Peer Review of the Monterey Bay Community Power CCA Technical Study

On Behalf of the County of Santa Cruz

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Executive Summary

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

9. Should any additional benefits or challenges be considered?

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

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

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

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

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

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

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

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

Introduction and Background

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

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

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

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

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

Demand Forecast

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

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

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

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

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

Supply Assumptions

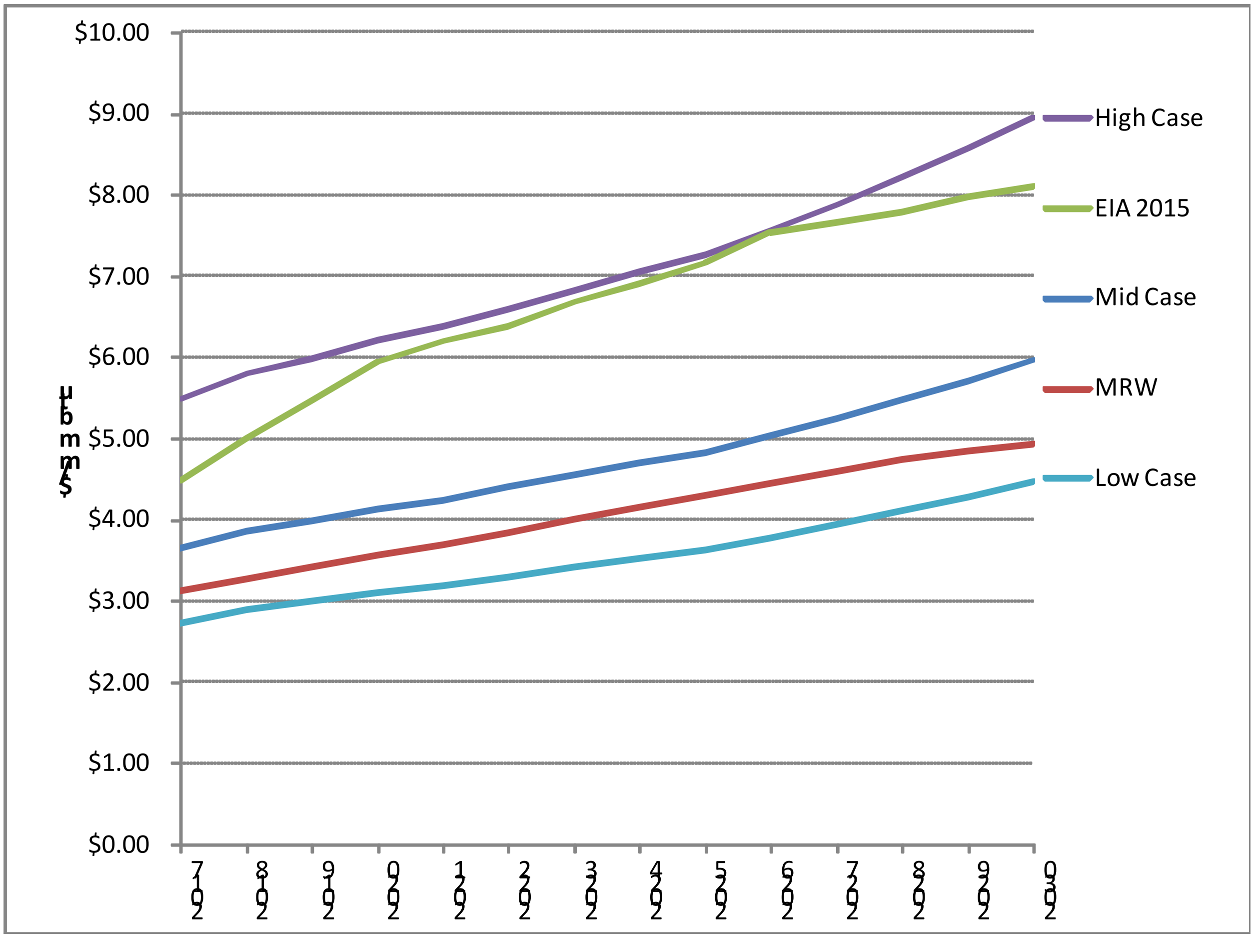
This section presents MRW's comments on the key elements of the supply forecast: renewable and non-renewable power prices, resource adequacy prices, associated greenhouse gas (GHG) costs, and the phasing in of MBCP power purchase agreements with specific renewable assets.

Non-Renewable Power and Underlying Gas Prices

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

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

Figure 1. Natural Gas Price Forecasts



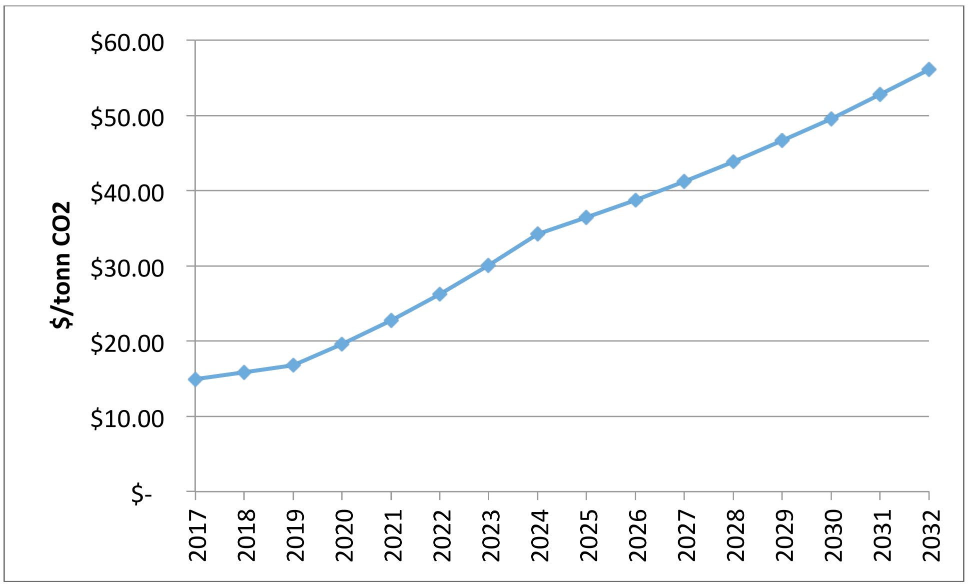
The Study uses a market heat rate of 8,000 Btu/kWh. This rate falls between that of a combustion turbine, which would set the wholesale power market price at times of higher demand, and a newer combined cycle power plant, which would set the wholesale market price most other hours. MRW finds the 8,000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

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

GHG Prices

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

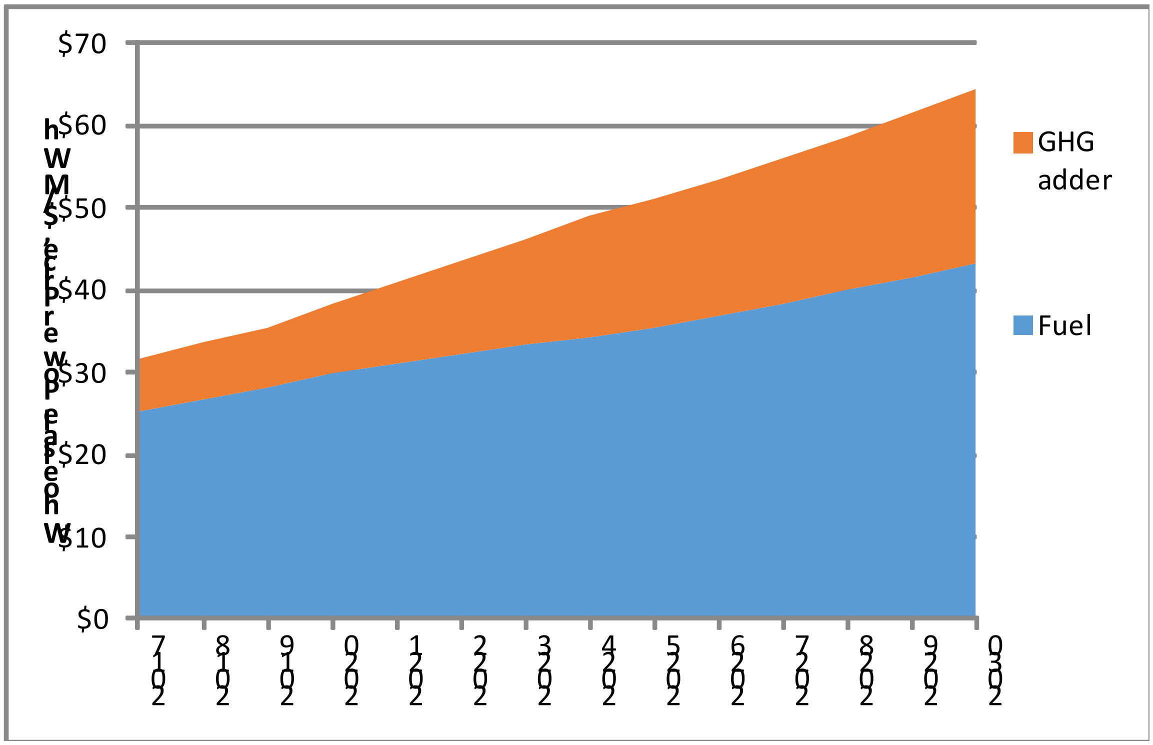
Figure 2. CO_2 Allownace Price Foreacst



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

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

Figure 3. Breakdown of Wholesale Market Power Cost

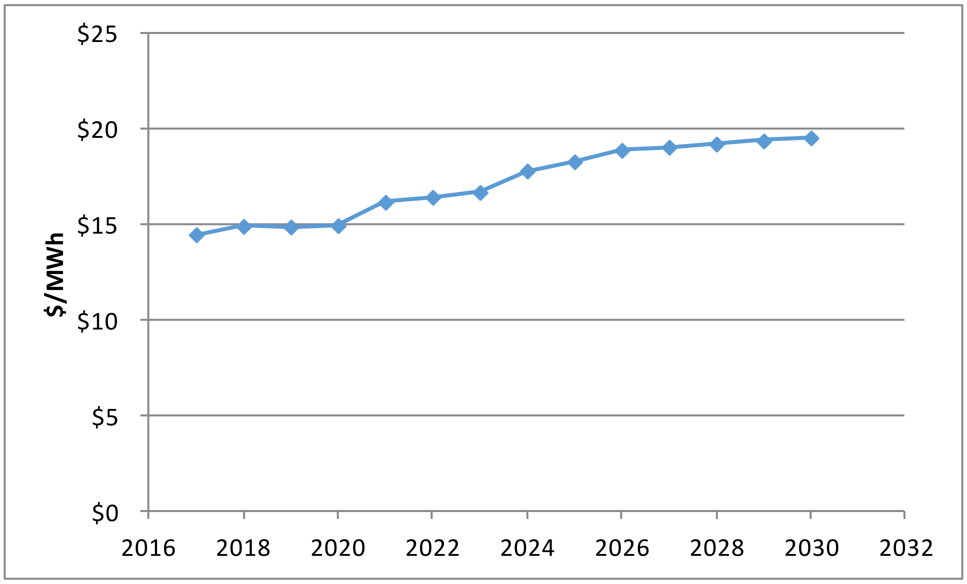


Renewable Power

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

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

Figure 4. Renewable Power Price Premium

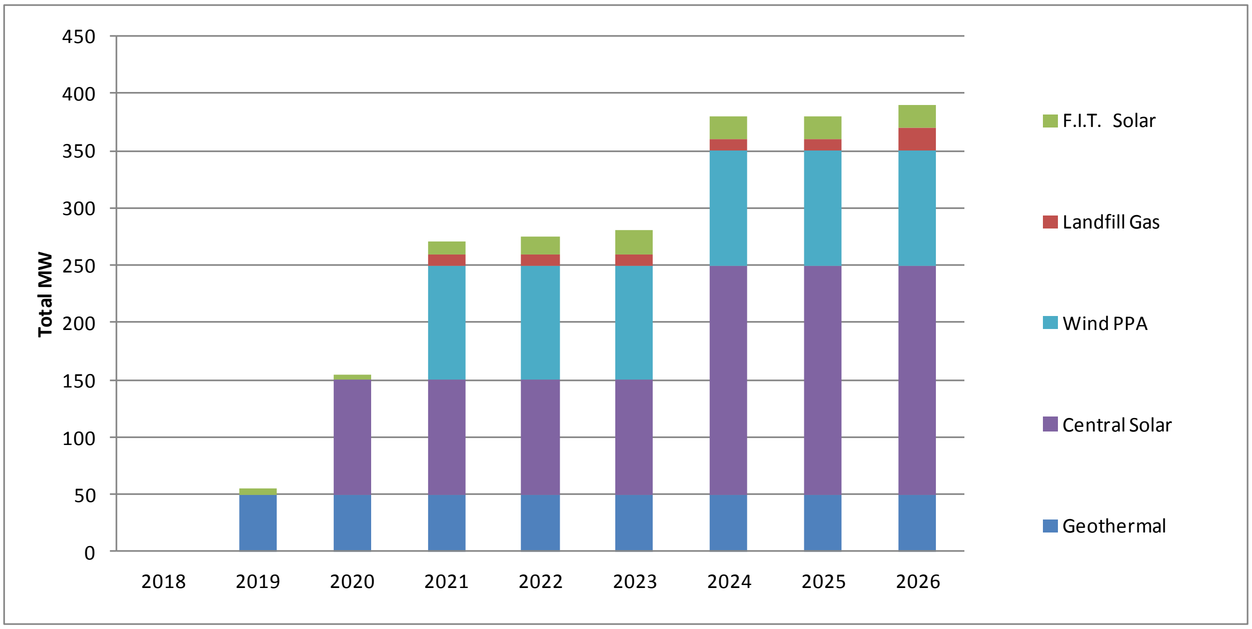


The long-term PPAs for renewable power assumed in the Study are shown in Table 1 and Figure 4. The prices for the large ground solar PV, wind and geothermal are reasonable and consistent with the current markets. As discussed below, the price for the feed-in tariff (FIT) solar power may be too low to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

Table 1. MBCP Renewable Additions

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

Figure 5. MBCP Renewable Additions



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

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

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

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

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

Transmission and Grid Services

The CAISO charges all entities that use its grid for the transmission and grid management services that it performs. These include costs of managing transmission congestion, acquiring operating reserves and other "ancillary services," and conducting CAISO markets and other grid operations. These charges amount to roughly 5-6% of the procurement costs. The values used by PEA are reasonable.

Other Cost of Service Elements

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

PG&E Fees paid by CCA Customers

PG&E imposes two surcharges that are unique to CCA and direct access customers: the Franchise Fee Surcharge and the Power Charge Indifference Adjustment (PCIA). These surcharges are not program costs *per se*, but impact how a customer's bill will compare between PG&E bundled service and CCA service. The franchise fee surcharge is a minor charge that ensures PG&E collects the same amount of franchise fee revenues whether a customer takes generation service from a CCA or from PG&E. The PCIA is a charge that is intended to ensure that generation costs incurred by PG&E before a customer transitions to CCA service are not shifted to remaining PG&E bundled service customers (following a customer's departure from PG&E to CCA service).

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

Sensitivity Analyses

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

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

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

Variables Considered

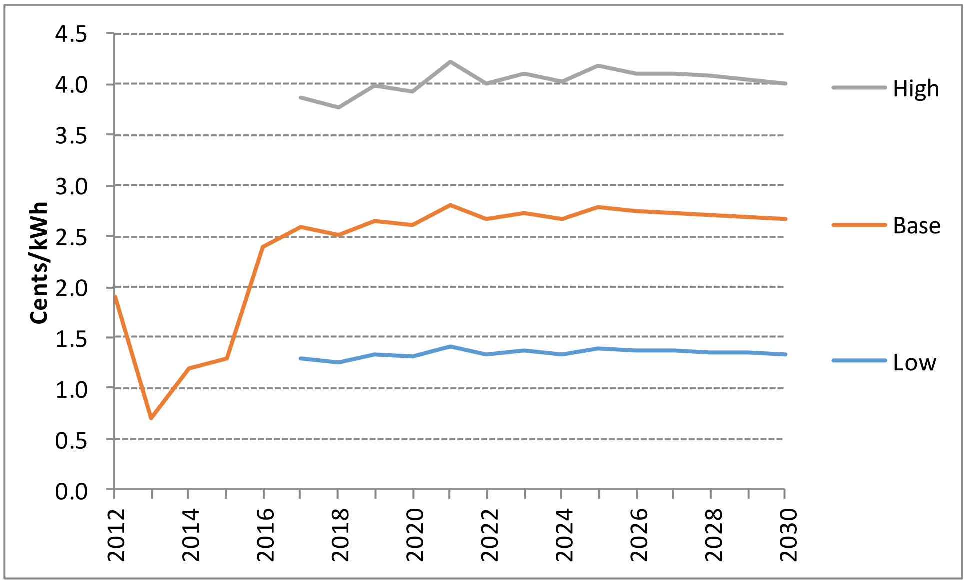
Natural Gas: Sensitivity to changes in natural gas and power prices were tested by varying the base case assumptions to create high and low cases. The high case reflects a 50% increase in this input relative to the base case and the low case reflects a 25% decrease relative to the base case. MRW finds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

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

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

Surcharges: The base case PCIA projections begin with the higher 2016 PCIA charges reported by PG&E and remain relatively flat over the forecast period. High and low cases were run at plus or minus 50% off of the base case (Figure 6). The PCIA is particularly difficult to model, as it is very sensitive to the inputs feeding into the underlying equations. As the 2016 PCIA is particularly high relative to recent PCIA values, using it as the default and exploring even higher PCIAs is reasonable to <u>very</u> conservative.

Figure 6. PCIA Sensitivities



Opt-Outs: PEA tested the sensitivity of ratepayer costs to customer participation in the CCA in Scenarios 1 and 2 by varying the opt-out rate from 25% in the high case to 5% in the low case. For Scenario 3, the high case was set to 35% for residential and small commercial customers and 60% for all other customer groups, while the low case was set to 15% for residential and small commercial and 40% for the other customer groups. MRW finds these opt-out rates to be reasonable.

Carbon-free: In consideration of the potential for increased CCA demand for low carbon content energy and the generally fixed supply of the large hydro-electric generation resource base available to California consumers, the Study explored the impact of increasing the carbon-free energy cost premium scenario by 300% (relative to the base case assumption), from about $3/MWh to $12/MWh. MRW finds this range to be reasonable.

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

Sensitivity Results

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

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

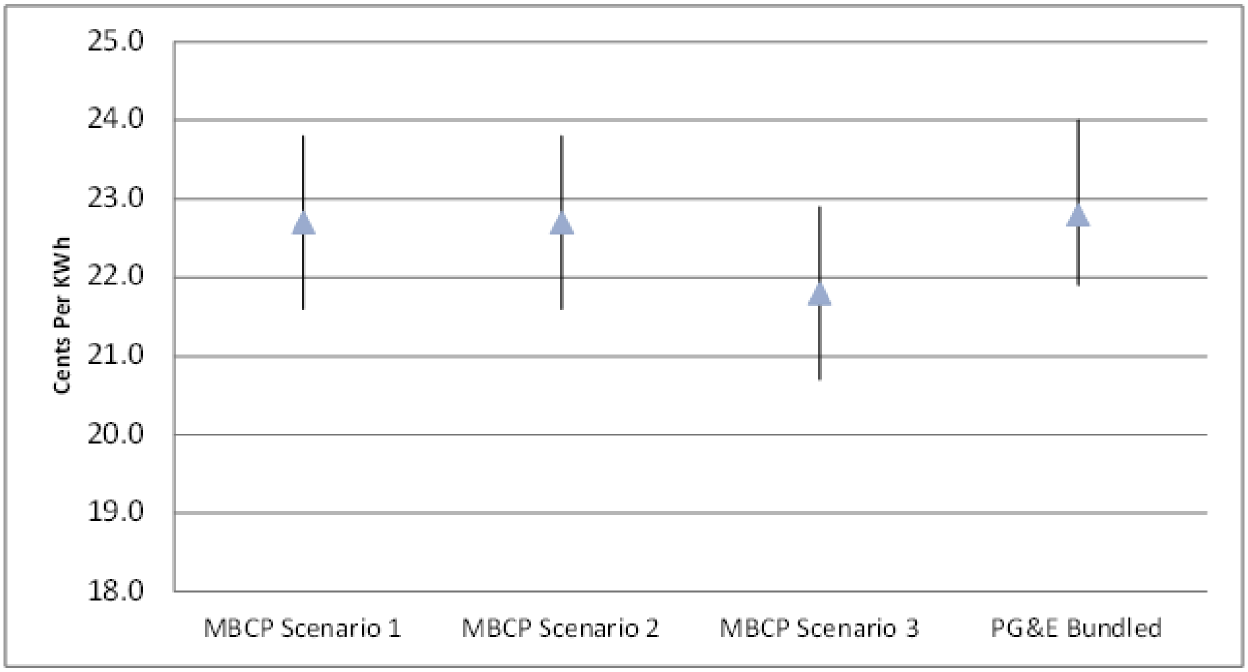


Table 2 below repeats the sensitivity results table on page 69 of the Study. The results for Scenarios 1 and 2—where MBCP average costs are modeled to equal PG&E’s rates are as one should expect. Variables that impact both PG&E and MBCP, such as gas and wholesale power cost, do not change the relative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

Table 2. Sensitvity Analysis: Scenarios 1 and 2 Leveized Ratpayer Costs (¢/kWh)

Rate Scenario	Base Case	High Gas/ Power	Low Gas/ Power	High R.E. Costs	Low R.E. Costs	High PG&E Rates	Low PG&E Rates	High PCIA	Low PCIA	High Opt Out	Low Opt Out	High Carbon Free Cost	Perfect Storm
MBCP Scenario 1	22.7	23.4	22.4	23.5	21.9	22.7	22.7	23.8	21.6	22.7	22.7	22.7	24.9
MBCP Scenario 2	22.7	23.3	22.3	23.4	21.9	22.7	22.7	23.8	21.6	22.7	22.6	22.7	24.8
MBCP Scenario 3	21.8	22.5	21.5	22.3	21.3	21.8	21.8	22.9	20.7	21.8	21.8	22.1	24.1
PG&E Bundled	22.8	23.5	22.5	22.8	22.8	24.0	21.9	22.8	22.8	22.8	22.8	22.8	22.8

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

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

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

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

[2] Subject to a CPUC reasonableness review.

Economic Development Impact Analysis

To quantify the economic impacts associated with new renewable generation projects that were incorporated in each of the three energy supply scenarios, the Study utilized the National Renewable Energy Laboratory's Jobs & Economic Development Impact (JEDI) models. The JEDI models are publicly available, spreadsheet-based tools that were specifically designed to "estimate the economic impacts of constructing and operating power plants, fuel production facilities, and other projects at the local (usually state) level. This is an appropriate tool for estimating the rough order of magnitude economic impacts of a CCA's supply portfolio.

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

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

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

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

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

Similarly the report states:

> As reflected in the previous table, the indicative long-term contract supply portfolio, which is assumed to exist in each of the CCA program's three planning scenarios, would result in **significant** economic benefits throughout the state and, **potentially, within the MBCP Communities**. (p. 36. Emphasis added.)

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

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

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

Risk Analysis

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

Financial Risks to MBCP Members

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

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

Deviations between Actual Energy Use and Contracted Purchases

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

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

Market Volatility and Price Risk

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

Availability of Requisite Renewable and Carbon-Free Energy Supplies

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

Legislative and Regulatory Risk

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

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

CCA Bonding Requirement

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

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

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

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

CCE Formation Activities

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

Conclusions

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

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