REPORT ON THE FEASIBILITY OF COMMUNITY CHOICE AGGREGATION IN SONOMA COUNTY

OCTOBER 10, 2011



PREPARED BY

SONOMA COUNTY WATER AGENCY
COUNTY OF SONOMA GENERAL SERVICES
DALESSI MANAGEMENT CONSULTING LLC
MRW & ASSOCIATES

Foreward

This report was prepared at the direction of the Board of Directors of the Sonoma County Water Agency. On March 11, 2011, the Board authorized the Agency to hire consultants to perform a study of whether a Community Choice Aggregation program would be feasible in Sonoma County. The Board also instructed staff to form a steering committee consisting of interested parties from local jurisdictions, non-profits, and other community members.

Contents of this Report

1. **Executive Summary**, prepared by Sonoma County Water Agency and Sonoma County General Services
2. **Community Choice Aggregation Feasibility Study**, prepared by Dalessi Management Consulting LLC
3. **Peer Review of the Community Choice Aggregation Feasibility Study**, prepared by MRW & Associates, LLC

Selection of Consultants

A Request for Qualifications was prepared for the selection of consultants qualified to perform an analysis of the County's electric load and how it might be served by a CCA. Statements of qualifications were received from five consulting firms. Dalessi Management Consultants was selected to perform the technical feasibility study and MRW & Associates was selected to perform a peer review of Dalessi's work.

Formation of Steering Committee

Invitations to take part in a steering committee were proffered at meetings of the Regional Climate Protection Authority (RCPA) and the City/County Managers' meeting. Additional invitations were made to non-profits and labor and development interests. The committee eventually consisted of Kathy Millison (City of Santa Rosa), Linda Kelly (City of Sonoma), Kevin Thompson (Town of Windsor), Suzanne Smith (Sonoma County Transit Authority), Bill Keene (Open Space and Agricultural Preservation District), Veronica Ferguson (County Administrator), Donna Dunk (Interim Auditor-Controller, Treasurer-Tax Collector), Jose Obregon (County of Sonoma, General Services), Ann Hancock (Climate Protection Campaign), Dick Dowd (Private Developer), John Lloyd (International Brotherhood of Electrical Workers), and Suzanne Doyle (Sierra Club). Representatives from the Water Agency and County Counsel and other county and city employees also participated on the committee.

A sub-committee of the Steering committee was formed to address some technical issues in detail, including consultant selection and identification of power supply scenarios.

The Steering committee met monthly and has been kept informed of all developments in the feasibility study as they occurred. The Steering Committee provided significant input into the power supply scenarios investigated by Dalessi.

Report on the Feasibility of Community Choice Aggregation in Sonoma County

Part I: Executive Summary

October 10, 2011

Prepared by
Sonoma County Water Agency
Sonoma County General Services

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I. Introduction and Summary

On March 22, 2011, the Board of Directors of the Sonoma County Water Agency authorized and directed staff to conduct a study of the feasibility of implementing a "Community Choice Aggregation" ("CCA") program in Sonoma County. This report summarizes the results of that work, and contains the following elements:

- Background on CCA programs generally
- Potential advantages of a CCA program
- The process used by staff to study CCA feasibility
- Summary of analysis and forecasts of CCA rates and other impacts under four different scenarios
- A discussion of CCA implementation risks
- A discussion of CCA organizational and governance issues
- Recommendations for next steps

The study concludes that implementation of a CCA program in Sonoma County is feasible. The study estimates customers of the CCA would pay higher power rates on average over the 20-year study period, with the difference between CCA rates and utility rates decreasing over the long term. The study shows that CCA implementation would significantly reduce greenhouse gas emissions, create local jobs, and have a substantial positive effect on the local economy. The precise impacts of a CCA on these factors (rates, GHG reduction, local jobs) vary depending upon what portion of the CCA's power supplies come from renewable or local sources.

The feasibility study is the first step in determining if a CCA program is right for Sonoma County. It provides estimates of the possible impacts of a CCA program on rates, costs, emissions, jobs and the economy. Because the estimates contained in the feasibility study are based on assumptions about future conditions, the estimates are inherently subject to some uncertainty, and should be thought of as the most likely values within a range of possible values, rather than precise predictions.

II. Community Choice Aggregation Background

In 2002, the California Legislature enacted legislation permitting the creation of "Community Choice Aggregation" (CCA) programs. Under the legislation, codified as Public Utilities Code §366.2, a city, county, or Joint Powers Authority comprised of two or more cities and counties may implement a CCA program. SB 790, signed by Gov. Jerry Brown on October 8, 2011, also allows the Sonoma County Water Agency to operate a CCA program. Once formed, customers within the CCA service area can opt out of the CCA and continue to receive power from the utility (e.g., PG&E). Those that do not opt out will have their power supplied by the CCA entity. The utility continues to provide and bill CCA customers for power transmission and other services (e.g., meter reading, billing). Only the electricity generation portion of electricity service is provided by the CCA entity. Customers of a CCA continue to pay the same charges for the delivery of the power (transmission and distribution) as customers that remain with the utility. The CCA entity must pay the utility for services provided to the CCA (such as billing services).

As noted, customers within a CCA jurisdiction may choose to opt out of the CCA program, and continue to receive electric power from the utility. Customers must receive at least four notices of their ability to opt out of the CCA program – two before CCA service starts, and two more in the first two billings after CCA service starts. Customers not opting out of the CCA program at the outset of the program nevertheless retain the ability to opt out later and return to receiving electrical power from the utility. In the case of a later opt-out by a customer, the CCA program can impose a surcharge to recover any unrecoverable costs of obtaining power supplies or generation capacity for that customer.

CCA programs have proven successful in other jurisdictions. In Ohio, the Northeast Ohio Public Energy Council (NOPEC) operates the largest CCA program in the United States. Formed in 2000, NOPEC represents 126 communities in eight counties, and has more than 420,000 electrical and 200,000 natural gas customers. Cape Light Compact, formed in 1997, aggregates power to serve more than 200,000 consumers on Cape Cod in Massachusetts.

CCA programs have been authorized in California since 2003. A number of CCA programs have been proposed but not implemented, including programs in San Francisco (Clean Power SF), the East Bay (Oakland, Emeryville and Berkeley), and the San Joaquin Valley (San Joaquin Valley Power Authority). The only CCA program operating in California was created in Marin County and began serving customers in May 2010. Called Marin Clean Energy, the program is operated by the Marin Energy Authority, a joint powers authority comprised of the County of Marin and the cities of Mill Valley, Fairfax, San Anselmo, San Rafael, Tiburon, and Sausalito (Novato, Ross, and Larkspur also recently decided to join the program). Marin Clean Energy currently serves approximately 8,000 customers, with a goal of having 70,000 customers by the end of 2012.

III. Statutory Requirements for Formation of CCA Program

Section 366.2 of the Public Utilities Code specifies the requirements for formation of a CCA program. The formation process begins with the adoption of an ordinance by the entity proposing to implement the CCA program, followed by preparation of an Implementation Plan, which must contain certain elements specified by the statute. The Implementation Plan must also contain a Statement of Intent by the public entity proposing the CCA program, stating its intention to provide universal access, reliability, equitable treatment of all classes of customers, and to meet any other requirements established by state law or by the California Public Utilities Commission (CPUC).

The Implementation Plan must be submitted to the CPUC for review. The entity proposing the CCA program must also provide to the CPUC any information necessary to allow the CPUC to determine the cost responsibility surcharge (CRS) applicable to CCA customers. To protect a utility's remaining customers from rate hikes, the CRS reimburses unavoidable utility power procurement costs resulting from the loss of customers to the CCA. Within 90 days, the CPUC must review and certify the Implementation Plan and inform the CCA program of the CRS applicable to it.

The CCA program must also register with the CPUC, and include with the registration an executed copy of a services agreement between the CCA entity and the utility, governing the services to be provided by the utility under the CCA program. The CCA entity must also submit evidence of insurance, self-insurance, or a bond that will cover such costs as potential re-entry fees, penalties for failing to meet operational deadlines, and errors in forecasting. Once the CCA entity has registered with the CPUC and signed the services agreement with the utility, the CCA entity must give the utility 30-days' notice of the commencement of CCA service.

IV. Potential Advantages of a CCA Program

There are a number of potential benefits to having a public CCA entity provide electrical power rather than a utility:

- *Increased Renewable Energy Use*: Because a CCA entity can select the type of power it provides to its customers, it can focus on carbon-free, renewable power sources, and reduce its reliance on generation using fossil fuels such as gas or coal.
- *Local Economic Benefits*: If the CCA entity were to focus on local renewable generation sources, the millions of dollars paid by residents of Sonoma County and the region would stay "at home" rather than be paid to the utility, thus creating local jobs and improving the local economy.
- *Local Control*: The operations and priorities of PG&E are determined by its shareholders, its management, and the CPUC. In contrast, the governing board of the CCA entity would be comprised of local elected officials, so that residents could more easily influence decisions about the operation and priorities of the CCA entity.
- *Lower Financing Costs*: Because public entities are able to finance electrical generation facilities with tax-exempt bonds and do not have to pay dividends to shareholders, a public CCA program may, in the long run, be able to provide electrical power at a lower cost than utilities.
- *Rate Stability*: By increasing the amount of power obtained from long-term contracts or self-owned generation facilities, a public CCA can lock in electricity prices and provide improved stability to its customers. Business customers in particular tend to value predictability in their energy costs to aid in business planning.
- *Increased Consumer Choice*: A public CCA increases consumer choice, by giving customers an option of receiving power from the CCA entity or remaining with the utility.
- *Increased Conservation Programs*: A public CCA could choose to undertake more aggressive energy conservation programs than the utility, reducing consumers' overall energy costs and further reducing greenhouse gas emissions.
- *Providing a Market for Small-Scale Renewables*: A public CCA can provide a market for small-scale private renewable energy projects (such as photovoltaics), and thus help encourage the development of those projects.

V. Development of Scenarios for Evaluation

An evaluation of the feasibility and potential impacts of a CCA program in Sonoma County requires making certain assumptions about the sources and characteristics of the electrical power the CCA would obtain to supply its customers. These include the relative contributions of renewable (clean/carbon-free) power as opposed to conventional (fossil fuel) power; whether power should be generated at facilities owned by the public CCA entity or acquired through contracts with private parties; and whether generation facilities should be located primarily in or near Sonoma County.

The Water Agency hired a consulting firm – Dalessi Management Consulting, LLC – with expertise in the areas of CCA formation and power markets to assist staff to evaluate CCA feasibility. Water Agency staff also formed a Steering Committee, consisting of representatives from the Office of the County Administrator, the City of Santa Rosa, the Town of Windsor, the City of Sonoma, the Regional Climate Protection Authority, the Open Space and Agricultural Preservation District, the Auditor-Controller-Treasurer-Tax Collector, Sonoma County General Services, the Climate Protection Campaign, the International Brotherhood of Electrical Workers, the Sierra Club, and private developers, assisted by Water Agency and County Counsel staff. The Steering Committee met monthly.

Water Agency staff worked with Dalessi and the Steering Committee to develop four power resource scenarios for evaluation by Dalessi. These scenarios varied according to two primary elements: the portion of the power coming from renewable, carbon-free sources, and the portion of the power generated from local facilities. Preliminary drafts of Dalessi's analysis were presented to Water Agency staff and the Steering Committee for review and comment. The Water Agency also engaged MRW & Associates, a consultant with expertise in power markets and CCA formation, to peer review the Dalessi analysis.

Dalessi evaluated four scenarios:

- Scenario 1: The electricity supplied by the CCA would meet – but not exceed – the State of California's "Renewable Portfolio Standards" for utilities (which requires 33% of all power to be generated from renewable sources by 2020). This is considered a "baseline" scenario, expected to have the lowest ratepayer cost but also the lowest environmental and economic benefit.
- Scenario 2: The CCA would move more aggressively into renewable energy sources, starting out at 33% renewable and increasing to 51% renewable by 2020. Power would be provided through a mix of non-renewable contract power purchases, power purchases of solar photovoltaic, wind and geothermal energy, and generation from CCA-owned biomass and solar photovoltaic resources. The geothermal and biomass energy would be generated locally, while the other resources are assumed to be sourced from other parts of Northern and Central California.
- Scenario 3: This scenario represents an even more aggressive transition to renewable resources, emphasizing development of renewable resources within Sonoma County, both large and small-scale. The Scenario 3 renewable energy content starts at 51% and increases to 75% by 2020.
- Scenario 4: Scenario 4 includes a resource mix modeled after those contained in the Sonoma County Community Climate Action Plan. Its aim is to maximize the use of the tools afforded by CCA to achieve the greatest amount of local distributed renewable generation at the lowest possible cost. Scenario 4 represents the most aggressive transition to renewable resources of the four scenarios analyzed and emphasizes development of renewable resources within Sonoma County, both large and small-scale. The Scenario 4 renewable energy content starts at 20% and increases to 85% by 2020.

VI. Summary of Results of Dalessi Analysis

Overall, the analysis estimates that a CCA program would increase the electricity bill for a typical residence by $4 to $10 per month (depending on the scenario), while significantly reducing greenhouse gas emissions. The analysis estimates that a CCA program would create local jobs and produce positive economic impacts, although the exact impacts were more difficult to quantify.

Rates

In every scenario studied, implementation of a CCA program results in an increase in power costs to consumers when averaged over the 20-year evaluation period. The difference between CCA rates and utility rates is highest in the early years, but gradually decreases over time. As noted by the MRW peer review, estimates further out in time tend to be less certain. The MRW peer review also suggested that the Dalessi estimate for future utility (PG&E) rates was too high, which if true would further increase the estimate of additional costs consumers would pay under a CCA program.

The chart below shows estimated additional consumer costs under a CCA program for the four scenarios considered by Dalessi. These estimates are calculated using the energy consumption data on page 19 of the Dalessi report and the estimated difference in "levelized" rates over the 20-year study period.

	Additional Annual Aggregate Customer Cost (Average, $ millions)	Additional Annual Aggregate Customer Cost (Highest Year)	Additional Annual Aggregate Customer Cost (Lowest Year)
Scenario 1	$14.1	$18.6 (2014)	$8.7 (2019)
Scenario 2	$16.1	$26.3 (2016)	($4.7) (2032)
Scenario 3	$34.3	$54.6 (2017)	$4.6 (2032)
Scenario 4	$18.2	$29.3 (2020)	($0.4) (2032)

	Additional Annual Cost Per Residential Account (Average)	Additional Annual Cost Per Residential Account (Highest Year)	Additional Annual Cost Per Residential Account (Lowest Year)
Scenario 1	$47	$63 (2014)	$29 (2019)
Scenario 2	$53	$87 (2016)	($15) (2032)
Scenario 3	$113	$181 (2017)	$15 (2032)
Scenario 4	$60	$97 (2020)	($1) (2032)

Although the estimated cost of power from a CCA program is higher than the cost of PG&E power when averaged over the 20-year study period, the CCA program could produce significant reductions in greenhouse gas emissions, and have a significant positive impact on the local Sonoma County economy.

Carbon Emission Reductions

The Dalessi study estimates that a CCA program would result in the following reductions in carbon emissions over the 20-year study period:

Scenario Number	Carbon Emission Reduction
Scenario 1	70,000 Metric Tons
Scenario 2	3,100,000 Metric Tons
Scenario 3	7,100,000 Metric Tons
Scenario 4	7,600,000 Metric Tons

To provide an idea of the magnitude of these reductions, according to the United States Environmental Protection Agency's "Greenhouse Gas Equivalencies Calculator," the total carbon emission reduction under Scenario 4 is equivalent to taking 74,500 carbon-emitting automobiles off the road for the entire 20-year study period.

Job Creation

Because a portion of the electricity supplied by the CCA program would come from local renewable energy sources, the CCA program will have a positive effect on the economy of Sonoma County and the region. The Dalessi report estimated the magnitude of these impacts by using the National Renewable Energy Laboratory's ("NREL") Jobs & Economic Development Impact ("JEDI") models, which are publicly available, spreadsheet-based tools that were specifically designed to estimate the economic impacts of constructing and operating power generation and biofuel plants at the local (usually state) level. Dalessi replaced the model's "default" assumptions with values more appropriate for the types of transactions and local development opportunities that the CCA program may actually pursue, thus generating economic development projections that should more accurately reflect local impacts that will likely accrue to Sonoma County. Dalessi also "fine tuned" the model to separate out local vs. non-local impacts. (For example, wind turbines would, in all likelihood, be purchased from a supplier outside of Sonoma County, but hardware required to install these turbines may be purchased from local suppliers, and local labor would be needed for the installation itself.)

Dalessi used the model to evaluate the economic impacts of each of the four scenarios. As noted in the Dalessi study, the economic impacts are much larger during the periods when local generation facilities are being constructed (estimated to take 24 months), although some long-term impacts continue as a result of the operation and maintenance of the facilities. The study thus estimates the economic impacts separately for these two periods of time.

A summary of the results of the Dalessi evaluation are below. Note that the figures for "Short-Term Jobs" are in units of 1 FTE per year. For example, an estimate of 500 jobs created over a two-year construction period would be the equivalent of 250 people working for two years.

Scenario	Short-Term Economic Output ($ Millions)	Short-Term Jobs (FTE/year)	Long-Term Economic Output ($ Millions/year)	Long-Term Jobs
Scenario 1	$15 - $50	100 - 300	$4 - $20	15 - 100
Scenario 2	$20 - $100	100 - 400	$10 - $20	20 - 100
Scenario 3	$100 - $200	700 - 1,500	$20 - $50	100 - 200
Scenario 4	$70 - $200	400 - 1,100	$30 - $80	100 - 400

As noted in the peer review, although the construction of local renewable energy projects would have a positive impact on the local economy, "all macro-economic models have built-in uncertainties," and thus the model output "should be seen as order-of-magnitude rather than precise." The peer review also noted that the Dalessi model did not account for the possible negative economic impact of the higher electricity rates that would be paid by consumers under the CCA program.

Nevertheless, the Dalessi report shows that creation of a CCA program, followed by the construction of local renewable energy projects, could have a significant positive effect on the local economy.

VII. Peer Review Comments

The MRW peer review of the Dalessi analysis generally found that Dalessi's general approach, assumptions, and methods of analysis were reasonable and sound. In particular, MRW concluded that Dalessi's methodology was sound, and that Dalessi had included all major CCA cost components in its evaluation. However, the MRW peer review noted several issues that could result in an increase in the estimates of CCA power costs or make the formation and operation of a CCA less feasible:

- Dalessi may have overestimated the likely short-term future increases in PG&E generation rates, as discussed at page 4-5 above.
- MRW notes that commercial and industrial power users are likely to be more rate-sensitive and thus more likely to opt out of the CCA than residential users. This would affect the CCA's load curve and could lead to higher power costs than estimated in Dalessi report.
- The CCA would be required to offer a reduced "CARE" rate to low-income residential customers, thus increasing the rates of non-CARE customers, but this was not accounted for in the Dalessi report.
- MRW questions whether the future local renewable power projects assumed under the Dalessi scenarios could actually be designed, approved, and constructed within the time frame

estimated by the Dalessi report, and whether the CCA would be able to obtain timely financing for CCA-owed generation facilities.

- The CCA statute requires a CCA entity to post a bond with the CPUC to cover the potential costs to the utility if the CCA entity fails and all CCA customers are returned to utility service. MRW noted that the amount of the bond the CPUC will require is uncertain, but could be greatly in excess of the $700,000 amount estimated by Dalessi. MRW is uncertain whether financial institutions would be willing to issue, and whether the Sonoma County CCA entity could afford, a bond amount greatly in excess of the Dalessi estimate.

MRW was not asked to estimate the effect of these factors on the specific results contained in the Dalessi report. It is likely, however, that these factors would result in CCA rates being higher than those estimated by Dalessi, and make CCA rates less competitive.

Many of the MRW comments resulted in changes in the final Dalessi analysis. These are described in a preface to the Dalessi report.

VIII. Risk Factors Associated with CCA Formation

The risks associated with CCA formation fall into two categories: Pre-formation risks and post-formation (operational) risks.

Pre-formation Risks

As noted above, creating a CCA program will require a number of political, engineering, legal, and financial steps, including the development of a detailed Implementation Plan that must be submitted to and certified by the California Public Utilities Commission. This CCA development work, and the preparation of the Implementation Plan, will require the hiring of expert consultants to perform engineering, legal, and financial work. Dalessi estimated the total start-up costs for the CCA to be $1.7 million. In addition, there are also “pre-start-up” costs (which may not be recoverable from CCA rates), such as the costs of investigating CCA feasibility, entering into necessary formation related agreements (such as a JPA), and so on. Staff estimates these at $500,000 to $750,000 based upon experiences in other jurisdictions.

During this pre-formation phase, the primary risks are the possibility that the incumbent utility (PG&E) will actively oppose CCA formation, or that changes in CPUC regulations will make CCA formation more difficult. To date, PG&E has not been overtly opposed to a Sonoma County CCA. In any event, there is a risk that additional funds will be spent to investigate and evaluate CCA formation and that the Board of Supervisors or City Councils will decide not to move forward. In that case, the money spent will not have resulted in any affirmative change.

Once the decision has been made to form a CCA program, the CCA entity will begin taking steps necessary to commence operations. Depending on how the CCA entity elects to structure its program, additional funds will be needed to finance the start-up activities. Necessary steps include the following:

- Recruit and hire staff;

- Develop informational and program marketing materials;
- Establish call center for customer inquiries;
- Contact key customers to explain program, obtain commitment, and release customer information;
- Prepare short and long-term load forecast;
- Develop capability or negotiate contracts for operational services (such as electronic data interchange with utility, customer bill calculations, schedule coordinator services, and so on);
- Execute contracts for electric supply; identify generation projects and negotiate participation, if applicable;
- Obtain financing for program capital requirements;
- Execute service agreement with utility;
- Send customer notices to eligible customers;
- Process customer opt-out requests; and
- Submit notification certification to the CPUC.

Post-formation Risks

Once in operation, the primary risks inherent in the CCA operations are that unanticipated events cause the CCA's costs to increase or PG&E's rates to decrease. As noted, the CCA statute permits residents to opt out of the CCA at any time. If the difference between the cost of power provided by the CCA entity and the cost of power provided by the utility increases, many residents will opt out of the CCA and return to utility service. If this occurs, there is a risk that the CCA entity will have contracted for more power than it can sell to residents, and have to sell that excess power to some third party, potentially taking a loss. In the worst case scenario, this loss of customers could theoretically result in a situation where "higher cost resources built or under long-term contract to the [CCA entity] are spread over an increasingly smaller number of customers until the [CCA entity] is forced to dissolve." (*Potential Benefits and Risks of Implementing Community Choice Energy* (City of Berkeley Energy Commission, June 28, 2010, page 38.) This worst-case scenario would only occur if utility rates became much lower than CCA rates, however. Given that a CCA program relying on its own generation resources would be *less* subject to volatility in the electricity market than the utility, the risk of this worst-case scenario occurring is likely very small.

Appropriate program rules that impose exit fees to compensate remaining program customers for commitments made on behalf of the departing customers will mitigate the risk of losing customers. However, if customers find themselves obligated to a program with higher rates than those offered by PG&E (or other competitors), their dissatisfaction may be directed at those responsible for administering the program.

The predominant cost of service variables and risks that might impact the CCA's operational costs are:

- The cost responsibility surcharge will vary year-to-year. The CRS is inversely related to the prevailing market price of electricity such that if market prices fall, the CRS will increase. To the extent the CRS increases and the CCA program has locked in electricity prices through long-term electricity or fuel contracts, the CCA customers' total rates will increase. (The Dalessi study estimates that the CRS increases CCA rates by 1.1 to 1.4 cents/kWh in early years, but gradually decreases to zero by 2020.)

- The CCA entity could improperly hedge its exposure to electricity and/or natural gas price volatility, and adverse price movements could cause rate increases for its customers. Similarly, the CCA program could over-rely on long-term contracts with fixed prices and find itself holding a high cost portfolio if market prices subsequently fall.
- The CCA program could fail to properly secure its customer base, making debt financing via the capital markets impossible to obtain and exposing the CCA program to stranded costs if customers opt-out of the CCA program. Even with appropriate switching rules, large customers may go out of business or leave the area and leave behind costs that must be paid by remaining program customers.
- The CCA program's energy suppliers could default on supply contracts (credit risk) at times when energy spot markets are high, forcing the CCA entity to purchase energy at excessively high prices. Customers could fail to pay the CCA program's charges, and the CCA program's credit policies and customer deposits may be insufficient to recover the uncollectible bills.
- PG&E could make changes to its rate designs that reduce the cost of generation services and increase the costs of delivery services or that shift costs among customer classes in a manner that disadvantages the customer mix served by the CCA program.
- Other regulatory risks associated with changes in the rules and tariffs administered by the CPUC or in the wholesale markets regulated by the Federal Energy Regulatory Commission (FERC) could increase the CCA program's cost of providing service. For example, a requirement to use geographic-specific load profiles for electricity procurement could advantage coastal communities to the detriment of those located in hotter, inland climates.

Each of these risks can be mitigated, although not altogether eliminated. Ultimately, the major operational risks are under the control of the program's management. Disciplined, professional management is key to managing risks inherent in offering retail electric services. The CCA program will be able to contract for services from a variety of large, experienced energy suppliers that have excellent operational capabilities. It should be noted that municipal utilities have been successfully managing commodity, credit, and operational risks for many decades, even during times of high commodity prices and supply shortages.

Finally, if the CCA program were operated by a Joint Powers Authority as described below (which would likely be the case), the general funds of the cities and counties participating in the CCA program could be immunized from any contractual liabilities resulting from the CCA program. Thus, although the risks above could affect the finances of the CCA program itself (and its ratepayers), those risks would not result in liabilities payable from the general funds of participating cities and counties.

IX. CCA Organizational and Governance Issues

An effective Sonoma County CCA program would require the participation of a number of separate jurisdictions (e.g., the County and the cities choosing to participate in the program). Collective participation can be accomplished through the creation of a Joint Powers Authority pursuant to Sections 6500 et seq. of the Government Code. The several jurisdictions can create a separate authority to operate the CCA program (as was done in Marin County for its CCA program). As noted above, this method has the additional advantage of allowing the participating jurisdictions to protect their general funds from any contractual liability or debt incurred by the JPA in connection with the CCA program.

A number of issues must be resolved in connection with the formation of a JPA, including determining the respective monetary contributions of the jurisdictions to offset start-up costs. The composition of the governing board of the JPA will also require negotiation, with consideration given both to the composition of the CCA ratepayer base (that is, assuring relatively equal representation for ratepayers regardless of jurisdiction) and to the need for each participating jurisdiction to have sufficient representation on the governing board. Resolution of these issues is necessary prior to the formation of a JPA to operate the CCA program.

X. Combined Operations with Marin Energy Authority

The Dalessi report noted that the costs of implementing and operating a CCA program in Sonoma County could be significantly reduced by cooperating with the Marin Energy Authority, which operates the CCA program in Marin County. Such cooperation could range from having Sonoma County jurisdictions join as full participants in MEA, to lesser forms of cooperation (such as shared administrative “back office” functions). The Dalessi report estimated maximum cooperation with MEA could result in savings of up to $1.5 million in start-up costs and up to $2.6 million annually thereafter.

However, the feasibility of joining MEA or engaging in some lesser type of cooperation is uncertain. Because Marin and Sonoma Counties share roughly similar electric load profiles and demand shapes, combining the two has the potential to increase the cost base to MEA customers. This could occur if additional evening residential demand and low daytime commercial/industrial demand were to create compounding demand peaks. In addition, due to Sonoma’s larger population, issues regarding weighting of votes in an expanded Joint Powers Authority may arise. Different priorities among parts of the North Bay population may result in disagreements over long-term priorities for the CCA. For example, it may be more difficult to obtain the local economic development benefits of construction of renewable generation facilities within Sonoma County under a common operation with MEA.

Further analysis of these issues is necessary to fully evaluate the feasibility of joint operations with MEA.

XI. Conclusions and Recommended Next Steps

Implementation of a CCA program in Sonoma County could result in significant reductions in greenhouse gas emissions, provide substantial local economic benefits and additional local jobs, provide greater electric rate stability, and give local ratepayers a choice over power providers. However, the Dalessi study estimated that electric rates under a CCA program would be higher than current utility rates, both in the short term and over the entire 20-year period studied. The magnitude of the increases depends upon the portfolio of power sources used by the CCA program – generally speaking, use of renewable sources and power from local generation facilities tends to increase the cost of power to CCA customers, although, as noted earlier, the use of renewable, local sources of power provide significant local economic benefits and result in a substantial reduction in greenhouse gas emissions.

Staff recommends that the Board authorize Water Agency staff, in consultation with the Steering Committee, to investigate ways to reduce the estimated rates that would be charged under a Sonoma County CCA program, and to develop more specific recommendations for the CCA program. In particular, we recommend the following:

- Initiation of preliminary discussions with staff from the Marin Energy Authority to determine possibilities for cooperation with MEA, and the extent to which a cooperative effort could still allow for Sonoma County control over the power mix, rates, and other service terms applicable to Sonoma County ratepayers.
- Investigation of whether varying the mix of power resources could reduce CCA power costs, while still providing greenhouse gas reduction benefits (e.g., increased use of larger-scale, non-local renewable power resources).
- Investigation of whether the addition of a significant energy efficiency component could result in a decrease in the estimated CCA program rates. The efficiency program could finance large-scale retrofit projects (commercial, industrial, and public facilities) and fold a portion of the economic benefit from the retrofits back into the CCA, to finance smaller-scale retrofits and reduce rates.
- Development of more specific proposals for organization and governance for the CCA program.

Part II: Sonoma County Community Choice Aggregation Feasibility Study

John Dalessi

Dalessi Management Consulting LLC

September 29, 2011

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Preface

Summary of Changes Made in Response to Peer Review

DMC received comments on the August 19, 2011 Draft Feasibility Study Report from members of the project Steering Committee and from an independent consultant review by MRW and Associates. The changes that were made in response to these comments are summarized below. Editorial, formatting and other minor changes reflected in the September 29, 2011 final report are not noted here.

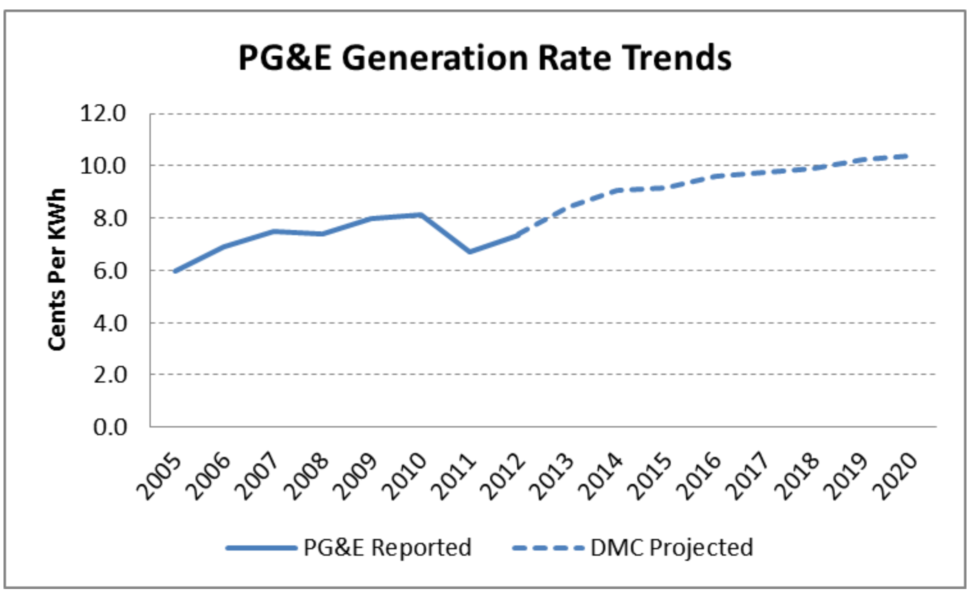
Load Growth

The projected baseline rate of growth in customer load was increased to 0.7% (from 0.5%), consistent with the more recent California Energy Commission estimates cited by MRW.

The adjustment to load growth to account for additional energy efficiency, conservation, and customer migration was reduced from 1% to 0.5%.

PG&E Rates and Surcharges

The estimate for the PG&E surcharge known as the Power Charge Indifference Adjustment ("PCIA") was modified to be consistent with the methodology set forth in the proposed decision of Administrative Law Judge Pulsiver in R.07-05-025, issued in August, 2011. This adjustment had the effect of increasing the PCIA estimates by approximately 0.6 cents per kWh in 2013 and reducing the estimated PG&E generation rate by 0.1 to 0.2 cents per kWh throughout the forecast period. With this adjustment the DMC rate forecast calibrates well with PG&E's estimate for 2012 (both show a 10% increase from 2011 to 2012). The projections for PG&E generation rates are consistent with historical trends as shown in the figure below.



DMC projects above average PG&E rate increases for the next few years as PG&E must increase its renewable energy content from 15% to 33% by 2020, and the PG&E generation rates begin to include the cost of GHG allowances under California's cap and trade program anticipated to begin in 2013.

DMC's input cost assumptions underlying its PG&E rate forecast are documented in Appendix B of the DMC final report.

Resource Development Assumptions

The composition of Supply Scenario 3 was modified to eliminate the assumption of a large, in-county solar project (115 MW) and replace this assumption with a series of small (25 MW total) and mid-size (90 MW total) installations. The assumed timeline for development of the mid-size ground mount PV projects was pushed out by two years to 2017.

A discussion of the challenges involved with developing electric generation resources was added, and the optimistic development timelines associated with Scenarios 3 and Scenario 4 was noted.

Economic Development Impacts

The economic development impacts were revised to show ranges, rather than single point estimates. Additional research to validate the NREL models used in the study was conducted and summarized. Additional discussion of the inherent difficulties in accurately capturing economic development impacts was added.

CCA Bond

Additional discussion of the CCA bond/security requirement was added, and the estimated bond amount was noted.

Greenhouse Gas Impacts

The quantification of greenhouse gas reductions in monetary terms was deleted. A new set of charts were added to show the CO2 emissions for each supply scenario and how these emissions would compare to the marginal emissions under the status quo.

Rate Presentation

Tables were added showing the estimated rates for each Scenario and for PG&E on a year-by-year as well as on a levelized basis.

Marin Energy Authority

A discussion of the possible disadvantages of partnering with the Marin Energy Authority was added. Additional explanation of how the potential cost savings from a MEA partnership were estimated was added.

Biomass Heat Rate

A correction was made to the erroneous heat rate assumption for biomass resources in the economic development impact appendix. The erroneous heat rate had not been used in the CCA cost/rate analysis, and no correction was necessary to the Supply Scenario cost estimates.

Start-up Costs

Additional detail supporting the startup cost assumptions was added.

I. Introduction

Dalessi Management Consulting ("DMC") was retained by the Sonoma County Water Agency to conduct a feasibility study for the formation of a Community Choice Aggregation program serving the County of Sonoma. DMC is an independent consulting firm specializing in providing strategic advice and technical support to organizations active in the California electricity market. DMC's consultants have been assisting local governments with evaluation and implementation of CCA programs since 2004, including the successful implementation of the first operational CCA program in California.[1] This feasibility study incorporates the best available information drawn from DMC's experience with CCA and utilizes transparent and documented assumptions to provide an objective assessment regarding the prospects for a CCA program in Sonoma County.

This study addresses the estimated costs and benefits of a potential CCA program that would provide electric generation service to customers served by Pacific Gas and Electric Company within the unincorporated portions of the County and within the following incorporated municipalities[2]:

- Cloverdale
- Cotati
- Petaluma
- Rohnert Park
- Santa Rosa
- Sebastopol
- Sonoma
- Windsor

Under existing rules administered by the CPUC, the local electric utility, PG&E, would use its transmission and distribution system to deliver the electricity supplied by the CCA program in a non-discriminatory manner, as it currently does for its own "bundled service" customers and for "direct access" customers who receive electricity provided by competitive retail electricity providers. PG&E would continue to provide all metering and billing services. Customers would receive a single electric bill each month from PG&E, and that bill would show both the charges for CCA generation services and the charges for PG&E delivery services. Money collected by PG&E on behalf of the CCA program would be electronically transferred each day to the CCA program's account. CCA customers would continue to be eligible for programs operated by PG&E and funded through distribution rates, such as subsidies for energy efficiency and customer solar incentives.

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[1] The Marin Clean Energy program began providing electric generation services to customers in Marin County in May, 2010. It is operated by the Marin Energy Authority, a joint powers authority comprised of the County of Marin and seven municipalities within Marin County.

[2] The CCA program would not service customers within the City of Healdsburg, which operates its own municipal electric utility.

The CCA program would participate in the electricity market to purchase electricity from generators, brokers, or marketers, and it may provide electricity generated from its own power plants that it develops or acquires. Other services may be offered as well, such as new programs to promote conservation or energy efficiency, local distributed generation such as on-site solar photovoltaic systems, electric vehicle charging, and customer load shifting.

DMC's analysis quantifies the expected costs and benefits of the CCA program in terms of ratepayer costs, reductions in emissions of greenhouse gases from resources used to supply customers within Sonoma County, and local (in-county) economic development impacts arising from new job creation and local spending. The remaining sections of this report are organized by subject matter as follows:

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

Section 3: Electric Consumption – describes the electric consumption patterns and electric resource requirements of customers within the County.

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

Section 5: Cost and Benefits Analysis – details the estimated costs and benefits for various potential resource mix scenarios in terms of ratepayer costs, reductions in greenhouse gas emissions, and local economic development impacts.

Section 6: Sensitivity Analyses – describes the variables that would have the largest impact on customer rates and shows the range of impacts for each of the key uncertain variables.

Section 7: CCA Formation Activities – summarizes the steps involved in forming a CCA program.

Section 8: Evaluation and Recommendations – summarizes the feasibility study results and provides recommendations based on the analysis.

Appendices – contains detailed input assumptions and other study data.

II. Study Methodology

The analytical framework for the study is a cost-of-service model that estimates all costs that would be incurred in providing aggregation services. The study examined projected economic impacts over a twenty-year study period. As detailed in Section IV, CCA program costs include those associated with energy purchases and/or production as well as administrative, financing and other costs that would be involved in the program's formation and ongoing operations. The sum total of costs over each twelve-month period represents amounts that must be funded through program rates. Program average rates, representing the total program costs divided by total program electricity sales, were calculated for each year as well as on a twenty-year levelized basis to facilitate comparisons among potential electric supply mixes and against projected PG&E rates.

The CCA program would have myriad choices in the types of resources that would comprise its electric supply portfolio. Choices include the mix between renewable and non-renewable generation sources, selection of specific generation technologies (solar photovoltaic, wind, geothermal, etc.), resource location (local, in-state, regional), ownership structure (power purchase agreement, asset acquisition), scale (large "utility-scale", small distributed generation), and duration (short, mid, long-term). Each of these choices presents economic and environmental tradeoffs. These resource choices would be made during the implementation and operations stage by those charged with leading and overseeing the CCA program. Resource planning would be a continual process, enabling adaptation to changing circumstances while respecting the CCA program's overarching policy objectives.

For purposes of the feasibility assessment, DMC worked with the Steering Committee to develop four representative supply portfolios that were evaluated on the basis of ratepayer cost, GHG emissions, and local economic development. The objective of evaluating alternative supply scenarios is to obtain a robust set of analytical results to inform decision-makers of a reasonable range of likely outcomes and to illustrate the inherent trade-offs among the different resource choices that may be made. It should be understood that the CCA program would not be limited to any particular supply scenario assessed in this study.

Supply Scenarios

The supply scenarios are representative of different choices that could be made in terms of overall renewable energy content, resource technologies and location of the electric resources used to supply the CCA program's customers. DMC prepared four scenarios that analyze possible development paths for a Sonoma County CCA. These four scenarios represent options from initial energy purchases from existing generation sources to new generation projects developed as a result of long-term power purchase agreements and/or independent development efforts of the CCA program. The fourth scenario, with accelerated development timelines and a predominantly local resource mix, was provided by members of the Steering Committee for inclusion in the analysis. Additional details regarding composition of the supply scenarios are contained in Appendix B.

Under each of the four supply scenarios, the CCA program would cause new renewable generation projects to be developed through a combination of long-term power purchase agreements and direct investment. In Scenarios 3 and 4, much of the generation development would occur within Sonoma County. It should be recognized that developing generation in California is a difficult and time-consuming process, and developing generation within Sonoma County may be even more difficult than in other parts of the state. Major development challenges include siting, permitting, financing and interconnection with the transmission system. Suitable sites must be identified and placed under control of the developer, and the required land can be quite significant, particularly for solar photovoltaic projects.[3] It is common for proposed new generation projects to draw opposition from local residents who may be impacted visually or otherwise by the project. Once a suitable site is secured and the necessary permits are in place, the project must be financed, and that financing will primarily depend upon the creditworthiness of the CCA program which may take three or more years to build. Considering the challenges inherent in generation project development, it is possible that the development timelines could be longer than assumed in these scenarios.

Scenario 1: 33% Renewable Energy Content by 2020

Scenario 1 can be considered a baseline for comparison of the other scenarios as it was structured to simply meet the legally required Renewable Portfolio Standards (“RPS”).[4] This scenario would be expected to offer among the lowest ratepayer costs during the study period but also offer the least environmental and economic development benefits.

The Scenario 1 resource portfolio contains a mix of system power purchases (non-renewable), power purchases of solar photovoltaic, wind and geothermal energy, and generation from CCA program-owned biomass and solar photovoltaic resources. The geothermal and biomass energy would be generated locally, while the other resources are assumed to be sourced from other parts of Northern and Central California.

A snapshot of the Scenario 1 resource mix as of 2020 is shown in Figure 1.

[3] Each MW of PV capacity requires approximately five to eight acres, depending upon the location.
[4] PG&E reports its current renewable energy content is 15%. State RPS law requires PG&E to increase its renewable energy content to 33% by 2020.

Figure 1: Scenario 1 Resource Mix in 2020

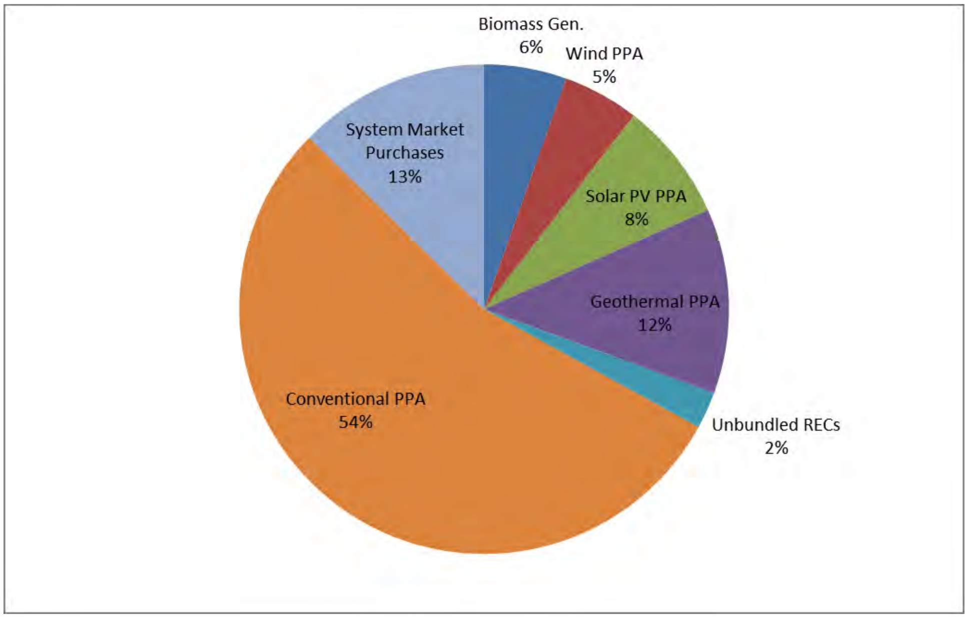
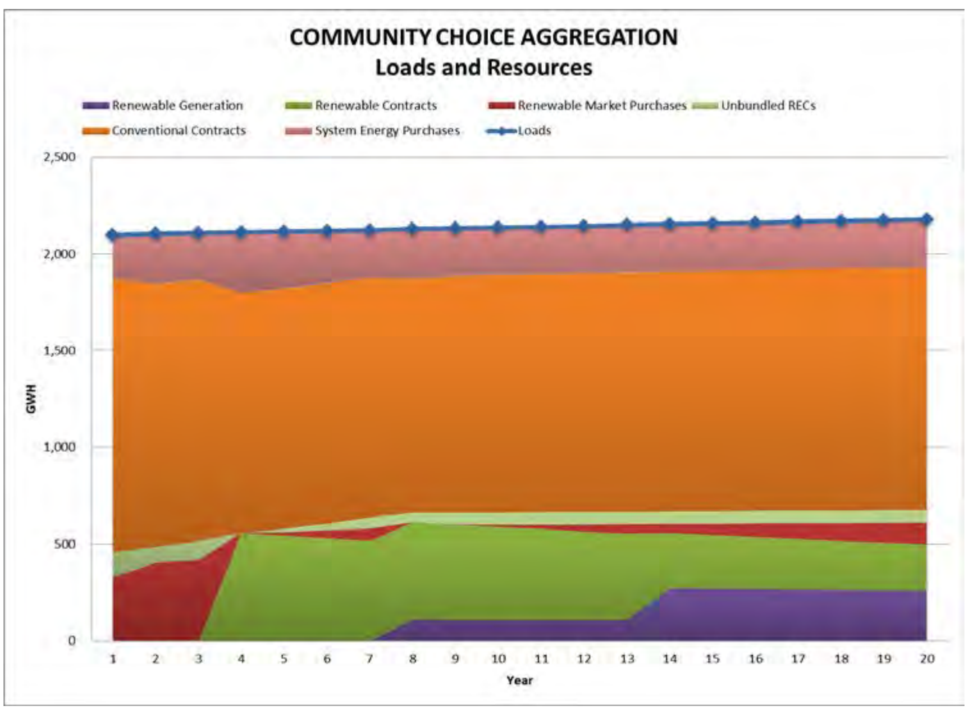


Figure 2 shows how composition of the Scenario 1 supply portfolio changes throughout the study period.

Figure 2: Scenario 1 Load and Resource Projections



Scenario 2: 51% Renewable Energy Content by 2020

Scenario 2 represents a more aggressive transition to renewable resources, starting out at a 33% renewable energy content and increasing to 51% by 2020. The mix of renewable resources is similar to those contained in Scenario 1, but is scaled up to achieve the higher renewable energy content.

The Scenario 2 resource portfolio contains a mix of system power purchases (non-renewable), power purchases of solar photovoltaic, wind and geothermal energy, and generation from CCA program-owned biomass and solar photovoltaic resources. The geothermal and biomass energy would be generated locally, while the other resources are assumed to be sourced from other parts of Northern and Central California.

A snapshot of the Scenario 2 resource mix as of 2020 is shown in Figure 3.

Figure 3: Scenario 2 Resource Mix in 2020

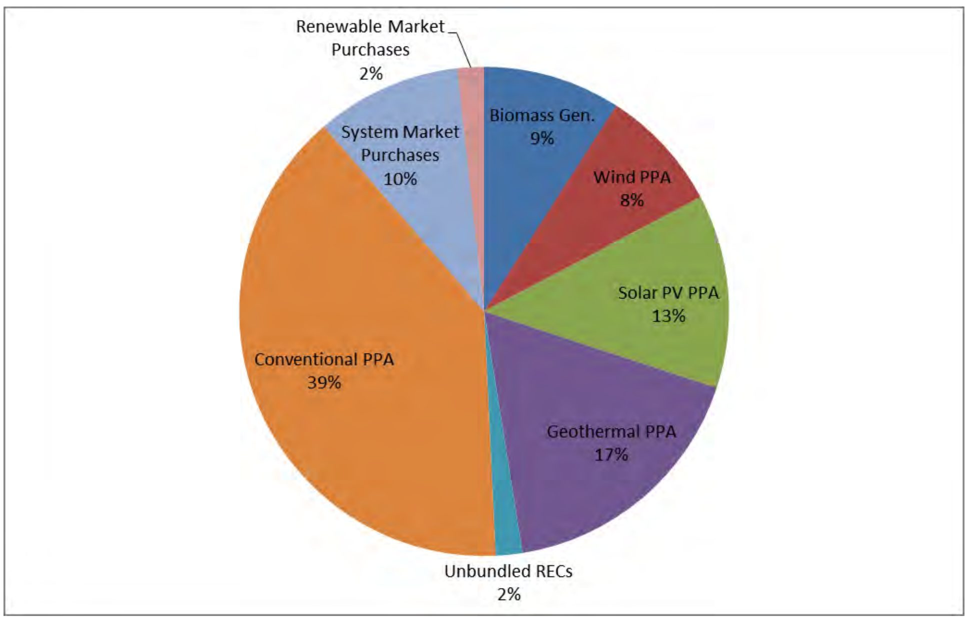
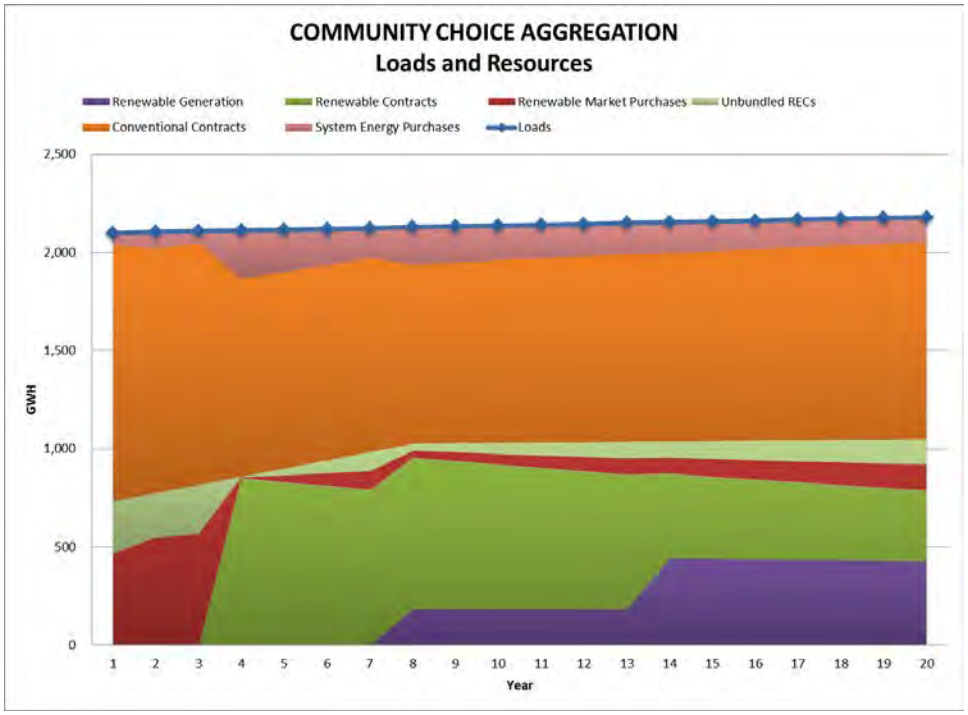


Figure 4 shows how composition of the Scenario 2 supply portfolio changes throughout the study period.

Figure 4: Scenario 2 Load and Resource Projections



Scenario 3: 75% Renewable Energy Content by 2020, Local Emphasis

Scenario 3 represents an even more aggressive transition to renewable resources and emphasizes development of renewable resources within Sonoma County, both large and small-scale. The Scenario 3 renewable energy content starts at 51% and increases to 75% by 2020.

The scenario 3 resource portfolio contains a mix of system power purchases (non-renewable), power purchases of small roof-top solar photovoltaic energy, small and mid-size ground mounted solar photovoltaic energy, wind and geothermal energy, and generation from CCA program-owned biomass and solar photovoltaic resources. The solar, geothermal and biomass energy would be generated locally, while the other resources are assumed to be sourced from other parts of Northern and Central California.

A snapshot of the Scenario 3 resource mix as of 2020 is shown in Figure 5.

Figure 5: Scenario 3 Resource Mix in 2020

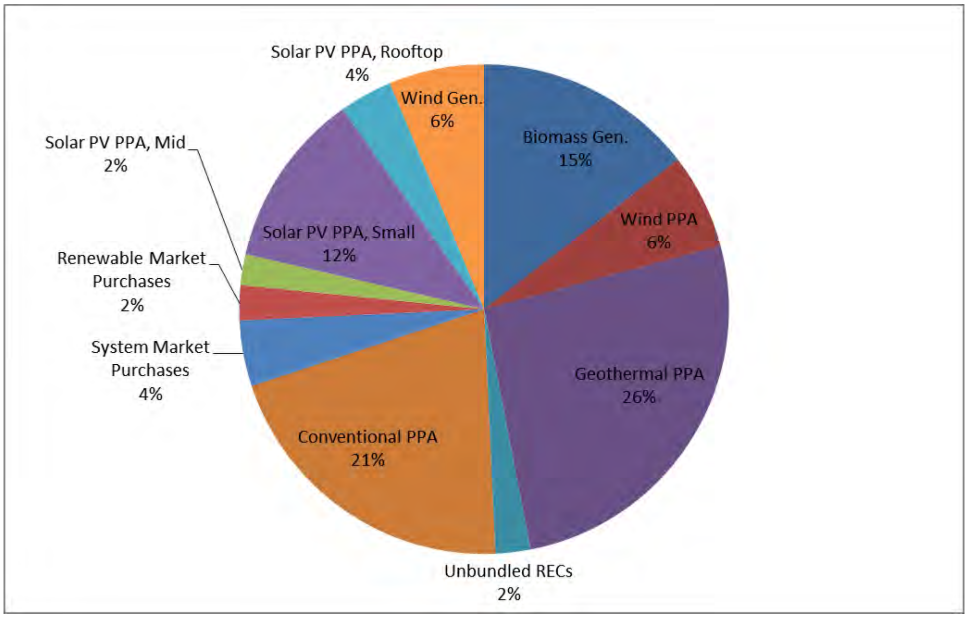
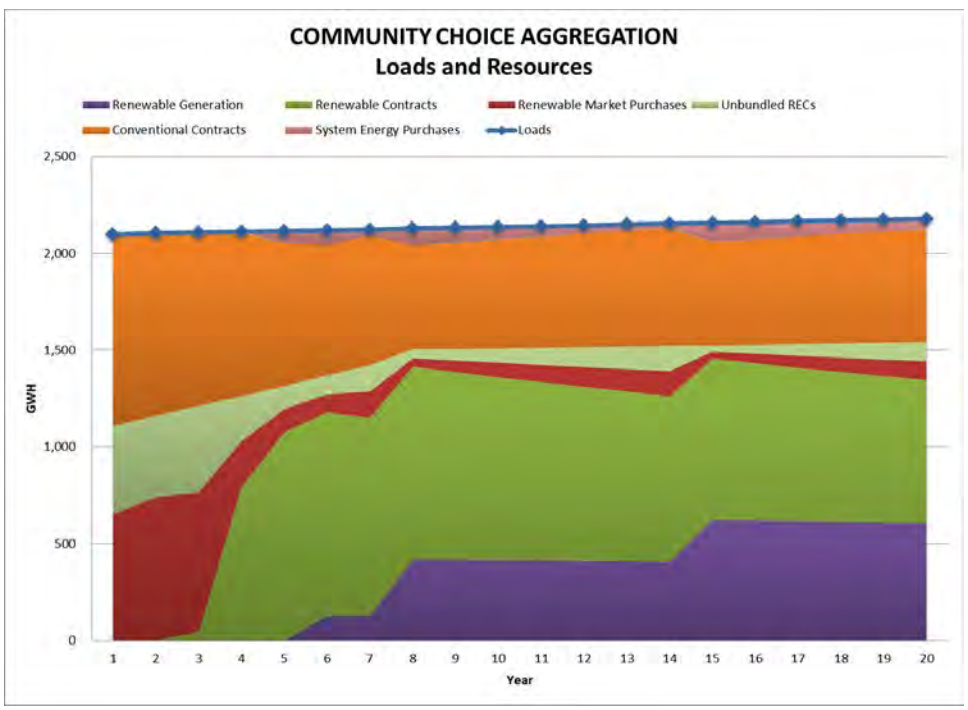


Figure 6 shows how composition of the Scenario 3 supply portfolio changes throughout the study period.

Figure 6: Scenario 3 Load and Resource Projections



Scenario 4: Climate Action Plan

Scenario 4 includes a resource mix modeled after that contained in the Climate Action Plan.[5] Scenario 4 represents the most aggressive transition to renewable resources of the four scenarios analyzed and strongly emphasizes development of renewable resources within Sonoma County, both large and small-scale. The Scenario 4 renewable energy content starts at 20% and increases to 85% by 2020.

The scenario 4 resource portfolio contains a mix of system power purchases (non-renewable), power purchases of wind and solar thermal energy, and CCA program-owned geothermal, biomass cogeneration, wind, rooftop solar photovoltaics, pumped storage, and battery storage.

With the exception of some wind and the solar thermal resources, all other energy would be generated locally.

A snapshot of the Scenario 4 resource mix as of 2020 is shown in Figure 7.

Figure 7: Scenario 4 Resource Mix in 2020

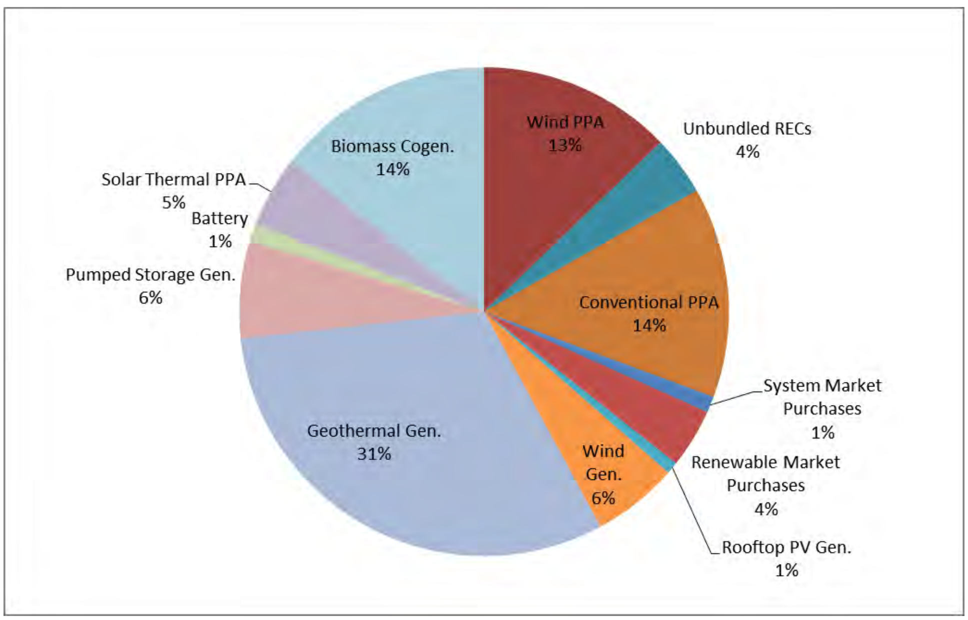
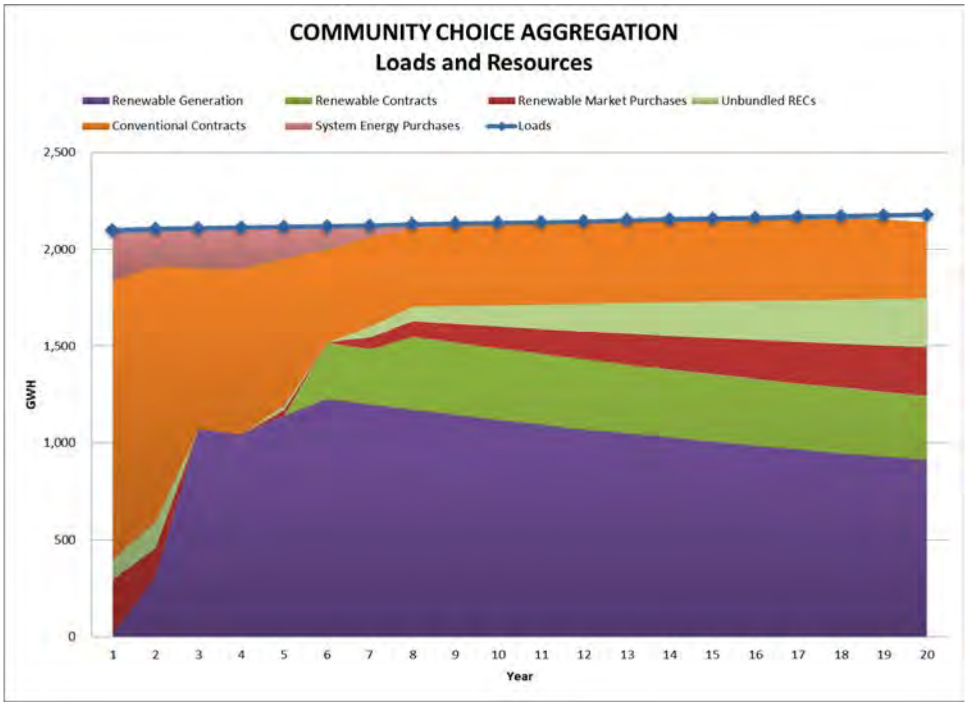


Figure 8 shows how composition of the Scenario 4 supply portfolio changes throughout the study period.

[5] Scenario 4 resource assumptions were provided by members of the Steering Committee representing the Climate Protection Campaign. DMC adjusted the assumed resource capacities by a factor of 0.67 to conform to the CCA program load projections.

Figure 8: Scenario 4 Load and Resource Projections



Additional details regarding the precise composition of each scenario, including assumed generation project sizes and assumed commercial operation dates, are contained in Appendix B.

Costs and Rates

For each supply scenario, detailed cost estimates were made for the electric power supply costs and all other program costs. Net ratepayer costs or benefits were calculated for each scenario as the difference between the costs ratepayers would pay under the CCA program and the costs ratepayers would pay under bundled service from PG&E. Two measures of ratepayer costs were calculated. The first is the difference in generation rates between the CCA program and PG&E, and the second is the difference in total electric rates between the CCA program and PG&E. The distinction between these two measures is that the latter examines the change in customers' total electric bills, including PG&E delivery charges and PG&E surcharges associated with its uneconomic generation commitments.

In order to compare ratepayer costs over the multi-year study period in which electric rates change from year-to-year, DMC calculated levelized electric rates on a per kWh basis for each CCA supply scenario and for PG&E bundled service. Levelized rates represent a constant electric rate that would yield equivalent revenues in present value terms to the projected rates over the study period. Levelized costs are commonly used in the industry to provide an apples-to-apples comparative basis for projects that have cash flows occurring at different points in time. Comparing levelized total electric rates for the CCA program against levelized total electric rates for PG&E service provides a simple measure of ratepayer impacts. Annual impacts are also provided for each scenario and provide a more detailed picture of ratepayer impacts.

Greenhouse Gas Emissions

Each supply scenario was evaluated based on the emissions of greenhouse gases associated with electricity production as compared to a reference case apportioned between renewable energy at the relevant renewable portfolio standards percentage for the year (e.g., 33% by 2020) and system purchases from the California power mix for the remainder. The emission profile of this mix of renewable energy and system purchases was selected as the benchmark for comparison because system purchases (primarily natural gas-fired generation) represent the marginal electricity source in PG&E's supply portfolio, and the renewable portfolio standards require PG&E to supply a specified percentage of its retail sales from renewable generation resources. If PG&E's retail sales were to decline due to migration to the CCA program, it would generally reduce its purchases of system energy and/or its use of natural gas fired generation, and it would be able to reduce its mandated purchases of renewable energy.

For each supply scenario, the difference in GHG emissions produced by the scenario's generation resources and the reference case was quantified for the twenty-year study period. The GHG impacts were quantified in terms of total tons of CO_2 emissions.

Economic Development Impacts

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

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

To quantify the economic impacts associated with locally developed renewable generation projects that have been specified in each of the four energy supply scenarios, DMC utilized the National Renewable Energy Laboratory's ("NREL") Jobs & Economic Development Impact ("JEDI") models. NREL is the principal research laboratory for the United States Department of Energy ("DOE") Office of Energy Efficiency and Renewable Energy and also provides research expertise for the Office of Science, and the

Office of Electricity Delivery and Energy Reliability. NREL is managed for DOE by the Alliance for Sustainable Energy, LLC.[6]

NREL JEDI models are publicly available, spreadsheet-based tools that were specifically designed to "estimate the economic impacts of constructing and operating power generation and biofuel plants at the local (usually state) level. Based on project-specific or default inputs (derived from industry norms), JEDI estimates the number of jobs and economic impacts to a local area that could reasonably be supported by a power generation project."[7] According to NREL, the JEDI models are peer reviewed and are intended to project gross job estimates. NREL also noted that, "We do interviews with developers throughout the year, and then update our model defaults. Our onsite project numbers generally match up with theirs. The updates occur 1-3 times per year."[8] DMC also completed research to validate the accuracy of NREL's JEDI model projections and found that supporting case studies, which document actual economic development statistics associated with renewable project development, were unavailable. Many reports have been developed for the purpose of discussing "projected" or "estimated" economic development impacts, and the information referenced therein generally supports the projections derived from use of the NREL models. Based on this information, DMC believes that NREL's JEDI models are the appropriate tools to forecast local economic development impacts associated with a CCA program in Sonoma County.

As noted by NREL, each JEDI model is reasonably flexible in accommodating project-specific assumptions, including fixed and variable costs associated with generator development and operation as well as financing costs. The comprehensive set of generator cost assumptions, which was prepared by DMC and sourced from highly credible public information sources, such as the California Energy Commission, the California Public Utilities Commission and the federal Energy Information Administration, was used to replace a significant portion of each model's default assumptions[9] with values more appropriate for the types of transactions and local development opportunities that may be pursued by a Sonoma County CCA program – consequently, economic development projections should more accurately reflect local impacts that will likely accrue to Sonoma County. Furthermore, DMC reviewed and updated other assumptions that are applied within each model to allocate proportionate spending for certain project development activities, including capital and labor, within the local economy. For example, wind turbines would, in all likelihood, be purchased from a supplier outside of Sonoma County, but select hardware required to install these turbines may be purchased from local suppliers. Projected impacts to local economic development were estimated by incorporating these adjustments to many of the models' default inputs.

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[6] National Renewable Energy Laboratory website, http://www.nrel.gov/overview/, September 27, 2011.

[7] National Renewable Energy Laboratory website: http://www.nrel.gov/analysis/jedi/about_jedi.html. According to the model's developer, IMpact analysis for PLANning ("IMPLAN") is an independently developed economic impact modeling system that is "used to create complete, extremely detailed Social Accounting Matrices and Multiplier Models of local economies.

[8] September 22, 2011 email response from Suzanne Tegen, NREL Ph.D., to DMC regarding JEDI models.

[9] According to NREL, all default values reflect information received through "interviews with industry experts and project developers. Economic multipliers contained within the model are derived from Minnesota IMPLAN Group's IMPLAN Professional

The resultant set of economic development projections for each supply scenario was identified as DMC's "base case." DMC then prepared a second set of economic development projections for each supply scenario based on a set of assumptions that would result in lower estimated economic development benefits for Sonoma County. In particular, DMC reduced model inputs to reflect reduced spending within the local economy, which could occur if project developers determine to fill jobs and procure necessary goods and services outside of Sonoma County. To account for the variation in possible outcomes that may occur as a result of local project investment, DMC utilized each set of economic development projections to develop a range of outcomes; all economic development estimates within this report are presented in consideration of these ranges, keeping in mind that subtle changes in the location of certain expenditures (and jobs) may result in significant changes to actual economic development impacts.

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

DMC has completed an economic development analysis for each supply scenario, inclusive of all anticipated, locally developed generation projects. Forecasted economic impacts associated with each supply scenario are presented in aggregate form, inclusive of all anticipated development/contract opportunities that have been identified under each scenario, by summing the project-specific impacts calculated by the JEDI models. This approach facilitates high level comparisons between the different supply scenarios but does not address temporal nuance related to the timing and receipt of economic benefits associated with specific projects. For example, the unique economic impacts of projects that will begin operation/delivery in 2016 and 2020, respectively, have been aggregated and presented within a single scenario-specific summary table. Detailed economic development projections associated with the unique development projects under each scenario are included in Appendix C.

When reviewing economic development projections within this feasibility analysis, it is important to distinguish between economic impacts related to the construction period and the ongoing operation and maintenance period. All job creation estimates are presented as full time equivalent positions ("FTEs"). Projections related to the construction period are intended to capture annual economic benefits received during the defined construction term (24 months, for example). Economic impacts during the ongoing operation and maintenance period are presented on an annual basis and are projected to persist throughout the project lifecycle.

As previously noted, NREL has developed unique JEDI models for several different generator types/fuel sources, including photovoltaic solar, wind, natural gas and biofuels. JEDI models are not currently available for geothermal and biomass resources. For purposes of the Sonoma County CCA economic development analysis, DMC used NREL's JEDI model for natural gas generators as the platform for estimating local economic impacts related to these renewable resource types. For these projects, the geographic footprint, operational considerations (staffing and maintenance) and employment impacts are sufficiently similar to warrant the use of this model's framework for the purpose of estimating economic development impacts related to biomass and geothermal generator construction. DMC updated all inputs within the JEDI model framework to reflect appropriate development and operating assumptions related to biomass and geothermal technologies, resulting in reasonable economic development projections for these renewable technologies.

III. Electric Consumption

Historical and Projected Electricity Consumption

Total electric consumption for eligible customers within Sonoma County was provided by PG&E for the 2008 calendar year. The PG&E historical data was used as the basis for the study's customer and electric load forecast. During 2008, the PG&E data indicate there were 218,130 electric customers within the potential CCA jurisdiction who together consumed 2,778 million kilowatt-hours of electricity.

Figure 9 shows how the potential electric customers are distributed throughout the County: the largest populations within the potential CCA jurisdiction are the unincorporated areas of the County, and the cities of Santa Rosa, Petaluma and Rohnert Park.

Figure 9: Geographic Distribution of Customers

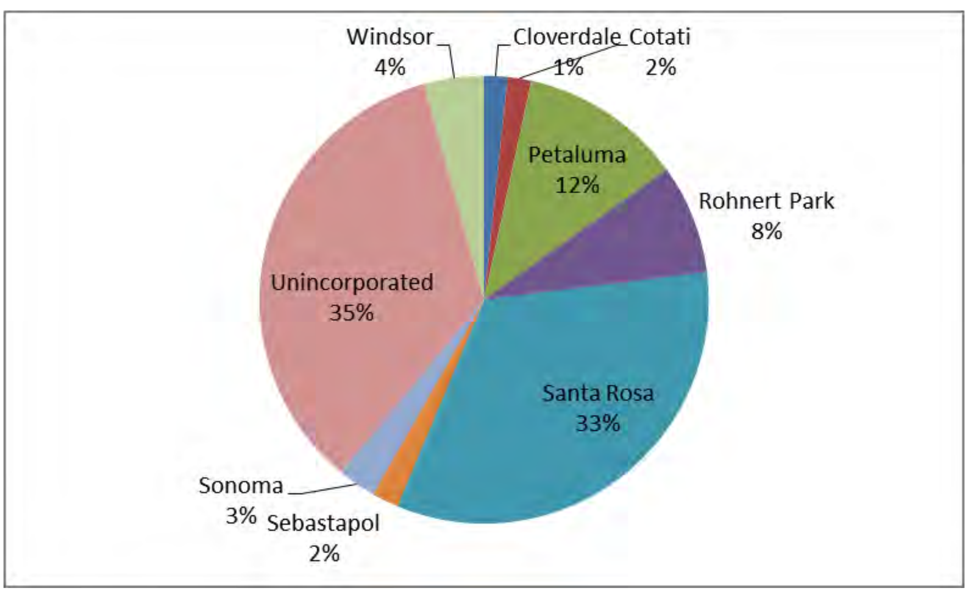
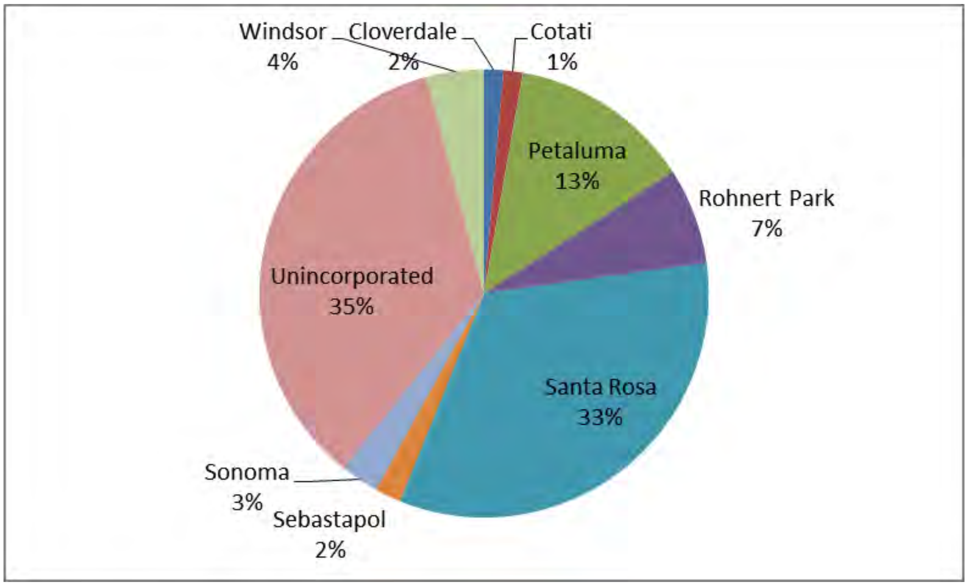


Figure 10 shows the distribution of electric consumption by municipality. The geographic distribution of energy consumption is closely aligned with the service account data in Figure 9 above, indicating a relative homogeneity among customer types throughout the County.

Figure 10: Geographic Distribution of Electric Consumption



In deriving the load projections used for the feasibility analysis, the 2008 PG&E data was adjusted downward by 7% based on the change in sales within the CAISO system between 2008 and 2011. Adjustments to the base forecast were made to remove customers identified as taking service under direct access[10] as it was assumed that direct access customers would remain with their current electric provider. Further adjustments were made to estimate customer opt-out rates during the statutory customer notification period when eligible customers would be offered CCA service and provided with information enabling them to opt out of the program. DMC assumed a 20% customer opt-out rate, which is consistent with the reported opt-out rate experienced in the Marin Clean Energy program during its initial customer enrollments. Sensitivities using different opt-out rates are presented in Section VI.

From 2011 onwards, potential customers and energy consumption were projected to increase by 0.7% annually, consistent with statewide projections and reflecting impacts from the significant emphasis being placed on energy efficiency in the state. This baseline sales growth was offset by an annual factor of -0.5%, representing the potential for additional conservation, energy efficiency, and the potential for customers to move back to PG&E bundled service or to direct access service after the close of the initial opt-out period. As a result, net program sales were projected to increase at an annual rate of 0.2%.

[10] Direct access allows customers to choose to receive generation service from competitive electricity providers.

Projected Customer Mix and Energy Consumption

The projections for enrolled customers and annual electricity consumption for the major customer classifications are shown in Table 1. Hourly electricity consumption and peak demand were estimated using hourly load profiles published by PG&E for each customer classification.

Table 1: Projected Customer Base

Customer Classification	Accounts	Energy Consumption (MWh)	Share of Energy Consumption (%)
Residential	142,724	950,294	48%
Small Commercial	15,673	278,613	14%
Medium Commercial	1,834	321,748	16%
Large Commercial	277	235,607	12%
Industrial	11	124,658	6%
Agricultural and Pumping	2,043	44,486	2%
Street Lighting	1,695	12,925	1%
Total	164,257	1,968,331	100%
Peak Demand (MW)		365	

The hourly load forecast indicates a peak demand of approximately 365 MW and a minimum demand of approximately 140 MW. The minimum demand establishes the requirement for baseload energy (constant production level), while the difference between the peak demand and the minimum demand would be met by peaking and dispatchable load-following resources.

Figures 11 through 14 show the hourly load projections for the CCA program for each calendar quarter.

Figure 11: First Quarter Projected Hourly Loads

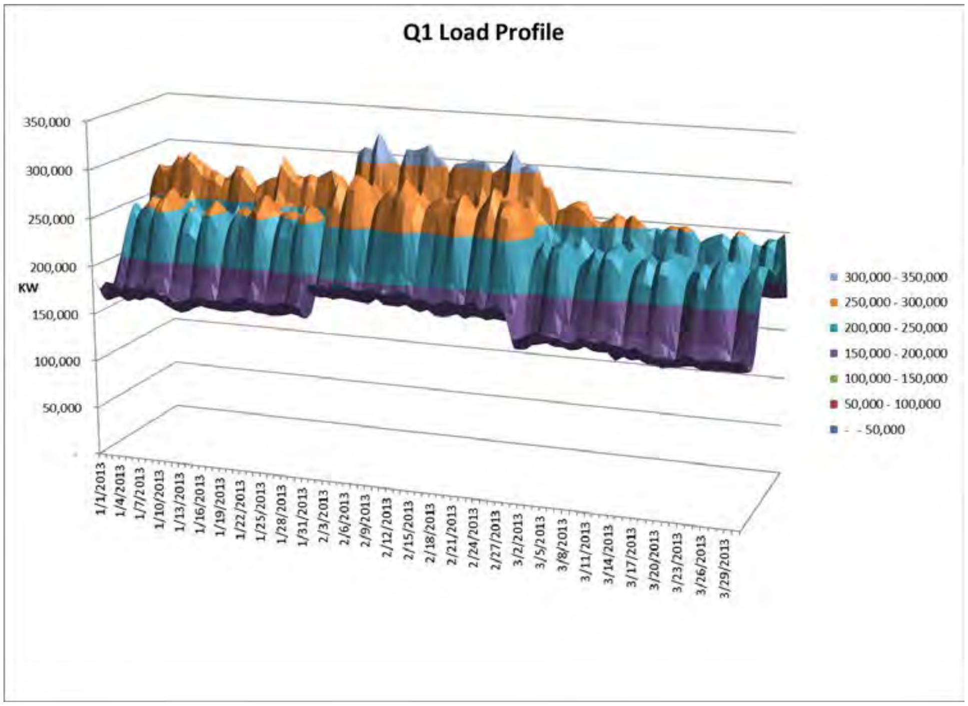


Figure 12: Second Quarter Projected Hourly Loads

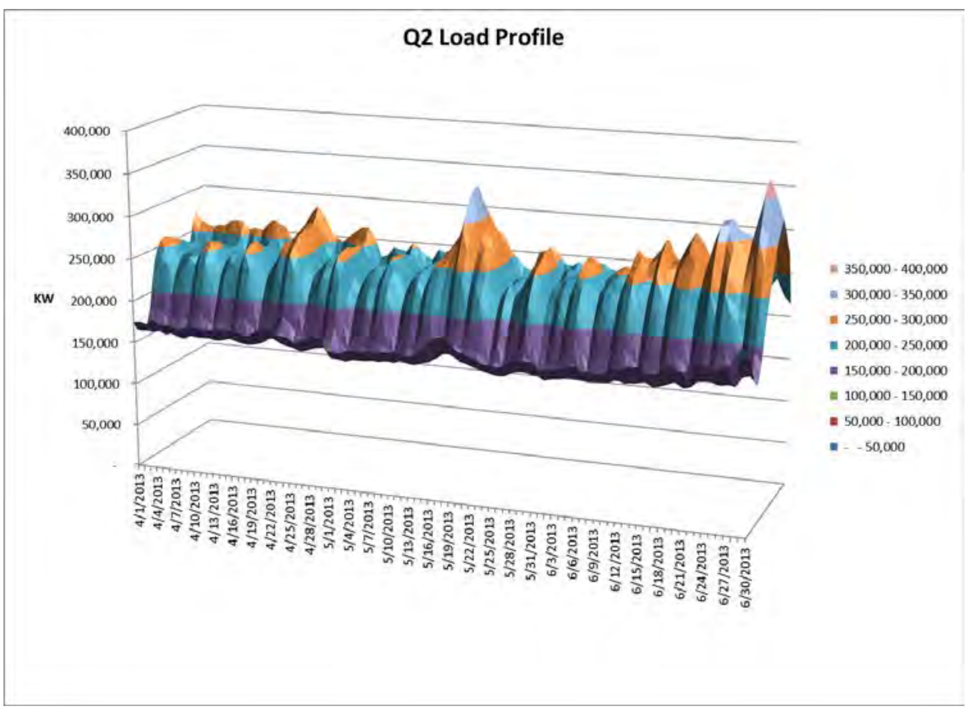


Figure 13: Third Quarter Projected Hourly Loads

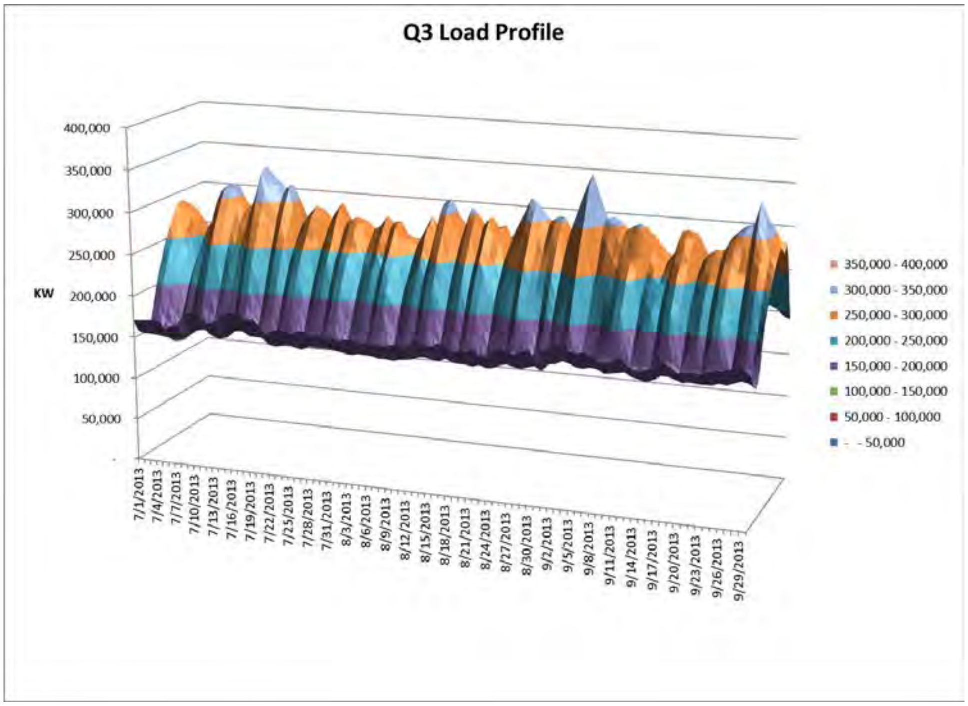
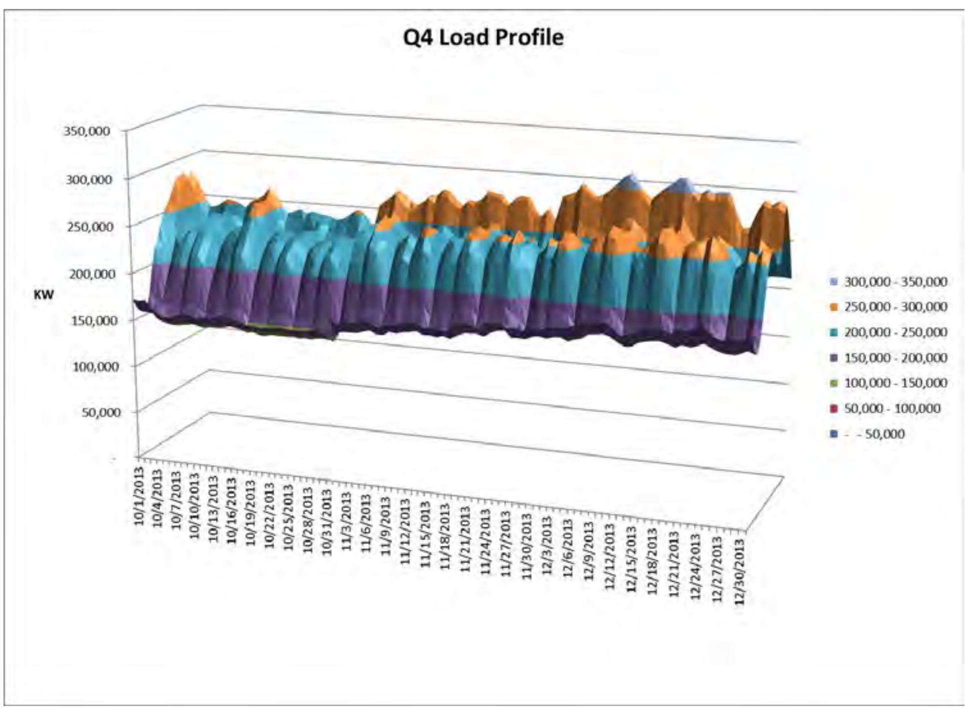


Figure 14: Fourth Quarter Projected Hourly Loads



Renewable Energy Portfolio Requirements

Current law requires that specified percentages of annual retail electricity sales be supplied from qualified renewable energy resources. Senate Bill X1 2 (April, 2011), established a 20% renewable portfolio requirement by 2013 and a 33% requirement by 2020. SBX1 2 also specified additional requirements for the types of resources that qualify to meet the renewable standards, creating three categories of resource procurement and limiting use of certain categories. Category 1 renewable procurement entails use of energy from qualified renewable energy generators located within the state or from out-of-state generators that can meet strict scheduling requirements to ensure deliverability to California. These resources are unlimited in their use for RPS compliance. Category 2 resource procurement entails "firming and shaping" transactions where the energy produced by the renewable resource is not necessarily delivered to California, but a like amount of energy from a different resource is delivered and bundled with the former's renewable energy attribute. Finally, Category 3 resource procurement relates to purchases of unbundled renewable energy certificates with no related physical energy delivery. Limits apply to Category 2 and Category 3 renewable energy procurement as shown in Table 2.

Table 2: Renewable Portfolio Standards Compliance Categories

Category or "Bucket"	Description	Usage Limits (% of Renewable Energy)
1	In-state or dynamically scheduled	Minimum of 50% through 2013, 65% through 2015, 75% after 2015
2	Firmed and shaped	Maximum of 50% through 2013, 35% through 2015, 25% after 2015
3	Unbundled renewable energy certificates	Maximum of 25% through 2013, 15% through 2015, 10% after 2015

The CPUC has not yet issued the specific regulations needed to implement the new standards. For purposes of this study, DMC assumed the following annual RPS requirements will be in place and that the limits shown in Table 3 apply to all renewable energy used for compliance. The CCA program would have discretion in how it meets voluntary renewable energy targets that are in excess of the mandated requirements.

Table 3: Renewable Energy Portfolio Standards Requirements

Year	Renewable Energy Portfolio Requirement (%)	Year	Renewable Energy Portfolio Requirement (%)
2013	20%	2017	25%
2014	23%	2018	25%
2015	23%	2019	25%
2016	25%	2020	33%

Capacity Requirements

The CCA program would be required to demonstrate it has sufficient physical generating capacity to meet its projected peak demand plus a 15% planning reserve margin, in accordance with resource adequacy regulations administered by the CPUC and the CEC. A specified portion of generating capacity must be located within certain local reliability areas and the remaining capacity requirement can be met with generating plants anywhere within the CAISO system. Presently, there are two local reliability areas that would apply to the CCA program: the “Greater Bay Area” and the “Other PG&E Areas”.

Using the most recent data from the 2011 compliance year, the following resource adequacy capacity requirements were assumed to apply:

Table 4: Resource Adequacy Capacity Requirements

Capacity Type	Percentage of Peak Demand
System	70%
Greater Bay Area	18%
Other PG&E Areas	27%
Total	115%

Accordingly, the resource adequacy requirement for 2013, the assumed first year of the CCA program, would be approximately 420 MW, with approximately 66 MW of the total procured from the Greater Bay Area region, 99 MW procured from any other local reliability area in the PG&E service area, and 255 MW procured from anywhere within the CAISO footprint.

IV. Cost of Service Elements

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

Electricity Purchases

The CCA program would be financially responsible for supplying the net electric demand of all enrolled customers, and it would be able to source that supply from a variety of markets and/or through the program's own generation resources. Energy requirements are ultimately financially settled by the CAISO. The CAISO provides a critical role in balancing supply and demand on the electric grid and operates short-term markets for energy as well as real-time balancing services to cover the moment-to-moment fluctuations in electricity consumption. The CCA program would interact with the CAISO through an intermediary known as a "Scheduling Coordinator", periodically reporting usage data of its customers and settling with the CAISO for any imbalances or transactions in the CAISO markets.

Bilateral markets exist for longer term purchases, which allow hedging against the fluctuations in CAISO market prices. Longer term purchases can range from a few weeks to many years, with the most active trading being for contracts with terms of less than three years. Contracts for new generation resources typically have ten year or longer terms.

Electric purchase costs were estimated using the projected energy demand during the industry-defined peak and off-peak time periods. CCA program generation and renewable energy contracts were subtracted from the peak and off-peak energy demands and the remainder was assumed to be met with short and mid-term contract purchases of system energy.

Renewable Energy Purchases

Renewable energy purchases may take two forms: 1) energy bundled with associated renewable attributes; or 2) unbundled renewable attributes, known as renewable energy certificates, or RECs, which are sold without the energy commodity. As described in Section III, use of unbundled RECs is limited for compliance purposes with the renewable portfolio standards.

Purchases of renewable energy from new resources are typically made under bundled, long-term contracts of 20 to 25 years. Shorter term purchases are common for existing renewable resources and for unbundled renewable energy certificates.

Renewable energy currently sells for a premium relative to the cost of system energy. However, when compared to the cost of new, natural gas-fueled generation, renewable resources tend to have lower levelized costs.[11]

Renewable energy purchase costs were estimated using predominantly long-term contracts for new renewable energy projects as specified for each supply scenario. Short term market purchases of bundled renewable energy and unbundled renewable energy certificates were assumed to fulfill remaining renewable energy needs.

Electric Generation

Generation projects developed or acquired by the CCA program would supplement energy purchases. Generation costs would include development costs, capital costs for land, plant and equipment, operations and maintenance costs, and, if applicable, fuel costs. Capital costs for publicly owned utilities such as a CCA are typically financed with long-term debt, and the annual debt service and required coverage would be an element of annual CCA program costs.

The analysis included various renewable generation investments as described in each representative supply scenario.

Transmission and Grid Services

The CAISO charges market participants for a number of transmission and grid management services that it performs. These include costs of managing transmission congestion, acquiring operating reserves and other “ancillary services”, and conducting CAISO markets and other grid operations. These costs would be assessed to the Scheduling Coordinator for the CCA program, and are assumed to be directly passed through to the CCA program with no markup.

Financing Costs

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

Start-up costs are estimated at $1.7 million, which would fund the program for approximately six months prior to commencement of service to customers. Start-up activities include costs for staffing and professional services, security deposits, the CCA bond/financial security requirement, communications and customer notices, data management, and other activities that must occur before the program begins providing electricity to customers. These costs would be recovered from program revenues after service commences.

A breakdown of estimated start-up costs is shown in Table 5.

[11] See for example, Table 1, Comparative Costs of California Central Station Electricity Generation, California Energy Commission, January 2010.

Table 5: Estimated CCA Program Start-Up Costs

Cost Item	Amount
Staffing and Professional Services	$1,125,000
Marketing and Communications	$180,000
Data Management	$150,000
PG&E Service Fees	$40,000
Miscellaneous Administrative and General	$150,000
Financial Security/Bond Carrying Cost	$3,000
Total	$1,648,000

Working capital requirements are estimated at $15 million, equivalent to one month's revenue, which would cover the timing lag between when invoices for power purchases must be paid and when cash is received from customers. Typical invoicing timelines for wholesale power purchase contracts require payment for the prior month's purchases by the 20th of the current month. Customer payments are typically received within about sixty to ninety days of when the electricity is delivered. The timing difference between cash outflows and inflows represents the working capital requirement.

Billing, Metering and Data Management

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

Uncollectible Accounts

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

Program Reserves

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

Bonding and Security Requirements

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

The currently effective financial security requirement is $100,000, but the CPUC is considering changes to the methodology that could, under certain market conditions, result in extremely large financial security requirements. DMC's estimate assumes a middle ground outcome from the CPUC process (R.03-10-003), where the financial security requirement is related to the number of customers served by the CCA and the expected costs that would by incurred by PG&E if customers were involuntarily returned to PG&E bundled service. DMC estimated the financial security requirement assuming it would be sized to cover the administrative cost of customer reentry plus the positive difference between prevailing market prices and the PG&E generation rate. The initial financial security requirement is estimated to be $700,000 and varies year-to-year depending upon market prices, PG&E rates and customers served.

PG&E Surcharges

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

The franchise fee surcharge is a minor charge that ensures PG&E collects the same amount of franchise fee revenues whether a customer takes generation service from a CCA or from PG&E. The PCIA is a substantial charge that is intended to ensure that generation costs incurred by PG&E before a customer transitions to CCA service are not shifted to remaining PG&E bundled service customers (following a customer's departure from PG&E to CCA service). The CPUC is considering revisions to the PCIA calculation methodology that would have the effect of reducing the charges. DMC's base case assumption is that the calculation will be revised consistent with Administrative Law Judge's proposed decision issued in that proceeding (R.07-05-025).

V. Costs and Benefits Analysis

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

Scenario 1 Study Results

Ratepayer Costs

Projected CCA customer rates in Scenario 1 are slightly higher than the projections for PG&E's rates, with positive differences over the tem ranging from 2% to 5%. Levelized rates over the study period are projected to be 3% higher than the projected PG&E rates. For a typical household using 500 kWh per month, a 3% rate difference would result in a cost increase of approximately $2.60 per month.

Projected average rates for the Sonoma County customer base are shown in Figure 15 and Table 6 under PG&E bundled service and CCA service.

Figure 15: Scenario 1 Annual Ratepayer Costs

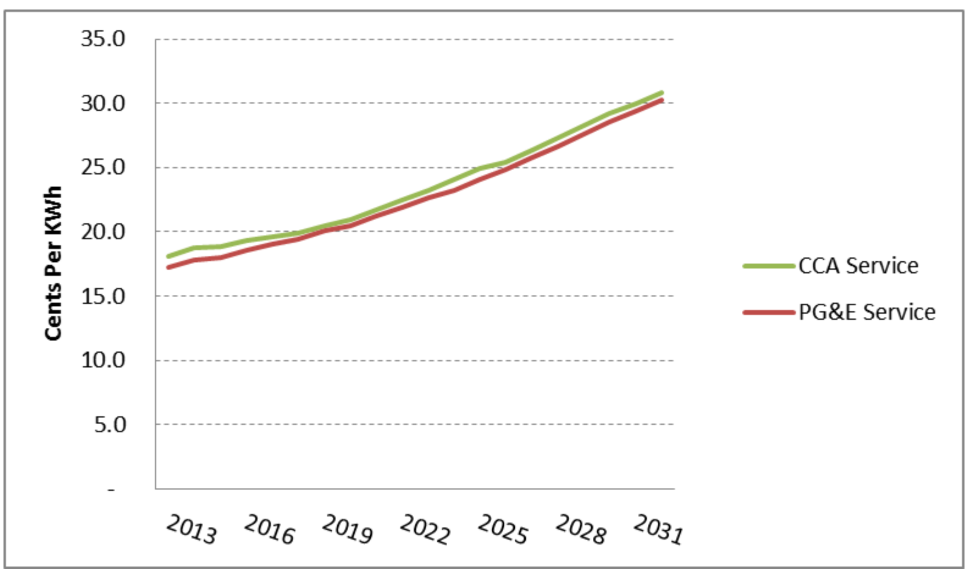


Table 6: Scenario 1 Ratepayer Impacts

Year	PG&E Total (₵/kWh)	CCA Total (₵/kWh)	Percent Difference
Levelized	21.6	22.3	3%
2013	17.2	18.1	5%
2014	17.8	18.8	5%
2015	18.0	18.9	5%
2016	18.6	19.3	4%
2017	19.0	19.7	3%
2018	19.4	19.9	2%
2019	20.0	20.5	2%
2020	20.5	20.9	2%
2021	21.2	21.7	3%
2022	21.9	22.5	3%
2023	22.6	23.3	3%
2024	23.3	24.1	4%
2025	24.1	24.9	4%
2026	24.9	25.4	2%
2027	25.8	26.4	2%
2028	26.7	27.3	2%
2029	27.6	28.2	2%
2030	28.5	29.2	2%
2031	29.4	30.0	2%
2032	30.3	30.8	2%

GHG Impacts

GHG impacts from Scenario 1 are minor as the resource mix trends toward the reference case after starting with modestly higher renewable energy content. These results are consistent with Scenario 1 representing essentially a status quo case for GHG emissions.

Figure 16: Scenario 1: Annual GHG Emissions

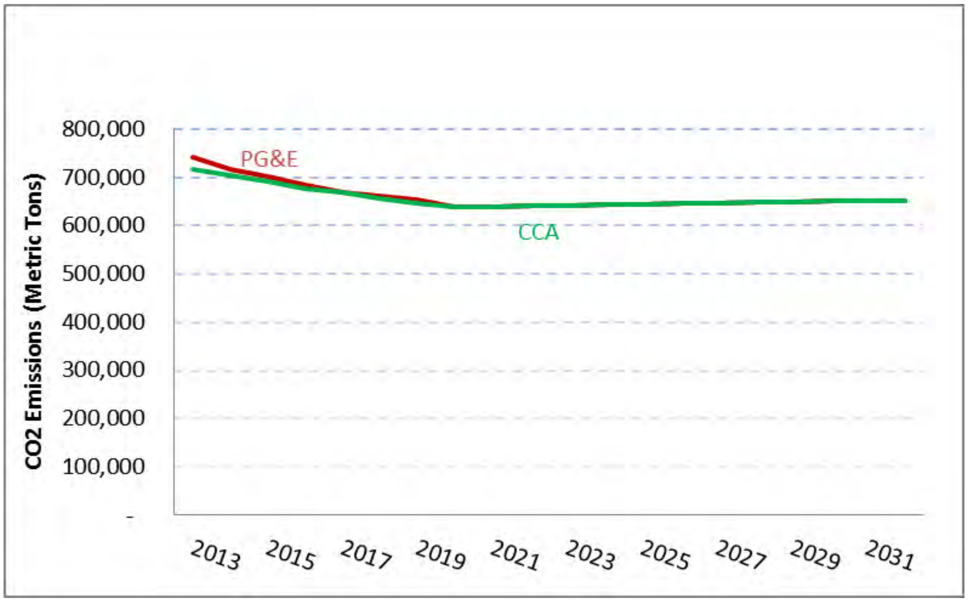


Table 7: Scenario 1 GHG Reductions

GHG Metric	Amount
GHG Reduction, Cumulative (2013-2032)	70,000 Metric Tons CO_2
GHG Reduction, Annual	3,500 Metric Tons CO_2
GHG Reduction, Change in Electric Sector CO_2 emissions	-1%

Economic Development

Energy supply Scenario 1 represents a portfolio of resources, predominantly power purchase agreements, that will be assembled to ensure compliance with California's recently adopted 33 percent Renewables Portfolio Standard (by 2020). Under this supply scenario, local economic development opportunities would be promoted by two specific projects: 1) a locally situated, utility scale geothermal generator with operating capacity of 35 MW that would begin delivering approximately 280 GWh (per year) of RPS-eligible renewable energy in 2016; and 2) a locally developed, utility scale biomass generator with operating capacity of 15 MW that would deliver approximately 110 GWh annually beginning in 2020. Output from the geothermal generator would be delivered under a long-term power purchase agreement between the Sonoma County CCA and a qualified developer/owner. The biomass generator would be internally developed and financed by the CCA program.

With respect to these two generators, it is assumed that the significant majority of plant equipment, including turbines and other materials, would be procured outside of Sonoma County. This equipment typically represents the largest single line item expenditure in generator construction. However, general site preparation and ancillary facility construction activities (concrete footings and structures not directly involved in the generation process) would rely heavily on local goods and services as well as labor. Sonoma's local economy would also benefit from the collection of requisite permitting fees during generator construction as well as annual property tax revenues related to the project site.

In total, supply Scenario 1 is projected to result in the creation of approximately 100-300 new jobs during each year of the respective construction period (each construction period has been estimated at 24 months) required to complete the geothermal and biomass generators. During each year of the construction period, individuals working directly on the projects, including electricians, engineers, construction workers and heavy equipment operators, attorneys and permitting specialists, would be responsible for as much as $20 million in new economic output of which as much as $10 million would be collected in the form of salaries and wages. Workers involved with supply chain activities, such as turbine manufacturing and assembly, cement producers and heavy equipment rental companies would be responsible for nearly $5 to $20 million in new economic activity of which $2 to $10 million would be collected in the form of salaries and wages. Furthermore, spending by the aforementioned individuals (as a result of salary and wage collection) would "induce" other local economic impacts at local businesses, including restaurants, grocery stores, gas stations and other providers of goods and services, totaling as much as $10 million of which $4 million would be collected as salaries and wages. In total, the locally developed generation projects identified under Scenario 1 would result in $15 to $50 million in new economic output during the construction process.

During ongoing operation of the renewable generators, it is projected that as many as 100 new jobs would be created with a total annual economic impact ranging from $4 to $20 million. It is anticipated that these jobs would remain effective as long as the generating facilities remain operational, resulting in significant, lasting impacts to Sonoma County's local economy. The following table summarizes the range of projected local economic impacts related to Scenario 1 implementation.

Table 8: Scenario 1 Local Economic Impacts

Local Economic Impacts - Scenario 1 Summary Results			
	Jobs	Earnings	Output
During construction period		($ - Millions)	($ - Millions)
Project Development and Onsite Labor Impacts	40 - 100	4 - 10	6 - 20
Construction and Interconnection Labor	30 - 100	4 - 10	
Construction Related Services	2 - 20	0 - 1	
Power Generation and Supply Chain Impacts	20 - 100	2 - 10	5 - 20
Induced Impacts	20 - 100	0 - 4	3 - 10
Total Impacts (Direct, Indirect, Induced)	100 - 300	10 - 20	15 - 50
During operating years (annual)			
Onsite Labor Impacts	1 - 3	0 - 0.2	0 - 0.2
Local Revenue and Supply Chain Impacts	10 - 40	0 - 3	3 - 10
Induced Impacts	10 - 20	0 - 1	1 - 4
Total Impacts (Direct, Indirect, Induced)	15 - 100	1 - 4	4 - 20
Notes: Totals may not add due to rounding. Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for each year of the 24-month construction period. Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted.			

Scenario 2 Study Results

Ratepayer Costs

Projected CCA customer rates in Scenario 2 are initially higher than the projections for PG&E's rates, with positive differences in the initial years of up to 7% before crossing over to fall below PG&E rates in the later years of the study period. These results reflect the impact of PG&E surcharges during the early years of the study period as well as initial renewable energy cost premiums, counterbalanced with the long term cost-stability achieved with this Scenario's heavier concentration of renewable resources.

Levelized rates over the term are approximately 4% higher than the projected PG&E rates. For a typical household using 500 kWh per month, a 4% rate difference would result in a cost increase of approximately $3.50 per month.

Projected average rates for the Sonoma County customer base are shown in Figure 17 and Table 9 under PG&E bundled service and CCA service.

Figure 17: Scenario 2 Annual Ratepayer Costs

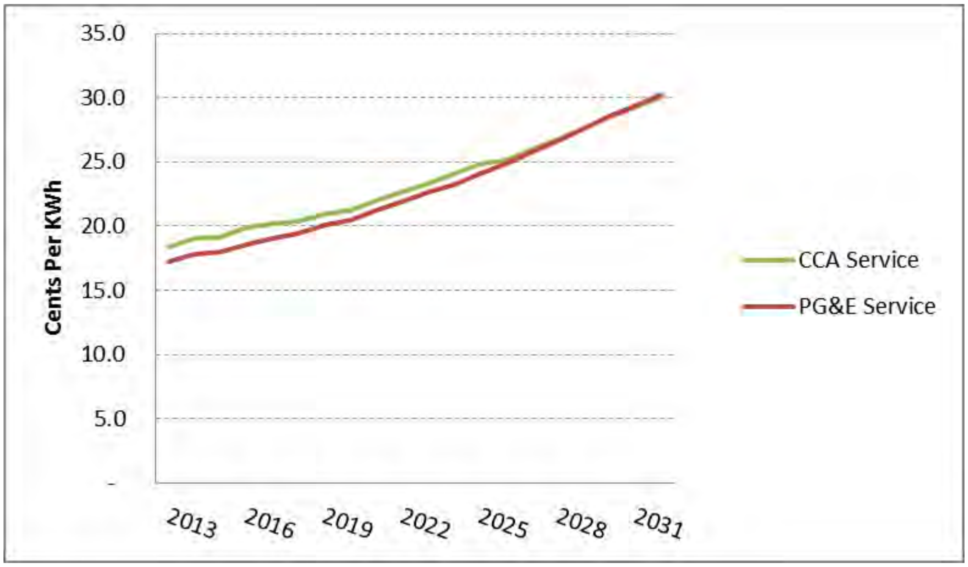


Table 9: Scenario 2 Ratepayer Impacts

Year	PG&E Total (₵/kWh)	CCA Total (₵/kWh)	Percent Difference
Levelized	21.6	22.4	4%
2013	17.2	18.3	7%
2014	17.8	19.1	7%
2015	18.0	19.2	6%
2016	18.6	19.9	7%
2017	19.0	20.2	6%
2018	19.4	20.3	5%
2019	20.0	20.9	4%
2020	20.5	21.3	4%
2021	21.2	22.0	4%
2022	21.9	22.6	3%
2023	22.6	23.4	3%
2024	23.3	24.1	4%
2025	24.1	24.9	3%
2026	24.9	25.1	1%
2027	25.8	25.9	1%
2028	26.7	26.8	0%
2029	27.6	27.6	0%
2030	28.5	28.5	0%
2031	29.4	29.3	0%
2032	30.3	30.1	-1%

GHG Impacts

GHG impacts from Scenario 2 are substantial as the renewable energy content exceeds the reference case in all years. Annual GHG reductions average approximately 155,000 metric tons of CO_2 per year, representing a decrease of 23% from electric sector GHG emissions within the County.

Figure 18: Scenario 2 Annual GHG Emissions

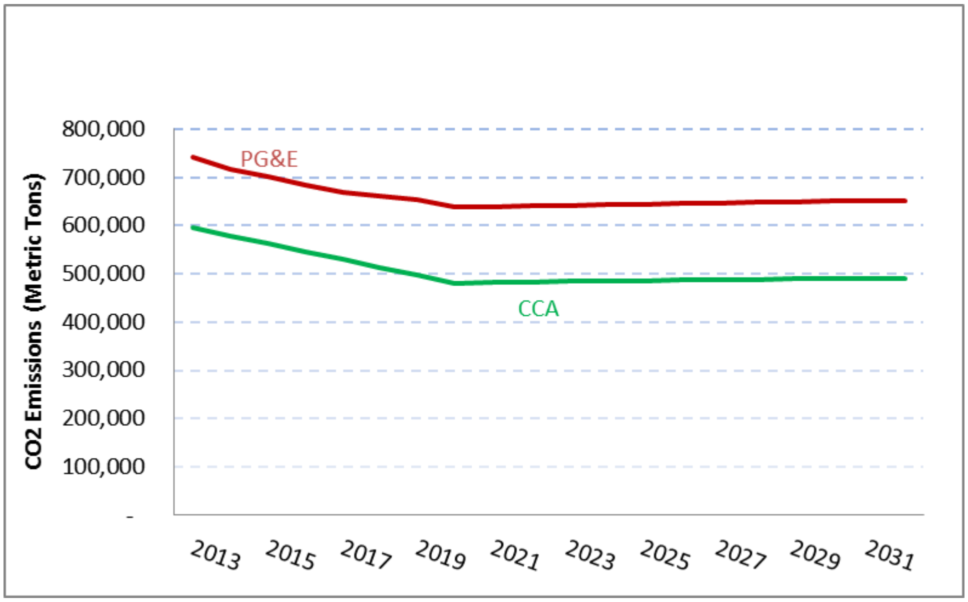


Table 10: Scenario 2 GHG Reductions

GHG Metric	Amount
GHG Reduction, Cumulative (2013-2032)	3.1 Million Metric Tons CO_2
GHG Reduction, Annual	155,000 Metric Tons CO_2
GHG Reduction, Change in Electric Sector CO_2 emissions	-23%

Economic Development

Similar to Scenario 1, energy supply Scenario 2 also represents a portfolio of resources, predominantly power purchase agreements, which will be assembled to achieve 51 percent renewable energy supply by 2020. In effect, Scenario 2 represents a “scaled up” version of Scenario 1 in order to promote achievement of the increased renewable energy objective. Under this supply scenario, local economic development opportunities would be promoted by two specific projects: 1) a locally situated, utility scale geothermal generator with operating capacity of 50 MW that would begin delivering over 400 GWh per year of RPS-eligible renewable energy in 2016; and 2) a locally developed, utility scale biomass generator with operating capacity of 25 MW that would deliver nearly 190 GWh annually beginning in 2020. Similar to Scenario 1, output from the geothermal generator would be delivered under a long-term power purchase agreement between the Sonoma County CCA and a qualified developer/owner. The biomass generator would be internally developed and financed by the CCA program.

As described under Scenario 1, it is assumed that the significant majority of plant equipment, including turbines and other materials required to implement Scenario 2, would be procured outside of Sonoma County. However, general site preparation and ancillary facility construction (concrete footings and structures not directly involved in the generation process) would rely heavily on local goods and services as well as labor. Sonoma County's local economy would also benefit from the collection of requisite permitting fees during generator construction as well as annual property tax revenues related to the project site.

In total, supply Scenario 2 is projected to result in the creation of 100-400 new jobs during each year of the respective construction period (24 months) required to complete the geothermal and biomass generators. This represents a 33 percent increase in total construction employment relative to Scenario 1. During each year of construction, individuals working directly on the projects would be responsible for $10-$20 million in new economic output of which the significant majority of this economic stimulus would be collected in the form of salaries and wages. Workers involved with supply chain activities, would be responsible for $10-$30 million in new economic activity of which $2-$10 million would be collected in the form of salaries and wages. Furthermore, spending by the aforementioned individuals (as a result of salary and wage collection) would "induce" other local economic impacts up to $20 million of which $2-$10 million would be collected as salaries and wages. In total, the locally developed generation projects identified under Scenario 2 would result in $20-$100 million in new economic output during each year of the construction process, as much as $50 million more than projected for Scenario 1.

During ongoing operation of the renewable generators, it is projected that as many as 100 new jobs would be created with a total annual economic impact ranging from $10-$20 million. It is anticipated that these jobs would remain effective as long as the generating facilities remain operational. The following table summarizes the range of projected local economic impacts related to Scenario 2 implementation.

Table 11: Scenario 2 Local Economic Impacts

Local Economic Impacts - Scenario 2 Summary Results			
	Jobs	**Earnings**	**Output**
During construction period		($ - Millions)	($ - Millions)
Project Development and Onsite Labor Impacts	50 - 100	10 - 20	10 - 20
Construction and Interconnection Labor	50 - 100	10 - 20	
Construction Related Services	3 - 20	0 - 2	
Power Generation and Supply Chain Impacts	40 - 100	2 - 10	10 - 30
Induced Impacts	30 - 100	2 - 10	10 - 20
Total Impacts (Direct, Indirect, Induced)	100 - 400	10 - 30	20 - 100
During operating years (annual)			
Onsite Labor Impacts	1 - 4	0 - 0.2	0 - 0.2
Local Revenue and Supply Chain Impacts	10 - 60	1 - 5	4 - 20
Induced Impacts	10 - 30	1 - 2	2 - 10
Total Impacts (Direct, Indirect, Induced)	20 - 100	1 - 10	10 - 20
Notes: Totals may not add due to rounding. Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for each year of the 24-month construction period. Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted.			

Scenario 3 Study Results

Ratepayer Costs

Projected CCA customer rates in Scenario 3 are generally higher than the projections for PG&E's rates, with positive differences of up to 11% seen before converging in later years. The higher overall renewable energy content and the higher unit costs of the small-scale and local generation projects result in increased electric supply costs. The heavy renewable energy content pressures rates in the near term and stabilizes rates over the longer term, ultimately producing ratepayer benefits toward the end of the study period.

Levelized rates over the term are approximately 8% higher than the projected PG&E rates. For a typical household using 500 kWh per month, an 8% rate difference would result in a cost increase of approximately $6.90 per month.

Projected average rates for the Sonoma County customer base are shown in Figure 19 and Table 12 under PG&E bundled service and CCA service.

Figure 19: Scenario 3 Annual Ratepayer Costs

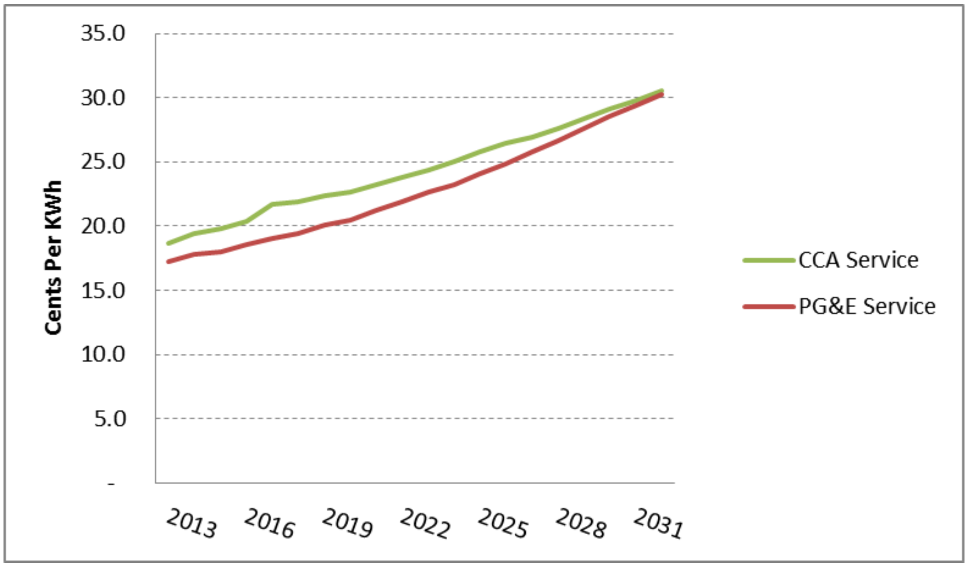


Table 12: Scenario 3 Ratepayer Impacts

Year	PG&E Total (₵/kWh)	CCA Total (₵/kWh)	Percent Difference
Levelized	21.6	23.3	8%
2013	17.2	18.7	9%
2014	17.8	19.4	9%
2015	18.0	19.8	10%
2016	18.6	20.4	10%
2017	19.0	21.7	14%
2018	19.4	21.9	13%
2019	20.0	22.3	11%
2020	20.5	22.6	11%
2021	21.2	23.2	10%
2022	21.9	23.8	9%
2023	22.6	24.4	8%
2024	23.3	25.1	8%
2025	24.1	25.7	7%
2026	24.9	26.5	6%
2027	25.8	26.9	5%
2028	26.7	27.6	4%
2029	27.6	28.4	3%
2030	28.5	29.1	2%
2031	29.4	29.8	1%
2032	30.3	30.5	1%

GHG Impacts

GHG impacts from Scenario 3 are extremely large as the renewable energy content greatly exceeds the reference case in all years. Annual GHG reductions average approximately 350,000 metric tons of CO_2 per year, representing a decrease of 54% from electric sector GHG emissions within the County.

Figure 20: Scenario 3 Annual GHG Emissions

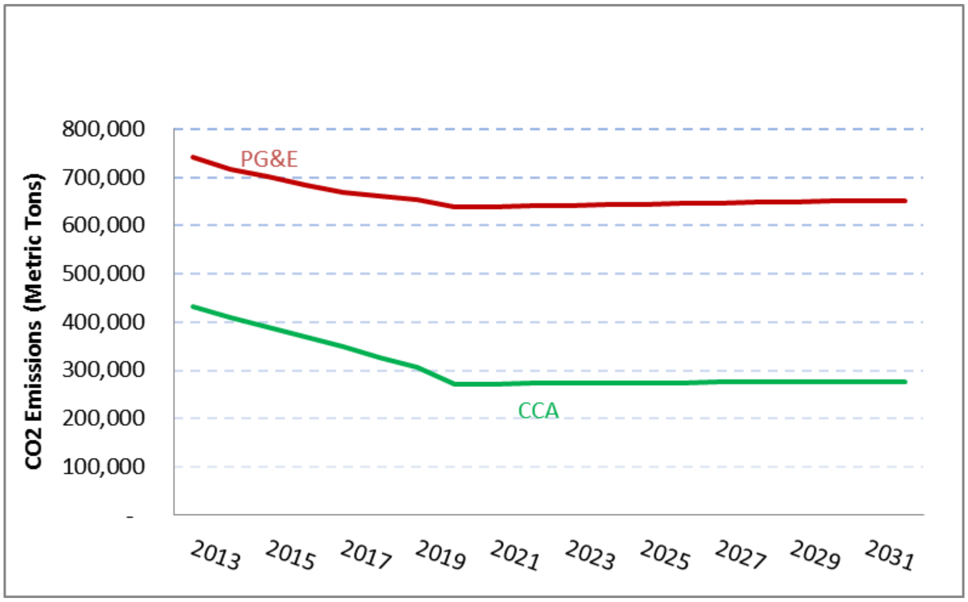


Table 13: Scenario 3 GHG Reductions

GHG Metric	Amount
GHG Reduction, Cumulative (2013-2032)	7.1 Million Metric Tons CO_2
GHG Reduction, Annual	355,000 Metric Tons CO_2
GHG Reduction, Change in Electric Sector CO_2 emissions	-54%

Economic Development

Supply Scenario 3 contemplates intensive use of renewable generating resources and power purchase agreements with the goal of delivering 75 percent renewable energy supply by 2020. The underlying, locally developed supply portfolio includes a combination of several development projects and contracts, including: 1) a locally situated, utility scale geothermal generator with operating capacity of 75 MW that would begin delivering over 600 GWh per year of RPS-eligible renewable energy in 2016; 2) a locally developed, utility scale biomass generator with operating capacity of 50 MW that would deliver more than 370 GWh annually beginning in 2020; 3) a series of locally situated, commercial scale photovoltaic solar generators with aggregate operating capacity of 25 MW that would begin delivering approximately 48 GWh (per year) of RPS-eligible renewable energy in 2015; 4) a series of locally situated, mid-sized, ground mounted photovoltaic solar generators of various sizes with aggregate operating capacity of 125 MW that would begin delivering approximately 240 GWh per year of RPS-eligible renewable energy in 2015; 5) a series of locally situated, small-sized, ground mounted photovoltaic solar generators of various sizes with aggregate operating capacity of 35 MW that would begin delivering over 67 GWh per year of RPS-eligible renewable energy in 2015; and 6) a locally developed, utility scale wind generator with operating capacity of 25 MW that would deliver nearly 66 GWh annually beginning in 2018. Based on current assumptions related to Scenario 3, output from the geothermal and all photovoltaic solar generators would be delivered under long-term power purchase agreements between the Sonoma County CCA and qualified developers/owners. The biomass and wind generators would be internally developed and financed by the CCA program. In aggregate, 335 MW of new, locally developed renewable generating capacity would be utilized to serve customer energy requirements under supply Scenario 3.

As described under Scenarios 1 and 2, it is assumed that the significant majority of plant equipment, including turbines and other materials required to implement Scenario 3, would be procured outside of Sonoma County. However, as with Scenarios 1 and 2, general site preparation and ancillary facility construction (concrete footings and structures not directly involved in the generation process) would rely heavily on local goods and services as well as labor. Sonoma County's local economy would also benefit from the collection of requisite permitting fees during generator construction as well as annual property tax revenues related to the project site.

In total, supply Scenario 3 is projected to result in the creation of 700-1,500 new jobs during each year of the respective construction period (24 months) for these resources. This represents an approximate 400 percent increase in total construction employment relative to Scenario 1 and a 275 percent increase in construction employment relative to Scenario 2 (based on the top end of each respective range representing projected outcomes). During each year of construction, individuals working directly on the projects would be responsible for $40-$80 million in new economic output of which $30-$60 million would be collected in the form of salaries and wages. Workers involved with supply chain activities, would be responsible for approximately $40-$90 million in new economic activity of which $10-$30 million would be collected in the form of salaries and wages. Furthermore, spending by the aforementioned individuals (as a result of salary and wage collection) would "induce" other local economic impacts totaling $20-$60 million of which $10-$20 million would be collected as salaries and wages. In total, the locally developed generation projects identified under Scenario 3 would result in $100-$200 million in new economic output during each year of the construction process, which is approximately $100 million, or 100 percent, more than projected for Scenario 2 and $150 million, or 300 percent more than projected for Scenario 1.

During ongoing operation of these renewable generators, it is projected that 100-200 new jobs would be created with a total annual economic impact of $20-$50 million. These projected economic impacts exceed similar projections for Scenario 2 by 150 percent, or approximately $30 million annually. It is anticipated that these jobs would remain effective as long as the generating facilities remain operational. The following table summarizes the range of projected local economic impacts related to Scenario 3 implementation.

Table 14: Scenario 3 Local Economic Impacts

Local Economic Impacts - Scenario 3 Summary Results			
	Jobs	Earnings	Output
During construction period		($ - Millions)	($ - Millions)
Project Development and Onsite Labor Impacts	300 - 700	30 - 60	40 - 80
Construction and Interconnection Labor	200 - 500	20 - 50	
Construction Related Services	80 - 200	5 - 10	
Power Generation and Supply Chain Impacts	200 - 500	10 - 30	40 - 90
Induced Impacts	100 - 400	10 - 20	20 - 60
Total Impacts (Direct, Indirect, Induced)	700 - 1500	50 - 110	100 - 200
During operating years (annual)			
Onsite Labor Impacts	10 - 30	1 - 2	1 - 2
Local Revenue and Supply Chain Impacts	30 - 140	2 - 10	10 - 40
Induced Impacts	30 - 70	0 - 4	5 - 10
Total Impacts (Direct, Indirect, Induced)	100 - 200	5 - 20	20 - 50
Notes: Totals may not add due to rounding. Earnings and Output values are millions of dollars in year 2011 dollars.			
Construction period related jobs are full-time equivalent for each year of the 24-month construction period. Plant workers			
includes operators, maintenance, administration and management. Economic impacts "During operating years"			
represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated			
with spending of plant "profits" and assumes no tax abatement unless noted.			

Scenario 4 Results

Ratepayer Costs

Projected CCA customer rates in Scenario 4 are generally higher than the projections for PG&E's rates, with positive differences of up to 7% seen before converging in later years. The assumption that the CCA is able to finance development of a significant portion of its power supply, particularly the geothermal generation and biomass cogeneration, tends to reduce costs relative to Scenario 3 despite the higher renewable energy content. Like Scenario 3, the high renewable energy content increases rates in the near term and stabilizes rates over the longer term, ultimately producing ratepayer benefits toward the end of the study period.

Levelized rates over the term are approximately 4% higher than the projected PG&E rates. For a typical household using 500 kWh per month, a 4% rate difference would result in a cost increase of approximately $3.50 per month.

Projected average rates for the Sonoma County customer base are shown in Figure 21 and Table 15 under PG&E bundled service and CCA service.

Figure 21: Scenario 4 Annual Ratepayer Costs

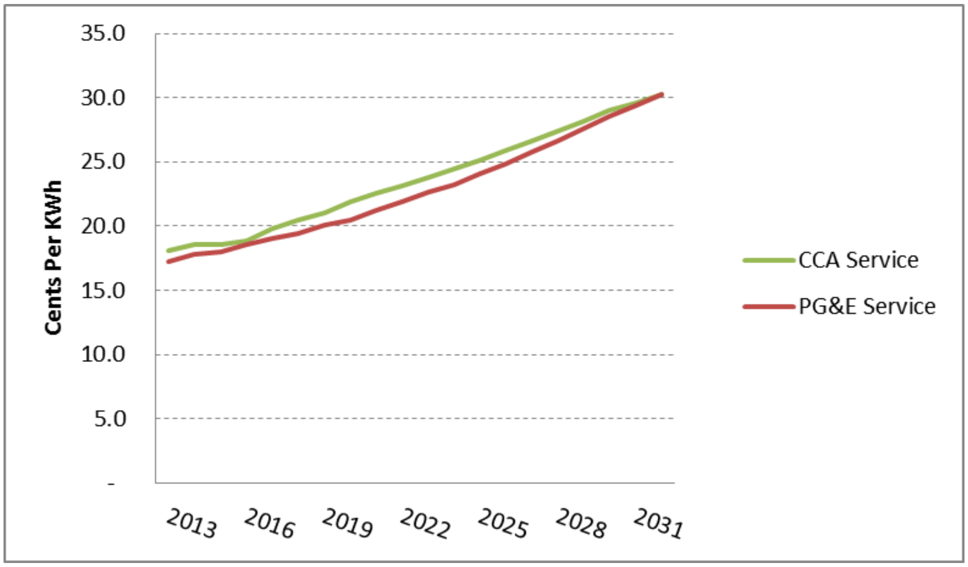


Table 15: Scenario 4 Ratepayer Impacts

Year	PG&E Total (₵/kWh)	CCA Total (₵/kWh)	Percent Difference
Levelized	21.6	22.5	4%
2013	17.2	18.1	5%
2014	17.8	18.6	4%
2015	18.0	18.6	3%
2016	18.6	18.9	2%
2017	19.0	19.8	4%
2018	19.4	20.5	6%
2019	20.0	21.0	5%
2020	20.5	21.9	7%
2021	21.2	22.5	6%
2022	21.9	23.1	6%
2023	22.6	23.8	5%
2024	23.3	24.5	5%
2025	24.1	25.1	4%
2026	24.9	25.9	4%
2027	25.8	26.6	3%
2028	26.7	27.4	3%
2029	27.6	28.2	2%
2030	28.5	29.0	2%
2031	29.4	29.6	1%
2032	30.3	30.3	0%

GHG Impacts

GHG impacts from Scenario 4 are extremely large as the renewable energy content initially matches and then greatly exceeds the reference case in all subsequent years. Annual GHG reductions average approximately 380,000 metric tons of CO_2 per year, representing a decrease of 58% from electric sector GHG emissions within the County.

Figure 22: Scenario 4 Annual GHG Emissions

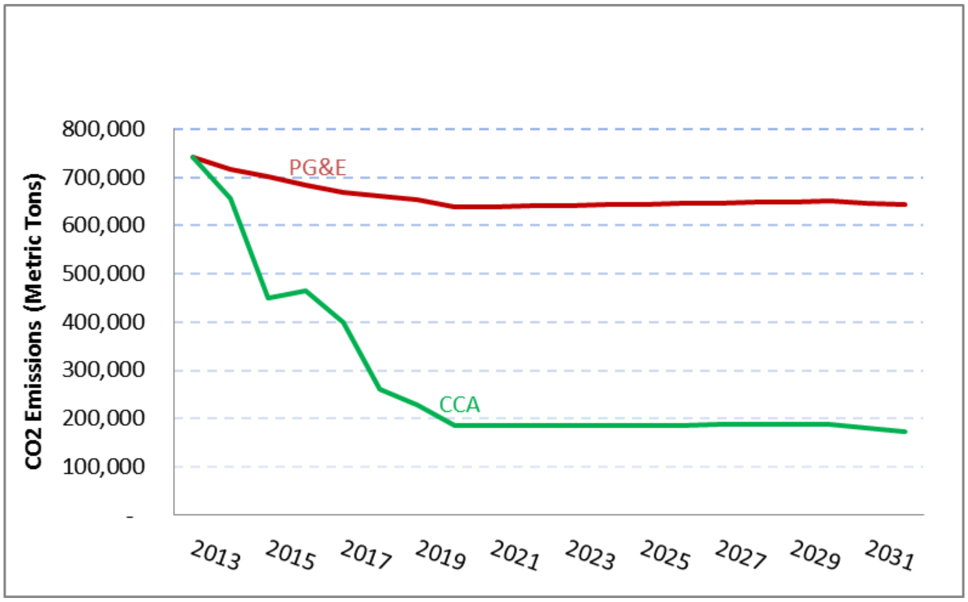


Table 16: Scenario 4 GHG Reductions

GHG Metric	Amount
GHG Reduction, Cumulative (2013-2032)	7.6 Million Metric Tons CO_2
GHG Reduction, Annual	380,000 Metric Tons CO_2
GHG Reduction, Change in Electric Sector CO_2 emissions	-58%

Economic Development

Much like supply Scenario 3, Scenario 4 contemplates intensive use of renewable generating resources but with stronger emphasis on local, CCA-financed project development (as opposed to contracting opportunities for electric output from locally developed facilities), resulting in more than 85 percent renewable energy supply by 2020. The underlying, locally developed supply portfolio includes a combination of several development projects and contracts, including: 1) a locally developed, utility scale geothermal generator with operating capacity of 95 MW that would begin delivering over 780 GWh per year of RPS-eligible renewable energy in 2015; 2) a series of locally developed, utility scale biomass cogeneration projects with aggregate operating capacity of 40 MW that would deliver nearly 300 GWh annually beginning in 2014; 3) a locally developed pumped storage facility with operating capacity of 60 MW that would begin delivering more than 130 GWh per year of GHG-free renewable energy in 2017; 4) a series of local residential photovoltaic solar installations of various sizes with aggregate operating capacity of 10 MW that would begin delivering approximately 19 GWh per year of RPS-eligible renewable energy in 2015; 5) a locally developed energy storage system (battery) with operating capacity of 12 MW that would have the capability to deliver more than 26 GWh per year in 2018; and 6) a locally developed, utility scale wind generator with operating capacity of 45 MW that would deliver nearly 120 GWh of RPS-eligible renewable energy annually beginning in 2018. Based on current assumptions related to Scenario 4, all noted projects, excepting the residential solar installations, would be internally developed and financed by the CCA program. In aggregate, 262 MW of new, locally developed renewable generating capacity would be utilized to serve customer energy requirements under supply Scenario 4.

As described under the other scenarios, it is assumed that the significant majority of plant equipment, including turbines and other materials required to implement Scenario 4, would be procured outside of Sonoma County. However, as with the other scenarios, general site preparation and ancillary facility construction (concrete footings and structures not directly involved in the generation process) would rely heavily on local goods and services as well as labor. In particular, work required to develop the noted pumped storage project is assumed to rely heavily on the Sonoma County Water Agency's work force, based on the breadth and scope of infrastructure project experience within this organization. Sonoma's local economy would also benefit from the collection of requisite permitting fees during generator construction as well as annual property tax revenues related to the project site.

In total, supply Scenario 4 is projected to result in the creation of 400-1,100 new jobs during each year of the respective construction period (a 24-month construction period is assumed) for these resources. Individuals working directly on the projects would be responsible for $30-$60 million in new, annual economic output of which $20-$50 million would be collected in the form of salaries and wages. Workers involved with supply chain activities, would be responsible for approximately $30-$80 million in new economic activity of which $10-$20 million would be collected in the form of salaries and wages. Furthermore, spending by the aforementioned individuals (as a result of salary and wage collection) would "induce" other local economic impacts totaling $20-$50 million of which $10-$20 million would be collected as salaries and wages. In total, the locally developed generation projects identified under Scenario 4 would result in $70-$200 million in new economic output during each year of the construction process.

During ongoing operation of these renewable generators, it is projected that 100-400 new jobs would be created with a total annual economic impact of $30-$80 million. The following table summarizes the projected range of local economic impacts related to Scenario 4 implementation.

Table 17: Scenario 4 Local Economic Impacts

Local Economic Impacts - Scenario 4 Summary Results			
	Jobs	**Earnings**	**Output**
During construction period		($ - Millions)	($ - Millions)
Project Development and Onsite Labor Impacts	200 - 400	20 - 50	30 - 60
Construction and Interconnection Labor	100 - 300	20 - 40	
Construction Related Services	30 - 100	2 - 10	
Power Generation and Supply Chain Impacts	100 - 400	10 - 20	30 - 80
Induced Impacts	100 - 300	10 - 20	20 - 50
Total Impacts (Direct, Indirect, Induced)	400 - 1100	30 - 90	70 - 200
During operating years (annual)			
Onsite Labor Impacts	10 - 20	0 - 1	0 - 1
Local Revenue and Supply Chain Impacts	60 - 300	4 - 20	24 - 60
Induced Impacts	50 - 100	3 - 10	8 - 20
Total Impacts (Direct, Indirect, Induced)	100 - 400	7 - 20	30 - 80
Notes: Totals may not add due to rounding. Earnings and Output values are millions of dollars in year 2011 dollars.			
Construction period related jobs are full-time equivalent for each year of the 24-month construction period. Plant workers			
includes operators, maintenance, administration and management. Economic impacts "During operating years"			
represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated			
with spending of plant "profits" and assumes no tax abatement unless noted.			

VI. Sensitivity Analysis

The economic analysis uses base case input assumptions for many variable factors that influence relative costs of the CCA program. Sensitivity analyses were performed to examine the range of impacts from changes in the most significant variables from the base case values. The key variables examined are: 1) power and natural gas prices; 2) renewable energy prices; 3) PG&E rates; and 4) customer participation/opt-out rates. A fifth sensitivity examined the impact of a potential shared services arrangement with the existing CCA program operated by the Marin Energy Authority.

Power and Natural Gas Prices

Electric power prices in California are influenced by natural gas prices due to natural gas-fired generation being predominantly used as the marginal resource in the system dispatch order. Changes in natural gas prices will also tend to change the power purchase costs of the CCA program. Changes in natural gas and power prices also influence PG&E's rates, and to a more or lesser degree depending upon differences in the resource mix between the CCA program and PG&E.

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

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

Renewable Energy Costs

There can be wide variation in renewable energy costs due to locational factors (wind regime, solar insolation, availability of feedstock, etc.), transmission costs, technological change, federal tax policy, and other factors.

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

PG&E Rates

The base case forecast for PG&E's generation rates yields a projected average annual increase of approximately 4%. The forecast relies on resource mix data PG&E provided in its most recent long term procurement plan, and incorporates many of the same core market cost assumptions (natural gas prices, power prices, GHG allowance prices, etc.) as used in the forecast of CCA program rates. Numerous factors can cause variances in PG&E's rates, and low and high cases were developed for this variable. One factor that could have a significant increase on PG&E's rates is the potential closure or rebuilding of the Diablo Canyon Nuclear Power Plant resulting from regulations prohibiting the use of once-through-cooling at the plant by 2024. A high case was created that reflects an average annual generation rate increase of 5%. The low case assumes 3% annual rate increases for PG&E.

Opt-Out Rates

Sensitivity of ratepayer costs to customer participation in the CCA program was tested by varying the opt-out rate from 40% in the high case to 5% in the low case. A higher opt-out rate would reduce sales volumes relative to base case assumptions, and increase the share of fixed costs paid by each customer, while a lower opt-out rate would have the opposite effect.

Joint Action with the Marin Energy Authority

The Marin Energy Authority ("MEA") is an existing Community Choice Aggregator that has been serving electric customers in Marin County since May, 2010. MEA has the first and currently only CCA program in operation, which is known as "Marin Clean Energy". A possibility exists for a Sonoma County CCA to work jointly with MEA to share certain services and costs. MEA has begun considering how it can work jointly with other communities whether through membership in MEA or some other shared services arrangement.

A shared services arrangement with MEA could reduce the costs of implementing and operating the CCA program. However, depending on how the relationship is structured, there could be a loss of autonomy and a potential for compromised objectives relative to an independent implementation approach. If the Sonoma County municipalities were to become MEA members (jointly or individually), board representation and voting shares would present important policy issues. Apart from membership, other partnership structures could be explored that might allow a Sonoma County CCA to receive services from MEA under an energy services contract and reduce CCA operating costs while preserving Sonoma County's autonomy over important issues such as resource planning, ratesetting, generation development, energy efficiency and other local programs.

In evaluating possible benefits, DMC examined the CCA operational activities that could be shared between a Sonoma County CCA and MEA and estimated the cost savings that could be achieved. Actual figures would, of course, reflect the outcome of future discussions between the Sonoma County CCA and MEA regarding how such a shared service arrangement might be structured and how costs might be allocated.

At the June 2, 2011 meeting of the MEA Board, MEA staff presented a preliminary estimate of costs that might be assessed for municipalities outside of Marin County to join MEA. The staff report presented a preliminary figure of $130,000 for the following tasks that would be involved:

- Obtain and analyze customer load data
- Analyze economic impact to MEA for serving customers
- Outreach/interface with City policy-makers and aid in adoption of enabling ordinance
- Determine and implement changes to Board composition/voting rights
- Modify, adopt and submit updated Implementation Plan
- Negotiate agreement for additional resource requirements
- Identify/secure any necessary short-term financing to support expansion
- Notice customers
- Provide call-center services for all customer inquiries
- Provide ongoing customer communication
- Provide for all regulatory compliance filings to cover new load being served
- Provide regulatory support at the CPUC

The activities that would be undertaken by MEA would largely eliminate Sonoma County's CCA program start-up costs, which are estimated at $1.7 million. These gross savings would be partially offset by the fees charged by MEA. The $130,000 preliminary membership fee figure cited in the MEA staff report may not have envisioned expanding service to an entity the size of Sonoma County, and it is reasonable to assume that the ultimate fee could be higher. Still, there appears to be the potential for one-time cost savings of over $1 million. Table 18 shows a range of cost savings under the assumption that MEA fees would range from a low of $130,000 to a high of $500,000.

Table 18: Shared Services Startup Cost Savings

Cost	Low	High
Start-up Cost Savings (one-time)	$1,650,000	$1,650,000
MEA Fees (one-time)	$500,000	$130,000
Net Savings (one-time)	**$1,150,000**	**$1,520,000**

On an ongoing basis, DMC has estimated annual program savings beginning at approximately $2.6 million and totaling $71 million over the study period. These figures were derived using estimates of the fixed costs of staffing and other administrative and general costs that could be avoided, assuming that MEA would be compensated for the incremental costs of providing these services to the Sonoma County CCA. As shown in the pro forma in Appendix A, the CCA program's annual costs for staffing and other administrative costs are estimated at $4.7 million. Incremental staffing and professional services costs (i.e., costs that increase with customers or sales volume) were estimated at approximately $1 per MWh or $2.1 million annually. Subtracting the $2.1 million presumed to be paid to MEA from the $4.7 million estimated CCA program costs for staffing and professional services yields annual savings potential of $2.6 million as shown in Table 19. Billing and data management costs are assumed to be entirely incremental and are not included in the savings estimates below.

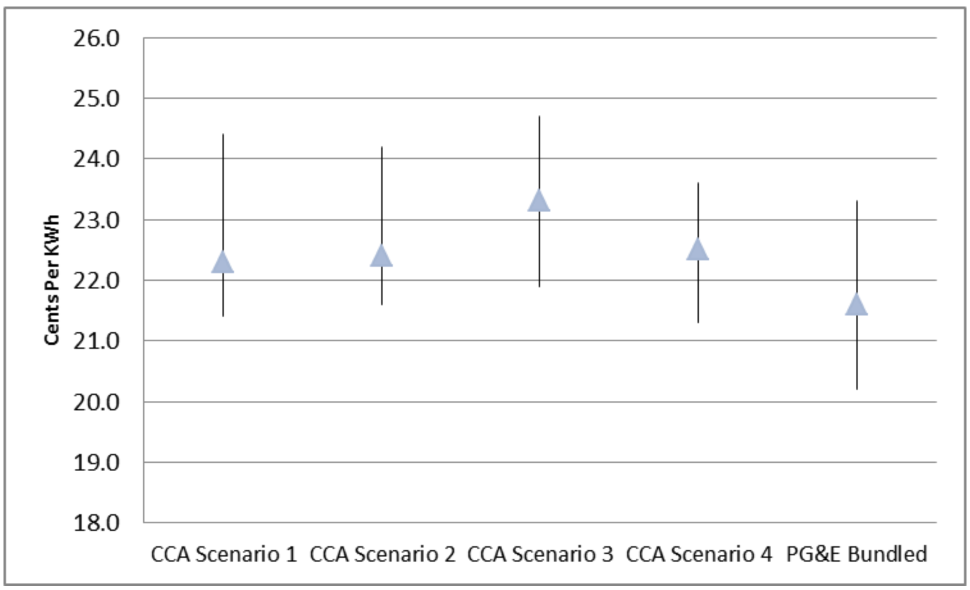
Table 19: Shared Services Annual Costs Savings, Year 1

Cost	Amount
Staff and Professional Services for Sonoma County CCA ($/Year)	$4,700,000
Incremental Costs assumed paid to MEA ($/Year)	-$2,100,000
Annual Cost Savings Potential ($/Year)	**$2,600,000**

Sensitivity Results

The sensitivity analysis produced a range of levelized electric rates for the CCA program and PG&E as shown in Figure 23. It should be noted that there is considerable overlap in the range of estimated rates, and while base case estimates show higher rates for the CCA program, any of the CCA Scenarios could potentially result in lower ratepayer costs than under the status quo.

Figure 23: Sensitivity Analysis Range of Levelized Electric Rates



The sensitivity to each tested variable is shown in Table 20. Natural Gas/Power prices had the greatest impact on CCA rates in Scenarios 1 and 2, while renewable energy costs were the most significant driver of CCA rates in Scenarios 3 and 4.

Table 20: Sensitivity Matrix, Levelized Electric Rates by Scenario

Rate Scenario	Base Case	High Gas	Low Gas	High R.E. Costs	Low R.E. Costs	High PG&E Rates	Low PG&E Rates	High Opt Out	Low Opt Out	MEA Shared Services
CCA Scenario 1	22.3	24.4	21.4	22.8	21.7	22.3	22.3	22.3	22.3	22.1
CCA Scenario 2	22.4	24.2	21.7	23.2	21.6	21.6	21.6	22.4	22.4	22.2
CCA Scenario 3	23.3	24.5	22.9	24.7	21.9	23.3	23.3	23.6	23.3	23.1
PG&E Bundled	22.5	23.5	22.1	23.6	21.3	22.5	22.5	22.6	22.5	22.3

The sensitivity results for each supply scenario are depicted graphically in Figures 24-27.

Figure 24: Scenario 1 Sensitivity Impacts on Levelized Electric Rates

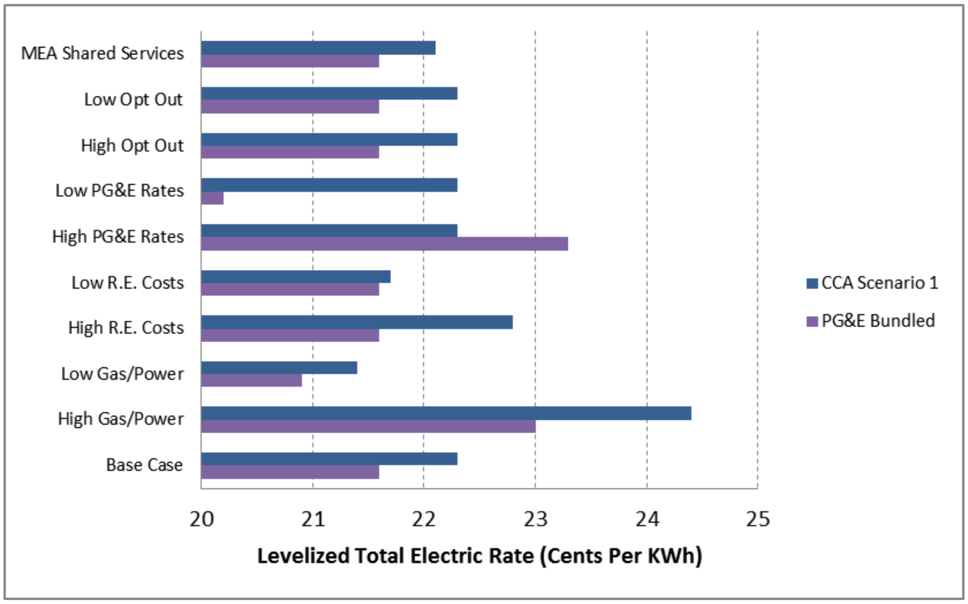


Figure 25: Scenario 2 Sensitivity Impacts on Levelized Electric Rates

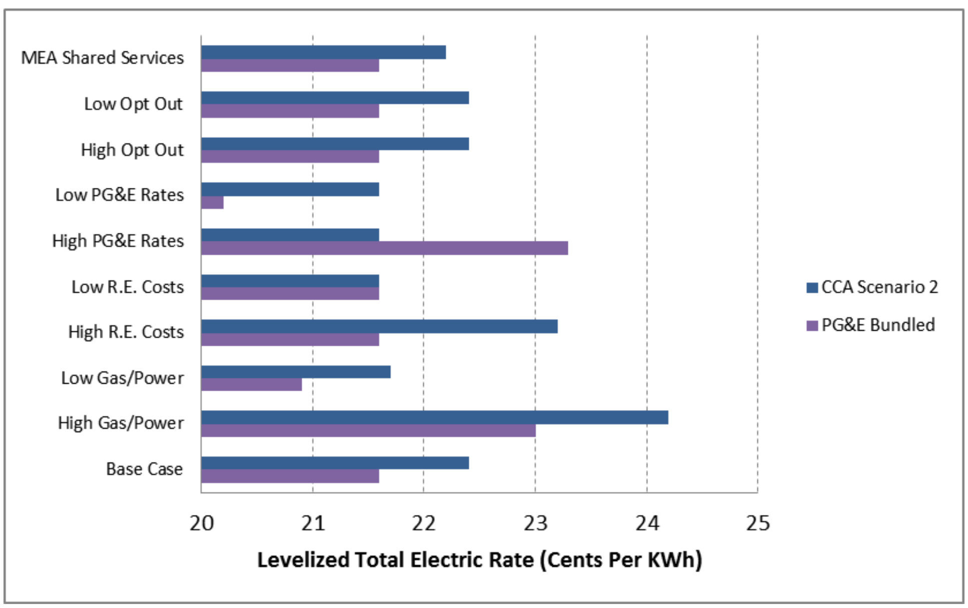


Figure 26: Scenario 3 Sensitivity Impacts on Levelized Electric Rates

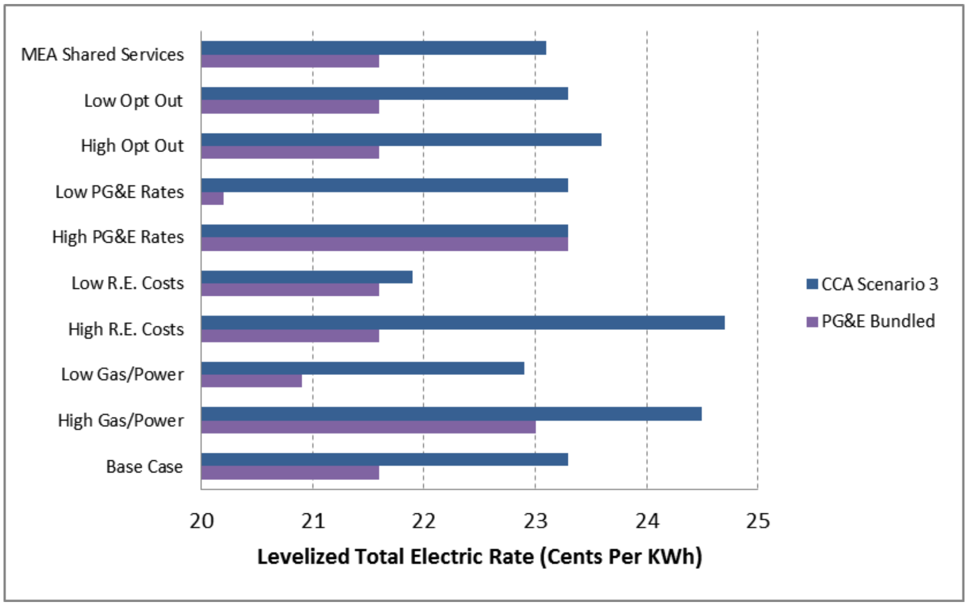
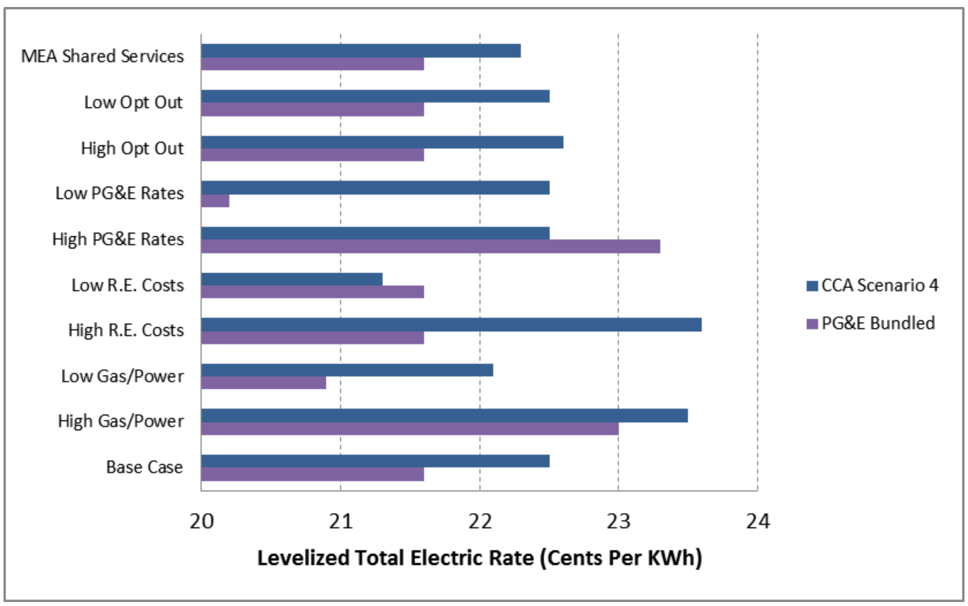


Figure 27: Scenario 4 Sensitivity Impacts on Levelized Electric Rates



VII. CCA Formation Activities

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

CCA Entity Formation

Unless the municipality that will legally register as the CCA entity already exists, it must be legally established. Municipalities electing to offer or allow others to offer CCA service within their jurisdiction must do so by ordinance.

Regulatory Requirements

Before aggregating customers, the CCA program must meet certain requirements set forth by the CPUC. An Implementation Plan must be adopted by the CCA municipal entity (city, county or joint powers authority), and that Implementation Plan must be submitted to the CPUC. The Implementation Plan must include the following:

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

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

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

The CPUC has ninety days to complete a review and certify the Implementation Plan. Following certification of the Implementation Plan, the CCA entity must submit a registration packet to the CPUC, which includes:

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

- A bond or evidence of sufficient insurance to cover any reentry fees that may be imposed against it by the CPUC for involuntarily returning customers to PG&E service.

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

Procurement

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

Financing

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

Organization

Initial staff positions would be filled several months in advance of service commencement to conduct the implementation process. Contracts with other service providers, such as for data management services, would be negotiated and put into effect.

Customer Notices

Customers must be provided notices regarding their pending enrollment in the CCA program and containing program terms and conditions and opt-out instructions at least twice within sixty days before automatic enrollment. These notices are referred to as "pre-enrollment" notices. Two additional "post-enrollment" notices must be provided within sixty days following enrollment during the statutory opt-out period.

VIII. Evaluation and Recommendations

This section provides an overall assessment of the feasibility for forming a CCA program in Sonoma County and provides DMC's recommendations in the event a decision is made to proceed with development of a CCA program.

DMC's analysis shows a Sonoma County CCA program would provide significant benefits – both economic and environmental – but would likely be accomplished with customer rates somewhat higher than current projections under the status quo. Under a reasonable range of sensitivity assumptions, the analysis shows that customer rates are projected to range from approximately 21 to 25 cents per kWh, on a 20-year levelized cost basis, while PG&E rates are projected to range from 20 to 23 cents per kWh on a levelized basis over this same time period.

Under base case assumptions, CCA program rates are projected to range from 22.3 cents per kWh to 23.3 cents per kWh, depending upon the ultimate CCA program resource mix, while PG&E's rates are projected to be slightly lower at 21.6 cents per kWh. Table 21 shows projected levelized electric rates and typical residential monthly electric bills under the base case assumptions.

Table 21: Summary of Ratepayer Costs

Ratepayer Impact	Scenario 1	Scenario 2	Scenario 3	Scenario 4	PG&E
Levelized Electric Rate (Cents/KWh)	22.3	22.4	23.3	22.5	21.6
Typical Residential Bill ($/Month)	$112	$112	$117	$113	$108

It should be noted that there is considerable overlap in the range of estimated rates, and while base case estimates show higher rates for the CCA program, any of the CCA scenarios could potentially result in lower ratepayer costs than under the status quo.

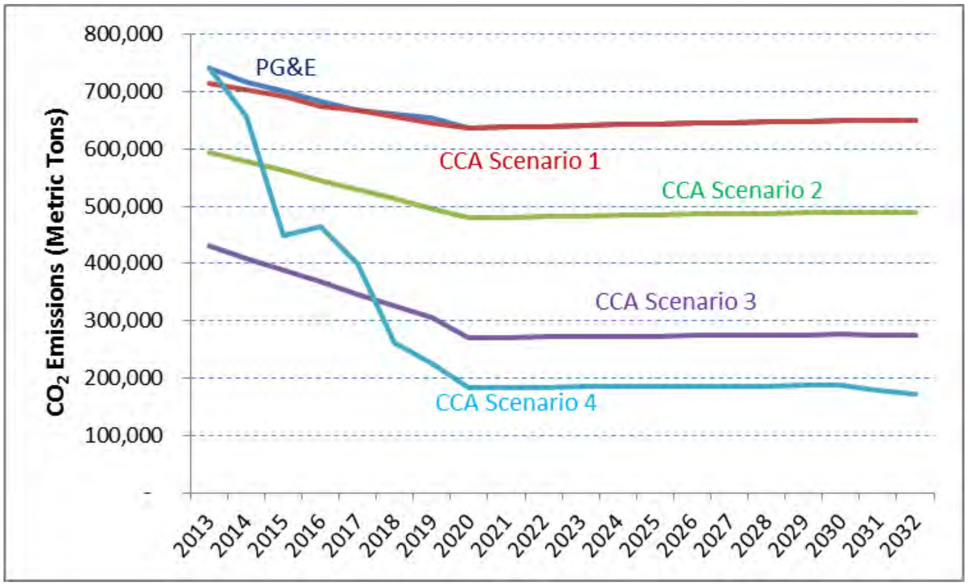
In regards to GHG emissions impacts, the ultimate CCA program resource mix will largely dictate the GHG emissions profile relative to the reference case. Depending upon resource choices made by the CCA program, reductions in GHG emissions could be minimal as in Scenario 1, or GHG emissions reductions could be as high as 390,000 tons per year as in Scenario 4. The GHG reductions estimated in Scenarios 2, 3 and 4 would represent significant cuts in GHG emissions associated with electricity consumption in Sonoma County. Table 22 summarizes projected GHG emissions reductions for each of the modeled supply scenarios.

Table 22: Summary of GHG Emissions Impacts

GHG Impact	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Annual GHG Reductions (Tons CO_2/Year)	3,500	155,000	355,000	380,000
Change in Electric Sector CO_2 Emissions in Sonoma County (%)	-1%	-23%	-54%	-58%

Figure 28 illustrates projected GHG emissions under the status quo and the GHG emissions associated with each CCA supply scenario.

Figure 28: Projected GHG Emissions



The potential for local generation investment arising from the CCA program appears to offer significant benefits to the local economy. Again, resource decisions will impact the degree to which generation investments yield local benefits as indicated by analysis of the local economic impact associated with the representative supply scenarios. Developing renewable generation projects along the timelines associated with Scenario 3 and Scenario 4 will be challenging, particularly considering the magnitude of local generation development assumed in these scenarios. The economic benefits from Scenario 3 and Scenario 4 are best considered as representative of the upper range of potential outcomes for a Sonoma County CCA program.

The range of local economic development impacts from the modeled supply scenarios are summarized in Table 23.

Table 23: Summary of Impacts to Sonoma County Economy

Impact	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Jobs – Construction Period (24 months)	100 - 300	100 - 400	700 - 1,500	400 - 1,100
Jobs - Permanent	15 – 100	20 - 100	100 - 200	100 - 400
Economic Output – Construction Period ($ Millions)	$15 - $50	$20 - $100	$100 - $200	$70 - $200
Economic Output – Permanent ($Millions/Year)	$4 - $20	$10 - $20	$20 - $50	$30 - $80

The feasibility analysis reveals the existence of tradeoffs between minimizing ratepayer costs and promoting economic benefits for the local economy through local resource development. Compared to some other areas in the state, Sonoma County is not the best resource area for solar and wind production, and local projects of this type will tend to have higher costs than projects sited in prime resource areas. Tradeoffs also exist between minimizing ratepayer costs in the short run and expanding use of renewable energy due to the cost premiums that currently exist for renewable energy. Decisions made during the implementation process and during the life of the CCA program will determine how these considerations are balanced. DMC recommends that considerable thought be given upfront to the ultimate goals of the CCA program so that clear objectives are established, giving those responsible for administering the CCA program the opportunity to develop and execute a plan that meets the community's objectives.

The potential cost savings from working with MEA under some form of membership or shared services arrangement appears worthy of further discussion with MEA to better understand how such a relationship might be structured. DMC has estimated the potential cost savings at approximately $71 million over the 20-year study period which results from economies of scale in managing CCA program operations. Actual cost savings would depend upon the outcome of negotiations with MEA. Other factors such as board representation, autonomy in resource planning and other political considerations that would be important to the decision to partner with MEA remain to be addressed. Sonoma County would be wise to prioritize its goals in pursuing a CCA program before any decision is made to partner with MEA, as some compromise of these objectives may be involved in any such partnership.

Appendix A

Financial Pro Forma Analyses

FINANCIAL PRO FORMA ANALYSIS
COMMUNITY CHOICE AGGREGATION
SCENARIO 1

CATEGORY	[3] 2013	[4] 2014	[5] 2015	[6] 2016	[7] 2017	[8] 2018	[9] 2019	[10] 2020	[11] 2021	[12] 2022
I, CUSTOMER ACCOUNTS:										
RESIDENTIAL (E-1)	143,577	143,860	144,142	144,426	144,709	144,994	145,279	145,564	145,850	146,137
GENERAL SERVICE (A-1)	14,851	14,880	14,909	14,938	14,968	14,997	15,026	15,056	15,086	15,115
SMALL TIME-OF-USE (A-6)	916	918	920	922	923	925	927	929	931	933
ALTERN. RATE FOR MEDIUM USE (A-10)	1,845	1,849	1,853	1,856	1,860	1,864	1,867	1,871	1,875	1,878
500 - 900kW DEMAND (E-19)	279	279	280	280	281	282	282	283	283	284
1000 + kW DEMAND (E-20)	11	11	11	11	11	12	12	12	12	12
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	1,705	1,708	1,712	1,715	1,718	1,722	1,725	1,728	1,732	1,735
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	2,055	2,059	2,063	2,067	2,071	2,075	2,079	2,084	2,088	2,092
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - CUSTOMER ACCOUNTS	165,240	165,564	165,890	166,216	166,542	166,870	167,198	167,526	167,855	168,185
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	955,978,769	957,857,267	959,739,457	961,625,345	963,514,939	965,408,246	967,305,273	969,206,028	971,110,517	973,018,750
GENERAL SERVICE (A-1)	219,198,358	219,629,083	220,060,654	220,493,073	220,926,342	221,360,462	221,795,435	222,231,263	222,667,948	223,105,490
SMALL TIME-OF-USE (A-6)	61,081,051	61,201,075	61,321,335	61,441,832	61,562,565	61,683,535	61,804,744	61,926,190	62,047,875	62,169,799
ALTERN. RATE FOR MEDIUM USE (A-10)	323,672,335	324,308,352	324,945,617	325,584,136	326,223,908	326,864,938	327,507,228	328,150,780	328,795,596	329,441,679
500 - 900kW DEMAND (E-19)	237,016,030	237,481,766	237,948,418	238,415,986	238,884,474	239,353,882	239,824,212	240,295,467	240,767,647	241,240,756
1000 + kW DEMAND (E-20)	125,403,846	125,650,264	125,897,167	126,144,555	126,392,429	126,640,790	126,889,639	127,138,977	127,388,806	127,639,125
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	13,001,863	13,027,412	13,053,011	13,078,660	13,104,359	13,130,110	13,155,910	13,181,762	13,207,664	13,233,617
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	44,752,095	44,840,033	44,928,143	45,016,427	45,104,884	45,193,515	45,282,321	45,371,300	45,460,455	45,549,785
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - LOAD REQUIREMENTS	1,980,104,346	1,983,995,252	1,987,893,802	1,991,800,014	1,995,713,901	1,999,635,478	2,003,564,762	2,007,501,767	2,011,446,508	2,015,399,000
III. CCA POWER SUPPLY REVENUE REQUIREMENT ($)										
(A) MARKET PURCHASES	$18,140,776	$18,048,601	$18,734,184	$17,881,239	$19,065,949	$20,302,989	$21,638,868	$22,786,339	$24,728,316	$26,174,796
(B) CONTRACT PURCHASES	$72,563,102	$72,194,406	$74,936,735	$128,704,106	$132,325,953	$136,203,264	$140,520,270	$144,126,267	$150,951,251	$155,833,618
(C) POWER PRODUCTION (NON-DEBT)	$0	$0	$0	$0	$0	$0	$0	$5,374,414	$5,384,188	$5,394,279
(D) RENEWABLE MARKET PURCHASES AND RECS	$31,155,311	$39,440,736	$41,831,275	$0	$1,716,762	$4,084,915	$6,642,486	$833,983	$1,068,488	$2,149,573
(E) ANCILLARY SERVICES AND CAISO CHARGES	$6,254,151	$6,460,748	$6,683,235	$6,920,783	$7,183,197	$7,459,651	$7,749,680	$8,059,507	$8,383,106	$8,690,356
(F) RESOURCE ADEQUACY CAPACITY	$12,800,272	$13,210,187	$13,633,230	$10,443,842	$10,871,878	$11,313,352	$11,768,711	$11,475,128	$11,936,765	$12,413,036
(G) GENERATION PROJECT CAPITAL	$0	$0	$0	$0	$0	$0	$0	$4,599,021	$4,599,021	$4,599,021
(H) STAFF AND OTHER OPERATIONS COSTS	$4,752,943	$4,899,783	$5,051,164	$5,207,227	$5,368,118	$5,533,984	$5,704,981	$5,881,267	$6,063,007	$6,250,368
(I) BILLING AND DATA MANAGEMENT	$5,720,562	$5,903,757	$6,092,819	$6,287,935	$6,489,300	$6,697,113	$6,911,581	$7,132,917	$7,361,341	$7,597,080
(J) UNCOLLECTIBLES EXPENSE	$1,549,481	$1,637,192	$1,705,236	$1,790,061	$1,865,821	$1,915,953	$2,009,366	$2,102,688	$2,204,755	$2,291,021
(K) STARTUP FINANCING	$3,560,946	$3,560,946	$3,560,946	$3,560,946	$3,560,946	$0	$0	$0	$0	$0
(L) CCA BOND CARRYING COST	$5,871	$6,059	$6,253	$6,453	$6,660	$6,873	$7,093	$7,320	$7,555	$7,797
SUBTOTAL - CCA COSTS	$156,503,415	$165,362,415	$172,235,076	$180,802,593	$188,454,584	$193,518,094	$202,953,036	$212,378,851	$222,687,792	$231,400,945
IV. REVENUES FROM MARKET SALES ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
V. PROGRAM RESERVES ($)	$4,695,102	$4,960,872	$5,167,052	$5,424,078	$5,653,638	$5,805,543	$6,088,591	$6,371,366	$6,680,634	$6,942,028
VI. CCA REVENUE REQUIREMENT ($)	$161,198,518	$170,323,288	$177,402,128	$186,226,671	$194,108,221	$199,323,637	$209,041,627	$218,750,217	$229,368,426	$238,342,974
VARIANCE - CCA COSTS MINUS PG&E ($)	($6,939,914)	($10,843,249)	($6,295,753)	($6,592,288)	($2,556,468)	($408,257)	$1,935,077	$8,614,078	$10,278,193	$11,042,758
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	**8.1**	**8.6**	**8.9**	**9.3**	**9.7**	**10.0**	**10.4**	**10.9**	**11.4**	**11.8**
PG&E AVERAGE GENERATION COST (CENTS/KWH)	8.5	9.1	9.2	9.7	9.9	10.0	10.3	10.5	10.9	11.3
PERCENTAGE PREMIUM (DISCOUNT) ON GENERATION RATES	-4%	-6%	-3%	-3%	-1%	0%	1%	4%	5%	5%
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
(A) EXIT FEES	$23,318,093	$28,778,209	$22,610,377	$20,995,431	$14,776,119	$8,788,087	$6,042,283	$0	$0	$0
(B) FRANCHISE FEE SURCHARGE	$673,235	$674,558	$675,884	$677,212	$678,543	$679,876	$681,212	$682,551	$683,892	$685,236
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 23,991,328	$ 29,452,767	$ 23,286,261	$ 21,672,643	$ 15,454,662	$ 9,467,963	$ 6,723,495	$ 682,551	$ 683,892	$ 685,236
TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES	$ 17,051,415	$ 18,609,519	$ 16,990,508	$ 15,080,356	$ 12,898,194	$ 9,059,706	$ 8,658,572	$ 9,296,628	$ 10,962,085	$ 11,727,994
PG&E CCA CUSTOMER SURCHARGE AVERAGE COST (CENTS/KWH)	1.2	1.5	1.2	1.1	0.8	0.5	0.3	0.0	0.0	0.0
PG&E DELIVERY COST (CENTS/KWH)	8.7	8.7	8.8	8.9	9.2	9.4	9.7	10.0	10.3	10.6
CCA CUSTOMER TOTAL DELIVERED RATE	18.1	18.8	18.9	19.3	19.7	19.9	20.5	20.9	21.7	22.5
PG&E TOTAL DELIVERED RATE (CENTS/KWH)	17.2	17.8	18.0	18.6	19.0	19.4	20.0	20.5	21.2	21.9
CHANGE IN CUSTOMER ELECTRIC CHARGES (%)	5%	5%	5%	4%	3%	2%	2%	2%	3%	3%

Financial Pro Forma Analysis

Scenario 1

FINANCIAL PRO FORMA ANALYSIS
COMMUNITY CHOICE AGGREGATION
SCENARIO 1

Financial Pro Forma Analysis

Scenario 1

CATEGORY	[13] 2023	[14] 2024	[15] 2025	[16] 2026	[17] 2027	[18] 2028	[19] 2029	[20] 2030	[21] 2031	[22] 2032
I, CUSTOMER ACCOUNTS:										
RESIDENTIAL (E-1)	146,424	146,712	147,000	147,289	147,578	147,868	148,159	148,450	148,742	149,034
GENERAL SERVICE (A-1)	15,145	15,175	15,204	15,234	15,264	15,294	15,324	15,354	15,385	15,415
SMALL TIME-OF-USE (A-6)	934	936	938	940	942	944	945	947	949	951
ALTERN. RATE FOR MEDIUM USE (A-10)	1,882	1,886	1,889	1,893	1,897	1,901	1,904	1,908	1,912	1,916
500 - 900kW DEMAND (E-19)	284	285	285	286	287	287	288	288	289	289
1000 + kW DEMAND (E-20)	12	12	12	12	12	12	12	12	12	12
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	1,739	1,742	1,745	1,749	1,752	1,756	1,759	1,763	1,766	1,770
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	2,096	2,100	2,104	2,108	2,112	2,116	2,121	2,125	2,129	2,133
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - CUSTOMER ACCOUNTS	168,516	168,847	169,179	169,511	169,844	170,178	170,512	170,847	171,183	171,519
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	974,930,731	976,846,470	978,765,974	980,689,249	982,616,303	984,547,144	986,481,779	988,420,216	990,362,462	992,308,524
GENERAL SERVICE (A-1)	223,543,893	223,983,156	224,423,283	224,864,275	225,306,133	225,748,860	226,192,456	226,636,925	227,082,266	227,528,483
SMALL TIME-OF-USE (A-6)	62,291,963	62,414,366	62,537,010	62,659,896	62,783,022	62,906,391	63,030,002	63,153,856	63,277,953	63,402,295
ALTERN. RATE FOR MEDIUM USE (A-10)	330,089,032	330,737,657	331,387,557	332,038,733	332,691,189	333,344,928	333,999,950	334,656,260	335,313,860	335,972,752
500 - 900kW DEMAND (E-19)	241,714,794	242,189,764	242,665,666	243,142,504	243,620,279	244,098,993	244,578,648	245,059,245	245,540,786	246,023,274
1000 + kW DEMAND (E-20)	127,889,935	128,141,239	128,393,037	128,645,329	128,898,117	129,151,402	129,405,184	129,659,466	129,914,246	130,169,528
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	13,259,621	13,285,676	13,311,782	13,337,940	13,364,149	13,390,410	13,416,722	13,443,086	13,469,501	13,495,969
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	45,639,290	45,728,971	45,818,829	45,908,863	45,999,074	46,089,462	46,180,028	46,270,771	46,361,693	46,452,794
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - LOAD REQUIREMENTS	2,019,359,259	2,023,327,300	2,027,303,138	2,031,286,789	2,035,278,268	2,039,277,589	2,043,284,770	2,047,299,824	2,051,322,769	2,055,353,618
III. CCA POWER SUPPLY REVENUE REQUIREMENT ($)										
(A) MARKET PURCHASES	$27,697,794	$29,339,218	$30,934,882	$32,587,834	$34,523,038	$36,291,169	$38,046,933	$39,846,740	$41,001,084	$42,272,972
(B) CONTRACT PURCHASES	$161,059,908	$166,796,278	$172,384,587	$157,493,434	$164,405,252	$170,679,371	$176,933,415	$183,391,879	$187,295,627	$191,695,632
(C) POWER PRODUCTION (NON-DEBT)	$5,404,696	$5,415,446	$5,426,536	$8,320,764	$8,329,332	$8,338,299	$8,347,671	$8,357,459	$8,350,363	$8,343,303
(D) RENEWABLE MARKET PURCHASES AND RECS	$3,605,317	$5,151,645	$6,772,953	$6,931,919	$8,718,678	$10,559,447	$12,471,618	$14,466,117	$16,337,904	$18,553,735
(E) ANCILLARY SERVICES AND CAISO CHARGES	$9,013,241	$9,351,010	$9,693,130	$10,048,989	$10,428,881	$10,805,894	$11,190,435	$11,586,471	$11,952,303	$12,335,183
(F) RESOURCE ADEQUACY CAPACITY	$12,904,430	$13,411,452	$13,934,621	$11,995,439	$12,478,165	$12,976,474	$13,490,890	$14,021,957	$14,570,233	$15,136,296
(G) GENERATION PROJECT CAPITAL	$4,599,021	$4,599,021	$4,599,021	$19,674,689	$19,674,689	$19,674,689	$19,674,689	$19,674,689	$19,674,689	$19,674,689
(H) STAFF AND OTHER OPERATIONS COSTS	$6,443,526	$6,642,659	$6,847,952	$7,059,597	$7,277,790	$7,502,734	$7,734,638	$7,973,718	$8,220,195	$8,474,300
(I) BILLING AND DATA MANAGEMENT	$7,840,369	$8,091,448	$8,350,568	$8,617,987	$8,893,969	$9,178,789	$9,472,730	$9,776,084	$10,089,153	$10,412,247
(J) UNCOLLECTIBLES EXPENSE	$2,385,683	$2,487,982	$2,589,443	$2,627,307	$2,747,298	$2,860,069	$2,973,630	$3,090,951	$3,174,916	$3,268,984
(K) STARTUP FINANCING	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(L) CCA BOND CARRYING COST	$8,046	$33,357	$36,913	$39,893	$44,718	$44,477	$41,798	$37,547	$21,954	$10,686
SUBTOTAL - CCA COSTS	$240,962,032	$251,319,515	$261,570,606	$265,397,852	$277,521,810	$288,911,411	$300,378,448	$312,223,612	$320,688,422	$330,178,026
IV. REVENUES FROM MARKET SALES ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
V. PROGRAM RESERVES ($)	$7,228,861	$7,539,585	$7,847,118	$7,961,936	$8,325,654	$8,667,342	$9,011,353	$9,366,708	$9,620,653	$9,905,341
VI. CCA REVENUE REQUIREMENT ($)	$248,190,893	$258,859,100	$269,417,724	$273,359,787	$285,847,464	$297,578,754	$309,389,802	$321,590,320	$330,309,075	$340,083,367
VARIANCE - CCA COSTS MINUS PG&E ($)	$11,992,330	$15,818,043	$16,715,345	$10,399,629	$11,514,470	$12,100,333	$12,492,747	$12,812,078	$11,440,566	$10,440,621
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	**12.3**	**12.8**	**13.3**	**13.5**	**14.0**	**14.6**	**15.1**	**15.7**	**16.1**	**16.5**
PG&E AVERAGE GENERATION COST (CENTS/KWH)	11.7	12.0	12.5	12.9	13.5	14.0	14.5	15.1	15.5	16.0
PERCENTAGE PREMIUM (DISCOUNT) ON GENERATION RATES	5%	7%	7%	4%	4%	4%	4%	4%	4%	3%
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
(A) EXIT FEES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(B) FRANCHISE FEE SURCHARGE	$686,582	$687,931	$689,283	$690,638	$691,995	$693,354	$694,717	$696,082	$697,450	$698,820
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 686,582	$ 687,931	$ 689,283	$ 690,638	$ 691,995	$ 693,354	$ 694,717	$ 696,082	$ 697,450	$ 698,820
TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES	$ 12,678,912	$ 16,505,975	$ 17,404,628	$ 11,090,267	$ 12,206,465	$ 12,793,687	$ 13,187,464	$ 13,508,160	$ 12,138,015	$ 11,139,442
PG&E CCA CUSTOMER SURCHARGE AVERAGE COST (CENTS/KWH)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PG&E DELIVERY COST (CENTS/KWH)	10.9	11.3	11.6	11.9	12.3	12.7	13.0	13.4	13.8	14.3
CCA CUSTOMER TOTAL DELIVERED RATE	23.3	24.1	24.9	25.4	26.4	27.3	28.2	29.2	30.0	30.8
PG&E TOTAL DELIVERED RATE (CENTS/KWH)	22.6	23.3	24.1	24.9	25.8	26.7	27.6	28.5	29.4	30.3
CHANGE IN CUSTOMER ELECTRIC CHARGES (%)	3%	4%	4%	2%	2%	2%	2%	2%	2%	2%

FINANCIAL PRO FORMA ANALYSIS
COMMUNITY CHOICE AGGREGATION
SCENARIO 2

Financial Pro Forma Analysis

Scenario 2

CATEGORY	[3] 2013	[4] 2014	[5] 2015	[6] 2016	[7] 2017	[8] 2018	[9] 2019	[10] 2020	[11] 2021	[12] 2022
I, CUSTOMER ACCOUNTS:										
RESIDENTIAL (E-1)	143,577	143,860	144,142	144,426	144,709	144,994	145,279	145,564	145,850	146,137
GENERAL SERVICE (A-1)	14,851	14,880	14,909	14,938	14,968	14,997	15,026	15,056	15,086	15,115
SMALL TIME-OF-USE (A-6)	916	918	920	922	923	925	927	929	931	933
ALTERN. RATE FOR MEDIUM USE (A-10)	1,845	1,849	1,853	1,856	1,860	1,864	1,867	1,871	1,875	1,878
500 - 900kW DEMAND (E-19)	279	279	280	280	281	282	282	283	283	284
1000 + kW DEMAND (E-20)	11	11	11	11	11	12	12	12	12	12
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	1,705	1,708	1,712	1,715	1,718	1,722	1,725	1,728	1,732	1,735
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	2,055	2,059	2,063	2,067	2,071	2,075	2,079	2,084	2,088	2,092
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - CUSTOMER ACCOUNTS	165,240	165,564	165,890	166,216	166,542	166,870	167,198	167,526	167,855	168,185
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	955,978,769	957,857,267	959,739,457	961,625,345	963,514,939	965,408,246	967,305,273	969,206,028	971,110,517	973,018,750
GENERAL SERVICE (A-1)	219,198,358	219,629,083	220,060,654	220,493,073	220,926,342	221,360,462	221,795,435	222,231,263	222,667,948	223,105,490
SMALL TIME-OF-USE (A-6)	61,081,051	61,201,075	61,321,335	61,441,832	61,562,565	61,683,535	61,804,744	61,926,190	62,047,875	62,169,799
ALTERN. RATE FOR MEDIUM USE (A-10)	323,672,335	324,308,352	324,945,617	325,584,136	326,223,908	326,864,938	327,507,228	328,150,780	328,795,596	329,441,679
500 - 900kW DEMAND (E-19)	237,016,030	237,481,766	237,948,418	238,415,986	238,884,474	239,353,882	239,824,212	240,295,467	240,767,647	241,240,756
1000 + kW DEMAND (E-20)	125,403,846	125,650,264	125,897,167	126,144,555	126,392,429	126,640,790	126,889,639	127,138,977	127,388,806	127,639,125
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	13,001,863	13,027,412	13,053,011	13,078,660	13,104,359	13,130,110	13,155,910	13,181,762	13,207,664	13,233,617
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	44,752,095	44,840,033	44,928,143	45,016,427	45,104,884	45,193,515	45,282,321	45,371,300	45,460,455	45,549,785
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - LOAD REQUIREMENTS	1,980,104,346	1,983,995,252	1,987,893,802	1,991,800,014	1,995,713,901	1,999,635,478	2,003,564,762	2,007,501,767	2,011,446,508	2,015,399,000
III. CCA POWER SUPPLY REVENUE REQUIREMENT ($)										
(A) MARKET PURCHASES	$16,743,865	$16,546,355	$17,107,095	$14,326,648	$15,193,507	$16,142,372	$17,162,349	$16,956,749	$18,404,597	$19,606,782
(B) CONTRACT PURCHASES	$66,975,460	$66,185,422	$68,428,381	$144,731,391	$146,603,370	$148,869,564	$151,483,830	$149,256,948	$153,702,647	$157,222,215
(C) POWER PRODUCTION (NON-DEBT)	$0	$0	$0	$0	$0	$0	$0	$8,957,356	$8,973,646	$8,990,465
(D) RENEWABLE MARKET PURCHASES AND RECS	$43,274,790	$52,280,732	$55,490,066	$298,197	$3,375,788	$6,685,697	$10,258,807	$3,949,603	$5,340,985	$6,743,279
(E) ANCILLARY SERVICES AND CAISO CHARGES	$6,254,151	$6,460,748	$6,683,235	$6,920,783	$7,183,197	$7,459,651	$7,749,680	$8,059,507	$8,383,106	$8,690,356
(F) RESOURCE ADEQUACY CAPACITY	$12,800,272	$13,210,187	$13,633,230	$8,488,437	$8,898,907	$9,322,234	$9,758,857	$8,937,077	$9,363,506	$9,803,494
(G) GENERATION PROJECT CAPITAL	$0	$0	$0	$0	$0	$0	$0	$7,665,035	$7,665,035	$7,665,035
(H) STAFF AND OTHER OPERATIONS COSTS	$4,752,943	$4,899,783	$5,051,164	$5,207,227	$5,368,118	$5,533,984	$5,704,981	$5,881,267	$6,063,007	$6,250,368
(I) BILLING AND DATA MANAGEMENT	$5,720,562	$5,903,757	$6,092,819	$6,287,935	$6,489,300	$6,697,113	$6,911,581	$7,132,917	$7,361,341	$7,597,080
(J) UNCOLLECTIBLES EXPENSE	$1,600,830	$1,690,479	$1,760,469	$1,898,216	$1,966,731	$2,007,106	$2,090,301	$2,167,965	$2,252,579	$2,325,691
(K) STARTUP FINANCING	$3,560,946	$3,560,946	$3,560,946	$3,560,946	$3,560,946	$0	$0	$0	$0	$0
(L) CCA BOND CARRYING COST	$5,871	$6,059	$6,253	$6,453	$6,660	$6,873	$7,093	$7,320	$7,555	$7,797
SUBTOTAL - CCA COSTS	$161,689,690	$170,744,469	$177,813,659	$191,726,233	$198,646,524	$202,724,594	$211,127,479	$218,971,745	$227,518,004	$234,902,562
IV. REVENUES FROM MARKET SALES ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
V. PROGRAM RESERVES ($)	$4,850,691	$5,122,334	$5,334,410	$5,751,787	$5,959,396	$6,081,738	$6,333,824	$6,569,152	$6,825,540	$7,047,077
VI. CCA REVENUE REQUIREMENT ($)	$166,540,381	$175,866,804	$183,148,069	$197,478,020	$204,605,920	$208,806,332	$217,461,304	$225,540,897	$234,343,544	$241,949,639
VARIANCE - CCA COSTS MINUS PG&E ($)	($1,598,050)	($5,299,733)	($549,812)	$4,659,062	$7,941,231	$9,074,438	$10,354,754	$15,404,758	$15,253,311	$14,649,424
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	**8.4**	**8.9**	**9.2**	**9.9**	**10.3**	**10.4**	**10.9**	**11.2**	**11.7**	**12.0**
PG&E AVERAGE GENERATION COST (CENTS/KWH)	8.5	9.1	9.2	9.7	9.9	10.0	10.3	10.5	10.9	11.3
PERCENTAGE PREMIUM (DISCOUNT) ON GENERATION RATES	-1%	-3%	0%	2%	4%	5%	5%	7%	7%	6%
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
(A) EXIT FEES	$23,318,093	$28,778,209	$22,610,377	$20,995,431	$14,776,119	$8,788,087	$6,042,283	$0	$0	$0
(B) FRANCHISE FEE SURCHARGE	$673,235	$674,558	$675,884	$677,212	$678,543	$679,876	$681,212	$682,551	$683,892	$685,236
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 23,991,328	$ 29,452,767	$ 23,286,261	$ 21,672,643	$ 15,454,662	$ 9,467,963	$ 6,723,495	$ 682,551	$ 683,892	$ 685,236
TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES	$ 22,393,278	$ 24,153,034	$ 22,736,448	$ 26,331,705	$ 23,395,893	$ 18,542,401	$ 17,078,249	$ 16,087,309	$ 15,937,202	$ 15,334,659
PG&E CCA CUSTOMER SURCHARGE AVERAGE COST (CENTS/KWH)	1.2	1.5	1.2	1.1	0.8	0.5	0.3	0.0	0.0	0.0
PG&E DELIVERY COST (CENTS/KWH)	8.7	8.7	8.8	8.9	9.2	9.4	9.7	10.0	10.3	10.6
CCA CUSTOMER TOTAL DELIVERED RATE	18.3	19.1	19.2	19.9	20.2	20.3	20.9	21.3	22.0	22.6
PG&E TOTAL DELIVERED RATE (CENTS/KWH)	17.2	17.8	18.0	18.6	19.0	19.4	20.0	20.5	21.2	21.9
CHANGE IN CUSTOMER ELECTRIC CHARGES (%)	7%	7%	6%	7%	6%	5%	4%	4%	4%	3%

FINANCIAL PRO FORMA ANALYSIS
COMMUNITY CHOICE AGGREGATION
SCENARIO 2

Financial Pro Forma Analysis

Scenario 2

CATEGORY	[13] 2023	[14] 2024	[15] 2025	[16] 2026	[17] 2027	[18] 2028	[19] 2029	[20] 2030	[21] 2031	[22] 2032
I, CUSTOMER ACCOUNTS:										
RESIDENTIAL (E-1)	146,424	146,712	147,000	147,289	147,578	147,868	148,159	148,450	148,742	149,034
GENERAL SERVICE (A-1)	15,145	15,175	15,204	15,234	15,264	15,294	15,324	15,354	15,385	15,415
SMALL TIME-OF-USE (A-6)	934	936	938	940	942	944	945	947	949	951
ALTERN. RATE FOR MEDIUM USE (A-10)	1,882	1,886	1,889	1,893	1,897	1,901	1,904	1,908	1,912	1,916
500 - 900kW DEMAND (E-19)	284	285	285	286	287	287	288	288	289	289
1000 + kW DEMAND (E-20)	12	12	12	12	12	12	12	12	12	12
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	1,739	1,742	1,745	1,749	1,752	1,756	1,759	1,763	1,766	1,770
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	2,096	2,100	2,104	2,108	2,112	2,116	2,121	2,125	2,129	2,133
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - CUSTOMER ACCOUNTS	168,516	168,847	169,179	169,511	169,844	170,178	170,512	170,847	171,183	171,519
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	974,930,731	976,846,470	978,765,974	980,689,249	982,616,303	984,547,144	986,481,779	988,420,216	990,362,462	992,308,524
GENERAL SERVICE (A-1)	223,543,893	223,983,156	224,423,283	224,864,275	225,306,133	225,748,860	226,192,456	226,636,925	227,082,266	227,528,483
SMALL TIME-OF-USE (A-6)	62,291,963	62,414,366	62,537,010	62,659,896	62,783,022	62,906,391	63,030,002	63,153,856	63,277,953	63,402,295
ALTERN. RATE FOR MEDIUM USE (A-10)	330,089,032	330,737,657	331,387,557	332,038,733	332,691,189	333,344,928	333,999,950	334,656,260	335,313,860	335,972,752
500 - 900kW DEMAND (E-19)	241,714,794	242,189,764	242,665,666	243,142,504	243,620,279	244,098,993	244,578,648	245,059,245	245,540,786	246,023,274
1000 + kW DEMAND (E-20)	127,889,935	128,141,239	128,393,037	128,645,329	128,898,117	129,151,402	129,405,184	129,659,466	129,914,246	130,169,528
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	13,259,621	13,285,676	13,311,782	13,337,940	13,364,149	13,390,410	13,416,722	13,443,086	13,469,501	13,495,969
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	45,639,290	45,728,971	45,818,829	45,908,863	45,999,074	46,089,462	46,180,028	46,270,771	46,361,693	46,452,794
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - LOAD REQUIREMENTS	2,019,359,259	2,023,327,300	2,027,303,138	2,031,286,789	2,035,278,268	2,039,277,589	2,043,284,770	2,047,299,824	2,051,322,769	2,055,353,618
III. CCA POWER SUPPLY REVENUE REQUIREMENT ($)										
(A) MARKET PURCHASES	$20,921,749	$22,340,008	$23,736,971	$24,947,662	$26,622,655	$28,183,120	$29,746,610	$31,356,682	$32,426,462	$33,593,294
(B) CONTRACT PURCHASES	$161,247,248	$165,737,690	$170,193,184	$140,245,752	$145,744,632	$150,829,276	$155,968,176	$161,333,922	$164,577,432	$168,246,564
(C) POWER PRODUCTION (NON-DEBT)	$9,007,827	$9,025,743	$9,044,227	$13,747,824	$13,762,239	$13,777,316	$13,793,069	$13,809,512	$13,797,815	$13,786,176
(D) RENEWABLE MARKET PURCHASES AND RECS	$8,221,750	$9,781,880	$11,386,764	$11,636,141	$13,407,770	$15,190,944	$17,022,464	$18,919,289	$20,631,163	$22,411,104
(E) ANCILLARY SERVICES AND CAISO CHARGES	$9,013,241	$9,351,010	$9,693,130	$10,048,989	$10,428,881	$10,805,894	$11,190,435	$11,586,471	$11,952,303	$12,335,183
(F) RESOURCE ADEQUACY CAPACITY	$10,257,506	$10,726,022	$11,209,540	$7,680,134	$8,074,354	$8,481,538	$8,902,141	$9,336,633	$9,785,502	$10,249,248
(G) GENERATION PROJECT CAPITAL	$7,665,035	$7,665,035	$7,665,035	$32,162,996	$32,162,996	$32,162,996	$32,162,996	$32,162,996	$32,162,996	$32,162,996
(H) STAFF AND OTHER OPERATIONS COSTS	$6,443,526	$6,642,659	$6,847,952	$7,059,597	$7,277,790	$7,502,734	$7,734,638	$7,973,718	$8,220,195	$8,474,300
(I) BILLING AND DATA MANAGEMENT	$7,840,369	$8,091,448	$8,350,568	$8,617,987	$8,893,969	$9,178,789	$9,472,730	$9,776,084	$10,089,153	$10,412,247
(J) UNCOLLECTIBLES EXPENSE	$2,406,182	$2,493,615	$2,581,274	$2,561,471	$2,663,753	$2,761,126	$2,859,933	$2,962,553	$3,036,430	$3,116,711
(K) STARTUP FINANCING	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(L) CCA BOND CARRYING COST	$8,046	$33,357	$36,913	$39,893	$44,718	$44,477	$41,798	$37,547	$21,954	$10,686
SUBTOTAL - CCA COSTS	$243,032,478	$251,888,466	$260,745,557	$258,748,445	$269,083,757	$278,918,210	$288,894,989	$299,255,407	$306,701,405	$314,798,507
IV. REVENUES FROM MARKET SALES ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
V. PROGRAM RESERVES ($)	$7,290,974	$7,556,654	$7,822,367	$8,040,749	$8,072,513	$8,367,546	$8,666,850	$8,977,662	$9,201,042	$9,443,955
VI. CCA REVENUE REQUIREMENT ($)	$250,323,453	$259,445,120	$268,567,924	$266,789,194	$277,156,269	$287,285,756	$297,561,839	$308,233,069	$315,902,447	$324,242,462
VARIANCE - CCA COSTS MINUS PG&E ($)	$14,124,890	$16,404,064	$15,865,545	$3,829,036	$2,823,275	$1,807,335	$664,784	($545,173)	($2,966,062)	($5,400,283)
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	**12.4**	**12.8**	**13.2**	**13.1**	**13.6**	**14.1**	**14.6**	**15.1**	**15.4**	**15.8**
PG&E AVERAGE GENERATION COST (CENTS/KWH)	11.7	12.0	12.5	12.9	13.5	14.0	14.5	15.1	15.5	16.0
PERCENTAGE PREMIUM (DISCOUNT) ON GENERATION RATES	6%	7%	6%	1%	1%	1%	0%	0%	-1%	-2%
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
(A) EXIT FEES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(B) FRANCHISE FEE SURCHARGE	$686,582	$687,931	$689,283	$690,638	$691,995	$693,354	$694,717	$696,082	$697,450	$698,820
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 686,582	$ 687,931	$ 689,283	$ 690,638	$ 691,995	$ 693,354	$ 694,717	$ 696,082	$ 697,450	$ 698,820
TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES	$ 14,811,472	$ 17,091,995	$ 16,554,829	$ 4,519,674	$ 3,515,270	$ 2,500,689	$ 1,359,501	$ 150,909	$ (2,268,612)	$ (4,701,463)
PG&E CCA CUSTOMER SURCHARGE AVERAGE COST (CENTS/KWH)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PG&E DELIVERY COST (CENTS/KWH)	10.9	11.3	11.6	11.9	12.3	12.7	13.0	13.4	13.8	14.3
CCA CUSTOMER TOTAL DELIVERED RATE	23.4	24.1	24.9	25.1	25.9	26.8	27.6	28.5	29.3	30.1
PG&E TOTAL DELIVERED RATE (CENTS/KWH)	22.6	23.3	24.1	24.9	25.8	26.7	27.6	28.5	29.4	30.3
CHANGE IN CUSTOMER ELECTRIC CHARGES (%)	3%	4%	3%	1%	1%	0%	0%	0%	0%	-1%

FINANCIAL PRO FORMA ANALYSIS
COMMUNITY CHOICE AGGREGATION
SCENARIO 3

Financial Pro Forma Analysis

Scenario 3

CATEGORY	[3] 2013	[4] 2014	[5] 2015	[6] 2016	[7] 2017	[8] 2018	[9] 2019	[10] 2020	[11] 2021	[12] 2022
I, CUSTOMER ACCOUNTS:										
RESIDENTIAL (E-1)	143,577	143,860	144,142	144,426	144,709	144,994	145,279	145,564	145,850	146,137
GENERAL SERVICE (A-1)	14,851	14,880	14,909	14,938	14,968	14,997	15,026	15,056	15,086	15,115
SMALL TIME-OF-USE (A-6)	916	918	920	922	923	925	927	929	931	933
ALTERN. RATE FOR MEDIUM USE (A-10)	1,845	1,849	1,853	1,856	1,860	1,864	1,867	1,871	1,875	1,878
500 - 900kW DEMAND (E-19)	279	279	280	280	281	282	282	283	283	284
1000 + kW DEMAND (E-20)	11	11	11	11	11	12	12	12	12	12
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	1,705	1,708	1,712	1,715	1,718	1,722	1,725	1,728	1,732	1,735
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	2,055	2,059	2,063	2,067	2,071	2,075	2,079	2,084	2,088	2,092
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - CUSTOMER ACCOUNTS	165,240	165,564	165,890	166,216	166,542	166,870	167,198	167,526	167,855	168,185
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	955,978,769	957,857,267	959,739,457	961,625,345	963,514,939	965,408,246	967,305,273	969,206,028	971,110,517	973,018,750
GENERAL SERVICE (A-1)	219,198,358	219,629,083	220,060,654	220,493,073	220,926,342	221,360,462	221,795,435	222,231,263	222,667,948	223,105,490
SMALL TIME-OF-USE (A-6)	61,081,051	61,201,075	61,321,335	61,441,832	61,562,565	61,683,535	61,804,744	61,926,190	62,047,875	62,169,799
ALTERN. RATE FOR MEDIUM USE (A-10)	323,672,335	324,308,352	324,945,617	325,584,136	326,223,908	326,864,938	327,507,228	328,150,780	328,795,596	329,441,679
500 - 900kW DEMAND (E-19)	237,016,030	237,481,766	237,948,418	238,415,986	238,884,474	239,353,882	239,824,212	240,295,467	240,767,647	241,240,756
1000 + kW DEMAND (E-20)	125,403,846	125,650,264	125,897,167	126,144,555	126,392,429	126,640,790	126,889,639	127,138,977	127,388,806	127,639,125
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	13,001,863	13,027,412	13,053,011	13,078,660	13,104,359	13,130,110	13,155,910	13,181,762	13,207,664	13,233,617
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	44,752,095	44,840,033	44,928,143	45,016,427	45,104,884	45,193,515	45,282,321	45,371,300	45,460,455	45,549,785
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - LOAD REQUIREMENTS	1,980,104,346	1,983,995,252	1,987,893,802	1,991,800,014	1,995,713,901	1,999,635,478	2,003,564,762	2,007,501,767	2,011,446,508	2,015,399,000
III. CCA POWER SUPPLY REVENUE REQUIREMENT ($)										
(A) MARKET PURCHASES	$14,848,058	$14,526,094	$14,871,919	$12,682,942	$10,960,302	$10,767,456	$11,408,360	$9,720,298	$10,703,568	$11,557,802
(B) CONTRACT PURCHASES	$59,392,232	$58,104,374	$69,145,576	$132,167,770	$175,072,055	$172,184,000	$172,725,587	$164,042,272	$166,131,702	$167,789,018
(C) POWER PRODUCTION (NON-DEBT)	$0	$0	$0	$0	$0	$1,650,790	$1,641,132	$15,963,340	$15,979,939	$15,997,479
(D) RENEWABLE MARKET PURCHASES AND RECS	$59,722,654	$69,548,314	$69,208,374	$22,346,721	$11,765,523	$9,825,232	$14,617,444	$5,193,590	$7,221,699	$9,272,255
(E) ANCILLARY SERVICES AND CAISO CHARGES	$6,254,151	$6,460,748	$6,683,235	$6,920,783	$7,183,197	$7,459,651	$7,749,680	$8,059,507	$8,383,106	$8,690,356
(F) RESOURCE ADEQUACY CAPACITY	$12,800,272	$13,210,187	$13,073,571	$9,859,594	$6,303,867	$6,446,798	$6,858,206	$5,246,958	$5,623,335	$6,011,588
(G) GENERATION PROJECT CAPITAL	$0	$0	$0	$0	$0	$9,375,181	$9,375,181	$21,639,237	$21,639,237	$21,639,237
(H) STAFF AND OTHER OPERATIONS COSTS	$4,752,943	$4,899,783	$5,051,164	$5,207,227	$5,368,118	$5,533,984	$5,704,981	$5,881,267	$6,063,007	$6,250,368
(I) BILLING AND DATA MANAGEMENT	$5,720,562	$5,903,757	$6,092,819	$6,287,935	$6,489,300	$6,697,113	$6,911,581	$7,132,917	$7,361,341	$7,597,080
(J) UNCOLLECTIBLES EXPENSE	$1,670,518	$1,762,142	$1,876,876	$1,990,339	$2,267,033	$2,299,402	$2,369,922	$2,428,794	$2,491,069	$2,548,052
(K) STARTUP FINANCING	$3,560,946	$3,560,946	$3,560,946	$3,560,946	$3,560,946	$0	$0	$0	$0	$0
(L) CCA BOND CARRYING COST	$5,871	$6,059	$6,253	$6,453	$6,660	$6,873	$7,093	$7,320	$7,555	$7,797
SUBTOTAL - CCA COSTS	$168,728,207	$177,982,405	$189,570,732	$201,030,711	$228,977,000	$232,246,480	$239,369,166	$245,315,501	$251,605,557	$257,361,032
IV. REVENUES FROM MARKET SALES ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
V. PROGRAM RESERVES ($)	$5,061,846	$5,339,472	$5,687,122	$6,030,921	$6,869,310	$6,967,394	$7,181,075	$7,359,465	$7,548,167	$7,720,831
VI. CCA REVENUE REQUIREMENT ($)	$173,790,053	$183,321,877	$195,257,854	$207,061,633	$235,846,310	$239,213,875	$246,550,241	$252,674,966	$259,153,724	$265,081,863
VARIANCE - CCA COSTS MINUS PG&E ($)	$5,651,622	$2,155,340	$11,559,973	$14,242,674	$39,181,621	$39,481,981	$39,443,692	$42,538,827	$40,063,491	$37,781,648
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	**8.8**	**9.2**	**9.8**	**10.4**	**11.8**	**12.0**	**12.3**	**12.6**	**12.9**	**13.2**
PG&E AVERAGE GENERATION COST (CENTS/KWH)	8.5	9.1	9.2	9.7	9.9	10.0	10.3	10.5	10.9	11.3
PERCENTAGE PREMIUM (DISCOUNT) ON GENERATION RATES	3%	1%	6%	7%	20%	20%	19%	20%	18%	17%
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
(A) EXIT FEES	$23,318,093	$28,778,209	$22,610,377	$20,995,431	$14,776,119	$8,788,087	$6,042,283	$0	$0	$0
(B) FRANCHISE FEE SURCHARGE	$673,235	$674,558	$675,884	$677,212	$678,543	$679,876	$681,212	$682,551	$683,892	$685,236
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 23,991,328	$ 29,452,767	$ 23,286,261	$ 21,672,643	$ 15,454,662	$ 9,467,963	$ 6,723,495	$ 682,551	$ 683,892	$ 685,236
TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES	$ 29,642,950	$ 31,608,108	$ 34,846,234	$ 35,915,318	$ 54,636,283	$ 48,949,944	$ 46,167,187	$ 43,221,377	$ 40,747,383	$ 38,466,883
PG&E CCA CUSTOMER SURCHARGE AVERAGE COST (CENTS/KWH)	1.2	1.5	1.2	1.1	0.8	0.5	0.3	0.0	0.0	0.0
PG&E DELIVERY COST (CENTS/KWH)	8.7	8.7	8.8	8.9	9.2	9.4	9.7	10.0	10.3	10.6
CCA CUSTOMER TOTAL DELIVERED RATE	18.7	19.4	19.8	20.4	21.7	21.9	22.3	22.6	23.2	23.8
PG&E TOTAL DELIVERED RATE (CENTS/KWH)	17.2	17.8	18.0	18.6	19.0	19.4	20.0	20.5	21.2	21.9
CHANGE IN CUSTOMER ELECTRIC CHARGES (%)	9%	9%	10%	10%	14%	13%	11%	11%	10%	9%

Financial Pro Forma Analysis

Scenario 3

FINANCIAL PRO FORMA ANALYSIS
COMMUNITY CHOICE AGGREGATION
SCENARIO 3

CATEGORY	[13] 2023	[14] 2024	[15] 2025	[16] 2026	[17] 2027	[18] 2028	[19] 2029	[20] 2030	[21] 2031	[22] 2032
I, CUSTOMER ACCOUNTS:										
RESIDENTIAL (E-1)	146,424	146,712	147,000	147,289	147,578	147,868	148,159	148,450	148,742	149,034
GENERAL SERVICE (A-1)	15,145	15,175	15,204	15,234	15,264	15,294	15,324	15,354	15,385	15,415
SMALL TIME-OF-USE (A-6)	934	936	938	940	942	944	945	947	949	951
ALTERN. RATE FOR MEDIUM USE (A-10)	1,882	1,886	1,889	1,893	1,897	1,901	1,904	1,908	1,912	1,916
500 - 900kW DEMAND (E-19)	284	285	285	286	287	287	288	288	289	289
1000 + kW DEMAND (E-20)	12	12	12	12	12	12	12	12	12	12
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	1,739	1,742	1,745	1,749	1,752	1,756	1,759	1,763	1,766	1,770
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	2,096	2,100	2,104	2,108	2,112	2,116	2,121	2,125	2,129	2,133
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - CUSTOMER ACCOUNTS	168,516	168,847	169,179	169,511	169,844	170,178	170,512	170,847	171,183	171,519
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	974,930,731	976,846,470	978,765,974	980,689,249	982,616,303	984,547,144	986,481,779	988,420,216	990,362,462	992,308,524
GENERAL SERVICE (A-1)	223,543,893	223,983,156	224,423,283	224,864,275	225,306,133	225,748,860	226,192,456	226,636,925	227,082,266	227,528,483
SMALL TIME-OF-USE (A-6)	62,291,963	62,414,366	62,537,010	62,659,896	62,783,022	62,906,391	63,030,002	63,153,856	63,277,953	63,402,295
ALTERN. RATE FOR MEDIUM USE (A-10)	330,089,032	330,737,657	331,387,557	332,038,733	332,691,189	333,344,928	333,999,950	334,656,260	335,313,860	335,972,752
500 - 900kW DEMAND (E-19)	241,714,794	242,189,764	242,665,666	243,142,504	243,620,279	244,098,993	244,578,648	245,059,245	245,540,786	246,023,274
1000 + kW DEMAND (E-20)	127,889,935	128,141,239	128,393,037	128,645,329	128,898,117	129,151,402	129,405,184	129,659,466	129,914,246	130,169,528
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	13,259,621	13,285,676	13,311,782	13,337,940	13,364,149	13,390,410	13,416,722	13,443,086	13,469,501	13,495,969
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	45,639,290	45,728,971	45,818,829	45,908,863	45,999,074	46,089,462	46,180,028	46,270,771	46,361,693	46,452,794
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - LOAD REQUIREMENTS	2,019,359,259	2,023,327,300	2,027,303,138	2,031,286,789	2,035,278,268	2,039,277,589	2,043,284,770	2,047,299,824	2,051,322,769	2,055,353,618
III. CCA POWER SUPPLY REVENUE REQUIREMENT ($)										
(A) MARKET PURCHASES	$12,490,231	$13,496,697	$14,502,310	$15,571,473	$13,714,542	$14,744,784	$15,791,679	$16,877,787	$17,626,852	$18,433,485
(B) CONTRACT PURCHASES	$169,839,873	$172,264,513	$174,760,370	$177,582,168	$168,768,568	$171,569,976	$174,501,761	$177,651,711	$179,512,450	$181,660,162
(C) POWER PRODUCTION (NON-DEBT)	$16,015,979	$16,035,461	$16,055,942	$16,077,445	$18,832,407	$18,851,692	$18,872,107	$18,893,674	$18,870,264	$18,846,993
(D) RENEWABLE MARKET PURCHASES AND RECS	$11,432,669	$13,711,314	$16,056,625	$18,516,742	$5,195,243	$7,436,811	$9,764,007	$12,184,236	$14,521,961	$16,930,093
(E) ANCILLARY SERVICES AND CAISO CHARGES	$9,013,241	$9,351,010	$9,693,130	$10,048,989	$10,428,881	$10,805,894	$11,190,435	$11,586,471	$11,952,303	$12,335,183
(F) RESOURCE ADEQUACY CAPACITY	$6,412,144	$6,825,444	$7,251,943	$7,692,113	$4,475,913	$4,834,780	$5,205,520	$5,588,571	$5,984,382	$6,393,420
(G) GENERATION PROJECT CAPITAL	$21,639,237	$21,639,237	$21,639,237	$21,639,237	$45,477,637	$45,477,637	$45,477,637	$45,477,637	$45,477,637	$45,477,637
(H) STAFF AND OTHER OPERATIONS COSTS	$6,443,526	$6,642,659	$6,847,952	$7,059,597	$7,277,790	$7,502,734	$7,734,638	$7,973,718	$8,220,195	$8,474,300
(I) BILLING AND DATA MANAGEMENT	$7,840,369	$8,091,448	$8,350,568	$8,617,987	$8,893,969	$9,178,789	$9,472,730	$9,776,084	$10,089,153	$10,412,247
(J) UNCOLLECTIBLES EXPENSE	$2,611,273	$2,680,578	$2,751,581	$2,828,058	$2,830,649	$2,904,031	$2,980,105	$3,060,099	$3,122,552	$3,189,635
(K) STARTUP FINANCING	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(L) CCA BOND CARRYING COST	$8,046	$33,357	$36,913	$39,893	$44,718	$44,477	$41,798	$37,547	$21,954	$10,686
SUBTOTAL - CCA COSTS	$263,746,587	$270,771,717	$277,946,572	$285,673,701	$285,940,317	$293,351,605	$301,032,418	$309,107,534	$315,399,704	$322,163,840
IV. REVENUES FROM MARKET SALES ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
V. PROGRAM RESERVES ($)	$7,912,398	$8,123,152	$8,338,397	$8,570,211	$11,369,409	$11,369,409	$11,369,409	$11,369,409	$11,369,409	$11,369,409
VI. CCA REVENUE REQUIREMENT ($)	$271,658,985	$278,894,868	$286,284,969	$294,243,912	$297,309,726	$304,721,014	$312,401,827	$320,476,944	$326,769,114	$333,533,250
VARIANCE - CCA COSTS MINUS PG&E ($)	$35,460,422	$35,853,812	$33,582,590	$31,283,754	$22,976,732	$19,242,593	$15,504,773	$11,698,701	$7,900,605	$3,890,504
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	**13.5**	**13.8**	**14.1**	**14.5**	**14.6**	**14.9**	**15.3**	**15.7**	**15.9**	**16.2**
PG&E AVERAGE GENERATION COST (CENTS/KWH)	11.7	12.0	12.5	12.9	13.5	14.0	14.5	15.1	15.5	16.0
PERCENTAGE PREMIUM (DISCOUNT) ON GENERATION RATES	15%	15%	13%	12%	8%	7%	5%	4%	2%	1%
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
(A) EXIT FEES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(B) FRANCHISE FEE SURCHARGE	$686,582	$687,931	$689,283	$690,638	$691,995	$693,354	$694,717	$696,082	$697,450	$698,820
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 686,582	$ 687,931	$ 689,283	$ 690,638	$ 691,995	$ 693,354	$ 694,717	$ 696,082	$ 697,450	$ 698,820
TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES	$ 36,147,005	$ 36,541,743	$ 34,271,873	$ 31,974,392	$ 23,668,726	$ 19,935,948	$ 16,199,489	$ 12,394,783	$ 8,598,054	$ 4,589,324
PG&E CCA CUSTOMER SURCHARGE AVERAGE COST (CENTS/KWH)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PG&E DELIVERY COST (CENTS/KWH)	10.9	11.3	11.6	11.9	12.3	12.7	13.0	13.4	13.8	14.3
CCA CUSTOMER TOTAL DELIVERED RATE	24.4	25.1	25.7	26.5	26.9	27.6	28.4	29.1	29.8	30.5
PG&E TOTAL DELIVERED RATE (CENTS/KWH)	22.6	23.3	24.1	24.9	25.8	26.7	27.6	28.5	29.4	30.3
CHANGE IN CUSTOMER ELECTRIC CHARGES (%)	8%	8%	7%	6%	5%	4%	3%	2%	1%	1%

Financial Pro Forma Analysis

Scenario 4

FINANCIAL PRO FORMA ANALYSIS
COMMUNITY CHOICE AGGREGATION
SCENARIO 4

CATEGORY	[3] 2013	[4] 2014	[5] 2015	[6] 2016	[7] 2017	[8] 2018	[9] 2019	[10] 2020	[11] 2021	[12] 2022
I, CUSTOMER ACCOUNTS:										
RESIDENTIAL (E-1)	143,577	143,860	144,142	144,426	144,709	144,994	145,279	145,564	145,850	146,137
GENERAL SERVICE (A-1)	14,851	14,880	14,909	14,938	14,968	14,997	15,026	15,056	15,086	15,115
SMALL TIME-OF-USE (A-6)	916	918	920	922	923	925	927	929	931	933
ALTERN. RATE FOR MEDIUM USE (A-10)	1,845	1,849	1,853	1,856	1,860	1,864	1,867	1,871	1,875	1,878
500 - 900kW DEMAND (E-19)	279	279	280	280	281	282	282	283	283	284
1000 + kW DEMAND (E-20)	11	11	11	11	11	12	12	12	12	12
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	1,705	1,708	1,712	1,715	1,718	1,722	1,725	1,728	1,732	1,735
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	2,055	2,059	2,063	2,067	2,071	2,075	2,079	2,084	2,088	2,092
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - CUSTOMER ACCOUNTS	165,240	165,564	165,890	166,216	166,542	166,870	167,198	167,526	167,855	168,185
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	955,978,769	957,857,267	959,739,457	961,625,345	963,514,939	965,408,246	967,305,273	969,206,028	971,110,517	973,018,750
GENERAL SERVICE (A-1)	219,198,358	219,629,083	220,060,654	220,493,073	220,926,342	221,360,462	221,795,435	222,231,263	222,667,948	223,105,490
SMALL TIME-OF-USE (A-6)	61,081,051	61,201,075	61,321,335	61,441,832	61,562,565	61,683,535	61,804,744	61,926,190	62,047,875	62,169,799
ALTERN. RATE FOR MEDIUM USE (A-10)	323,672,335	324,308,352	324,945,617	325,584,136	326,223,908	326,864,938	327,507,228	328,150,780	328,795,596	329,441,679
500 - 900kW DEMAND (E-19)	237,016,030	237,481,766	237,948,418	238,415,986	238,884,474	239,353,882	239,824,212	240,295,467	240,767,647	241,240,756
1000 + kW DEMAND (E-20)	125,403,846	125,650,264	125,897,167	126,144,555	126,392,429	126,640,790	126,889,639	127,138,977	127,388,806	127,639,125
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	13,001,863	13,027,412	13,053,011	13,078,660	13,104,359	13,130,110	13,155,910	13,181,762	13,207,664	13,233,617
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	44,752,095	44,840,033	44,928,143	45,016,427	45,104,884	45,193,515	45,282,321	45,371,300	45,460,455	45,549,785
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - LOAD REQUIREMENTS	1,980,104,346	1,983,995,252	1,987,893,802	1,991,800,014	1,995,713,901	1,999,635,478	2,003,564,762	2,007,501,767	2,011,446,508	2,015,399,000
III. CCA POWER SUPPLY REVENUE REQUIREMENT ($)										
(A) MARKET PURCHASES	$18,416,321	$17,454,374	$11,547,029	$12,547,774	$11,654,785	$7,898,472	$8,145,648	$7,365,643	$8,198,384	$8,939,158
(B) CONTRACT PURCHASES	$73,665,283	$69,817,498	$46,188,115	$50,191,098	$46,619,141	$60,738,407	$61,215,965	$78,887,695	$81,632,565	$84,024,807
(C) POWER PRODUCTION (NON-DEBT)	$233,652	$12,492,410	$21,905,029	$21,737,288	$34,581,741	$35,911,906	$35,753,405	$35,600,496	$35,452,961	$35,310,587
(D) RENEWABLE MARKET PURCHASES AND RECS	$26,867,122	$13,095,092	$0	$0	$2,698,282	$0	$6,239,091	$8,802,241	$11,240,859	$13,669,495
(E) ANCILLARY SERVICES AND CAISO CHARGES	$6,254,151	$6,460,748	$6,683,235	$6,920,783	$7,183,197	$7,459,651	$7,749,680	$8,059,507	$8,383,106	$8,690,356
(F) RESOURCE ADEQUACY CAPACITY	$12,589,259	$11,288,190	$7,483,562	$7,735,662	$5,202,126	$4,046,955	$4,233,770	$3,103,590	$3,269,847	$3,441,797
(G) GENERATION PROJECT CAPITAL	$3,863,140	$15,169,891	$48,450,371	$48,450,371	$56,930,434	$65,368,097	$65,368,097	$65,368,097	$65,368,097	$65,368,097
(H) STAFF AND OTHER OPERATIONS COSTS	$4,752,943	$4,899,783	$5,051,164	$5,207,227	$5,368,118	$5,533,984	$5,704,981	$5,881,267	$6,063,007	$6,250,368
(I) BILLING AND DATA MANAGEMENT	$5,720,562	$5,903,757	$6,092,819	$6,287,935	$6,489,300	$6,697,113	$6,911,581	$7,132,917	$7,361,341	$7,597,080
(J) UNCOLLECTIBLES EXPENSE	$1,559,234	$1,601,427	$1,569,623	$1,626,391	$1,802,881	$1,936,546	$2,013,222	$2,202,015	$2,269,702	$2,332,917
(K) STARTUP FINANCING	$3,560,946	$3,560,946	$3,560,946	$3,560,946	$3,560,946	$0	$0	$0	$0	$0
(L) CCA BOND CARRYING COST	$5,871	$6,059	$6,253	$6,453	$6,660	$6,873	$7,093	$7,320	$7,555	$7,797
SUBTOTAL - CCA COSTS	$157,488,485	$161,750,175	$158,538,145	$164,271,928	$182,097,609	$195,598,004	$203,342,533	$222,410,788	$229,247,423	$235,632,459
IV. REVENUES FROM MARKET SALES ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
V. PROGRAM RESERVES ($)	$4,724,655	$4,852,505	$13,002,829	$13,002,829	$15,122,845	$16,342,024	$16,342,024	$16,342,024	$16,342,024	$16,342,024
VI. CCA REVENUE REQUIREMENT ($)	$162,213,139	$166,602,681	$171,540,974	$177,274,757	$197,220,454	$211,940,028	$219,684,557	$238,752,812	$245,589,448	$251,974,484
VARIANCE - CCA COSTS MINUS PG&E ($)	($5,925,292)	($14,563,855)	($12,156,907)	($15,544,201)	$555,765	$12,208,134	$12,578,007	$28,616,673	$26,499,215	$24,674,268
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	**8.2**	**8.4**	**8.6**	**8.9**	**9.9**	**10.6**	**11.0**	**11.9**	**12.2**	**12.5**
PG&E AVERAGE GENERATION COST (CENTS/KWH)	8.5	9.1	9.2	9.7	9.9	10.0	10.3	10.5	10.9	11.3
PERCENTAGE PREMIUM (DISCOUNT) ON GENERATION RATES	-4%	-8%	-7%	-8%	0%	6%	6%	14%	12%	11%
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
(A) EXIT FEES	$23,318,093	$28,778,209	$22,610,377	$20,995,431	$14,776,119	$8,788,087	$6,042,283	$0	$0	$0
(B) FRANCHISE FEE SURCHARGE	$673,235	$674,558	$675,884	$677,212	$678,543	$679,876	$681,212	$682,551	$683,892	$685,236
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 23,991,328	$ 29,452,767	$ 23,286,261	$ 21,672,643	$ 15,454,662	$ 9,467,963	$ 6,723,495	$ 682,551	$ 683,892	$ 685,236
TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES	$ 18,066,036	$ 14,888,912	$ 11,129,354	$ 6,128,442	$ 16,010,427	$ 21,676,097	$ 19,301,502	$ 29,299,223	$ 27,183,106	$ 25,359,504
PG&E CCA CUSTOMER SURCHARGE AVERAGE COST (CENTS/KWH)	1.2	1.5	1.2	1.1	0.8	0.5	0.3	0.0	0.0	0.0
PG&E DELIVERY COST (CENTS/KWH)	8.7	8.7	8.8	8.9	9.2	9.4	9.7	10.0	10.3	10.6
CCA CUSTOMER TOTAL DELIVERED RATE	18.1	18.6	18.6	18.9	19.8	20.5	21.0	21.9	22.5	23.1
PG&E TOTAL DELIVERED RATE (CENTS/KWH)	17.2	17.8	18.0	18.6	19.0	19.4	20.0	20.5	21.2	21.9
CHANGE IN CUSTOMER ELECTRIC CHARGES (%)	5%	4%	3%	2%	4%	6%	5%	7%	6%	6%

FINANCIAL PRO FORMA ANALYSIS
COMMUNITY CHOICE AGGREGATION
SCENARIO 4

CATEGORY	[13] 2023	[14] 2024	[15] 2025	[16] 2026	[17] 2027	[18] 2028	[19] 2029	[20] 2030	[21] 2031	[22] 2032
I, CUSTOMER ACCOUNTS:										
RESIDENTIAL (E-1)	146,424	146,712	147,000	147,289	147,578	147,868	148,159	148,450	148,742	149,034
GENERAL SERVICE (A-1)	15,145	15,175	15,204	15,234	15,264	15,294	15,324	15,354	15,385	15,415
SMALL TIME-OF-USE (A-6)	934	936	938	940	942	944	945	947	949	951
ALTERN. RATE FOR MEDIUM USE (A-10)	1,882	1,886	1,889	1,893	1,897	1,901	1,904	1,908	1,912	1,916
500 - 900kW DEMAND (E-19)	284	285	285	286	287	287	288	288	289	289
1000 + kW DEMAND (E-20)	12	12	12	12	12	12	12	12	12	12
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	1,739	1,742	1,745	1,749	1,752	1,756	1,759	1,763	1,766	1,770
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	2,096	2,100	2,104	2,108	2,112	2,116	2,121	2,125	2,129	2,133
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - CUSTOMER ACCOUNTS	168,516	168,847	169,179	169,511	169,844	170,178	170,512	170,847	171,183	171,519
II. LOAD REQUIREMENTS (KWH):										
RESIDENTIAL (E-1)	974,930,731	976,846,470	978,765,974	980,689,249	982,616,303	984,547,144	986,481,779	988,420,216	990,362,462	992,308,524
GENERAL SERVICE (A-1)	223,543,893	223,983,156	224,423,283	224,864,275	225,306,133	225,748,860	226,192,456	226,636,925	227,082,266	227,528,483
SMALL TIME-OF-USE (A-6)	62,291,963	62,414,366	62,537,010	62,659,896	62,783,022	62,906,391	63,030,002	63,153,856	63,277,953	63,402,295
ALTERN. RATE FOR MEDIUM USE (A-10)	330,089,032	330,737,657	331,387,557	332,038,733	332,691,189	333,344,928	333,999,950	334,656,260	335,313,860	335,972,752
500 - 900kW DEMAND (E-19)	241,714,794	242,189,764	242,665,666	243,142,504	243,620,279	244,098,993	244,578,648	245,059,245	245,540,786	246,023,274
1000 + kW DEMAND (E-20)	127,889,935	128,141,239	128,393,037	128,645,329	128,898,117	129,151,402	129,405,184	129,659,466	129,914,246	130,169,528
STREET LIGHTING AND TRAFFIC CONTROL (LS-3)	13,259,621	13,285,676	13,311,782	13,337,940	13,364,149	13,390,410	13,416,722	13,443,086	13,469,501	13,495,969
AGRICULTURAL (AG-1B, AG-4A, AG-4B, AG-5A, AG-5B, AG-5C)	45,639,290	45,728,971	45,818,829	45,908,863	45,999,074	46,089,462	46,180,028	46,270,771	46,361,693	46,452,794
	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0
SUBTOTAL - LOAD REQUIREMENTS	2,019,359,259	2,023,327,300	2,027,303,138	2,031,286,789	2,035,278,268	2,039,277,589	2,043,284,770	2,047,299,824	2,051,322,769	2,055,353,618
III. CCA POWER SUPPLY REVENUE REQUIREMENT ($)										
(A) MARKET PURCHASES	$9,745,895	$10,616,064	$11,490,858	$12,420,885	$13,467,298	$14,470,157	$15,486,920	$16,539,585	$16,884,800	$17,278,790
(B) CONTRACT PURCHASES	$86,695,497	$89,633,899	$92,604,200	$95,808,273	$99,490,203	$103,009,727	$106,596,195	$110,337,146	$111,258,730	$112,385,438
(C) POWER PRODUCTION (NON-DEBT)	$35,173,170	$35,040,517	$34,912,438	$34,788,755	$34,669,294	$34,553,890	$34,442,383	$34,334,621	$34,230,456	$34,129,747
(D) RENEWABLE MARKET PURCHASES AND RECS	$16,227,859	$18,923,762	$21,684,796	$24,576,766	$27,699,162	$30,811,678	$33,993,684	$37,279,649	$40,181,679	$43,202,044
(E) ANCILLARY SERVICES AND CAISO CHARGES	$9,013,241	$9,351,010	$9,693,130	$10,048,989	$10,428,881	$10,805,894	$11,190,435	$11,586,471	$11,952,303	$12,335,183
(F) RESOURCE ADEQUACY CAPACITY	$3,619,662	$3,803,675	$3,994,074	$4,191,106	$4,395,026	$4,606,100	$4,824,601	$5,050,811	$5,285,024	$5,527,541
(G) GENERATION PROJECT CAPITAL	$65,368,097	$65,368,097	$65,368,097	$65,368,097	$65,368,097	$65,368,097	$65,368,097	$65,368,097	$65,368,097	$65,368,097
(H) STAFF AND OTHER OPERATIONS COSTS	$6,443,526	$6,642,659	$6,847,952	$7,059,597	$7,277,790	$7,502,734	$7,734,638	$7,973,718	$8,220,195	$8,474,300
(I) BILLING AND DATA MANAGEMENT	$7,840,369	$8,091,448	$8,350,568	$8,617,987	$8,893,969	$9,178,789	$9,472,730	$9,776,084	$10,089,153	$10,412,247
(J) UNCOLLECTIBLES EXPENSE	$2,401,273	$2,474,711	$2,549,461	$2,628,805	$2,716,897	$2,803,071	$2,891,097	$2,982,462	$3,034,704	$3,091,134
(K) STARTUP FINANCING	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(L) CCA BOND CARRYING COST	$8,046	$33,357	$36,913	$39,893	$44,718	$44,477	$41,798	$37,547	$21,954	$10,686
SUBTOTAL - CCA COSTS	$242,536,636	$249,979,199	$257,532,487	$265,549,152	$274,451,336	$283,154,613	$292,042,577	$301,266,190	$306,527,094	$312,215,206
IV. REVENUES FROM MARKET SALES ($)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
V. PROGRAM RESERVES ($)	$16,342,024	$16,342,024	$16,342,024	$16,342,024	$16,342,024	$16,342,024	$16,342,024	$16,342,024	$16,342,024	$16,342,024
VI. CCA REVENUE REQUIREMENT ($)	$258,878,660	$266,321,223	$273,874,512	$281,891,176	$290,793,360	$299,496,637	$308,384,602	$317,608,214	$322,869,118	$328,557,231
VARIANCE - CCA COSTS MINUS PG&E ($)	$22,680,097	$23,280,167	$21,172,133	$18,931,018	$16,460,366	$14,018,216	$11,487,547	$8,829,972	$4,000,609	($1,085,515)
CCA PROGRAM AVERAGE RATE (CENTS/KWH)	**12.8**	**13.2**	**13.5**	**13.9**	**14.3**	**14.7**	**15.1**	**15.5**	**15.7**	**16.0**
PG&E AVERAGE GENERATION COST (CENTS/KWH)	11.7	12.0	12.5	12.9	13.5	14.0	14.5	15.1	15.5	16.0
PERCENTAGE PREMIUM (DISCOUNT) ON GENERATION RATES	10%	10%	8%	7%	6%	5%	4%	3%	1%	0%
VII. PG&E CCA CUSTOMER SURCHARGES ($)										
(A) EXIT FEES	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(B) FRANCHISE FEE SURCHARGE	$686,582	$687,931	$689,283	$690,638	$691,995	$693,354	$694,717	$696,082	$697,450	$698,820
SUBTOTAL - PG&E CCA CUSTOMER SURCHARGES	$ 686,582	$ 687,931	$ 689,283	$ 690,638	$ 691,995	$ 693,354	$ 694,717	$ 696,082	$ 697,450	$ 698,820
TOTAL CHANGE IN CUSTOMER ELECTRIC CHARGES	$ 23,366,679	$ 23,968,098	$ 21,861,416	$ 19,621,656	$ 17,152,361	$ 14,711,571	$ 12,182,264	$ 9,526,054	$ 4,698,059	$ (386,695)
PG&E CCA CUSTOMER SURCHARGE AVERAGE COST (CENTS/KWH)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PG&E DELIVERY COST (CENTS/KWH)	10.9	11.3	11.6	11.9	12.3	12.7	13.0	13.4	13.8	14.3
CCA CUSTOMER TOTAL DELIVERED RATE	23.8	24.5	25.1	25.9	26.6	27.4	28.2	29.0	29.6	30.3
PG&E TOTAL DELIVERED RATE (CENTS/KWH)	22.6	23.3	24.1	24.9	25.8	26.7	27.6	28.5	29.4	30.3
CHANGE IN CUSTOMER ELECTRIC CHARGES (%)	5%	5%	4%	4%	3%	3%	2%	2%	1%	0%

Financial Pro Forma Analysis

Scenario 4

Appendix B

Study Input Assumptions

Sonoma County CCA Feasibility Study Input Assumptions

Input	Source	Input Value
I. Program and Load Inputs		
Start Year		2013
Participating Communities		County and all Cities/Towns Except Healdsburg
Annual Load Growth (%)	7% reduction from 2008 to 2010 per CAISO change in system sales during this period (-4.3% and -2.5% in 2009 and 2010, respectively).	0.70%
Annual Attrition Rate (%)	DMC estimate	0.5%
Initial Opt Out Rates (%)		
Residential	DMC estimates	20%
Small Commercial	DMC estimates	20%
Medium Commercial	DMC estimates	20%
Large Commercial	DMC estimates	20%
Industrial	DMC estimates	20%
Street Lighting	DMC estimates	20%
Agricultural & Pumping	DMC estimates	20%
Customer Load Profiles	2008-2010 PG&E Class Load Profiles, PG&E Monthly Usage Data for Sonoma County, CCA Info Tariff Item 14	
Uncollectibles Factor (% of Revenue)	DMC estimates based on PG&E uncollectibles factor	1.00%
Distribution Losses (%)	CPUC Standard Planning Assumptins, PG&E 2010 LTTP	6%
NPV Discount Rate (%)	DMC estimate	6%
Program Reserves (% of Revenue)	DMC estimate	3%
II. Power Market Inputs		
NP-15 Market Heat Rate (btu/MWh)	DMC estimate	8,000
GHG Allowance Price ($/Metric Ton)	CPUC Standard Planning Assumptions, 2009 MPR (Synapse Energy Economics Study, July 2008)	See annual data
System Power Emissions Rate (Metric Tons/MWh)	PG&E 2012 ERRA, CARB default value for unspecified resources.	0.435
Natural Gas Generation Emissions Rate (Metric Tons/MMBTU)	PG&E 2012 ERRA, CARB default value for natural gas generation.	0.05302
RPS Premiums ($/MWh)		
Category 1	MEA/SENA Agreement, May 17, 2011	$50.00
Category 2	MEA/SENA Agreement, May 17, 2011	$20.00
Category 3	MEA/SENA Agreement, May 17, 2011	$17.00
RPS Premiums Annual Escalator (%)		
Category 1	DMC estimate	0%
Category 2	DMC estimate	0%
Category 3	DMC estimate	0%
RPS Compliance		
Category 1 Minimum	DMC estimates per SB1X2	See annual data
Category 2 Maximum	DMC estimates per SB1X2	See annual data
Category 3 Maximum	DMC estimates per SB1X2	See annual data
Natural Gas Prices ($/MMBTU)		
Base	EIA Annual Energy Outlook 2011	See annual data
Low	DMC estimate	0.75 X Base Price
High	DMC estimate	1.5 X Base Price
Resource Adequacy Cost ($/KW-Year)		
System	MEA/SENA Agreement, May 17, 2011	$24.00
Local, Bay Area	MEA/SENA Agreement, May 17, 2011	$48.00
Local, Other PG&E	MEA/SENA Agreement, May 17, 2011	$39.00
Resource Adequacy Cost Annual Escalator (%)		
System	DMC estimates	3%
Local, Bay Area	DMC estimates	3%
Local, Other PG&E	DMC estimates	3%
Spot Power Prices		
On-peak Ratio (% of flat price)	Calibration of modeled numbers to broker forward market data	120%
Off-peak Ratio (% of flat price)	Calibration of modeled numbers to broker forward market data	85%
Monthly Electric Profile (% of Annual)	Ratios Based on CAISO Day Ahead Market for twelve months ended June, 2011	See annual data
Ancillary Services Costs (% MCP)	CAISO 2010 Market Performance and Issues Annual Report	1%
Planning Reserve Requirement (% of monthly peak load)	CPUC Resource Adequacy Standard	115%
Other CAISO Costs ($/MWh)	CAISO 2010 Market Performance and Issues Annual Report (GMC, Bid Cost Recovery and Reliability) + $1 per MWh for congestion/other.	$2.50
Other CAISO Costs Annual Escalator (%)	DMC estimate	3%
Energy Remarketing Price Factor (% of MCP)	DMC estimate to reflect hourly price shape on excess sales.	90%
III. CCA Operations Inputs		
Operations and Scheduling Coordination		
Minimum ($/Year)	MEA budget for staff and professional services.	$2,500,000
Maximum ($/Year)	DMC estimate	$10,000,000
Variable ($/MWh)	DMC estimate	$1.00
Escalation	DMC estimate	3%
Data Management		
Customer ($/Account-Month)	MEA/Noble Energy Solutions Agreement, March 15, 2010	$1.75
Energy ($/MWh)	MEA/Noble Energy Solutions Agreement, March 15, 2010	$0.45
Billing and Metering ($/Account-Month)	PG&E E-CCA, Items 6A and 7A	$0.52
Startup Costs ($)		
Study Costs	DMC estimate	$300,000
Implementation Costs	DMC Estimate for Procurement, Regulatory, and Utility Interface Prior to Launch	$1,500,000
Working Capital	DMC Estimate of One Month's Gross Revenue	$15,000,000
Startup Costs Amortization		
Study Costs (Years)	Assumed "equity" contribution	None
Implementation Costs (Years)	Assumed "equity" contribution	None
Working Capital (Years)	DMC estimate	5
Startup Costs Interest Costs		

Sonoma County CCA Feasibility Study Input Assumptions

Input	Source		Input Value
Study Costs (%)	DMC estimate		N/A
Implementation Costs (%)	DMC estimate		N/A
Working Capital (%)	DMC estimate		6%
IV. PG&E Rate Inputs			
PG&E Total Electric Rates ($/KWh)			
Residential	Effective January, 2011, AL 3727-E-A, Table 3		0.15658
Small Commercial (A-1)	Effective January, 2011, AL 3727-E-A, Table 3		0.17952
Small Commercial (A-6)	Effective January, 2011, AL 3727-E-A, Table 3		0.17313
Medium Commercial (A-10)	Effective January, 2011, AL 3727-E-A, Table 3		0.15818
Large Commercial (E-19)	Effective January, 2011, AL 3727-E-A, Table 3		0.137
Industrial (E-20)	Effective January, 2011, AL 3727-E-A, Table 3		0.11496
Street Lighting and Traffic Control	Effective January, 2011, AL 3727-E-A, Table 3		0.16269
Agricultural and Pumping	Effective January, 2011, AL 3727-E-A, Table 3		0.14581
PG&E Generation Electric Rates ($/KWh)			
Residential	Effective January, 2011, AL 3727-E-A, Table 3		0.06399
Small Commercial (A-1)	Effective January, 2011, AL 3727-E-A, Table 3		0.07135
Small Commercial (A-6)	Effective January, 2011, AL 3727-E-A, Table 3		0.07111
Medium Commercial (A-10)	Effective January, 2011, AL 3727-E-A, Table 3		0.07567
Large Commercial (E-19)	Effective January, 2011, AL 3727-E-A, Table 3		0.06962
Industrial (E-20)	Effective January, 2011, AL 3727-E-A, Table 3		0.06485
Street Lighting and Traffic Control	Effective January, 2011, AL 3727-E-A, Table 3		0.06336
Agricultural and Pumping	Effective January, 2011, AL 3727-E-A, Table 3		0.05839
PG&E Surcharges			
PCIA ($/MWh)	Assumes new methodology for 2012 and modeled based on PG&E revenue requirements and market projections.		See annual data
Franchise Fee ($/KWh)	PG&E tariff E-FFS, 2011 vintage		$0.00034
Non-Generation Rate Annual Escalator (%)	DMC estimate		3.00%
PG&E Generation Rate Annual Escalator - Static (%)			2012
Low	DMC estimate		See annual data
Base	DMC estimate		See annual data
High	DMC estimate		See annual data
PG&E Generation Rate Annual Escalator - Dynamic (%)	Based on DMC projections of revenue requirements for PG&E generation costs.		See annual data
CCA Bond			
Administrative Reentry Fee ($/Account)	PG&E Tariff E-CCA		3.94
Administrative Reentry Fee Annual Escalation (%)	DMC estimate		3.00%
Commodity Stress Factor	DMC estimate		1.00
Collateral Cost (Basis Points)	DMC estimate		0.85
V. Resource Options			
Renewable Resource Categorization for Voluntary Short-Term Purchases			
Category 1	DMC estimate		0%
Category 2	DMC estimate		50%
Category 3	DMC estimate		50%
Generation Resources			
PV (Thin Film, Central Valley) Installed Cost ($/KW)	CPUC Standard Planning Assumptions, E3 RPS Calculator		$3,400
PV (Thin Film) Fixed O&M($/KW)	CPUC Standard Planning Assumptions, E3 RPS Calculator		$32.00
PV (Thin Film) Variable O&M ($/MWh)	CPUC Standard Planning Assumptions, E3 RPS Calculator		$0.00
PV (Thin Film) Capacity Factor (%)	CPUC Standard Planning Assumptions, E3 RPS Calculator		23.50%
PV (Thin Film) Annual Degradation (%)	CPUC Standard Planning Assumptions, E3 RPS Calculator		1%
PV (Thin Film) Net Qualifying Capacity (% of Nameplate)	CPUC Standard Planning Assumptions, E3 RPS Calculator		51%
PV (Thin Film) Other Cost ($/MWh)	DMC estimate for balancing		$2.00
PV (Large Crystalline, Central Valley) Installed Cost ($/KW)	CPUC Standard Planning Assumptions, E3 RPS Calculator		$4,000
PV (Large Crystalline) Fixed O&M($/KW)	CPUC Standard Planning Assumptions, E3 RPS Calculator		$44.00
PV (Large Crystalline) Variable O&M ($/MWh)	CPUC Standard Planning Assumptions, E3 RPS Calculator		$0.00
PV (Large Crystalline) Capacity Factor (%)	CPUC Standard Planning Assumptions, E3 RPS Calculator		26.70%
PV (Large Crystalline) Annual Degradation (%)	CPUC Standard Planning Assumptions, E3 RPS Calculator		0.75%
PV (Large Crystaline) Net Qualifying Capacity (% of Nameplate)	CPUC Standard Planning Assumptions, E3 RPS Calculator		65%
PV (Large Crystalline) Other Cost ($/MWh)	DMC estimate for balancing		$2.00
PV (Large Ground Mount, North Coast) Installed Cost ($/KW)	CPUC Standard Planning Assumptions, E3 RPS Calculator		$3,700
PV (Large Ground Mount) Fixed O&M($/KW)	CPUC Standard Planning Assumptions, E3 RPS Calculator		$20.00
PV (Large Ground Mount) Variable O&M ($/MWh)	CPUC Standard Planning Assumptions, E3 RPS Calculator		$0.00
PV (Large Ground Mount) Capacity Factor (%)	CPUC Standard Planning Assumptions, E3 RPS Calculator		21.90%
PV (Large Ground Mount) Annual Degradation (%)	CPUC Standard Planning Assumptions, E3 RPS Calculator		1%
PV (Large Ground Mount) Net Qualifying Capacity (% of Nameplate)	CPUC Standard Planning Assumptions, E3 RPS Calculator		51%
PV (Large Ground Mount) Other Cost ($/MWh)	DMC estimate for balancing		$2.00
PV (Mid Ground Mount, North Coast) Installed Cost ($/KW)	CPUC Standard Planning Assumptions, E3 RPS Calculator		$3,900
PV (Mid Ground Mount) Fixed O&M($/KW)	CPUC Standard Planning Assumptions, E3 RPS Calculator		$20.00
PV (Mid Ground Mount) Variable O&M ($/MWh)	CPUC Standard Planning Assumptions, E3 RPS Calculator		$0.00
PV (Mid Ground Mount) Capacity Factor (%)	CPUC Standard Planning Assumptions, E3 RPS Calculator		21.90%
PV (Mid Ground Mount) Annual Degradation (%)	CPUC Standard Planning Assumptions, E3 RPS Calculator		1%
PV Mid Ground Mount) Net Qualifying Capacity (% of Nameplate)	CPUC Standard Planning Assumptions, E3 RPS Calculator		51%
PV (Mid Ground Mount) Other Cost ($/MWh)	DMC estimate for balancing		$2.00
Geothermal Installed Cost ($/KW)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 14.		$3,718
Geothermal Fixed O&M($/KW)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 14.		$58.38
Geothermal Variable O&M ($/MWh)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 14.		$5.06
Geothermal Capacity Factor (%)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 11.		94%

Sonoma County CCA Feasibility Study Input Assumptions

Input	Source		Input Value
Geothermal Annual Degradation (%)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 11.		4%
Geothermal Net Qualifying Capacity (% of Nameplate)	CPUC Standard Planning Assumptions, E3 RPS Calculator		100%
Geothermal Other Cost ($/MWh)			$0.00
Wind Installed Cost ($/KW)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 14.		$1,990
Wind Fixed O&M($/KW)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 14.		$13.70
Wind Variable O&M ($/MWh)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 14.		$5.50
Wind Capacity Factor (%)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 11, shows 37%, used 30% to reflect potentially lower class wind resource area.		30%
Wind Annual Degradation (%)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 11.		1%
Wind Net Qualifying Capacity (% of Nameplate)	CPUC Standard Planning Assumptions, E3 RPS Calculator		11%
Wind Other Cost ($/MWh)	DMC estimate for balancing		$2.00
Biomass Installed Cost ($/KW)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 14.		$3,254
Biomass Fixed O&M($/KW)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 14.		$99.50
Biomass Variable O&M ($/MWh)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 14.		$4.47
Biomass Capacity Factor (%)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 11, shows 37%, used 30% to reflect potentially lower class wind resource area.		85%
Biomass Annual Degradation (%)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 11.		0.10%
Biomass Net Qualifying Capacity (% of Nameplate)	CPUC Standard Planning Assumptions, E3 RPS Calculator		100%
Biomass Fuel Cost ($/MMBTU)	CPUC Standard Planning Assumptions, E3 RPS Calculator		$2.48
Biomass Heat Rate ($/MWh)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 11.		
Biomass Cogeneration Installed Cost ($/KW)	Sonoma CCA Steering Committee/Climate Protection Campaign		$3,000.00
Biomass Cogeneration Fixed O&M($/KW)	Sonoma CCA Steering Committee/Climate Protection Campaign		$0.00
Biomass Cogeneration Variable O&M ($/MWh)	Sonoma CCA Steering Committee/Climate Protection Campaign		$22.00
Biomass Cogeneration Capacity Factor (%)	Sonoma CCA Steering Committee/Climate Protection Campaign		85%
Biomass Cogeneration Annual Degradation (%)	DMC estimate based on CEC's Biomass Generation degradation figure.		0.10%
Biomass Cogeneration Net Qualifying Capacity (% of Nameplate)	DMC estimate		100%
Biomass Cogeneration Fuel Cost ($/MWh)	Sonoma CCA Steering Committee/Climate Protection Campaign		$20.00
Hyrdo-electric Pumped Storage Installed Cost ($/KW)	Sonoma CCA Steering Committee/Climate Protection Campaign		$1,500.00
Hyrdo-electric Pumped Storage Fixed O&M($/KW)	Sonoma CCA Steering Committee/Climate Protection Campaign		$0.00
Hyrdo-electric Pumped Storage Variable O&M ($/MWh)	Sonoma CCA Steering Committee/Climate Protection Campaign		$10.00
Hyrdo-electric Pumped Storage Capacity Factor (%)	Sonoma CCA Steering Committee/Climate Protection Campaign		25%
Hyrdo-electric Pumped Storage Annual Degradation (%)	DMC estimate		0%
Hyrdo-electric Pumped Storage Net Qualifying Capacity (% of Nameplate)	DMC estimate		100%
Hyrdo-electric Pumped Storage Net Power Input Cost ($/MWh)	Sonoma CCA Steering Committee/Climate Protection Campaign		$91.00
Battery Storage Installed Cost ($/KW)	Sonoma CCA Steering Committee/Climate Protection Campaign		$2,500.00
Battery Storage Fixed O&M($/KW)	Sonoma CCA Steering Committee/Climate Protection Campaign		$0.00
Battery Storage Variable O&M ($/MWh)	Sonoma CCA Steering Committee/Climate Protection Campaign		$10.00
Battery Storage Capacity Factor (%)	Sonoma CCA Steering Committee/Climate Protection Campaign		25%
Battery Storage Annual Degradation (%)	DMC estimate		5%
Battery Storage Net Qualifying Capacity (% of Nameplate)	DMC estimate		100%
Battery Storage Net Power Input Cost ($/MWh)	Sonoma CCA Steering Committee/Climate Protection Campaign		$85.00
VI. Financing Inputs			
Generation Debt Ratio (%)	DMC estimates		100%
Generation Bond Term (Years)	DMC estimates		20
Generation Interest Rate (%)	DMC estimates		5.5%
Debt Coverage Ratio (%)	DMC estimates		125%
Bond Insurance (% of Financed Amount)	DMC estimates		1.60%
Bond Issuance Costs (% of Financed Amount)	DMC estimates		1.00%
Debt Reserve Fund (% of Financed Amount)	DMC estimates		10%
VII. Power Purchase Contracts			
NP-15 Peak PPA Price ($/MWh)	DMC estimates		MCP
NP-15 Peak PPA Price Annual Escalator (%)	DMC estimates		MCP
NP-15 Peak PPA Term (Years)	DMC estimates		1 to 5 years
NP-15 Baseload PPA Price ($/MWh)	DMC estimates		MCP
NP-15 Baseload PPA Price Annual Escalator (%)	DMC estimates		MCP
NP-15 Baseload PPA Term (Years)	DMC estimates		1 to 5 years
PV, Central Valley PPA Price ($/MWh)	DMC estimates for recent transactions		$120.00
PV, Central Valley PPA Price Annual Escalator (%)	DMC estimates for recent transactions		1.50%
PV, Central Valley PPA Term (Years)	DMC estimates for recent transactions		25
PV, Central Valley PPA RPS Category (1,2 or 3)	DMC estimate		1
PV, Central Valley PPA Capacity Factor (%)	DMC estimates for recent transactions		23.5%
PV, Central Valley PPA Annual Degradation (%)	CPUC Standard Planning Assumptions, E3 RPS Calculator		1.00%
PV, Central Valley PPA NQC (% of Nameplate)	CPUC Standard Planning Assumptions, E3 RPS Calculator		65%

Sonoma County CCA Feasibility Study Input Assumptions

Input	Source		Input Value
PV, Central Valley PPA Production Profile	DMC estimate		6 X 16, as available
PV, Sonoma, Large-Size Ground Mount PPA Price ($/MWh)	E3 RPS Calculator for large ground mount north cost PV, adjusted for cost reductions indicated in recent transactions (-18%).		$158.00
PV, Sonoma, Large-Size Ground Mount PPA Price Annual Escalator (%)	DMC estimates for recent transactions		1.50%
PV, Sonoma, Large-Size Ground Mount PPA Term (Years)	DMC estimates for recent transactions		25
PV, Sonoma, Large-Size Ground Mount PPA RPS Category (1,2 or 3)	DMC estimate		1
PV, Sonoma, Large-Size Ground Mount PPA Capacity Factor (%)	CPUC Standard Planning Assumptions, E3 RPS Calculator		21.90%
PV, Sonoma, Large-Size Ground Mount PPA Annual Degradation (%)	CPUC Standard Planning Assumptions, E3 RPS Calculator		1%
PV, Sonoma, Large-Size Ground Mount PPA NQC (% of Nameplate)	CPUC Standard Planning Assumptions, E3 RPS Calculator		51%
PV, Sonoma, Large-Size Ground Mount PPA Production Profile	DMC estimate		6 X 16, as available
PV, Sonoma, Mid-Size Ground Mount PPA Price ($/MWh)	E3 RPS Calculator for mid ground mount north cost PV, adjusted for cost reductions indicated in recent transactions (-18%).		$164.00
PV, Sonoma, Mid-Size Ground Mount PPA Price Annual Escalator (%)	DMC estimates for recent transactions		1.50%
PV, Sonoma, Mid-Size Ground Mount PPA Term (Years)	DMC estimates for recent transactions		25
PV, Sonoma, Mid-Size Ground Mount PPA RPS Category (1,2 or 3)	DMC estimate		1
PV, Sonoma, Mid-Size Ground Mount PPA Capacity Factor (%)	CPUC Standard Planning Assumptions, E3 RPS Calculator		21.90%
PV, Sonoma, Mid-Size Ground Mount PPA Annual Degradation (%)	CPUC Standard Planning Assumptions, E3 RPS Calculator		1%
PV, Sonoma, Mid-Size Ground Mount PPA NQC (% of Nameplate)	CPUC Standard Planning Assumptions, E3 RPS Calculator		51%
PV, Sonoma, Mid-Size Ground Mount PPA Production Profile	DMC estimate		6 X 16, as available
PV, Sonoma, Small-Size Ground Mount PPA Price ($/MWh)	E3 RPS Calculator for small ground mount north cost PV, adjusted for cost reductions indicated in recent transactions (-18%).		$178.00
PV, Sonoma, Small-Size Ground Mount PPA Price Annual Escalator (%)	DMC estimates for recent transactions		1.50%
PV, Sonoma, Small-Size Ground Mount PPA Term (Years)	DMC estimates for recent transactions		25
PV, Sonoma, Small-Size Ground Mount PPA RPS Category (1,2 or 3)	DMC estimate		1
PV, Sonoma, Small-Size Ground Mount PPA Capacity Factor (%)	CPUC Standard Planning Assumptions, E3 RPS Calculator		23.70%
PV, Sonoma, Small-Size Ground Mount PPA Annual Degradation (%)	CPUC Standard Planning Assumptions, E3 RPS Calculator		1%
PV, Sonoma, Small-Size Ground Mount PPA NQC (% of Nameplate)	CPUC Standard Planning Assumptions, E3 RPS Calculator		65%
PV, Sonoma, Small-Size Ground Mount PPA Production Profile	DMC estimate		6 X 16, as available
PV, Sonoma, Rooftop PPA Price ($/MWh)	E3 RPS Calculator for small ground mount north cost PV, adjusted for cost reductions indicated in recent transactions (-18%).		$225.00
PV, Sonoma, Rooftop PPA Price Annual Escalator (%)	DMC estimates for recent transactions		1.50%
PV, Sonoma, Rooftop PPA Term (Years)	DMC estimates for recent transactions		25
PV, Sonoma, Rooftop PPA RPS Category (1,2 or 3)	DMC estimate		1
PV, Sonoma, Rooftop PPA Capacity Factor (%)	CPUC Standard Planning Assumptions, E3 RPS Calculator		19.60%
PV, Sonoma, Rooftop PPA Annual Degradation (%)	CPUC Standard Planning Assumptions, E3 RPS Calculator		1%
PV, Sonoma, Rooftopt PPA NQC (% of Nameplate)	CPUC Standard Planning Assumptions, E3 RPS Calculator		51%
PV, Sonoma, Rooftop PPA Production Profile	DMC estimate		6 X 16, as available
Concentrating Solar Parabolic Trough PPA Price ($/MWh)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 6, Total Levelized Cost.		$225
Concentrating Solar Parabolic Trough PPA Price Annual Escalator (%)	N/A with Levelized Cost Input		0%
Concentrating Solar Parabolic Trough PPA Term (Years)	DMC estimate		20
Concentrating Solar Parabolic Trough PPA RPS Category (1,2 or 3)	DMC estimate		1
Concentrating Solar Parabolic Trough PPA Capacity Factor (%)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 11.		27%
Concentrating Solar Parabolic Trough PPA Annual Degradation (%)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 11.		0.50%
Concentrating Solar Parabolic Trough PPA NQC (% of Nameplate)	CPUC Standard Planning Assumptions, E3 RPS Calculator		74%
Concentrating Solar Parabolic Trough PPA Production Profile	DMC estimate		6 X 16, as available
Geothermal PPA Price ($/MWh)	Average of CEC ($70/MWh) and E3 RPS Calculator ($115/MWh) levelized cost estimates.		$97.00
Geothermal PPA Price Annual Escalator (%)	DMC estimate		0%
Geothermal PPA Term (Years)	DMC estimate		25
Geothermal PPA RPS Category (1,2 or 3)	DMC estimate		1
Geothermal PPA Capacity Factor (%)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 11.		94%
Geothermal PPA Annual Degradation (%)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 11.		4%
Geothermal PPA NQC (% of Nameplate)	CPUC Standard Planning Assumptions, E3 RPS Calculator		100%
Geothermal PPA Production Profile	DMC estimate		7 x 24
Wind PPA Price ($/MWh)	DMC estimates for recent transactions		$90.00
Wind PPA Price Annual Escalator (%)	DMC estimates for recent transactions		0%
Wind PPA Term (Years)	DMC estimates for recent transactions		20
Wind PPA RPS Category (1,2 or 3)	DMC estimates for recent transactions		1%
Wind PPA Capacity Factor (%)	DMC estimates for recent transactions		30%
Wind PPA Annual Degradation (%)	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 11.		1%
Wind PPA NQC (% of Nameplate)	CPUC Standard Planning Assumptions, E3 RPS Calculator		11%
Wind PPA Production Profile	DMC estimate		7 x 24, as available
VIII. PG&E Revenue Requirement Inputs			
PG&E Load Forecast (GWh)	PG&E 2010 LTPP, Table PGE-2		
Resource Production (GWH)			
PG&E-Owned Fossil Resources	Assumed 60% Capacity Factor		
PG&E-Owned Nuclear Resources	PG&E 2010 LTPP, Table PGE-2, calculated using average production for 2011-2013 redacted period.		
PG&E-Owned Hydro-electric Resources	PG&E 2010 LTPP, Table PGE-2		
PG&E-Owned Solar Resources	PG&E 2010 LTPP, Table PGE-2		
DWR Contractual Resources	PG&E 2010 LTPP, Table PGE-2		
Qualifying Facility (QF) Contractual Resources	2009 FERC Form 1, Adjust based on ERRA Portfolo		

Sonoma County CCA Feasibility Study Input Assumptions			
Input	Source		Input Value
Renewable Energy Contractual Resources	PG&E 2010 LTPP, Table PGE-2		
Other Bilateral Resources	PG&E 2010 LTPP, Table PGE-2		
Spot Market Purchases	PG&E 2010 LTPP, Table PGE-2, Calcualated resdiually for 2011-2013 redacted period.		
Spot Market Sales	PG&E 2010 LTPP, Table PGE-2		
Peak Load Forecast (MW)	PG&E 2010 LTPP, Table PGE-2		
Resource Capacity (MW)			
PG&E-Owned Fossil Resources	PG&E 2010 LTPP, Table PGE-1		
PG&E-Owned Nuclear Resources	PG&E 2010 LTPP, Table PGE-1		
PG&E-Owned Hydro-electric Resources (1 in 5)	PG&E 2010 LTPP, Table PGE-1		
PG&E-Owned Solar Resources	PG&E 2010 LTPP, Table PGE-1		
DWR Contractual Resources	PG&E 2010 LTPP, Table PGE-1		
Qualifying Facility (QF) Contractual Resources	Assumed 50% capacity factor.		
Renewable Energy Contractual Resources	PG&E 2010 LTPP, Table PGE-1		
Other Bilateral Resources	PG&E 2010 LTPP, Table PGE-1		
Bilateral Capacity Cost ($/MW-Year)	DMC estimate		$120,000
Bilateral Capacity Cost Annual Escalator (%)	DMC estimate		3%
New Bilateral Capacity Cost ($/MW-Year)	2010 CEC Comparative Cost of California Central Station Electricity Generation, fixed cost for CCGT		$191,000
New Bilateral Capacity Cost Annual Escalator (%)	DMC estimate		3%
PG&E Natural Gas Generation Heat Rate	California Energy Commission, Comparative Costs of California Central Station Electricity Generation, Table 11, Conventional Combined Cycle		7100
New Renewable PPA Cost ($/MWh)	DMC estimate		$120.00
New Renewable PPA Cost Annual Escalator (%)	DMC estimate		1.5%
Existing Renewable PPA Cost ($/MWh)	2009 FERC Form 1		$65.00
Existing Renewable Volume (GWh)	2009 FERC Form 1		5,744
DWR Capacity Cost ($/MW-Year)	DMC estimate		$120,000
DWR Re-allocation Credit ($)	D.10-12-006, Appendix A		($486,000,000)
Renewable Content for MPB Calc. (%)	DMC estimate of PG&E RE % (see annual data)		
QF Firm Capacity Cost ($/MW-Year)	D.07-09-040		$92,000
QF As Available Capacity Cost ($/MW-Year)	D.07-09-040		$33,000
Capacity Cost Annual Escalator (%)	DMC estimate		3%
QF TOU Factor	DMC estimate		1.15
QF VOM Adder ($/MWh)	D.07-09-040		$2.60
QF VOM Adder Annual Escalator (%)	DMC estimate		3%
CAISO Cost ($/MWh)	Ancillary Services and Other CAISO, estimated based on CAISO 2010 Market Performance and Issues Annual Report, + $3/MWh congestion/other.		$5.00
CAISO Cost Annual Escalator (%)	DMC estimate		3%
QF Energy Revenue Requirement ($)	Priced at SRAC per QF/CHP Settlement		
QF Capacity Revenue Requirement ($)	20% as available, 80% firm per D.07-09-040, Table 5		
Bilateral Energy Revenue Requirement ($)	Priced at MCP		
Net Purchases (Sales) Energy Revenue Requirement ($)	Priced at MCP		
Net Purchases Capacity Revenue Requirement ($)	Priced at cost of new bilateral capacity		
Nuclear Fuel Revenue Requirement ($)	Estimated based on historical data		$80,000,000
Nuclear Fuel Revenue Requirement Annual Escalation (%)	DMC estimate		3%
Renewable Resources Revenue Requirment ($)	Total cost estimated as cost of existing renewables plus incremental renewable purchases priced at cost of new renewables.		
GHG Compliance Revenue Requirement ($)	Direct cost of offsets for PG&E owned generation.		
Other Generation Costs Revenue Requirement ($)	Electric procurement, gen-ties, other generation related costs, 2011 ERRA PCIA Workpapers.		$175,000,000
DWR Revenue Requirement ($)	Energy at MCP plus capacity cost less re-allocation credit		
Existing Generation Base Revenue Requirement ($)	2011 GRC Phase 1 Settlement, Table 3-2		
Current Rate Base ($)	2011 GRC Phase 1 Settlement, Table 3-2		
Annual Capital Additions (% of Rate Base)	DMC estimate		5%
O&M Annual Escalator (%)	DMC estimate		3%
Return on Rate Base (%)	2011 GRC Phase 1 Settlement, Table 3-2		8.79%
Taxes Other Than Income ($)	Percent of production O&M		
Taxes On Income ($)	Percent of return		
Depreciation ($)	Percent of rate base		
New Generation Rate Base			
PV UOG Program	Cummulative 100 MW in 2012, 150 MW in 2013, 200 MW in 2014, 250 MW in 2015		
Annual Capital Additions (% of Rate Base)	Incremental Capacity (MW) X $4,000,000/MW Installed Cost, CPUC Standard Planning Assumptions, E3 RPS Calculator		
Return on Rate Base (%)	2011 GRC Phase 1 Settlement, Table 3-2		8.79%
Production O&M ($)	Production X $47.03 per MWh Fixed and Variable O&M, CEC Comparative Cost of California Central Station Electric Generation, Table 6		
Other Operating Expenses ($)	Percent of production O&M		
Taxes Other Than Income ($)	Percent of production O&M		
Taxes On Income ($)	Percent of return less 30% ITC		
Depreciation ($)	Percent of rate base		
New Fossil Generation	586 MW in 2016 per PG&E 2010 LTPP, Table PGE-1		
Annual Capital Additions (% of Rate Base)	DMC estimate		5%
Return on Rate Base (%)	2011 GRC Phase 1 Settlement, Table 3-2		8.79%
Production O&M ($)	Production X $5.27 per MWh Fixed and Variable O&M, CEC Comparative Cost of California Central Station Electric Generation, Table 6		
Other Operating Expenses ($)	Percent of production O&M		
Taxes Other Than Income ($)	Percent of production O&M		
Taxes On Income ($)	Percent of return		
Depreciation ($)	Percent of rate base		

Sonoma County CCA Feasibility Study Input Assumptions

IX. Annual Inputs		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
RPS Compliance Resource Categories																							
Overall Renewable Energy Content (%)	DMC estimates per SB1X2	20%	20%	20%	23%	23%	25%	25%	25%	25%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%
Category 1 Minimum	DMC estimates per SB1X2	50%	50%	50%	65%	65%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
Category 2 Maximum	DMC estimates per SB1X2	50%	50%	50%	35%	35%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%	25%
Category 3 Maximum	DMC estimates per SB1X2	25%	25%	25%	15%	15%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
PG&E Renewable Energy Content (%)	DMC estimates	14%	17%	20%	23%	25%	27%	29%	30%	31%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%
GHG Allowance Price ($/Metric Ton)	CPUC Standard Planning Assumptions, 2009 MPR (Synapse Energy Economics Study, July 2008)	$0.00	$0.00	$17.83	$21.08	$24.35	$27.91	$31.49	$35.37	$39.29	$43.52	$47.94	$52.40	$57.21	$62.07	$67.30	$72.59	$78.27	$84.01	$90.17	$96.59	$99.00	$101.48
Natural Gas Prices ($/MMBTU)	EIA Annual Energy Outlook 2011, Electric Power Projections for EMM Region, Western Electricity Coordinating Council/California, Reference Case.	$4.96	$4.92	$5.00	$5.04	$5.14	$5.28	$5.53	$5.81	$6.13	$6.51	$6.92	$7.19	$7.49	$7.83	$8.13	$8.46	$8.86	$9.19	$9.49	$9.79	$10.08	$10.41
PCIA/NSGC - ($/MWh)	Assumes new methodology for 2012; new system generation charge not vintaged.	$20.09	$12.36	$11.78	$14.51	$11.37	$10.54	$7.40	$4.39	$3.02	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
PG&E Generation Rate Annual Escalator (%)																							
Low	DMC estimate		10%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
High	DMC estimate		20%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
PG&E Generation Rate Annual Escalator - Base (%)	Based on DMC projections of revenue requirements for PG&E generation costs.		10%	14%	8%	1%	5%	2%	1%	3%	1%	4%	4%	4%	3%	4%	4%	4%	4%	4%	4%	3%	3%
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec										
Monthly Electric Profile (% of Annual)	Ratios Based on CAISO Day Ahead Market for twelve months ended June, 2011	1.120	1.086	1.143	1.100	1.150	1.107	1.054	1.031	0.819	0.813	0.761	0.815										

Sonoma County CCA Feasibility Study Preliminary Input Assumptions

= local projects

X. Supply Scenario Inputs	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Scenario 1																						
Achieve 33% RPS by 2020	20%	22%	23%	25%	26%	28%	29%	31%	32%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%
PPA: Central Valley PV, 80 MW, 2016																						
PPA: NP-15 Wind, 40 MW, 2016																						
PPA: North Coast Geothermal, 35 MW, 2016																						
Development: Biomass, 15 MW, 2020																						
Buyout: Central Valley PV, 80 MW, 2026																						
Scenario 2																						
Achieve 51% RPS by 2020	33%	35%	37%	39%	41%	43%	45%	47%	49%	51%	51%	51%	51%	51%	51%	51%	51%	51%	51%	51%	51%	51%
PPA: Central Valley PV, 130 MW, 2016																						
PPA: NP-15 Wind, 65 MW, 2016.																						
PPA: North Coast Geothermal, 50 MW, 2016.																						
Development: Biomass, 25 MW, 2020																						
Buyout: Central Valley PV, 130 MW, 2025																						
Scenario 3																						
Achieve 75% RPS by 2020	51%	54%	56%	59%	61%	64%	66%	69%	71%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
PPA: NP-15 Wind, 50 MW, 2016.																						
PPA: North Coast Geothermal, 75 MW, 2016.																						
PPA: Large Commercial Rooftop PV, 25 MW, 2015																						
PPA: Mid Ground-Mount PV, 125 MW, 2017																						
PPA: Small Ground-Mount PV, 35 MW, 2017																						
Development: Biomass, 50 MW, 2020																						
Development: Wind, Sonoma, 25 MW, 2018																						
Buyout: North Coast PV Mid, 115 MW, 2027																						
Scenario 4																						
Achieve 85% RPS by 2020	20%	20%	20%	30%	55%	54%	60%	79%	80%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
PPA: Solar Parabolic Trough, 40 MW, 2020																						
PPA: NP-15 Wind, 100 MW, 2018																						
Development: Geothermal, 95 MW, 2015																						
Development: Biomass Cogeneration, 40 MW, 2014																						
Development: Wind, 45 MW, 2018																						
Development: Rooftop PV, 10 MW, 2013																						
Development: Hydro Pumped Storage, 60 MW, 2017																						
Development: Battery Storage, 12 MW, 2018																						

Appendix C

Economic Development Tables

Appendix C - Economic Development

Scenario 1 – Base Case

The following tables provide project-specific details related to prospective geothermal and biomass generators that have been identified as part of the prospective resource portfolio that would be used to supply Sonoma CCA customers under Scenario 1. All input assumptions, such as construction costs, capacity factor and operation and maintenance as well as others, within this table are based on current data available from the California Energy Commission and the California Public Utilities Commission. All outputs related to the prospective geothermal generator, including local spending totals and annual operating costs, were derived through the use of NREL's JEDI model for natural gas generators, which can be used (after updating pertinent input assumptions) to reasonably approximate the economic impacts related to development and operation of a geothermal generating facility.

Geothermal Generator

North Coast Geothermal PPA (35 MW; 2016)	
Geothermal Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2014
Project Size - Nameplate Capacity (MW)	35
Capacity Factor (Percentage)	94%
Heat Rate (Btu per kWh)	NA
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$3,718
Cost of Fuel ($/mmbtu)	NA
Produced Locally (Percent)	NA
Fixed Operations and Maintenance Cost ($/kW)	$58.38
Variable Operations and Maintenance Cost ($/MWh)	$5.06
Money Value (Dollar Year)	2011
Project Construction Cost	$130,130,000
Local Spending	$43,017,533
Total Annual Operational Expenses	$19,464,715
Direct Operating and Maintenance Costs	$3,501,612
Local Spending	$1,728,897
Other Annual Costs	$15,963,103
Local Spending	$3,100,579
Debt and Equity Payments	$0
Property Taxes	$1,301,300

Local Economic Impacts - 35 MW Geothermal PPA Summary Results			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	145	$19.08	$23.84
Construction and Interconnection Labor	122	$17.04	
Construction Related Services	23	$2.04	
Power Generation and Supply Chain Impacts	115	$7.61	$26.86
Induced Impacts	114	$6.14	$18.93
Total Impacts (Direct, Indirect, Induced)	374	$32.83	$69.63
During operating years (annual)			
Onsite Labor Impacts	2	$0.11	$0.11
Local Revenue and Supply Chain Impacts	15	$1.16	$4.03
Induced Impacts	10	$0.54	$1.66
Total Impacts (Direct, Indirect, Induced)	27	$1.81	$5.80

Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 190 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.

Biomass Generator

Internally Developed Biomass (15 MW; 2020)	
Biomass Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2018
Project Size - Nameplate Capacity (MW)	15
Capacity Factor (Percentage)	85%
Heat Rate (Btu per kWh)	15000
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$3,254
Cost of Fuel ($/mmbtu)	$2.48
Produced Locally (Percent)	50%
Fixed Operations and Maintenance Cost ($/kW)	$99.50
Variable Operations and Maintenance Cost ($/MWh)	$4.47
Money Value (Dollar Year)	2011
Project Construction Cost	$48,810,000
Local Spending	$16,135,294
Total Annual Operational Expenses	$10,485,080
Direct Operating and Maintenance Costs	$6,146,622
Local Spending	$3,390,697
Other Annual Costs	$4,338,458
Local Spending	$7,747,927
Debt and Equity Payments	$3,831,585
Property Taxes	$488,100

Local Economic Impacts - 15MW Internally Developed Biomass Generator Summary Results			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	54	$7.16	$8.94
Construction and Interconnection Labor	46	$6.39	
Construction Related Services	9	$0.76	
Power Generation and Supply Chain Impacts	43	$2.85	$10.07
Induced Impacts	43	$2.30	$7.10
Total Impacts (Direct, Indirect, Induced)	140	$12.31	$26.12
During operating years (annual)			
Onsite Labor Impacts	1	$0.05	$0.05
Local Revenue and Supply Chain Impacts	24	$1.83	$7.37
Induced Impacts	12	$0.62	$1.92
Total Impacts (Direct, Indirect, Induced)	36	$2.50	$9.34
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 70 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.			

Scenario 1 – Reduced Local Economic Benefit Case

As described within DMC's report, a second set of economic development projections was prepared for each supply scenario based on a set of assumptions that would result in reduced economic development benefits for Sonoma County. The following tables reflect reduced economic impacts that would accrue within Sonoma County under Scenario 1.

Geothermal Generator

North Coast Geothermal PPA (35 MW; 2016) - Reduced Econ Impacts	
Geothermal Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2014
Project Size - Nameplate Capacity (MW)	35
Capacity Factor (Percentage)	94%
Heat Rate (Btu per kWh)	7000
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$3,718
Cost of Fuel ($/mmbtu)	$0.00
Produced Locally (Percent)	$0.00
Fixed Operations and Maintenance Cost ($/kW)	$58.38
Variable Operations and Maintenance Cost ($/MWh)	$5.06
Money Value (Dollar Year)	2011
Project Construction Cost	$130,130,000
Local Spending	$10,525,221
Total Annual Operational Expenses	$19,464,715
Direct Operating and Maintenance Costs	$3,501,612
Local Spending	$37,693
Other Annual Costs	$15,963,103
Local Spending	$1,338,993
Debt and Equity Payments	$0
Property Taxes	$1,301,300

Local Economic Impacts - 35 MW Geothermal PPA Summary Results - Reduced Econ Impacts			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	48	$4.77	$7.96
Construction and Interconnection Labor	48	$4.77	
Construction Related Services	0	$0.00	
Power Generation and Supply Chain Impacts	29	$1.93	$6.63
Induced Impacts	26	$1.39	$4.28
Total Impacts (Direct, Indirect, Induced)	104	$8.09	$18.88
During operating years (annual)			
Onsite Labor Impacts	0	$0.03	$0.03
Local Revenue and Supply Chain Impacts	1	$0.06	$1.49
Induced Impacts	5	$0.27	$0.82
Total Impacts (Direct, Indirect, Induced)	6	$0.35	$2.34

Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 50 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.

Biomass Generator

Internally Developed Biomass (15 MW; 2020) - Reduced Econ Impacts	
Biomass Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2018
Project Size - Nameplate Capacity (MW)	15
Capacity Factor (Percentage)	85%
Heat Rate (Btu per kWh)	15000
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$3,254
Cost of Fuel ($/mmbtu)	$2.48
Produced Locally (Percent)	0%
Fixed Operations and Maintenance Cost ($/kW)	$99.50
Variable Operations and Maintenance Cost ($/MWh)	$4.47
Money Value (Dollar Year)	2011
Project Construction Cost	$48,810,000
Local Spending	$6,208,740
Total Annual Operational Expenses	$10,485,080
Direct Operating and Maintenance Costs	$6,146,622
Local Spending	$498,002
Other Annual Costs	$4,338,458
Local Spending	$995,488
Debt and Equity Payments	$0
Property Taxes	$488,100

Local Economic Impacts - 15MW Internally Developed Biomass Generator Summary Results - Reduced Econ Impacts			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	23	$3.12	$3.73
Construction and Interconnection Labor	19	$2.81	
Construction Related Services	3	$0.31	
Power Generation and Supply Chain Impacts	17	$1.08	$3.81
Induced Impacts	16	$0.87	$2.69
Total Impacts (Direct, Indirect, Induced)	56	$5.06	$10.23
During operating years (annual)			
Onsite Labor Impacts	0	$0.02	$0.02
Local Revenue and Supply Chain Impacts	5	$0.33	$1.28
Induced Impacts	3	$0.18	$0.54
Total Impacts (Direct, Indirect, Induced)	8	$0.53	$1.84
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 25 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.			

Scenario 2

The following tables provide project-specific details related to prospective geothermal and biomass generators that have been identified as part of the prospective resource portfolio that would be used to supply Sonoma CCA customers under Scenario 2. All input assumptions, such as construction costs, capacity factor and operation and maintenance as well as others, within this table are based on current data available from the California Energy Commission and the California Public Utilities Commission. All outputs related to the prospective geothermal generator, including local spending totals and annual operating costs, were derived through the use of NREL's JEDI model for natural gas generators, which can be used (after updating pertinent input assumptions) to reasonably approximate the economic impacts related to development and operation of a geothermal generating facility.

Geothermal Generator

North Coast Geothermal PPA (50 MW; 2016)	
Geothermal Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2014
Project Size - Nameplate Capacity (MW)	50
Capacity Factor (Percentage)	94%
Heat Rate (Btu per kWh)	NA
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$3,718
Cost of Fuel ($/mmbtu)	NA
Produced Locally (Percent)	NA
Fixed Operations and Maintenance Cost ($/kW)	$58.38
Variable Operations and Maintenance Cost ($/MWh)	$5.06
Money Value (Dollar Year)	2011
Project Construction Cost	$185,900,000
Local Spending	$61,453,619
Total Annual Operational Expenses	$27,806,736
Direct Operating and Maintenance Costs	$5,002,303
Local Spending	$2,469,853
Other Annual Costs	$22,804,433
Local Spending	$4,429,398
Debt and Equity Payments	$0
Property Taxes	$1,859,000

Local Economic Impacts - 50 MW Geothermal PPA Summary Results	Jobs	Earnings	Output
During construction period			
Project Development and Onsite Labor Impacts	207	$27.25	$34.06
Construction and Interconnection Labor	174	$24.34	
Construction Related Services	33	$2.91	
Power Generation and Supply Chain Impacts	165	$10.87	$38.37
Induced Impacts	163	$8.77	$27.04
Total Impacts (Direct, Indirect, Induced)	534	$46.90	$99.47
During operating years (annual)			
Onsite Labor Impacts	3	$0.16	$0.16
Local Revenue and Supply Chain Impacts	22	$1.65	$5.75
Induced Impacts	14	$0.77	$2.38
Total Impacts (Direct, Indirect, Induced)	39	$2.58	$8.29
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 270 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.			

Biomass Generator

Internally Developed Biomass (25 MW; 2020)	
Biomass Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2018
Project Size - Nameplate Capacity (MW)	25
Capacity Factor (Percentage)	85%
Heat Rate (Btu per kWh)	15000
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$3,254
Cost of Fuel ($/mmbtu)	$2.48
Produced Locally (Percent)	50%
Fixed Operations and Maintenance Cost ($/kW)	$99.50
Variable Operations and Maintenance Cost ($/MWh)	$4.47
Money Value (Dollar Year)	2011
Project Construction Cost	$81,350,000
Local Spending	$26,892,157
Total Annual Operational Expenses	$17,475,133
Direct Operating and Maintenance Costs	$10,244,371
Local Spending	$5,651,161
Other Annual Costs	$7,230,763
Local Spending	$12,913,212
Debt and Equity Payments	$6,385,975
Property Taxes	$813,500

Local Economic Impacts - 25MW Internally Developed Biomass Generator Summary Results			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	90	$11.93	$14.91
Construction and Interconnection Labor	76	$10.65	
Construction Related Services	14	$1.27	
Power Generation and Supply Chain Impacts	72	$4.76	$16.79
Induced Impacts	71	$3.84	$11.83
Total Impacts (Direct, Indirect, Induced)	234	$20.52	$43.53
During operating years (annual)			
Onsite Labor Impacts	1	$0.08	$0.08
Local Revenue and Supply Chain Impacts	40	$3.04	$12.29
Induced Impacts	19	$1.04	$3.21
Total Impacts (Direct, Indirect, Induced)	61	$4.16	$15.57
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 120 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.			

Scenario 2 – Reduced Local Economic Benefit Case

As described within DMC's report, a second set of economic development projections was prepared for each supply scenario based on a set of assumptions that would result in reduced economic development benefits for Sonoma County. The following tables reflect reduced economic impacts that would accrue within Sonoma County under Scenario 2.

Geothermal Generator

North Coast Geothermal PPA (50 MW; 2016) - Reduced Econ Impacts	
Geothermal Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2014
Project Size - Nameplate Capacity (MW)	50
Capacity Factor (Percentage)	94%
Heat Rate (Btu per kWh)	7000
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$3,718
Cost of Fuel ($/mmbtu)	$0.00
Produced Locally (Percent)	$0.00
Fixed Operations and Maintenance Cost ($/kW)	$58.38
Variable Operations and Maintenance Cost ($/MWh)	$5.06
Money Value (Dollar Year)	2011
Project Construction Cost	$185,900,000
Local Spending	$15,036,029
Total Annual Operational Expenses	$27,806,736
Direct Operating and Maintenance Costs	$5,002,303
Local Spending	$53,848
Other Annual Costs	$22,804,433
Local Spending	$1,912,848
Debt and Equity Payments	$0
Property Taxes	$1,859,000

Local Economic Impacts - 50 MW Geothermal PPA Summary Results - Reduced Econ Impacts			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	69	$6.81	$11.37
Construction and Interconnection Labor	69	$6.81	
Construction Related Services	0	$0.00	
Power Generation and Supply Chain Impacts	42	$2.76	$9.48
Induced Impacts	37	$1.98	$6.12
Total Impacts (Direct, Indirect, Induced)	148	$11.56	$26.96
During operating years (annual)			
Onsite Labor Impacts	1	$0.04	$0.04
Local Revenue and Supply Chain Impacts	1	$0.08	$2.12
Induced Impacts	7	$0.38	$1.18
Total Impacts (Direct, Indirect, Induced)	9	$0.50	$3.34
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 70 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.			

Biomass Generator

Internally Developed Biomass (25 MW; 2020) - Reduced Econ Impacts	
Biomass Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2018
Project Size - Nameplate Capacity (MW)	25
Capacity Factor (Percentage)	85%
Heat Rate (Btu per kWh)	15000
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$3,254
Cost of Fuel ($/mmbtu)	$2.48
Produced Locally (Percent)	$0.00
Fixed Operations and Maintenance Cost ($/kW)	$99.50
Variable Operations and Maintenance Cost ($/MWh)	$4.47
Money Value (Dollar Year)	2011
Project Construction Cost	$81,350,000
Local Spending	$10,347,899
Total Annual Operational Expenses	$17,475,133
Direct Operating and Maintenance Costs	$10,244,371
Local Spending	$830,003
Other Annual Costs	$7,230,763
Local Spending	$1,659,147
Debt and Equity Payments	$0
Property Taxes	$813,500

Local Economic Impacts - 25MW Internally Developed Biomass Generator Summary Results - Reduced Econ Impacts			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	38	$5.19	$6.22
Construction and Interconnection Labor	32	$4.68	
Construction Related Services	6	$0.51	
Power Generation and Supply Chain Impacts	28	$1.79	$6.35
Induced Impacts	27	$1.45	$4.48
Total Impacts (Direct, Indirect, Induced)	93	$8.44	$17.06
During operating years (annual)			
Onsite Labor Impacts	1	$0.04	$0.04
Local Revenue and Supply Chain Impacts	8	$0.55	$2.13
Induced Impacts	5	$0.29	$0.90
Total Impacts (Direct, Indirect, Induced)	14	$0.89	$3.07
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 50 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.			

Scenario 3

The following tables provide project-specific details related to prospective geothermal, biomass, photovoltaic solar and wind generators that have been identified as part of the prospective resource portfolio that would be used to supply Sonoma CCA customers under Scenario 3. All input assumptions, such as construction costs, capacity factor and operation and maintenance as well as others, within this table are based on current data available from the California Energy Commission and the California Public Utilities Commission. All outputs related to the prospective geothermal generator, including local spending totals and annual operating costs, were derived through the use of NREL's JEDI model for natural gas generators, which can be used (after updating pertinent input assumptions) to reasonably approximate the economic impacts related to development and operation of a geothermal generating facility.

Geothermal Generator

North Coast Geothermal PPA (75 MW; 2016)	
Geothermal Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2014
Project Size - Nameplate Capacity (MW)	75
Capacity Factor (Percentage)	94%
Heat Rate (Btu per kWh)	NA
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$3,718
Cost of Fuel ($/mmbtu)	NA
Produced Locally (Percent)	NA
Fixed Operations and Maintenance Cost ($/kW)	$58.38
Variable Operations and Maintenance Cost ($/MWh)	$5.06
Money Value (Dollar Year)	2011
Project Construction Cost	$278,850,000
Local Spending	$92,180,429
Total Annual Operational Expenses	$41,710,104
Direct Operating and Maintenance Costs	$7,503,455
Local Spending	$3,704,779
Other Annual Costs	$34,206,649
Local Spending	$6,644,097
Debt and Equity Payments	$0
Property Taxes	$2,788,500

Local Economic Impacts - 75 MW Geothermal PPA Summary Results			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	310	$40.88	$51.10
Construction and Interconnection Labor	261	$36.52	
Construction Related Services	49	$4.37	
Power Generation and Supply Chain Impacts	247	$16.31	$57.56
Induced Impacts	244	$13.16	$40.56
Total Impacts (Direct, Indirect, Induced)	801	$70.35	$149.21
During operating years (annual)			
Onsite Labor Impacts	4	$0.24	$0.24
Local Revenue and Supply Chain Impacts	33	$2.48	$8.63
Induced Impacts	21	$1.16	$3.56
Total Impacts (Direct, Indirect, Induced)	58	$3.87	$12.43

Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 400 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.

Biomass Generator

Internally Developed Biomass (50 MW; 2020)	
Biomass Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2018
Project Size - Nameplate Capacity (MW)	50
Capacity Factor (Percentage)	85%
Heat Rate (Btu per kWh)	15000
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$3,254
Cost of Fuel ($/mmbtu)	$2.48
Produced Locally (Percent)	50%
Fixed Operations and Maintenance Cost ($/kW)	$99.50
Variable Operations and Maintenance Cost ($/MWh)	$4.47
Money Value (Dollar Year)	2011
Project Construction Cost	$162,700,000
Local Spending	$53,784,313
Total Annual Operational Expenses	$34,950,267
Direct Operating and Maintenance Costs	$20,488,741
Local Spending	$11,302,323
Other Annual Costs	$14,461,526
Local Spending	$25,826,424
Debt and Equity Payments	$12,771,950
Property Taxes	$1,627,000

Local Economic Impacts - 50 MW Internally Developed Biomass Generator Summary Results			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	181	$23.85	$29.81
Construction and Interconnection Labor	152	$21.31	
Construction Related Services	29	$2.55	
Power Generation and Supply Chain Impacts	144	$9.52	$33.58
Induced Impacts	142	$7.68	$23.66
Total Impacts (Direct, Indirect, Induced)	467	$41.05	$87.06
During operating years (annual)			
Onsite Labor Impacts	3	$0.16	$0.16
Local Revenue and Supply Chain Impacts	80	$6.09	$24.57
Induced Impacts	39	$2.08	$6.41
Total Impacts (Direct, Indirect, Induced)	121	$8.33	$31.15
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 230 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.			

Photovoltaic Solar Generators

Large Commercial PV PPA (25 MW; 2015)	
Photovoltaic - Project Data Summary	
Project Location	**CALIFORNIA**
Year of Construction or Installation	2015
Average System Size - DC Nameplate Capacity (KW)	1000
Number of Systems Installed	25.00
Total Project Size - DC Nameplate Capacity (KW)	25,000
System Type	Large Commercial
Base Installed System Cost ($/KWDC)	$4,200
Annual Direct Operations and Maintenance Cost ($/kW)	$20.00
Money Value - Current or Constant (Dollar Year)	2,011
Project Construction or Installation Cost	$ 111,616,187
Local Spending	$ 38,369,345
Total Annual Operational Expenses	$ 12,680,000
Direct Operating and Maintenance Costs	$ 500,000
Local Spending	$ 342,746
Other Annual Costs	$ 12,180,000
Local Spending	$ 9,135,000
Debt Payments	$ 9,135,000
Property Taxes	$ 1,050,000

Local Economic Impacts - 25 MW Large Commercial Solar PV PPA Summary Results			
During construction and installation period	**Jobs**	**Earnings**	**Output**
Project Development and Onsite Labor Impacts	190.1	$12.7	$19.5
Construction and Installation Labor	99.6	$7.8	$0.0
Construction and Installation Related Services	90.4	$4.8	$0.0
Module and Supply Chain Impacts	182.1	$9.8	$26.9
Induced Impacts	101.9	$5.7	$17.4
Total Impacts	**474.0**	**$28.2**	**$63.9**
During operating years			
Onsite Labor Impacts			
PV Project Labor Only	4.2	$0.3	$0.3
Local Revenue and Supply Chain Impacts	15.7	$1.0	$4.2
Induced Impacts	5.1	$0.3	$0.9
Total Impacts	**25.0**	**$1.5**	**$5.4**
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction and operating period jobs are full-time equivalent for one year (1 FTE = 2,080 hours). Economic impacts "During operating years" represent annual impacts that occur from system/plant operations/expenditures. Totals may not add up due to independent rounding.			

PV PPA (125 MW Mid Ground Mount; 2015)	
Photovoltaic - Project Data Summary	
Project Location	**CALIFORNIA**
Year of Construction or Installation	2015
Average System Size - DC Nameplate Capacity (KW)	1,000
Number of Systems Installed	125
Total Project Size - DC Nameplate Capacity (KW)	125,000
System Type	Large Commercial
Base Installed System Cost ($/KWDC)	$3,900
Annual Direct Operations and Maintenance Cost ($/kW)	$23.84
Money Value - Current or Constant (Dollar Year)	2,011
Project Construction or Installation Cost	$ 518,218,011
Local Spending	$ 65,086,352
Total Annual Operational Expenses	$ 59,530,000
Direct Operating and Maintenance Costs	$ 2,980,000
Local Spending	$ 1,021,384
Other Annual Costs	$ 56,550,000
Local Spending	$ -
Debt Payments	$ -
Property Taxes	$ 4,875,000

Local Economic Impacts - 125 MW Solar PV PPA Summary Results			
During construction and installation period	**Jobs**	**Earnings**	**Output**
Project Development and Onsite Labor Impacts	461.7	$33.4	$45.2
Construction and Installation Labor	308.4	$24.3	
Construction and Installation Related Services	153.2	$9.2	
Module and Supply Chain Impacts	303.4	$17.1	$47.2
Induced Impacts	163.8	$9.1	$28.0
Total Impacts	**928.9**	**$59.6**	**$120.4**
During operating years			
Onsite Labor Impacts			
PV Project Labor Only	12.5	$0.8	$0.8
Local Revenue and Supply Chain Impacts	2.8	$0.2	$0.6
Induced Impacts	1.9	$0.1	$0.3
Total Impacts	**17.2**	**$1.1**	**$1.7**
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction and operating period jobs are full-time equivalent for one year (1 FTE = 2,080 hours). Economic impacts "During operating years" represent annual impacts that occur from system/plant operations/expenditures. Totals may not add up due to independent rounding.			

PV PPA (35 MW Small Ground Mount; 2015)	
Photovoltaic - Project Data Summary	
Project Location	**CALIFORNIA**
Year of Construction or Installation	2015
Average System Size - DC Nameplate Capacity (KW)	250
Number of Systems Installed	140
Total Project Size - DC Nameplate Capacity (KW)	35,000
System Type	Large Commercial
Base Installed System Cost ($/KWDC)	$3,900
Annual Direct Operations and Maintenance Cost ($/kW)	$23.84
Money Value - Current or Constant (Dollar Year)	2,011
Project Construction or Installation Cost	$ 145,101,043
Local Spending	$ 18,224,178
Total Annual Operational Expenses	$ 16,668,400
Direct Operating and Maintenance Costs	$ 834,400
Local Spending	$ 285,988
Other Annual Costs	$ 15,834,000
Local Spending	$ -
Debt Payments	$ -
Property Taxes	$1,365,000

Local Economic Impacts - 35 MW Solar PV PPA Summary Results			
During construction and installation period	**Jobs**	**Earnings**	**Output**
Project Development and Onsite Labor Impacts	129.3	$9.4	$12.7
Construction and Installation Labor	86.4	$6.8	
Construction and Installation Related Services	42.9	$2.6	
Module and Supply Chain Impacts	85.0	$4.8	$13.2
Induced Impacts	45.9	$2.5	$7.9
Total Impacts	**260.1**	**$16.7**	**$33.7**
During operating years			
Onsite Labor Impacts			
PV Project Labor Only	3.5	$0.2	$0.2
Local Revenue and Supply Chain Impacts	0.8	$0.1	$0.2
Induced Impacts	0.5	$0.0	$0.1
Total Impacts	**4.8**	**$0.3**	**$0.5**
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction and operating period jobs are full-time equivalent for one year (1 FTE = 2,080 hours). Economic impacts "During operating years" represent annual impacts that occur from system/plant operations/expenditures. Totals may not add up due to independent rounding.			

Wind Generator

Internally Developed Wind (25 MW; 2018)	
Wind - Project Data Summary	
Project Location	**CALIFORNIA**
Year of Construction	2018
Total Project Size - Nameplate Capacity (MW)	25
Number of Projects (included in total)	100%
Turbine Size (KW)	2000
Number of Turbines	13
Installed Project Cost ($/KW)	$1,995
Annual Direct O&M Cost ($/KW) + Variable O&M	$15.34
Money Value (Dollar Year)	2,011
Installed Project Cost	$49,884,764
Local Spending	$9,949,715
Total Annual Operational Expenses	4518794
Direct Operating and Maintenance Costs	$383,500
Local Spending	$267,537
Other Annual Costs	$4,135,294
Local Spending	$4,135,294
Debt and Equity Payments	$3,915,954
Property Taxes	$141,340
Land Lease	$78,000

Local Economic Impacts - 25 MW Internally Developed Wind Generator Summary Results			
During construction period	**Jobs**	**Earnings**	**Output**
Project Development and Onsite Labor Impacts	49	$3.73	$3.90
Construction and Interconnection Labor	47	$3.54	
Construction Related Services	2	$0.20	
Turbine and Supply Chain Impacts	59	$4.00	$10.95
Induced Impacts	24	$1.32	$4.06
Total Impacts	**131**	**$9.05**	**$18.92**
During operating years (annual)			
Onsite Labor Impacts	2	$0.17	$0.17
Local Revenue and Supply Chain Impacts	5	$0.29	$2.57
Induced Impacts	4	$0.20	$0.60
Total Impacts	**10**	**$0.65**	**$3.35**
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction and operating jobs are full-time equivalent for a period of one year (1 FTE = 2,080 hours). Wind farm workers includes field technicians, administration and management. Economic impacts "During operating years" represent impacts that occur from wind farm operations/expenditures. The analysis does not include impacts associated with spending of wind farm "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding. Results are based on model default values.			

Scenario 3 – Reduced Local Economic Benefit Case

As described within DMC's report, a second set of economic development projections was prepared for each supply scenario based on a set of assumptions that would result in reduced economic development benefits for Sonoma County. The following tables reflect reduced economic impacts that would accrue within Sonoma County under Scenario 3.

Geothermal Generator

North Coast Geothermal PPA (75 MW; 2016) - Reduced Econ Impacts	
Geothermal Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2014
Project Size - Nameplate Capacity (MW)	75
Capacity Factor (Percentage)	94%
Heat Rate (Btu per kWh)	7000
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$3,718
Cost of Fuel ($/mmbtu)	$0.00
Produced Locally (Percent)	$0.00
Fixed Operations and Maintenance Cost ($/kW)	$58.38
Variable Operations and Maintenance Cost ($/MWh)	$5.06
Money Value (Dollar Year)	2011
Project Construction Cost	$278,850,000
Local Spending	$22,554,044
Total Annual Operational Expenses	$41,710,104
Direct Operating and Maintenance Costs	$7,503,455
Local Spending	$80,772
Other Annual Costs	$34,206,649
Local Spending	$2,869,272
Debt and Equity Payments	$0
Property Taxes	$2,788,500

Local Economic Impacts - 75 MW Geothermal PPA Summary Results - Reduced Econ Impacts			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	104	$10.22	$17.06
Construction and Interconnection Labor	104	$10.22	
Construction Related Services	0	$0.00	
Power Generation and Supply Chain Impacts	63	$4.14	$14.21
Induced Impacts	55	$2.98	$9.17
Total Impacts (Direct, Indirect, Induced)	222	$17.33	$40.45
During operating years (annual)			
Onsite Labor Impacts	1	$0.06	$0.06
Local Revenue and Supply Chain Impacts	2	$0.12	$3.18
Induced Impacts	11	$0.57	$1.77
Total Impacts (Direct, Indirect, Induced)	13	$0.76	$5.01

Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 110 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.

Biomass Generator

Internally Developed Biomass (50 MW; 2020) - Reduced Econ Impacts	
Biomass Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2018
Project Size - Nameplate Capacity (MW)	50
Capacity Factor (Percentage)	85%
Heat Rate (Btu per kWh)	15000
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$3,254
Cost of Fuel ($/mmbtu)	$2.48
Produced Locally (Percent)	0%
Fixed Operations and Maintenance Cost ($/kW)	$99.50
Variable Operations and Maintenance Cost ($/MWh)	$4.47
Money Value (Dollar Year)	2011
Project Construction Cost	$162,700,000
Local Spending	$20,695,799
Total Annual Operational Expenses	$34,950,267
Direct Operating and Maintenance Costs	$20,488,741
Local Spending	$1,660,005
Other Annual Costs	$14,461,526
Local Spending	$3,318,293
Debt and Equity Payments	$0
Property Taxes	$1,627,000

Local Economic Impacts - 50 MW Internally Developed Biomass Generator Summary Results - Reduced Econ Impacts			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	75	$10.39	$12.44
Construction and Interconnection Labor	64	$9.37	
Construction Related Services	11	$1.02	
Power Generation and Supply Chain Impacts	56	$3.59	$12.71
Induced Impacts	54	$2.91	$8.97
Total Impacts (Direct, Indirect, Induced)	186	$16.88	$34.12
During operating years (annual)			
Onsite Labor Impacts	1	$0.08	$0.08
Local Revenue and Supply Chain Impacts	16	$1.11	$4.25
Induced Impacts	11	$0.59	$1.80
Total Impacts (Direct, Indirect, Induced)	28	$1.77	$6.14

Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 90 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.

Photovoltaic Solar Generators

Large Commercial PV PPA (25 MW; 2015) - Reduced Econ Impacts	
Photovoltaic - Project Data Summary	
Project Location	**CALIFORNIA**
Year of Construction or Installation	2015
Average System Size - DC Nameplate Capacity (KW)	1000
Number of Systems Installed	25
Total Project Size - DC Nameplate Capacity (KW)	25000
System Type	Large Commercial
Base Installed System Cost ($/KWDC)	$4,200
Annual Direct Operations and Maintenance Cost ($/kW)	$20.00
Money Value - Current or Constant (Dollar Year)	2,011
Project Construction or Installation Cost	$ 111,616,187
Local Spending	$ 24,563,350
Total Annual Operational Expenses	$ 12,680,000
Direct Operating and Maintenance Costs	$ 500,000
Local Spending	$ 171,373
Other Annual Costs	$ 12,180,000
Local Spending	$ 6,090,000
Debt Payments	$ 6,090,000
Property Taxes	$ 1,050,000

Local Economic Impacts - 25 MW Large Commercial Solar PV PPA Summary Results - Reduced Econ Impacts			
During construction and installation period	**Jobs**	**Earnings**	**Output**
Project Development and Onsite Labor Impacts	115.5	$8.0	$11.7
Construction and Installation Labor	66.4	$5.2	
Construction and Installation Related Services	49.1	$2.8	
Module and Supply Chain Impacts	97.2	$5.3	$14.7
Induced Impacts	68.5	$3.8	$11.7
Total Impacts	**281.2**	**$17.1**	**$38.2**
During operating years			
Onsite Labor Impacts			
PV Project Labor Only	2.1	$0.1	$0.1
Local Revenue and Supply Chain Impacts	10.3	$0.6	$2.8
Induced Impacts	3.3	$0.2	$0.6
Total Impacts	**15.7**	**$0.9**	**$3.5**
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction and operating period jobs are full-time equivalent for one year (1 FTE = 2,080 hours). Economic impacts "During operating years" represent annual impacts that occur from system/plant operations/expenditures. Totals may not add up due to independent rounding.			

PV PPA (125 MW Mid Ground Mount; 2015) - Reduced Econ Impacts	
Photovoltaic - Project Data Summary	
Project Location	**CALIFORNIA**
Year of Construction or Installation	2015
Average System Size - DC Nameplate Capacity (KW)	1,000
Number of Systems Installed	125
Total Project Size - DC Nameplate Capacity (KW)	125,000
System Type	Large Commercial
Base Installed System Cost ($/KWDC)	$3,900
Annual Direct Operations and Maintenance Cost ($/kW)	$23.84
Money Value - Current or Constant (Dollar Year)	2,011
Project Construction or Installation Cost	$ 518,218,011
Local Spending	$ 30,424,547
Total Annual Operational Expenses	$ 59,530,000
Direct Operating and Maintenance Costs	$ 2,980,000
Local Spending	$ 497,954
Other Annual Costs	$ 56,550,000
Local Spending	$ -
Debt Payments	$ -
Property Taxes	$ 4,875,000

Local Economic Impacts - 125 MW Solar PV PPA Summary Results - Reduced Econ Impacts			
During construction and installation period	**Jobs**	**Earnings**	**Output**
Project Development and Onsite Labor Impacts	223.4	$16.3	$21.7
Construction and Installation Labor	154.2	$12.1	
Construction and Installation Related Services	69.2	$4.2	
Module and Supply Chain Impacts	134.3	$7.6	$21.0
Induced Impacts	77.3	$4.3	$13.2
Total Impacts	**434.9**	**$28.2**	**$55.9**
During operating years			
Onsite Labor Impacts			
PV Project Labor Only	6.2	$0.4	$0.4
Local Revenue and Supply Chain Impacts	1.3	$0.1	$0.3
Induced Impacts	0.9	$0.1	$0.2
Total Impacts	**8.5**	**$0.6**	**$0.8**
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction and operating period jobs are full-time equivalent for one year (1 FTE = 2,080 hours). Economic impacts "During operating years" represent annual impacts that occur from system/plant operations/expenditures. Totals may not add up due to independent rounding.			

PV PPA (35 MW Small Ground Mount; 2015) - Reduced Econ Impacts	
Photovoltaic - Project Data Summary	
Project Location	**CALIFORNIA**
Year of Construction or Installation	2015
Average System Size - DC Nameplate Capacity (KW)	250
Number of Systems Installed	140
Total Project Size - DC Nameplate Capacity (KW)	35,000
System Type	Large Commercial
Base Installed System Cost ($/KWDC)	$3,900
Annual Direct Operations and Maintenance Cost ($/kW)	$23.84
Money Value - Current or Constant (Dollar Year)	2,011
Project Construction or Installation Cost	$145,101,043.13
Local Spending	$8,518,873.07
Total Annual Operational Expenses	16668400
Direct Operating and Maintenance Costs	$834,400
Local Spending	$139,427
Other Annual Costs	$15,834,000
Local Spending	$0
Debt Payments	$0
Property Taxes	$1,365,000

Local Economic Impacts - 35 MW Solar PV PPA Summary Results - Reduced Econ Impacts			
During construction and installation period	**Jobs**	**Earnings**	**Output**
Project Development and Onsite Labor Impacts	62.5	$4.6	$6.1
Construction and Installation Labor	43.2	$3.4	
Construction and Installation Related Services	19.4	$1.2	
Module and Supply Chain Impacts	37.6	$2.1	$5.9
Induced Impacts	21.6	$1.2	$3.7
Total Impacts	**121.8**	**$7.9**	**$15.6**
During operating years			
Onsite Labor Impacts			
PV Project Labor Only	1.7	$0.1	$0.1
Local Revenue and Supply Chain Impacts	0.4	$0.0	$0.1
Induced Impacts	0.3	$0.0	$0.0
Total Impacts	**2.4**	**$0.2**	**$0.2**
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction and operating period jobs are full-time equivalent for one year (1 FTE = 2,080 hours). Economic impacts "During operating years" represent annual impacts that occur from system/plant operations/expenditures. Totals may not add up due to independent rounding.			

Wind Generator

Internally Developed Wind (25 MW; 2018) - Reduced Econ Impacts	
Wind - Project Data Summary	
Project Location	**CALIFORNIA**
Year of Construction	2018
Total Project Size - Nameplate Capacity (MW)	25
Number of Projects (included in total)	100%
Turbine Size (KW)	2000
Number of Turbines	13
Installed Project Cost ($/KW)	$1,995
Annual Direct O&M Cost ($/KW) + Variable O&M	$15.34
Money Value (Dollar Year)	2,011
Installed Project Cost	$49,884,764
Local Spending	$5,948,512
Total Annual Operational Expenses	4518794
Direct Operating and Maintenance Costs	$383,500
Local Spending	$190,895
Other Annual Costs	$4,135,294
Local Spending	$4,135,294
Debt and Equity Payments	$3,915,954
Property Taxes	$141,340
Land Lease	$78,000

Local Economic Impacts - 25 MW Internally Developed Wind Generator Summary Results - Reduced Econ Impacts			
During construction period	**Jobs**	**Earnings**	**Output**
Project Development and Onsite Labor Impacts	33	$2.46	$2.55
Construction and Interconnection Labor	32	$2.36	
Construction Related Services	1	$0.10	
Turbine and Supply Chain Impacts	34	$2.35	$6.37
Induced Impacts	14	$0.80	$2.45
Total Impacts	**82**	**$5.61**	**$11.37**
During operating years (annual)			
Onsite Labor Impacts	2	$0.13	$0.13
Local Revenue and Supply Chain Impacts	4	$0.27	$2.49
Induced Impacts	3	$0.19	$0.58
Total Impacts	**9**	**$0.58**	**$3.19**
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction and operating jobs are full-time equivalent for a period of one year (1 FTE = 2,080 hours). Wind farm workers includes field technicians, administration and management. Economic impacts "During operating years" represent impacts that occur from wind farm operations/expenditures. The analysis does not include impacts associated with spending of wind farm "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding. Results are based on model default values.			

Scenario 4

The following tables provide project-specific details related to prospective geothermal, biomass, photovoltaic solar, pumped storage, battery storage and wind generators that have been identified as part of the prospective resource portfolio that would be used to supply Sonoma CCA customers under Scenario 4. All input assumptions, such as construction costs, capacity factor and operation and maintenance as well as others, within this table are based on current data available from the California Energy Commission and the California Public Utilities Commission as well as certain assumptions provided by Sonoma's Climate Protection Campaign and the CCA Steering Committee. All outputs for geothermal, pumped storage and battery storage development opportunities, including local spending totals and annual operating costs, were derived through the use of NREL's JEDI model for natural gas generators, which can be used (after updating pertinent input assumptions) to reasonably approximate the economic impacts related to development and operation of the aforementioned generating facility.

Geothermal Generator

Internally Developed Geothermal (95 MW; 2015)	
Geothermal Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2013
Project Size - Nameplate Capacity (MW)	95
Capacity Factor (Percentage)	94%
Heat Rate (Btu per kWh)	NA
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$3,718
Cost of Fuel ($/mmbtu)	NA
Produced Locally (Percent)	NA
Fixed Operations and Maintenance Cost ($/kW)	$58.38
Variable Operations and Maintenance Cost ($/MWh)	$5.06
Money Value (Dollar Year)	2011
Project Construction Cost	$353,210,000
Local Spending	$116,761,876
Total Annual Operational Expenses	$40,858,979
Direct Operating and Maintenance Costs	$9,504,376
Local Spending	$6,030,345
Other Annual Costs	$31,354,603
Local Spending	$9,753,480
Debt and Equity Payments	$0
Property Taxes	$3,532,100

Local Economic Impacts - 95 MW Internally Developed Geothermal Generator Summary Results			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	393	$51.78	$64.72
Construction and Interconnection Labor	331	$46.25	
Construction Related Services	62	$5.53	
Power Generation and Supply Chain Impacts	313	$20.66	$72.91
Induced Impacts	309	$16.67	$51.37
Total Impacts (Direct, Indirect, Induced)	1,015	$89.11	$189.00
During operating years (annual)			
Onsite Labor Impacts	5	$0.30	$0.30
Local Revenue and Supply Chain Impacts	57	$3.87	$12.86
Induced Impacts	31	$1.64	$5.07
Total Impacts (Direct, Indirect, Induced)	92	$5.82	$18.23
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 510 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.			

Biomass Cogeneration Projects (10 x 4MW)

Internally Developed Biomass Cogeneration (40 MW; 2014)	
Biomass Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2012
Project Size - Nameplate Capacity (MW)	40
Capacity Factor (Percentage)	85%
Heat Rate (Btu per kWh)	10000
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$3,000
Cost of Fuel ($/mmbtu)	$0.00
Produced Locally (Percent)	50%
Fixed Operations and Maintenance Cost ($/kW)	$0.00
Variable Operations and Maintenance Cost ($/MWh)	$42.00
Money Value (Dollar Year)	2011
Project Construction Cost	$120,000,000
Local Spending	$39,668,824
Total Annual Operational Expenses	$23,288,234
Direct Operating and Maintenance Costs	$12,509,280
Local Spending	$6,891,462
Other Annual Costs	$10,778,954
Local Spending	$17,829,371
Debt and Equity Payments	$9,420,000
Property Taxes	$1,200,000

Local Economic Impacts - 40 MW Internally Developed Biomass Cogeneration Generator Summary Results			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	133	$17.59	$21.99
Construction and Interconnection Labor	112	$15.71	
Construction Related Services	21	$1.88	
Power Generation and Supply Chain Impacts	106	$7.02	$24.77
Induced Impacts	105	$5.66	$17.45
Total Impacts (Direct, Indirect, Induced)	345	$30.27	$64.21
During operating years (annual)			
Onsite Labor Impacts	2	$0.13	$0.13
Local Revenue and Supply Chain Impacts	76	$4.00	$16.34
Induced Impacts	27	$1.45	$4.47
Total Impacts (Direct, Indirect, Induced)	105	$5.58	$20.94
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 170 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.			

Residential Photovoltaic Solar Installations

Residential PV Installation (10 MW; 2015)	
Photovoltaic - Project Data Summary	
Project Location	**CALIFORNIA**
Year of Construction or Installation	2013
Average System Size - DC Nameplate Capacity (KW)	5
Number of Systems Installed	2,000
Total Project Size - DC Nameplate Capacity (KW)	10000
System Type	sidential Retrofit
Base Installed System Cost ($/KWDC)	$4,500
Annual Direct Operations and Maintenance Cost ($/kW)	$20.00
Money Value - Current or Constant (Dollar Year)	$2,011.00
Project Construction or Installation Cost	$47,563,119.23
Local Spending	$19,048,377.98
Total Annual Operational Expenses	5420000
Direct Operating and Maintenance Costs	$200,000
Local Spending	$128,712
Other Annual Costs	$5,220,000
Local Spending	$4,390,631
Debt Payments	$3,915,000
Property Taxes	$475,631

Local Economic Impacts - 10 MW Residential Solar PV Installations Summary Results			
During construction and installation period	**Jobs**	**Earnings**	**Output**
Project Development and Onsite Labor Impacts	90.5	$5.8	$9.8
Construction and Installation Labor	37.6	$3.0	$0.0
Construction and Installation Related Services	53.0	$2.8	$0.0
Module and Supply Chain Impacts	99.4	$5.2	$14.2
Induced Impacts	49.7	$2.8	$8.5
Total Impacts	**239.7**	**$13.7**	**$32.5**
During operating years			
Onsite Labor Impacts			
PV Project Labor Only	1.5	$0.1	$0.1
Local Revenue and Supply Chain Impacts	6.7	$0.4	$1.8
Induced Impacts	2.2	$0.1	$0.4
Total Impacts	**10.4**	**$0.6**	**$2.3**

Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction and operating period jobs are full-time equivalent for one year (1 FTE = 2,080 hours). Economic impacts "During operating years" represent annual impacts that occur from system/plant operations/expenditures. Totals may not add up due to independent rounding.

Pumped Storage Generator

Internally Developed Pumped Storage (60 MW; 2017)	
Biomass Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2015
Project Size - Nameplate Capacity (MW)	60
Capacity Factor (Percentage)	25%
Heat Rate (Btu per kWh)	0
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$1,500
Cost of Fuel ($/mmbtu)	$0.00
Produced Locally (Percent)	100%
Fixed Operations and Maintenance Cost ($/kW)	$0.00
Variable Operations and Maintenance Cost ($/MWh)	$101.00
Money Value (Dollar Year)	2011
Project Construction Cost	$90,000,000
Local Spending	$32,398,676
Total Annual Operational Expenses	$21,404,518
Direct Operating and Maintenance Costs	$13,271,400
Local Spending	$10,447,684
Other Annual Costs	$8,133,118
Local Spending	$18,748,920
Debt and Equity Payments	$7,065,000
Property Taxes	$900,000

Local Economic Impacts - 60 MW Internally Developed Pumped Storage Summary Results			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	116	$15.80	$19.14
Construction and Interconnection Labor	84	$12.98	
Construction Related Services	32	$2.82	
Power Generation and Supply Chain Impacts	87	$5.73	$19.84
Induced Impacts	87	$4.68	$14.43
Total Impacts (Direct, Indirect, Induced)	290	$26.21	$53.41
During operating years (annual)			
Onsite Labor Impacts	3	$0.19	$0.19
Local Revenue and Supply Chain Impacts	112	$5.77	$19.97
Induced Impacts	33	$1.79	$5.50
Total Impacts (Direct, Indirect, Induced)	148	$7.75	$25.67

Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 150 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.

Battery Storage Generator

Internally Developed Battery Storage (12 MW; 2018)	
Biomass Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2016
Project Size - Nameplate Capacity (MW)	12
Capacity Factor (Percentage)	25%
Heat Rate (Btu per kWh)	0
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$2,500
Cost of Fuel ($/mmbtu)	$0.00
Produced Locally (Percent)	$0.50
Fixed Operations and Maintenance Cost ($/kW)	$0.00
Variable Operations and Maintenance Cost ($/MWh)	$95.00
Money Value (Dollar Year)	2011
Project Construction Cost	$30,000,000
Local Spending	$9,917,206
Total Annual Operational Expenses	$5,183,205
Direct Operating and Maintenance Costs	$2,496,600
Local Spending	$2,396,686
Other Annual Costs	$2,686,605
Local Spending	$5,114,896
Debt and Equity Payments	$2,355,000
Property Taxes	$300,000

Local Economic Impacts - 12 MW Internally Developed Battery Storage Summary Results			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	33	$4.40	$5.50
Construction and Interconnection Labor	28	$3.93	
Construction Related Services	5	$0.47	
Power Generation and Supply Chain Impacts	27	$1.75	$6.19
Induced Impacts	26	$1.42	$4.36
Total Impacts (Direct, Indirect, Induced)	86	$7.57	$16.05
During operating years (annual)			
Onsite Labor Impacts	1	$0.04	$0.04
Local Revenue and Supply Chain Impacts	27	$1.38	$5.04
Induced Impacts	8	$0.46	$1.40
Total Impacts (Direct, Indirect, Induced)	36	$1.88	$6.49
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 40 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.			

Wind Generator

Internally Developed Wind (45 MW; 2018)	
Wind - Project Data Summary	
Project Location	CALIFORNIA
Year of Construction	2018
Total Project Size - Nameplate Capacity (MW)	45
Number of Projects (included in total)	100%
Turbine Size (KW)	2000
Number of Turbines	23
Installed Project Cost ($/KW)	$1,993
Annual Direct O&M Cost ($/KW) + Variable O&M	$15.34
Money Value (Dollar Year)	2,011
Installed Project Cost	$89,687,591
Local Spending	$16,193,791
Total Annual Operational Expenses	8122890
Direct Operating and Maintenance Costs	$690,300
Local Spending	$471,932
Other Annual Costs	$7,432,590
Local Spending	$7,432,590
Debt and Equity Payments	$7,040,476
Property Taxes	$254,115
Land Lease	$138,000

Local Economic Impacts - 45 MW Internally Developed Wind Generator Summary Results			
During construction period	**Jobs**	**Earnings**	**Output**
Project Development and Onsite Labor Impacts	61	$4.69	$5.01
Construction and Interconnection Labor	57	$4.32	
Construction Related Services	4	$0.37	
Turbine and Supply Chain Impacts	103	$7.03	$19.15
Induced Impacts	39	$2.14	$6.59
Total Impacts	**203**	**$13.85**	**$30.74**
During operating years (annual)			
Onsite Labor Impacts	4	$0.29	$0.29
Local Revenue and Supply Chain Impacts	8	$0.52	$4.62
Induced Impacts	6	$0.35	$1.08
Total Impacts	**18**	**$1.16**	**$5.99**
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction and operating jobs are full-time equivalent for a period of one year (1 FTE = 2,080 hours). Wind farm workers includes field technicians, administration and management. Economic impacts "During operating years" represent impacts that occur from wind farm operations/expenditures. The analysis does not include impacts associated with spending of wind farm "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding. Results are based on model default values.			

Scenario 4 – Reduced Local Economic Benefit Case

As described within DMC's report, a second set of economic development projections was prepared for each supply scenario based on a set of assumptions that would result in reduced economic development benefits for Sonoma County. The following tables reflect reduced economic impacts that would accrue within Sonoma County under Scenario 4.

Geothermal Generator

Internally Developed Geothermal (95 MW; 2015) - Reduced Econ Impacts	
Geothermal Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2013
Project Size - Nameplate Capacity (MW)	95
Capacity Factor (Percentage)	94%
Heat Rate (Btu per kWh)	7000
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$3,718
Cost of Fuel ($/mmbtu)	$0.00
Produced Locally (Percent)	$0.00
Fixed Operations and Maintenance Cost ($/kW)	$58.38
Variable Operations and Maintenance Cost ($/MWh)	$5.06
Money Value (Dollar Year)	2011
Project Construction Cost	$353,210,000
Local Spending	$28,568,456
Total Annual Operational Expenses	$40,858,979
Direct Operating and Maintenance Costs	$9,504,376
Local Spending	$102,311
Other Annual Costs	$31,354,603
Local Spending	$3,634,411
Debt and Equity Payments	$0
Property Taxes	$3,532,100

Local Economic Impacts - 95 MW Internally Developed Geothermal Generator Summary Results - Reduced Econ Impacts			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	132	$12.95	$21.61
Construction and Interconnection Labor	132	$12.95	
Construction Related Services	0	$0.00	
Power Generation and Supply Chain Impacts	80	$5.24	$18.00
Induced Impacts	70	$3.77	$11.62
Total Impacts (Direct, Indirect, Induced)	281	$21.96	$51.23
During operating years (annual)			
Onsite Labor Impacts	1	$0.08	$0.08
Local Revenue and Supply Chain Impacts	2	$0.16	$4.03
Induced Impacts	13	$0.73	$2.24
Total Impacts (Direct, Indirect, Induced)	17	$0.96	$6.35

Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 140 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.

Biomass Cogeneration Projects (10 x 4MW)

Internally Developed Biomass Cogeneration (40 MW; 2014) - Reduced Econ Impacts	
Biomass Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2012
Project Size - Nameplate Capacity (MW)	40
Capacity Factor (Percentage)	85%
Heat Rate (Btu per kWh)	10000
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$3,000
Cost of Fuel ($/mmbtu)	$0.00
Produced Locally (Percent)	50%
Fixed Operations and Maintenance Cost ($/kW)	$0.00
Variable Operations and Maintenance Cost ($/MWh)	$42.00
Money Value (Dollar Year)	2011
Project Construction Cost	$120,000,000
Local Spending	$15,440,735
Total Annual Operational Expenses	$23,288,234
Direct Operating and Maintenance Costs	$12,509,280
Local Spending	$657,740
Other Annual Costs	$10,778,954
Local Spending	$1,937,217
Debt and Equity Payments	$0
Property Taxes	$1,200,000

Local Economic Impacts - 40 MW Internally Developed Biomass Cogeneration Generator Summary Results - Reduced Econ Impacts			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	56	$7.76	$9.18
Construction and Interconnection Labor	47	$7.01	
Construction Related Services	8	$0.75	
Power Generation and Supply Chain Impacts	42	$2.71	$9.62
Induced Impacts	40	$2.16	$6.66
Total Impacts (Direct, Indirect, Induced)	138	$12.63	$25.46
During operating years (annual)			
Onsite Labor Impacts	1	$0.06	$0.06
Local Revenue and Supply Chain Impacts	4	$0.30	$2.33
Induced Impacts	6	$0.32	$0.98
Total Impacts (Direct, Indirect, Induced)	11	$0.68	$3.38
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 70 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.			

Residential Photovoltaic Solar Installations

Residential PV Installation (10 MW; 2015) - Reduced Econ Impacts	
Photovoltaic - Project Data Summary	
Project Location	**CALIFORNIA**
Year of Construction or Installation	2013
Average System Size - DC Nameplate Capacity (KW)	5
Number of Systems Installed	2,000
Total Project Size - DC Nameplate Capacity (KW)	10000
System Type	sidential Retrofit
Base Installed System Cost ($/KWDC)	$4,500
Annual Direct Operations and Maintenance Cost ($/kW)	$20.00
Money Value - Current or Constant (Dollar Year)	2,011
Project Construction or Installation Cost	$47,563,119.23
Local Spending	$9,908,560.63
Total Annual Operational Expenses	5420000
Direct Operating and Maintenance Costs	$200,000
Local Spending	$64,356
Other Annual Costs	$5,220,000
Local Spending	$2,610,000
Debt Payments	$2,610,000
Property Taxes	$475,631

Local Economic Impacts - 10 MW Residential Solar PV Installations Summary Results - Reduced Econ Impacts			
During construction and installation period	**Jobs**	**Earnings**	**Output**
Project Development and Onsite Labor Impacts	51.5	$3.4	$5.4
Construction and Installation Labor	25.0	$2.0	
Construction and Installation Related Services	26.5	$1.4	
Module and Supply Chain Impacts	50.1	$2.6	$7.2
Induced Impacts	25.8	$1.4	$4.4
Total Impacts	**127.4**	**$7.4**	**$17.0**
During operating years			
Onsite Labor Impacts			
PV Project Labor Only	0.8	$0.1	$0.1
Local Revenue and Supply Chain Impacts	4.4	$0.3	$1.2
Induced Impacts	1.4	$0.1	$0.2
Total Impacts	**6.6**	**$0.4**	**$1.5**

Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction and operating period jobs are full-time equivalent for one year (1 FTE = 2,080 hours). Economic impacts "During operating years" represent annual impacts that occur from system/plant operations/expenditures. Totals may not add up due to independent rounding.

Pumped Storage Generator

Internally Developed Pumped Storage (60 MW; 2017) - Reduced Econ Impacts	
Biomass Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2015
Project Size - Nameplate Capacity (MW)	60
Capacity Factor (Percentage)	25%
Heat Rate (Btu per kWh)	0
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$1,500
Cost of Fuel ($/mmbtu)	$0.00
Produced Locally (Percent)	$0.00
Fixed Operations and Maintenance Cost ($/kW)	$0.00
Variable Operations and Maintenance Cost ($/MWh)	$101.00
Money Value (Dollar Year)	2011
Project Construction Cost	$90,000,000
Local Spending	$14,425,809
Total Annual Operational Expenses	$21,404,518
Direct Operating and Maintenance Costs	$13,271,400
Local Spending	$3,799,156
Other Annual Costs	$8,133,118
Local Spending	$11,932,273
Debt and Equity Payments	$7,065,000
Property Taxes	$900,000

Local Economic Impacts - 60 MW Internally Developed Pumped Storage Summary Results - Reduced Econ Impacts			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	51	$7.46	$8.47
Construction and Interconnection Labor	35	$6.05	
Construction Related Services	16	$1.41	
Power Generation and Supply Chain Impacts	38	$2.40	$8.27
Induced Impacts	39	$2.12	$6.54
Total Impacts (Direct, Indirect, Induced)	128	$11.98	$23.28
During operating years (annual)			
Onsite Labor Impacts	2	$0.10	$0.10
Local Revenue and Supply Chain Impacts	43	$2.27	$10.24
Induced Impacts	17	$0.90	$2.78
Total Impacts (Direct, Indirect, Induced)	61	$3.27	$13.12
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 60 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.			

Battery Storage Generator

Internally Developed Battery Storage (12 MW; 2018) - Reduced Econ Impacts	
Biomass Plant - Project Data Summary based on User modifications to default values	
Project Location	**CALIFORNIA**
Year Construction Starts	2016
Project Size - Nameplate Capacity (MW)	12
Capacity Factor (Percentage)	25%
Heat Rate (Btu per kWh)	0
Construction Period (Months)	24
Plant Construction Cost ($/KW)	$2,500
Cost of Fuel ($/mmbtu)	$0.00
Produced Locally (Percent)	25%
Fixed Operations and Maintenance Cost ($/kW)	$0.00
Variable Operations and Maintenance Cost ($/MWh)	$95.00
Money Value (Dollar Year)	2011
Project Construction Cost	$30,000,000
Local Spending	$4,588,015
Total Annual Operational Expenses	$5,183,205
Direct Operating and Maintenance Costs	$2,496,600
Local Spending	$220,357
Other Annual Costs	$2,686,605
Local Spending	$2,906,962
Debt and Equity Payments	$2,355,000
Property Taxes	$300,000

Local Economic Impacts - 12 MW Internally Developed Battery Storage Summary Results - Reduced Econ Impacts			
	Jobs	**Earnings**	**Output**
During construction period			
Project Development and Onsite Labor Impacts	16	$1.91	$2.60
Construction and Interconnection Labor	16	$1.91	
Construction Related Services	0	$0.00	
Power Generation and Supply Chain Impacts	12	$0.76	$2.67
Induced Impacts	12	$0.65	$2.01
Total Impacts (Direct, Indirect, Induced)	40	$3.32	$7.28
During operating years (annual)			
Onsite Labor Impacts	0	$0.02	$0.02
Local Revenue and Supply Chain Impacts	3	$0.20	$1.88
Induced Impacts	3	$0.16	$0.50
Total Impacts (Direct, Indirect, Induced)	6	$0.38	$2.40
Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction period related jobs are full-time equivalent for the 24 months (an annual average of approximately 20 full-time equivalent jobs). Plant workers includes operators, maintenance, administration and management. Economic impacts "During operating years" represent impacts that occur from plant operations/expenditures. The analysis does not include impacts associated with spending of plant "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding.			

Wind Generator

Internally Developed Wind (45 MW; 2018) - Reduced Econ Impacts	
Wind - Project Data Summary	
Project Location	**CALIFORNIA**
Year of Construction	2018
Total Project Size - Nameplate Capacity (MW)	45
Number of Projects (included in total)	100%
Turbine Size (KW)	2000
Number of Turbines	23
Installed Project Cost ($/KW)	$1,993
Annual Direct O&M Cost ($/KW) + Variable O&M	$15.34
Money Value (Dollar Year)	$2,011.00
Installed Project Cost	$89,687,591
Local Spending	$9,524,339
Total Annual Operational Expenses	8122890
Direct Operating and Maintenance Costs	$690,300
Local Spending	$335,575
Other Annual Costs	$7,432,590
Local Spending	$7,432,590
Debt and Equity Payments	$7,040,476
Property Taxes	$254,115
Land Lease	$138,000

Local Economic Impacts - 45 MW Internally Developed Wind Generator Summary Results - Reduced Econ Impacts			
During construction period	**Jobs**	**Earnings**	**Output**
Project Development and Onsite Labor Impacts	41	$3.06	$3.22
Construction and Interconnection Labor	39	$2.88	
Construction Related Services	2	$0.18	
Turbine and Supply Chain Impacts	60	$4.10	$11.05
Induced Impacts	23	$1.27	$3.92
Total Impacts	**124**	**$8.44**	**$18.19**
During operating years (annual)			
Onsite Labor Impacts	3	$0.22	$0.22
Local Revenue and Supply Chain Impacts	8	$0.48	$4.46
Induced Impacts	6	$0.33	$1.03
Total Impacts	**16**	**$1.03**	**$5.71**

Notes: Earnings and Output values are millions of dollars in year 2011 dollars. Construction and operating jobs are full-time equivalent for a period of one year (1 FTE = 2,080 hours). Wind farm workers includes field technicians, administration and management. Economic impacts "During operating years" represent impacts that occur from wind farm operations/expenditures. The analysis does not include impacts associated with spending of wind farm "profits" and assumes no tax abatement unless noted. Totals may not add up due to independent rounding. Results are based on model default values.

Part 3: Peer Review of the Sonoma County Community Choice Aggregation Feasibility Study

On Behalf of the Sonoma County Water Agency

MRW & Associates, LLC
1814 Franklin Street, Suite 720
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September 20, 2011

Contents

Introduction

Background

Community choice aggregation (CCA) is the vehicle by which local governments, including cities, counties, or a combination of jurisdictions, can provide commodity electricity services to their constituents instead of the local utility. The legal authority to form a CCA program was created by the California Legislature in 2002 in the wake of the state's electricity crisis. Many communities at that time were primarily concerned with addressing volatile electricity prices and securing a reliable supply of power. Since the legislation passed, environmental concerns related to electricity supply have also become an important factor for communities. For many local governments, CCA provides an opportunity to pursue their goals of obtaining a reliable electric supply with stable prices for their constituents while, at the same time, having electric supplies that contain a greater proportion of renewable energy resources than the local utility.

In March 2011, the Sonoma County Water Agency (SCWA) approved funding to study the feasibility of developing a CCA program for Sonoma County (County). A CCA program in the County would further the Water Agency's energy policy goals of developing renewable energy projects and programs that benefit businesses and residents of the County. The purpose of the feasibility study authorized by SCWA is to assess whether a CCA program can provide Sonoma County businesses and residents with reliable, cost-effective electricity while also meeting goals for replacing fossil-fired generation with energy from renewable energy sources, reducing greenhouse gas emissions, and furthering energy efficiency and conservation efforts.

In August 2011, Dalessi Management Consulting LLC (DMC) issued a draft version of the feasibility study, "Sonoma County Community Choice Aggregation Feasibility Study" (Draft Report), which examined the economic feasibility of forming a Community Choice Aggregation program serving the majority of electric consumers in the County.[1] The Draft Report evaluated four scenarios, representing differing levels of renewable content in the CCA's power procurement portfolio.

MRW and Associates, LLC (MRW) was retained by SCWA to provide this professional peer review of the Draft Report. MRW's review examines the key elements of the feasibility study that affect the viability of forming a CCA in order to verify the feasibility of establishing a CCA and achieving the objectives described above. This review includes:

- A review of the Draft Report's assumptions, forecasts and scenarios;
- Identification and assessment of the assumptions that are most critical to the financial success of the CCA, and conditions under which CCA prices might exceed PG&E prices over the study period;
- A brief identification of other issues that require further study or should be addressed in the next phase of SCWA's evaluation of CCA; and
- An overall assessment of the accuracy and completeness of the study.

[1] The study does not consider including Healdsburg in the potential CCA, since Healdsburg has its own municipal utility.

MRW's Summary and Conclusions

The general approach used in the Draft Report to examine the feasibility of a CCA is sound and all major cost components are addressed. However, MRW found that the manner in which the results in the Draft Report were presented, while not unreasonable, tended to be more favorable towards CCA formation and the risks and down-sides of CCA formation were not highlighted. MRW also found that some of the results in the Draft Report were also presented in a way so as to minimize the appearance of cost differences between the CCA and PG&E.

With respect to assumptions used in the Draft Report, MRW found that:

- The gas price and power price forecasts are reasonable.
- The greenhouse gas (GHG) emissions assumptions are conservative.
- The projected CCA load is generally reasonable, although the growth rate assumption may be too low.
- A 20% opt-out rate for CCA customers is reasonable, but in any future studies, the mix of opt-outs should be refined to reflect the greater likelihood of opt-outs among large customers.
- With the exception of the efficiency (heat rate) and fuel price of biomass-fueled generation, the renewable project costs are reasonable. However, the assumed time it would take develop local projects, especially in Scenario 4, is unreasonably optimistic.
- The estimates of the CCA startup costs, the billing and data management costs, and ongoing CCA operations cost are reasonable.
- The Pacific Gas & Electric (PG&E) generation rate against which the CCA cost is compared is overstated due to high escalation rate assumptions from 2011 to 2014. Higher PG&E rates can make the CCA appear more cost-effective than it might actually be.
- The forecast of the ongoing Power Charge Indifference Amount (PCIA or "exit fee") is optimistic but not unreasonable.
- The assumptions concerning the CCA bond amount are reasonable, while the assumption that a CCA bond could be financed in the short term is questionable. Furthermore, the risk of a very high CCA bond amount that could occur during a period of high prices in the wholesale power market was not mentioned or addressed.

MRW's overall conclusions and recommendations are:

- The methodology used by DMC to assess the feasibility of a Sonoma CCA is sound and included all major cost components.
- The average rate that could be offered by the CCA, including the exit fee, would in all likelihood be higher than PG&E's generation rate.
- MRW agrees qualitatively with the Draft Report that local projects would stimulate local economic activity. However, MRW finds that the Draft Report's estimates of the quantitative economic development benefits associated with a CCA in Sonoma County to be overstated.
- MRW agrees with DMC that the County would achieve net greenhouse gas reductions with Scenarios 2 through 4. MRW believes that the "dollar values" of the GHG reductions, (calculated by multiplying the tonnage reduction by the assumed GHG cost) are misleading and should not be included in the feasibility study.
- The aggressive timing of CCA-developed in-county renewable resources in Scenario 4 is excessively optimistic and is not likely achievable.

- MRW endorses DMC's recommendation that the County explicitly determine what the goals of a CCA Program are so that clear objectives can be set. It may be the case that the higher electric costs for the citizens and businesses of Sonoma County are an acceptable tradeoff for the potential for local economic growth, local control, and other potential benefits of a CCA. However, MRW believes that such a tradeoff should be explicitly identified.
- With respect to working with the Marin Energy Authority (MEA), MRW agrees with DMC's observation that further discussion with MEA is reasonable to "better understand how such a relationship might be structured." This discussion should occur in light of the goals and objectives of a Sonoma CCA. To actively pursue a relationship with MEA without first setting Sonoma's goals and objectives would be premature.

Some additional observations include:

- In all four scenarios, the Draft Report uses unbundled Renewable Energy Credits (RECs) to meet a portion the CCA's renewable percentage targets. This means that the actual power corresponding to the RECs would be generated using fossil resources and that "credits" from renewable generators who are providing power to another entity would be purchased to effectively convert the CCA's fossil resources into green power. While from a global perspective this is reasonable, the CCA would need to be clear that not every kilowatt hour of "green" power is necessarily generated by renewable resources owned by or contracted to the CCA.
- As noted above, MRW believes that Scenarios 2 through 4 would result in net greenhouse gas reductions. This is because the average GHG emissions from the CCA would be lower than the <u>*marginal*</u> emissions from PG&E (i.e., the actual incremental emissions that PG&E would incur if it were serving that load). However, because PG&E has large amounts of carbon-free generation (large hydroelectric dams and the Diablo Canyon nuclear plant), PG&E's <u>*average*</u> GHG emissions rate might still be lower than the CCA's, even if the CCA has more "renewable" generation.
- Joining with MEA may make sense, but there is no way to tell at this point in time. Sonoma should expect to compromise on some of its goals, be it building local generation, meeting GHG targets, or meeting rate impact goals, in order to gain the benefits of the synergies of joining, or working with, MEA.

General Approach

Methodology

The Draft Report used a "cost-of-service" model to estimate all costs that would be incurred by the CCA to provide commodity electric service to the customers of the CCA. It then compared those costs against a projection of the future generation rates that would be offered by PG&E. MRW found that the overall approached used by DMC was sound, and that DMC included all the major cost categories that a CCA would incur. This included those costs associated with energy purchases and/or production, internal administrative costs, billing and data management costs, fees paid to PG&E for services, exit fees (the Power Charge Indifference Amount or "PCIA") and financing and other costs that would be involved in the CCA's formation and ongoing operations. The *pro forma* financial analysis included with the Draft Report presented the sum total of the CCA costs over each year, which in turn would have to be funded through revenues collected from customers. The CCA's average rates, representing the total program costs divided by total program electricity sales, were graphically shown for each year for comparison against projected PG&E rates.

The Draft Report also presented four CCA resource procurement scenarios, which explored the costs and GHG benefits of differing levels of renewables. The Draft Report appropriately noted that:

> "[t]he objective of evaluating alternative supply scenarios is to obtain a robust set of analytical results to inform decision-makers of a reasonable range of likely outcomes and to illustrate the inherent trade-offs among the different resource choices that may be made. It should be understood that the CCA program would not be limited to any particular supply scenario assessed in this study."

The Draft Report also provided estimates of local macro-economic impacts of each scenario. The macro-economic impacts included job creation and economic stimulus resulting from locally-developed renewable generation projects. These estimates were created using the National Renewable Energy Laboratory's Jobs & Economic Impact Development ("JEDI") models.

Presentation of Pricing Results

The Draft Report presented the cost results as a 20-year levelized cost and showed annual costs only in total average rate graphs. While levelized costs are a helpful tool for comparing scenarios, they lack the temporal detail needed to clearly assess the trade-offs between CCA and PG&E service. The data need also be seen on an annual basis so that near-term and long-term impacts can be examined.

For example, Table 1 below shows the annual rates for CCA and PG&E service in Scenario 2.[2] From this table it is evident that CCA rates are projected to be higher than PG&E rates in during the first 13 years and lower in the latest 5 years of the forecast. This fact cannot be seen in a levelized cost over a 20-year period. As the costs are less uncertain in the near term than 15-20 years into the future, it is prudent to discount the benefits associated with the out-year "savings" at a greater rate than near-term costs.

[2] Scenario 2 was chosen for illustrative purposes only.

Table 1. : Total Rate Comparison – Scenario 2

Year	CCA Total Rate (¢/kWh)	PG&E Total Rate (¢/kWh)	Percent Difference	
Levelized	21.9	21.6	1%	
2013	17.71	17.33	2%	CCA Total Rate higher than PG&E (first 13 years)
2014	18.39	17.98	2%	
2015	18.44	18.18	1%	
2016	19.13	18.71	2%	
2017	19.47	19.16	2%	
2018	19.92	19.57	2%	
2019	20.61	20.20	2%	
2020	21.28	20.62	3%	
2021	21.98	21.34	3%	
2022	22.63	22.04	3%	
2023	23.32	22.77	2%	
2024	24.05	23.41	3%	
2025	24.79	24.20	2%	
2026	24.99	25.02	-0%	CCA Total Rate equal or lower than PG&E
2027	25.79	25.91	-0%	
2028	26.58	26.79	-1%	
2029	27.38	27.70	-1%	
2030	28.21	28.64	-2%	
2031	28.91	29.51	-2%	
2032	29.65	30.42	-3%	

Second, regardless of whether a customer elects to receive generation service from PG&E or from the CCA, they will receive transmission and distribution (T&D) services from PG&E and will pay PG&E for these T&D services. As illustrated in Figure 1, T&D services represents nearly 50% of a ratepayer's charge for electric service from PG&E (or the CCA). Figure 2 shows the forecast of costs a customer would incur for services provided by the CCA (i.e., the generation component of their electric service plus exit fees) and the forecast of PG&E's generation cost. This presentation better shows the cost differences between CCA and PG&E service and is more consistent with how these comparisons have historically been presented.[3]

[3] For example, this is how this sort of comparison was presented in MEA's feasibility studies and in MEA's public presentations in 2009 and 2010.

Figure 1: Total Rate Comparison – Scenario 2

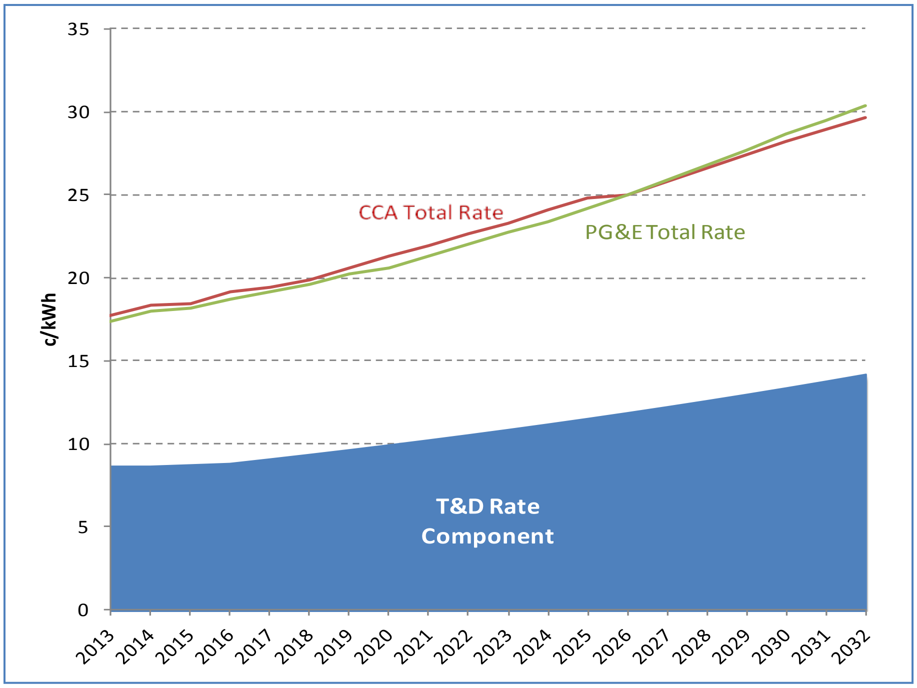


Figure 2: Generation Rate Comparison – Scenario 2

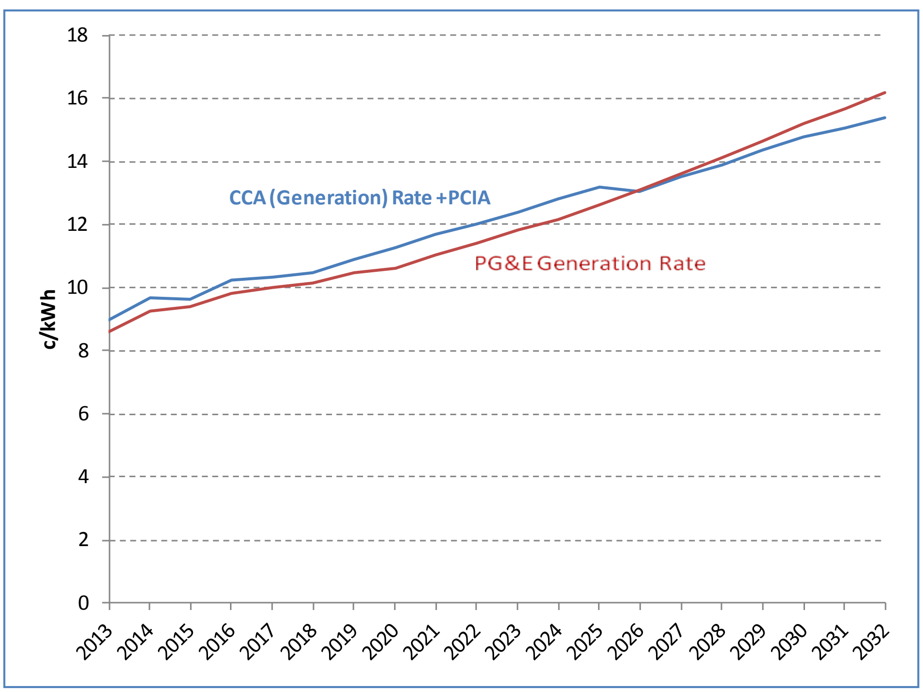


Figure 2 (above) and Table 2 show the average CCA cost (plus PCIA) and PG&E average generation rate component customers for Scenario 2. With this presentation, it is clear that CCA generation rates are expected to vary from as much as 6% higher to 5% lower than PG&E's rates under this scenario, depending on the year forecasted. Including the common transmission and distribution rate, as is done in the Draft Report and shown in the last column of Table 2, minimize the impact of the differences in cost of service from the CCA and PG&E.

Table 2. Generation Rate Comparison – Scenario 2

Year	CCA Gen Rate (¢/kWh)	PG&E Gen Rate (¢/kWh)	% Difference (Generation Rate only)	% Difference (Generation Rate + T&D)
2013	8.99	8.61	4%	2%
2014	9.67	9.27	4%	2%
2015	9.64	9.38	3%	1%
2016	10.25	9.83	4%	2%
2017	10.32	10.01	3%	2%
2018	10.50	10.14	3%	2%
2019	10.90	10.49	4%	2%
2020	11.28	10.62	6%	3%
2021	11.68	11.04	6%	3%
2022	12.02	11.43	5%	3%
2023	12.39	11.84	5%	2%
2024	12.80	12.15	5%	3%
2025	13.20	12.60	5%	2%
2026	13.05	13.08	-0%	-0%
2027	13.49	13.61	-1%	-0%
2028	13.91	14.13	-2%	-1%
2029	14.33	14.65	-2%	-1%
2030	14.77	15.20	-3%	-2%
2031	15.07	15.67	-4%	-2%
2032	15.40	16.16	-5%	-3%

Customer Mix and Load Shape

Load

The Draft Report showed the estimated load the CCA might serve based on data supplied by PG&E for the year 2008. DMC adjusted these data downward by 7% to reach 2011 levels, based on the change in sales within the CAISO system. MRW finds this assumption reasonable. Analysis of PG&E-specific sales data for the years 2008-2011 shows a similar percent reduction in load.[4] Further examination of historical load data from the California Energy Crisis shows that this magnitude of reduction is not unprecedented: in the two years from 2000 to 2002 PG&E's load decreased 5%.[5] Nonetheless, MRW recommends monitoring updated load information from PG&E to ensure that the most recent load data are included in any subsequent feasibility report.

[4] PG&E FERC Form 1, Section 304 years 2008-2010, PG&E Advice Letter AL-3856-E.
[5] PG&E FERC Form 1, Section 304 years 2000-2002.

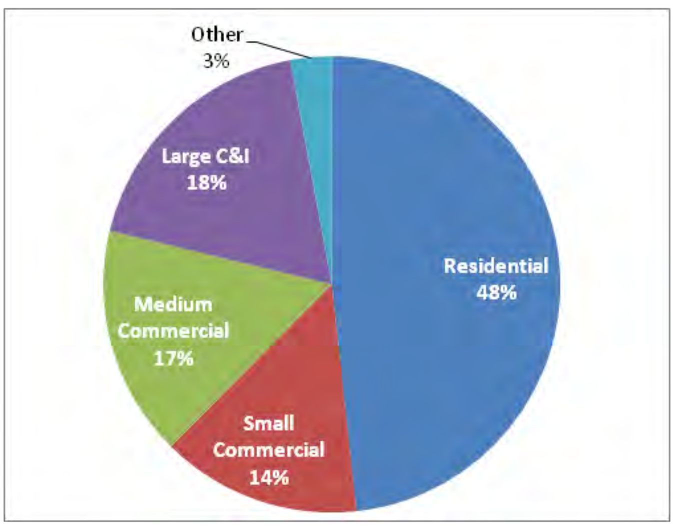
To predict the CCA load during the forecast period (2011-2032), DMC escalated 2011 loads by 0.5% per year. MRW finds that this assumption is reasonable, although it may underestimate future growth. The California Energy Commission's most recent demand forecast and a subsequent report updating the forecast for future expected savings due to energy efficiency programs shows that PG&E's load is expected to increase by 0.7% annually from 2011 through 2020.[6] In addition, Sonoma County may experience greater growth in demand than the PG&E system average. In the three years from 2011 through 2014 Sonoma's Gross Metro Product is expected to increase 4% annually while California's Gross State Product is expected to increase 3% annually.[7] This above-average economic growth may, to some extent, translate to greater demand for electricity. DMC should consider examining a sensitivity case with a higher growth rate.

Customer Opt-Outs

The customer mix and resulting load that a Sonoma CCA would serve depends upon (a) the native customer mix in the region and (b) the number and type of customers who opt-out of CCA service. The Draft Report took the forecasted load and assumed that 20% of each customer group would opt out.

Figure 3 below shows the projected energy usage by customer class for a Sonoma CCA. Since each customer group is assumed to opt-out at the same rate (i.e., 20%), it also reflects the energy usage by customer class for potential customers in a Sonoma CCA as it is currently served by PG&E.

Figure 3. Fraction of Sonoma CCA Energy Usage by Customer Class (GWh Basis)



[6] Kavalec, Chris and Tom Gorin, 2009. *California Energy Demand 2010-2020, Adopted Forecast*. California Energy Commission. CEC-200-2009-012-CMF; Itron, *Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the 2009 Integrated Energy Policy Report Adopted Demand Forecast*, page 142.

[7] Sonoma County Economic Development Board, Local Economic Report, Spring 2011; Legislative Analyst's Office, California's Fiscal Outlook, November 2008, page 8.

While the actual opt-out rate is difficult to predict, the composition of the customer base is very important for understanding the shape of the load that is to be served. Residential and small commercial customers tend to have “peakier” loads, as they have relatively high demands during late summer afternoons (driven by air conditioning) and winter evenings (driven by lighting and appliances). Large commercial and industrial customers tend to have “flatter” loads, as their electricity demand is not as sensitive to weather or daylight hours. “Peakier” loads tend to be more costly to serve than flatter loads.

Because the total composite load is important, the assumptions concerning how each class is likely to participate in the CCA or opt out is likewise important. If Direct Access[8] participation statistics are a reasonable indicator (which we think they are), the industrial, large commercial and to a lesser degree medium commercial customer classes will tend to be more price sensitive and risk averse than other customer classes. Therefore, any CCA plan that shows base case increases to rates with risks of even higher rates in the future would likely generate a higher fraction of opt-outs among large electricity users.

The assumption in the Draft Report that 20% of the customers will opt-out from each customer class does not reflect this fact. The Draft Report states that the 20% opt-out rate is based on MEA’s experience in its first phase, which did not include a significant fraction of large commercial customers (other than municipal and county accounts). Thus, while the 20% opt-out rate might be appropriate for residential and small commercial customers, it is questionable for larger commercial and industrial customers.

This opt-out question impacts the load that would have to be served by the Sonoma CCA. If fewer large commercial and industrial customers participate in the CCA, the aggregate load served by the CCA would be “peakier;” the “mountains” seen in the Draft Report’s Figures 9-12 would become steeper, albeit smaller. Thus, on an average per-kilowatt-hour basis, a CCA with a customer mix that is dominated by residential and small commercial customers would require higher rates to cover its procurement costs.

Overall, a 20% opt-out rate is reasonable, but in any future studies, the mix of opt-outs should be refined to reflect the greater likelihood of opt-outs among large customers.

Customer Attrition

The Draft Report assumes that 1% per year of the load will return to PG&E bundled service after having initially taken CCA service. It is reasonable to assume a small loss of customer base, and the Draft Report’s assumption for customer attrition is conservative for a CCA offering stable rates that are competitive with the rates charged by PG&E.

The best mitigation strategy to address customer attrition is to have competitive, stable rates. Acknowledging that rates cannot always be managed, especially the rates of a CCA’s competitors, attrition risk can be also be addressed by crafting appropriate switching rules, exit fees, and special contracts with key large customers. Nonetheless, if a major taxpaying entity (e.g., a large industrial customer) is interested in departing from CCA service, then that customer likely has significant political clout, which will make it difficult to simply “impose an exit fee.” The CPUC has imposed exit fees and has

[8] Direct Access is the current program whereby some non-residential customers may elect to receive power from providers other than their host investor-owned utility.

seen well-funded efforts by certain customers to attempt to avoid paying those exit fees (with some success).

CARE Customers

To protect low-income households against escalating electricity bills, the CPUC froze rates for the California Alternate Rates for Energy (CARE) program at July 2001 levels. As general rates have increased with CARE rates remaining frozen, the effective CARE discounts now range from 29 to 30 percent in the lower two residential rate tiers and up to 76 percent in Tier 4. While recent Commission action is moving to adjust its rate design to modestly increase the CARE Tier 3 rates, these customers will continue to receive significant discounts relative to other residential customers.

The discounts for CARE customers are taken in both the distribution and generation components. This means that the level of CARE discount in the generation rate will have to be accounted for in setting an equivalent CARE rate for low-income CCA customers. We assume that the CCA would not wish to impose rate increases on low-income residents simply because they are taking CCA service (i.e., at least for CARE customers, the CCA would at least meet, if not beat PG&E's CARE rate).

This has two implications. First, to the extent that the residential rate charged by the CCA exceeds PG&E's CARE rate, which is likely in all the scenarios explored in the Draft Report, then the remaining CCA customers will subsidize the CARE customer's CCA rate so that the low-income CARE customer is paying no higher rates than they would have with PG&E. Second, in order to not exceed PG&E's CARE rate, these low income customers would also be relieved of paying any PCIA charge, which would the have to be picked up in CCA rates by the other CCA customers.

Based on the above, it is clear that a proposed CCA must account for any subsidies provided to low-income customers that currently participate in the CARE program. For example, if 25 percent of a CCA's residential load is on CARE (the PG&E system average) and the average rate generation rate differential is 2¢/kWh,[9] the low-income CCA subsidy would be on the order of $4.7 million. This would negatively affect the cost-competitiveness of the rates the CCA could offer to its non-CARE customers.

The Draft Report did not address the potential CARE subsidy issue, as it focused on the total cost to serve the CCA customers rather than what it could collect in rates from them. If or when a more detailed assessment is prepared that explicitly addresses CCA rates and ratemaking, this CARE issue will have to be addressed.

Supply Assumptions

Natural Gas Prices

The long-term natural gas forecast is critical to evaluating what the cost of power would be for the CCA and PG&E. DMC used the Department of Energy's Energy Information Administration's *Annual Energy Outlook 2011*, Electric Power Projections for EMM Region, Western Electricity Coordinating Council/California Reference Case. This is the source that was recommended to DMC by MRW when MRW reviewed DMC's preliminary assumptions for the feasibility study.

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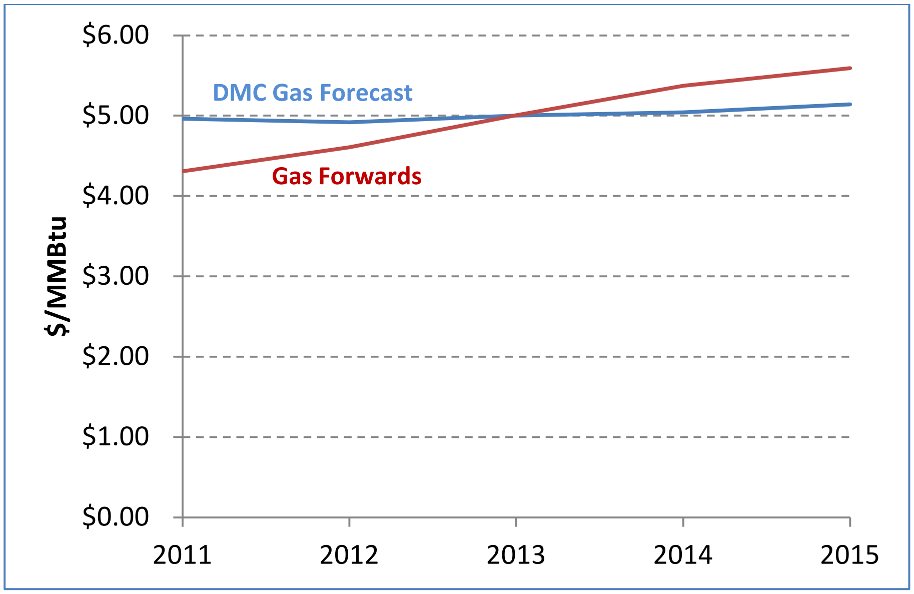
[9] See PG&E Advice Letter 3896-E, Table 3, page 3, E-1 generation rate versus EL-1 generation rate.

Figure 4 below shows the near-term DMC gas price forecast and the NYMEX Gas Forward prices.[10] As the figure shows, the DMC forecast based on the EIA forecast may be a bit low in the 2011-12 timeframe and a bit high in 2014 and 2015. However, given the long-term nature of this feasibility study, these differences are not material.

Figure 4. DMC Gas Price Forecast and NYMEX Gas Futures



Given the uncertainty is future prices for natural gas, these prices should be reviewed and updated in any future feasibility report. Furthermore, future feasibility assessments must continue to evaluate the impact of volatile gas prices on financial performance of the CCA by examining a wide range of future gas price scenarios. The plus 50% or minus 25% sensitivity used in the Draft Report is adequate for this preliminary study, however a more thorough analysis of the impact of both short- and long-term gas price uncertainty should be explored.[11]

Market Heat Rate

The key driver to the cost of power from fossil-fueled generation resources in California is the cost of natural gas. However, one has to translate this fuel cost into a cost of power by accounting for how efficiently the marginal power plants convert natural gas into electricity. This efficiency is generally reported as the "market heat rate," which is the number of BTUs of gas needed generate one kilowatt-hour of electricity.

[10] Henry Hub price, average of trading days from August 15 to September 15, plus basis differential to PG&E City Gate.

[11] Year-to-year gas price volatility can have an impact on cash flow requirements for the CCA if the CCA makes a commitment to "meet or beat" PG&E rates.

DMC reports the market heat rate used in its analysis at 8,000 Btu/kWh. On average, over the time frame being examined, this is a conservative estimate of market heat rate. Based on CAISO data, MRW calculated the market heat rate in northern California in 2010 to be ~7,500 Btu/kWh. However, it should be noted that market heat rates will vary year-to-year based upon market conditions. For example, if there is a glut of generation in California, as is currently the case, the market heat rate will be lower and if generating capacity is tight then it will be higher. It is also particularly sensitive to hydroelectric conditions: in a wet year, the market heat rate is driven down while in dry years with poor run-off the market heat rate is higher. Finally, if power generators in the western power markets have to internalize greenhouse gas costs, then this will tend to increase the implicit market heat rate.

Renewable Energy Assumptions

In general, MRW finds most of the DMC assumptions concerning renewable costs and performance of individual renewable technologies to be reasonable. There are two exceptions: the assumptions for the heat rate and fuel price used for biomass power. The Draft Report assumes a heat rate for biomass plants of 7,000 Btu/kWh. This is too low (i.e., too efficient) by a factor of two for a small biomass plant. For example, the CEC's 2007 "Comparative Costs Of California Central Station Electricity Generation Technologies" report places the heat rate for a 25 MW biomass plant at 15,500 Btu/kWh.[12] Second, the Draft Report also assumes a biomass fuel price of $2.40/MMBtu. This is also on the low end for biomass fuel, albeit not completely unreasonable.

The Draft Report presented three scenarios (and referred to a fourth, whose results were provided later) with differing assumptions concerning the amount, type, and location of renewables resources in the CCA portfolio. In the first three scenarios during the first three years of CCA operation (2013-2015), the Draft Report assumes that the CCA purchases renewable power and that the CCA also acquires unbundled Renewable Energy Credits (RECs) to meet its renewable energy targets. In general this is a sound assumption, as the CCA would not have had sufficient time to either develop its own renewable power projects or enter into long-term PPAs.

However, in this respect we note two irregularities in Draft Report Figures 2, 4, and 6. These figures show year-by-year load and resource projections for the first three scenarios. In each of these, "unbundled RECS" are shown as a resource. This is not correct since RECs are not a resource; they are a financial product. While we would assume that there is some kind of system or gas-fired power providing the actual GWhs associated with the unbundled RECs, that fact is not shown or noted in the text. MRW therefore recommends two year-by-year figures be presented for each scenario: one showing the actual sources of the energy for the CCA and one showing the mix of renewables, which would include any projected purchases of unbundled RECs.

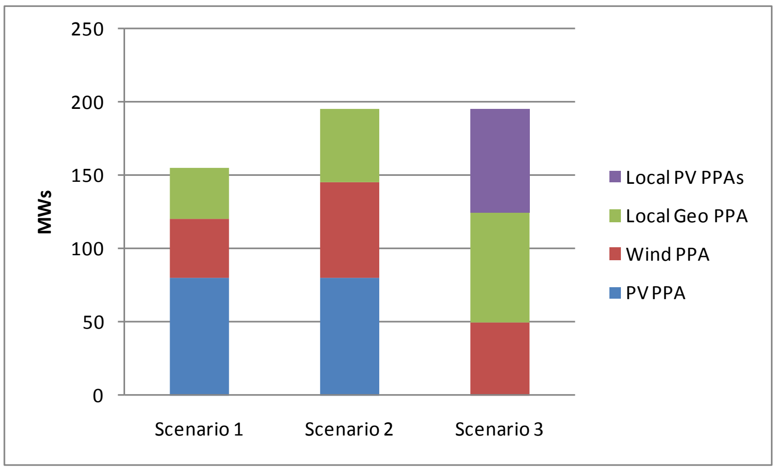
Second, as noted in Table 2 on page 21 of the Draft Report, current regulations limit the amount of unbundled RECS that can be used for RPS compliance. Under the RPS legislation, no more than 25% of the renewable requirements can be met in 2013 with unbundled RECs, and that fraction drops to 15% in 2014, and 10% in 2016. While it appears that all four scenarios comply with these requirements, in Scenarios 2 and 3 much of the renewable power in excess of the RPS requirements in a number of years is made up predominantly, if not exclusively, with unbundled RECs. Some individuals may not interpret unbundled RECs as "complying" with the CCA's renewable energy procurement goals (e.g., delivering

[12] CEC-200-2007-011-SF, December 2007. Page 18, Table 6.

50% or more renewable power). If unbundled RECS are used in this manner, then the fact that they are used and the justification for doing so would need to be clearly communicated.

Also in the first three scenarios presented in the Draft Report, DMC assumes that a significant amount of renewable generation would be procured under power purchase agreements (PPAs) starting in 2016 (see Figure 5). While the amounts of PPA-based power are not unreasonable, the timing for such deliveries might be optimistic. For a project to be available and delivering in 2016—5 years from today—it should already be identified and in at least the early stages development. This is particularly true for power purchased from local renewable resources.

Figure 5. New Renewable PPAs Assumed in 2016



Scenario 4, the data for which was provided later but did not appear in the Draft Report, assumes 10 MW of CCA-owned, locally sited PV capacity in 2013, 40 MW of CCA-owned, locally sited biomass capacity in 2014, and 95 MW of CCA-owned, locally sited geothermal capacity in 2015. Unless SCWA has specific projects under development, MRW finds the timelines to be unreasonable. This is especially true for the 95 MW of geothermal power, which would not only have to be approved by local environmental authorities but would also have to go through the California Energy Commission's siting process, which can take one year or more.[13]

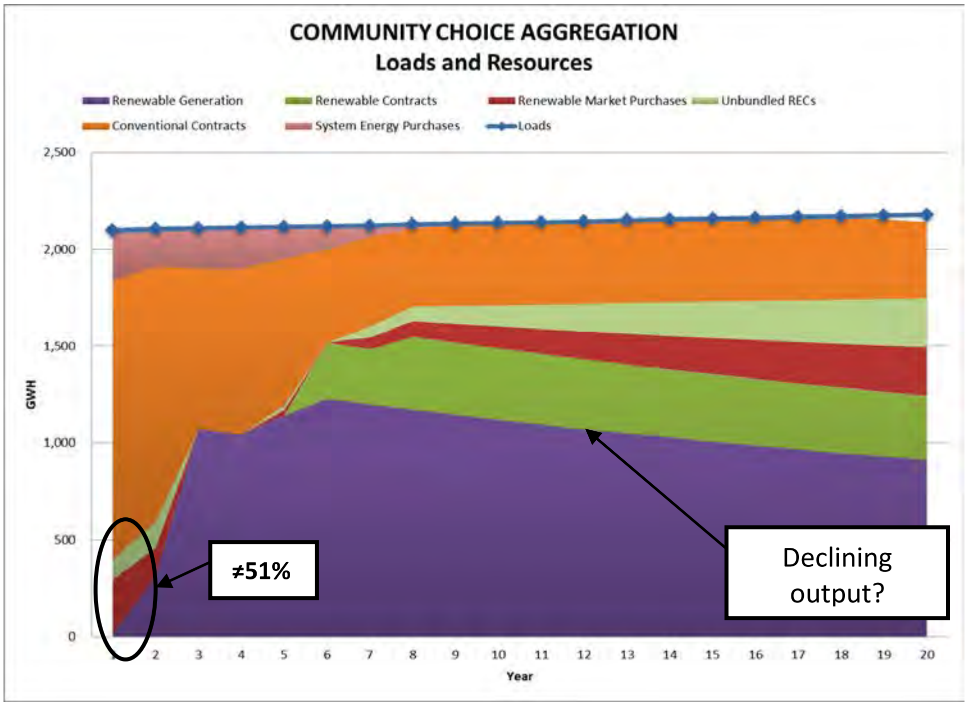
Furthermore, financing projects in the first few years of a CCA's existence might be very difficult. Banks or other lenders would likely be reticent to lend to an entity with no credit history or a track record of power project development, such as a new CCA. This is particularly true for the 10 MW PV capacity projected for 2013, which would need to (1) have financing in place and (2) have construction underway even before the CCA begins to receive revenues from power sales.

In addition, the figures provided for Scenario 4 do not appear to match the description of Scenario 4 in the Draft Report. The Draft Report says that Scenario 4 starts at 51% renewables, ramping up to 85% in

[13] All thermal power generation projects rated at 50 MW or more must be approved by the CEC.

2020. Assuming that year 1 in the Loads and Resource Projections figures is 2013, then the renewables content for Scenario 4 appears to be closer to 20% in 2013 and does not reach 51% until 2015. In addition, once the in-county generation is completed in the 6th year (2018), it declines at a rate of approximately 2% per year through to the end of the study period in year 20 (2032). While some output degradation is to be expected, a 2% degradation rate is too high. Furthermore, no output degradation of in-County renewables appears to have been assumed in any of the other scenarios presented in the Draft Report.

Figure 6: Scenario 4 Load and Resource Projections



PG&E Rates and Fees

Whether or not a Sonoma CCA can provide power to customers at prices that meet or beat the total costs of power provided by PG&E depends not only upon how well the CCA procures power, but also what happens at PG&E. For this feasibility study, this means not only making reasonable forecasts of the costs the CCA might incur, but also ensuring that the price to beat is calculated using a consistent set of assumptions.

As noted above, the electricity costs incurred by a customer of the CCA will consist of power purchased from the CCA and any exit fees charged by PG&E. These costs must be less than PG&E's generation rate in order to meet or beat the costs that the customer would incur if it remained a PG&E customer. Thus, the two key PG&E rates that must be forecast are the generation rate that would appear in the default bundled tariff and the PCIA element of CCA Cost Responsibility Surcharge (CCA CRS). The Draft Report correctly identifies these two factors in its sensitivities section.

It is important to note that PG&E rates, the PCIA, and CCA procurement costs are interrelated. All three rely on underlying wholesale power costs, natural gas prices and the cost of renewable energy, including renewable energy credits. For example, low wholesale power costs will not only reduce the cost of

PG&E power, it will increase the PCIA. If one does not acknowledge that the CCA CRS and wholesale market prices are inversely related, then the risk assessment may miss important feedbacks and understate risks faced by customers. The DMC analysis includes these interconnections.

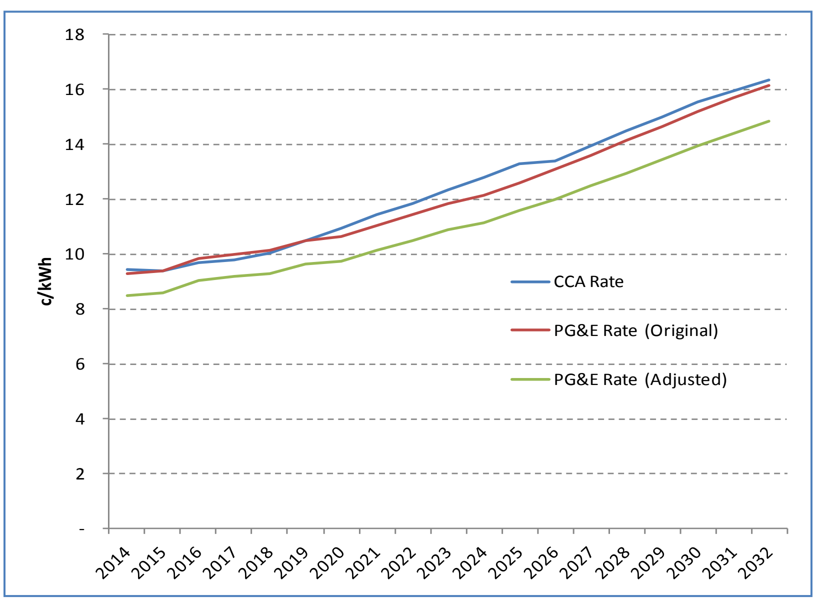
PG&E Generation Rate Forecast

The Draft Report forecasts an average annual increase for PG&E rates from 2013 to 2030 of 4%. This is consistent with MRW's projections of PG&E generation rates. However, the Draft Report assumes too high an escalation rate in PG&E's generation rate for the period from 2011-2014.

The assumptions underlying the DMC analysis show a 27.6% increase in PG&E generation rates from 2011 to 2013, plus an additional 7.6% increase from 2013 to 2014. Thus, DMC projects a 37.2% increase in PG&E rates from 2011 to 2014, or an average annual compound growth rate of 11.1% per year over those three years. While MRW's independent rate forecasts also suggest a significant rate increase in the next few years, MRW believes that the 11.1% per annum growth rate in the Draft Report is too high. MRW's conclusion is supported by PG&E's September 1, 2011 Advice Letter A-3896-E, which projects the utility's rates for 2012. That advice letter shows an estimated generation rate increase from 2011 to 2012 of approximately 9.5% while the DMC *pro formas* show an increase of 12.3% for the same time period.

The level of PG&E's rates in 2013 have a significant impact on the ability of a CCA to meet or beat PG&E's rates. For example, if the rate increase from 2011-2014 is reduced from the 37.2% assumed in the Draft Report to a 30% increase (9.1%/year over 3 years) and all other assumptions are held constant, the base PG&E rate in 2014 decreases from 9.3¢/kWh to 8.5¢/kWh, a decrease of 0.7¢/kWh, which would reduce levelized costs of service from PG&E by approximately 0.7¢/kWh. As shown in Figure 6 below, with this lower PG&E bundled rate, the average costs incurred by the CCA's customers would consistently exceed the costs under PG&E service.

Figure 7: Scenario 1 CCA versus PG&E Generation Rate, Original and Adjusted



Overall, MRW finds the PG&E rate forecast in the Draft Report to be optimistic (i.e., too high). While the average escalation rate from 2014 through 2023 of 4% per year is reasonable, the escalation from current rates to 2014 is too high, resulting in an optimistic starting point, which is then escalated throughout the study period. As always, the implications of down-side cases with lower PG&E generation rates should be considered before moving forward with CCA formation.

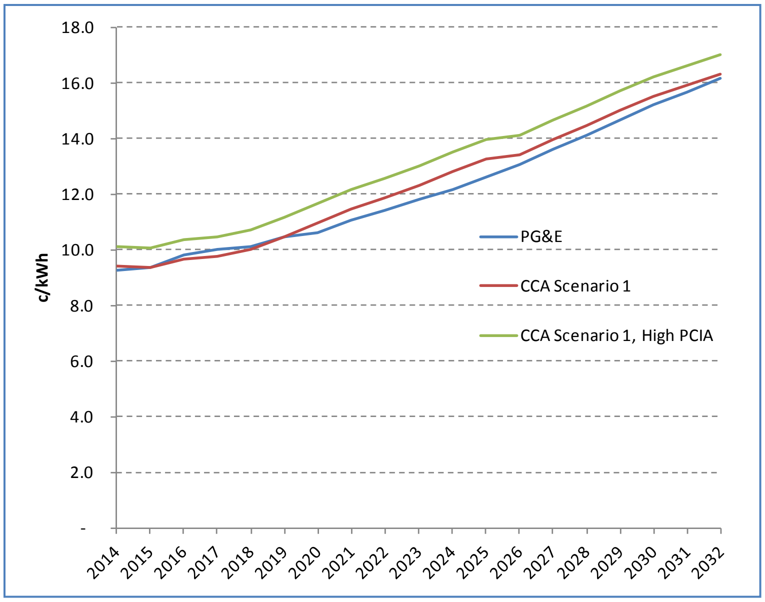
PG&E PCIA Forecast

The DMC Report describes the PCIA as "…a substantial charge that is intended to ensure that generation costs incurred by PG&E before a customer transitions to CCA service are not shifted to remaining PG&E bundled service customers (following a customer's departure from PG&E to CCA service)." Even though there is an explicit formula for calculating the PCIA, forecasting the PCIA is difficult since many of the key inputs to the calculation are not publically available.

To further add to the uncertainty, the CPUC is considering revisions to the PCIA calculation methodology. DMC's base case assumption is that the CPUC will revise the PCIA calculation consistent with proposals put forth by the non-utility CCA and Direct Access proponents; the Draft Report's sensitivity case assumes that the CPUC will adopt the utilities' primary recommendations for the PCIA calculation methodology. However, the Proposed Decision in that proceeding does not adopt the CCA/Direct Access proposal but instead recommends a compromise position between the CCA/DA proponents and the utilities, albeit more heavily weighted towards the CCA/DA proponents' position used in DMC's analysis. In the final version of the Draft Report, MRW recommends that the PCIA formula recommended in the Proposed Decision (or Final Decision, if it is issued in time) be used.

Even though the formula for calculating the PCIA is more certain now than when the Draft Report was prepared, due to its sensitivity to inputs as well as the redaction of those inputs from the public, examining the sensitivity of the results to different PCIA values is needed. While the structure of the Draft Report's High PCIA Sensitivity Case is no longer fully valid (with the issuance of the Proposed Decision), the numeric value that arose from it, +0.7¢/kWh, is still a reasonable placeholder for a down-side assessment of the PCIA. Using this assumption for PCIA, the only sensitivity case in which the costs to CCA customers are less than under PG&E service is in the High PG&E rate scenarios; under the Low Gas Case or Low Renewable Cost scenarios, service from PG&E is less expensive than service under a CCA.

Figure 8: Comparison of High PCIA Scenario Generation Rates



Overall, MRW finds DMC's assumptions for the ongoing PCIA charge to be optimistic, but not unreasonable. SCWA should have explicit plans for how a high PCIA would be addressed (i.e., how that risk would be split between the CCA and its customers).

Gas Price Sensitivity

The Draft Report correctly identifies gas price as a key sensitivity to be explored, and calculated the CCA average cost and the PG&E generation rate with gas prices 25% lower and 50% higher than that used in the base case scenario. While in any given year the gas price could fall outside of that range, overall, it provides a reasonable envelope of gas prices to be explored.

For the CCA cost cases, the greater the amount of renewables in the portfolio, the smaller the impact of changed gas price assumption had on average CCA costs. This implicitly illustrates one of the advantages of having higher penetrations of renewables in a supply portfolio: less rate volatility due to underlying commodity costs. CCA Scenario 1, which assumes that the CCA complies with the State's RPS law, has the highest rate changes in the gas price sensitivity scenarios: +2.3¢/kWh (assuming a 50% increase in gas price) to -1.1¢/kWh (assuming a 25% decrease in gas price).

DMC also modeled the impact on PG&E generation rates of the changes in gas prices: +1.3¢/ kWh (50% increase in gas price) to -0.7¢/kWh (25% decrease in gas price). In a recent filing to the CPUC, PG&E provided information on how much its procurement costs would change in 2012 under differing gas price assumptions.[14] This filing supports the magnitude of DMC's sensitivity findings.

[14] A.11-06-004, Gas Price Sensitivity Analysis Testimony 2012 Energy Resource Recovery Account (ERRA) and 2012 Generation Non-Bypassable Charges Forecast. September 8, 2011

Operations

CCA Startup and Operating Costs

While power procurement represents the greatest cost to a CCA, one must also consider the internal costs of CCA operations, including the up-front costs to providing service. DMC estimated the startup costs for a Sonoma CCA at $1.65 million, ongoing internal administrative costs at $5.7 million per year (2013), and billing and data management costs at $5.6 million per year (2013). The administrative, billing and data management costs are escalated at 2.5% (admin costs) to 2.8% (billing and data management costs) per year. The pro forma also shows a ~$3.5 million annual expense for "startup financing" for the first four years. This expense would recover the startup costs and the fund the generation of a cash reserve equaling approximately one month of the CCA's anticipated revenue.

The assumptions for the annual administrative costs provided by DMC showed a range of $2.5 million to $10 million plus $1/MWh variable costs (which would add ~$2 million). Thus, the $5.7 million is within the low-to-high range for annual administrative costs, albeit falling closer to the low end:

DMC Low:	$2.5 million (fixed)	+ $2 million (variable)	=	$4.5 million
DMC High:	$10 million (fixed)	+ $2 million (variable)	=	$12 million
		In Draft Report:		$5.7 million

MRW finds the startup cost estimate to be reasonable, the sources for the billing and data management costs to be sound, and the cost estimate reasonable.

Bonding and Financial Security

As noted in the Draft Report, the CCA Program would be required to post a bond with the CPUC as part of its registration process. The CCA bond is to designed cover the potential reentry costs if the CCA were to fail and return all customers back to PG&E bundled service. The Draft Report estimated that the bond would be sized to cover the administrative cost of customer reentry plus the positive difference between prevailing market prices and the PG&E generation rate. In the early years, it appears that the CCA bond consists primarily, if not exclusively, of administrative costs of customer re-entry. After 2018, the DMC *pro formas* show the CCA bond increasing, indicating a bond amount greater than the simple administrative fees. The Draft Report assumes a carrying cost of 85 basis points on the amount of the CCA bond.

The financial risk associated with this CCA bond is twofold. First, as will be discussed in more detail below, the calculation methodology for the CCA bond amount has not been set and there is a proposal that could result in CCA bond amounts much greater than that assumed in the Draft Report. Second, even under the calculation methodology used by DMC, a significant increase in wholesale power prices would result in a dramatic increase in the CCA bond. Unfortunately, the Draft Report does not consider such a scenario. Examining what might be required in the CCA bond in the event of a hypothetical price spike is appropriate. For example, if in 2015 market prices were to exceed PG&E's generation rates by $10/MWh (or about 10%), under DMC's assumed methodology for determining the size of the CCA bond, the CCA would have to post a bond of approximately $195 million.

More importantly, there is a yet-to-be approved settlement at the CPUC in the CCA Docket (R.03-10-003) that proposes a formula that would result in even higher CCA bond amounts.[15] The parties in the Settlement do not include any active or near-term prospective CCAs (i.e., MEA or City and County of San Francisco (CCSF)), and both MEA and San Francisco have vigorously opposed the settlement. Furthermore, the CPUC has set the settlement aside while addressing the same fundamental issue for Electricity Service Providers (ESPs) serving direct access customers. In addition, the same Proposed Decision that would revise the PCIA calculation (discussed above), would also apply that formula from CCA bond Settlement for setting ESP financial security requirements. Given that the DA program often sets precedent for CCAs (and vice-versa), there is still a distinct risk that the higher Settlement formula could be adopted for CCAs.

To get an order of magnitude estimate of the bond amount the Settlement calculation would produce, the City and County of San Francisco examined what its CCA bond amount would have been had it been serving customers from 2005 through 2010. It found that over that period, the Settlement bond amount would have averaged $24 per megawatt-hour (MWh) served per year, going as high as $58 per MWh of load served.[16] Multiplying these by the estimated Sonoma CCA load of 1.9 million MWh per year results in an average bond amount ranging from $45 million to $110 million.

There is also the question of how a CCA could finance such a bond. In its comments on the Settlement, CCSF noted:

> Based on the market experience of MEA, CCSF has learned that bonding, insurance and finance companies do not currently offer and are not willing to provide the bond or other security instruments in the Settlement, regardless of the risk to provide of a CCA's operations. As a result, CCAs will be forced to post cash to meet the Settlement's bond requirement.[17]

CCSF goes on to note "even if a CCA's risk of ceasing operations is minimal, the expense of the bond requirement, by itself, could force a CCA out of business."[18]

In comments filed in February 2011 in that same proceeding, MEA and CCSF refined their credit position to state that it would take "at least 3 years" before a CCA could become sufficiently credit worthy to engage an insurance or finance company to underwrite the CCA Bond.[19]

Overall, for the purposes of this initial CCA feasibility study, the DMC assumptions concerning the CCA bond amount are reasonable, while the assumption that a CCA could ultimately get the CCA bond financed, at least in the first few years, is questionable. As the CCA bond Settlement calculation

[15] R.03-01-033, Joint Motion Of City Of Victorville, Pacific Gas And Electric Company (U 39-E), San Diego Gas & Electric Company (U 902-E), San Joaquin Valley Power Authority, Southern California Edison Company (U 338-E), And The Utility Reform Network For Adoption Of Settlement Agreements. June 24, 2009.

[16] R.03-10-003, (Revised) Comments of the City and County of San Francisco on the Proposed Decision of Administrative Law Judge Yip-Kikugawa, December 9, 2010. Page 7.

[17] Op cit at 2. Supported Opening Comments Of Marin Energy Authority On Proposed Decision Adopting Bond And Other Requirements For Community Choice Aggregators, December 9, 2010. Page 2.

[18] Op cit at 2.

[19] R.03-10-003, Supplemental Brief Of Marin Energy Authority On Proposed Bond Methodology, February 28, 2011. Page 6.

methodology could be ultimately adopted, and/or finance companies may continue not to offer suitable products to CCAs to meet their bonding requirements, there are distinct risks that should be explored in any future feasibility analyses.

Greenhouse Gas Impacts

To calculate the greenhouse gas (GHG) impacts of the Sonoma CCA providing service to customers instead of PG&E it is necessary to identify the marginal generating resources on the PG&E system that would not operate due to Sonoma's departure. The emission factors for these resources can be used to create a baseline for comparison with each of the Draft Report's scenarios. If Sonoma customers were to depart, PG&E would need to procure less renewable generation in order to meet the state's standard, thus it is reasonable to apply the same renewable standard to avoided generation assumptions. The remainder of the baseline consists of electricity generation "on the margin" that PG&E would not procure due to customer departure.

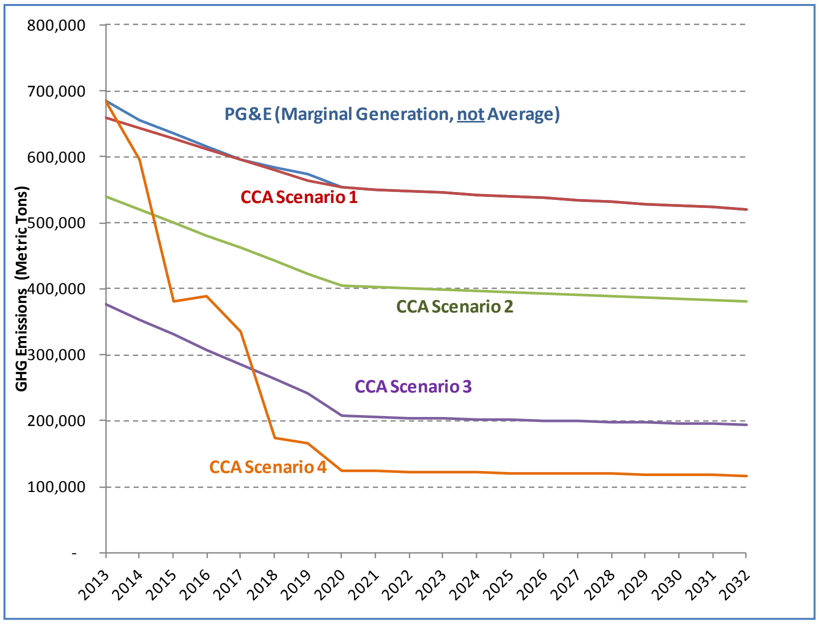
DMC's baseline emissions rate assumption properly includes the RPS percentage, and for the remainder relies on the unspecified power emissions rate as determined by the California Air and Resources Board of 0.435 Metric Tons/MWh. This is probably a conservative assumption (i.e., the emissions rate avoided by the CCA) because this emissions rate includes both marginal resources and more efficient gas-fired resources that are likely to be on the margin for very few hours of the year, if at all. A more accurate emission rate may be 0.499 Metric Tons/MWh, which is the value recommended by the California Energy Commission and the California Public Utilities Commission.[20] Updating the assumption for the higher marginal emissions rate yields a baseline emissions rate that is ~15% higher than the emissions rate used in DMC's analysis. Thus, the Draft Report may *underestimate* the GHG emission reductions associated with the CCA.

It should also be noted that even with accelerated renewables deployment, the Sonoma CCA's *average* emission rates would exceed PG&E's average emission rates in all but the most aggressive scenario. This is due to PG&E's fleet of GHG-neutral generation resources, in particular its large hydroelectric facilities and nuclear power generation.[21] While comparison of the average emission rate is not the proper means of evaluating the GHG impacts of Sonoma CCA customers departing PG&E load, Sonoma should be aware that opponents may point to these figures as they did in the case of Marin Clean Energy.

The Draft Report shows GHG emissions reductions for each scenario separately and does not offer a value for PG&E emissions. This makes it difficult to assess whether the reductions represented are a large percentage of overall emissions. Figure 9 below shows the GHG emissions expected in each year of the forecast for PG&E and for each CCA Scenario. From this figure, it is clear that the more aggressive scenarios (Scenarios 2 through 4) offer substantial reductions relative to PG&E's marginal emissions.

[20] California Air Resources Board Staff Report. Initial Statement of Reasons for Rulemaking: Revisions to the Regulation for Mandatory Reporting of Greenhouse Gas Emissions Pursuant to the California Global Warming Solutions Act of 2006. October 28, 2010, p. 168.
[21] Note that PG&E's large hydroelectric and nuclear facilities are not counted toward meeting PG&E's RPS goals.

Figure 9: Forecasted GHG Emissions



In addition to showing the overall emissions reductions in each CCA scenario, the Draft Report offers a monetary value for those emissions based on what the cost would be to procure GHG emission allowances for that level of emissions. MRW finds this representation misleading. These monetary benefits would not be accrued to Sonoma County or to Sonoma CCA ratepayers. Inclusion of these data in the analysis would likely be confusing to members of the public and we recommend their removal from the final Report.

Economic Development Impacts

DMC assessed the potential economic development benefits associated with the creation of a CCA using the Jobs & Economic Impact Development (JEDI) model developed by the National Renewable Energy Laboratory. The key outputs of this model are jobs, earnings and economic output. The results of the model for the three scenarios developed by DMC are shown in Table 3.

Table 3. Summary of Reported Economic Development Benefits ($millions)

	Scenario 1			Scenario 2			Scenario 3			Scenario 4		
	Jobs	Earnings	Output	Jobs	Earnings	Output	Jobs	Earnings	Output	Jobs	Earnings	Output
During Construction												
Project Development and Onsite Labor Impacts	199	$26.23	$32.79	297	$39.18	$48.97	1,261	$119.97	$155.96	413	$49.98	$63.04
Power Gen & Supply Chain Impacts	158	$10.47	$36.93	237	$15.63	$55.16	972	$59.12	$182.78	368	$23.70	$78.51
Induced Impacts	157	$8.44	$26.03	234	$12.61	$38.87	700	$38.22	$117.80	308	$16.66	$51.35
Total Impacts	514	$45.14	$95.75	768	$67.42	$143.00	2,932	$217.31	$456.54	1,088	$90.34	$192.90
During Operating Years												
Onsite Labor Impacts	3	$0.16	$0.16	4	$0.24	$0.24	27	$1.79	$1.79	16	$1.05	$1.05
Local Revenue and Supply Chain	35	$2.61	$11.25	54	$4.08	$17.80	125	$8.99	$41.92	201	$11.95	$58.56
Induced Impacts	21	$1.14	$3.51	33	$1.77	$5.46	71	$3.87	$11.92	98	$5.28	$16.26
Total Impacts	59	$3.91	$14.92	91	$6.09	$23.49	223	$14.65	$55.63	314	$18.27	$75.87

The model attempts to quantify direct, indirect and induced benefits associated with the construction of local power projects. Each of these benefits is discussed below.

Direct Benefits

The direct benefits include the jobs and earnings resulting from the construction and operation of local power projects. For example, in Scenario 1, the JEDI model estimates that 199 jobs will be created during construction (approximately 99 during each year of construction) and 3 jobs will be created for operation of the power projects. Earnings assume salaries of approximately $130,000 per year for project development and $53,000 per year for operation. As the scenarios demonstrate, jobs and earnings increase with additional local power projects.

The estimates associated with the direct impacts are the most certain, but depend on the number of jobs created and the salaries for each position. In addition, if the jobs are not sourced locally, but rely on workers from other areas of the country, state or region, the local direct impacts would diminish.

Indirect Benefits

The indirect benefits include the jobs and earnings that are an indirect result of power project construction and operation. For example, this might include jobs associated with manufacturing equipment necessary for the power project. In Scenario 1 above, DMC estimates that 158 indirect jobs would be created as a result of the power project, with salaries of approximately $66,000. The indirect effects increase with the number of local power projects.

The estimates associated with the indirect impacts are more uncertain than the direct impacts discussed above. The JEDI model uses “economic multipliers” to approximate impacts within the supply chain (e.g., manufacturing job creation). These multipliers are only estimates of potential effects and, perhaps more importantly, may not fully take into consideration that these effects may occur outside the local area. It is possible, for example, that the manufacturing jobs created as a result of power projects would be out of the local area or the U.S. entirely. DMC indicated that it made subtle adjustments to attempt to account for these issues,[22] but to the extent that these multiplier effect assumptions miss the mark, the indirect job and earnings figures could be overestimated.

Induced Benefits

The induced benefits are jobs and earnings resulting from spending made by those with additional jobs as a result of new power projects. In Scenario 1, DMC estimates that 157 induced jobs would be created as a result of the power projects, with salaries of approximately $55,000. As with the other benefits, the induced effects increase with the number of local power projects.

The estimates associated with the induced impacts are also fairly uncertain. The JEDI model uses "economic multipliers" to approximate the induced effects. These multipliers are only estimates of potential effects and, again, may not fully take into consideration that these effects may occur outside the local area. It is possible, for example, that the spending associated with either directly created or indirectly created jobs would occur out of the local area. To the extent that these multiplier effect assumptions overestimate the extent of *local* spending, the induced job and earnings estimates could be too high.

Conclusions on Economic Development Estimates

Overall, MRW agrees qualitatively with the Draft Report that local projects would stimulate local economic activity. However, MRW has three general concerns with the quantitative economic development estimates. First, all macro-economic models have build-in uncertainties and whose forecasts should be seen as order-of-magnitude indicative rather than precise. Second, the models are generally designed to look at larger geographic areas than Sonoma County. When attempting to apply the JEDI model to a smaller area, uncertainty is greatly increased due to the impact of "spillover" into adjacent areas (i.e., workers on Sonoma projects living and spending money in Marin or Napa Counties.) DMC appears to have attempted to take this issue at least partially into account, but it is not clear to what degree.

Third, the JEDI model estimates the direct, indirect and induced effects associated with new power projects, but does not take into consideration that there could be a negative "ripple" effect associated with higher rates necessary to pay for these projects over time. In other words, if residents and businesses pay higher rates for local projects, they could spend less money in the local economy, which could have negative indirect and induced multiplier effects. While we would not expect that these negative indirect and induced effects would cancel out benefits of local projects, they were not acknowledged or included in the analysis.

Sensitivities

The Draft Report examined the sensitivity of the results to a number of factors, most of which have been discussed above. Table 4, below, replicates Table 13 in the Draft Report, but adds some additional information to better draw attention to the results: the least cost rate scenario is highlighted, along with

[22] "Furthermore, DMC reviewed and updated other assumptions that are applied within each model to allocate proportionate spending for certain project development activities, including capital and labor, within the local economy. For example, wind turbines would, in all likelihood, be purchased from a supplier outside of Sonoma County, but select hardware required to install these turbines may be purchased from local suppliers. Projected impacts to local economic development were "fine-tuned" by incorporating these subtle adjustments to many of the models' default inputs." Draft Report, p. 14.

the price and NPV cost differences between the least cost CCA scenario and PG&E's generation rates. As Table 4 shows, of the 11 sensitivity cases shown, the PG&E bundled rate is the lowest in 7 of the 11 and equal to the CCA Scenario 1 in one case (MEA Shared Savings).

The Draft Report did not include sensitivity analysis for CCA Scenario 4. However, given the resource mix and base case levelized cost for this Scenario, it is conceivable that it would have the lowest levelized price in the low renewable cost scenario.

Table 4. Summary Sensitivity Cases

Rate Scenario	Base Case	High Gas	Low Gas	High R.E. Costs	Low R.E. Costs	High PG&E Rates	Low PG&E Rates	High PCIA	High Opt Out	Low Opt Out	MEA Shared Services
CCA Scenario 1	21.8	24.1	20.7	22.3	21.2	21.8	21.8	22.5	21.9	21.7	21.6
CCA Scenario 2	21.9	23.8	21.0	22.7	21.0	21.9	21.9	22.6	22.0	21.8	21.7
CCA Scenario 3	22.8	24.2	22.1	24.2	21.4	22.8	22.8	23.5	22.9	22.7	22.6
CCA Scenario 4	22.0	Not Reported									
PG&E Bundled	21.6	22.9	20.9	21.6	21.6	23.1	20	21.6	21.6	21.6	21.6
Difference, Best CCA Scenario & PG&E Bundled	+0.2	+0.9	-0.2	+0.7	-0.6	-1.4	-0.8	-0.9	-0.3	-0.1	n/a
NPV of cost difference, ($ millions)	$43.5	$195.6	($43.5)	$152.1	($130.4)	($282.5)	$391.2	$195.6	$65.2	$21.7	n/a

Joint Action with MEA

The Draft Report notes that the Marin Energy Authority (MEA) is exploring opening up membership to municipalities outside of Marin County, and that MEA staff presented an estimated cost (to be paid by the new MEA member communities) of $130,000. The Draft Report noted that an entity as large as Sonoma County joining MEA might likely incur higher costs, which were estimated at $500,000. The Draft Report further estimated that some level of operational savings would occur, which was estimated to "begin" at $2.6 million per year and total $74 million over the study period. MRW agrees that there would likely be reduced startup costs and operational synergies in joining MEA, and finds the DMC estimates to be reasonable rough cut estimates. However, MRW believes that there is significant uncertainty in the overall level of benefits of joining MEA.

A key uncertainty is what is meant by membership or a "shared services arrangement." In particular, some major unknowns are how much autonomy would Sonoma lose in such a partnership and what non-financial considerations would be asked of the County. In the conclusions section of the Draft Report, DMC notes that "board representation, autonomy in resource planning and other political considerations" would need to be addressed. These issues are not trivial and should not be underestimated. MEA would not enter into an arrangement with Sonoma or any other entity if MEA felt that such an arrangement did not benefit MEA or the Marin residents and businesses that MEA currently serves. Thus, Sonoma should expect to have to compromise on some of its goals, be it building local generation, meeting GHG targets, or meeting rate impact goals, in order to gain the benefits of the synergies of joining, or working with, MEA.

Draft Report's Evaluations and Recommendations

The Draft Report's main conclusion appears to be that "a Sonoma County CCA Program would provide significant benefits – both economic and environmental – and could be accomplished with customer rates little changed from current projections of the status quo." MRW finds this conclusion overstates the likely results of formation of a CCA. First, while economic benefits will likely occur from any local generation projects undertaken by the CCA (either directly or via a PPA), the values shown in the Draft Report are uncertain and overstated. Furthermore, the Draft Report is clear that under the base case assumptions and most sensitivity scenarios, PG&E will offer lower rates that can be afforded by the CCA. A summary of all benefits and costs associated with formation of a CCA (e.g., net benefits equal the economic development benefits *less* the incremental rates paid and the indirect and induced negative economic impacts from the higher rates) was not presented to demonstrate this conclusion. MRW believes a more accurate conclusion would be that local economic benefits would likely accrue to the County, but at a cost of electricity rates that will be, in all likelihood higher than PG&E's.

The Draft Report appropriately acknowledges that:

> Tradeoffs also exist between minimizing ratepayer costs in the short run and expanding use of renewable energy due to the cost premiums that currently exist for renewable energy. Decisions made during the implementation process and during the life of the CCA Program will determine how these considerations are balanced. DMC recommends that considerable thought be given upfront to the ultimate goals of the CCA Program so that clear objectives are established, giving those responsible for administering the CCA Program the opportunity to develop and execute a plan that meets the community's objectives.[23]

MRW heartily endorses DMC's last recommendation: that the County explicitly determines what the goals of a CCA Program are so that clear objectives can be set. It may be the case that the higher electric costs for the citizens and businesses of Sonoma County are an acceptable tradeoff for the potential for local economic growth, local control, and other potential benefits of a CCA. However, MRW believes that such a tradeoff should be explicitly identified.

With respect to working with MEA, the Draft Report notes that further discussion with MEA is reasonable to "better understand how such a relationship might be structured."[24] MRW agrees. This discussion should occur in light of the goals and objectives of a Sonoma CCA. However, to actively pursue a relationship with MEA without first setting Sonoma's goals and objectives would be premature.

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[23] Draft Report, page 48.
[24] Draft Report, page 48.