

# Potential Benefits and Risks of Implementing Community Choice Energy

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## City of Berkeley Energy Commission Final Report

**Principal Authors: Scott Murtishaw, Kirsten Schwind, Pepper Yelton, Kay  
Hutchison, Gerry Abrams, and Jane Bergen**

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## Contents

Acknowledgements.....	iii
List of Acronyms.....	iv
List of Figures .....	v
List of Tables.....	vi
Summary of Key Conclusions.....	vii
Executive Summary .....	1
1 Introduction .....	7
2 Background on CCAs and California’s Electricity Market Structure.....	8
2.1 Enabling Statute and Regulatory Decisions .....	8
2.2 CCA Activity in Other California Jurisdictions.....	9
2.3 Summary of the Navigant Business Plan and City Manager Report.....	11
2.4 Structure of California’s Electricity Market.....	12
3 Proposed Criteria for Choosing to Implement CCA.....	13
3.1 Environmental Performance.....	13
3.1.1 Energy Efficiency .....	13
3.1.2 Share of Renewable Energy .....	14
3.1.3 Greenhouse Gas Reduction .....	14
3.2 Rate Parity.....	14
3.3 Financial Risk to the City of Berkeley.....	15
3.4 Local Green Jobs.....	15
3.5 Local Participation.....	15
4 CCA Opportunities to Improve the Environmental Performance of Berkeley’s Electricity .....	16
4.1 Opportunities to Achieve Greater Energy Savings .....	16
4.2 Increasing the Share of Renewable Energy.....	19

4.2.1	Background on Grid Reliability and Renewable Energy Technologies	19
4.2.2	Current Renewable Electricity Requirements and PG&E Performance	23
4.2.3	Local Energy .....	25
4.2.4	CCA Potential to Exceed PG&E's Share of Renewable Electricity .....	26
4.3	Reduction of Greenhouse Gases .....	27
4.3.1	Overview of Cap and Trade and Status of Federal and State Implementation.....	27
4.3.2	Implications of Cap and Trade Programs on Individual GHG Reductions	29
5	Maintaining Rate Parity .....	29
5.1	Background on PG&E's Rates .....	30
5.2	Assessment of Factors Affecting Rate Parity .....	31
5.2.1	Near-Term Costs of Energy and Potential CCA Cost Advantages.....	32
5.2.2	Long-Term Costs of Energy and Potential CCA Cost Advantages .....	35
5.2.3	Long-Term Costs of Natural Gas .....	36
5.2.4	GHG Compliance Costs.....	36
6	Financial Risk to the EBPA and City of Berkeley .....	37
7	Local Green Job Promotion.....	39
8	Conclusions.....	41
9	References.....	43

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## List of Acronyms

CAES	compressed air energy storage
CARB	California Air Resources Board
CCA	Community Choice Aggregation
CEC	California Energy Commission
CHP	combined heat and power
CPUC	California Public Utilities Commission
CEC	California Energy Commission
CRS	cost responsibility surcharge
EBPA	East Bay Power Authority
GHG	greenhouse gas
IOU	investor-owned utility
LSE	load-serving entity
MEA	Marin Energy Authority
MW	megawatt
MWh	megawatt-hour
PG&E	Pacific Gas and Electric Company
POU	publicly-owned utility
PV	photovoltaic
RPS	renewable portfolio standard
SJVPA	San Joaquin Valley Power Authority

## List of Figures

Figure 1. PG&E Expenditures on Energy Efficiency Programs, 2006 to 2008 .....	17
Figure 2. Avoided Energy Consumption Resulting from Recent IOU and POU Energy Efficiency Programs as a Share of Annual Load.....	18
Figure 3. Wind Power Production in the Pacific Northwest .....	21
Figure 4. Comparison of PG&E Load Profile and Altamont Pass Wind Output.....	22
Figure 5. Annual Output of Existing and Expected Renewable Energy Sources Serving PG&E at End of 2009, in Millions of Megawatt-Hours .....	24
Figure 6. PG&E Residential Rates and California Natural Gas Prices for Electricity Generators.....	30
Figure 7. Average Hourly Wholesale Electricity Prices in the PG&E Service Area during the Week of 2/1/2010 .....	32
Figure 8. Estimated Ranges and Median Costs of Energy from Large Scale, New Renewable Energy Projects in the Western U.S. and Canada .....	33
Figure 9. Twenty-Year Levelized Energy Supply Costs of PG&E and SF CCA Portfolios.....	34

## List of Tables

Table 1. Cost of Large-Scale Generation Projects in Service in 2009, \$ per MWh .....	35
Table 2. Cost of Large-Scale Generation Projects in Service in 2018, \$ per MWh .....	36
Table 3. Cost of Large-Scale Generation Projects in Service in 2018 with \$30 per Metric Ton GHG Compliance Cost, \$ per MWh .....	37
Table 4. Direct and Indirect Job Creation from Energy Efficiency and Solar PV Projects .....	40



## Summary of Key Conclusions

- This report was written to inform the Berkeley City Council regarding the decision about whether to form an East Bay Power Authority (EBPA) to implement a Community Choice Aggregation program. The Berkeley Energy Commission suggests that the City Council use the following five criteria to guide its choice about whether to form an EBPA or retain electrical service with Pacific Gas and Electric (PG&E): environmental performance, maintaining relative rate parity, financial risks to the City of Berkeley, local green job promotion, and local participation in setting electricity policy priorities. Below, we provide our evaluation of the risks, challenges and potential benefits of forming an EBPA using these five criteria.
- Environmental performance: It is possible that the EBPA could achieve more energy efficiency than PG&E, but this is uncertain. The EBPA is likely to be able to use a greater share of renewable energy than PG&E. Ultimately, the implementation of a state or federal cap and trade system may impact whether the additional renewable energy reduces overall greenhouse gas emissions.
- Rate parity: Maintaining relative rate parity with a higher share of renewable energy will be challenging. Natural gas prices have fallen sharply from recent highs, reducing the cost of non-renewable energy. In the long run, factors such as renewable technology costs, expiration of federal renewable tax credits, natural gas prices, and greenhouse gas compliance costs will influence the ability to maintain rate parity. While these factors cannot be predicted with great confidence, the EBPA would benefit from a significant financial advantage to the extent that it invests in its own generation resources, particularly if and when renewable tax credits for private developers expire. Before launching an EBPA, the participating cities should explore a variety of supply portfolios using different cost assumptions for the above factors to determine the likelihood of maintaining rate parity while offering a larger share of renewable energy.
- Financial risk: If the EBPA fails to maintain relative rate parity, a large number of customers may opt out, jeopardizing the EBPA's ability to repay any money loaned or guaranteed by the participating cities. According to the EBPA business plan, Berkeley's share of money at risk may range from \$200 thousand to \$3.3 million. The probability of losing this money appears to be quite low. However, the business plan did not account for any loan guarantees that investors may require from the cities before lending the much larger sums of money needed for the EBPA to construct its own generation facilities. It is unknown whether this would be necessary or how much money the cities would need to guarantee.

- Local green jobs: By “local,” we mean jobs created in Berkeley or Oakland. We estimate, with a high degree of uncertainty, that aggressive targets for efficiency and local solar energy could produce approximately 100 to 120 additional local full-time jobs over the next several years. It is unknown how many more jobs this represents compared to retaining service with PG&E.
- Local participation: PG&E’s rates and policy priorities are determined largely by the California Public Utilities Commission. The governing structure of the EBPA will need to be determined by the participating cities, but the EBPA Board is likely to be composed of the mayors and/or city council members of Berkeley and Oakland. Given the more local and directly elected nature of the EBPA Board members, residents and businesses of the EBPA cities should be able to more easily influence EBPA rates and priorities than they can influence PG&E’s rates and priorities.

## Executive Summary

Community choice aggregation (CCA), also known as community choice energy, is a provision of California law that allows cities, counties or joint powers agencies to purchase electricity and other necessary electrical services on behalf of the customers in their territories. CCAs differ from municipal utility districts in that the investor-owned utility (IOU), in this case Pacific Gas and Electric (PG&E), continues to own the electricity distribution infrastructure and to provide electricity transmission, distribution, billing, and related customer services. However, CCAs are able to determine their own energy supply mixes and rate structures.

For several years now, the cities of Berkeley and Oakland have been considering whether to form an East Bay Power Authority (EBPA), which would serve as a CCA for both cities.<sup>1</sup> The Berkeley Energy Commission (Commission) has produced this report to help the Berkeley City Council understand the costs, benefits and risks involved with forming the EBPA. The Commission proposes five criteria for the City Council's consideration, which are described below.

### ***Environmental Performance: Efficiency, Renewables and Greenhouse Gases***

We break “environmental performance” into three related components: energy efficiency, renewable energy development, and greenhouse gas reductions. In theory, EBPA-managed energy efficiency programs could benefit from better knowledge about local conditions and the ability to focus on a more homogenous climate and customer base. However, PG&E already funds several local energy efficiency programs, and the state legislature and the California Public Utilities Commission (CPUC) have authorized large increases in IOU efficiency spending in recent years and to meet extremely ambitious goals they have set for the state's utilities. Nonetheless, the EBPA may achieve more energy efficiency savings than PG&E, but estimating the likelihood of this occurring or the magnitude of additional savings is difficult to determine.

The EBPA could also include a larger share of renewable energy in its portfolio than PG&E, but because the California Air Resources Board (CARB) is in the process of finalizing a 33% minimum renewable electricity standard for all utilities, the incremental difference will be less than under the existing 20% requirement. Two factors may render higher renewable targets more difficult in the future: competition for the locations with better, lower-cost renewable resources and the

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<sup>1</sup> The business plan prepared by Navigant Consulting analyzed the costs, benefits and risks of a CCA comprised of Berkeley, Emeryville and Oakland. Emeryville has decided not to participate, and Oakland's participation is not certain. However, we use the model of an EBPA for this report because it is the assumption the Navigant analysis is based on. If Oakland decides not to form an EBPA with Berkeley, Berkeley might be able join the CCA of a non-adjacent jurisdiction such as Marin County or San Francisco by paying an entry fee to compensate them for implementation costs incurred prior to Berkeley's accession.

grid's total capacity to handle additional renewable generation. The renewable energy sources capable of providing large amounts of new energy in the near-term (wind and solar) are intermittent, and the supply and demand of electricity must be balanced in real-time to maintain grid stability. Over the next ten to twenty years, California's electrical grid will need to undergo a substantial shift in order to handle larger volumes of renewable energy, both in terms of new transmission lines to major renewable resources, and the technology to balance more intermittent generation.

Another significant factor that may affect a CCA's environmental performance compared to PG&E is whether a greenhouse gas (GHG) cap and trade program is implemented at either the state or federal level. Under cap and trade programs, GHG reductions are achieved collectively rather than individually. In other words, by issuing a fixed and declining number of pollution allowances from year to year, the government ensures reductions occur even though it is not possible to know exactly where or how they will occur. Thus, total GHGs would not be reduced by the EBPA under cap and trade unless a "set-aside" of allowances is created by which the government pulls allowances out of circulation (thereby reducing the allowable pollution levels) on behalf of entities that "overcomply" with the cap and trade by, for example, using voluntary renewable energy that is above any mandated levels. Currently, CARB is in the process of developing a cap and trade program, with an expected launch in 2012, and CARB is considering a set-aside mechanism in the design of the program. None of the federal cap and trade bills proposed over the past several years have included a voluntary renewable set-aside.

The EBPA's actions would also contribute to emission reduction if either the state or federal governments does not enact cap and trade programs in the foreseeable future. This is a distinct possibility in California's current political climate. A proposition that has qualified for the November ballot would delay implementation of California's program indefinitely if it passes. Additionally, one of the candidates for the Governor's office, Megan Whitman, has made a campaign promise to roll back the CARB cap and trade program. At the federal level, the U.S. House of Representatives passed a cap and trade bill in 2009, but passage by the Senate is highly uncertain.

### ***Rate Parity***

The ability of a CCA to maintain rate parity is governed by a number of factors, chief of which are the sources of energy used to supply customers with electricity. Offering multiple products allows a CCA to meet different goals, depending on what customers want. A tiered approach that allows CCA customers to choose a rate parity product or a higher percentage renewable product could help the EBPA maintain rate parity. In this approach, customers would be enrolled in a "medium-green" program by default but would be allowed to opt for either a "light green/rate parity" product or a "deep green" 100% renewable product.

Because renewable energy sources tend to be more expensive than other sources of generation, maintaining rate parity will be challenging if a key goal of the CCA program is to ensure that EBPA customers receive a larger share of renewable energy than PG&E customers. In the near term, the EBPA will have to buy most of its power from the wholesale market. Natural gas prices have fallen sharply from their recent highs, and the U.S. Energy Information Administration does not project significant increases until after 2020. This means that prices of generic wholesale power have also fallen, which increases the price gap between renewable energy and conventional energy. By foregoing the relatively low prices of generic power in favor of renewables, the EBPA will find it more difficult to maintain rate parity.

In the longer term, there are four primary factors that influence the ability of the EBPA to maintain rate parity while offering more renewable energy: 1) the capital costs of renewable energy technologies, 2) the cost advantages a CCA may have when financing generation facilities compared to PG&E or independent developers, 3) the cost of natural gas, and 4) the cost of GHG compliance (whether due to cap and trade or a carbon tax). The future path of these factors is difficult to predict. As renewable energy technologies improve, their costs should continue to fall relative to conventional energy sources, but it is uncertain how far and how fast those costs will fall. To incorporate more renewable energy while maintaining rate parity, the EBPA would need to build its own generation facilities at lower cost than PG&E or independent power producers. Normally, public agencies have a significant advantage when financing electricity generation facilities, but federal renewable tax credits have leveled the playing field between public and private financing for many renewable technologies. Most of the renewable tax credits are set to expire at the end of 2012 or 2013. If Congress fails to reauthorize them, the EBPA may then have a financial advantage compared to private developers of renewable energy.

Because gas-fired power provides the vast majority of generic power available in wholesale power markets in the western U.S. and Canada, whatever share of the EBPA's portfolio is not composed of renewable energy owned by or under contract to the EBPA will be composed almost entirely of gas-fired power. PG&E's portfolio consisted of approximately 47% gas-fired power in 2009. If that share remains fairly constant over the next several years, the EBPA will be more exposed to the risks of volatility and sustained increases in the price of natural gas until its portfolio consists of 50% or more renewable energy. PG&E is largely unexposed to the risk of high GHG compliance costs because nuclear energy, hydropower and, increasingly, other renewable energy sources, none of which emit GHGs when they generate, comprise a large share of PG&E's energy mix. Because the EBPA will have to rely on gas-fired power for most of its power needs, the EBPA's GHG compliance costs exposure is similar to its gas price exposure. Likewise, the EBPA would have to generate 50% or more of its energy from renewable sources to reduce its GHG compliance cost exposure to the level of PG&E's. GHG compliance costs would add

to the EBPA's difficulty in maintaining rate parity until the EBPA can build or procure a large proportion of renewable energy.<sup>2</sup>

### ***Financial Risk to the City of Berkeley***

It is important for the City Council to consider that there is some risk associated with forming a CCA. Financial risk to the participating cities arises if the CCA dissolves and if there are any funds spent by the cities to implement the EBPA or any loans provided by the cities to the EBPA that have not yet been repaid.

If the EBPA is unable to maintain rates at or near PG&E's rates, increasing numbers of customers may opt out of EBPA service and return to PG&E. Customer attrition could theoretically result in a downward spiral in which higher cost resources built or under long-term contract to the EBPA are spread over an increasingly smaller number of customers until the EBPA is forced to dissolve.

In the memo to the Berkeley Energy Commission recommending that Berkeley not pursue CCA implementation, Berkeley staff estimated that the financial risk to Berkeley ranges from \$200 thousand to approximately \$3.3 million. This risk stems from Berkeley's share of pre-implementation expenditures and start-up costs. In the EBPA business plan, the Navigant consultants' report estimates that the start-up costs could be recovered through rates within five years. As long as the EBPA retains most of its customers in the first five years, start-up cost exposure to the cities would be minimal.

Of greater concern are the much larger financial commitments the EBPA would make to construct its own electricity generation facilities. While establishing a financial firewall between the EBPA and the city is possible, it is not clear that creditors will be willing to lend the large sums of money needed to develop generating facilities knowing that the EBPA's customer base is not absolutely secure. Bond markets may react by either requiring a higher rate of interest than a traditional publicly-owned utility would enjoy, because their customers cannot opt out, or by requiring the member cities to guarantee the debt. If the EBPA constructs its own generation facilities, the facilities themselves are significant sources of collateral. Thus, the cities might not have to guarantee the entire value of the bonds but only the difference between the resale value of the asset and the outstanding debt. If the cities agree to such an arrangement, they may only have to guarantee a fraction of the total bond value, but the Commission does not have enough information to estimate how large a guarantee would be required.

### ***Local Green Jobs***

For purposes of this report, we define "local" jobs as jobs created in the cities of Berkeley or Oakland. Most of the increase in local jobs would happen as a result of

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<sup>2</sup> Hedging strategies could help protect the EBPA from volatility but would be less effective at shielding it from a sustained rise in gas prices or GHG costs.

increased expenditures on energy efficiency and local solar photovoltaic panels in the participating cities.

Determining the effect of implementing the EBPA on local job creation is challenging because it is difficult to estimate how many additional local jobs a CCA would create above those that already exist and will exist in the future due to PG&E practices and operations. Another consideration is that while the jobs created will be performed in the EBPA cities, they will not necessarily result in employment of EBPA residents unless the EBPA includes local hire requirements or preferences in its solicitations for efficiency and solar panel installation services. Such requirements necessarily limit the number of firms that compete to offer these services and may therefore increase costs to the EBPA.

To estimate a plausible scenario for local energy investments the EBPA may make, we used the resource portfolio proposed in San Francisco's CCA Draft Implementation Plan and reduced it by half to account for the EBPA's smaller load. San Francisco aims to achieve 107 megawatts (MW) of energy efficiency and 31 MW of in-city solar capacity by 2017; therefore, we used 53.5 MW of energy efficiency and 15.5 MW of solar capacity. Using published values of direct jobs created per megawatt of efficiency and solar capacity, we estimate that the EBPA's investments in these resources would create roughly 100 to 120 full-time jobs. In order to determine the incremental number of local jobs resulting from the CCA investments, the number of jobs added under business-as-usual PG&E service should be subtracted from the estimate above. Since this number would depend on very rough estimates, the 100 to 120 range can be considered an upper estimate.

### ***Local Participation***

A final consideration is the potential for CCA to increase local participation in decision-making related to electricity rates, resources and priorities. This criterion was included to reflect both the civic value of participation per se as well as the greater influence that Berkeley residents may have on other decisions such as rate design and energy efficiency program priorities.<sup>3</sup>

PG&E's rates and policy priorities are determined largely by the CPUC, whose members are appointed by the Governor and confirmed by the state Senate. The governing structure of the EBPA will need to be determined by the participating cities, but the EBPA Board is likely to be composed of the mayors and/or city council members of Berkeley and Oakland. Given the more local and directly elected nature of the EBPA Board members, residents and businesses of the EBPA cities should be able to more easily influence EBPA rates and policies than they can influence PG&E's rates and policies by participating in the CPUC's regulatory processes.

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<sup>3</sup> To the extent that Berkeley residents desire superior environmental performance, rates comparable to PG&E's, and local job creation those values are captured by the previous listed criteria.

## ***Conclusions***

Numerous factors govern the costs of generating electricity from renewable and non-renewable resources. These factors, such as natural gas prices, the cost of renewable energy technologies, the extension of federal renewable energy tax credits and possible future GHG compliance costs are impossible to predict with much certainty. Given current natural gas prices and renewable energy costs, it will be challenging for a CCA to quickly achieve the ambitious renewable energy goals envisioned in the EBPA business plan while maintaining rates comparable to PG&E's rates.

Before committing to the formation of a CCA, Berkeley and Oakland should perform an analysis of the long term performance of the CCA based on the cost of a variety of energy supply scenarios using different assumptions for the factors listed above. A realistic evaluation of the likelihood of meeting ambitious renewable energy goals while maintaining rate parity is essential. Based on this analysis, the EBPA should set renewable portfolio goals that seem achievable.

Over the long run, the financial advantages that the EBPA may enjoy as a public agency imply that the EBPA will likely be able to offer electricity, even with a higher share of renewable energy, at or below PG&E's rates. However, it will be critical for the EBPA to retain its customers during the first several years of its existence, a period during which renewable energy is likely to cost much more than prevailing market prices of electricity.

A final factor that would favor forming a CCA is that it could allow Berkeley to remain committed to its environmental goals despite any backsliding at the state or federal level. The state legislature and state agencies have committed to an array of ambitious environmental goals in the electricity sector. These policies and programs reduce the scope for additional improvements to environmental performance in providing electric service. For example, if the minimum renewable energy requirement rises to 33%, then the EBPA would have only 17% more renewable energy than PG&E in its portfolio rather than 30% more if the requirement remains at 20%. But state policies and programs are subject to change. Ballot measures or a change in administration could prevent the implementation of state-level policies currently underway. By forming or joining a CCA, Berkeley can help to ensure that its environmental goals are met, regardless of what occurs at the state or federal level.

Overall, CCA formation offers the potential to reduce environmental impact, increase public involvement in energy policy, and produce local green jobs. However, it is a difficult undertaking, requiring a large effort and entailing some risk. The City Council should evaluate whether the benefits outweigh the amount of effort needed. The progress of the CCAs in Marin and San Francisco over the next few years will help to shed light on this question.



# 1 Introduction

Community choice aggregation (CCA), also known as community choice energy, is a provision of California law that allows cities, counties or joint powers agencies to purchase electricity and other necessary electrical services on behalf of the customers in their territories. CCAs are able to determine their own energy supply mixes and rate structures. CCAs differ from municipal utility districts because the investor-owned utility (IOU), in this case Pacific Gas and Electric (PG&E), continues to own the electricity distribution infrastructure and to provide electricity transmission, distribution, billing, and related customer services.

The City of Berkeley, in conjunction with the cities of Oakland and Emeryville, has been considering whether to implement a CCA for several years.<sup>4</sup> This is an important issue for the City Council because it would affect every resident and business in Berkeley. While a CCA could create significant community benefits, it also entails a start-up investment of staff time, money and resources. The Berkeley Energy Commission (Commission) offers this report to the City Council in order to inform the Council's decision on this issue.

Four central motives for creating an East Bay Power Authority (EBPA) to act as a CCA have emerged from the Commission's internal deliberations and the public comments we have received. One of the main motives cited is the opportunity for CCA to reduce the environmental impact of consuming electricity. Berkeley's Measure G, which passed in 2006 with 81% of the vote, commits Berkeley to a goal of reducing greenhouse gases (GHGs) by 80% by 2050. As part of its Climate Action Plan, the City developed an interim target of a 33% reduction below 2000 levels by 2020 (City of Berkeley, 2009). The Climate Action Plan identifies CCA as one policy mechanism that may help reach this goal by increasing access to renewable energy and energy efficiency services beyond the level offered by PG&E, thereby reducing the GHG emissions of Berkeley's energy portfolio.

The second motive for implementing CCA is to offer electricity at rates equal to, if not below, PG&E's while achieving better environmental performance. Both the San Francisco and Marin County CCA efforts include rate parity with PG&E as a goal. Because Marin Clean Energy was the only operational CCA at the time this report was finalized, and it had just begun delivering electricity to customers, we do not yet have much evidence of how easily rate parity can be achieved. There may be significant challenges to meeting this goal, which are discussed in Section 5 of this report.

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<sup>4</sup> The business plan prepared by Navigant Consulting analyzed the costs, benefits and risks of a CCA comprised of Berkeley, Emeryville and Oakland. Emeryville has decided not to participate, and Oakland's participation is not certain. However, we use the model of an EBPA for this report because it is the assumption the Navigant analysis is based on. If Oakland also decides not to form an EBPA with Berkeley, Berkeley might be able join the CCA of a non-adjacent jurisdiction such as Marin County or San Francisco by paying an entry fee to compensate them for implementation costs incurred prior to Berkeley's accession.

A third motive is the potential to generate local green jobs. This may occur if the EBPA directs more ratepayer funds to energy efficiency measures or distributed generation within the EBPA cities than PG&E would.<sup>5</sup> It is important to note that implementing CCA does not significantly affect jobs that already exist within PG&E, as the utility continues to provide the labor-intensive services of maintaining transmission and distribution infrastructure and other services.

Finally, implementing a CCA may allow EBPA customers to have more influence in the decisions related to their electricity service such as the energy mix and rate structure. Both Berkeley and Oakland have passed ordinances committing to climate action goals that are stronger than those passed at the state level. With a CCA, Berkeley would have significantly more control over the energy mix used by its residents.

## **2 Background on CCAs and California's Electricity Market Structure**

### **2.1 Enabling Statute and Regulatory Decisions**

The statute that enables local governments to form community choice energy programs was passed by the legislature as AB 117 in 2002.<sup>6</sup> This statute allows a local government or group of local governments "to combine the loads of its residents, businesses, and municipal facilities, in a community-wide electricity buyers' program." In order to form a CCA, the bill requires jurisdictions to submit an implementation plan to the California Public Utilities Commission (CPUC) that provides information on the proposed CCA's organizational structure, rate setting procedures, and a description of the financial and technical capabilities of any third parties that will supply power to the CCA.

AB 117 further stipulates that the CPUC shall ensure that no costs are shifted to the remaining customers of the incumbent utility as a result of the CCA customers' departure from the load served by the utility. Examples of such "stranded" costs include expenses related to the electricity crisis of 2001 (primarily the bond payments and energy expenditures of the Department of Water Resources for contracts negotiated during the crisis on behalf of the IOUs) and other contracts previously negotiated by the incumbent utility on behalf of the departing customers.

The CPUC has established the methodology for determining how stranded costs will be calculated (CPUC, 2005). This CPUC decision instituted a Cost Responsibility Surcharge (CRS) that CCAs must pay to incumbent utilities until stranded costs are paid off. The CRS potentially affects the cost-competitiveness of CCAs because a high CRS must be recovered in the CCA's rates. However, Navigant estimates that

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<sup>5</sup> Distributed generation refers to electric generation resources either located on a customer site (such as a residential solar photovoltaic system) or connected at distribution voltage.

<sup>6</sup> California Public Utilities Code § 331.1(a)

the CRS is among the least significant factors affecting CCA rate parity (Navigant, 2008, p. 83).

## **2.2 CCA Activity in Other California Jurisdictions**

### **SAN JOAQUIN VALLEY POWER AUTHORITY**

In 2007, the San Joaquin Valley Power Authority (SJVPA) became the first jurisdiction to submit a CCA Implementation Plan to the CPUC. The SJVPA consists of the unincorporated areas of Kings County and the municipalities of Clovis, Corcoran, Dinuba, Kerman, Kingsburg, Lemoore, Hanford, Parlier, Reedley, Selma, and Sanger. However, the SJVPA Board of Directors voted to temporarily suspend implementation activities in June 2009. The reasons given for suspending the program were: (1) tightness in the credit market and the volatility of energy prices; (2) concerns about uncertainty with California's energy regulations including the possibility that the state would increase utilities' minimum renewable energy requirements from 20% to 33%; and (3) the need to contract for additional energy to meet resource adequacy requirements (Community Choice, 2009).<sup>7</sup> In addition, in a June 2009 response to the CPUC in connection with the CPUC's consideration of San Francisco's community choice program, SJVPA declared that "based largely on PG&E's unending assaults, SJVPA's Board of Directors suspended the implementation of SJVPA's CCA program" (SJVPA, 2010).

### **MARIN CLEAN ENERGY**

The Marin Energy Authority (MEA) is the not-for-profit public agency that was created in December 2008 to implement the Marin Clean Energy CCA program. The members of the Marin Clean Energy service territory are Belvedere, Fairfax, Mill Valley, San Anselmo, San Rafael, Sausalito, Tiburon, and the unincorporated areas of Marin County. As stated in the MEA's mission statement:

It is the intent of the MEA to promote the development and use of a wide range of renewable energy sources and energy efficiency programs, including but not limited to solar and wind energy production at competitive rates for customers (MEA, 2009).

On February 4, 2010, the MEA board unanimously approved a five-year contract with Shell Energy North America to supply it with electricity. MEA states that it will offer 25% renewable energy for the same price that PG&E is charging, and, for an additional 7% charge, residential customers will be able to buy electricity generated from 100% renewable sources (MEA, 2010a). MEA began deliveries to its first customers on May 7, 2010. The content of Marin Clean Energy's electricity portfolio

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<sup>7</sup> The resource adequacy program requires all electricity providers to have enough generating capacity owned or under contract to meet their peak energy demands.

is outlined in its April 21, 2010 press release:

...Marin Clean Energy will get 9 percent of its power content from landfill gas in Oregon, 8 percent from wind in Washington and another 5 percent from biomass, also from Washington. Another 9 percent will come from a variety of smaller energy sources that are either certified renewable or eligible for certification. The remainder of power will come from the state power system. Marin Clean Energy's renewable energy mix also includes 3 percent renewable energy credits backed by a solar project operated by the South San Joaquin Irrigation District (MEA, 2010b).

#### SAN FRANCISCO - CLEANPOWERSF

In 2007, San Francisco adopted a CCA program, known as CleanPowerSF. The program's goal is to provide electric energy to San Franciscans that is significantly greener than what PG&E currently delivers, at competitive rates. To achieve this, CleanPowerSF intends to use voter-approved bonds to finance a substantial increase in solar, wind and other renewable energy resources in and outside the city. CleanPowerSF has a goal of supplying at least half of its power from renewable resources and energy efficiency within ten years of commencing operations (CleanPowerSF, 2010).

On November 5, 2009, the San Francisco Public Utilities Commission released its Request for Proposals for Electrical Supply Services. The Request states the following energy targets: (1) 51% of electric energy should be from renewable sources by 2017; (2) 40% of energy needs should be met from a combination of local and renewable sources by 2012; and (3) rates must be competitive with PG&E (SFPUC, 2009). San Francisco spent several months negotiating a contract with its first choice bidder, Power Choice LLC, to provide the electricity supply services. However, the *San Francisco Chronicle* reported that negotiations between the two parties have "collapsed" and that San Francisco will look for a new partner to help run their CCA. The *Chronicle* reported that San Francisco would not accept a request by Power Choice to secure the loans needed to start up the program (Baker, 2010).

San Francisco is actively addressing efforts by PG&E to thwart implementation of its CCA. On January 11, 2010, the City and County of San Francisco petitioned the CPUC to modify the Commission's December 2005 decision implementing CCA for the following reason:

This petition is necessary because one of the Decision's key assumptions – that the utilities were neutral (or even supportive) toward community choice aggregation ("CCA") programs – is no longer true, as evidenced by the very public reversal by at least one utility, Pacific Gas & Electric ("PG&E"),

from a stance of support to staunch opposition to CCA programs.” (City and County of San Francisco, 2010, p. 1)

In its petition before the CPUC, San Francisco specifically calls for the Commission to “prohibit the utilities from engaging in any conduct that is designed to impede or frustrate the investigation, pursuit, or implementation of a CCA program or programs” (City and County of San Francisco, 2010, p. 11). On May 3, 2010, the Executive Director of the CPUC sent a letter to PG&E declaring that its attempts to interfere with CCA implementation activities violate state law and CPUC orders. The letter directs PG&E to cease its efforts to solicit opt outs from Marin’s CCA and to comply with other various provisions of AB 117 and CPUC regulations (Clanon, 2010).

### PROPOSITION 16

On June 8, 2010 California voters rejected Proposition 16, in which PG&E attempted to impose a two-thirds vote requirement on communities trying to implement CCA or expand a publicly-owned utility (POU). PG&E spent approximately \$46 million on this effort to change the state constitution to erect barriers to implementation of CCA. It is significant that most Bay Area counties rejected Proposition 16 by more than a 60% majority.

## **2.3 Summary of the Navigant Business Plan and City Manager Report**

In September, 2008, Navigant Consulting released its final proposed business plan for the EBPA (Navigant, 2008). The business plan proposed that:

- The Authority could gradually increase its renewable energy procurement until it procures at least one half of its electric supply from renewable resources, such as wind, solar, geothermal and biomass within seven years.
- The Authority could promote additional energy efficiency and energy conservation efforts within its jurisdiction, as envisioned by AB 117.
- The business plan anticipated rates 3% higher than PG&E’s for the first four years of EBPA operation, followed by comparable rates in the future, with an estimated range of 10% lower to 6% higher.
- Through implementation of the proposed CCA, the cities would cause a reduction in greenhouse gas emissions of approximately 325,000 metric tons per year within seven years, as the renewable resources procured and developed by the Authority would displace production from natural gas

fueled power plants.<sup>8</sup>

The Secretary of the Berkeley Energy Commission delivered a joint City Managers' response at the October 2008 meeting of the Commission. In the report, staff recommended that the City of Berkeley not move forward with implementing the EBPA. Several reasons were cited, including:

- the CCA may not be able to maintain rate parity with PG&E, with a risk that rates may be as much as 6% higher;
- the city could be liable for start up expenses ranging from \$0.2 million to nearly \$3.3 million for which cost recovery could not be guaranteed;
- the regulations governing CCAs are uncertain and potentially expensive; and
- the environmental benefits of the program would be diminished if the state increased the renewable energy requirement for all utilities from 20% to 33% (DeSnoo, 2008).

In response, the Commission decided to form a CCA subcommittee to discuss the staff report and provide the Commission with a recommendation on whether to approve the report. At the December 2008 meeting of the Commission, the subcommittee reported back that it was premature to reject CCA and that in light of CCA activity in other jurisdictions, the issue warranted further consideration (BEC, 2008).

## **2.4 Structure of California's Electricity Market**

In discussing the merits of CCA relative to continuing service with PG&E, it is important to keep in mind the implications of the restructuring of California's electricity sector that occurred in 1996 under AB 1890. The restructuring of the IOUs created a competitive market for the wholesale generation of electricity. PG&E and the other large IOUs were incentivized to sell the majority of their generation assets, particularly those facilities (generally fossil-fired) that determine prices in a competitive market.<sup>9</sup> Under utility restructuring, California's IOUs play two main roles: 1) building and maintaining the transmission and distribution infrastructure in their service territories and 2) buying electricity from other utilities or independent ("merchant") power producers in wholesale markets on behalf of their customers.

PG&E's profit is set at a fixed rate of return based on its investments in transmission and distribution infrastructure. Thus, PG&E does not earn a profit on the sale of

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<sup>8</sup> This estimate assumes that the statewide renewable energy requirement remains at 20%.

<sup>9</sup> Because nuclear and hydro facilities have physical constraints to their dispatch and because they have very low operating costs, the IOUs were not incentivized to sell their hydro and nuclear facilities.

electricity. PG&E purchases power from the wholesale market on behalf of its customers and these costs are passed through to customers. The costs of operating and maintaining the transmission and distribution system are determined separately, and this portion of customers' bills is not affected by changes in the wholesale price of power. Whether a customer is served by PG&E or a CCA, PG&E will make virtually the same profit for its shareholders.

Because PG&E's profits do not depend on the volume of electricity sold, PG&E and the other California IOUs do not face a disincentive to implementing energy efficiency programs. This has been the case in California even before the restructuring of 1996 because California was a pioneer in a type of utility rate reform known as "decoupling," so called because profits are decoupled from sales. This approach to utility rate setting guarantees the utility a fixed rate of return on its capital assets while treating other costs (such as fuel costs or power purchased from other generators) as pass-through costs on which the utility does not earn a profit. If the utility sells more electricity in one period than was projected, excess revenues are returned to ratepayers in the following period. California first implemented decoupling in 1981 (NARUC, 2007).

### **3 Proposed Criteria for Choosing to Implement CCA**

The City Council should articulate a set of criteria to evaluate whether forming a CCA is preferable to continuing service with PG&E. The Commission recommends the following five criteria for the Council's consideration: environmental performance, maintaining relative rate parity, financial risks to the City of Berkeley, promoting local green jobs, and local participation in setting electricity policy priorities. The criteria are largely drawn from the motives described in Section 1. Financial risk is an additional criterion that represents the extent to which forming or joining a CCA may entail financial risks to the City of Berkeley. Below, we provide a brief description of each criterion. Each criterion, with the exception of "local participation," receives a more thorough analysis in a subsequent section.

#### **3.1 Environmental Performance**

One of the goals most often cited by proponents of CCA is the opportunity to reduce the environmental impact of providing electrical service. We break down this criterion into three of its most salient components: energy efficiency, renewable energy, and GHG reduction.

##### **3.1.1 Energy Efficiency**

A CCA has the potential to increase energy efficiency within its service area, but doing so may be difficult. In the wake of utility restructuring in the late 1990s, energy efficiency spending by California's IOUs fell sharply. In the past few years, the IOUs, under direction of the state legislature and the CPUC, have more than doubled annual spending on energy efficiency programs (Martinez, Wang and Chou,

2010). Efficiency program spending may continue to grow as the CPUC has a stated goal of achieving all cost-effective energy efficiency. However, a CCA could potentially spend more per customer on energy efficiency programs, or spend comparable amounts more effectively.

### **3.1.2 Share of Renewable Energy**

This subcriterion concerns whether the EBPA can deliver a higher share of renewable energy than PG&E. PG&E is currently required by statute to use a minimum of 20% renewable energy in its power mix. The California Air Resources Board (CARB) is developing a regulation that would require all California load-serving entities (LSEs) to use a minimum of 33% renewable energy by 2020.<sup>10</sup> Section 4.2 explores the possible advantages that a CCA might have in providing a greater share of renewable energy to its customers compared to PG&E.

### **3.1.3 Greenhouse Gas Reduction**

A final metric of environmental performance that is important to Berkeley's residents is the reduction of GHG emissions. While Measure G commits Berkeley to a long-term goal of reducing GHGs by 80% by 2050, the City developed an interim target of 33% reductions below 2000 levels by 2020 as part of its Climate Action Plan (City of Berkeley, 2009).

The City's ability to influence total emissions could be greatly affected by the implementation of cap and trade systems at the state or federal level. This is due to a fundamental characteristic of cap and trade systems, that under cap and trade the allowable level of pollution is decided in advance. This allowable level acts as both a ceiling (pollution levels may not exceed the limit) and a floor (emission reductions by one entity free up allowances that may be used elsewhere by another regulated source). Further discussion of cap and trade and options to structure cap and trade programs to facilitate emission reductions beyond the level of the cap in recognition of voluntary actions is provided below in Section 4.3.

## **3.2 Rate Parity**

One important criterion that the City Council should consider is whether a CCA will be able to maintain comparable rates but with a higher share of renewable energy in the portfolio. It is vital that the CCA maintain relative rate parity with PG&E because if the CCA's rates significantly exceed PG&E's, many customers, particularly business customers, may choose to opt-out of CCA service.

There is a natural tension between this criterion and the desire to increase the share of renewable energy. The cost of renewable energy is generally higher than the cost of fossil-fired electricity with today's technologies, government incentives and lack

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<sup>10</sup> "Load serving entity" refers to any retail electricity supplier: investor-owned utilities, publicly-owned utilities, CCAs, and direct access electric service providers.



of a price on GHG pollution. The greater the share of renewable energy in the portfolio, the harder it will be to maintain parity with PG&E's rates. If a CCA benefits from advantages in financing the construction of generation assets, the lower financing costs may help to offset any higher costs from offering a larger proportion of renewable energy. These factors are analyzed in detail in Section 5. Additionally, if the CCA can outperform PG&E's energy efficiency programs, it may be possible to provide matching, or slightly higher rates, but charge lower bills than PG&E because EBPA customers would consume less energy than under PG&E service.

### **3.3 Financial Risk to the City of Berkeley**

While the other criteria reflect desired outcomes from implementing CCA, this criterion reflects the potential risks. These risks are related to various forms of start-up costs and long-term financial obligations that may not be fully recovered by the city if the CCA fails to retain a large and stable customer base. Financial risks are described in more detail in Section 6.

### **3.4 Local Green Jobs**

A CCA may choose to spend its revenues in ways that promote more local employment. We define "local" in this context to mean jobs created within the territory of the EBPA. Note that investment in additional renewable energy or energy efficiency would need to be deliberately structured to lead to higher local employment. A discussion of the opportunities for a CCA to increase local green jobs and an estimate of the number of jobs that may be created is provided in Section 7.

### **3.5 Local Participation**

An additional criterion is that forming a CCA will give Berkeley residents and businesses more control over the decisions of their electricity supplier. There is some overlap with this criterion and those listed above because to the extent that Berkeley residents want superior environmental performance, rates below or on par with PG&E's, and local job creation those values are captured by the previous criteria. This criterion was included to reflect both the civic value of participation per se as well as the greater influence that Berkeley residents and businesses can have on other decisions such as rate design and energy efficiency program priorities.

PG&E's rates and policy priorities are determined largely by the CPUC, whose members are appointed by the Governor and confirmed by the state senate. The governing structure of the EBPA will need to be determined by the participating cities, but the EBPA Board is likely to be composed of the mayors and/or city council members of Berkeley and Oakland. Given the more local and directly elected nature of the EBPA Board members, residents and businesses of the EBPA cities should be

able to more easily influence EBPA rates and policies than they can influence PG&E's rates and policies.

## **4 CCA Opportunities to Improve the Environmental Performance of Berkeley's Electricity**

The impact that a load serving entity (LSE) has on the environment may be thought of as a function of the number of customers it serves, the average consumption per customer (which depends on factors such as the shares of residential, commercial, and industrial customers it serves; local climate; and the level and efficacy of energy efficiency spending), and the average environmental impact per megawatt-hour (MWh) of its energy mix. Thus, for a given customer base, an LSE may reduce its environmental impact by helping its customers to use less energy and/or by using more environmentally benign energy sources in its mix. This section addresses both opportunities and explores the impact that cap and trade programs have on reducing GHG emissions.

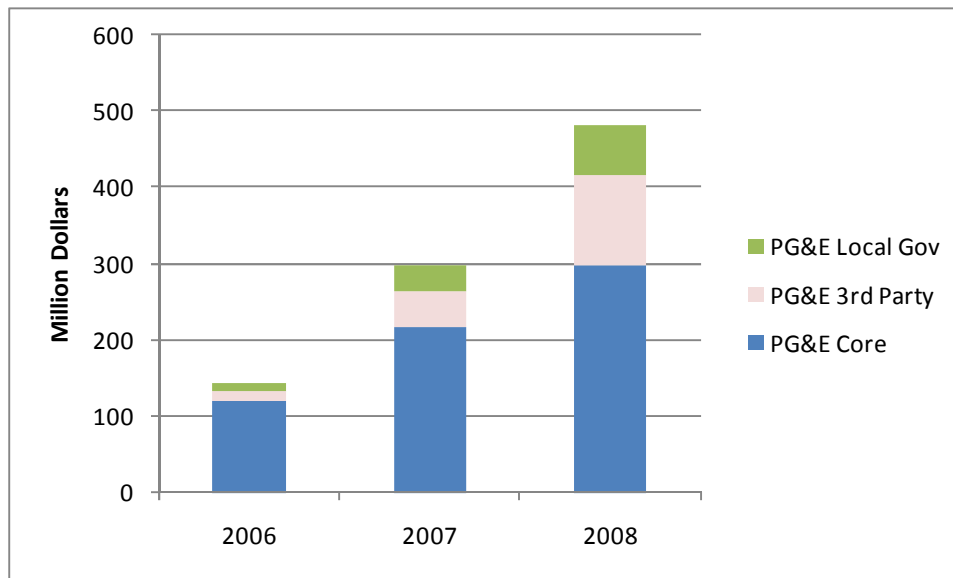
### **4.1 Opportunities to Achieve Greater Energy Savings**

A central question to the CCA decision is whether a CCA would achieve greater energy savings than PG&E. Currently, all electricity customers in California pay surcharges on their electricity and gas bills to fund energy research and energy efficiency programs. When local jurisdictions form a CCA, PG&E would continue to collect those surcharges and serve as the default provider of energy efficiency programs for the CCA's customers. AB 117 specifically gives CCAs and other third parties the right to apply to the CPUC to administer energy efficiency programs. The CPUC does allow local governments and other third parties to submit applications to receive program funding; however, no rules that apply specifically to CCAs have yet been issued by the CPUC. The CPUC has stipulated, pursuant to requirements in AB 117, that should a CCA form and it is *not* the program administrator for its customers, the incumbent utility must allocate approximately a "proportional share" of energy efficiency program funds to the CCA's service territory (CPUC, 2003). In other words, the statute and subsequent CPUC decision prevent the incumbent IOUs from retaliating against CCAs by directing the revenues from their energy efficiency surcharges elsewhere.

PG&E, under direction of the CPUC, administers a variety of energy efficiency programs in its service territory. PG&E designs and implements only some of these programs. Many are actually run by firms that specialize in program implementation while others are conducted as partnerships with local governments. In 2008 PG&E spent nearly \$482 million on energy efficiency programs, 62% of which was spent by PG&E on its "core" programs, while 13% was spent in partnership with local governments and 25% was directed to non-government third parties (Tagnipes, 2010). This represents an increase in the share of spending on local government programs from 6% in 2006 (see Figure 1). Due to the success of existing local government programs in the EBPA cities in attracting funding, it is

unclear whether a proportional allocation would result in a net gain compared to what they currently receive from PG&E.

**Figure 1. PG&E Expenditures on Energy Efficiency Programs, 2006 to 2008**



Source: Tagnipes, 2010

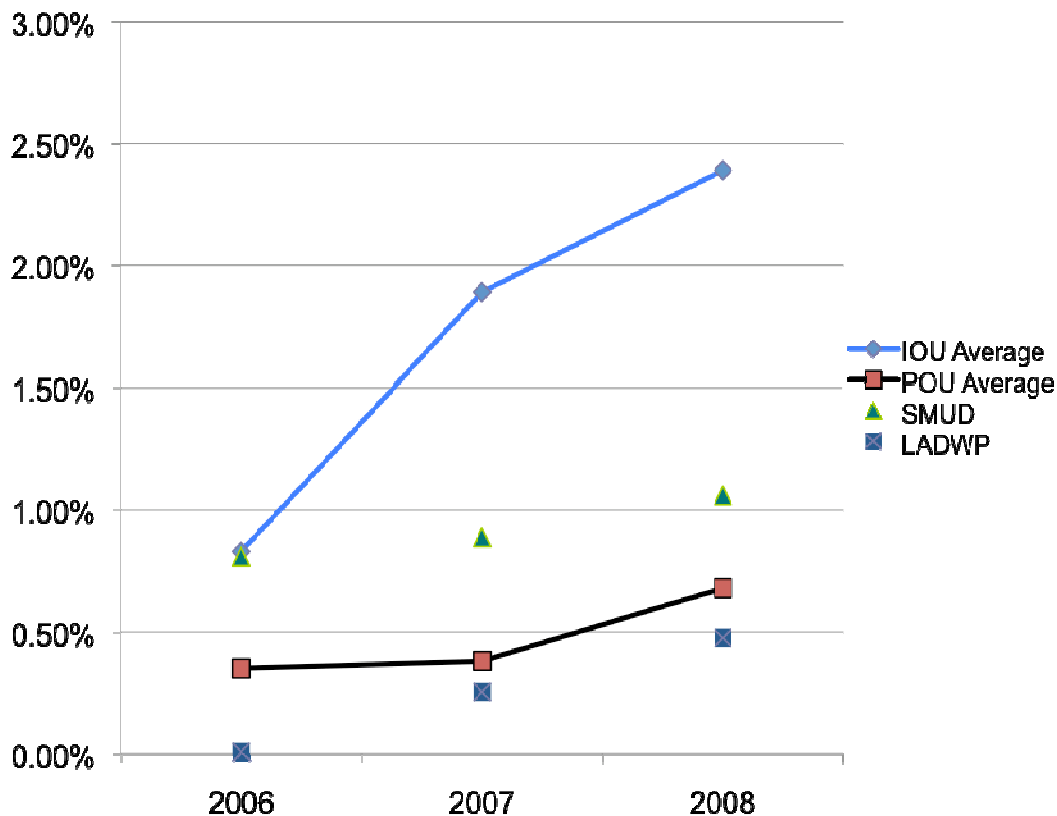
Fundamentally, a CCA could achieve greater energy savings than PG&E in one of two ways: spending more money per customer than PG&E or spending a similar amount of money per customer more effectively than PG&E. To meet the first goal, a CCA would be able to levy energy efficiency surcharges in excess of the levels the CPUC requires of the IOUs. The legislature and the CPUC have set ambitious goals for the state's POUs and IOUs, and the CPUC has authorized substantial increases in efficiency spending to reach those goals. As Figure 1 shows, energy efficiency spending by PG&E (and the other IOUs) is scaling up rapidly in response to direction from the CPUC. State policy directs utilities to achieve all possible cost-effective energy efficiency going forward. The spending levels envisioned over the next few years may already be pushing against the institutional capacity of the IOUs and implementation firms to spend the program funds effectively. Given recent trends, the EBPA would have to collect an unprecedented amount of money as a share of revenues to outspend PG&E.

Alternatively, a CCA could spend energy efficiency funds more effectively than PG&E. As explained in Section 2.4, PG&E does not face a disincentive to increase energy efficiency because PG&E's profits depend mostly on the fixed rate of return it receives on its transmission and distribution assets. The CPUC, and Public Utilities Commissions of other states, have experimented with a variety of shareholder incentive mechanisms to encourage energy efficiency. In a couple of recent CPUC Decisions, the CPUC adopted a "risk/reward incentive mechanism" that penalizes or rewards the shareholders of IOUs depending on whether the IOUs efficiency programs fell below or exceeded certain thresholds. The program has not been

without controversy, and critics have alleged the IOUs were rewarded without merit (Bowe, 2009).

Whether a CCA will outperform PG&E (and the third parties it helps fund) in achieving energy savings at lower cost is unclear. In theory, a public agency such as the EBPA would not need a monetary incentive to maximize efficiency. However, most publicly owned utilities (POUs) in California have not historically developed very aggressive energy efficiency programs and, according to the California Energy Commission (CEC), have not performed as well as the IOUs in attaining energy savings in recent years (Lewis et al., 2009). Figure 2 shows that from 2006 to 2008, the IOUs saved more energy relative to their loads than POUs. However, the POUs have developed ambitious plans to expand their efficiency programs, and the past performance of the POUs does not serve as a reliable indicator of the EBPA's expected performance, particularly given the high priority afforded to environmental responsibility by the citizens and municipal governments of Berkeley and Oakland.

**Figure 2. Avoided Energy Consumption Resulting from Recent IOU and POU Energy Efficiency Programs as a Share of Annual Load**



Source: Lewis et al., 2009

Perhaps the clearest argument for CCA administration of efficiency programs is that they would have better information about local conditions. Greater local

participation and input may help tailor efficiency programs to local needs. Additionally, a CCA would serve a more homogenous customer base in a more homogenous climate relative to PG&E, which may facilitate more effective program design and outreach. On the other hand, PG&E's programs may benefit from greater economies of scale and an ability to implement programs aimed at promoting energy efficient products at stores throughout northern California.

While IOUs have been given incentives to effectively administer their energy efficiency programs, CPUC staff has significant criticisms of their methods. A recent CPUC review of PG&E's proposed energy efficiency measures for 2010 to 2012 indicates that the CPUC does not agree with many of PG&E's estimates of the energy likely to be saved (CPUC, 2009a). In particular, they cite the lack of market baseline data that could be used to evaluate program effectiveness and the emphasis on the promotion of compact fluorescent lights, which are near market saturation in California. In general, the CPUC found a number of flaws in most of PG&E's planned programs, often related to the lack of baseline data, performance metrics, and the transparency of assumptions. A CCA could potentially improve upon this performance.

A final consideration in forming a CCA is whether local governments believe that PG&E's energy efficiency performance is adequate, or is otherwise motivated to design and run their own efficiency programs. The CPUC already requires PG&E to allocate some funds to local government programs. Local governments also have the option of using tax revenues to fund a municipal or regional efficiency office to supplement any funding received from PG&E. In order for an organization of this sort to be effective, it would have to cover a large service area to take advantage of economies of scale, which would probably necessitate creating an entity at the county or regional level.

## **4.2 Increasing the Share of Renewable Energy**

### **4.2.1 Background on Grid Reliability and Renewable Energy Technologies**

To provide reliable electricity service, the supply and demand on electricity grids must be carefully balanced in real time. Any deviation from matching generation to load threatens the reliability of the system because system balance is necessary to maintain the desired frequency and voltage. Excess generation increases frequency and voltage, which leads to higher losses of electricity on the transmission and distribution system<sup>11</sup> and can damage sensitive equipment. Insufficient generation causes voltage to drop, which produces brown-outs or, in more extreme cases, black-outs (Meier, 2006).

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<sup>11</sup> "Transmission" refers to the transport of electricity over long distances on high voltage lines. "Distribution" means the delivery of electricity to customers on lower voltage lines.

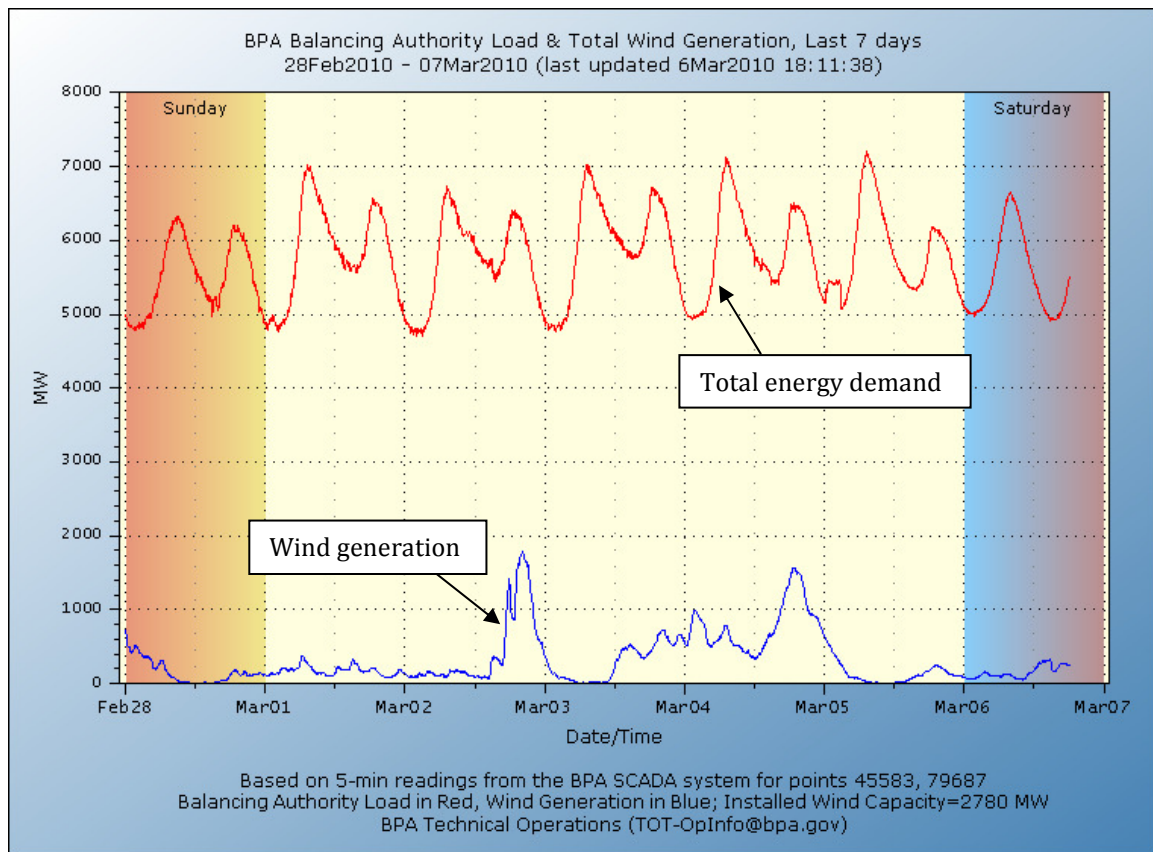
Unfortunately, many sources of renewable energy are intermittent in nature, particularly wind and solar which have the most near-term potential for significant growth.<sup>12</sup> A large share of intermittent resources on a grid affects reliability over two time frames. First, the output of solar and wind facilities can swing dramatically within minutes. This necessitates having additional resources on the grid that can ramp up or ramp down production quickly to maintain supply and demand balance (Porter, 2007). Other than hydro power, the only resources capable of providing this agility are gas-fired generating units, particularly combustion turbines. While compensating for intermittency may require relatively little actual energy over the course of a year, it does impose additional costs.

Intermittent sources may also not generate much energy over several days or weeks. Solar output drops considerably in the winter, and during certain periods of the year many wind resource locations experience prolonged low-wind conditions. Figure 3, which shows the output of wind power in the Pacific Northwest (specifically in the control area of the federal Bonneville Power Authority) during one week in March, illustrates a striking example of wind's intermittency. As the chart shows, wind farms in Bonneville's control area produced very little generation for the first two days of the week, output spiked on the evenings of March 2<sup>nd</sup> and March 4<sup>th</sup>, and output again fell to almost zero over the subsequent two days. In order to produce the energy demanded by customers, resources that do not rely on as-available energy inputs such as wind and sunlight must be also available.

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<sup>12</sup> In electricity planning and operations, a distinction is made between dispatchable resources, which can be called upon when needed, and non-dispatchable resources like wind and solar, which cannot.

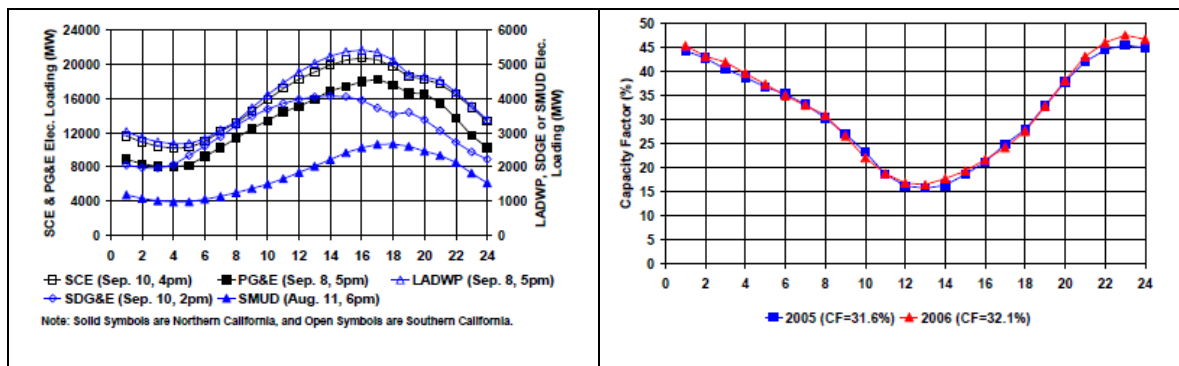
**Figure 3. Wind Power Production in the Pacific Northwest**



Source: BPA, 2010

In addition to the intermittency of wind power, the output from wind farms in many wind resource areas does not fit well with patterns of demand. With the exception of a few areas of the country, demand for electricity follows a standard pattern of climbing from low levels of demand at night to a peak demand in the early to mid-afternoon. The increase in daytime load is driven largely by lighting and air-conditioning in schools, offices, retail stores, and other commercial and government buildings. Figure 4 compares the average hourly output of a wind farm located in Altamont Pass, one of the three major wind resource zones in California, to the demand of the major California utilities on their peak days. As the right-hand chart indicates, wind generation at Altamont peaks between 8 pm and 4 am and falls to its lowest levels between 10 am and 4 pm. The left-hand chart shows that demand peaks between 2 pm and 8 pm and falls to its minimum around 4 am. The major wind resource areas in southern California are characterized by a flatter generation profile that is somewhat more desirable for providing power when it is needed (Vick, Clark and Mehos, 2008).

**Figure 4. Comparison of PG&E Load Profile and Altamont Pass Wind Output**



Source: Vick, Clark and Mehos, 2008

Unlike wind power, solar power's generation profile matches demand more closely, but solar power, particularly from solar photovoltaic (PV) panels, still suffers from a highly variable intermittent output. The output from a solar PV array can drop 40% to 80% within seconds when a cloud passes overhead, and output can increase just as rapidly when cloud cover leaves. Work is just beginning on developing tools to predict cloud cover impacts on solar electric output in order to help grid operators maintain reliability while integrating larger shares of solar power (Graham, 2010).

Several recent studies, mostly focused on wind generation, have addressed the implications of adding larger shares of intermittent resources.<sup>13</sup> These studies have broadly concluded that intermittent sources can provide up to 20% of a grid's total energy needs with relatively minor impacts on grid reliability and modest balancing costs (e.g., increasing use of combustion turbines to provide quickly rampable power to match wind's fluctuating output). At penetration levels much beyond that, significant transmission upgrades and changes to grid operating procedures may be needed. The California Independent System Operator, the entity that manages the grids owned by California's three largest IOUs, is expected to release its assessment of the challenges of meeting the 33% renewable target this year, but it was not available at the time this report was completed.

Two factors would help facilitate the integration of more intermittent renewable energy. Electricity storage could help solve both the intra-hour and intra-day reliability problems, but that necessarily adds to the cost of developing renewable energy. Moreover, electricity storage results in significant losses, on the order of 20% or more, as the energy is converted from one form to another. Pumped hydro storage is the only large-scale affordable electricity storage technology that currently exists. Pumped hydro facilities pump water into a reservoir at night and then release it during the day in order to generate power when it's more valuable. This resource requires the damming of a large area to form a reservoir capable of providing the required energy storage and production. Given the environmental

<sup>13</sup> The Utility Wind Integration Group's Wind Integration Library provides links to several studies on this topic. See <http://www.uwig.org/opimpactsdocs.html>



constraints to building new dams in California, there may be little additional pumped hydro potential.<sup>14</sup> Besides storage, the adoption of more electric vehicles, which are likely to be charged at night when electricity prices are lower (for customers on time-differentiated tariffs), would provide an additional source of demand for off-peak output from wind farms. Technology allowing grid operators to remotely control vehicle charging would further enhance the grid's ability to cope with wind's variable output.

#### **4.2.2 Current Renewable Electricity Requirements and PG&E Performance**

One of the primary reasons for supporting CCA that residents of Berkeley have expressed to the Commission is the desire to increase the share of renewable electricity used to serve Berkeley customers.<sup>15</sup> The current renewable portfolio standard (RPS) statute requires LSEs' shares of renewable energy to be 20% by 2010 and every year thereafter.<sup>16</sup> Gov. Schwarzenegger called for increasing the requirement to 33% by 2020 in a 2008 Executive Order (EO S-14-08). A 2009 bill would have codified the order in statute, but Gov. Schwarzenegger vetoed it due to its complexity and discrimination against out-of-state renewable energy. Instead, the Governor issued a new Executive Order directing CARB to adopt a 33% renewable energy standard by July 31, 2010.<sup>17</sup>

PG&E has been criticized for failing to develop enough renewable energy to meet the 20% by 2010 target. PG&E's share of renewable energy was 14% for 2009 (PG&E, 2010a), and the share will not reach 20% by the end of this year.<sup>18</sup> However, it is important to understand the underlying reasons that PG&E, and the other LSEs subject to the RPS, are presently behind in meeting the 2010 goal.

The California legislature first passed an RPS in 2002 under Senate Bill (SB) 1078. That statute required LSEs to serve 20% of their retail loads with eligible renewable sources by 2017. Under SB 1078, California LSEs would have had 15 years to gradually increase the share of renewable energy in their portfolios to meet the

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<sup>14</sup> Another promising storage option is compressed air energy storage (CAES). Currently, there are only three operational CAES facilities in the world. The CPUC recently approved funding to match a grant from the Dept. of Energy for PG&E to conduct a CAES feasibility study at a site in Kern County (Westervelt, 2010).

<sup>15</sup> By "renewable" we generally mean those technologies the California Energy Commission determines to be eligible for the statewide Renewable Portfolio Standard. Large hydro facilities (from dams with greater than 30 megawatt capacity) are excluded from eligibility (CEC, 2008).

<sup>16</sup> The 20% RPS requirement does not apply to POUs. They are required to set a target, but they have the latitude to define their own targets, set their own deadlines, and are allowed to count sources (such as large hydro) that do not count as "eligible" resources for the IOUs.

<sup>17</sup> See Executive Order S-21-09 and the accompanying press release at <http://gov.ca.gov/press-release/13273/>.

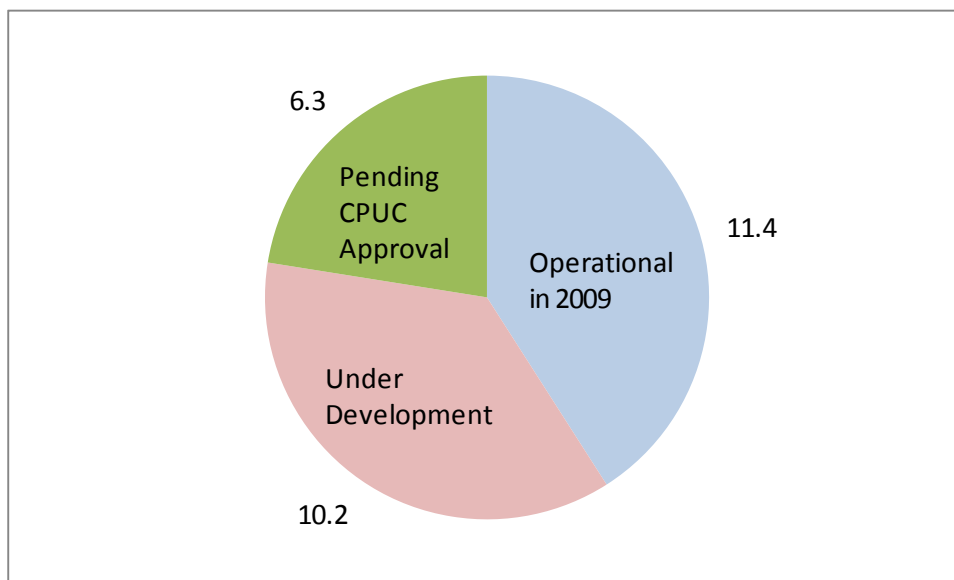
<sup>18</sup> For comparison, the fifteen largest POUs in California averaged 12% renewable energy in their portfolios, but only 8% "eligible" renewable energy because many of the POUs counted large hydro and other ineligible resources (Woodward and Pryor, 2009).

20% goal. In 2006, the legislature passed SB 107, which accelerated the 20% target to 2010, giving LSEs and renewable developers only four years to issue bids, signs contracts, obtain financing, site new renewable facilities, obtain permits and build any new transmission capacity necessary to deliver electricity from renewable resource areas to load centers. It is not surprising that the accelerated targets have not been met.

Every quarter the CPUC delivers an RPS progress report to the legislature. The most recent report was released in February 2010. This report only covered performance by the three big IOUs: PG&E, Southern California Edison, and San Diego Gas & Electric. The Quarterly Report shows that while new renewables came online slowly in the early years (as would be expected under the requirements of the original RPS bill), new capacity has come online in much larger quantities in the last couple of years. In fact, more new renewable capacity was added in 2008 (352 megawatts, or MW) than in all previous years of the RPS program combined (2002 to 2007). Another 357 MW came online in 2009 (CPUC, 2010a). With the recent boom in completed construction and the capacity of facilities that are currently in development or pending CPUC approval, the CPUC projects that the IOUs will meet the 20% goal sometime in the 2013 to 2014 timeframe (CPUC, 2009b).

Figure 5 below offers a sense of the scale of renewable development currently underway to serve PG&E's retail load. In 2009, the output of renewable facilities owned or under contract to PG&E equaled more than 11.4 million MWh. The expected annual output of projects under development would nearly double the amount of existing renewable generation. Adding the expected output from all facilities whose contracts with PG&E are pending approval by the CPUC would increase the quantity of PG&E's renewable energy by over 140%.

**Figure 5. Annual Output of Existing and Expected Renewable Energy Sources Serving PG&E at End of 2009, in Millions of Megawatt-Hours**



### 4.2.3 Local Energy

In addition to investing in large-scale renewable energy projects, a CCA could also produce a greater share of renewable energy than PG&E by facilitating the development of more local energy. By “local” we mean energy generated within the jurisdictions of the cities forming the EBPA. Local energy would most likely occur in one of two forms: either gas-fired combined heat and power (CHP) units located at industrial or commercial facilities or electricity from solar PV modules. Using CHP technology efficiently usually requires placing it in a facility with a relatively large and constant heating requirement. Assessing the untapped potential for CHP in the three EBPA cities is a complex task, beyond the Commission’s capability.

Regardless, the legislature and the CPUC have initiated process reforms to facilitate the ability of smaller CHP units to connect to the IOUs systems and receive fixed, guaranteed payments under a feed-in tariff.<sup>19</sup> Due to the complexity of ascertaining local CHP potential and the limited potential for a CCA to incentivize CHP beyond programs under development, we focus on solar PV potential in this section.<sup>20</sup>

A recent estimate of the structurally unshaded roof space in Berkeley indicates that there may be approximately 3.6 million meters (39 million square feet) of space potentially available for solar development (DeSnoo, 2010). “Structurally” unshaded space does not account for shading from trees, the presence of rooftop air-conditioning units or roof space that is otherwise unusable or unsuitable for solar panels. City of Berkeley staff recommended decreasing the estimate of structurally unshaded space by half as a rough approximation of what may actually be available for housing solar PV arrays (DeSnoo, 2010).

Using an estimate of 100 watts (alternating current) of maximum output per square meter yields a peak production potential of 180 MW.<sup>21</sup> While the Commission is unaware of unshaded roof space estimates for Oakland, its land area, excluding water area, is nearly 5.5 times the land area of Berkeley.<sup>22</sup> Assuming the proportion of unshaded roof space to total land area is comparable to Berkeley’s, total solar PV potential in a Berkeley-Oakland EBPA may equal roughly 1,200 MW. This capacity is nearly three times the estimated peak loads for the entire EBPA (including Emeryville) of approximately 430 MW in the early years of its operation (Navigant, 2008).

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<sup>19</sup> For documents related to this Rulemaking see [http://docs.cpuc.ca.gov/proceedings/R0806024\\_doc.htm](http://docs.cpuc.ca.gov/proceedings/R0806024_doc.htm)

<sup>20</sup> When the grid is served by a large share of renewable, zero-GHG electricity, gas-fired CHP, particularly smaller, less efficient systems, could potentially increase GHG emissions compared to separate heat and power.

<sup>21</sup> The figure of 100 watts per square meter is based on a range of likely output provided by Yun Lee, an engineer with Sun Light & Power.

<sup>22</sup> Land area values taken from Wikipedia.

The above estimates concern solar PV capacity but not the actual output. Fixed-axis solar panels produce much less power during the early morning and late afternoon, leaving only a five-hour “solar day” that a panel can operate near its maximum rating. Solar PV panels in PG&E’s service territory installed under the California Solar Initiative have averaged about an 18% capacity factor relative to their AC rated maximum output (Itron Inc., 2010). This means that panels in this area produce 18% of the power they could theoretically produce if the sun shone on them from directly overhead every hour of the year. This indicates that the maximum potential output of solar panels in the EBPA territory would amount to approximately 1.8 million MWh per year. According to the EBPA business plan, total annual load in the EBPA cities is currently about 2.5 to 2.6 million MWh (Navigant, 2008).

These calculations indicate that based on maximum technical potential, local distributed solar PV could theoretically supply a large share of the entire EBPA load. Of course, it is infeasible that all property owners in the EBPA cities will install solar panels on their roofs in the foreseeable future, much less the maximum capacity. Additionally, there are technical limits to the amount of intermittent generation that distribution systems can handle.

Large fluctuations in solar PV output that result from passing cloud cover put strains on the distribution system that it is not designed to handle. In a recent analysis for California’s Renewable Energy Transmission Initiative, E3 and Black & Veatch suggest that the capacity of solar PV systems should not exceed 30% of the capacity on any given feeder or substation (E3 and Black & Veatch, 2009). This limitation could greatly reduce the actual potential for solar PV. For example, E3 and Black & Veatch estimate that the potential to develop solar PV on all large and small rooftops in PG&E’s entire service territory is approximately 1700 MW, only 500 MW more than our rough estimate of the technical potential in Berkeley and Oakland (E3 and Black & Veatch, 2009). This comparison indicates that the true potential for solar PV capacity in Berkeley and Oakland may be considerably less than 1200 MW.

#### **4.2.4 CCA Potential to Exceed PG&E’s Share of Renewable Electricity**

The EBPA could build or procure more renewable energy than PG&E as long as it is willing to pay the expenditures necessary to build or buy it. Historically, the main factor that has impeded the development of renewable energy is simply its cost. In general, renewable energy sources produce electricity at a higher cost than more conventional sources of power. This is why their uptake has required significant federal, and often state, incentives and RPS laws that require LSEs to use a certain share of renewable energy.

One early indication of the ability of a CCA to provide more renewable energy is the contract that Shell Energy recently signed with MEA to provide electricity to Marin’s CCA. The contract requires that Shell provide a “Light Green” product with a

minimum of 25% renewable energy to all customers and an option for customers to choose a “Deep Green” 100% renewable energy product.<sup>23</sup> In addition to the initial levels of renewable energy provided by Shell Energy, MEA reserves the right to invest in its own renewable energy resources to further increase the share of renewable energy (MEA, 2010a). MEA aims to make the “Light Green” base product 50% renewable energy within five years of commencing operation (MEA, 2010c).

While a CCA the size of MEA might be able to provide 50% or more renewable energy to its customers in the near term, such a goal is not currently feasible for a utility the size of PG&E. One reason is simply the scale of renewable development needed. The annual load of the jurisdictions served by MEA is less than 1 million MWh. In contrast, the load served by PG&E in 2007 was over 85 million MWh (CEC, 2009a). This means that PG&E requires nearly 30 times as much renewable energy to meet a 33% RPS target than MEA does to be 100% renewable. Moreover, while MEA could meet 100% of its load with renewable energy with very little, if any, new transmission capacity, PG&E could not. Another reason is related to the reliability concerns explained above in Section 4.2.1. If MEA manages to achieve a renewable share of 50% or more by 2020, it will only be possible because the jurisdictions it serves comprise a relatively small load in a much larger power pool with dispatchable resources. For a large utility, much less the entire state, to operate the grid with 50% or more renewable energy (assuming that most of it will be provided by wind and solar), substantial developments and investment in storage and other technologies that facilitate the integration of renewable energy will probably be necessary.

## **4.3 Reduction of Greenhouse Gases**

### **4.3.1 Overview of Cap and Trade and Status of Federal and State Implementation**

“Cap and trade” is a regulatory approach to reducing various types of pollution. The basic principles are fairly simple:

1. total annual (or seasonal) emission limits are established that generally decline over time,
2. the agency overseeing the program issues allowances, whether through free distribution or auctioning, that permit a regulated entity to emit a certain amount of the pollutant (for example, one metric ton of CO<sub>2</sub>),
3. the number of allowances issued for a given year is equal to the quantity of emissions allowed for that year,

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<sup>23</sup> Note that the contract does not require the additional renewable energy for the “Deep Green” product to be procured from “eligible” renewable resources, meaning that the 75% additional renewable energy could come from large hydro or other sources ineligible to meet IOU RPS goals.

4. regulated entities must hold and retire enough allowances to cover their emissions, and
5. regulated entities are fined for each unit of pollution they emit that is not covered by an allowance.

Regulated entities are able to buy (from an auction or from other regulated entities or brokers in a secondary market) or sell allowances in order to obtain the amount they need. Because only a limited number of allowances are issued, they are scarce and regulated entities are willing to pay for them to continue emitting GHGs into the atmosphere. The cost of the measures necessary to meet the annual targets determines the price of the allowances. This “carbon price” propagates throughout the economy affecting the price of all goods and services. The more carbon intensive a good is to manufacture, the more its price increases. In this way, all producers and users of energy are incentivized to use less energy and find lower-carbon sources of energy. Cap and trade programs and pollution taxes therefore function very similarly in that both approaches reduce pollution by putting a price on it. Because cap and trade programs provide much greater flexibility than more traditional “command and control” programs (such as programs that mandate the use of specific pollution-control technologies), they offer the potential to save substantial amounts of money to achieve a given compliance target. Cap and trade systems have proven effective at reducing acid rain and nitrogen oxide pollution in the United States over the last fifteen years.<sup>24</sup>

Cap and trade programs for GHGs have only recently been implemented in two regions: the Regional Greenhouse Gas Initiative in the northeastern U.S., which caps emissions from power plants and went into effect in 2009, and the European Union Emission Trading Scheme, whose pilot phase went into effect in 2005. Both programs issued a number of allowances that exceeded actual emission levels at the start of their respective programs, although the European program has largely corrected this problem in its second phase (a period covering 2008 to 2012) by having collected better data and by reforming the allowance budget setting process.

An important difference between GHG cap and trade programs and the federal acid rain and nitrogen oxide programs is the provision GHG programs generally include for the use of offsets. Because a large degree of uncertainty is inherent in the measurement of emissions reduced via most offset projects, the use of offsets may threaten the environmental integrity of cap and trade programs.

In the U.S., a GHG cap and trade bill was passed by the House of Representatives in 2009, but the Senate has not yet, at the time this report was written, moved their version of a cap and trade bill to a floor vote. CARB is in the process of designing a GHG cap and trade program to meet the AB 32 goal of reducing statewide GHG

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<sup>24</sup> See <http://www.epa.gov/captrade/> and [http://www.sightline.org/research/energy/res\\_pubs/cap-and-trade-101](http://www.sightline.org/research/energy/res_pubs/cap-and-trade-101) for a good repository of introductory documents on cap and trade.

emissions to 1990 levels by 2020. The program is set to begin in 2012 and will eventually cover approximately 85% of the state's GHG emissions by regulating (i) large stationary sources that emit 25,000 metric tons of CO<sub>2</sub> or more per year, (ii) natural gas distribution companies for the portion of natural gas delivered to users that emit less than 25,000 metric tons of CO<sub>2</sub>, and (iii) the upstream suppliers of transportation fuels. A preliminary draft version of the regulation was released in late 2009 (CARB, 2009).<sup>25</sup>

#### **4.3.2 Implications of Cap and Trade Programs on Individual GHG Reductions**

Under cap and trade programs, GHG reductions are achieved collectively rather than individually. In other words, the actions of individuals and organizations do not reduce or increase emissions because the cap acts as both a ceiling and a floor for emission levels. For example, under the federal Acid Rain Program, efforts to conserve energy do not reduce sulfur dioxide emissions because the allowable level of emissions has already been set by the EPA, and the number of allowances issued does not change. Similarly, Berkeley's efforts to reduce GHG emissions covered by the cap<sup>26</sup> will not reduce absolute emissions under a traditional state or federal GHG cap and trade program.

A CCA will only reduce total GHG emissions under cap and trade if CARB adopts a renewable energy set-aside (or if California's cap and trade regulations are suspended). Set-asides are an administrative mechanism by which CARB would retire allowances on behalf of purchases of renewable energy that are beyond those required by law. With a voluntary renewable set-aside in place, a CCA's purchases of eligible renewable energy that are in addition to the applicable RPS requirement would result in CARB retiring allowances and thereby reducing total emissions. CARB is considering a voluntary renewable set-aside, but its cap and trade rules will not be finalized until the end of 2010 (CARB, 2009). A set-aside has been adopted by nine of the ten states participating in the Regional Greenhouse Gas Initiative. However, none of the federal cap and trade bills that have been introduced to date include a provision for a voluntary renewable set-aside.<sup>27</sup>

## **5 Maintaining Rate Parity**

A central question concerning the long-term viability of the EBPA is the ability of the EBPA to maintain rate parity with PG&E. In this section we identify the most important factors that may affect the EBPA's ability to maintain rate parity if it strives to offer a significantly higher share of renewable energy than PG&E. Some

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<sup>25</sup> CARB's cap and trade regulation faces two potential threats. A measure that has qualified for the November ballot would, if passed, suspend AB 32 until the unemployment rate falls to 5.5% or less. Additionally, both Republican candidates for governor have expressed that if elected, they may use their authority to suspend AB 32 indefinitely.

<sup>26</sup> Emission sources that are difficult to quantify, such as nitrous oxide emissions from agricultural soils or methane emissions from landfills, are generally not covered by cap and trade programs.

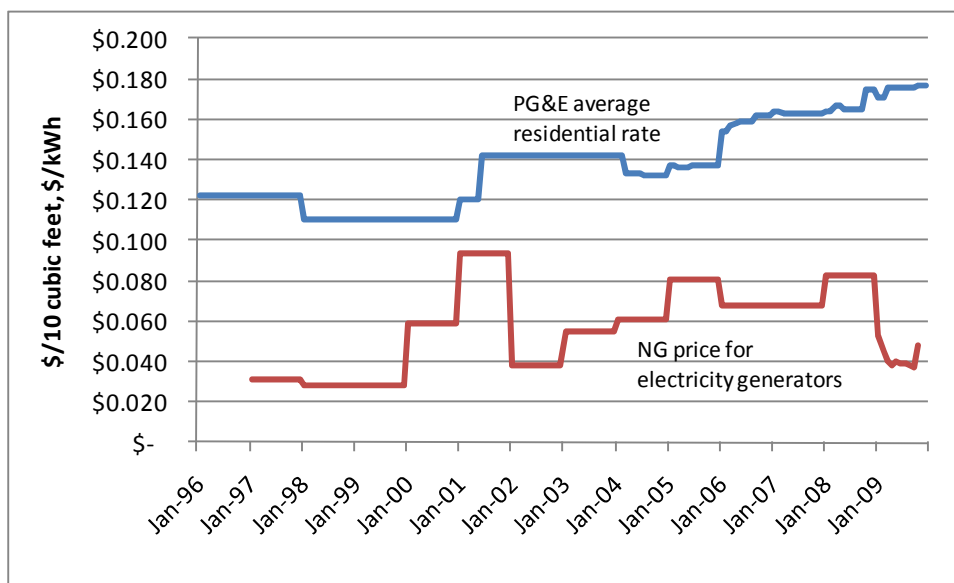
<sup>27</sup> For more information on voluntary renewable energy set-asides, see WCI, 2010.

aspects of the analysis in this section would not apply to an electricity product that contains the same share of renewable energy as PG&E's portfolio, an option that we discuss in Section 6. First, we provide some background on PG&E's rates and the factors that have led to relatively high rates for California's IOUs.

## 5.1 Background on PG&E's Rates

Before delving into the factors affecting the ability of a CCA to match PG&E's rates in the future, we review the recent history of PG&E's rates. PG&E's average residential rate in 1996, the year that the California legislature enacted the restructuring of the IOUs, was 12.2 cents per kWh. By 2009, the average residential rate had climbed to 17.7 cents per kWh (PG&E, 2010b). This amounts to an average annual increase of approximately 2.8% per year. For comparison, the consumer price index rose at an average annual rate of 2.4% over the same time period (BLS, 2010). The historical trend in residential rates is shown in Figure 6.

**Figure 6. PG&E Residential Rates and California Natural Gas Prices for Electricity Generators**



Sources: PG&E, 2010b; EIA, 2010a; EIA 2010b

PG&E's rate increases since 1996 have been driven largely by two factors: 1) costs related to the 2001 electricity crisis, and 2) the increasing price of natural gas. California's IOUs rely on a large share of natural gas fired generation when compared to most POUs in California and utilities in other states. This reliance on gas-fired power exposes IOUs to the volatility of the natural gas markets. Figure 6 also depicts the prices that California electricity generators have paid for natural gas since 1997. Between 1997 and 2008, natural gas prices increased at an average annual rate of over 9%. However, they have fallen dramatically since late 2008 (EIA, 2010a; EIA, 2010b).



The electric rates of California's IOUs, including PG&E, are significantly higher than the national average and higher than the rates of many California POUs. There are several underlying reasons for these differences. As explained above, PG&E relies largely on gas-fired electricity whereas most POUs in Southern California have large shares of cheap coal-fired power in their portfolios and many Northern California POUs own their own hydroelectric facilities or receive significant amounts of at-cost hydro generation from federal dams (Dame, 2010).<sup>28</sup> PG&E's 2009 resource mix consisted of approximately 2% coal-fired power and 16% large hydro. In contrast, the Los Angeles Department of Water and Power used 44% coal, Anaheim Public Utilities used 68% coal, and Turlock Irrigation District used 20% coal and 22% large hydro. PG&E also uses a higher share of renewable energy than most publicly-owned utilities (PG&E, 2009; LADWP, 2009; Anaheim Public Utilities, 2009; TID, 2010; Woodward and Pryor, 2009).

## **5.2 Assessment of Factors Affecting Rate Parity**

In order for a CCA to offer rates lower than PG&E's, or alternatively to maintain rate parity while using a larger share of higher cost renewable energy, a CCA must invest in its own generation facilities. Otherwise, the CCA will simply purchase energy from the same market as the IOUs (Stoner and Dalessi, 2009). This section evaluates the cost advantages that a CCA may enjoy compared to IOUs or independent power producers and explores other factors that will affect a CCA's ability to maintain rate parity with PG&E.

The EBPA business plan evaluates costs and rates using a scenario in which renewable energy would comprise 50% of the EBPA's energy mix within eight years of commencing operations (Navigant, 2008). The MEA and San Francisco PUC have supported similar or higher renewable energy goals for their CCAs. Given the relatively ambitious renewable energy goals stated by these CCA programs, the ability of these CCAs to maintain relative rate parity will depend on the near-term and long-term costs of renewable and conventional energy sources. In turn, the relative costs of renewable and conventional energy depend largely on four factors:

1. the near-term and long-term costs of renewable technologies compared to conventional technologies,
2. the cost advantages that a CCA may have when financing electricity generating facilities relative to IOUs or independent power producers,
3. the long-run cost of natural gas,<sup>29</sup>
4. the long-run cost of GHG allowances (or carbon taxes).

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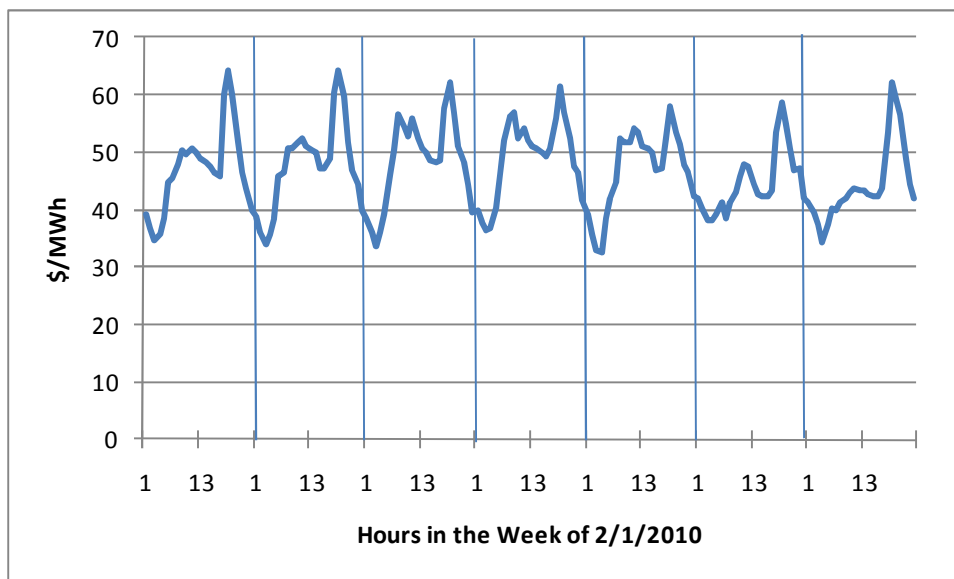
<sup>28</sup> None of these resources would be available to a CCA.

<sup>29</sup> The future price of natural gas is important because gas-fired power will provide nearly all of the EBPA's non-renewable energy and because gas-fired power is the only non-renewable energy source likely to provide new electricity capacity in California.

### 5.2.1 Near-Term Costs of Energy and Potential CCA Cost Advantages

First we examine the near-term cost of renewable and non-renewable energy. Maintaining rate parity while developing or purchasing the shares of renewable energy in the short time frames proposed in the EBPA business plan will be exceedingly challenging because renewable energy is much more expensive than current market prices of generic wholesale power. Figure 7 below shows a week's worth of hourly wholesale electricity prices in the PG&E service area during the first week of February 2010. The chart illustrates that wholesale spot market prices, which are largely set by gas-fired generators, during this week ranged mostly between \$40 per MWh and \$50 per MWh with prices spiking a few hours of each day to around \$60 per MWh.

**Figure 7. Average Hourly Wholesale Electricity Prices in the PG&E Service Area during the Week of 2/1/2010**



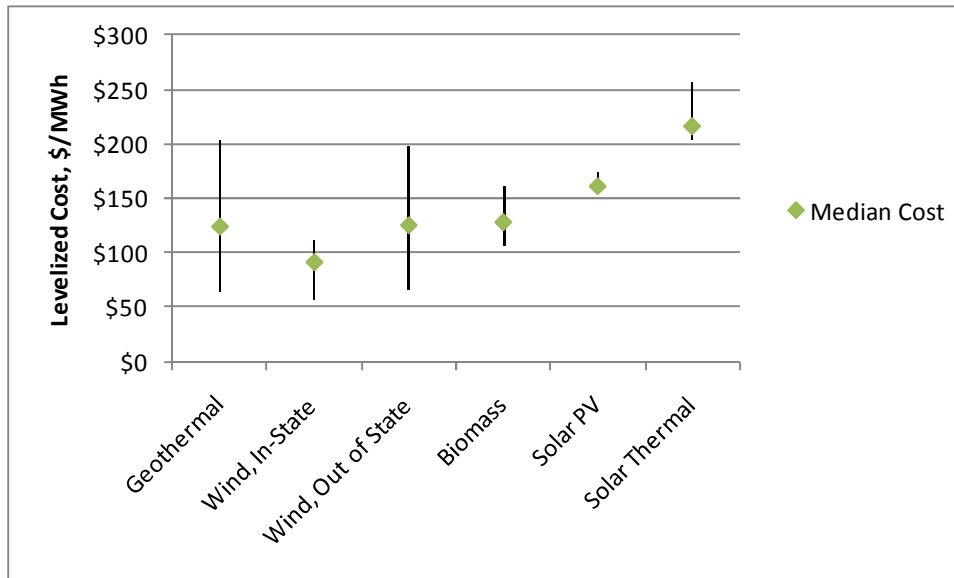
Source: Helman, 2010

In order to compare the generation costs of different technologies, it is necessary to use levelized costs that convert all costs, including tax credits and other incentives, into net present costs. This allows a comparison of technologies with relatively low capital costs but high operating costs (for example, a gas-fired power plant) to technologies with high initial costs but low operating costs (a wind or solar facility).

As part of the Renewable Energy Transmission Initiative, Black & Veatch has prepared estimates of the levelized cost of new renewable energy projects disaggregated by location and technology type. These estimates are listed in a spreadsheet available on the CEC website (Black & Veatch, 2010). Figure 8 depicts the high, low and median estimated costs of renewable energy in several renewable

resource zones scattered across the western grid of North America.<sup>30</sup> The median value for every technology, with the exception of wind built in California, is well over \$100 per MWh.<sup>31, 32, 33</sup>

**Figure 8. Estimated Ranges and Median Costs of Energy from Large Scale, New Renewable Energy Projects in the Western U.S. and Canada**



Note: The costs shown do not include the costs of the transmission needed to deliver the energy.  
Source: Black & Veatch, 2010

A report commissioned by the San Francisco PUC to inform its decision regarding whether to proceed with a CCA for San Francisco corroborates the intuitive conclusion that maintaining rate parity will be difficult while using more expensive sources of energy. This report compares three different PG&E rate escalation scenarios to three different CCA generation portfolios. The report finds that in either scenario in which the SF CCA reaches its goal of using 51% renewable energy, its costs will significantly exceed PG&E's even under the most pessimistic scenario for PG&E's costs. Of the scenarios examined, only the combination of the San Francisco CCA meeting the minimum 20% renewable requirement and the highest

<sup>30</sup> These values include federal tax incentives available for projects constructed in the U.S. but do not include transmission costs or costs related to integrating intermittent resources.

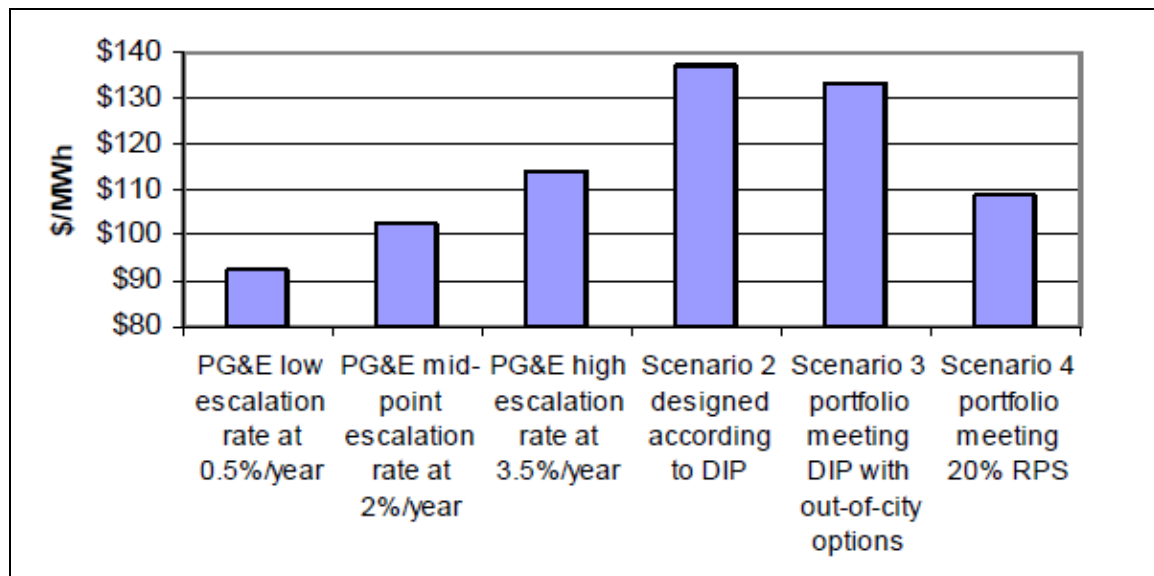
<sup>31</sup> While wind is a comparatively cheap source of renewable energy, the power it produces is not very valuable due to wind's variable output and the tendency for wind to produce mostly during off-peak hours. Refer to the discussion in Section 4.2.1.

<sup>32</sup> The cost range shown for solar PV applies to utility-scale projects. The generation cost for distributed local solar PV would be higher because large scale installations benefit from cost reductions due to bulk purchasing of panels. Ground-mounted systems also benefit from significantly lower per-unit installation costs. Thus, a large, utility scale installation is cheaper than a reasonably large installation on the roof of a commercial building. Small solar PV systems mounted on the pitched roofs of single family homes are the most expensive way to produce energy from PV.

<sup>33</sup> This is consistent with the terms of MEA's contract with Shell Energy, which stipulates that MEA must pay Shell Energy a \$39 premium for every MWh of RPS-eligible renewable energy. (See footnote 15 for an explanation of eligible renewable energy sources.)

cost escalation assumptions for PG&E results in a case where the CCA's costs are slightly less than PG&E's (Sansoucy, 2009).

**Figure 9. Twenty-Year Levelized Energy Supply Costs of PG&E and SF CCA Portfolios**



Note: "DIP" refers to San Francisco's Draft Implementation Plan in which the CCA uses 51% renewable energy.

Source: Sansoucy, 2009

The wholesale power prices shown in Figure 7 are set mostly by plants that have been in service for many years. These plants are mostly or completely depreciated and are able to sell power at a lower cost than would be profitable from a gas-fired power plant built today. In the long-run, as all LSEs must invest in new generation to keep up with rising demand and/or the retirement of aging power plants, new renewable facilities compete against new gas-fired facilities to provide the additional capacity.

The CEC publishes a report every two years on the levelized cost of new large-scale generation technologies. Table 1 below summarizes the costs for several key technologies from the most recent report (Klein, 2010). The table provides estimates for plants that commenced operation in 2009.<sup>34</sup> Table 1 allows comparison of costs across different technology types and different investor types. Costs differ by investor type because public entities, such as POUs or CCAs, generally have significant financing advantages due to their tax-exempt status, lack of need to generate profits for shareholders, and ability to finance capital projects with tax-free bonds.

The cost estimates in Table 1 reveal a couple of interesting findings. The estimated cost of producing renewable energy from 2009 projects is lower for independent power producers than it is for either IOUs or POUs. This exception to the general

<sup>34</sup> The values shown reflect all available federal and state financial incentives for renewable energy.

financing advantage that public entities possess is due to the suite of tax credits for renewable energy available from the federal government. Because the incentives are tax credits, they do not help lower the development cost for public entities, which pay no taxes. In effect, the federal tax incentives level the playing field between public agencies and private developers with respect to building renewable energy facilities.

In the short-term, private developers should be able to provide renewable energy at lower cost than public agencies. However, this does not represent a disadvantage for the EBPA's ability to match PG&E costs per renewable MWh because the EBPA can enter into power purchase contracts with the same pool of potential developers that would serve PG&E. It does mean that the EBPA will not benefit from a cost advantage by financing the construction of its own renewable facilities in the short-term. Note, however, that POUs retain a substantial cost advantage when constructing fossil-fired generation facilities.<sup>35</sup>

**Table 1. Cost of Large-Scale Generation Projects in Service in 2009, \$ per MWh**

Technology Type	Investor Type		
	Merchant Power Producer	Investor-Owned Utility	Publicly-Owned Utility
Advanced Gas Combined Cycle	114	107	100
Coal Gasification	117	98	99
Biomass <sup>a</sup>	104	101	106
Geothermal, Binary	83	94	107
Solar, Parabolic Trough	225	228	272
Solar Photovoltaic	262	279	320
Onshore Wind, Class 3 to 4	72	78	81

<sup>a</sup> Note that the costs shown for biomass, geothermal, and wind energy appear to be optimistic compared to the Black & Veatch values shown in Figure 8. We do not know what accounts for this discrepancy.

Source: adapted from Klein, 2010

## 5.2.2 Long-Term Costs of Energy and Potential CCA Cost Advantages

The CEC report also provides estimates of the levelized costs for projects that commence operation in 2018, when the renewable tax incentives are assumed to have expired.<sup>36</sup> These estimates are shown in Table 2. It is possible that tax incentives for some of the renewable technologies will be renewed through 2018, but since the subsidies are intended to support new technologies until they are mature enough to compete with more established technologies, it is likely that many

<sup>35</sup> An alternative strategy to maintaining rate parity that the EBPA could explore is to utilize the advantageous terms of public financing to invest in its own gas-fired generation facility. The EBPA may then be able to generate gas-fired electricity at a lower cost than the independent producers that supply much of PG&E's electricity. The cost savings from the non-renewable portion of the EBPA's portfolio could help to offset the higher costs it is likely to bear by procuring a larger share of renewables.

<sup>36</sup> The exception is geothermal energy whose federal investment credit, according to Klein (2010), does not have a set expiration date.

of the renewable technologies that exist today will not benefit from the same level of support they currently enjoy. The CEC's analysis indicates that once the federal tax credits expire, projects financed by public agencies can provide renewable power at approximately 10% to 30% lower cost than projects financed by merchant developers or IOUs.

**Table 2. Cost of Large-Scale Generation Projects in Service in 2018, \$ per MWh**

Technology Type	Investor Type		
	Merchant Power Producer	Investor-Owned Utility	Publicly-Owned Utility
Advanced Gas Combined Cycle	157	147	140
Coal Gasification	178	143	113
Biomass	160	148	128
Geothermal, Binary	129	137	125
Solar, Parabolic Trough	299	289	256
Solar Photovoltaic	306	295	262
Onshore Wind, Class 3 to 4	127	121	91

Source: adapted from Klein, 2010

### 5.2.3 Long-Term Costs of Natural Gas

The long-term price of natural gas is an important factor to consider because a large jump in the price of natural gas would improve renewable energy's competitiveness compared to gas-fired generation. It would also make maintaining rate parity more difficult for whichever electricity provider, whether PG&E or the EBPA, relies on more gas-fired power. Because gas-fired power provides the vast majority of generic power available in wholesale power markets in the western U.S. and Canada, whatever share of the EBPA's portfolio is not composed of renewable energy owned by or under contract to the EBPA will be composed almost entirely of gas-fired power. PG&E's portfolio consisted of approximately 47% gas-fired power in 2009 (PG&E, 2009). If that share remains fairly constant over the next several years, the EBPA will be more exposed to the risks of natural gas price volatility until its portfolio consists of 50% or more renewable energy. Although it is impossible to accurately predict long-term prices of natural gas, the Energy Information Administration's most recent Annual Energy Outlook does not project a significant increase until after 2020 (EIA, 2010c). These projections indicate that a large increase in natural gas prices is not likely to exacerbate the EBPA's difficulty in maintaining rate parity.

### 5.2.4 GHG Compliance Costs

A final factor to consider when assessing the likelihood of maintaining rate parity is the role that GHG compliance costs may play. Emitters of GHGs are likely to have to pay for GHG pollution in the next few years either due to a cap and trade program or a carbon tax. The requirement to pay for emitting GHGs will make fossil-fired power relatively more expensive compared to zero-GHG sources. Table 3 shows the

same generation costs as Table 2 but with a \$30 per metric ton GHG compliance cost imposed on the coal-fired and gas-fired generation facilities.

**Table 3. Cost of Large-Scale Generation Projects in Service in 2018 with \$30 per Metric Ton GHG Compliance Cost, \$ per MWh**

Technology Type	Investor Type		
	Merchant Power Producer	Investor-Owned Utility	Publicly-Owned Utility
Advanced Gas Combined Cycle <sup>a</sup>	169	159	152
Coal Gasification <sup>b</sup>	204	169	139
Biomass	160	148	128
Geothermal, Binary	129	137	125
Onshore Wind, Class 3 to 4	127	121	91

<sup>a</sup> assumes a GHG emission rate of 0.4 metric tons per MWh

<sup>b</sup> assumes a GHG emission rate of 0.85 metric tons per MWh

Source: Klein, 2010 and authors' estimates

Because natural gas is nearly the only fossil-fired energy source in PG&E's mix and natural gas comprises 47% of its mix, PG&E is largely unexposed to the risk of high GHG compliance costs. In this regard, PG&E benefits from the nuclear and large hydro energy, in addition to the renewable energy, in its portfolio. Because the EBPA will have to rely on gas-fired power for most of its power needs, the EBPA's GHG compliance costs exposure is similar to its gas price exposure. Likewise, the EBPA would have to generate 50% or more of its energy from renewable sources to reduce its GHG compliance cost exposure to the level of PG&E's. Since CARB anticipates having a cap and trade program in place by 2012, GHG compliance costs will add to the EBPA's difficulty in maintaining rate parity.

While it may seem that a CCA would have a difficult time maintaining rate parity, the only currently operating CCA in California, the Marin Energy Authority, has recently secured a contract with Shell Energy North America to supply it with electricity at rates equal to PG&E's in its first year of operation. For more information regarding this contract see sections 2.2 and 4.2.4.

## 6 Financial Risk to the EBPA and City of Berkeley

In this section we discuss the types of financial risk to the EBPA and the City of Berkeley related to the implementation of a CCA. CCAs differ from traditional POUs in one critical aspect: POU customers are captive whereas CCA customers can opt out and return to IOU service. Due to this opt-out provision, the risk of large numbers of customers returning to IOU service threatens the viability of a CCA. If the EBPA is unable to maintain rates at or near PG&E's rates, increasing numbers of customers may opt out of EBPA service and return to PG&E. Customer attrition could theoretically result in a downward spiral in which higher cost resources built or under long-term contract to the EBPA are spread over an increasingly smaller number of customers until the EBPA is forced to dissolve. Financial risk to the participating cities arises if the CCA dissolves and if there are any funds spent by the

cities to implement the EBPA or any loans provided by or guaranteed by the cities that have not yet been repaid.

The Navigant business plan identifies three broad types of financial risks to the city:

1. pre-implementation expenses related to performing the necessary legal and regulatory steps to establish the CCA,
2. start-up costs and working capital necessary to hire staff and secure energy contracts to prepare the CCA for its initial retail sales, and
3. the longer-term financial liabilities from investment in generation facilities or long-term power purchase agreements that the city might bear in the event the CCA program is terminated (Navigant, 2008).

Navigant estimates that pre-implementation expenditures by the EBPA cities to adopt the necessary ordinances, conduct public meetings, select an initial electric service supplier and obtain necessary regulatory approvals are likely to range from \$500,000 to \$750,000. Navigant estimates Berkeley's share would range from \$130,000 to \$200,000.<sup>37</sup> These relatively small expenditures could be recovered quickly from EBPA rates, but if the cities undertake the pre-implementation activities and ultimately do not implement the EBPA, this money would be non-recoverable.

Start-up costs include hiring staff and contractors and covering other program initiation costs such as securing office space. Navigant estimates that start-up costs amount to approximately \$3.3 million. As Navigant explains, the EBPA may be able to secure a line of credit to cover these initial expenses, but creditors may not be willing to extend credit without a loan guarantee by the participating cities. Navigant estimates that the start-up costs could be recovered within five years. As long as the EBPA retains most of its customers in the first five years, financial risk exposure to the cities should be minimal. If the cities guarantee the \$3.3 million in start-up costs, Berkeley's share, based on its share of the EBPA electric load, would amount to approximately \$660,000.

Navigant also indicates that nearly \$14 million in working capital may be required to cover the initial round of power purchase agreements before revenues are generated. A large electric service firm could probably loan the working capital until it was recovered in revenues, but the cities might be able to secure more favorable interest rates by electing to guarantee the working capital. Berkeley's share of the \$14 million, based on its load, would amount to about \$2.8 million. Navigant acknowledges that the proposed financial arrangement would result in some risk to the cities' general funds if the authority is unable to repay the initial

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<sup>37</sup> Recall that the estimates in the business plan include Emeryville as a participating city. Berkeley's and Oakland's costs may be slightly higher without Emeryville's contribution.



startup financing but asserts that this exposure would be limited to the amount of the financing explicitly guaranteed by the cities.

In its 2008 report, city staff noted that a private law firm had been retained by the City of Berkeley to provide a legal analysis of protecting the City from obligations to pay for EBPA cost overruns or debts. According to staff, the law firm concluded that the EBPA could be structured to place a financial firewall between CCA activities and the city's municipal corporation (DeSnoo, 2008). While setting up a firewall is possible, it is not clear that creditors will be willing to lend the large sums of money needed by a CCA to develop its own generating facilities knowing that a CCA's customer base is not absolutely secure. Bond markets may react by either requiring a higher rate of interest than a traditional POU would enjoy or by requiring the member cities to guarantee the debt. Note that if the EBPA constructs its own generation facilities, the facilities themselves are significant source of collateral. Thus, the cities might not have to guarantee the entire value of the bonds but only the difference between the resale value of the asset and the outstanding debt (Dame, 2010). If the cities agree to such an arrangement, they may only have to guarantee a fraction of the \$190 million that Navigant estimates the EBPA would need to supply 10% of its power from an EBPA-owned wind farm (Navigant, 2008), but the Commission does not have enough information to estimate how large a guarantee would be required.

One approach that CCAs could explore to ensure a higher probability of retaining their customer base is to offer their own "rate parity" electricity product. The CCA programs in place or proposed by Marin, San Francisco and the East Bay have focused on offering a larger share of renewable energy than PG&E. If achieving the renewable goal is likely to lead to higher rates that may induce customers to opt out, the CCA could retain customers by offering its own lower-cost option that seeks to maintain rate parity with PG&E while meeting, or beating, the state's minimum renewable content requirement. Customers would be enrolled in a "medium-green" program by default but would be allowed to opt for either a "light green/rate parity" product or a "deep green" 100% renewable product.

## **7 Local Green Job Promotion**

The Local Clean Energy Alliance produced estimates of jobs created by implementing a sample CCA in Oakland and Berkeley, as described below. For the purposes of this estimate, "local" jobs are defined as jobs created within the cities of Oakland and Berkeley. Additional jobs in the region may be created by other investments, such as developing wind resources in Alameda County's Altamont Pass or geothermal resources in the greater Bay Area.

Many existing local jobs in the electricity sector would remain under PG&E since PG&E would continue to maintain the local grid and provide meter reading, billing, and customer service. We do not expect that PG&E would experience any significant job losses from implementation of a CCA. PG&E also contracts with local businesses

and nonprofits to provide energy efficiency services. CCAs may have the opportunity to gain control of and spend local energy efficiency funds collected under the public good charge on customer bills within the service territory. In this case, the CCA can choose to continue to work with the same experienced local organizations.

The major opportunities for CCAs to create additional local jobs come from increased investment in energy efficiency and local distributed generation above the levels that would occur under PG&E's continued service. Determining the effect of implementing the EBPA on local job creation is challenging because it is difficult to estimate how many additional local jobs a CCA would create above those that already exist and would exist in the future under PG&E's service. Additionally, while the jobs created will be performed in the EBPA cities, they will not necessarily result in employment of EBPA residents unless the EBPA includes local hire requirements or preferences in its solicitations for efficiency and distributed generation services. Such requirements necessarily limit the number of firms that compete to offer these services and may therefore increase costs to the EBPA.

The table below provides estimates on the number of jobs produced per year for investment in one MW of energy produced or saved. While the direct jobs would be located in Berkeley and Oakland, some of the indirect jobs may be located elsewhere.<sup>38</sup> Because we have no basis for knowing where the indirect jobs will be located, we focus our analysis on the direct jobs.

**Table 4. Direct and Indirect Job Creation from Energy Efficiency and Solar PV Projects**

Type of Investment	Job Years Created/MW Installed	Indirect Job Years Created for Every Direct Job Year
Energy Efficiency	11	0.33
Solar Photovoltaics	7.41	0.90

Sources: Energy Efficiency direct jobs data is from Bell and Honea, 2007. Solar PV data is from the RAEL Green Jobs Calculator (RAEL, 2009). Indirect jobs data is from BKi Consulting, 2009. See references for complete citations.

To estimate a plausible scenario for local energy investments the EBPA may make, we used the resource portfolio proposed in San Francisco's CCA Draft Implementation Plan and reduced it by half to account for the EBPA's smaller load. San Francisco aims to achieve 107 MW of energy efficiency and 31 MW of in-city solar capacity by 2017; thus we used 53.5 MW of energy efficiency and 15.5 MW of solar PV for our calculations. Multiplying these values by their respective direct jobs factors yields approximately 700 job-years of employment. To convert that to the number of jobs, it is necessary to divide by the number of years over which the work takes place. We use the same assumption as San Francisco's Draft Implementation Plan, which anticipates installing the solar and efficiency capacity over the course of

<sup>38</sup> Examples of indirect jobs are jobs created by the purchases of materials to perform the work and the money spent on goods and services by those hired to perform the direct jobs.

six to seven years (2011 to 2017). Dividing the job-years by the years yields an estimate of 100 to 120 full-time jobs created. Whatever indirect jobs created that are located in the EBPA cities would add to our estimate.

In order to determine the incremental number of local jobs resulting from the CCA, the number of jobs added under business-as-usual PG&E service should be subtracted from the estimate above. Some of these jobs will occur anyway under PG&E's energy efficiency programs, private customers' investment in solar PV systems, and PG&E's proposed distributed 500 MW solar initiative (CPUC, 2010c). Calculating how much more solar capacity the EBPA is likely to produce depends on how much of PG&E's 500 MW, if approved, will be installed in the EBPA cities. Since the number of local jobs created under PG&E's service would depend on very rough estimates, the 100 to 120 range can be considered an upper range of additional jobs created by the EBPA.

## **8 Conclusions**

Numerous factors govern the costs of generating electricity from renewable and non-renewable resources. These factors, such as natural gas prices, the cost of renewable energy technologies, the extension of federal renewable energy tax credits and possible future GHG compliance costs are impossible to predict with much certainty. Given current natural gas prices and renewable energy costs, it will be challenging for a CCA to quickly achieve the ambitious renewable energy goals envisioned in the EBPA business plan while maintaining rates comparable to PG&E's rates.

Before committing to the formation of a CCA, Berkeley and Oakland should perform an analysis of the long term cost of a variety of energy supply scenarios using different assumptions for the factors listed above. A realistic evaluation of the likelihood of meeting ambitious renewable energy goals while maintaining rate parity is essential. Based on this analysis, the EBPA should set renewable portfolio goals that seem achievable.

Over the long run, the financial advantages that the EBPA may enjoy as a public agency imply that the EBPA will likely be able to offer electricity, even with a higher share of renewable energy, at or below PG&E's rates. However, it will be critical for the EBPA to retain the bulk of its customers during the first several years of its existence, a period during which renewable energy is likely to cost much more than prevailing market prices of electricity.

A final factor that would favor forming a CCA is that it could allow Berkeley to remain committed to its environmental goals despite any backsliding at the state or federal level. The state legislature and state agencies have committed to an array of ambitious environmental goals in the electricity sector. These policies and programs reduce the scope for additional improvements to environmental performance in providing electric service. For example, if the minimum renewable

energy requirement rises to 33%, then the EBPA would have only 17% more renewable energy than PG&E in its portfolio rather than 30% more if the requirement remains at 20%. But state policies and programs are subject to change. Ballot measures or a change in administration could prevent the implementation of state-level policies currently underway. By forming or joining a CCA, Berkeley can help to ensure that its environmental goals are met, regardless of what occurs at the state or federal level.

Overall, CCA formation offers the potential to reduce environmental impact, increase public involvement in energy policy, and produce local green jobs. However, it is a difficult undertaking, requiring a large effort and entailing some risk. The City Council should evaluate whether the benefits outweigh the amount of effort needed. The progress of the CCAs in Marin and San Francisco over the next few years will help to shed light on this question.

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