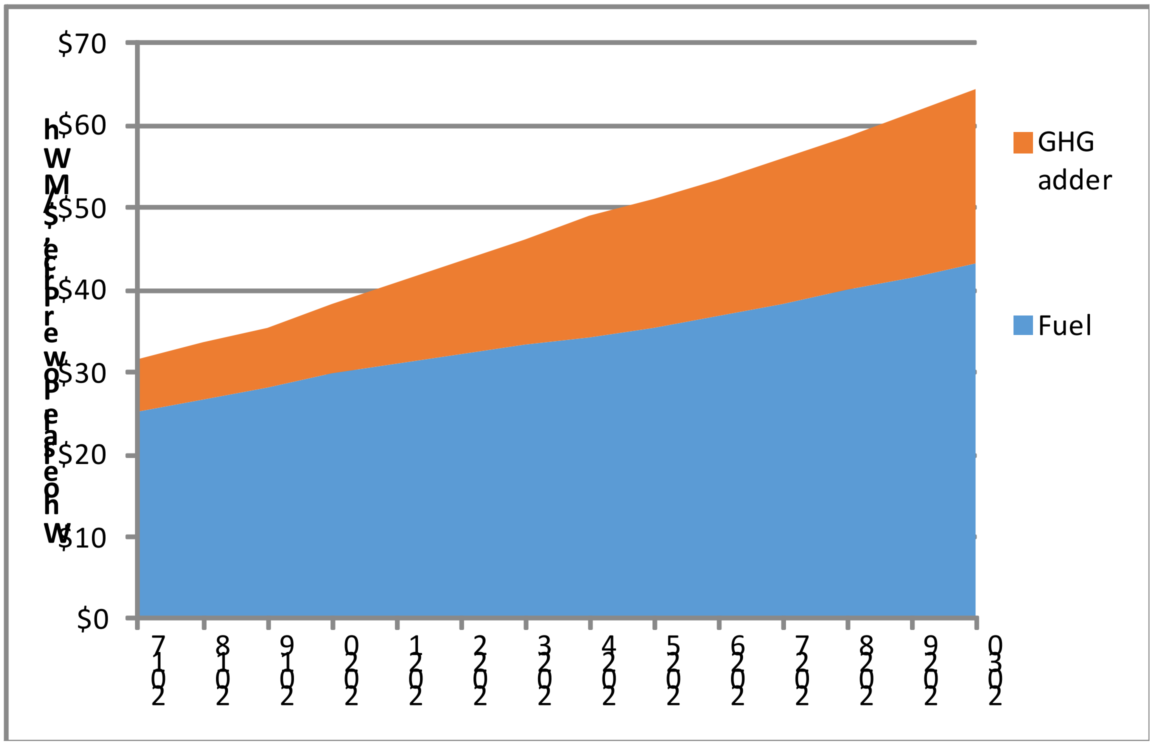
Figure 2. CO_2 Allownace Price Foreacst



Forecasting the price of carbon allowances is highly uncertain. For the past 2 to 3 years, the allowances have remained at or near the California Air Resources Board's (CARB's) auction reserve price. This reserve price escalates at 7% per year through 2020. Thus, the very near term values are likely reasonable. Beyond 2020 the prices are much more uncertain. PEA should provide its rationale for the significantly higher escalation rates in 2020 through 2024.

The import of the GHG price forecast is shown in Figure 3. This figure breaks down the wholesale power price by the underlying fuel cost and the GHG adder. The figure shows that the GHG adder is projected to grow at a much faster rate than the underlying fuel cost. In 2017, the GHG adder constitutes 20% of the total market price. By 2030, it grows to over 33% of the price—over $21/MWh (2.1¢/MWh).

Figure 3. Breakdown of Wholesale Market Power Cost

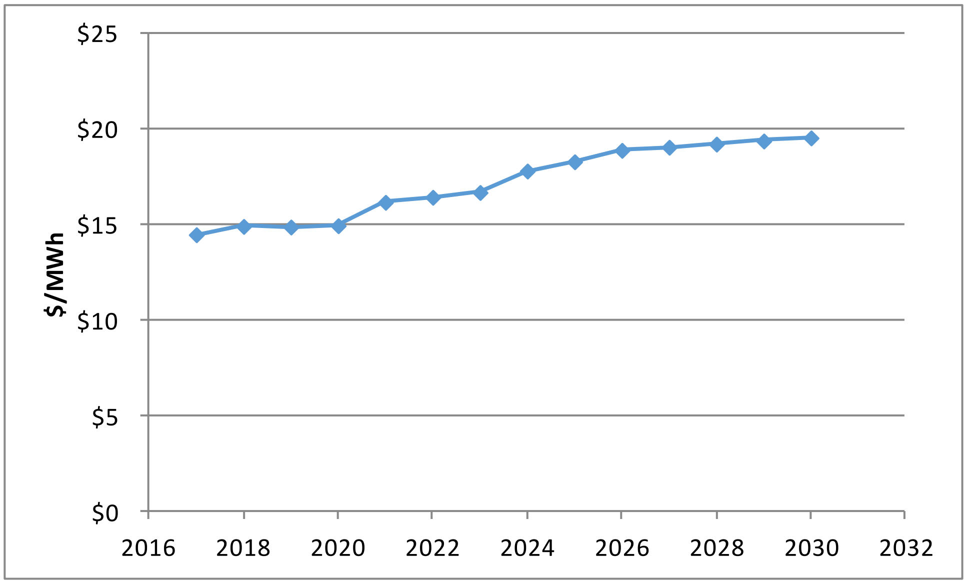


Renewable Power

Market Renewable Power. PEA set the value of market renewable power (Bucket 1) as a premium over the standard market power price. Thus, the price of market renewable power will follow the general price of power plus the premium. The assumed RPS premiums are shown in Figure 4. Overall, the renewable adder escalates at near inflation: 2.7%.

Because of the relative newness of the explicit market for renewable power, it is difficult to forecast it with any certainty. PEA assumes that given the likely continued demand for market renewable power, even though the underlying generation cost of renewable power may fall below the wholesale market price (particularly with the GHG adder), renewables will still be priced at a premium above the standard wholesale price due to demand. Given this, MRW finds escalating the renewable adder at something close to inflation is reasonable, however flat or even declining renewable energy premiums can also be plausibly argued.

Figure 4. Renewable Power Price Premium

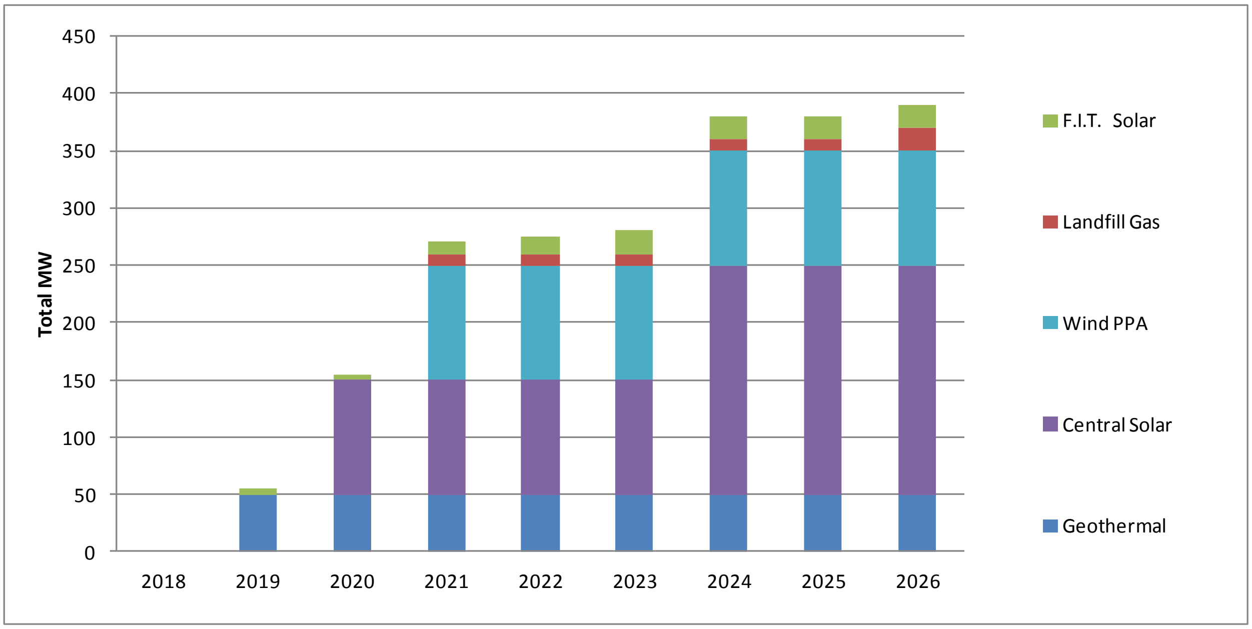


The long-term PPAs for renewable power assumed in the Study are shown in Table 1 and Figure 4. The prices for the large ground solar PV, wind and geothermal are reasonable and consistent with the current markets. As discussed below, the price for the feed-in tariff (FIT) solar power may be too low to generate the capacity additions assumed.

Table 1. MBCP Renewable Additions

	Capacity (MW)	Price ($/MWh)	Load Shape	Year in Place
Solar PV, utility scale	100	$55	PV	2020
Solar PV, utility scale	100	$65	PV	2024
Wind	100	$60	WIND	2021
Landfill Gas	10	$80	7 X 24	2021
Landfill Gas	10	$80	7 X 24	2024
Geothermal	45	$80	7 X 24	2019
Solar PV, FIT	5	$100	PV	2019
Solar PV, FIT	5	$90	PV	2021
Solar PV, FIT	5	$90	PV	2022
Solar PV, FIT	5	$90	PV	2023

Figure 5. MBCP Renewable Additions



The Study's schedule of renewable additions is aggressive and may not to be met. The initial 45 MW of geothermal power would have to come from the geysers or other existing facility. MRW finds this to be likely attainable. The 10 MW of landfill gas is also likely attainable, particularly if the landfill gas generator is already in existence, or at worst, already permitted.

Acquiring 100 MW of utility scale solar PV by 2020 is less certain. Utility-scale projects do not get constructed without a sales agreement in place, which do not occur without the necessary permits in hand and a place in the CAISO interconnection queue. Thus, the facility or facilities underlying the 100 MW would have be projects that have all their requisite permits in place and a place in the CAISO interconnection queue. A contract would need to be signed quickly once the CCA is established so that the developer(s) can begin construction to deliver power by 2019. While there are projects that meet these criteria, banks or investors that fund the project for the developer might find the counterparty risk associated with a brand-new entity to be too great.

The response to the California utilities' "Renewable Auction Mechanism" (RAM), a CPUC-prescribed solicitation for renewables under 20 MW, received many times more offers than they were able to sign contracts. Thus, there are likely developers with viable projects who were not selected in the RAM and are thus looking for another off taker. It is from this pool of candidates that the 2020 solar will likely come from.

The feed-in-tariff amounts also may be optimistic. For the past two years, Santa Cruz San Benito and Monterey counties have been add approximately 12 MW of net-energy metered (NEM) solar PV in 2014 and over 18 MW in 2015. These installations have been primarily using a lease/PPA model, and thus having the developer bear the financing. Since NEM is valued at retail rates, this means that the effective price the leaseholders (or homeowners) are receiving is approximately

20¢/kWh. That is, by offsetting 20¢/kWh retail rates, value of a solar panel is 20¢/kWh to the homeowner or panel owner. Thus, the FIT would be attracting 33% as much solar PV at 9¢/kWh as the NEM installations at 20¢/kWh. Unless there is a major market change in solar NEM policy (which is not unthinkable) and firms that currently do utility-scale solar or rooftop solar become interested in FIT-sized installations at 9¢/kWh, MRW has reservations that the FIT targets can be fully met.

Transmission and Grid Services

The CAISO charges all entities that use its grid for the 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. These charges amount to roughly 5-6% of the procurement costs. The values used by PEA are reasonable.

Other Cost of Service Elements

While power procurement costs are by far the greatest expense, MBCP will incur a number of overhead and operating expenses. The Study used reasonable estimates of these costs, consistent with that seen by the operating CCAs.

PG&E Fees paid by CCA Customers

PG&E imposes two surcharges that are unique to CCA and direct access customers: the Franchise Fee Surcharge and the Power Charge Indifference Adjustment (PCIA). These surcharges are not program costs *per se*, but 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 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).

The Study set the initial PCIA at the relatively high 2016 level of approximatelty 2.5¢/kWh for residential customers, and assumes it will remain at this high level the forecast period. As the PCIA is notoriously difficult to forecast, and its current level is very high relatively to prior years, this assumption is reasonable to conservative. Note that the PCIA is further addressed in the Sensitivity Analysis and Risk sections.

Sensitivity Analyses

The Study explored the sensitivity of the results of its analysis to six major areas of uncertainty. As detailed below, MRW finds that the areas explored and range of the inputs encompass the reasonable expectations of the extremes that might occur in the values. Of course, unexpected events can occur that would result in inputs outside of the ranges presented here.

The Study presents the results of this analysis as a 10-year levelized cost of power (CCA and PG&E). While this provides a good snapshot of the gross impacts of different assumptions, the temporal aspect is lost. In other words, the levelized results do not say if the different assumption set makes CCA more costly in the first two years, less costly in the following eight years (such that the ten-year levelized cost is lower for the CCA than for PG&E.). Or perhaps the other way around, where the CCA costs are lower in the near term and greater in the longer-term.

MRW therefore recommends that PEA identify any sensitivity cases where the PG&E and CCA rate lines "cross," present those results, discuss the likelihood of that case coming to fruition, and describe how the CCA might address that risk.

Variables Considered

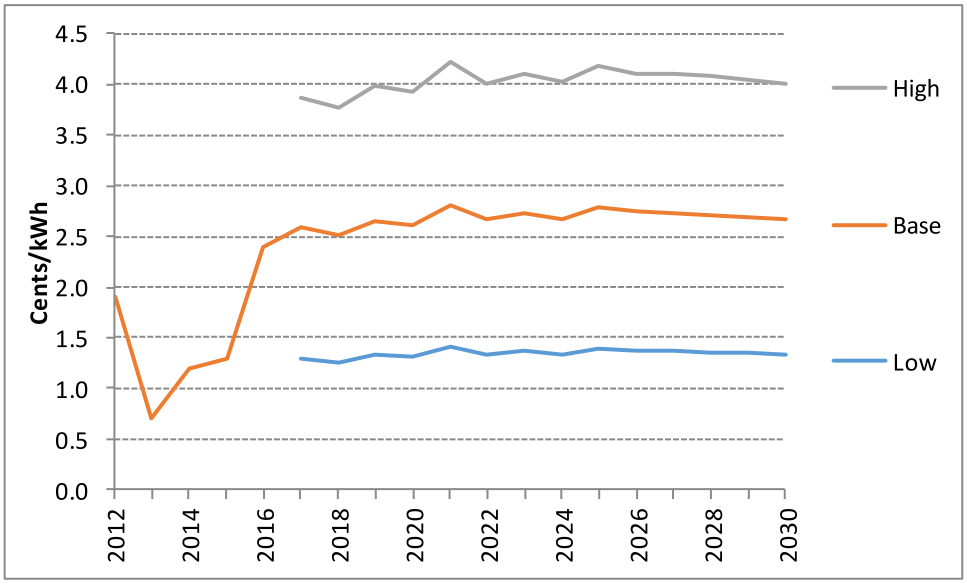
Natural Gas: Sensitivity to changes in natural gas and power prices were tested by varying the base case assumptions to create high and low cases. The high case reflects a 50% increase in this input relative to the base case and the low case reflects a 25% decrease relative to the base case. MRW finds that this range reasonably encompasses the likely natural gas price trajectory.

Renewables: The cost of renewables to MBCP was increased and decreased by 25%. As this sensitivity was to the difference MBCP would pay for renewables relative to PG&E, this range is reasonable.

PG&E Rate: PEA changed the PG&E generation rate escalation from 2.5% in base case to 5% for a high case and 1.5% for a low. This was a simple change to the escalation rate, without any underlying modeling assumptions. In particular, this case could use a year-by-year presentation. The better question answered in these scenarios is when the PG&E rate became consistently lower than the CCA cases. This cannot be answered with the results presented on a levelized basis.

Surcharges: 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 (Figure 6). The PCIA is particularly difficult to model, as it is very sensitive to the inputs feeding into the underlying equations. As the 2016 PCIA is particularly high relative to recent PCIA values, using it as the default and exploring even higher PCIAs is reasonable to very conservative.

Figure 6. PCIA Sensitivities



Opt-Outs: PEA tested the sensitivity of ratepayer costs to customer participation in the CCA in Scenarios 1 and 2 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. MRW finds these opt-out rates to be reasonable.

Carbon-free: 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, the Study explored the impact of increasing the carbon-free energy cost premium scenario by 300% (relative to the base case assumption), from about $3/MWh to $12/MWh. MRW finds this range to be reasonable.

Perfect Storm: The Study states that the "Perfect Storm" sensitivity examines the cumulative effects of adverse changes to all of the key variables to present what could be considered a worst case. AS the Study rightly notes, "The likelihood that all of these variables change in unison is remote; many of the key variables are negatively correlated meaning that increases in one variable would normally be associated with decreases in another." In particular, the combination of the very high PCIA—over 4¢/kWh—in conjunction with high market prices is implausible, as the two are negatively correlated.

Sensitivity Results

The Study presents the results of its sensitivity cases in two ways. First, it shows in Figure 25 (repeated here as Figure 7) the levelized rate for PG&E and each of the three CCA Scenarios. The triangle for each Scenario shows the base case value, with wings showing the range from the sensitivity cases. While overall this is a helpful figure, it may be a bit misleading. Fox example, one might infer that because the “wings” of scenario 1 and 2 overlap with (or are slightly less than) those of the PG&E rates, then the two will consistently have rates that are equal to(or lower than PG&E. This may not be the case. The circumstances that results in the bottom of the PG&E wing may not correspond to the circumstances of the lower wing in for CCA. The results of the tables provide a more indicative presentation of the sensitivity analysis results.

Figure 7. Sensitivity Analysis Range of Levelized Electric Rates (Study Figure 25)

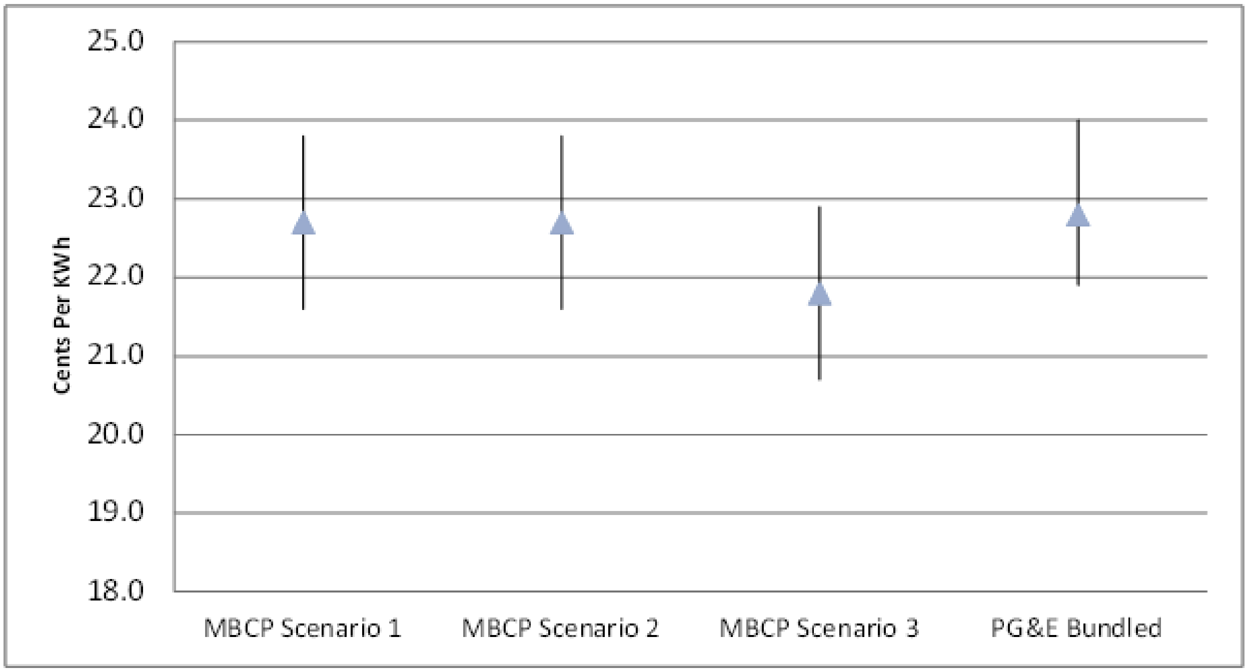


Table 2 below repeats the sensitivity results table on page 69 of the Study. The results for Scenarios 1 and 2—where MBCP average costs are modeled to equal PG&E’s rates are as one should expect. Variables that impact both PG&E and MBCP, such as gas and wholesale power cost, do not change the relative positions of MBCP and PG&E: MBCP remains marginally lower cost. Sensitivity variables that disproportionally impact MBCP or PG&E—high renewable cost, low PG&E rates, high PCIA –all cause the results to flip, with MBCP’s average costs exceeding PG&E’s rates.

Table 2. Sensitvity Analysis: Scenarios 1 and 2 Leveized Ratpayer Costs (¢/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	Perfect Storm
MBCP Scenario 1	22.7	23.4	22.4	23.5	21.9	22.7	22.7	23.8	21.6	22.7	22.7	22.7	24.9
MBCP Scenario 2	22.7	23.3	22.3	23.4	21.9	22.7	22.7	23.8	21.6	22.7	22.6	22.7	24.8
MBCP Scenario 3	21.8	22.5	21.5	22.3	21.3	21.8	21.8	22.9	20.7	21.8	21.8	22.1	24.1
PG&E Bundled	22.8	23.5	22.5	22.8	22.8	24.0	21.9	22.8	22.8	22.8	22.8	22.8	22.8

Also, as one should expect, the results with Scenario 3 are more robust. Here, the only case besides the Perfect Storm where the results flip and MBCP costs exceed PG&E rates is with the High PCIA. Even then, the MBCP average cost exceeds PG&E's rates by only 0.1¢/kWh. Given that MRW finds the high PCIA case to be very improbable, this 0.1¢/kWh difference underscores the greater robustness of Scenario 3.

It is also important to note that the high- and low-opt out scenarios do not affect the results. Underlying this result is the fact that most of the costs, power in particular, vary with electricity use or number of customers. Nonetheless, imprudent planning with insufficient portfolio flexibility could more negatively affect these results.

Also, it should be no surprise that the Perform Storm case results in PG&E rates that are markedly below those of MBCP. However, it is MRW's opinion that the storm is perhaps too perfect to be meaningful. As noted above, high PCIAs and high market costs can't exist simultaneously given the current PCIA protocol.

Even though the vast majority of the sensitivity cases show that the CCA could be cost-competitive, it is likely that in an isolated year or two that PG&E's rates will be less than the MBCP's average cost of service. In large part this is because of how utility rates are set in California. The California Public Utilities Commission (CPUC) allows PG&E to collect a certain amount of money each year. In each year, the amounts from the prior year are "trued up" so that PG&E collects the full cost of providing energy to its customers.[2] In some years, there can be a significant "over collection," whereby literally hundreds of millions of dollars of revenue collected for generation must be refunded to bundled customers. This refund depresses the PG&E's generation rate, quite plausibly below that of the CCA. As discussed in the risk section, this likelihood must be accounted for

[2] Subject to a CPUC reasonableness review.

Economic Development Impact Analysis

To quantify the economic impacts associated with new renewable generation projects that were incorporated in each of the three energy supply scenarios, the Study utilized the National Renewable Energy Laboratory's Jobs & Economic Development Impact (JEDI) models. The 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. This is an appropriate tool for estimating the rough order of magnitude economic impacts of a CCA's supply portfolio.

The Study presented results for three scenarios for job creation, earnings and economic output. These are summarized in Table 12 on page 36 of the Technical Study.

Overall, MRW commends PEA in explaining the impacts. However, it should be noted that the "jobs" during the construction period are better understood by laymen as job-years. Since the development and construction will occur over roughly 8 years (2019-2026), the results show an average of about 500 full-time jobs in place during the 8-year construction period. Of these, about 210 will be construction, while the remaining would be in other industries and induced in the greater economy.

MRW found that the Study can be misleading when characterizing these economic impacts. For example:

> During ongoing operation of the renewable generators, it is projected that **as many as** 185 new jobs would be created with a total annual economic impact ranging from $18 to $28 million. It is anticipated that these jobs would remain effective as long as the generating facilities remain operational, **resulting in significant, lasting impacts to the local economies of the MBCP Communities**. (p. 37. Emphasis added.)

First, "as many as" is the top of a range of estimates, and thus not indicative. Second, only the construction of the feed-in-tariff renewable capacity would assuredly be constructed in the Monterey Bay areas. Thus to suggest that the operation of these remote generators will have "significant, lasting impacts to the regions local economy" is misleading.

Similarly the report states:

> 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 MBCP Communities**. (p. 36. Emphasis added.)

While these impacts are positive, to characterize them as "significant" in the context of the California economy is an overstatement. There are 19 million workers in California and an annual gross state product of over $2.3 trillion. While 100+ jobs in locations where unemployment is high would be a real boost to a local economy, it is not significant when considered state-wide. Also, given the locations of the generators, to suggest that they would create significant benefits to Monterey Bay region is misleading. Benefits, yes, but modest ones.

MRW concurs with the Study that MBCP would have little to no impact on the PG&E workforce. PG&E would still need to service and maintain its distribution system in the county and provide most of the same general service functions (i.e., billing and collections).

Overall, the jobs and economic impact analysis must be seen as very roughly indicative and not predictive. MRW cautions that Community Choice Energy decisions should not be made solely—or even primarily—as an economic development strategy.

Risk Analysis

MBCP faces numerous risks as a CCA. The Study identified many of these risks, assessed the likelihood of occurrence, the magnitude of the risk, and impact of negative consequences resulting from the risk. The Study also presented its assessment of the ways that MBCP could mitigate the risk and/or adapt its operations going forward to account for the risk. MRW has examined the Study's risk assessment (both that presented in the report as well as the "Risk Assessment Matrix") and overall find that PEA has done an excellent job at identifying these risks and suggesting ways to mitigate them. Still, MRW has several comments related to the types of risk and the manner in which MBCP might hedge the risks.

Financial Risks to MBCP Members

PEA correctly notes that the financial risk to the MBCP members (i.e., participating cities and counties) is minimal. Through the use of a well-constructed joint powers authority (JPA) agreement, none of the MBCP obligations should flow onto the local governments. MRW notes that the JPA agreements used by Sonoma Clean Power and Marin Clean Energy could provide a template or jumping-off point for MBCP to draft its JPA agreement.

Thus, the only financial risk to the MBCP members is that associated with the possibility of more costly power. This risk is addressed in the sensitivity section.

Deviations between Actual Energy Use and Contracted Purchases

PEA correctly notes that contracted energy purchases and actual consumption will often not match. To the extent that this occurs, the MBCP would have to make additional market purchases or sales. The financial exposure to MBCP of these transactions can be minimized by appropriate risk management tools, such as the "laddering" discussed by PEA.

Overall, MRW concurs that the risk of supply and demand mismatch is real and will in all likelihood occur, but the financial impact of the mismatches can be managed by professional portfolio management.

Market Volatility and Price Risk

MRW agrees market volatility is a concern for MBCP and its impact is somewhat important. The Study suggests that one way to mitigate against power market volatility is laddering and entering into multi-year purchase agreements. This is generally true. However, it is important to note that while longer-term agreements reduce volatility, they do so at a cost, just as insurance can reduce the risk of catastrophic accidents but will cost more if such an accident does not occur. Over-insuring could put MBCP in a position of being unable to remain competitive with PG&E in times of declining market prices. It is the case that gas prices are very low and, as a result, market prices are low as well. Thus, MRW believes there is likely greater risk of increases in market prices and those risks would be mitigated by longer-term agreements.

Availability of Requisite Renewable and Carbon-Free Energy Supplies

At the present time, it is relatively easy to procure renewable and GHG-free resources. As such, there is a low likelihood of supply shortages in the near- and intermediate term. However, as California's load-serving entities start to procure resources to meet the 50% RPS requirements and as additional CCAs are formed and attempt to provide lower GHG levels than the local IOU, it may become more difficult to procure resources at competitive prices. The Study's recommendations regarding making multi-year forward purchases are sound.

Legislative and Regulatory Risk

MRW agrees with the Study's view that it is important for MBCP to actively monitor and, if necessary, intervene in the regulatory and/or legislative processes to defend its interests. While PG&E has taken a lower profile position regarding CCAs, it will continue to defend and attempt to disadvantage CCAs at the CPUC and the Legislature.

MRW also comments PEA on the excellent summary of recent legislative activities that could affect CCA operations and formation.

CCA Bonding Requirement

While mentioned in the Study (p. 76) and generally lumped into "regulatory risk," the risks of changes to the CCA Financial Security Requirement should be remembered. Pursuant to CPUC Decision 05-12-041, a new CCA must provide evidence of insurance or bond that will cover such costs as potential re-entry fees, i.e., the cost to PG&E if the CCA were to suddenly fail and be forced to return all its customers back to PG&E bundled service. Currently, a bond amount for CCAs is set at $100,000.

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

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

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

CCE Formation Activities

The Study accurately summarizes the activities needed to form a CCE. It should be noted that financing can be a particularly high barrier, as the initial costs must be put up, at risk, by one or more prospective member governments, and that a significant loan or line of credit must be secured for initial working capital.

Conclusions

Overall, MRW finds that the Study was thorough and professionally performed. We found no "fatal flaws" or major assumptions that require revision. As noted here, there are a few areas that may benefit from clarification, expansion or revision, but overall the Study is sound.

Even though the Study finds that the CCA would be cost-competitive under a wide range of assumptions over the 10-year period, given ratemaking in California, it is likely that in an isolated year, PG&E's rates will be less than the MBCP's average cost of service. This would be more likely under the Scenarios 1 or 2, where costs are designed for parity with PG&E's rates. In the long run, this can be addressed both through sufficient rate stabilization reserves and good communications with its customers.

TO: Monterey Bay Community Power, Project Development Advisory Committee

FROM: Pacific Energy Advisors, Inc.

SUBJECT: Response to MRW & Associates Peer Review of the Monterey Bay Community Power Community Choice Aggregation Technical Study

DATE: April 11, 2016

On March 31, 2016, MRW & Associates, LLC ("MRW") published a report summarizing the findings of MRW's peer review of the draft Monterey Bay Community Power ("MBCP") Community Choice Aggregation Technical Study ("Technical Study"), which was authored by Pacific Energy Advisors, Inc. ("PEA") and presented to the MBCP Project Development Advisory Committee ("PDAC") on March 10, 2016. Although the MRW peer review did not find any "fatal flaws" or "major assumptions that require revision," MRW did provide certain comments and recommendations that PEA would like to address through this memorandum. In PEA's opinion, the other comments and recommendations reflected in MRW's peer review report are generally informational and do not require formal responses at this time. With regard to the points that will be addressed in this memorandum, these items include:

1. Observation that the projected contracting timeline for MBCP's potential long-term renewable generating facilities, which were included within an indicative portfolio of generating facilities that would serve the MBCP program, "may be optimistic";
2. Observation regarding the uncertainty of longer-term greenhouse gas ("GHG") allowance pricing and its impact on MBCP's projected power costs;
3. Observation that the characterization of projected economic development impacts may be misleading; and
4. Recommendation that MBCP's sensitivity results should be presented on an annual, rather than levelized, basis.

One of MRW's key findings is that the proposed long-term renewable contracting timeline for new resources "may be optimistic" and therefore, MRW recommends that PEA develop a sensitivity for a more conservative long-term renewable contracting timeline. In consideration of this comment, PEA acknowledges that MRW's observation is reasonable and agrees that the assumptions reflected in MBCP's indicative portfolio of new renewable generating are indeed optimistic but not unrealistic. Given PEA's extensive experience with renewable project contracting, PEA believes that the proposed project development/completion timeline reflected in the Technical Study remains reasonable and obtainable, so long as MBCP's actual implementation schedule does not materially differ from PEA's current assumption (that MBCP will commence customer service no sooner than May/June 2017). To the extent that MBCP's implementation schedule is delayed, it is reasonable to assume that long-term renewable contracting efforts would also be pushed back, resulting in initial energy delivery dates that extend beyond the timelines reflected in the Technical Study. Note that PEA does not believe that such a sensitivity is necessary, as MBCP could address renewable project development delays by engaging in additional short-term renewable energy contracting efforts to cover any "gaps" between anticipated and actual renewable generator start dates. PEA has conferred with Santa Cruz County ("County") staff regarding this item, and staff agreed that it is not necessary to complete the recommended sensitivity analysis at this point in time.

Second, MRW highlights that PEA's estimates related to "very near term" GHG allowance prices are "likely reasonable;" however, MRW explains that there is much uncertainty around longer term pricing for GHG allowances. Therefore, MRW recommends that PEA develop an additional sensitivity around the potential fluctuation of future GHG allowance prices (with ranges established above and below the base case). MRW also requested additional information related to PEA's rationale for higher escalation rates (associated with GHG allowance pricing) between 2020 and 2025. In response to MRW's inquiry focused on the higher rate of escalation for GHG allowance pricing during the 2020-2025 calendar years, PEA utilized a GHG allowance price forecast published by the California Energy Commission,[1] which is reflected in the standard planning assumptions utilized by the investor owned utilities in their integrated resource planning proceedings before the California Public Utilities Commission. It is PEA's understanding that the higher escalation rate reflected in the longer term forecast reflects anticipated reductions in available GHG allowances under California's cap and trade program. PEA has relied upon the forecast published by the state's energy agencies and has not conducted an independent assessment of GHG allowance prices as part of the Technical Study scope. Regarding the additional sensitivity scenario recommended by MRW, PEA has conferred with County staff, which indicated that such a sensitivity analysis was not necessary at this point in time.

PEA also notes MRW's indication that the presentation of economic development benefits, including prospective job creation, within MBCP's Technical Study "can be misleading." In particular, MRW points out that certain elements of the narrative discussion could be misinterpreted by the reader, leading to a potentially inflated understanding of job impacts that may occur within California and throughout the region. With regard to these comments, PEA points out that all economic development impacts reflected in the Technical Study were appropriately characterized as "order of magnitude estimates" that generally lack predictive precision. Care was also taken to point out the relatively small level of local economic development impacts that were assumed to occur within the prospective MBCP service footprint: "only a relatively small portion of the total potential economic development benefits are assumed to accrue within the MBCP Communities." From a practical perspective, PEA acknowledges that the information presented within the Technical Study's economic development discussion is subject to a certain level of interpretation. For example, use of the phrase "as many as," which was highlighted by MRW as potentially misleading, is not inaccurate or inappropriate – as MRW observes, this phrase simply points to the upper end of projected ranges reflected in the economic development discussion. PEA assumes that readers of the Technical Study will understand this characterization and temper expectations in light of the top-end estimates that have been provided within the document. However, based on discussions with County staff, certain revisions were incorporated in the Technical Study narrative to avoid overstating the magnitude of expected economic benefits associated with MBCP implementation.

With regard to the economic development impacts discussion, MRW also observes that use of the term "significant", when characterizing jobs and economic development impacts within California, may be contextually inappropriate in light of the fact that, "There are 19 million workers in California and an

[1] CEC 2013 Natural Gas Issues, Trends, and Outlook, July 2014, Table E-2: Carbon Price.

annual gross state product of over $2.3 trillion." PEA agrees that the projected jobs impacts would represent a relatively small component of California's broader workforce. However, when considering such jobs impacts in light of a recently struggling economy, the prospect of job creation (as a direct result of MBCP's contracting efforts and general operation) is not insignificant, particularly to the individuals that may benefit from gainful employment. This noted, PEA discussed MRW's observation with County staff and agreed to include revisions in the Technical Study narrative that more appropriately characterize the relative impact of economic benefits that may be created through MBCP implementation.

Another noteworthy recommendation provided by MRW, and the final item addressed in this memorandum, relates to the manner in which the sensitivity analyses are presented within the Technical Study. More specifically, MRW believes that it would be "useful to see the year-by-year results for the sensitivities" in addition to the current presentation of such information on a 10-year levelized basis. MRW believes that the year-by-year results would highlight points in time when CCA costs exceed PG&E rates and therefore recommends that PEA "identify any sensitivity cases where the PG&E and CCA rate lines cross." PEA notes that Table 28, Sensitivity Analysis - Levelized Ratepayer Costs (Cents per KWh), provides summary-level insight regarding such scenarios. Within this table, PEA highlighted specific sensitivity scenarios under which MBCP's rates are expected to exceed similar rates charged by the utility. In such instances, it is reasonable to assume that MBCP's rates will exceed those of the incumbent utility at various points in time – such relationships result in the levelized MBCP rate exceeding the projected, levelized rate of PG&E. Conversely, scenarios reflecting levelized rates that are projected to be lower than similar PG&E rate projections subsume annual rate relationships in which MBCP rates are generally lower than PG&E's. Based on PEA's understanding, the MBCP Technical Study was generally intended to inform a "go/no-go" decision by the participating communities as well as provide general information regarding CCA formation within the MBCP footprint. Use of a 10-year levelized rate comparison is both effective and appropriate for this purpose. PEA has conferred with County staff regarding MRW's recommendation, and it was agreed that year-by-year sensitivity results were not necessary to include in the Technical Study.

PEA appreciates the careful and methodical peer review that was completed by MRW. To the extent that the PDAC and/or County would like to further discuss any of the items addressed in MRW's report, PEA is available to do so.

Revised March 28, 2016

Monterey Bay Community Power
Formation Timeline, Key Tasks and Staff Leads

Key: Description of task (Who Leads) **Tasks already completed by the project team in green.** **Tasks in progress or to be done by project team in blue.** **Tasks to be done by lead staff, consultants, PDAC in red.**	**2013-2015**	**Q1 2016**	**Q2 2016**	**Q3 2016**	**Q4 2016**
Phase I/Task 1: Internal Affairs (Who Leads)					
Form a core Project Team and develop a workplan with timelines and goals for initial partner engagement, formation of working groups, website development, scoping of the technical study, fundraising and support for the regional Project Development Advisory Committee- PDAC. (Project Team)	2012-2013				
Manage implementation of all aspects of the project formation work plan.	2013-2015	Current Project Team manages through Q1-2016	Nancy Gordon, Director SCC General Services	Nancy Gordon, Director SCC General Services	Nancy Gordon, Director SCC General Services
Phase I/Task 2: External Affairs (Who Leads)					
Coordinate County & City Partner engagement & raise $400K to fund tech study without impacts to local general budgets. (Project Team)	2012-2014				
Deliver local government briefings toward executed partnership resolutions from all 21 County & City partners. (Project Team)	2013				
Form the Project Development Advisory Committee and coordinate regular public meetings. (Project Team & PDAC)	2013-2015+	Current Project Team manages through Q1-2016	PDAC Hosts Special Study Sessions for county/city partners	PDAC Continues to meet until JPA Board is formed	CCE Board Formed
Develop informational website and educational slide deck.(Project Team & PDAC)	2013				
Develop and deliver "investigative phase" presentations to county and city partners and community groups as requested. (Project Team manages Ambassadors through Q1-2016, then transitions to professional outreach consultant.)	2013-2015	Current Project Team manages through Q1-2016	Professional outreach consultant hired in March 2016-Miller/Maxfield	Professional outreach consultant hired in March 2016-Miller/Maxfield	Professional outreach consultant hired in March 2016-Miller/Maxfield
Prepare and issue RFP to hire a consulting firm to develop and implement a comprehensive outreach plan with the PDAC. (SCC Purchasing, Planning with input from PDAC & Project Team)		RFP issued 1/26/16 Selection 3/4/16			
Outreach consultant develops the comprehensive outreach plan with an ad hoc subcommittee appointed by the PDAC. (PDAC & Project Team & Consultant)		Pre-meetings 3/7 through 3/9 - 3/10/16 - 4/14/16 PDAC meetings			
PDAC review and approval of outreach plan. (PDAC & Project Team & Consultant)		4/14/2016			
Consultant implements the outreach plan. (SCC Exec Staff & SCC Plannind Dept. manages contract with feedback from PDAC.)		Starts 4/15/16	Professional outreach consultant hired in March 2016-Miller/Maxfield	Professional outreach consultant hired in March 2016-Miller/Maxfield	Professional outreach consultant hired in March 2016-Miller/Maxfield

Revised March 28, 2016

Monterey Bay Community Power
Formation Timeline, Key Tasks and Staff Leads

Key: Description of task (Who Leads) **Tasks already completed by the project team in green.** **Tasks in progress or to be done by project team in blue.** **Tasks to be done by lead staff, consultants, PDAC in red.**	**2013-2015**	**Q1 2016**	**Q2 2016**	**Q3 2016**	**Q4 2016**
Phase I/Task 3: Technical Support (Who Leads)					
Scope work, prepare and issue Technical Study RFP. (SCC Purchasing with SCC Planning)	2015				
Hire technical consultants. (SCC Purchasing with SCC Planning)	2015				
Prepare/submit load data request for PG&E. (SCC Planning Staff)	2015				
Conduct Technical Study to be due 100 days after load data is provided by PG&E (SCC Planning Staff with consultants)	4-Mar-16				
Prepare and issue Peer Review RFP. (SCC Planning Staff)	2015				
Hire technical consultants to conduct peer review. (SCC Planning Staff)	2015				
Conduct Peer Review due 30 days after the draft study is complete and PDAC feedback received. (SCC Planning Staff with consultants)		By April 14 PDAC meeting			
Scope the contents of the information packet to provide to County & City partners. (Project Team & PDAC)	2015				
Research and assemble contents of the information packet, final review by PDAC on 4/14/16, then distribution to project partners. (Project Team, consultants & PDAC)	2015	By April 14 PDAC meeting			
Phase I/Task 4: Conduct a deeper analysis of financing, governance & JPA formation options to inform Task 5 decision making process. (Who Leads)					
Research CCA start-up options for financing, governance and JPA formation to be part of the "Go Now or Go Later" info packet. Review/discuss information with the PDAC. (Project Team, consultants & PDAC)	2014-2015	Final PDAC Review at April 14 meeting			
PDAC hosts special study sessions for County/City partners executive, finance and legal staff regarding finance, governance and JPA formation options and process. Peers from other Counties and Cities who have formed or are in the process will be engaged for these workshops. (PDAC hosts. Consultants, peers and other lead staff to be determined to inform content and process.)			PDAC Hosts Special Study Sessions for County & City partners		
Phase 1/Task 5: County & City Partners Decision Making Process & JPA Formation (Who Leads)					
Analysis & deliberations take 3-4 months after each County & City partner has received the information packet on 4/14/16 PDAC approval. (Partners lead their own process and request assistance from PDAC, SCC Planning staff and Project Team as needed.)		After the 4/14/16 PDAC meeting - Lead SCC Exec Staff, Nancy Gordon, to facilitate the County's internal process & discussion with external partners	Lead SCC Exec Staff, Nancy Gordon, to facilitate the County's internal process & discussion with external partners	Tentative Deadline for County & City partners to decide 10/31/16	

Revised March 28, 2016

Monterey Bay Community Power
Formation Timeline, Key Tasks and Staff Leads

Key: Description of task (Who Leads) **Tasks already completed by the project team in green.** **Tasks in progress or to be done by project team in blue.** **Tasks to be done by lead staff, consultants, PDAC in red.**	**2013-2015**	**Q1 2016**	**Q2 2016**	**Q3 2016**	**Q4 2016**
Provide formal presentations to County & City Boards as needed upon request. ***Note that this is in addition to the major communications and outreach effort to be implemented by a consultant and the study sessions hosted by the PDAC.*** (SCC Planning Staff, consultants, Project Team with Political Leaders and Executive Staff)		Coordinated by current Project Team with others to be determined	Coordinated by current Project Team with others to be determined	Coordinated by current Project Team with others to be determined	Coordinated by current Project Team with others to be determined
Conduct smaller ad hoc political meetings with County and City leaders identified as probable "early adopters" . (Project Team with Political Leaders and Executive Staff)		Coordinated by current Project Team with others to be determined	Coordinated by current Project Team with others to be determined	Coordinated by current Project Team with others to be determined	Coordinated by current Project Team with others to be determined
All tasks associated w/ JPA Formation: legal requirements, organizing docs/bylaws, governance issues, budget, staffing plan, etc. (Staff and funding to be determined as part of start up analysis options and decision making process.)			Exec Staff from County & City partners to be determined	Exec Staff from County & City partners to be determined	JPA Board sits by 10/30/16
Phase 1/Task 6: Conduct a recruitment process to hire a CEO and present the CCE governing board with final candidates. (Who Leads)					
An intial HR recruitment process on behalf of the partnership pending final governance board formation in September/October could ensue to present the CCE Board with final candidates to interview. Hiring a CEO to manage Phase II Tasks listed on page 4 of this formation work plan is the first most important decision the Board makes once formed.				After decisions are made by early adoptive partners to move forward, they agree on a process.	Final hiring process to be determined at the 1st JPA Board meeting and implemented shortly thereafter.

Revised March 28, 2016

Monterey Bay Community Power
Formation Timeline, Key Tasks and Staff Leads

Lead staff for all Phase II tasks is the full time CEO to be hired by the JPA Board with additional CCE agency staff and consultants brought on board by the CEO.	October 2016 through September 2017	Q4 2016	Q1 2017	Q2 2017	Q3 2017
Phase II/Task 1: Internal Planning & Deveplopment (Lead- New CEO with transition assistance from key SCC staff)					
Transition JPA to independent Agency: Coordinate Board meetings, hire initial staff, office space, set rates toward Sept 2017 launch.					
Confirm data service/customer management and other JPA vendor contracts					
Post CCA bond; establish reserve accounts					
Gain party status/register at CPUC; legislative participation					
Phase II/Task 2: External Affairs					
Select firm for marketing/communiations -- branding, messaging, website build out, social and print media, collateral design, customer enrollment/opt-out notification.					
Continue local govt and community outreach -- workshops, public meetings, local events, etc.					
Work with community advocates-- social media, endorsements, et al					
Media relations -- editorial boards, op-eds, etc.					
Establish Call Center					
Opt-Out/Customer Enrollment Process					
Phase II/Task 3: Technical Support					
Determine initial portfolio composition, service area, customer base					
Draft CCA Implementation Plan (90 day CPUC review)					
Identify/select data management services provider and complete related contract negotiations.					
Prepare solicitation document for energy supply and scheduling coordinator services					
Begin work on utility service agreement					
Negotiate terms, indicative pricing, and select energy services provider					
Execute contract(s) with third party energy supplier(s); final pricing					
Pre-start up registrations/reporting (resource adequacy, RPS, WREGIS account setup, CRR holder registration, etc)					
Phase II/Task 4: Financing					
Begin bank/funder meetings for JPA working capital					
Finalize terms of initial working cap/bridge loan; secure guarantees as needed					
Draw down initial working capital					
Begin start-up cost repayments					

Launch-- by Sept/Oct 2017

ORDINANCE NO. ___ .

AN ORDINANCE OF THE CITY COUNCIL OF THE CITY OF ___________ AUTHORIZING THE IMPLEMENTATION OF A COMMUNITY CHOICE AGGREGATION (CCA) PROGRAM

The City Council of the City of ____________________ does ordain as follows:

SECTION 1. FINDINGS. The City Council finds as follows:

1. The Cities of Cupertino, Mountain View and Sunnyvale and the County of Santa Clara formed and sponsored the Silicon Valley Community Choice Energy Partnership (SVCCEP) to investigate options to provide electric service to customers within the City of _______________ and surrounding municipalities with the intent of achieving greater local control and involvement over the provision of electric services, competitive electric rates, the development of local renewable energy projects, reduced greenhouse gas emissions, and the implementation of energy conservation and efficiency projects and programs.

2. The City of ______________, through its participation in SVCCEP, has prepared a Technical Feasibility Study for a Community Choice Aggregation ("CCA") program under the provisions of Public Utilities Code Section 366.2. The Technical Feasibility Study shows that implementing a community choice aggregation program would likely provide multiple benefits, including the following:
   a. Providing customers a choice of power providers;
   b. Increasing local control over energy rates and other energy-related matters;
   c. Providing electric rates that are competitive with those provided by the incumbent utility;
   d. Reducing greenhouse gas emissions arising from electricity use in the City;
   e. Increasing local and regional renewable generation capacity;
   f. Increasing energy conservation and efficiency projects and programs;
   g. Increasing regional energy self-sufficiency; and
   h. Improving the local economy by implementing new local renewable and energy conservation and efficiency projects.

3. The Joint Powers Agreement creating the Silicon Valley Clean Energy Authority ("Authority") will govern and operate the CCA program on behalf of its member jurisdictions. The Initial Participants within the County of Santa Clara, as defined by the Joint Powers Agreement, may participate in the Authority by adoption of a resolution approving the execution of the Joint Powers Agreement and adoption of the CCA ordinance required by Public Utilities Code Section 366.2(c)(12) by March 31, 2016. Municipalities choosing to participate in the Authority will have membership on the Board of Directors of the Authority as provided in the Joint Powers Agreement.

4. The Authority will enter into agreements with electric power suppliers and other service providers and, based upon those agreements, the Authority plans to provide electrical power to residents and businesses at rates that are competitive with those of the incumbent utility. Once the California Public Utilities Commission approves the implementation plan prepared by the Authority, the Authority may provide service to customers within the City of _______________ and those cities that choose to participate in the Silicon Valley Clean Energy Authority; and

5. Under Public Utilities Code Section 366.2, customers have the right to opt-out of a CCA program and continue to receive service from the incumbent utility. Customers who wish to continue to receive service from the incumbent utility will be able to do so at any time; and

6. On ______________, 2015/2016, the ____________ City Council held a public hearing at which time interested persons had an opportunity to testify either in support or in opposition to implementation of the Silicon Valley Clean Energy CCA program in the City of ________________.

7. This ordinance is exempt from the requirements of the California Environmental Quality Act (CEQA) pursuant to the State CEQA Guidelines, as it is not a "project" and has no potential to result in a direct or reasonably foreseeable indirect physical change to the environment. (14 Cal. Code Regs. § 15378(a).) Further, the ordinance is exempt from CEQA as there is no possibility that the ordinance or its implementation would have a significant negative effect on the environment. (14 Cal. Code Regs.§ 15061(b)(3).) The ordinance is also categorically exempt because it is an action taken by a regulatory agency to assure the maintenance, restoration, enhancement or protection of the environment. (14 Cal. Code Regs. § 15308.) The Director of ___________________ shall cause a Notice of Exemption to be filed as authorized by CEQA and the State CEQA Guidelines.

SECTION 2. The above findings are true and correct.

SECTION 3. AUTHORIZATION TO IMPLEMENT A COMMUNITY CHOICE AGGREGATION PROGRAM. Based upon the foregoing, and in order to provide businesses and residents within the City of _________________ with a choice of power providers, the City of ______________ hereby elects to implement a community choice aggregation program within the jurisdiction of the City by participating in the Community Choice Aggregation program of the Silicon Valley Clean Energy Authority, as described in its Joint Powers Agreement.

SECTION 4. This Ordinance shall be in full force and effect 30 days after its adoption, and shall be published and posted as required by law. This Ordinance was introduced by the City Council of the City of ___________________ on _______________, 2015/16 and was adopted on ___________________, 2015/16 by the following roll call vote:

AYES:

NOES:

ABSENT:

ABSTAIN:

____
MAYOR

ATTEST:

____
CITY CLERK

RESOLUTION NO.

BOARD OF SUPERVISORS, COUNTY OF SAN MATEO, STATE OF CALIFORNIA

* * * * * *

RESOLUTION AUTHORIZING AND DIRECTING THE PRESIDENT OF THE BOARD OF SUPERVISORS TO EXECUTE THE JOINT EXERCISE OF POWERS AGREEMENT, WHICH WILL ESTABLISH THE PENINSULA CLEAN ENERGY AUTHORITY WITH THE COUNTY AS A CHARTER MEMBER

RESOLVED, by the Board of Supervisors of the County of San Mateo, State of California, that

WHEREAS, the Board of Supervisors of the County of San Mateo has investigated options to provide electric services to customers within the County, including incorporated and unincorporated areas, with the intent of achieving greater local control and involvement over the provision of electric services, competitive electric rates, the development of clean, local, renewable energy projects, reduced greenhouse gas emissions, and the wider implementation of energy conservation and efficiency projects and programs; and

WHEREAS, the County of San Mateo has prepared a Feasibility Study for a community choice aggregation ("CCA") program in San Mateo County under the provisions of the Public Utilities Code section 366.2. The Feasibility Study shows that implementing a community choice aggregation program would provide multiple benefits, including:

a. Providing customers a choice of power providers;

b. Increasing local control and involvement in and collaboration on energy rates and other energy-related matters;

c. Providing more stable long-term electric rates that are competitive with those provided by the incumbent utility;

d. Reducing greenhouse gas emissions arising from electricity use within San Mateo County;

e. Increasing local renewable generation capacity;

f. Increasing energy conservation and efficiency projects and programs; Increasing regional energy self-sufficiency; and

g. Improving the local economy resulting from the implementation of local renewable and energy conservation and efficiency projects; and

WHEREAS, the County wishes to be a community choice aggregator and has adopted the Ordinance required by Public Utilities Code Section 366.2 in order to do so;

WHEREAS, the County believes that other cities and towns within San Mateo County also wish to be community choice aggregators;

WHEREAS, pursuant to Section 366.2 two or more entities authorized to be a community choice aggregator, may participate as a group in a community choice aggregation program through a joint powers agency established pursuant to Chapter 5 (commencing with Section 6500) of Division 7 of Title 1 of the Government Code, if each entity adopts the aforementioned ordinance.

WHEREAS, there has been presented to this Board of Supervisors for its consideration and acceptance a Joint Powers Agreement, reference to which is hereby made for further particulars, whereby the County of San Mateo shall participate in the creation of the Peninsula Clean Energy Authority ("Authority") with at least two other cities and/or towns and become a charter member;

WHEREAS, the Joint Powers Agreement entered into between the County of San Mateo and the participating cities of the Peninsula will create and form the Peninsula Clean Energy Authority ("Authority"). Under the Joint Powers Agreement, the County and cities and towns within San Mateo County choosing to participate in the CCA program will have membership on the Board of Directors of the Authority as provided in the Joint Powers Agreement if they execute the Agreement and adopt the ordinance required by the Public Utilities Code;

WHEREAS, the newly created Authority will enter into Agreements with electric power suppliers and other service providers, and based upon those Agreements the Authority will be able to provide power to residents and business at rates that are competitive with those of the incumbent utility ("PG&E"). Once the California Public Utilities Commission approves the implementation plan created by the Authority, the Authority will provide service to customers within the unincorporated area of San Mateo County and within the jurisdiction of those cities who have chosen to participate in the CCA program; and

WHEREAS, under Public Utilities Code section 366.2, customers have the right to opt-out of a CCA program and continue to receive service from the incumbent utility. Customers who wish to continue to receive service from the incumbent utility will be able to do so; and

WHEREAS, this Board has been presented with a form of such Agreement and said Board has examined and approved same as to both form and content and desires to enter into same.

NOW THEREFORE, IT IS HEREBY RESOLVED THAT the Board of Supervisors of San Mateo County wishes to enter into the Joint Exercise of Powers Agreement with participating Cities and Towns of the Peninsula to form the Peninsula Clean Power Agency and the President of the Board is authorized and directed to execute the Joint Exercise of Powers Agreement, which will establish the Authority with the County as a charter member; and

NOW THEREFORE, LET IT BE FURTHER RESOLVED THAT the County Manager is authorized to execute any and all other necessary documents to enter into the Joint Exercise of Powers Agreement to form Peninsula Clean Energy.

* * * * * *

PENINSULA CLEAN ENERGY

DRAFT COMMUNITY CHOICE AGGREGATION IMPLEMENTATION PLAN AND STATEMENT OF INTENT

March 2016

Table of Contents

CHAPTER 1 – **Introduction**

The Peninsula Clean Energy Authority ("PCEA") is a public agency located within the geographic boundaries of San Mateo County, formed for the purposes of implementing a community choice aggregation ("CCA") program (the "PCE Program" or "PCE"). Member Agencies of the PCEA include the twenty (20) municipalities located within the County of San Mateo ("County") as well as the unincorporated areas of the County (together, the "Members"), all of which have elected to allow the PCEA to provide electric generation service within their respective jurisdictions. Currently, the following Members have elected to join the PCEA:

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	

This Implementation Plan and Statement of Intent ("Implementation Plan") describes the PCEA's plans to implement a voluntary CCA program for electric customers within the jurisdictional boundaries of its Member Agencies that currently take bundled electric service from Pacific Gas and Electric Company ("PG&E"). The PCE Program will give electricity customers the opportunity to join together to procure electricity from competitive suppliers, with such electricity being delivered over PG&E's transmission and distribution system. The planned start date for the Program is October 1, 2016 (subject to the final review and approval of the PCEA Governing Board). All current PG&E customers within the PCEA service area will receive information describing the PCE Program and will have multiple opportunities to express their desire to remain full requirement ("bundled") customers of PG&E, in which case they will not be enrolled. Thus, participation in the PCE Program is completely voluntary; however, customers, as provided by law, will be automatically enrolled according to the anticipated phase-in schedule later described in Chapter 5 unless they affirmatively elect to opt-out.

Implementation of PCE will enable customers within PCEA's service area to take advantage of the opportunities granted by Assembly Bill 117 ("AB 117"), the Community Choice Aggregation Law. The PCEA's primary objectives in implementing this Program are to provide cost competitive electric services; reduce electric sector greenhouse gas emissions within the County; stimulate and sustain the local economy by developing local jobs in renewable energy and energy efficiency; implement energy efficiency and demand reduction programs; and develop long-term rate stability and energy reliability for residents through local control. The prospective benefits to consumers include a substantial increase in renewable energy supply, stable and competitive electric rates, public participation in determining which technologies are utilized to meet local electricity needs, and local/regional economic benefits.

To ensure successful operation of the Program, the PCEA will receive assistance from experienced energy suppliers and contractors in providing energy services to Program customers. Following a competitive solicitation process and subsequent contract negotiations (which are expected to occur during the months of April, May and June 2016), one or more qualified energy services providers will be selected to support PCE implementation, providing requisite energy products and scheduling coordinator services to meet the electric energy requirements of PCE's initial customer phase. Information regarding the anticipated solicitation process for PCE's initial energy services providers is contained in Chapter 10. As planned, final selection of PCE's initial energy supplier(s) will be made by the PCEA Board following administration of the aforementioned solicitation process and related contract negotiations.

The PCEA's Implementation Plan reflects a collaborative effort among the PCEA, its Members, the PCE Advisory Committee and members of the public to bring the benefits of competition and choice to residents and businesses within the Member communities. By exercising its legal right to form a CCA Program, PCEA will enable its Members' constituents to access the competitive market for energy products and services for purposes of obtaining access to increased clean energy supplies and resultant reductions in GHG emissions. Absent action by the PCEA and its individual Members, most customers would have no ability to choose an electric supplier and would remain captive customers of the incumbent utility.

The California Public Utilities Code provides the relevant legal authority for the PCEA to become a Community Choice Aggregator and invests the California Public Utilities Commission ("CPUC" or "Commission") with the responsibility for establishing the cost recovery mechanism that must be in place before customers can begin receiving electrical service through the PCE Program. The CPUC also has responsibility for registering the PCEA as a Community Choice Aggregator and ensuring compliance with basic consumer protection rules. The Public Utilities Code requires that an Implementation Plan be adopted at a duly noticed public hearing and that it be filed with the Commission in order for the Commission to determine the cost recovery mechanism to be paid by customers of the Program in order to prevent shifting of costs to bundled customers of the incumbent utility.

On March 31, 2016, the PCEA, at a duly noticed public hearing, considered and adopted this Implementation Plan, through PCEA Resolution No. ______ (a copy of which is included as part of Appendix A). The Commission has established the methodology that will be used to determine the cost recovery mechanism, and PG&E now has approved tariffs for imposition of the cost recovery mechanism. Finally, each of the PCEA's Members has adopted an ordinance to implement a CCA program through its participation in the PCEA, and each of the Members has adopted a resolution permitting the PCEA to provide service within its jurisdiction.[1] With each of these milestones having been accomplished, PCE now submits this Implementation Plan to the CPUC. Following the CPUC's certification of its receipt of this Implementation Plan and resolution of any outstanding issues, the PCEA will take the final steps needed to register as a CCA prior to initiating the customer notification and enrollment process.

Organization of this Implementation Plan

The content of this Implementation Plan complies with the statutory requirements of AB 117. As required by PU Code Section 366.2(c)(3), this Implementation Plan details the process and consequences of aggregation and provides PCEA's statement of intent for implementing a CCA program that includes all of the following:

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

The remainder of this Implementation Plan is organized as follows:

Chapter 2: Aggregation Process
Chapter 3: Organizational Structure
Chapter 4: Startup Plan and Funding
Chapter 5: Program Phase-In
Chapter 6: Load Forecast and Resource Plan
Chapter 7: Financial Plan
Chapter 8: Ratesetting
Chapter 9: Customer Rights and Responsibilities
Chapter 10: Procurement Process
Chapter 11: Contingency Plan for Program Termination
Appendix A: PCEA Resolution Approving Implementation Plan and Member Ordinances
Appendix B: Joint Powers Agreement

The requirements of AB 117 are cross-referenced to Chapters of this Implementation Plan in the following table.

[1] Copies of individual ordinances adopted by PCEA's Members are included within Appendix A.

AB 117 Cross References

AB 117 REQUIREMENT	IMPLEMENTATION PLAN CHAPTER
Statement of Intent	Chapter 1: Introduction
Process and consequences of aggregation	Chapter 2: Aggregation Process
Organizational structure of the program, its operations and funding	Chapter 3: Organizational Structure Chapter 4: Startup Plan and Funding Chapter 7: Financial Plan
Disclosure and due process in setting rates and allocating costs among participants	Chapter 8: Ratesetting
Ratesetting and other costs to participants	Chapter 8: Ratesetting Chapter 9: Customer Rights and Responsibilities
Participant rights and responsibilities	Chapter 9: Customer Rights and Responsibilities
Methods for entering and terminating agreements with other entities	Chapter 10: Procurement Process
Description of third parties that will be supplying electricity under the program, including information about financial, technical and operational capabilities	Chapter 10: Procurement Process
Termination of the program	Chapter 11: Contingency Plan for Program Termination

CHAPTER 2 – **Aggregation Process**

Introduction

This chapter describes the background leading to the development of this Implementation Plan and describes the process and consequences of aggregation, consistent with the requirements of AB 117.

Beginning in late 2014, the County began investigating formation of a CCA Program, pursuant to California state law, with the following objectives: 1) provide cost competitive electric services; 2) reduce greenhouse gas emissions related to the use of electric power within the County; 3) develop long-term rate stability and energy reliability for residents through local control; and 4) stimulate and sustain the local economy by developing local jobs in renewable energy. A technical feasibility study for a CCA Program serving the County was completed in October 2015 and an independent review of the study was completed thereafter in February 2016.

After nearly a year of collaborative work by representatives of the participating municipalities, independent consultants, the PCE Advisory Committee, local experts and stakeholders, the County released a draft Implementation Plan in February 2016, which described the planned organization, governance and operation of the CCA Program. Consistent with the Implementation Plan's described organizational structure, the PCEA was formed in January 2016 to implement the PCE Program.

The PCE Program represents a culmination of planning efforts that are responsive to the expressed needs and priorities of the citizenry and business community within San Mateo County. The PCEA plans to expand the energy choices available to eligible customers through creation of innovative new programs for voluntary purchases of renewable energy, net energy metering to promote customer-owned renewable generation, energy efficiency, demand responsiveness to promote reductions in peak demand, customized pricing options for large energy users, and support of local renewable energy projects through the eventual offering of a standardized power purchasing agreement or "feed-in-tariff".

Process of Aggregation

Before customers are enrolled in the Program, customers will receive two written notices in the mail, from the PCEA, that will provide information needed to understand the Program's terms and conditions of service and explain how customers can opt-out of the Program, if desired. All customers that do not follow the opt-out process specified in the customer notices will be automatically enrolled, and service will begin at their next regularly scheduled meter read date at least thirty days following the date of automatic enrollment, subject to the service phase-in plan described in Chapter 5. The initial enrollment notices will be provided to the first phase of customers in July 2016. Initial enrollment notices will be provided to subsequent customer phases consistent with statutory requirements and based on schedule(s) determined by PCE's Board of Directors. These notices will be sent to customers in subsequent phases beginning 90 to 105 days prior to commencement of service (or twice within 60 days of automatic enrollment).

Customers enrolled in the PCE Program will continue to have their electric meters read and to be billed for electric service by the distribution utility (PG&E). The electric bill for Program customers will show separate charges for generation procured by the PCEA as well as other charges related to electricity delivery and other utility charges assessed by PG&E.

After service cutover, customers will have approximately 60 days (two billing cycles) to opt-out of the PCE Program without penalty and return to the distribution utility (PG&E). PCE customers will be advised of these opportunities via the distribution of two additional enrollment notices provided within the first two months of service. Customers that opt-out between the initial cutover date and the close of the post enrollment opt-out period will be responsible for program charges for the time they were served by PCE but will not otherwise be subject to any penalty for leaving the program. Customers that have not opted-out within thirty days of the fourth enrollment notice will be deemed to have elected to become a participant in the PCE Program and to have agreed to the PCE Program's terms and conditions, including those pertaining to requests for termination of service, as further described in Chapter 8.

Consequences of Aggregation

Rate Impacts

PCE Customers will pay the generation charges set by the PCEA and no longer pay the costs of PG&E generation. Customers enrolled in the Program will be subject to the Program's terms and conditions, including responsibility for payment of all Program charges as described in Chapter 9.

The PCEA's rate setting policies described in Chapter 7 establish a goal of providing rates that are competitive with the projected generation rates offered by the incumbent distribution utility (PG&E). The PCEA will establish rates sufficient to recover all costs related to operation of the Program, and actual rates will be adopted by the PCEA's governing board.

Initial PCE Program rates will be established following approval of the PCEA's inaugural program budget, reflecting final costs from the PCE Program's energy supplier(s). The PCEA's rate policies and procedures are detailed in Chapter 7. Information regarding final PCE Program rates will be disclosed along with other terms and conditions of service in the pre-enrollment and post-enrollment notices sent to potential customers.

Once the PCEA gives definitive notice to PG&E that it will commence service, PCE customers will generally not be responsible for costs associated with PG&E' future electricity procurement contracts or power plant investments. Certain pre-existing generation costs and new generation costs that are deemed to provide system-wide benefits will continue to be charged by PG&E to CCA customers through separate rate components, called the Cost Responsibility Surcharge and the New System Generation Charge. These charges are shown in PG&E's electric service tariffs, which can be accessed from the utility's website, and the costs are included in charges paid by both PG&E bundled customers as well as CCA and Direct Access customers.[2]

Renewable Energy Impacts

A second consequence of the Program will be an increase in the proportion of energy generated and supplied by renewable resources. The resource plan includes procurement of renewable energy sufficient to meet a minimum 50 percent of the PCE Program's electricity needs for all enrolled customers, increasing annually thereafter, subject to economic and operational constraints. PCE customers may also voluntarily participate in a 100 percent renewable supply option. To the extent that customers choose PCE's 100 percent renewable energy option, the renewable content of PCE's aggregate supply portfolio will be even greater. Initially, requisite renewable energy supply will be sourced through one or more power purchase agreements. Over time, however, the PCEA may consider independent development of new renewable generation resources, subject to then-current considerations (such as development costs, regulatory requirements and other concerns). The PCEA will emphasize procurement from locally situated renewable energy projects to the greatest extent practical.

Energy Efficiency Impacts

A third consequence of the Program will be an anticipated increase in energy efficiency program investments and activities. The existing energy efficiency programs administered by the distribution utility are not expected to change as a result of PCE Program implementation. CCA customers will continue to pay the public benefits surcharges to the distribution utility, which will fund energy efficiency programs for all customers, regardless of generation supplier. The energy efficiency investments ultimately planned for the PCE Program, as described in Chapter 6, will be in addition to the level of investment that would continue in the absence of the PCE Program. Thus, the PCE Program has the potential for increased energy savings and a further reduction in emissions due to expanded energy efficiency programs. As planned, PCE will apply for administration of requisite program funding from the CPUC to independently administer energy efficiency programs within its jurisdiction.

---

[2] For PG&E bundled service customers, the Power Charge Indifference Adjustment element of the Cost Responsibility Surcharge is contained within the tariffed Generation rate. Other elements of the Cost Responsibility Surcharge are set forth in PG&E's tariffs as separate rate charges paid by all customers (with limited exceptions).

CHAPTER 3 – **Organizational Structure**

This section provides an overview of the organizational structure of the PCEA and its proposed implementation of the CCA program. Specifically, the key agreements, governance, management, and organizational functions of the PCEA are outlined and discussed below.

Organizational Overview

The PCE Program will have a governing board that establishes PCE Program policies and objectives; management that is responsible for operating the PCE Program in accordance with such policies, and contractors that will provide energy and other specialized services necessary for PCE Program operations.

Governance

The PCE Program would be governed by the PCEA's Board of Directors ("Board"), which shall include one appointed designee from each of the Members. The PCEA is a joint powers agency created in January 2016 and formed under California law. The Members of the PCEA include the twenty (20) municipalities located within the County as well as the unincorporated areas of the County, all of which have elected to allow the PCEA to provide electric generation service within their respective jurisdictions. The PCEA is the CCA entity that will register with the CPUC, and it is responsible for implementing and managing the program pursuant to the PCEA's Joint Powers Agreement ("JPA Agreement"). The PCEA Board is comprised of representatives appointed by each of the Members in accordance with the JPA agreement. The PCE Program will be operated under the direction of an Executive Director appointed by the Board, with legal and regulatory support provided by a Board appointed General Counsel.

The Board's primary duties will be to establish program policies, approve rates and provide policy direction to the Executive Director, who will have general responsibility for program operations, consistent with the policies established by the Board. The Board will establish a Chairman and other officers from among its membership and may establish an Executive Committee and other committees and sub-committees as needed to address issues that require greater expertise in particular areas (e.g., finance or contracts). The PCEA may also form various standing and ad hoc committees, as appropriate, which would have responsibility for evaluating various issues that may affect the PCEA and its customers, including rate-related and power contracting issues, and would provide analytical support and recommendations to the Board in these regards.

Management

The Executive Director may be a person or an operating entity. The Executive Director could be an employee of the PCEA, an individual under contract with the PCEA, a public agency, a private entity, or any other person or organization so designated by the Board. The Board will be responsible for evaluating and managing the Executive Director's performance.

The Executive Director will have management responsibilities over the functional areas of Resource Planning, Electric Supply, Local Energy Programs, Finance and Rates, Customer Services and Regulatory Affairs. In performing his or her obligations to the PCEA, the Executive Director may utilize a combination of internal staff and/or contractors. Certain specialized functions needed for program operations, namely the electric supply and customer account management functions described below, will be performed initially by experienced third-party contractors.

Major functions of the PCEA that will be managed by the Executive Director are summarized below.

Resource Planning

The PCEA must plan for meeting the electricity needs of its customers utilizing resources consistent with its policy goals and objectives as well as applicable legislative and/or regulatory mandates. The Executive Director will oversee development of long term resource plans under the policy guidance provided by the Board and in compliance with California Law and other requirements of California regulatory bodies.

Long-term resource planning includes load forecasting and supply planning on a ten- to twenty-year time horizon. The PCEA will develop integrated resource plans that meet program supply objectives and balance cost, risk and environmental considerations. Such integrated resource plans will also conform to applicable requirements imposed by the State of California. Integrated resource planning efforts of the PCEA will make maximum use of demand side energy efficiency, distributed generation and demand response programs as well as traditional supply options, which rely on structured wholesale transactions to meet customer energy requirements. The PCE Program will require an independent planning function even if the day-to-day electric supply operations are contracted to a third party energy supplier. Resource plans will be updated and adopted by the Board on an annual basis.

Electric Supply Operations

Electric supply operations encompass the activities necessary for wholesale procurement of electricity to serve end use customers. These highly specialized activities include the following:

- *Electricity Procurement* – assemble a portfolio of electricity resources to supply the electric needs of Program customers.
- *Risk Management* – application of standard industry techniques to reduce exposure to the volatility of energy and credit markets and insulate customer rates from sudden changes in wholesale market prices.
- *Load Forecasting* – develop accurate load forecasts, both long-term for resource planning and short-term for the electricity purchases and sales needed to maintain a balance between hourly resources and loads.
- *Scheduling Coordination* – scheduling and settling electric supply transactions with the CAISO.

The PCEA will initially contract with one or more experienced and financially sound third party energy services providers to perform most of the electric supply operations for the PCE Program. These requirements include the procurement of energy, capacity and ancillary services, scheduling coordinator services, short-term load forecasting and day-ahead and real-time electricity trading. Longer term energy procurement and generation project development will be managed by the Executive Director.

Local Energy Programs

A key focus of the PCE Program will be the development and implementation of local energy programs, including energy efficiency programs, distributed generation programs and other energy programs responsive to community interests. The Executive Director will be responsible for further development of these programs, as these are likely to be implemented on a phased basis during the first several years of operations.

The PCEA will administer energy efficiency, demand response and distributed generation programs that can be used as cost-effective alternatives to procurement of supply-side resources while supporting the local economy. The PCEA will attempt to consolidate existing demand side programs into this organization and leverage the structure to expand energy efficiency offerings to customers throughout its service territory, including the CPUC application process for third party administration of energy efficiency programs and use of funds collected through the existing public benefits surcharges paid by PCE customers.

Finance and Rates

The Executive Director will be responsible for managing the financial affairs of the PCEA, including the development of an annual budget, revenue requirement and rates; managing and maintaining cash flow requirements; arranging potential bridge loans as necessary; and other financial tools.

The Board of Directors has the ultimate responsibility for approving the electric generation rates for the PCE Program's customers. The Executive Director, in cooperation with staff and appropriate advisors, consultants and committees of the Board will be responsible for developing proposed rates and options for the Board to consider before finalization. The final approved rates must, at a minimum, meet the annual budgetary revenue requirement developed by the Executive Director, including recovery of all expenses and any reserves or coverage requirements set forth in bond covenants or other agreements. The Board will have the flexibility to consider rate adjustments within certain ranges, provided that the overall revenue requirement is achieved. The PCEA will administer a standardized set of electric rates and may offer optional rates to encourage policy goals such as economic development or low income subsidy programs.

The PCEA may also offer customized pricing options such as dynamic pricing or contract-based pricing for energy intensive customers to help these customers gain greater control over their energy costs. This would provide such customers – mostly larger energy users within the commercial sector – with a greater range of power options than is currently available.

The PCEA's finance function will be responsible for arranging financing necessary for any capital projects, preparing financial reports, and ensuring sufficient cash flow for successful operation of the PCE Program. The finance function will play an important role in risk management by monitoring the credit of energy suppliers so that credit risk is properly understood and mitigated. In the event that changes in a supplier's financial condition and/or credit rating are identified, the PCEA will be able to take appropriate action, as would be provided for in the electric supply agreement(s). The Finance function establishes general credit policies that the PCE Program must follow.

Communications and Customer Services

The customer services function includes general program marketing and communications as well as direct customer interface ranging from management of key account relationships to call center and billing operations. The PCEA will conduct program marketing to raise consumer awareness of the PCE Program and to establish the PCE "brand" in the minds of the public, with the goal of retaining and attracting as many customers as possible into the PCE Program. Communications will also be directed at key policy-makers at the state and local level, community business and opinion leaders, and the media.

In addition to general program communications and marketing, a significant focus on customer service, particularly representation for key accounts, will enhance the PCEA's ability to differentiate itself as a highly customer-focused organization that is responsive to the needs of the community. The PCEA will also establish a customer call center designed to field customer inquiries and routine interaction with customer accounts.

The customer service function also encompasses management of customer data. Customer data management services include retail settlements/billing-related activities and management of a customer database. This function processes customer service requests and administers customer enrollments and departures from the PCE Program, maintaining a current database of enrolled customers. This function coordinates the issuance of monthly bills through the distribution utility's billing process and tracks customer payments. Activities include the electronic exchange of usage, billing, and payments data with the distribution utility and the PCEA, tracking of customer payments and accounts receivable, issuance of late payment and/or service termination notices (which would return affected customers to bundled service), and administration of customer deposits in accordance with credit policies of the PCEA.

The customer data management services function also manages billing-related communications with customers, customer call centers, and routine customer notices. The PCEA will initially contract with a third party, who has demonstrated the necessary experience and administers appropriate computer systems (customer information system), to perform the customer account and billing services functions.

Legal and Regulatory Representation

The PCE Program will require ongoing regulatory representation to manage various regulatory compliance filings related to resource plans, resource adequacy, compliance with California's Renewables Portfolio Standard ("RPS"), and overall representation on issues that will impact the PCEA, its Members and customers. The PCEA will maintain an active role at the CPUC, the California Energy Commission, the California Independent System Operator, the California legislature and, as necessary, the Federal Energy Regulatory Commission.

Under the direction of its General Counsel, the PCEA will retain outside legal services, as necessary, to administer the PCEA, review contracts, and provide overall legal support related to activities of the PCE Program.

CHAPTER 4 – **Startup Plan and Funding**

This Chapter presents the PCEA's plans for the start-up period, including the necessary expenses and capital outlays, which will commence once the CPUC certifies its receipt of this Implementation Plan. As described in the previous Chapter, the PCEA may utilize a mix of staff and contractors in its CCA Program implementation.

Startup Activities

The initial program startup activities include the following:

- Hire staff and/or contractors to manage implementation
- Identify qualified suppliers (of requisite energy products and related services) and negotiate supplier contracts
    - Electric supplier and scheduling coordinator
    - Data management provider (if separate from energy supply)
- Define and execute communications plan
    - Customer research/information gathering
    - Media campaign
    - Key customer/stakeholder outreach
    - Informational materials and customer notices
    - Customer call center
- Post CCA bond and complete requisite registration requirements
- Pay utility service initiation, notification and switching fees
- Perform customer notification, opt-out and transfers
- Conduct load forecasting
- Establish rates
- Legal and regulatory support
- Financial management and reporting

Other costs related to starting up the PCE Program will be the responsibility of the PCE Program's contractors (and are assumed to be covered by any fees/charges imposed by such contractors). These include capital requirements needed for collateral/credit support for electric supply expenses, customer information system costs, electronic data exchange system costs, call center costs, and billing administration/settlements systems costs.

Staffing and Contract Services

Personnel in the form of PCEA staff or contractors will be added incrementally to match workloads involved in forming the new organization, managing contracts, and initiating customer outreach/marketing during the pre-operations period. During the startup period, minimal personnel requirements would include an Executive Director, a General Counsel, and other personnel needed to support regulatory, procurement, finance, legal and communications activities.

For budgetary purposes, it is assumed that three to five full-time equivalents staff as well as supporting contracted professional services would be engaged during the initial start-up period. Following this period, additional staff and/or contractors will be retained to support the roll-out of additional value-added services (e.g., efficiency projects) and local generation projects and programs.

Capital Requirements

The Start-up of the CCA Program will require capital for three major functions: (1) staffing and contractor costs; (2) deposits and reserves; and (3) working capital. Each of these functions and associated capital requirements are discussed below. The finance plan in Chapter 7 provides a more detailed discussion of the capital requirements and Program finances.

Staffing and contractor costs during startup and pre-startup activities are estimated to be approximately $2.2 million, including direct costs related to public relations support, technical support, and customer communications. Actual costs may vary depending upon how PCE manages its start-up activities and the degree to which some or most of these start-up activities are performed by the selected energy services provider rather than by PCE.

Requisite deposits and operating reserves of the PCE program are estimated to approximate $6.7 million and include the following items: 1) operating reserves to address anticipated cash flow variations (as well as operating reserve deposits that will likely be required by the PCEA's power supplier(s)) - $6.1 million; 2) requisite deposit with the California Independent System Operator prior to commencing market operations - $500,000; 3) CCA bond (posted with the CPUC) - $100,000; and 4) PG&E service fee deposit - $30,000.

Operating revenues from sales of electricity will be remitted to the PCEA beginning approximately sixty days after the initial customer enrollments. This lag is due to the distribution utility's standard meter reading cycle of 30 days and a 30 day payment/collections cycle. The PCEA will need working capital to support electricity procurement and costs related to program management, which will be included in the financing program associated with start-up funding. As discussed in Chapter 7, the initial working capital requirement is estimated at $4.6 million.

Therefore, the total staffing and contractor costs, applicable deposits and working capital costs are expected to be approximately $13.5 million. These are costs that ultimately will be collected through PCE Program rates; however, some of these costs will be incurred prior to the PCEA selling its first kWh of electricity and will require financing.

Financing Plan

The majority of anticipated start-up funding (approximately $12 million) will be provided to the PCEA via a bank credit facility that can be drawn upon as needed to cover expenditures; the balance of requisite start-up funding ($1.5 million) has been provided by the County and the PCEA will make monthly repayments (including interest) to the County over a thirty-six month term starting in January 2017. The PCEA will recover the principal and interest costs associated with the start-up funding via retail generation rates charged PCE customers. It is anticipated that the start-up costs will be fully recovered through such customer generation rates within the first several years of operations.

CHAPTER 5 – **Program Phase-In**

The PCEA will roll out its service offering to customers over the course of three or more phases:

Phase 1. All municipal accounts, all small and medium commercial accounts, 20 percent of residential accounts, and all customer accounts that have voluntarily expressed interest in Phase 1 enrollment.

Phase 2. All large commercial and industrial accounts as well as 35 percent of residential accounts.

Phase 3. All agricultural and street lighting accounts as well as the remaining 45 percent of residential accounts.

Phase 4. Any remaining accounts, if necessary.

This approach provides the PCEA with the ability to initiate its program with sufficient economic scale and with a manageable number of accounts served, before gradually building to full program integration for an expected customer base of approximately 257,000 accounts. This approach also allows the PCEA and its energy supplier(s) to address all system requirements (billing, collections, payments) under a phase-in approach to minimize potential customer service challenges as well as exposure to uncertainty and financial risk. The PCEA will offer service to all customers on a phased basis expected to be completed within twelve months of initial service to Phase 1 customers.

Phase 1 of the Program is targeted to begin on or about October 1, 2016, subject to a decision to proceed by the Board. During Phase 1, the PCEA anticipates serving approximately 68,000 accounts, comprised of all municipal accounts, small and medium commercial accounts, and a certain portion of residential accounts, totaling nearly 1,185 GWh of annual energy sales. The PCEA is currently refining the potential composition of Phase 1 accounts in consideration of opportunities for maximizing energy efficiency and renewable energy impacts, synergies with local ordinances and other customer programs such as a municipally financed solar program, cost of service and customer load characteristics, and other operational considerations. Specific accounts to be included in Phase 1 will approximate 35 percent of the PCEA's total customer load and will be specifically defined after further analysis and consideration of the Board.

The PCEA will provide the opportunity for any future PCE customer to make a positive election to enroll in Phase 1, even if that customer is not initially scheduled to be offered service during Phase 1. This early enrollment period will open around April 2016 and close at the end of June 2016, prior to the execution of PCE's initial electric power supply contract(s). Depending on the level of early enrollment interest for Phase 1, the PCEA could choose to offer an additional early enrollment period prior to the launch of Phase 2.

Phase 2 of the Program will commence following successful operation of the PCE Program over an approximate 6-month term. It is anticipated that approximately 82,000 additional customers, comprised of large commercial, industrial and additional residential accounts, will be included in Phase 2, with annual energy consumption of approximately 1,570 GWh, or 47 percent of the PCEA's total prospective customer load.

Following this initial operating period, expected to continue for no more than twelve months, the Board will commence the process of completing the CCA roll out to all remaining customers in Phase 3. This phase is expected to comprise the remaining residential accounts within the PCEA's service territory as well as all agricultural and street lighting accounts. Phase 3 is expected to total approximately 107,000 accounts with annual energy consumption of approximately 610 GWh, or 18 percent of the PCEA's total prospective customer load.

To the extent that additional customers require enrollment after the completion of Phase 3, the PCEA will evaluate a subsequent phase of CCA enrollment.

The Board may also evaluate other phase-in options based on then-current market conditions, statutory requirements and regulatory considerations as well as other factors potentially affecting the integration of additional customer accounts.

CHAPTER 6 - **Load Forecast and Resource Plan**

Introduction

This Chapter describes the planned mix of electric resources and demand reduction programs that will meet the energy demands of the PCEA's customers using a highly renewable, diversified portfolio of electricity supplies. Several overarching policies govern the resource plan and the ensuing resource procurement activities that will be conducted in accordance with the plan. These key polices are as follows:

- The PCEA will seek to increase use of renewable energy resources and reduce reliance on fossil-fueled electric generation.
- The PCEA will manage a diverse resource portfolio to increase control over energy costs and maintain competitive and stable electric rates.
- The PCEA will help customers reduce energy costs through investment in and administration of enhanced customer energy efficiency, distributed generation, and other demand reducing programs.
- The PCEA will benefit the area's economy through investment in local infrastructure, projects and energy programs.

The PCEA's initial resource mix will include a renewable energy content of at least 50%. As the PCE Program moves forward, incremental renewable supply additions will be made based on resource availability as well as economic goals of the PCE Program to achieve increased renewable energy content over time. The PCEA's aggressive commitment to renewable generation adoption may involve both direct investment in new renewable generating resources, partnerships with experienced public power developers/operators and purchases of renewable energy from third party suppliers.

The PCEA will seek to supply the program with local renewable resources to the greatest extent technically and economically feasible. Specific objectives will be identified in resource plans and other planning documents prepared by the PCEA.

The resource plan also sets forth ambitious targets for improving customer side energy efficiency.

The plan described in this section would accomplish the following:

- ➢ Procure energy needed to offer two generation rate tariffs: 100 percent renewable and minimum 50 percent renewable through one or more contracts with experienced, financially stable energy suppliers.
- ➢ Continue increasing minimum renewable energy supplies over time, subject to resource availability and economic viability.
- ➢ Administer customer programs to reduce net electricity purchases by 1%-2% annually.

- Encourage distributed renewable generation in the local area through the offering of a net energy metering tariff; a standardized power purchase agreement or "Feed-In Tariff"; and other creative, customer-focused programs targeting increased access to local renewable energy sources.

The PCEA will be responsible for complying with regulatory rules applicable to California load serving entities. The PCEA will arrange for the scheduling of sufficient electric supplies to meet the hour-by-hour demands of its customers. The PCEA will adhere to capacity reserve requirements established by the CPUC and the CAISO designed to address uncertainty in load forecasts and potential supply disruptions caused by generator outages and/or transmission contingencies. These rules also ensure that physical generation capacity is in place to serve the PCEA's customers, even if there were a need for the PCE Program to cease operations and return customers to PG&E. In addition, the PCEA will be responsible for ensuring that its resource mix contains sufficient production from renewable energy resources needed to comply with the statewide RPS (33 percent renewable energy by 2020, increasing to 50 percent by 2030). The resource plan will meet or exceed all of the applicable regulatory requirements related to resource adequacy and the RPS.

Resource Plan Overview

To meet the aforementioned objectives and satisfy the applicable regulatory requirements pertaining to the PCEA's status as a California load serving entity, PCEA's resource plan includes a diverse mix of power purchases, renewable energy, new energy efficiency programs, demand response, and distributed generation. A diversified resource plan minimizes risk and volatility that can occur from over-reliance on a single resource type or fuel source, and thus increases the likelihood of rate stability. The ultimate goal of the PCEA's resource plan is to minimize customer energy consumption and maximize use of renewable resources, particularly local resources, subject to economic and operational constraints. The planned power supply is initially comprised of power purchases from third party electric suppliers and, in the longer-term, may also include renewable generation assets owned and/or controlled by the PCEA.

Once the PCE Program demonstrates it can operate successfully, the PCEA may begin evaluating opportunities for investment in renewable generating assets, subject to then-current market conditions, statutory requirements and regulatory considerations. Any renewable generation owned by the PCEA or controlled under long-term power purchase agreement with a proven public power developer, could provide a portion of the PCEA's electricity requirements on a cost-of-service basis. Depending upon market conditions and, importantly, the applicability of tax incentives for renewable energy development, electricity purchased under a cost-of-service arrangement can be more cost-effective than purchasing renewable energy from third party developers, which will allow the PCE Program to pass on cost savings to its customers through competitive generation rates. Any investment decisions will be made following thorough environmental reviews and in consultation with qualified financial and legal advisors.

As an alternative to direct investment, the PCEA may consider partnering with an experienced public power developer (the Northern California Power Agency, for example) and enter into a long-term (20-to-30 year) power purchase agreement that would support the development of new renewable generating capacity. Such an arrangement could be structured to reduce the PCE Program's operational risk associated with capacity ownership while providing its customers with all renewable energy generated by the facility under contract. This option may be preferable to the PCEA as it works to achieve increasing levels of renewable energy supply to its customers.

The PCEA's resource plan will integrate supply-side resources with programs that will help customers reduce their energy costs through improved energy efficiency and other demand-side measures. As part of its integrated resource plan, the PCEA will actively pursue, promote and ultimately administer a variety of customer energy efficiency programs that can cost-effectively displace supply-side resources.

The PCEA's proposed resource plan for the years 2016 through 2025 is summarized in the following table:

Peninsula Clean Energy
Proposed Resource Plan
(GWH)
2016 to 2025

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PCE Demand (GWh)										
Retail Demand	-253	-2,447	-3,382	-3,399	-3,416	-3,433	-3,451	-3,468	-3,485	-3,503
Distributed Generation	0	0	3	4	6	7	9	10	12	13
Energy Efficiency	0	0	0	3	7	10	14	17	21	25
Losses and UFE	-15	-147	-203	-203	-204	-205	-206	-206	-207	-208
Total Demand	-268	-2,593	-3,582	-3,595	-3,608	-3,621	-3,633	-3,646	-3,659	-3,672
PCE Supply (GWh)										
Renewable Resources										
Total Renewable Resources	127	1,223	1,691	1,700	1,708	1,803	1,898	1,994	2,091	2,189
Conventional Resources										
Total Conventional Resources	142	1,370	1,891	1,895	1,900	1,818	1,736	1,652	1,568	1,483
Total Supply	268	2,593	3,582	3,595	3,608	3,621	3,633	3,646	3,659	3,672
Energy Open Position (GWh)	0	0	0	0	0	0	0	0	0	0

Supply Requirements

The starting point for the PCEA's resource plan is a projection of participating customers and associated electric consumption. Projected electric consumption is evaluated on an hourly basis, and matched with resources best suited to serving the aggregate of hourly demands or the program's "load profile". The electric sales forecast and load profile will be affected by the PCEA's plan to introduce the PCE Program to customers in phases and the degree to which customers choose to remain with PG&E during the customer enrollment and opt-out periods. The PCEA's phased roll-out plan and assumptions regarding customer participation rates are discussed below.

Customer Participation Rates

Customers will be automatically enrolled in the PCE Program unless they opt-out during the customer notification process conducted during the 60-day period prior to enrollment and continuing through the 60-day period following commencement of service. The PCEA anticipates an overall customer participation rate of approximately 85 percent of PG&E bundled service customers, based on reported opt-out rates for the Marin Clean Energy, Sonoma Clean Power and Lancaster Choice Energy CCA programs. It is assumed that customers taking direct access service from a competitive electricity provider will elect to remain with their current supplier.

The participation rate is not expected to vary significantly among customer classes, in part due to the fact that the PCEA will offer two distinct rate tariffs that will address the needs of cost-sensitive customers as well as the needs of both residential and business customers that prefer a highly renewable energy product. The assumed participation rates will be refined as the PCEA's public outreach and market research efforts continue to develop.

Customer Forecast

Once customers enroll in each phase, they will be switched over to service by the PCEA on their regularly scheduled meter read date over an approximately thirty day period. Approximately 2,276 service accounts per day will be switched over during the first month of service. For Phase 2, the number of accounts switched over to PCE service will increase to about 2,759 accounts per day. For Phase 3, the number of accounts switched over to PCE service will increase again to about 3,531 accounts per day. The number of accounts served by the PCEA at the end of each phase is shown in the table below.

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

	Oct-16	Apr-17	Oct-17
PCE Customers			
Residential	46,199	127,682	232,150
Small Commercial	19,808	19,907	19,907
Medium Commercial	2,288	2,299	2,299
Large Commercial	-	1,150	1,150
Industrial	-	37	37
Street Lighting & Traffic	-	-	1,236
Agricultural & Pumping	-	-	237
Total	**68,295**	**151,075**	**257,016**

The PCEA assumes that customer growth will generally offset customer attrition (opt-outs) over time, resulting in a relatively stable customer base (0.5% annual growth) over the noted planning horizon. While the successful operating track record of California CCA programs continues to grow, there is a relatively short history with regard to CCA operations, which makes it fairly difficult to anticipate the actual levels of customer participation within the PCE Program. The

PCEA believes that its assumptions regarding the offsetting effects of growth and attrition are reasonable in consideration of the historical customer growth within San Mateo County and the potential for continuing customer opt-outs following mandatory customer notification periods. The forecast of service accounts (customers) served by the PCEA for each of the next ten years is shown in the following table:

Peninsula Clean Energy
Retail Service Accounts (End of Year)
2016 to 2025

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PCE Customers										
Residential	46,199	232,150	233,311	234,477	235,650	236,828	238,012	239,202	240,398	241,600
Small Commercial	19,808	19,907	20,006	20,106	20,207	20,308	20,410	20,512	20,614	20,717
Medium Commercial	2,288	2,299	2,311	2,322	2,334	2,346	2,357	2,369	2,381	2,393
Large Commercial	-	1,150	1,156	1,162	1,167	1,173	1,179	1,185	1,191	1,197
Industrial	-	37	37	37	38	38	38	38	38	39
Street Lighting & Traffic	-	1,236	1,242	1,248	1,255	1,261	1,267	1,274	1,280	1,286
Agricultural & Pumping	-	237	238	239	241	242	243	244	245	247
Total	**68,295**	**257,016**	**258,301**	**259,593**	**260,891**	**262,195**	**263,506**	**264,824**	**266,148**	**267,479**

Sales Forecast

The PCEA's forecast of kWh sales reflects the roll-out and customer enrollment schedule shown above. The annual electricity needed to serve the PCEA's retail customers increases from nearly 270 GWh in 2016 to approximately 3,600 GWh at full roll-out. Annual energy requirements are shown below.

Peninsula Clean Energy
Energy Requirements
(GWH)
2016 to 2025

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PCE Energy Requirements (GWh)										
Retail Demand	253	2,447	3,382	3,399	3,416	3,433	3,451	3,468	3,485	3,503
Distributed Generation	0	0	-3	-4	-6	-7	-9	-10	-12	-13
Energy Efficiency	0	0	0	-3	-7	-10	-14	-17	-21	-25
Losses and UFE	15	147	203	203	204	205	206	206	207	208
Total Load Requirement	268	2,593	3,582	3,595	3,608	3,621	3,633	3,646	3,659	3,672

Capacity Requirements

The CPUC's resource adequacy standards applicable to the PCE Program require a demonstration one year in advance that the PCEA has secured physical capacity for 90 percent of its projected peak loads for each of the five months May through September, plus a minimum 15 percent reserve margin. On a month-ahead basis, the PCEA must demonstrate 100 percent of the peak load plus a minimum 15 percent reserve margin.

A portion of the PCEA's capacity requirements must be procured locally, from the Greater Bay area as defined by the CAISO and another portion must be procured from local reliability areas outside the Greater Bay Area. The PCEA would be required to demonstrate its local capacity requirement for each month of the following calendar year. The local capacity requirement is a percentage of the total (PG&E service area) local capacity requirements adopted by the CPUC based on the PCEA's forecasted peak load. The PCEA must demonstrate compliance or request a waiver from the CPUC requirement as provided for in cases where local capacity is not available.

The PCEA is also required to demonstrate that a specified portion of its capacity meets certain operational flexibility requirements under the CPUC and CAISO's flexible resource adequacy framework.

The estimated forward resource adequacy requirements for 2016 through 2018 are shown in the following tables[3]:

Peninsula Clean Energy
Forward Capacity and Reserve Requirements
(MW)
2016 to 2018

Month	2016	2017	2018
January	-	264	780
February	-	289	839
March	-	246	709
April	-	499	789
May	-	650	785
June	-	692	837
July	-	665	799
August	-	708	854
September	-	719	866
October	165	716	770
November	268	767	769
December	261	769	771

The PCEA's plan ensures that sufficient reserves will be procured to meet its peak load at all times. The PCEA's projected annual capacity requirements are shown in the following table:

[3] The figures shown above are estimates. PCEA's resource adequacy requirements will be subject to modification due to application of certain coincidence adjustments and resource allocations relating to utility demand response and energy efficiency programs, as well as generation capacity allocated through the Cost Allocation Mechanism. These adjustments are addressed through the CPUC's resource adequacy compliance process.

Peninsula Clean Energy
Capacity Requirements
(MW)
2016 to 2025

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Demand (MW)										
Retail Demand	220	631	713	716	720	723	727	731	734	738
Distributed Generation	-	-	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Energy Efficiency	-	-	-	(1)	(1)	(2)	(3)	(4)	(4)	(5)
Losses and UFE	13	38	43	43	43	43	43	43	43	43
Total Net Peak Demand	233	669	753	755	757	759	761	763	765	767
Reserve Requirement (%)	15%	15%	15%	15%	15%	15%	15%	15%	15%	15%
Capacity Reserve Requirement	35	100	113	113	114	114	114	114	115	115
Capacity Requirement Including Reserve	268	769	866	869	871	873	875	878	880	882

Local capacity requirements are a function of the PG&E area resource adequacy requirements and the PCEA's projected peak demand. The PCEA will need to work with the CPUC's Energy Division and staff at the California Energy Commission to obtain the data necessary to calculate its monthly local capacity requirement. A preliminary estimate of the PCEA's annual local capacity requirement for the ten-year planning period ranges from approximately 268 MW to 882 MW as shown in the following table:

Peninsula Clean Energy
Local Capacity Requirements
(MW)
2016 to 2025

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PCE Peak (MW)	233	669	753	755	757	759	761	763	765	767
Local Capacity Requirement (% of Peak)	-	36%	36%	36%	36%	36%	36%	36%	36%	36%
Greater Bay Area Share of Local Capacity Requirment (%)	-	34%	34%	34%	34%	34%	34%	34%	34%	34%
Other PG&E Areas Share of Local Capacity Requirment (%)	-	66%	66%	66%	66%	66%	66%	66%	66%	66%
Authority Local Capacity Requirement Greater Bay (MW)	-	82	92	92	93	93	93	93	94	94
Authority Local Capacity Requirement Other PG&E (MW)	-	159	179	179	180	180	181	181	182	182
Authority Local Capacity Requirement, Total (MW)	-	241	271	272	273	273	274	275	275	276

Due to the timing of Phase 1 customer enrollment, the PCEA will not receive a 2016 local capacity requirement from the CPUC. The CPUC assigns local capacity requirements during the year prior to the compliance period; thereafter, the CPUC provides local capacity requirement true-ups for the second half of each compliance year. Therefore, since PCE does not launch until October 2016, PCE will not have a local capacity requirement until the compliance month of January 2017.

The PCEA will coordinate with PG&E and appropriate state agencies to manage the transition of responsibility for resource adequacy from PG&E to the PCEA during CCA program phase-in. For system resource adequacy requirements, the PCEA will make month-ahead showings for each month that the PCEA plans to serve load, and load migration issues would be addressed through the CPUC's approved procedures. The PCEA will work with the California Energy Commission and CPUC prior to commencing service to customers to ensure it meets its local and system resource adequacy obligations through its agreement(s) with its chosen electric supplier(s).

Renewables Portfolio Standards Energy Requirements

Basic RPS Requirements

As a CCA, the PCEA will be required by law and ensuing CPUC regulations to procure a certain minimum percentage of its retail electricity sales from qualified renewable energy resources. For purposes of determining the PCEA's renewable energy requirements, the same standards for RPS compliance that are applicable to the distribution utilities are assumed to apply to PCE.

California's RPS program is currently undergoing reform. On October 7, 2015, Governor Brown signed Senate Bill 350 ("SB 350"; De Leon and Leno), the Clean Energy and Pollution Reduction Act of 2015, which increased California's RPS procurement target from 33 percent by 2020 to 50 percent by 2030 amongst other clean-energy initiatives. Many details related to SB 350 implementation 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 percent procurement mandate – for planning purposes, the PCEA has assumed straight-line annual increases (1.7 percent per year) to the RPS procurement target beginning in 2021, as the state advances on the 50 percent RPS. Prior to 2021, the PCEA will adopt a resource plan that complies with SB x1 2, including certain procurement quantity requirements identified in D.11-12-020 (December 1, 2011).

PCEA's Renewables Portfolio Standards Requirement

The PCEA's annual RPS procurement requirements, as specified under California's RPS program, are shown in the table below. When reviewing this table, it is important to note that the PCEA projects increases in energy efficiency savings as well as increases in locally situated distributed generation capacity, resulting in only a slight upward trend in projected retail electricity sales.

Peninsula Clean Energy
RPS Requirements
(MWH)
2016 to 2025

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Retail Sales	253,061	2,446,569	3,382,353	3,399,265	3,416,261	3,433,343	3,450,509	3,467,762	3,485,101	3,502,526
Annual Procurement Target	63,265	660,574	980,882	1,053,772	1,127,366	1,191,370	1,255,985	1,321,217	1,387,070	1,453,548
% of Current Year Retail Sales*	25%	27%	29%	31%	33%	35%	36%	38%	40%	42%

*Note: Specific details related to SB 350 implementation have yet to be identified. For purposes of this table, the PCEA assumed a straight-line increase from California's 33 percent RPS procurement mandate in 2020 to California's new, 50 percent RPS procurement mandate in 2030.

Based on planned renewable energy procurement objectives, the PCEA anticipates that it will significantly exceed the minimum RPS requirements as shown below.

Peninsula Clean Energy
RPS Requirements and Program Renewable Energy Targets
(MWH)
2016 to 2025

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Retail Sales (MWh)	253,061	2,446,569	3,382,353	3,399,265	3,416,261	3,433,343	3,450,509	3,467,762	3,485,101	3,502,526
Annual RPS Target (Minimum MWh)	50,612	489,314	676,471	679,853	741,329	799,969	862,627	936,296	1,010,679	1,085,783
Program Target (% of Retail Sales)	50%	50%	50%	50%	50%	53%	55%	58%	60%	63%
Program Renewable Target (MWh)	**126,530**	**1,223,284**	**1,691,177**	**1,699,632**	**1,708,131**	**1,802,505**	**1,897,780**	**1,993,963**	**2,091,060**	**2,189,079**
Surplus In Excess of RPS (MWh)	**75,918**	**733,971**	**1,014,706**	**1,019,779**	**966,802**	**1,002,536**	**1,035,153**	**1,057,667**	**1,080,381**	**1,103,296**
Annual Increase (MWh)	126,530	1,096,754	467,892	8,456	8,498	94,374	95,275	96,183	97,097	98,018

Purchased Power

Power purchased from power marketers, public agencies, generators, and/or utilities will be a significant source of supply during the first several years of PCE Program operation. The PCEA will initially contract to obtain all of its electricity from one or more third party electric providers under one or more power supply agreements, and the supplier(s) will be responsible for procuring the specified resource mix, including PCEA's desired quantities of renewable energy, to provide a stable and cost-effective resource portfolio for the Program. Based on terms established in the third-party contract(s), the PCEA will be able to substitute electric energy generated by PCE-owned/controlled renewable resources for certain contract quantities in the event that such resources become operational during the delivery period. Initially, it is assumed that one of the Program's third party electric suppliers will be responsible for fulfilling the needs of PCEA's overall supply portfolio.

Renewable Resources

The PCEA will initially secure necessary renewable power supply from its third party electric supplier(s). The PCEA may supplement the renewable energy provided under the initial power supply contract(s) with direct purchases of renewable energy from renewable energy facilities or from renewable generation developed and owned by the PCEA. At this point in time, it is not possible to predict what projects might be proposed in response to future renewable energy solicitations administered by the PCEA, unsolicited proposals or discussions with other agencies. Renewable projects that are located virtually anywhere in the Western Interconnection can be considered (with a preference for local projects) as long as the electricity is deliverable to the CAISO control area, as required to meet the Commission's RPS rules and any additional guidelines ultimately adopted by the PCEA's Board of Directors. The costs of transmission access and the risk of transmission congestion costs would need to be considered in the bid evaluation process if the delivery point is outside of the PCEA's load zone, as defined by the CAISO.

Energy Efficiency

The PCEA's energy efficiency goals will reflect a strong commitment to increasing energy efficiency within the County, expanding beyond the savings achieved by PG&E's programs. The PCEA will seek to maximize end-use customer energy efficiency by facilitating customer participation in existing utility programs as well as by forming new programs that will displace the PCEA's need for traditional electric procurement activities.

Forecast energy efficiency savings building to 0.5 percent of the PCEA's projected energy sales (by 2023) appears to be a reasonable baseline for the demand-side portion of its resource plan. For example, the National Action Plan for Energy Efficiency states among its key findings "consistently funded, well-designed efficiency programs are cutting annual savings for a given program year of 0.15 to 1 percent of energy sales."[4] The American Council for an Energy-Efficient Economy (ACEEE) reports for states already operating substantial energy efficiency programs that an energy efficiency goal of one percent, as a percentage of energy sales, is a reasonable level to target.[5] These savings would be in addition to the savings achieved by PG&E administered programs. Achieving this goal would mean at least a doubling of energy savings relative to the status quo (without the program administered by the PCEA). It is assumed that energy efficiency programs of the PCEA will focus on closing the gap between the vast economic potential of energy efficiency within the County and what is actually achieved.

The PCEA will develop specific energy efficiency programs and seek requisite program funding from the CPUC to administer such programs. Additional details of the PCEA's energy efficiency plan will be developed once the first phase of the PCE Program is underway.

Demand Response

Demand response programs provide incentives to customers to reduce demand upon request by the load serving entity (i.e., the PCEA), reducing the amount of generation capacity that must be maintained as infrequently used reserves. Demand response programs can be cost effective alternatives to procured capacity that would otherwise be needed to comply with California's resource adequacy requirements. The programs also provide rate benefits to customers who have the flexibility to reduce or shift consumption for relatively short periods of time when generation capacity is most scarce. Like energy efficiency, demand response can be a win/win proposition, providing economic benefits to the electric supplier as well as customer service benefits.

In its ruling on local resource adequacy, the CPUC found that dispatchable demand response resources as well as distributed generation resources should be allowed to count for local capacity requirements. This resource plan anticipates that the PCEA's demand response programs would partially offset its local capacity requirements beginning in 2019.

PG&E offers several demand response programs to its customers, and the PCEA intends to recruit those customers that have shown a willingness to participate in utility programs into similar programs offered by the PCEA.[6] The goal for this resource plan is to meet 5 percent of the PCE

---

[4] National Action Plan for Energy Efficiency, July 2006, Section 6: Energy Efficiency Program Best Practices (pages 5-6)

[5] Energy Efficiency Resource Standards: Experience and Recommendations, Steve Nadel, March 2006, ACEEE Report E063 (pages 28 - 30).

[6] These utility programs include the Base Interruptible Program (E-BIP), the Demand Bidding Program (E-DBP), Critical Peak Pricing (E-CPP), Optional Binding Mandatory Curtailment Plan (E-OBMC), the Scheduled Load

Program's total capacity requirements through dispatchable demand response programs that qualify to meet local resource adequacy requirements. This goal translates into approximately 44 MW of peak demand enrolled in PCE's demand response programs. Achievement of this goal would displace approximately 47 percent of the PCEA's local capacity requirement within the "Greater Bay Area" Local Reliability Area.[7]

Peninsula Clean Energy
Demand Response Goals
(MW)
2016 to 2025

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Capacity Requirement (MW)	268	769	866	869	871	873	875	878	880	882
Greater Bay Area Capacity Requirement (MW)	-	82	92	92	93	93	93	93	94	94
Demand Response Target (MW)	-	-	-	4	11	17	24	31	37	44
Percentage of Local Capacity Requirment	0%	0%	0%	5%	12%	19%	26%	33%	40%	47%

The PCEA will adopt a demand response program that enables it to request customer demand reductions during times when capacity is in short supply or spot market energy costs are exceptionally high. The level of customer payments should be related to the cost of local capacity that can be avoided as a result of the customer's willingness to curtail usage upon request.

Appropriate limits on customer curtailments, both in terms of the length of individual curtailments and the total number of curtailment hours that can be called should be included in the PCEA's demand response program design. It will also be important to establish a reasonable measurement protocol for customer performance of its curtailment obligations and deploy technology to automate customer notifications and responses. Performance measurement should include establishing a customer specific baseline of usage prior to the curtailment request from which demand reductions can be measured. The PCEA will likely utilize experienced third party contractors to design, implement and administer its demand response programs.

Distributed Generation

Consistent with the PCEA's environmental policies and the state's Energy Action Plan, clean distributed generation is a significant component of the integrated resource plan. The PCEA will work with state agencies and PG&E to promote deployment of photovoltaic (PV) systems within the PCEA's jurisdiction, with the goal of maximizing use of the available incentives that are funded through current utility distribution rates and public benefits surcharges. The PCEA will also implement an aggressive net energy metering program and eventually a feed-in-tariff to promote local investment in distributed generation.

Reduction Program (E-SLRP), and the Capacity Bidding Program (E-CBP). The PCEA plans to develop its own demand response programs, which may be similar to those currently administered by the incumbent utility.

[7] The California Public Utilities Commission has defined five local Resource Adequacy areas, including the "Other PG&E" local area (which represents an aggregation of various locations within the PG&E service territory), which have been designated as transmission-constrained. Load serving entities, including the PCEA, must procure a certain portion of their respective resource adequacy obligations from resources located within these transmission-constrained areas. However, demand response programs may be used to directly reduce local resource adequacy obligations; the PCEA plans to reduce such obligations through the implementation of effective demand response programs.

There are significant environmental benefits and strong customer interest in distributed PV systems. The PCEA may provide direct financial incentives from revenues funded by customer rates to further support use of solar power within the local area. Finally, the PCEA plans to provide direct incentives for PV by offering a net metering rate to customers who install PV systems so that customers are able to sell excess energy to the PCEA. Such a program would be generally consistent with principles identified in Assembly Bill 920 ("AB 920"), which directed the CPUC to establish and implement a compensation methodology for surplus renewable generation produced by net energy metered facilities located within the service territories of California's large investor owned utilities, including PG&E. However, the PCEA may choose to offer enhanced compensation structures, relative to those implemented as a result of AB 920, as part of the direct incentives that may be established to promote distributed generation development within San Mateo County. To the extent that incentives offered by the PCEA improve project economics for its customers, it is reasonable to assume that the penetration of distributed generation within the County would increase.

CHAPTER 7 – **Financial Plan**

This Chapter examines the monthly cash flows expected during the startup and customer phase-in period of the PCE Program and identifies the anticipated financing requirements. It includes estimates of program startup costs, including the necessary expenses and capital outlays which will commence once the CPUC has certified its receipt of the Implementation Plan submitted by the PCEA. It also describes the requirements for working capital and long-term financing for the potential investment in renewable generation, consistent with the resource plan contained in Chapter 6.

Description of Cash Flow Analysis

The PCEA's cash flow analysis estimates the level of capital that will be required during the startup and phase-in period. The analysis focuses on the PCE Program's monthly costs and revenues and specifically accounts for the phased enrollment of PCE Program customers described in Chapter 5.

Cost of CCA Program Operations

The first category of the cash flow analysis is the Cost of CCA Program Operations. To estimate the overall costs associated with CCA Program Operations, the following components were taken into consideration:

- Electricity Procurement;
- Ancillary Service Requirements;
- Exit Fees;
- Staffing and Professional Services;
- Data Management Costs;
- Administrative Overhead;
- Billing Costs;
- Scheduling Coordination;
- Grid Management and other CAISO Charges;
- CCA Bond and Security Deposit;
- Pre-Startup Cost Reimbursement; and
- Debt Service.

Revenues from CCA Program Operations

The cash flow analysis also provides estimates for revenues generated from CCA operations or from electricity sales to customers. In determining the level of revenues, the analysis assumes the customer phase-in schedule described herein, and assumes that the PCEA charges a standard, default electricity tariff similar to the generation rates of the existing distribution utility for each customer class and an optional 100% renewable energy tariff at a premium reflective of incremental renewable power costs. PCE Program rates are assumed to increase by 2.5% annually, which would support the cash flows presented herein – this projected rate increase is somewhat lower than the historical average rate increase that has been observed within the PG&E service territory.[8] More detail on PCE Program rates can be found in Chapter 8.

Cash Flow Analysis Results

The results of the cash flow analysis provide an estimate of the level of capital required for the PCEA to move through the CCA startup and phase-in periods. This estimated level of capital is determined by examining the monthly cumulative net cash flows (revenues from CCA operations minus cost of CCA operations) based on assumptions for payment of costs or other cash requirements (e.g., deposits) by the PCEA, along with estimates for when customer payments will be received. This identifies, on a monthly basis, what level of cash flow is available in terms of a surplus or deficit.

The cash flow analysis identifies funding requirements in recognition of the potential lag between payments received and payments made during the phase-in period. The estimated financing requirements for the startup and phase-in period, including working capital needs associated with all three phases of customer enrollments, is approximately $13.5 million. Of this total, approximately $8.9 million would be needed during the startup period prior to the time Phase 1 customers are enrolled. Working capital requirements peak soon after enrollment of the Phase 1 customers.

CCA Program Implementation Pro Forma

In addition to developing a cash flow analysis which estimates the level of working capital required to move the PCEA through full CCA phase-in, a summary pro forma analysis that evaluates the financial performance of the CCA program during the phase-in period is shown below. The difference between the cash flow analysis and the CCA pro forma analysis is that the pro forma analysis does not include a lag associated with payment streams. In essence, costs and revenues are reflected in the month in which service is provided. All other items, such as costs associated with CCA Program operations and rates charged to customers remain the same. Cash provided by financing activities are not shown in the pro forma analysis, although payments for debt service are included as a cost item.

The results of the pro forma analysis are shown in the following table. Under these assumptions, over the entire phase-in period (which is projected to occur through 2017) the CCA program is projected to accrue a reserve account balance of approximately $26 million. The following

[8] According to the California Energy Commission Utility-wide Weighted Average Electric Utility Prices report, PG&E average electric rates have increased by an average of 4.6% per year since 2000 and 3.4% annually since 2005.

summary of CCA program startup and phase-in addresses projected PCE Program operations for the period beginning January 2016 through December 2025. [9]

Peninsula Clean Energy
Summary of CCA Program Startup and Phase-In
(January 2016 through December 2025)

CATEGORY	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	TOTAL
I. REVENUES FROM OPERATIONS ($)											
ELECTRIC SALES REVENUE	16,643,801	182,856,794	246,925,988	254,330,641	261,958,189	269,815,346	277,909,028	286,246,360	294,834,680	303,681,550	2,395,202,375
LESS UNCOLLECTIBLE ACCOUNTS	(82,713)	(909,391)	(1,227,865)	(1,264,855)	(1,302,958)	(1,342,210)	(1,382,644)	(1,424,296)	(1,467,203)	(1,511,403)	(11,915,538)
TOTAL REVENUES	16,561,088	181,947,403	245,698,123	253,065,786	260,655,230	268,473,136	276,526,384	284,822,063	293,367,477	302,170,147	2,383,286,837
II. COST OF OPERATIONS ($)											
(A) OPERATIONS AND ADMINISTRATIVE (O&A)											
STAFFING & PROFESSIONAL SERVIC	1,892,292	3,681,606	4,206,469	4,332,663	4,462,642	4,596,522	4,734,417	4,876,450	5,022,743	5,173,426	42,979,229
MARKETING	657,856	1,715,780	1,429,511	1,474,513	1,520,940	1,568,837	1,618,250	1,669,228	1,721,821	1,776,080	15,152,815
DATA MANAGEMENT SERVICES	307,326	2,825,116	4,649,417	4,672,664	4,696,027	4,719,507	4,743,105	4,766,820	4,790,655	4,814,608	40,985,244
IOU FEES (INCLUDING BILLING)	101,558	928,367	1,558,033	1,612,798	1,669,488	1,728,170	1,788,916	1,851,796	1,916,887	1,984,265	15,140,278
OTHER ADMINISTRATIVE & GENER	406,250	901,250	928,288	956,136	984,820	1,014,365	1,044,796	1,076,140	1,108,424	1,141,677	9,562,144
ENERGY PROGRAMS	125,000	901,250	1,060,900	1,092,727	1,125,509	1,159,274	1,194,052	1,229,874	1,266,770	1,304,773	10,460,129
SUBTOTAL O&A	3,490,281	10,953,368	13,832,617	14,141,501	14,459,427	14,786,675	15,123,536	15,470,308	15,827,299	16,194,828	134,279,841
(B) COST OF ENERGY	13,695,230	141,106,875	195,219,317	201,877,099	208,735,199	216,393,701	224,359,013	232,643,378	241,259,517	250,220,653	1,925,509,981
(C) DEBT SERVICE	359,374	3,110,953	3,110,953	3,110,953	2,587,491	2,228,118	-	-	-	-	14,507,843
TOTAL COST OF OPERATION	17,544,885	155,171,196	212,162,887	219,129,553	225,782,118	233,408,493	239,482,549	248,113,686	257,086,816	266,415,481	2,074,297,664
CCA PROGRAM SURPLUS/(DEFICIT)	(983,797)	26,776,207	33,535,236	33,936,233	34,873,112	35,064,642	37,043,835	36,708,378	36,280,661	35,754,666	308,989,173

The surpluses achieved during the phase-in period serve to build the PCEA's net worth and credit profile and to provide operating reserves for the PCEA in the event that operating costs (such as power purchase costs) exceed collected revenues for short periods of time.

PCE Financings

It is anticipated that a single financing will be necessary to support PCE Program implementation. Subsequent capital requirements will be self-funded from the PCEA's accrued financial reserves. The anticipated financings are described below.

CCA Program Start-up and Working Capital

As previously discussed, the anticipated start-up and working capital requirements for the PCE Program are $13.5 million. This amount is dependent upon the amount of load initially served by the PCEA, actual energy prices, payment terms established with the third-party supplier, and program rates. This figure would be refined during the startup period as these variables become known. Once the PCE Program is up and running, these costs would be recovered from customers of the PCEA Program through retail rates.

It is assumed that this financing will be via a short term loan or letter of credit, which would allow the PCEA to draw cash as required. This financing would need to commence in the second quarter of 2016.

[9] Costs projected for staffing & professional services and other administrative & general relate to energy procurement, administration of energy efficiency and other local programs, generation development, customer service, marketing, accounting, finance, legal and regulatory activities necessary for program operation.

Phases 2 and 3 Working Capital

The next potential financing would be working capital for Phase 2. It is currently estimated that Phases 2 and 3 can be financed with internally generated cash. If external financing were needed, it could be an extension (increase) of the letter of credit for the PCE Program's start-up capital or a new short-term credit facility. This financing would need to commence prior to the Phase 2 customer enrollments. Another short-term credit facility could be used to support the Phase 3 customer enrollments, if necessary (see table below).

Renewable Resource Project Financing

The PCEA may consider project financings for renewable resources, likely local wind, solar, biomass and/or geothermal as well as energy efficiency projects. These financings would only occur after a sustained period of successful PCE Program operation and after appropriate project opportunities are identified and subjected to appropriate environmental review. The PCEA's ability to directly finance projects will likely require a track record of five to ten years of successful program operations demonstrating strong underlying credit to support the financing; direct financing undertaken by the PCEA would not be expected to occur sooner than 2021.

In the event that such financing occurs, funds would include any short-term financing for the renewable resource project development costs, and would likely extend over a 20- to 30-year term. The security for such bonds would be the revenue from sales to the retail customers of the PCEA.

The following table summarizes the potential financings in support of the PCE Program:

PCE Program Financing Summary

Proposed Financing	Estimated Total Amount	Estimated Term	Estimated Issuance
1. Start-Up (County)	$1.5 million	3 years	Issued
2. Start-Up (Bank)	$12 million	5 years	Second Quarter 2016
3. Phase 2 Working Capital	$0 million	5 years	Late 2016, if needed
4. Phase 3 Working Capital	$0 million	5 years	Mid 2017, if needed
5. Potential Renewable Resource Project Financings	$TBD	20-30 years	TBD

CHAPTER 8 - Ratesetting and Program Terms and Conditions

Introduction

This Chapter describes the initial policies proposed for the PCEA in setting its rates for electric aggregation services. These include policies regarding rate design, rate objectives, and provision for due process in setting Program rates. Program rates are ultimately approved by the Board. The Board would retain authority to modify program policies from time to time at its discretion.

Rate Policies

The PCEA will establish rates sufficient to recover all costs related to operation of the PCE Program, including any reserves that may be required as a condition of financing and other discretionary reserve funds that may be approved by the Board. As a general policy, rates will be uniform for all similarly situated customers enrolled in the PCE Program throughout the service area of the PCEA.

The primary objectives of the ratesetting plan are to set rates that achieve the following:

- 100 percent renewable energy supply option (voluntary service offering);
- Rate competitive tariff option (default service offering) with minimum 50% renewable energy;
- Rate stability;
- Equity among customers in each tariff;
- Customer understanding; and
- Revenue sufficiency.

Each of these objectives is described below.

Rate Competitiveness

The primary goal is to offer competitive rates for electric services that the PCEA would provide to participating customers. For participants in the PCEA's standard Tariff, the goal would be for PCE Program rates to be generally equivalent to (or potentially less than, subject to actual energy product pricing and decisions of the PCEA Board of Directors) the generation rates offered by PG&E. For voluntary participants in the PCE Program's 100 percent renewable energy Tariff, the goal would be to offer the lowest possible customer rates with an incremental monthly cost premium reflective of the actual cost of additional renewable energy supply required to serve such customers – based on current estimates, the anticipated cost premium for the PCE Program's 100 percent renewable supply option would be 5 to 10 percent relative to the default PCE tariff.

Competitive rates will be critical to attracting and retaining key customers. In order for the PCEA to be successful, the combination of price and value must be perceived as superior when compared to the bundled utility service alternative. The value provided by the PCE Program will include a higher proportion of renewable energy relative to the incumbent utility, enhanced energy efficiency and customer programs, community focus and investment, local control, and general benefits that stem from PCE's mission to serve its customers rather than the interests of utility shareholders.

As previously discussed, the PCE Program will significantly increase renewable energy supply to program customers, relative to the incumbent utility, by offering two distinct rate tariffs. The default tariff for PCE Program customers will be the standard Tariff, which will maximize renewable energy supply while maintaining generation rates that are comparable to PG&E's. The initial renewable energy content provided under the standard Tariff will be at least 50%, and the PCEA will endeavor to increase this percentage on a going forward basis, subject to operational and economic constraints. The PCEA will also offer its customers a voluntary 100% renewable energy Tariff, which will supply participating customers with 100 percent renewable energy at rates that reflect PCE's cost for procuring related energy supplies.

Participating qualified low- or fixed-income households, such as those currently enrolled in the California Alternate Rates for Energy (CARE) program, will be automatically enrolled in the standard Tariff and will continue to receive related discounts on monthly electricity bills through PG&E.

Rate Stability

The PCEA will offer stable rates by hedging its supply costs over multiple time horizons and by including renewable energy supplies that exhibit stable costs. Rate stability considerations may prevent PCE Program rates from directly tracking similar rates offered by the distribution utility, PG&E, and may result in differences from the general rate-related targets initially established for the PCE Program. The PCEA will attempt to maintain general rate parity with PG&E to ensure that PCE Program rates are not drastically different from the competitive alternative.

Equity among Customer Classes

Initial rates of the PCE Program will be set based on cost-of-service considerations with reference to the rates customers would otherwise pay to PG&E. Rate differences among customer classes will reflect the rates charged by the local distribution utility as well as differences in the costs of providing service to each class. Rate benefits may also vary among customers within the major customer class categories, depending upon the specific rate designs adopted by the Board.

Customer Understanding

The goal of customer understanding involves rate designs that are relatively straightforward so that customers can readily understand how their bills are calculated. This not only minimizes customer confusion and dissatisfaction but will also result in fewer billing inquiries to the PCE Program's customer service call center. Customer understanding also requires rate structures to reflect rational rate design principles (i.e., there should not be differences in rates that are not justified by costs or by other policies such as providing incentives for conservation).

Revenue Sufficiency
PCE Program rates must collect sufficient revenue from participating customers to fully fund the PCEA's annual budget. Rates will be set to collect the adopted budget based on a forecast of electric sales for the budget year. Rates will be adjusted as necessary to maintain the ability to fully recover all of costs of the PCE Program, subject to the disclosure and due process policies described later in this chapter.

Rate Design
The PCEA will generally match the rate structures from the utilities' standard rates to avoid the possibility that customers would see significantly different bill impacts as a result of changes in rate structures that would take effect following enrollment in the PCE Program. The PCEA may also introduce new rate options for customers, such as rates designed to encourage economic expansion or business retention within the PCEA service area.

Initial PCE Program rates are projected to average 6.9 cents per KWh on an annualized basis, which is below PG&E's reported average generation rate. PCE customers' electric bills may increase somewhat due to PG&E's collection of its excess power supply costs through the surcharge known as the Power Charge Indifference Adjustment ("PCIA"). PG&E will add the PCIA to PCE customers' monthly electric bills along with other utility service charges. The PCIA is identified in each of PG&E's rate schedules and is expected to decline over time.

Custom Pricing Options
The PCEA will work to develop specially-tailored rate and electric service products that meet the specific load characteristics or power market risk profiles of larger commercial and industrial customers. This will allow such customers to have access to a wider range of products than is currently available under the incumbent utility and potentially reduce the cost of power for these customers. The PCEA may provide large energy users with custom pricing options to help these customers gain greater control over their energy costs. Some examples of potential custom pricing options are rates that are based on an observable market index (e.g., CAISO prices) or fixed priced contracts of various terms.

Net Energy Metering
Customers with on-site generation eligible for net metering from PG&E will be offered a net energy metering rate from the PCEA. Net energy metering allows for customers with certain qualified solar or wind distributed generation to be billed on the basis of their net energy consumption. The PG&E net metering tariff (NEM) requires the CCA to offer a net energy metering tariff in order for the customer to continue to be eligible for service on Schedule E-NEM. The objective is that the PCEA's net energy metering tariff will apply to the generation component of the bill, and the PG&E net energy metering tariff will apply to the utility's portion of the bill. The PCEA will pay customers for excess power produced from net energy metered generation systems in accordance with the rate designs adopted by the PCE Board.

The PCEA may also implement tariff and financing programs to provide incentives to residents and businesses to maximize the size of photovoltaic and other renewable energy systems in order to increase the amount of locally-produced renewable power. Current tariffs create an incentive for residents and businesses considering new PV or renewable systems to limit the size of those systems so that annual generation matches annual on-site load. By implementing tariffs and programs to provide an incentive to maximize the output of such systems, the PCEA can help to increase the amount of local PV and renewable generation with minimal impact on the environment or existing infrastructure.

Disclosure and Due Process in Setting Rates and Allocating Costs among Participants
Initial program rates will be adopted by the Board of Directors following the establishment of the first year's operating budget prior to initiating the customer notification process. Subsequently, the Executive Director, with support of appropriate staff, advisors and committees, will prepare an annual budget and corresponding customer rates and submit these as an application for a change in rates to the Board of Directors. The rates will be approved at a public meeting of the Board of Directors no sooner than sixty days following submission of the proposed rates, during which affected customers will be able to provide comment on the proposed rate changes.

Within forty-five days after submitting an application to increase any rate, the PCEA will furnish notice of its application to its customers affected by the proposed increase, either by mailing such notice postage prepaid to such customers or by including such notice with the regular bill for charges transmitted to such customers. The notice will provide a summary of the proposed rate increase and include a link to the PCE Program website where information will be posted regarding the amount of the proposed increase (expressed in both dollar and percentage terms), a brief statement of the reasons the increase is required or sought, and the mailing address of the PCEA to which any customer inquiries relative to the proposed increase, including a request by the customer to receive notice of the date, time, and place of any hearing on the application, may be directed.

CHAPTER 9 – **Customer Rights and Responsibilities**

This chapter discusses customer rights, including the right to opt-out of the PCE Program and the right to privacy of customer usage information, as well as obligations customers undertake upon agreement to enroll in the CCA Program. All customers that do not opt out within 30 days of the fourth enrollment notice will have agreed to become full status program participants and must adhere to the obligations set forth below, as may be modified and expanded by the PCE Board from time to time.

By adopting this Implementation Plan, the PCEA Board will have approved the customer rights and responsibilities policies contained herein to be effective at Program initiation. The Board retains authority to modify program policies from time to time at its discretion.

Customer Notices

At the initiation of the customer enrollment process, a total of four notices will be provided to customers describing the Program, informing them of their opt-out rights to remain with utility bundled generation service, and containing a simple mechanism for exercising their opt-out rights. The first notice will be mailed to customers approximately sixty days prior to the date of automatic enrollment. A second notice will be sent approximately thirty days later. The PCEA will likely use its own mailing service for requisite enrollment notices rather than including the notices in PG&E's monthly bills. This is intended to increase the likelihood that customers will read the enrollment notices, which may otherwise be ignored if included as a bill insert. Customers may opt out by notifying the PCEA using the PCE Program's designated telephone-based or internet opt-out processing service. Should customers choose to initiate an opt-out request by contacting PG&E, they would be transferred to the PCE Program's call center to complete the opt-out request. Consistent with CPUC regulations, notices returned as undelivered mail would be treated as a failure to opt out, and the customer would be automatically enrolled.

Following automatic enrollment, a third enrollment notice will be mailed to customers, and a fourth and final enrollment notice will be mailed 30 days after automatic enrollment. Opt-out requests made on or before the sixtieth day following start of PCE Program service will result in customer transfer to bundled utility service with no penalty. Such customers will be obligated to pay charges associated with the electric services provided by the PCEA during the time the customer took service from the PCE Program, but will otherwise not be subject to any penalty or transfer fee from the PCEA.

Customers who establish new electric service accounts within the Program's service area will be automatically enrolled in the PCE Program and will have sixty days from the start of service to opt out if they so desire. Such customers will be provided with two enrollment notices within this sixty-day post enrollment period. Such customers will also receive a notice detailing the PCEA's privacy policy regarding customer usage information. The PCEA's Board of Directors will have the authority to implement entry fees for customers that initially opt out of the Program, but later decide to participate. Entry fees, if deemed necessary, would aid in resource planning by providing additional control over the PCE Program's customer base.

Termination Fee

Customers that are automatically enrolled in the PCE Program can elect to transfer back to the incumbent utility without penalty within the first two months of service. After this free opt-out period, customers will be allowed to terminate their participation subject to payment of a Termination Fee. The Termination Fee will apply to all customers of the PCE Program that elect to return to bundled utility service or elect to take "direct access" service from an energy services provider following the aforementioned two-month window. Customers that relocate within the PCEA's service territory would have their CCA service continued at the new address. If a customer relocating to an address within the PCEA's service territory elected to cancel CCA service, the Termination Fee will apply. Program customers that move out of the PCEA's service territory would not be subject to the Termination Fee.

PG&E will collect the Termination Fee from returning customers as part of the final bill to the customer from the CCA Program.

The Termination Fee would vary by customer class as set forth in the table below, subject to adjustment by the PCEA's Board as described below.

PCE Program: Schedule of Fees for Service Termination

Customer Class	Fee
Residential	$5
Non-Residential	$25

The Termination Fee will be clearly disclosed in the four enrollment notices sent to customers during the sixty-day period before automatic enrollment and following commencement of service. The fee could be changed prospectively by the PCEA's Board of Directors, subject to applicable customer noticing requirements; provided, however, that in no event will any Termination Fee in excess of the amounts set forth above be imposed on any customer leaving before January 1, 2018, except for terminating customers participating in a voluntary tariff. As previously noted, customers that opt-out during the statutorily mandated notification period will not pay the Termination Fee that may be imposed by the PCEA.

Customers electing to terminate service after the initial notification period (that provided them with at least four enrollment notices) would be transferred to PG&E on their next regularly scheduled meter read date if the termination notice is received a minimum of fifteen days prior to that date. Such customers would also be liable for the nominal reentry fees imposed by PG&E and would be required to remain on bundled utility service for a period of one year, as described in the utility CCA tariffs.

Customer Confidentiality

The PCEA will establish policies covering confidentiality of customer data that are fully compliant with the California Public Utilities Commission's required privacy protection rules for CCA customer energy usage information, as detailed within Decision 12-08-045. The PCEA will maintain the confidentiality of individual customers' names, service addresses, billing addresses, telephone numbers, account numbers, and electricity consumption, except where reasonably necessary to conduct business of the PCEA or to provide services to customers, including but not limited to where such disclosure is necessary to (a) comply with the law or regulations; (b) enable the PCEA to provide service to its customers; (c) collect unpaid bills; (d) obtain and provide credit reporting information; or (e) resolve customer disputes or inquiries. The PCEA will not disclose customer information for telemarketing, e-mail, or direct mail solicitation. Aggregate data may be released at the PCEA's discretion. The PCEA will handle customer energy usage information in a manner that is fully compliant with the California Public Utility Commission's required privacy protections for customers of Community Choice Aggregators, as defined in Decision 12-08-045.

Responsibility for Payment

Customers will be obligated to pay PCE Program charges for service provided through the date of transfer including any applicable Termination Fees. Pursuant to current CPUC regulations, the PCEA will not be able to direct that electricity service be shut off for failure to pay PCE bills. However, PG&E has the right to shut off electricity to customers for failure to pay electricity bills, and PG&E Electric Rule 23 mandates that partial payments are to be allocated pro rata between PG&E and the CCA. In most circumstances, customers would be returned to utility service for failure to pay bills in full and customer deposits (if any) would be withheld in the case of unpaid bills. PG&E would attempt to collect any outstanding balance from customers in accordance with Rule 23 and the related CCA Service Agreement. The proposed process is for two late payment notices to be provided to the customer within 30 days of the original bill due date. If payment is not received within 45 days from the original due date, service would be transferred to the utility on the next regular meter read date, unless alternative payment arrangements have been made. Consistent with the CCA tariffs, Rule 23, service cannot be discontinued to a residential customer for a disputed amount if that customer has filed a complaint with the CPUC, and that customer has paid the disputed amount into an escrow account.

Customer Deposits

Under certain circumstances, PCE customers may be required to post a deposit equal to the estimated charges for two months of CCA service prior to obtaining service from the PCE Program. A deposit would be required for an applicant who previously had been a customer of PG&E or the PCEA and whose electric service has been discontinued by PG&E or the PCEA during the last twelve months of that prior service arrangement as a result of bill nonpayment. Such customers may be required to reestablish credit by depositing the prescribed amount. Additionally a customer who fails to pay bills before they become past due as defined in PG&E Electric Rule 11 (Discontinuance and Restoration of Service), and who further fails to pay such bills within five days after presentation of a discontinuance of service notice for nonpayment of bills, may be required to pay said bills and reestablish credit by depositing the prescribed amount. This rule will apply regardless of whether or not service has been discontinued for such nonpayment[10]. Failure to post deposit as required would cause the account service transfer request to be rejected, and the account would remain with PG&E.

[10] A customer whose service is discontinued by the PCEA is returned to PG&E generation service.

CHAPTER 10 - **Procurement Process**

Introduction

This Chapter describes the PCEA's initial procurement policies and the key third party service agreements by which the PCEA will obtain operational services for the PCE Program. By adopting this Implementation Plan, the PCEA's Board of Directors will have approved the general procurement policies contained herein to be effective at Program initiation. The Board retains authority to modify Program policies from time to time at its discretion.

Procurement Methods

The PCEA will enter into agreements for a variety of services needed to support program development, operation and management. It is anticipated that the PCEA will generally utilize Competitive Procurement methods for services but may also utilize Direct Procurement or Sole Source Procurement, depending on the nature of the services to be procured. Direct Procurement is the purchase of goods or services without competition when multiple sources of supply are available. Sole Source Procurement is generally to be performed only in the case of emergency or when a competitive process would be an idle act.

The PCEA will utilize a competitive solicitation process to enter into agreements with entities providing electrical services for the program. Agreements with entities that provide professional legal or consulting services, and agreements pertaining to unique or time sensitive opportunities, may be entered into on a direct procurement or sole source basis at the discretion of the PCEA's Executive Director or Board of Directors.

The Executive Director will be required to periodically report (e.g., quarterly) to the Board a summary of the actions taken with respect to the delegated procurement authority.

Authority for terminating agreements will generally mirror the authority for entering into such agreements.

Key Contracts

Electric Supply Contract

The PCEA will initiate service using one or more multi-year electricity supply contracts with one or more qualified providers. The third party provider(s) will supply electricity and related services to customers under contract(s) between the provider and the PCEA. The PCEA may complete additional solicitations to supplement its energy supply and/or to replace contract volumes provided under the original contract. The PCEA would begin such procurement sufficiently in advance of contract expiration so that the transition from the initial supply contract occurs smoothly, avoiding dependence on market conditions existing at any single point in time.

As anticipated, a primary supplier will be identified and placed under contract, committing such supplier serving the composite electrical loads of customers in the Program. The primary supplier will also be responsible for ensuring that a certified Scheduling Coordinator schedules the loads of all customers in the PCE Program, providing necessary electric energy, capacity/resource adequacy requirements, renewable energy and ancillary services. The primary supplier is responsible for day-to-day energy supply operations of the PCE Program and for managing the predominant supply risks for the term of the contract. It is anticipated that the primary supplier will also contribute to meeting the Program's renewable energy supply goals. However, additional suppliers may be identified to supplement requisite renewable energy supplier of the PCE program. Finally, the primary supplier will be responsible for ensuring the PCEA's compliance with all applicable resource adequacy and regulatory requirements imposed by the CPUC or FERC.

The PCEA anticipates executing the electric supply contract for Phase 1 loads in mid-2016. The contract for Phase 2 and Phase 3 loads will be executed approximately four months prior to commencement of service to these customers.

Data Management Contract

A data manager will provide the retail customer services of billing and other customer account services (electronic data interchange or EDI with PG&E, billing, remittance processing, and account management). Recognizing that some qualified wholesale energy suppliers do not typically conduct retail customer services whereas others (i.e., direct access providers) do, the data management contract may be separate from the electric supply contract. A single contractor will be selected to perform all of the data management functions.[11]

The data manager is responsible for the following services:

- Data exchange with PG&E;
- Technical testing;
- Customer information system;
- Customer call center;
- Billing administration/retail settlements; and
- Settlement quality meter data reporting
- Reporting and audits of utility billing.

Utilizing a third party for account services eliminates a significant expense associated with implementing a customer information system. Such systems can impose significant information technology costs and take significant time to deploy. A longer term contract is appropriate for this service because of the time and expense that would be required to migrate data to a new

[11] The contractor providing data management may also be the same entity as the contractor supplying electricity for the program.

system. Separation of the data management contract from the energy supply contract gives the PCEA greater flexibility to change energy suppliers, if desired, without facing an expensive data migration issue.

It is anticipated that PCE will execute a contract for data management services in mid-2016.

Electric Supply Procurement Process

The PCEA plans to issue a request for proposals ("RFP") for shaped energy, renewable energy, carbon free energy, resource adequacy capacity, and scheduling coordinator services as part of a competitive solicitation process. This RFP will be released early in the second quarter of 2016 with responses due approximately two weeks thereafter. Contract negotiations will commence immediately following proposal evaluation and short-list selection. Similar to the initial supplier selection processes administered by California's currently operating CCA programs, the PCEA intends to identify a highly qualified pool of suppliers for further negotiations, which will be completed prior to initiation of CCA service. Following the identification of short-listed energy services provider candidates, the PCEA will update the Commission regarding its selection process. It is anticipated that final supplier selection will be made by the PCEA Board by mid-2016.

CHAPTER 11 – **Contingency Plan for Program Termination**

Introduction

This Chapter describes the process to be followed in the case of PCE Program termination. By adopting the original Implementation Plan, the PCEA's Board of Directors will have approved the general termination process contained herein to be effective at Program initiation. In the unexpected event that the PCEA would terminate the PCE Program and return its customers to PG&E service, the proposed process is designed to minimize the impacts on its customers and on PG&E. The proposed termination plan follows the requirements set forth in PG&E's tariff Rule 23 governing service to CCAs. The Board retains authority to modify program policies from time to time at its discretion.

Termination by PCE

The PCEA will offer services for the long term with no planned Program termination date. In the unanticipated event that the majority of the Member's governing bodies (County Board of Supervisors and/or City/Town Councils) decide to terminate the Program, each governing body would be required to adopt a termination ordinance or resolution and provide adequate notice to the PCEA consistent with the terms set forth in the JPA Agreement. Following such notice, the PCEA would vote on Program termination subject to voting provisions as described in the JPA Agreement. In the event that the Board affirmatively votes to proceed with JPA termination, the Board would disband under the provisions identified in its JPA Agreement.

After any applicable restrictions on such termination have been satisfied, notice would be provided to customers six months in advance that they will be transferred back to PG&E. A second notice would be provided during the final sixty-days in advance of the transfer. The notice would describe the applicable distribution utility bundled service requirements for returning customers then in effect, such as any transitional or bundled portfolio service rules.

At least one year advance notice would be provided to PG&E and the CPUC before transferring customers, and the PCEA would coordinate the customer transfer process to minimize impacts on customers and ensure no disruption in service. Once the customer notice period is complete, customers would be transferred *en masse* on the date of their regularly scheduled meter read date.

The PCEA will post a bond or maintain funds held in reserve to pay for potential transaction fees charged to the Program for switching customers back to distribution utility service. Reserves would be maintained against the fees imposed for processing customer transfers (CCASRs). The Public Utilities Code requires demonstration of insurance or posting of a bond sufficient to cover reentry fees imposed on customers that are involuntarily returned to distribution utility service under certain circumstances. The cost of reentry fees are the responsibility of the energy services provider or the community choice aggregator, except in the case of a customer returned for default or because its contract has expired. The PCEA will post financial security in the appropriate amount as part of its registration materials and will maintain the financial security in the required amount, as necessary.

Termination by Members

The JPA Agreement defines the terms and conditions under which Members may terminate their participation in the program.

CHAPTER 12 – **Appendices**

Appendix A: PCEA Resolution Adopting Implementation Plan

Appendix B: Peninsula Clean Energy Authority Joint Powers Agreement

MARIN CLEAN ENERGY
OPERATING FUND
Proposed Budget
Fiscal Year 2016/17

	Projected 2016 Results (information only)	Proposed 2017 Budget	Variation	Variation %
ENERGY REVENUE				
Revenue - Electricity (net of allowance)	147,443,380	$ 144,507,000	(2,936,380)	-2.0%
Other Revenue	428,512		(428,512)	
TOTAL ENERGY REVENUE	**147,871,892**	**144,507,000**	(3,364,892)	-2.3%
ENERGY EXPENSES				
Cost of energy	125,671,563	126,864,000	1,192,437	0.9%
Service fees - PG&E	882,146	918,000	35,854	4.1%
TOTAL ENERGY EXPENSES	**126,553,709**	**127,782,000**	1,228,291	1.0%
NET ENERGY REVENUE	**21,318,183**	**16,725,000**	(4,593,183)	-21.5%
OPERATING EXPENSES				
Personnel	3,141,797	4,489,000	1,347,203	42.9%
Data manager	2,868,024	2,899,000	30,976	1.1%
Technical consultants	638,795	536,000	(102,795)	-16.1%
Legal counsel	386,793	717,000	330,207	85.4%
Communications consultants & related	751,000	751,000	-	0.0%
Other services	465,040	404,000	(61,040)	-13.1%
General and administration	343,930	368,000	24,070	7.0%
Occupancy	233,706	288,000	54,294	23.2%
Integrated demand side pilot programs	36,190	50,000	13,810	38.2%
Marin County green business program	10,000	10,000	-	0.0%
Low income solar programs	35,000	35,000	-	0.0%
TOTAL OPERATING EXPENSES	**8,910,275**	**10,547,000**	1,636,725	18.4%
OPERATING INCOME	**12,407,909**	**6,178,000**	(6,229,909)	-50.2%
NONOPERATING REVENUES (EXPENSES)				
Interest income	7,500	15,000	7,500	100.0%
Interest expense and financing costs	(123,680)	(213,000)	(89,320)	72.2%
Depreciation (supplemental)	(80,000)	(100,000)	(20,000)	25.0%
TOTAL NONOPERATING REVENUES (EXPENSES)	(196,180)	(298,000)	(101,820)	
CHANGE IN NET POSITION	**12,211,729**	**5,880,000**	(6,331,729)	-51.8%
Net position beginning of period	13,256,319	25,468,048	12,211,729	92.1%
Change in net position	12,211,729	5,880,000	(6,331,729)	-51.8%
Net position end of period	25,468,048	31,348,048	5,880,000	23.1%
CAPITAL EXPENDITURES, INTERFUND TRANSFERS & OTHER				
Capital Outlay	(295,656)	(156,000)	139,656	-47.2%
Depreciation (supplemental)	80,000	100,000	20,000	25.0%
Repayment of Loan Principal	(2,024,038)	-	2,024,038	-100.0%
Transfer to Renewable Energy Reserve	(1,000,000)	-	1,000,000	-100.0%
Transfer to Local Renewable Energy Development Fund	(151,383)	(173,263)	(21,880)	14.5%
TOTAL CAPITAL EXPENDITURES, INTERFUND TRANSFERS & OTHER	(3,391,077)	(229,263)	3,161,814	
Net increase (decrease) in Operating Fund balance	$ 8,820,652	$ 5,650,737	$(3,169,915)	-35.9%

MARIN CLEAN ENERGY
ENERGY EFFICIENCY PROGRAM FUND
Proposed Budget
Fiscal Year 2016/17

	Projected 2016 Results (information only)	Proposed 2017 Budget	Increase (Decrease)
REVENUE AND OTHER SOURCES:			
Public purpose energy efficiency program	$ 1,505,702	$1,220,267	$ (285,435)
EXPENDITURES AND OTHER USES:			
CURRENT EXPENDITURES			
Public purpose energy efficiency program	1,505,702	$1,220,267	(285,435)
Net increase (decrease) in fund balance	$ -	-	-

LOCAL RENEWABLE ENERGY DEVELOPMENT FUND
Proposed Budget
Fiscal Year 2016/17

	Projected 2016 Results (information only)	Proposed 2017 Budget	Increase (Decrease)
REVENUE AND OTHER SOURCES:			
Transfer from Operating Fund	151,383	$ 173,263	$ 21,880
EXPENDITURES AND OTHER USES:			
Capital Outlay	111,115	173,263	62,148
Net increase (decrease) in fund balance	$ 40,268	$ -	

RENEWABLE ENERGY RESERVE FUND
Proposed Budget
Fiscal Year 2016/17

	Projected 2016 Results (information only)	Proposed 2017 Budget	Increase (Decrease)
REVENUE AND OTHER SOURCES:			
Transfer from Operating Fund	$ 1,000,000	$ -	$ (1,000,000)
EXPENDITURES AND OTHER USES:	-		-
Net increase (decrease) in fund balance	$ 1,000,000	$ -	

MAHER ACCOUNTANCY 1101 FIFTH AVENUE • SUITE 200 • SAN RAFAEL, CA 94901

Financial Plumbline

ACCOUNTANTS' COMPILATION REPORT

Management
Sonoma Clean Power

Management is responsible for the accompanying financial statements of Sonoma Clean Power (a California Joint Powers Authority) which comprise the statement of net position as of January 31, 2016, and the related statement of revenues, expenses, and changes in net position, and the statement cash flows for the period then ended in accordance with accounting principles generally accepted in the United States of America. We have performed a compilation engagement in accordance with Statements on Standards for Accounting and Review Services promulgated by the Accounting and Review Services Committee of the AICPA. We did not audit or review the accompanying statements nor were we required to perform any procedures to verify the accuracy or completeness of the information provided by management. Accordingly, we do not express an opinion, conclusion, nor provide any assurance on these financial statements.

Management has elected to omit substantially all of the disclosures required by accounting principles generally accepted in the United States of America. If the omitted disclosures were included in the financial statements, they might influence the user's conclusions about the Authority's financial position, results of operations, and cash flows. Accordingly, the financial statements are not designed for those who are not informed about such matters.

We are not independent with respect to the Authority because we performed certain accounting services that impaired our independence.

Maher Accountancy

San Rafael, CA
February 25, 2016

TEL 415.459.1249
FAX 415.459.5406
WEB www.mahercpa.com

SONOMA CLEAN POWER AUTHORITY

STATEMENT OF NET POSITION
As of January 31, 2016

ASSETS		
Current assets		
Cash and cash equivalents	$	28,004,428
Accounts receivable, net of allowance		15,251,949
Accrued revenue		7,368,043
Prepaid expenses		27,781
Short-term investments		7,000,000
Total current assets		57,652,201
Noncurrent assets		
Capital assets, net of depreciation		201,375
Deposits		894,666
Total noncurrent assets		1,096,041
Total assets		58,748,242
LIABILITIES		
Current liabilities		
Accounts payable		520,376
Accrued cost of electricity		20,231,332
Other accrued liabilities		156,066
User taxes and energy surcharges due to other governments		366,987
Loan payable to Sonoma County Water Agency		237,440
Total current liabilities		21,512,201
Noncurrent liabilities		
Loan payable to Sonoma County Water Agency		1,234,648
Total liabilities		22,746,849
NET POSITION		
Net investment in capital assets		201,375
Unrestricted		35,800,018
Total net position	$	36,001,393

SONOMA CLEAN POWER AUTHORITY

STATEMENT OF REVENUES, EXPENSES AND CHANGES IN NET POSITION
July 1, 2015 through January 31, 2016

OPERATING REVENUES		
Electricity sales, net	$	100,853,126
Evergreen electricity premium		158,170
Total operating revenues		101,011,296
OPERATING EXPENSES		
Cost of electricity		73,808,772
Staff compensation		855,776
Data manager		1,914,080
Service fees - PG&E		605,876
Consultants		435,741
Legal		300,036
Communications		524,766
General and administration		195,283
Total operating expenses		78,640,330
Operating income		22,370,966
NONOPERATING REVENUES (EXPENSES)		
Interest income		919
Interest expense		(27,507)
Total nonoperating revenues (expenses)		(26,588)
CHANGE IN NET POSITION		22,344,378
Net position at beginning of period		13,657,015
Net position at end of period	$	36,001,393

SONOMA CLEAN POWER AUTHORITY

STATEMENT OF CASH FLOWS
July 1, 2015 through January 31, 2016

CASH FLOWS FROM OPERATING ACTIVITIES	
Cash receipts from customers	$ 99,185,261
Return of supplier security deposits	(3,450,000)
Cash payments to purchase electricity	(67,848,046)
Cash payments for staff compensation	(823,556)
Cash payments for contract services	(3,335,225)
Cash payments for communications	(416,996)
Cash payments for general and administration	(221,096)
Net cash provided (used) by operating activities	23,090,342
CASH FLOWS FROM NON-CAPITAL FINANCING ACTIVITIES	
Principal payments on loan	(168,449)
Deposits and collateral paid	(560,200)
Deposits and collateral returned	5,300
Interest expense payments	(31,552)
Net cash provided (used) by non-capital financing activities	(754,901)
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES	
Acquisition of capital assets	(58,338)
CASH FLOWS FROM INVESTING ACTIVITIES	
Purchase of certificate of deposit	(7,000,000)
Interest income received	919
Net cash provided (used) by investing activities	(6,999,081)
Net change in cash and cash equivalents	15,278,022
Cash and cash equivalents at beginning of year	12,726,406
Cash and cash equivalents at end of period	$ 28,004,428

SONOMA CLEAN POWER AUTHORITY

STATEMENT OF CASH FLOWS (continued)
July 1, 2015 through January 31, 2016

RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES

Operating income	$	22,370,966
Adjustments to reconcile operating income to net		
cash provided (used) by operating activities		
Depreciation expense		21,557
(Increase) decrease in net accounts receivable		(3,072,990)
(Increase) decrease in accrued revenue		872,518
(Increase) decrease in prepaid expenses		651,725
Increase (decrease) in accounts payable		(89,117)
Increase (decrease) in accrued cost of electricity		5,376,126
Increase (decrease) in accrued liabilities		452,682
Increase (decrease) in user taxes and energy surcharges due to other governments		(43,125)
Increase (decrease) in supplier security deposits		(3,450,000)
Net cash provided (used) by operating activities	$	23,090,342

Electric Sample Form No. 79-1029
COMMUNITY CHOICE AGGREGATOR (CCA)
SERVICE AGREEMENT

Please Refer to Attached
Sample Form

Pacific Gas and Electric Company

COMMUNITY CHOICE AGGREGATOR (CCA) SERVICE AGREEMENT

This Community Choice Aggregator (CCA) Service Agreement ("Agreement") is made and entered into as of this 15th day of December, 2009, by and between "Marin Energy Authority" ("CCA"), a Joint Powers Authority organized and existing under the laws of the state of California, and Pacific Gas and Electric Company "PG&E", a corporation organized and existing under the laws of the state of California. From time to time, CCA and PG&E shall be individually referred to herein as a "Party" and collectively as the "Parties."

Section 1: General Description of Agreement

1.1 This Agreement is a legally binding contract. The Parties named in this Agreement are bound by the terms set forth herein and otherwise incorporated herein by reference. This Agreement shall govern the business relationship between the Parties hereto by which CCA shall offer electrical energy services. Each Party, by agreeing to undertake specific activities and responsibilities for or on behalf of customers, acknowledges that each Party shall relieve and discharge the other Party of the responsibility for said activities and responsibilities with respect to those customers. Except where explicitly defined herein (including Attachment A hereto) the definitions controlling this Agreement are contained in PG&E's applicable rules or in the relevant community choice aggregation tariff.

1.2 The form of this Agreement has been developed as part of the CPUC regulatory process to implement Assembly Bill 117, was intended to conform to CPUC directions, was filed and approved by the CPUC for use between PG&E and CCAs and may not be waived, altered, amended or modified, except as provided herein or in the applicable community choice aggregation tariff, or as may otherwise be authorized by the CPUC.

1.3 This Agreement incorporates by reference the applicable community choice aggregation tariff as authorized and modified from time to time by the CPUC.

Section 2: Representations

2.1 Each Party represents that it is and shall remain in compliance with all applicable laws and tariffs, including applicable CPUC requirements.

2.2 Each person executing this Agreement for the respective Parties expressly represents and warrants that he or she has authority to bind the entity on whose behalf this Agreement is executed.

2.3 Each Party represents that (a) it has the full power and authority to execute and deliver this Agreement and to perform its terms and conditions; (b) the execution, delivery and performance of this Agreement have been duly authorized by all necessary corporate or other action by such Party; and (c) this agreement constitutes such Party's legal, valid and binding obligation, enforceable against such Party in accordance with its terms.

2.4 Each Party shall (a) exercise all reasonable care, diligence and good faith in the performance of its duties pursuant to this Agreement; and (b) carry out its duties in accordance with applicable recognized professional standards in accordance with the requirements of this Agreement.

Section 3: Term of Service

The term of this Agreement shall commence on the date of execution by both Parties hereto (the "Effective Date") and shall terminate on the earlier of (a) the date CCA informs PG&E that it is no longer operating as a CCA in PG&E's service territory; (b) the earlier termination pursuant to Section 4 hereof; or (c) the effective date of a new CCA Service Agreement between the Parties hereto. Notwithstanding the Effective Date of this Agreement, the CCA acknowledges that it may only offer Community Choice Aggregation Services to customers effective on or after the CPUC-approved date for commencement of such services by CCAs, and only after it has complied with all provisions of this Agreement and PG&E's applicable tariffs.

Section 4: Events of Default and Remedy for Default

4.1 An Event of Default under this Agreement shall include either Party's material breach of any provision of this Agreement, including those incorporated by reference herein, and failure to cure such breach within thirty (30) calendar days after receipt of written notice thereof from the non-defaulting Party; or such other period as may be provided by this Agreement or PG&E's applicable community choice aggregation tariff.

4.2 In the event of such an Event of Default, the non-defaulting Party shall be entitled to exercise any and all remedies (a) available under PG&E's applicable community choice aggregation tariff; and/or (b) provided for by law or in equity to the extent not inconsistent with PG&E's community choice aggregation tariff. In addition, in the event of an Event of Default, this Agreement may be effectively terminated upon Commission authorization.

4.3 Breach by any Party hereto of any provision of PG&E's community choice aggregation tariff, including a breach occurring during Exigent Circumstances as defined in Section T.3 of such tariff, which circumstances also shall include bankruptcy of CCA, shall be governed by applicable provisions contained therein and each Party will retain all rights granted thereunder. A breach of said tariff for which no remedy is specified therein shall be governed by this Agreement as an Event of Default.

Section 5: Billing and Payment

PG&E will bill and the CCA agrees to pay PG&E for all services and products provided by PG&E in accordance with the terms and conditions set forth in PG&E's community choice aggregation tariff, as stated in PG&E's Electric Rule 23 and PG&E's rate schedules. Any services provided by the CCA to PG&E shall be by separate agreement between the Parties and are not a subject of this Agreement.

Section 6: Limitation of Liability

Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorneys' fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred, except as provided for in this Section. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages of any kind whatsoever, whether in contract, tort or strict liability, except in the event of an action covered by the Indemnification provisions of Section 7 of this Agreement or by the indemnification provisions in any Nondisclosure Agreement relating to the disclosure of confidential information to the CCA, in which event this Section 6 shall not be applicable.

Section 7: Indemnification

7.1 To the fullest extent permitted by law, and subject to the limitations set forth in Section 6 of this Agreement, each Party (the "Indemnifying Party") shall indemnify and hold harmless the other Party, and its current and future direct and indirect parent companies, affiliates and their shareholders, officers, directors, employees, agents, servants and assigns (collectively, the "Indemnified Party"), and at the Indemnified Party's option, the Indemnifying Party shall defend the Indemnified Party, from and against any and all claims and/or liabilities for losses, expenses, damage to property, injury to or death of any person, including, but not limited to, the Indemnified Party's employees and its affiliates' employees, subcontractors and subcontractors' employees, or any other liability incurred by the Indemnified Party, including reasonable expenses, legal and otherwise, which shall include reasonable attorneys' fees, caused wholly or in part by any negligent, grossly negligent or willful act or omission by the Indemnifying Party, its officers, directors, employees, agents or assigns arising out of this Agreement, except to the extent caused wholly or in part by any negligent, grossly negligent or willful act or omission of the Indemnified Party.

7.2 If any claim covered by Section 7.1 is brought against the Indemnified Party, then the Indemnifying Party shall be entitled to participate in, and unless in the opinion of counsel for the Indemnified Party a conflict of interest between the Parties may exist with respect to such claim, assume the defense of such claim, with counsel reasonably acceptable to the Indemnified Party. If the Indemnifying Party does not assume the defense of the Indemnified Party, or if a conflict precludes the Indemnifying Party from assuming the defense, then the Indemnifying Party shall reimburse the Indemnified Party on a monthly basis for the Indemnified Party's defense through separate counsel of the Indemnified Party's choice. Even if the Indemnifying Party assumes the defense of the Indemnified Party with acceptable counsel, the Indemnified Party, at its sole option, may participate in the defense, at its own expense, with counsel of its own choice without relieving the Indemnifying Party of any of its obligations hereunder. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages of any kind whatsoever, whether in contract, tort or strict liability.

7.3 The Indemnifying Party's obligation to indemnify under this Section 7 shall survive termination of this Agreement, and shall not be limited in any way by any limitation on the amount or type of damages, compensation or benefits payable by or for the Indemnifying Party under any statutory scheme, including, without limitation, under any Worker's Compensation Acts, Disability Benefit Acts or other Employee Benefit Acts.

<u>Section 8</u>: <u>Assignment and Delegation</u>

8.1 Neither Party to this Agreement shall assign any of its rights or obligations under this Agreement, except with the prior written consent of the other Party, which consent shall not be unreasonably withheld or delayed. No assignment of this Agreement shall relieve the assigning Party of any of its obligations under this Agreement until such obligations have been assumed by the assignee. When duly assigned in accordance with the foregoing, this Agreement shall be binding upon and shall inure to the benefit of the assignee and the assignor shall be relieved of its rights and obligations. Any assignment in violation of this Section 8 shall be void.

8.2 Notwithstanding the provisions of this Section 8, either Party may subcontract its duties under this Agreement to a subcontractor, provided that the subcontracting Party shall remain fully responsible as a principal and not as a guarantor for performance of any subcontracted duties, shall serve as the point of contact between its subcontractor and the other Party, and shall provide the other Party with thirty (30) calendar days' prior written notice of any such subcontracting, which notice shall include such information about the subcontractor as the other Party shall reasonably require. If either Party subcontracts any of its duties hereunder, it shall cause its subcontractors to perform in a manner which is in conformity with that Party's obligations under this Agreement.

Section 9: Independent Contractors

Each Party shall perform its obligations under this Agreement (including any obligations performed by a Party's designees as permitted under Section 8 of this Agreement) as an independent contractor.

Section 10: Entire Agreement

This Agreement consists of, in its entirety, this Community Choice Aggregator Service Agreement and all attachments hereto, all Community Choice Aggregation Service Requests submitted pursuant to this Agreement and PG&E's community choice aggregation tariffs. This Agreement supersedes all other agreements or understandings, written or oral, between the Parties related to the subject matter hereof, with the express exception of any Nondisclosure Agreement relating to the disclosure of confidential information to the CCA. This Agreement may be modified from time to time only by an instrument in writing, signed by both Parties.

Section 11: Nondisclosure

11.1 Notwithstanding anything provided below, prior to receiving any PG&E confidential customer information, CCA agrees to enter into the CCA Non-Disclosure Agreement and be bound by its terms with respect to Confidential Information as defined therein.

Neither Party may disclose any Confidential Information obtained pursuant to this Agreement to any third party, including affiliates of such Party, without the express prior written consent of the other Party. As used herein, the term "Confidential Information" shall include, but not be limited to, all business, financial, and commercial information pertaining to the Parties, customers of either or both Parties, suppliers for either Party, personnel of either Party, any trade secrets, and other information of a similar nature, whether written or in intangible form that is marked proprietary or confidential with the appropriate owner's name. Confidential Information shall not include information known to either Party prior to obtaining the same from the other Party, information in the public domain, or information obtained by a Party from a third party who did not, directly or indirectly, receive the same from the other Party to this Agreement or from a party who was under an obligation of confidentiality to the other Party to this Agreement or information developed by either Party independent of any Confidential Information. The receiving Party shall use the higher of the standard of care that the receiving Party uses to preserve its own confidential information or a reasonable standard of care to prevent unauthorized use or disclosure of such Confidential Information.. Each receiving Party shall, upon termination of this Agreement or at any time upon the request of the disclosing Party, promptly return or destroy all Confidential Information of the disclosing Party then in its possession.

11.2 Notwithstanding the preceding, Confidential Information may be disclosed to any governmental, judicial or regulatory authority requiring such Confidential

Information pursuant to any applicable law, regulation, ruling, or order, provided that: (a) such Confidential Information is submitted under any applicable provision, if any, for confidential treatment by such governmental, judicial or regulatory authority; and (b) prior to such disclosure, the other Party is given prompt notice of the disclosure requirement so that it may take whatever action it deems appropriate, including intervention in any proceeding and the seeking of any injunction to prohibit such disclosure.

Section 12: Enforceability

If any provision of this Agreement or the application thereof, is to any extent held invalid or unenforceable, the remainder of this Agreement and the application thereof, other than those provisions which have been held invalid or unenforceable, shall not be affected and shall continue in full force and effect and shall be enforceable to the fullest extent permitted by law or in equity.

Section 13: Notices

13.1 Except as otherwise provided in this Agreement, any notices under this Agreement shall be in writing and shall be effective upon delivery if delivered by (a) hand; (b) U.S. Mail, first class postage pre-paid, or (c) facsimile, with confirmation of receipt to the Parties as follows:

If the notice is to CCA:

1- Name of Entity: Marin Energy Authority

Contact Name: Dawn Weisz, Interim Director

Business Address: 3501 Civic Center Drive, Room 308
San Rafael, CA 94903

Facsimile: 415-499-7880

2- Greg Stepanicich
Richards, Watson & Gershon
44 Montgomery Street, Suite 3800
San Francisco, CA 94104-4811

If the notice is to PG&E:

Contact Name: JESS BROWN

Business Address: P.O. BOX 770000, M/C N8C SAN FRANCISCO, CA 94177

Facsimile: 415-973-8499

13.2 Each Party shall be entitled to specify as its proper address any other address in the United States upon written notice to the other Party.

13.3 Each Party shall designate on Attachment A the person(s) to be contacted with respect to specific operational matters relating to Community Choice Aggregation service. Each Party shall be entitled to specify any change to such person(s) upon written notice to the other Party.

Section 14: Time of Essence

The Parties expressly agree that time is of the essence for all portions of this Agreement.

Section 15: Dispute Resolution

15.1 The form of this Agreement has been filed with and approved by the CPUC as part of PG&E's applicable tariffs. Except as provided in Section 15.2 and 15.3, any dispute arising between the Parties relating to interpretation of the provisions of this Agreement or to the performance of PG&E's obligations hereunder shall be reduced to writing and referred to the Parties' representatives identified on Attachment A for resolution, with the responding Party filing its written response within thirty (30) business days after receiving the written position of the complaining party. Thereafter, the Parties shall be required to meet and confer within ten (10) business days in a good faith effort to resolve their dispute. Pending such resolution, the Parties shall continue to proceed diligently with the performance of their respective obligations under this Agreement, unless this Agreement has been terminated under Section 4.2. If the Parties fail to reach an agreement within ten (10) additional business days of the last session to meet and confer, the matter shall, upon demand of either Party, be submitted to resolution before the CPUC in accordance with the CPUC's rules, regulations and procedures applicable to resolution of such disputes.

15.2 Except as provided in Section T.3 of PG&E's applicable community choice aggregation tariff (Rule 23), any dispute arising between the Parties relating to interpretation of the provisions of this Agreement or to the performance of the CCA's obligations hereunder shall be reduced to writing and referred to the Parties' representatives identified on Attachment A for resolution, with the responding Party filing its written response within thirty (30) business days after receiving the written position of the complaining party. Thereafter, the Parties shall be required to meet and confer within ten (10) business days in a good faith effort to resolve their dispute. Pending resolution, the Parties shall continue to proceed diligently with the performance of their respective obligations under this Agreement, unless this Agreement has been terminated under Section 4.2. If the Parties fail to reach an agreement within ten (10) additional business days of the last session to meet and confer, the matter shall, upon demand of either Party, be submitted to resolution before the CPUC in accordance with the CPUC's rules, regulations and procedures applicable to resolution of such disputes, as allowed by law or in equity, or the parties may mutually agree to pursue mediation or binding arbitration to resolve such issues.

15.3 Notwithstanding the provisions of Paragraph 15.1 and 15.2 above: (a) all disputes between the Parties relating to the payment by the CCA of any PG&E fees or charges shall be subject to the provisions of PG&E's applicable tariffs governing disputes over customer bills; (b) all disputes between the Parties regarding non-bypassable charges (including Competition Transition Charges, Cost Responsibility Surcharges, and any other nonbypassable charges adopted by the Commission) payable by community choice aggregation customers or the CCA on behalf of such customers shall be subject to the provisions of PG&E's applicable tariffs; and (c) PG&E may pursue available remedies in law or equity for unauthorized electrical use by the CCA in a court of competent jurisdiction.

15.4 If the dispute involves a request for damages, parties understand that the Commission has no authority to award damages. To resolve such issues, the parties may mutually agree to pursue mediation or binding arbitration to resolve such issues, or if no such agreement is reached, to pursue other legal or equitable remedies that are available to the parties.

Section 16: Applicable Law and Venue

This Agreement shall be interpreted, governed by and construed in accordance with the laws of the State of California, and shall exclude any choice of law rules that direct the application of the laws of another jurisdiction, irrespective of the place of execution or of the order in which the signatures of the parties are affixed or of the place or places of performance. Except for matters and disputes with respect to which the CPUC is the initial proper venue for dispute resolution pursuant to applicable law or this Agreement, the federal and state courts located in San Francisco County, California shall constitute the sole proper venue for resolution of any matter or dispute hereunder, and the Parties submit to the exclusive jurisdiction of such courts with respect to such matters and disputes.

Section 17: Force Majeure

Neither Party shall be liable for any delay or failure in the performance of any part of this Agreement (other than obligations to pay money) due to any event of force majeure or other cause beyond its reasonable control, including but not limited to, unusually severe weather, flood, fire, lightning, epidemic, quarantine restriction, war, sabotage, act of a public enemy, earthquake, insurrection, riot, civil disturbance, strike, work stoppage caused by jurisdictional and similar disputes, restraint by court order or public authority, or action or non-action by or inability to obtain authorization or approval from any governmental authority, or any combination of these causes, which by the exercise of due diligence and foresight such Party could not reasonably have been expected to avoid and which by the exercise of due diligence is unable to overcome. It is agreed that upon the Party so affected giving written notice and reasonably full particulars of such force majeure to the other Party within a reasonable time after the cause relied on, then the obligations of the Party, so far as they are affected by the event of force majeure, shall be suspended during the continuation of such inability and circumstance and shall, so far as possible, be remedied with all reasonable dispatch. In the event of force majeure, as described herein, both Parties shall take all reasonable steps to comply with this Agreement and PG&E's applicable tariffs despite occurrence of a force majeure event.

Section 18: Unauthorized Use of Energy (Energy Theft)

18.1 The CCA represents and warrants that for each of its Customers, and at all times during which it provides community choice aggregation services as a Community Choice Aggregator, the CCA shall completely, accurately, and in a timely manner account for each of its Customer's loads. Load data not accounted for in this manner may provide grounds for termination of this Agreement. For verification purposes only, PG&E shall have complete access to the load data provided to the CAISO by the CCA. Such information is to remain confidential, and shall not be disclosed to any unauthorized person other than the CPUC, the California Independent System Operator or other law enforcement or regulatory authority.

18.2 PG&E shall notify the CCA immediately and the CCA shall notify PG&E immediately of any suspected unauthorized energy use. The Parties agree to preserve any evidence of unauthorized energy use. Once unauthorized energy use is suspected, PG&E, in its sole discretion, may take any or all of the actions permitted under PG&E's applicable tariffs.

Section 19: **Not a Joint Venture**

Unless specifically stated in this Agreement to be otherwise, the duties, obligations, and liabilities of the Parties are intended to be several and not joint or collective. Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation, or liability on or with regard to either Party. Each Party shall be liable individually and severally for its own obligations under this Agreement.

Section 20: **Conflicts Between this Agreement and PG&E's Community Choice Aggregation Tariff**

Should a conflict exist or develop between the provisions of this Agreement and PG&E's community choice aggregation tariff, as approved by the CPUC, the provisions of PG&E's community choice aggregation tariff shall prevail.

Section 21: **Amendments or Modifications**

21.1 Except as provided in Section 21.2, no amendment or modification shall be made to this Agreement, in whole or in part, except by an instrument in writing executed by authorized representatives of the Parties, and no amendment or modification shall be made by course of performance, course of dealing or usage of trade.

21.2 This Agreement may be subject to such changes or modifications as the CPUC may from time to time direct or necessitate in the exercise of its jurisdiction, and the Parties may amend the Agreement to conform to changes directed or necessitated by the CPUC. In the event the Parties are unable to agree on the required changes or modifications to this Agreement, their dispute shall be resolved in accordance with the provisions of Section 15 hereof or, in the alternative, CCA may elect to terminate this Agreement upon written notice to PG&E, which shall be effective upon the receipt thereof. PG&E retains the right to unilaterally file with the CPUC, pursuant to the CPUC's rules and regulations, an application for a change in PG&E's rates, charges, classification, service or rules, or any agreement relating thereto.

Section 22: **Audits**

22.1 PG&E shall retain such specific records as may be required to support the accuracy of meter data provided in PG&E's consolidated billings. When the CCA reasonably believes that errors related to metering or billing activity may have occurred, the CCA may request the production of such documents as may be required to verify the accuracy of such metering and consolidated billing. Such documents shall be provided within ten (10) business days of such request. In the event the CCA, upon review of such documents, continues to believe that PG&E's duty to accurately meter and provide consolidated billing for usage has been breached, the CCA may direct that an audit be conducted. The CCA shall designate their own employee representative or their contracted representative to audit PG&E's records.

22.2 Any such audit shall be undertaken by the CCA, or their contracted representative at reasonable times without interference with PG&E's business operations, and in compliance with the PG&E's security procedures. PG&E and the CCA agree to cooperate fully with any such audit.

22.3 Specific records to support the accuracy of meter data provided in the consolidated billings may require examination of billing and metering support documentation maintained by subcontractors. PG&E shall include a similar clause in its agreements with subcontractors reserving the right to designate their own employee representative, or their contracted representative to audit records related to consolidated billing to Community Choice Aggregation Customers.

22.4 The CCA will notify PG&E in writing of any exception taken as a result of an audit. PG&E shall refund the amount of any undisputed exception to the CCA within ten (10) days. If PG&E fails to make such payment, PG&E agrees to pay interest, accruing monthly, at a rate equal to the prime rate plus two percent (2%) of Bank of America NT&SA, San Francisco, or any successor institution, in effect from time to time, but not to exceed the maximum contract rate permitted by the applicable usury laws of the State of California. Interest will be computed from the date of written notification of exceptions to the date PG&E reimburses the CCA for any exception. The cost of such audit shall be paid by the auditing Party; provided, however, that in the event an audit verifies overcharges of five percent (5%) or more, then PG&E shall reimburse the CCA for the cost of the audit.

22.5 This right to audit shall extend for a period of three (3) years following the date of final payment under this Agreement. Each party and each subcontractor shall retain all necessary records and documentation for the entire length of this audit period.

Section 23: Miscellaneous

23.1 Unless otherwise stated in this Agreement: (a) any reference in this Agreement to a section, subsection, attachment or similar term refers to the provisions of this Agreement; (b) a reference to a section includes that section and all its subsections; and (c) the words "include," "includes," and "including" when used in this Agreement shall be deemed in each case to be followed by the words "without limitation." The Parties agree that the normal rule of construction to the effect that any ambiguities are to be resolved against the drafting Party shall not be employed in the interpretation of this Agreement

23.2 The provisions of this Agreement are for the benefit of the Parties and not for any other person or third party beneficiary. The provisions of this Agreement shall not impart rights enforceable by any person, firm or organization other than a Party or a successor or assignee of a Party to this Agreement.

23.3 The descriptive headings of the various sections of this Agreement have been inserted for convenience of reference only and shall in no way define, modify or restrict any of the terms and provisions thereof.

23.4 Any waiver at any time by either Party of its rights with respect to a default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not be deemed a waiver with respect to any other or subsequent default or matter and no waiver shall be considered effective unless in writing.

23.5 Each Party shall be responsible for paying its own attorneys' fees and other costs associated with this Agreement, except as provided in Sections 6 and 7 hereof. If a dispute exists hereunder, the prevailing Party, as determined by the CPUC, or as may otherwise be determined by the dispute resolution procedure contained in Section 15 hereof, if used, or by a court of law, shall be entitled to reasonable attorneys' fees and costs.

23.6 To the extent that the CPUC has a right under then-current law to audit either Party's compliance with this Agreement or other legal or regulatory requirements pertaining to Community Choice Aggregation transactions, that Party shall cooperate with such audits. Nothing in this Section shall be construed as an admission by either Party with respect to the right of the CPUC to conduct such audits or the scope thereof.

23.7 Except as otherwise provided in this Agreement, all rights of termination, cancellation or other remedies in this Agreement are cumulative. Use of any remedy shall not preclude any other remedy in this Agreement.

The Parties have executed this Agreement on the dates indicated below, to be effective upon the later date.

On Behalf of CCA	**On Behalf of PG&E**
By: Dawn Weisz	By: Felecia Lokey
Name: Dawn Weisz	Name: FeleciA Lokey
Title: Interim Director	Title: Senior Director
Date: 12-15-2009	Date: 02-16-2010

ATTACHMENT A

A. <u>Definitions</u>:

<u>Billing Services</u> - The consolidated billing services described in PG&E's community choice aggregation tariff which are provided by PG&E.

<u>Community Choice Aggregation Customer</u> - An end-use customer located within PG&E's service territory who purchases Community Choice Aggregation Services through the CCA.

<u>Community Choice Aggregator (CCA)</u> – An entity that provides electric supply services to Community Choice Aggregation customers within PG&E's service territory. A CCA may also provide certain energy efficiency and conservation programs to its Community Choice Aggregation customers as provided for under PG&E's tariffs.

<u>CCA Charges</u> - Charges for Community Choice Aggregation Services provided by the CCA.

<u>PG&E Charges</u> - Charges (a) for services provided by PG&E; or (b) which are energy-related and which are approved by the CPUC or the Federal Energy Regulatory Commission (including any nonbypassable charges (such as Competition Transition Charges, Cost Responsibility Surcharges, and any other nonbypassable charges adopted by a regulatory body) or Fixed Transition Amount Charges owing to PG&E or its affiliates, as those terms are defined under the California Public Utilities Code). Fixed Transition Amount Charges are also referred to as Trust Transfer Amount (TTA) Charges.

B. <u>Contact Persons (Section 13.3)</u>:

<u>Billing Services</u>

PG&E Contact: CALVIN YEE 415-973-5683

CCA Contact: Dawn Weisz, Interim Director

C. <u>Parties' Representatives (Section 15.1)</u>:

PG&E Representative:

Contact Name CALVIN YEE

Business Address P.O. BOX 770000, SAN FRANCISCO, CA 94177
M/C N8C, 245 MARKET ST., ROOM 871B

CCA Representative: 1- Jamie Tuckey, Project Coordinator

Contact Name 2- Dawn Weisz, Interim Director

Business Address 3501 Civic Center Drive Room 308
San Rafael, CA 94903

3- Greg Stepanicich
Richards, Watson & Gershon
44 Montgomery Street, Suite 3800
San Francisco, CA 94104-4811

marin clean energy

renewable. reliable. affordable.

781 Lincoln Avenue, Suite 320
San Rafael, CA 94901

Important information about your electric account.

marin clean energy
renewable. reliable. affordable.

A SMARTER ROUTE TO RELIABLE, RENEWABLE ENERGY.

This mailer is to notify you that, in accordance with California state law, your electric account(s) will be enrolled with Marin Clean Energy's Light Green 50% renewable energy service in July 2012 unless you choose to opt out.

Marin Clean Energy (MCE), a not-for-profit public agency based in San Rafael, offers a greener choice of electricity from power sources including solar, wind, biogas, biomass, and hydroelectric. MCE purchases electricity for customers and works with PG&E, which delivers your electricity and sends your monthly utility bill just like before.

Choosing Marin Clean Energy supports a healthier environment, new California-built renewable power, local control and local green programs such as energy efficiency and solar rebates.

You now have three choices for your electric service:

- PG&E's 20% renewable energy
- MCE's 50% renewable Light Green energy
- MCE's 100% renewable Deep Green energy

Customers who do not contact MCE will be served with Light Green 50% renewable energy in July, 2012.

For more information, to opt out of MCE Light Green or to sign up for Deep Green please call us at 1-888-632-3674 or visit www.marincleanenergy.com. Please have your PG&E bill handy because your account information will be needed in order to process your request.

We are happy to honor your choice and look forward to continuing to serve Marin County.

Información importante sobre su recibo de electricidad. 1-888-632-3674
Tin quan trọng về hóa đơn điện lực. www.marincleanenergy.com

TERMS AND CONDITIONS OF SERVICE

RATES

MCE electric generation rates are stable and affordable. View our rates at www.marincleanenergy.com/rates or call 1-888-632-3674 for more information. Any changes to MCE rates will be adopted at duly noticed public meetings of the Marin Energy Authority Board of Directors. PG&E will also charge MCE customers a Power Charge Indifference Adjustment (PCIA) and Franchise Fee Surcharge. Please contact PG&E for more information.

BILLING

You will receive a single monthly bill from PG&E which will include all of your electric charges. MCE customers do not pay duplicate charges for electricity. PG&E's charges for transmission, distribution, and public goods programs will still apply at the same rates they would otherwise charge you. MCE charges will appear on your PG&E bill to cover the cost of procuring electricity on your behalf, called generation. PG&E will no longer charge you for generation.

ENROLLMENT

California State Assembly Bill 117, passed and signed into law in 2002, requires that MCE automatically enroll customers. MCE is now the default electricity provider in Marin County. Your electric account(s) will be enrolled with MCE's Light Green 50% renewable energy in July 2012 unless you choose to opt out. You may request to opt out at any time. You may also choose Deep Green 100% renewable energy. To opt out, or to sign up for Deep Green, please call 1-888-632-3674 or visit www.marincleanenergy.com. Please have your PG&E bill handy so that we may process your request.

OPT OUT

You may request to opt out of MCE at any time by calling 1-888-632-3674 or by visiting www.marincleanenergy.com. Please have your PG&E bill handy so that we may process your request. If you do not opt out within 60 days after the start of service with MCE you will be subject to the payment of a one-time $5 (residential) or $25 (commercial) termination fee, will be subject to PG&E's terms and conditions of service, and will not have the option to return to MCE for one year. You will not be charged a termination fee if you opt out before enrollment with MCE or within the first 60 days after your enrollment with MCE, or if you cancel electric service. You will be charged for all electricity procured by MCE on your behalf prior to the cancellation or transfer of electric service to PG&E. Accounts will be transferred to PG&E on the day of the electric account meter read and cannot be transferred during a billing cycle. In order for your opt out request to be processed on your next meter read date, your request must be received 5 business days prior to the meter read date.

FAILURE TO PAY

MCE may transfer your account to PG&E upon 14 calendar days' written notice to you if you fail to pay any portion of the MCE charges on your bill or fail to meet any agreed-upon payment or credit arrangements. If your service is transferred you will be required to pay the termination fee described above.

marin clean energy

renewable. reliable. affordable.

781 Lincoln Avenue, Suite 320
San Rafael, CA 94901

Important information about your electric account.

marin clean energy
renewable. reliable. affordable.

A SMARTER ROUTE TO RELIABLE, RENEWABLE ENERGY.

This mailer is to notify you that, in accordance with California state law, your electric account(s) will be enrolled with Marin Clean Energy's Light Green 50% renewable energy service in July 2012 unless you choose to opt out.

Marin Clean Energy (MCE), a not-for-profit public agency based in San Rafael, offers a greener choice of electricity from power sources including solar, wind, biogas, biomass, and hydroelectric. MCE purchases electricity for customers and works with PG&E, which delivers your electricity and sends your monthly utility bill just like before.

Choosing Marin Clean Energy supports a healthier environment, new California-built renewable power, local control and local green programs such as energy efficiency and solar rebates.

You now have three choices for your electric service:

- PG&E's 20% renewable energy
- MCE's 50% renewable Light Green energy
- MCE's 100% renewable Deep Green energy

Customers who do not contact MCE will be served with Light Green 50% renewable energy in July, 2012.

For more information, to opt out of MCE Light Green or to sign up for Deep Green please call us at 1-888-632-3674 or visit www.marincleanenergy.com. Please have your PG&E bill handy because your account information will be needed in order to process your request.

We are happy to honor your choice and look forward to continuing to serve Marin County.

Información importante sobre su recibo de electricidad. 1-888-632-3674
Tin quan trọng về hóa đơn điện lực. www.marincleanenergy.com

TERMS AND CONDITIONS OF SERVICE

RATES

MCE electric generation rates are stable and affordable. View our rates at www.marincleanenergy.com/rates or call 1-888-632-3674 for more information. Any changes to MCE rates will be adopted at duly noticed public meetings of the Marin Energy Authority Board of Directors. PG&E will also charge MCE customers a Power Charge Indifference Adjustment (PCIA) and Franchise Fee Surcharge. Please contact PG&E for more information.

BILLING

You will receive a single monthly bill from PG&E which will include all of your electric charges. MCE customers do not pay duplicate charges for electricity. PG&E's charges for transmission, distribution, and public goods programs will still apply at the same rates they would otherwise charge you. MCE charges will appear on your PG&E bill to cover the cost of procuring electricity on your behalf, called generation. PG&E will no longer charge you for generation.

ENROLLMENT

California State Assembly Bill 117, passed and signed into law in 2002, requires that MCE automatically enroll customers. MCE is now the default electricity provider in Marin County. Your electric account(s) will be enrolled with MCE's Light Green 50% renewable energy in July 2012 unless you choose to opt out. You may request to opt out at any time. You may also choose Deep Green 100% renewable energy. To opt out, or to sign up for Deep Green, please call 1-888-632-3674 or visit www.marincleanenergy.com. Please have your PG&E bill handy so that we may process your request.

OPT OUT

You may request to opt out of MCE at any time by calling 1-888-632-3674 or by visiting www.marincleanenergy.com. Please have your PG&E bill handy so that we may process your request. If you do not opt out within 60 days after the start of service with MCE you will be subject to the payment of a one-time $5 (residential) or $25 (commercial) termination fee, will be subject to PG&E's terms and conditions of service, and will not have the option to return to MCE for one year. You will not be charged a termination fee if you opt out before enrollment with MCE or within the first 60 days after your enrollment with MCE, or if you cancel electric service. You will be charged for all electricity procured by MCE on your behalf prior to the cancellation or transfer of electric service to PG&E. Accounts will be transferred to PG&E on the day of the electric account meter read and cannot be transferred during a billing cycle. In order for your opt out request to be processed on your next meter read date, your request must be received 5 business days prior to the meter read date.

FAILURE TO PAY

MCE may transfer your account to PG&E upon 14 calendar days' written notice to you if you fail to pay any portion of the MCE charges on your bill or fail to meet any agreed-upon payment or credit arrangements. If your service is transferred you will be required to pay the termination fee described above.