Community Choice Aggregation

Base Case Feasibility Evaluation

County of Marin

Prepared By Navigant Consulting, Inc

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EXECUTIVE SUMMARY

This report offers Navigant Consulting, Inc.'s (NCI) evaluation of the feasibility of forming a Community Choice Aggregation program, pursuant to provisions of Assembly Bill 117, whereby the County and the cities within the County would aggregate the electric loads of customers within their jurisdictions for purposes of procuring electrical services. Community Choice Aggregation relates to electric generation services only. Delivery of the electric power would continue to be provided over PG&E transmission and distribution facilities at rates regulated by the California Public Utilities Commission (CPUC) and under the same terms and conditions that apply today. Community Choice Aggregation allows the County to provide retail generation services to customers without the need to acquire transmission and distribution infrastructure. All PG&E customers within the County would have the option of buying electricity from the County or, alternatively, remaining as generation customers of PG&E by exercising their rights to opt-out of the program.

AB 117 grants the County authority to competitively procure electric services rather than continuing to rely on PG&E as the single supplier for electric services provided to customers within the County. Implementation of Community Choice Aggregation provides the community the power to choose what resources will serve their loads. Expanded access to competitive suppliers and local control of resource planning decisions provides opportunities to enhance rate stability for customers, significantly increase utilization of renewable energy resources, and generate electricity cost savings.

The detailed analysis performed for the County suggests that by forming a Community Choice Aggregation program, backed by investments in generation resources, the County program could:

- Achieve nominal electricity cost savings averaging $6.8 million per year, equivalent to approximately 3% of total electricity bills;
- Increase renewable energy utilization to 51% by 2017, more than doubling the renewable energy content that PG&E would provide over the same time period;
- Obtain control over electric generation costs to provide a higher level of rate stability for local residents and businesses;

The scenario sensitivity analysis contained in this report shows that the existence of cost savings is not dependent upon the specific financial assumptions underlying the base case feasibility assessment but is primarily dependent upon the supply portfolio developed for the program. The average program savings range from a low of 1% to a high of 14% across the eight scenarios evaluated to test the sensitivity of these results to changes in wholesale energy market conditions, PG&E rate projections, and cost responsibility surcharges. Although the County could implement a CCA program without investing in generation resources, such a strategy is unlikely to yield sustainable electricity cost savings. NCI recommends a staged approach to implementation that includes initially purchasing all of the program's electric supply requirements on the open market and transitioning to a strategy of generating the bulk of the program's resource needs through community-owned generation.

The conclusions and recommendations of this study took into consideration the County's known interests and objectives. The study reflects substantial involvement of County staff, both individually and through a series of discussions with other local governments participating in the project. Various portfolio options were evaluated in terms of their effectiveness in meeting the objectives and interests of the community. Following detailed review of the options, a preferred portfolio option was jointly developed with staff that would best satisfy the stated objectives and interests of the County.

This report and supporting analysis show that it would be feasible and economically viable for the County to implement a Community Choice Aggregation program as early as 2006. Whereas all current CPUC decisions are reflected in the feasibility assessment, the CPUC is still in the process of finalizing certain detailed rules and protocols that will apply to Community Choice Aggregation. The ongoing phase of the CPUC rulemaking is focused on operations and transactional issues that will be important to a Community Choice Aggregation program's operations but that are unlikely to materially impact the base case feasibility assessment presented herein.

Energy procurement and resource planning are subject to certain risks or uncertainties that must be managed by the energy supplier, whether it is PG&E or the operator of a Community Choice Aggregation program. Forming a Community Choice Aggregation program would not increase operational risks, but responsibility for their management would transfer to the Community Choice Aggregator and/or its suppliers. The County will be able to obtain services from a variety of large, experienced suppliers to help manage the Community Choice Aggregation program. It would therefore be able to manage energy procurement risks at least as effectively as does PG&E. Professional program management and application of standard industry risk management practices will be keys to this effort.

The County can phase-in implementation of Community Choice Aggregation to help ensure a smooth transition for customers that join the program. A phase-in would reduce implementation risk, contribute to the program's financial benefits during the initial startup stage, and reduce the need for initial capital to startup the program.

NCI recommends that the County implement its Community Choice Aggregation program through formation of a joint powers agency (JPA) with the cities within the County. The JPA structure provides critical mass for the program and provides an appropriate financing vehicle for the capital investments needed to support a cost-effective aggregation program. Additional financial benefits could be obtained by jointly operating the program with other local governments in Northern California that are also participants in the Community Choice Aggregation Demonstration Project via formation of a wider regional JPA or through contractual arrangement with these entities, enabling common program operations. Regional program operations provide economies of scale that enhance the economic benefits available to the County through Community Choice Aggregation.

LIST OF ACRONYMS

A&G – Administrative and General
AB 1890 – Assembly Bill 1890
AB 117 – Assembly Bill 117
CAISO – California Independent System Operator
CCA – Community Choice Aggregation
CEC – California Energy Commission
CPUC – California Public Utilities Commission
CRS – Cost Responsibility Surcharge
CTC – Competition Transition Charge
DG – Distributed Generation
DWR – Department of Water Resources
FERC – Federal Energy Regulatory Commission
GRC – General Rate Case
IOU – Investor Owned Utilities
IT – Information Technology
JPA – Joint Powers Agency
KW - Kilowatt
KWh – Kilowatt hour
MW – Megawatt
MWh – Megawatt hour
NOPEC – Northern Ohio Public Energy Council
NOx – Nitrogen Oxides
NP15 – North of Path 15
O&M – Operations and Maintenance
PG&E – Pacific Gas and Electric Company
PTC – Production Tax Credit
PUC – Public Utilities Code
PUCO – Public Utilities Commission of Ohio
PV - Photovoltaic
QF – Qualifying Facilities
RE – Renewable Energy
REC – Renewable Energy Certificate
RPS – Renewable Portfolio Standard
RRDR – Renewable Resource Development Report
SCE – Southern California Edison Company
SDG&E – San Diego Gas and Electric Company
SEP – Supplemental Energy Payment
VEE – Verification, Editing and Estimation

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1 INTRODUCTION

1.1 Objective

The County is a participant in the Local Government Commission Community Choice Aggregation Demonstration Project, which was commissioned by the California Energy Commission (CEC) and the United States Department of Energy to assist local governments in evaluating and implementing Community Choice Aggregation. Under Community Choice Aggregation, the County and the cities within the County would aggregate the electric loads of customers within their jurisdictions for purposes of procuring electrical services.[1]

The purpose of this report is to evaluate the feasibility of the County forming a Community Choice Aggregation Program. The report contains detailed economic feasibility analyses and recommendations to help the community evaluate the costs and benefits afforded by Community Choice Aggregation and move towards development of an Implementation Plan.

The report and analyses contained herein comprise project deliverable Task 4: Load Analysis and CPUC Decision Based Feasibility Analysis. This report builds upon the Load Analysis and Assumptions Based Feasibility Analysis previously provided to the County, which presented economic feasibility results for a CCA program utilizing four alternative supply portfolios. Upon review of the preliminary results, the County provided input on its preferred supply portfolios with respect to the percentage of its supply it desires to be produced from renewable energy resources and whether the County intends to utilize its municipal financing capabilities to reduce the costs of is electricity procurement program by financing energy development projects. These supply preferences and other feedback received from the County staff are reflected in this final report. This report additionally incorporates the CPUC's December 16, 2004 decision in Phase 1 of the CCA rulemaking (Decision No. D.04-12-046).

As second phase of the Demonstration Project will include the development of a template for use by communities in developing Implementation Plans for submission to the California Public Utilities Commission (CPUC). Communities can utilize the template to help them develop their Implementation Plans.

[1] Throughout this report, the entity formed to become a Community Choice Aggregator, comprised of the County and the cities within the County, is denoted by the term "Aggregator".

1.2 Project Elements And Timeline

NCI recommends a two-phased approach for consideration of forming a CCA program. Phase 1 includes the base case feasibility study and report, while Phase 2 includes development of an Implementation Plan for submittal to the CPUC. A high level overview of these phases is shown below:

Phase 1 Element	Timeline
Community Selection	Complete
Participant Orientation	Complete
Renewable Resources Workshop	Complete
Base Case Feasibility Analysis	Complete
Participation in CPUC CCA Rulemaking Phase 1	Complete
Draft Evaluation and Report	Complete
Final Feasibility Analysis	March 2005
Final Evaluation and Report	March 2005
Phase 2 Element	
Development of Implementation Plan Template	Ongoing
Participation in CPUC CCA Rulemaking Phase 2	Jan. 2005 – Jun. 2005
Prepare and Submit Implementation Plan	Summer 2005
Support Implementation Plan Filing At CPUC	Summer 2005

1.3 Phase 2 - Implementation Plan

After considering the expected benefits and costs of forming a CCA program, communities that wish to proceed with forming a CCA program will need to develop an Implementation Plan. AB 117 requires submission of an Implementation Plan to the CPUC prior to the CCA commencing operations. The law requires the Implementation Plan to "detail the process and consequences of aggregation." The Implementation Plan and subsequent changes to it must be adopted at a duly noticed public hearing. The Implementation Plan must contain all of 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;
- 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 CCA must prepare a statement of intent with the Implementation Plan. Any CCA program shall provide for the following:

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

The California Public Utilities Commission has responsibility to review the Implementation Plan submitted by an Aggregator, and it may establish additional detail regarding the form and content of an Implementation Plan in Phase 2 of R.03-10-003.

2 OVERVIEW OF CCA

2.1 What Is CCA?

Assembly Bill 117 permits California cities, counties, or city and county joint powers agencies ("local governments"), to implement a program to aggregate the electric loads of electric service customers within their jurisdictional boundaries to facilitate the purchase and sale of electricity. The local government would become a Community Choice Aggregator ("Aggregator") to procure electric energy for residents and businesses within a community. All customers currently receiving electric generation services from PG&E would be automatically enrolled in the program, unless the customer notifies the Aggregator of its desire to opt-out and remain a bundled service customer of PG&E. The Aggregator would be responsible for operating the CCA program, either by performing the functions necessary for program operations utilizing its own employees or by contracting out operations to one or more third-party operators or energy services providers.

Within the context of CCA, "*electricity*" means the electric energy commodity only. CCA's enabling legislation requires local utilities such as PG&E to provide electricity delivery over its existing distribution system and provide end-consumer metering, billing, collection and all traditional retail customer services (i.e., call centers, outage restoration, extension of new service). Accordingly, the infrastructure requirements of the CCA program do not include any electric transmission or distribution related facilities to serve CCA retail loads. PG&E must provide delivery services to CCA customers under the same terms and conditions as provided to other of its customers.

It is important to distinguish an Aggregator from municipal utilities and from energy service providers as each of these entities provides different services, has different responsibilities, and operates under different regulatory frameworks. A local government that implements a community choice aggregation program does not become a municipal utility in the manner of the Los Angeles Department of Water and Power or the Sacramento Municipal Utility District, which own and operate transmission and distribution systems. A critical distinguishing factor is that the Aggregator would not own the electric distribution system within the County. Rather, it would own or procure electric power from the wholesale markets, either through ownership of resources, market purchases, or through a partner on behalf of the customers that choose to aggregate their loads. The local investor owned utility (PG&E, SCE, or SDG&E) would then be required to deliver the electric energy to the end-use customer across its transmission and distribution facilities. In this sense, an Aggregator is similar to an electricity service provider that sells electricity to direct access customers. However, there are important differences between CCA and direct access, and these two programs will operate under different sets of rules established by the CPUC.

Customers of the CCA will pay the same charges for delivery (transmission and distribution) as customers that remain as full service, "bundled" customers of PG&E. These delivery charges represent approximately one half of the typical household's monthly electric bill. The Aggregator will establish rates for the generation services it provides to CCA customers, and these customers will no longer pay PG&E for generation services. However, PG&E will be authorized to assess a surcharge for certain of its generation related costs that might otherwise be shifted to its remaining bundled service customers. This surcharge is known as the "cost responsibility surcharge" or "CRS", and it will be regulated by the CPUC. The cost responsibility surcharge is discussed in greater detail in Section 5.3.2.

By law, PG&E will perform all metering and billing for CCA customers. PG&E will collect the Aggregator's charges from CCA customers and transfer the funds collected to the Aggregator in the monthly billing process. To a large extent PG&E's costs of providing metering, billing and customer services are included in their existing delivery charges. However, the utilities have asserted that CCA programs will cause additional costs related to metering, billing and customer services, and they have requested the CPUC to authorize additional charges to be assessed on Aggregators or CCA customers. This and other issues in the CPUC Rulemaking are discussed in Section 2.5.

2.2 Legal And Regulatory Authority

A CCA program for electric customers is governed by the Community Choice Aggregation legislation (AB 117, Chapter 838, September 24, 2002[2]). A local government could become an Aggregator for electric utility generation by developing an Implementation Plan, and then having this plan approved by the CPUC. AB 117 offers flexibility in that it is an "opt-out" program rather than an "opt-in" program. This would allow the Aggregator to sign up customers willing to switch from PG&E generation service to CCA service without the necessity of developing an active marketing effort to lure customers. Instead, the Aggregator would merely need to notify customers of the impending Community Choice Aggregation program. Any customers that do not want to participate in the program would be required to notify the Aggregator of their election to opt-out within a specified amount of time.

[2] AB 117 became effective January 1, 2003 amends Sections 218.3, 366, 394, and 394.25 of the Public Utilities Code and creates Sections 331.1, 366.2, and 381.1 to the same Code.

AB 117 also requires full cooperation by the host investor owned utility in any CCA program implemented by the County. In this regard, AB 117 would require PG&E to provide necessary load information and other important data and continue to provide transmission, distribution, metering, meter reading, billing and other essential customer services.

2.2.1 Requirements After Filing The Implementation Plan

1. Within 10 days after the Implementation Plan is filed, the CPUC will notify PG&E (PUC Section 366.2(c)(6)).

2. Within 90 days after the Aggregator files an Implementation Plan the CPUC shall certify that it has received the Implementation plan, including any additional information necessary to determine a cost recovery mechanism. The Commission shall designate the earliest possible date for implementation of a CCA program (PUC Section 366.2(c)(7)).

3. The Aggregator must offer the opportunity to purchase electricity to all residential customers within its political boundaries (PUC Section 266.2(b))

4. PG&E shall fully cooperate with the Aggregator, including providing appropriate billing, and electrical load data, in accordance with CPUC procedures (PUC Section 366.2(c)(9))

5. The Aggregator must fully inform all customers of their right to opt-out of the CCA program and to continue to receive service as a bundled customer from PG&E. All customers must be notified twice within two months or 60 days prior to the date of automatic enrollment. In addition, notification must continue for participating customers for at least two consecutive billing cycles after enrollment (PUC Section 366.2(c)(11),(13).

6. Notification must contain the following information:
   - Customer will be automatically enrolled
   - Each customer has the right to opt-out of the program without penalty
   - The terms and conditions of CCA service (PUC Section 366.2(13)(A))

7. 7The Aggregator may request the Commission to approve and order PG&E to provide the customer notifications (PUC Section 366.2(13)(B)).

8. The Aggregator must register with the CPUC and may be required to provide additional information in order to verify compliance with rules for consumer protection and other procedures (PUC 366.2(c)(14)). At the time

of registration, the Aggregator must post a bond or provide evidence of sufficient insurance to cover any reentry fees that may be imposed against it by the CPUC for involuntarily returning a customer to service of PG&E (PUC Section 394.25(e)).

9. The Aggregator must notify PG&E that CCA service will begin within 30 days (PUC Section 366.2(c)(15)).

10. Once notified, PG&E shall transfer all applicable accounts to the new supplier within a 30-day period from the date of the close of their normally scheduled monthly metering and billing process (PUC Section 366.2(c)(16)).

11. PG&E shall recover from the Aggregator any costs reasonably attributable to the Aggregator, as determined by the CPUC (PUC Section 366.2(c)(17)).

2.3 Status Of CPUC Rulemaking

While AB 117 does provide a statutory basis for Community Aggregation projects, the CPUC has not yet developed and implemented final rules for the development of such programs. On September 4, 2003, the CPUC issued an order instituting a rulemaking or "OIR" (Rulemaking 03-09-007) in order to develop the guidelines for community aggregation programs, as it was directed to do under AB 117. On October 2, 2003, the CPUC reissued the rulemaking under Docket No. R.03-10-003. The CPUC bifurcated the proceeding into two phases. The scope of Phase 1 is to determine issues related to costs imposed by the local utilities on Aggregators and CCA customers, namely cost responsibility surcharges, transaction fees, and implementation costs. The general scope of Phase 2 is to address the processes for interactions between Aggregators and the local utilities and other operational details. The issues identified with each phase are listed below:

2.3.1 Phase 1 Issues

- Cost responsibility surcharges – methodology, transparency, caps, new utility procurement, rate design, phasing, assumption of in lieu MWh
- Transactions costs - implementation fees, fees related to CCA establishment, enrollment fees, billing, payment and collection, monthly account maintenance fee, interval metering fee, termination of CCA program fee, special request fee, information fees
- Customer information issues – data needs of Aggregators, customer confidentiality protections

2.3.2 Phase 2 Issues

- The detailed processes, costs, and fees authorized for the utilities' CCA implementation activities and utility transactions with CCAs (e.g., metering, billing, CCA establishment, notifications, enrollments, account maintenance, termination)
- Rules and formats for notifying customers of CCA service and customer opt-out opportunities
- Rules for switching customers to CCA service, processing customer opt-outs, and returning CCA customers to utility service
- Customer reentry fees and bonding requirements imposed on CCAs
- CCA phase-in mechanisms and guidelines
- CCA consumer protection obligations
- CCA Implementation Plan requirements

The Commission issued its final decision (D.04-12-046) in Phase 1 on December 16, 2004. The schedule for Phase 2 has not yet been established, but it is expected to conclude in the second or third quarter of 2005.

2.4 Aggregation In Other States

Aggregation programs exist in both Massachusetts and Ohio, with the Ohio program being most similar to Community Choice Aggregation in California. Ohio includes provisions for government aggregation on an opt-in or opt-out basis. According to the Public Utilities Commission of Ohio (PUCO), Ohio has had among the most successful electric choice programs in the nation, with government aggregation leading the way.[3] The greatest success is in those areas of Ohio that have adopted aggregation. Northern Ohio has enjoyed a high rate of customer switching due in large part to this process whereby communities band together to buy electricity, in bulk, for their residents. In the first two years of electric choice:

- More than 150 local governments passed ballot issues and were certified by the PUCO to allow local units of government to represent their communities in the competitive electricity market. Ohio is home to the Northeast Ohio Public Energy Council (NOPEC), the largest public aggregator in the United States. NOPEC represents 112 communities in eight counties and more than 350,000 residential customers.

[3] Information about the Ohio aggregation experience was obtained from The Ohio Retail Electric Choice Programs Report of Market Activity 2001-2002, A Report by The Public Utilities Commission of Ohio, May 2003.

Of those customers who have switched in Ohio, aggregation programs account for:

- Nearly 93% of residential customers who have switched in Ohio
- More than 88% of commercial customers who have switched in Ohio
- Nearly 20% of industrial customers who have switched in Ohio

2.5 Implementation Models

There are a variety of approaches the County could take in implementing a CCA program, varying in the degree of operational control, risk and benefits afforded to the County.

2.5.1 Single Third Party Supplier

At one end of the spectrum, the County could pursue a minimalist approach, essentially serving as a conduit between electric customers within the County and a third party electric supplier. The Aggregator would solicit offers from electric suppliers to serve the customers that choose to participate in the program (i.e., do not opt out) and would largely rely on the supplier to administer the program. An example would be for the Aggregator to negotiate a guaranteed discount to the prevailing PG&E rate such that the supplier absorbs the risks of meeting the obligation to provide electricity cost savings. This approach offers very little risk to the Aggregator but also limits the potential upside, especially with respect to the benefits offered by municipal-financed generation assets or financing arrangements.[4] Suppliers may not be willing to absorb the risks associated with factors that are outside the control of the supplier, such as those posed by changes in PG&E rates or the CRS. Furthermore, under the assumption that suppliers would not charge less than the market price of electricity as utilized in this analysis, the imposition of the CRS would appear to eliminate the opportunity for cost savings to be obtained in the near term. Indicative bids from electricity suppliers should be obtained early in the County's implementation planning to help determine whether this approach is financially viable.

2.5.2 Multiple Third Party Service Providers

In pursuing this approach, the Aggregator would "unbundle" the electric services needed for the program and negotiate contracts with third parties for provision of these discrete services (e.g., billing services, scheduling

[4] It may be possible to negotiate agreements with the electric supplier to integrate municipal resources or utilize municipal bonding, but this would necessitate greater County involvement than represented by the pure minimalist approach outlined here.

coordination, electric supply). The Aggregator would assume overall responsibility for the program and for the performance of its contractors. The Aggregator would be responsible for setting rates and program policies and for general administration of the program. This approach offers several advantages, including limited staffing requirements, greater control, diffusion of risk (associated with supplier default), and the accumulation of industry knowledge and experience that creates strategic value at the Aggregator. Under this approach, the Aggregator would bear sole accountability for the results achieved by the program; regardless of whether these are successes or failures.

2.5.3 Municipal Operations

In the longer term, the Aggregator could create the organization needed to operate the CCA program, utilizing in-house staff and resources. Recruiting skilled professional staff with electricity operations experience would be a challenging endeavor in the near term and is probably not feasible for a planned 2006 start date. Over time, as the Aggregator gains experience with the program, some or all functions that were initially contracted out to third parties could be brought in-house, if desired.

2.5.4 Unilateral or Joint Operations

The County could implement a CCA program on its own or in combination with other cities and/or counties through a Joint Powers Agency (JPA). Clearly, there would be efficiencies and cost savings achieved by jointly implementing a single program. Such a combined program provides scale economies, improving terms of financing and power supply options. Customers would get the benefits of greater bulk buying power and professional expertise available through a larger organization. A larger organization would wield greater political influence and more effectively participate in the regulatory process to protect member interests. Individual implementation would require a greater investment of time and expense by the County, and would entail generally higher operations costs. A common program also removes some of the risk in making the decision to offer aggregation services to customers because the County would not be proceeding alone.

The primary disadvantage of implementation through a JPA is a joint program could reduce the degree of autonomy exercised by the County over its program.

This report is premised on the County implementing a CCA program in conjunction with the Marin County cities. The report also includes a pro forma analysis of a joint CCA program, in combination with other local government participants in the Demonstration Project. NCI recommends the County coordinate with the other local governments to investigate formation of a regional JPA or, alternatively, contractual arrangements that would provide the efficiencies of combined operations.

3 BENEFITS OF CCA

The primary benefits offered by CCA are local control over the energy resources utilized by the community and the ability to provide electricity to customers at a lower overall cost. The cost savings can accrue to customers through lower electric bills or can be used by the County to provide enhanced services to its constituents. Local control manifests in a variety of benefits giving customers a means to effectuate their preferences regarding the type of electricity production they support as well as obtaining energy services that satisfy their unique needs. Through CCA, the Aggregator can choose to structure a supply portfolio that achieves cost efficiencies, fuel and technological diversity, environmental improvement, and/or cost stability. The Aggregator can choose to develop its own energy resources and decide which type of resources will be developed and where such resources should be located, consistent with its general planning responsibilities.

CCA would facilitate the County's implementation of an aggressive program to increase utilization of renewable energy resources and promote improved energy efficiency. The Aggregator's local perspective and its primary mission to serve its customers rather than maximize profits for shareholders places it in a unique position to integrate effective demand-side energy efficiency programs with procurement of electricity supplies to lower overall energy costs for the community.

Generally speaking, the cost competitiveness of the CCA program will depend on the following factors:

- The mix of customers served by the Aggregator and the rate designs charged by PG&E for the various customer classes
- The composite load profiles (hour-by-hour energy consumptions) of the Aggregator's customer portfolio
- The resource mix utilized by the Aggregator
- The use of low cost municipal bonds to finance generation resource projects
- Electricity prices and prices for other services negotiated with third party electric suppliers
- The trajectory of PG&E's generation costs and whether all cost increases are passed on to CCA customers through the cost responsibility surcharge
- The costs charged by PG&E for implementation activities and transactions such as metering, billing, and customer services.

A CCA program would enable the County to capture the benefits of competition among suppliers for the right to serve the community's load. California's experience with direct access showed that suppliers were willing to offer discounts to large customers of the investor owned utilities (IOUs). For the most part, discounted rates were not offered to residential customers because of their relatively small loads and the high marketing and transactions costs related to serving mass-market customers. Some suppliers were able to charge higher prices than the IOU's for renewable or "green" energy, and most residential customers that switched to direct access did so to increase the amount of renewable energy used to supply their homes. The opt-out feature of CCA eliminates most of the marketing and transactions costs that limited the opportunities in the direct access market for residential and small commercial customers. Through community aggregation, small customers can obtain competitive electricity supplies directly from the wholesale market on a scale that was simply not feasible under direct access rules.

3.1.1 Lower Electricity Costs

To the extent the Aggregator can obtain electricity at a lower cost than charged by PG&E, the margin can be used to lower rates for CCA customers, contribute to reserve or contingency funds, or augment the County's revenues for provision of public services to its constituents.

A comparison of PG&E's rates to current market prices for electricity indicates the margin embedded in the generation rates charged by PG&E. The table below compares the current system average generation rate for PG&E to the estimated cost of supplying the County at current market prices of electricity.

Cost	Cents Per KWh
PG&E Avg. Generation Rate	7.6
Estimated Supply Cost	5.6
Gross Margin	2.0

Absent the imposition of a CRS, the Aggregator could capture up to 2.0 cents per kWh of margin by procuring electricity at market prices to supply the program. However, AB 117 and ensuing CPUC rules authorize PG&E to impose surcharges on customers of the CCA that are designed to shield PG&E and its remaining customers from the costs of losing customers to the CCA. The surcharge represents the difference, on a system average basis, of the average cost of PG&E's supply portfolio and the market price of electricity. Conceptually, the imposition of the CRS on CCA customers means the Aggregator must obtain electricity supplies at <u>below market</u> prices if it is to provide electricity cost savings to its customers during the time period that the CRS applies.

There are essentially two ways the Aggregator could obtain below-market electricity prices: 1) the Aggregator could negotiate for low cost electric supplies from third party providers, some of whom may be willing to offer discounted prices in order to gain market share and position their firms for sales of other value added services; or 2) the Aggregator could utilize its ability to issue low cost municipal bonds to develop or contract for generation resources. Whereas the opportunity for negotiation of low cost supplies would be circumstantial and ultimately may not materialize, the Aggregator's financing advantage offers a clear and lasting competitive advantage.[5] The Aggregator, being a public agency, can finance generation projects at an effective cost of capital that is approximately one half of PG&E's or the typical merchant generation developer's. As described in greater detail in Section 6.3.2, the municipal financing advantage is particularly well-suited to development of renewable generation projects, with their relatively high capital costs and low operating costs. By financing generation resources (conventional or renewable) or providing capital to prepay for electricity purchases, the Aggregator can obtain electricity at below market costs.

Once the CRS terminates at some point in the future, the Aggregator will compete against PG&E's then current supply portfolio, and PG&E will no longer have the protection afforded by the CRS. By 2013, approximately 40% of the PG&E supply portfolio will be comprised of power purchase contracts executed after 2005. Therefore, the cost competitiveness of PG&E's portfolio in the post CRS timeframe will largely depend upon how efficiently PG&E procures electricity supplies during the next several years. The conservative assumption would be that PG&E will procure electricity at prevailing market prices and that the Aggregator will need to bring its financing advantages to bear in order to obtain electricity cost savings in the post CRS period.

3.1.2 Fuel Efficiency and Environmental Benefits

By implementing a CCA program, the Aggregator can cause new generation to be developed, either by offering contracts to suppliers for the purchase of energy or by direct involvement in developing new resources. Development of new generation, whether renewable or fossil fueled, will displace production from old, inefficient generation sources, which can significantly reduce environmental impacts of electricity production. According to the CEC, approximately one third of natural gas consumption in California derives from production of electricity. Today's natural gas-fired generation units can operate 30% to 40%

[5] For the financial analysis contained in this feasibility analysis it is assumed that third party electric suppliers would offer electricity at the full market price of electricity and would not offer discounts.

more efficiently than the 1960's era generators that are currently online in California. For every kWh produced from a new generation resource, there would be up to 40% less natural gas consumption and even greater reductions in air emissions and greenhouse gases.

A benefit that is particularly important to some communities is the ability to promote use of renewable energy resources and significantly exceed the renewable energy standards applicable to PG&E. Increased renewable generation would reduce air pollution and emissions of greenhouse gases and reduce dependence on natural gas consumption even further. For the same kWh produced by renewable energy resources, natural gas consumption would drop to zero and, depending on the renewable technology employed, air emissions could also be eliminated.

3.1.3 Rate Stability

CCA enables the Aggregator to lock in electricity prices and provide multi-year rate stability to its customers. Business customers in particular tend to value predictability in their energy costs to aid in business planning. Rate stability can be an attractive feature to help lure new businesses into the community or retain those that may be considering leaving due to high and unstable electricity costs. CCA allows the community to negotiate for long-term, fixed priced electric supplies from a variety of suppliers. Likewise, increased reliance on renewable energy technologies reduces exposure to the volatile natural gas market, which in turn is a primary driver of electricity price volatility.

Historically, PG&Es rates have exhibited periods of relative stability punctuated by periods of high rates during times of crisis or the addition of major generation investments. Due to actions taken in response to the energy crisis of 2000-2001, PG&E's current supply portfolio is much more heavily weighted toward fixed price contracts and renewable energy contracts than in the years immediately preceding the energy crisis, and should be expected to deliver relatively stable (but increasing) costs over the next several years. However, PG&E is not free to operate in the market in the most efficient manner and must make procurement decisions within the regulatory context in which it operates. To a large extent, PG&E does not control its own destiny the way an Aggregator can.

The Aggregator would possess autonomy over its electricity procurement decisions and the rates it charges to customers, which provides more control over its costs and greater flexibility in its rate structures than PG&E is allowed under CPUC regulation. More tools are available to the Aggregator to control its electric supply costs and rates. For example, publicly owned (i.e., municipal) utilities commonly create rate stabilization funds using retained margins that enable the utility to weather short-term cost increases without the need to increase rates. In contrast, PG&E cannot execute supply contracts or build new generation resources without CPUC approval, nor can it establish or modify its rates or reserve accounts without express approval from the CPUC. The regulatory approval process can take many months, and the CPUC may in the end deny the utility's requested authorization. Put simply, the Aggregator has more autonomy in its operations than does PG&E, which enhances the Aggregator's ability to provide rate stability to its customers.

New generation is needed to serve California's increasing population and to replace thousands of megawatts of aging power plants that will be retired in the next several years. California is entering a period of major electricity infrastructure investments, and the addition of new utility-owned generation will place upward pressure on PG&E's rates, contributing to future rate instability. By assuming the responsibility for developing the infrastructure needed to serve the County's constituents, the County can shield its constituents from future rate increases caused by PG&E generation investments.

3.1.4 Energy Security

As the majority of new power plants in the United States are fueled by natural gas, the nation is increasingly becoming dependent upon imported natural gas. The flurry of activity related to construction of new liquefied natural gas terminals (LNG) along the California and Baja California coast attests to the increased demand for imported natural gas. Many people are concerned that during the next ten to twenty years the United States will become as dependent on natural gas imports as it currently has become on imported oil. Such dependence raises a host of political, environmental and security issues that potentially threaten the nation's vital interests. By implementing a CCA program that relies more heavily on renewable energy resources, the Aggregator can ensure that the electricity consumption of customers participating in the program does not contribute to the problems associated with increased dependence on imported natural gas.

3.1.5 Customer Choice

CCA provides choice to all electricity customers because all customers have the option of being automatically enrolled in the CCA program or of remaining with PG&E for provision of generation services. Direct access has been "suspended" by the California legislature, and presently CCA is the only mechanism that allows customers to buy electricity from an entity other than PG&E. All customers can benefit from opportunities for choice and the disciplinary effects of competition on PG&E's service even if they do not take advantage of the CCA program.

3.1.6 Demand Side Energy Efficiency

A CCA program would provide an organizational structure to support administration of energy efficiency programs, and it would also enable seamless integration of energy efficiency into the resource planning process of the Aggregator. Energy efficiency or demand side management programs can be tailored to the unique needs of the community and can be integrated with the supply planning of the Aggregator, yielding overall lower supply costs. The Aggregator's rates can provide the revenue bonding capacity to finance worthy public benefits programs such as installation of rooftop photovoltaic systems and energy efficiency investments, with debt service provided via monthly customer bills. The Aggregator's knowledge of the community can help improve the effectiveness of energy efficiency investments, as the Aggregator would be in a better position to identify high potential energy efficiency opportunities in the community.

Local governments should also have strong motivation to deploy effective energy efficiency programs. Investor-owned utilities, such as PG&E, face an inherent conflict of interest in administering energy efficiency programs because the success of their programs reduces the utilities' sales growth and potentially their profitability. As an Aggregator, the County would be motivated to reduce overall energy costs, both on the supply and demand side. An integrated approach to supply planning, energy efficiency and demand response, which reflects the specific circumstances of the community, should translate into greater energy savings.

AB 117 requires that a proportional share of energy efficiency funding be spent in the County if it forms a CCA program. Thus, formation of a CCA program would obligate PG&E to ensure that the County is not under-served by current energy efficiency programs administered by PG&E or third party administrators. The Aggregator could seek authority to replace PG&E as administrator of energy efficiency programs by submitting a program application to the CPUC. However, current CPUC rules do not grant Aggregators special rights regarding access to public goods funding for purposes of administering energy efficiency programs. This issue may be reevaluated in Phase 2 of the CCA rulemaking (R.03-10-003).

3.1.7 Self Generation And Wheeling

A CCA program would provide a legal mechanism to transmit excess power from generation located "behind-the-meter" to other loads within the County. For example, excess production from a County cogeneration or solar facility could be used to serve other facilities rather than being sold to PG&E or lost to the system. The CCA program could enable the County to obtain greater value for its distributed generation facilities.[6]

3.1.8 Regional Economic Competitiveness

The Aggregator could use its ratemaking authority to establish economic development and business attraction rates to help lure desirable businesses and jobs to the community with the benefit of lower rates. Competitive electric rates can also be a factor in retaining businesses that might otherwise leave the community, seeking locations with lower costs of doing business. A CCA program that provides low and stable rates can be an important factor in maintaining regional economic competitiveness.

To the extent the Aggregator initiates development of local generation resources to serve the CCA program, the reliability of the local area would be enhanced.

3.1.9 Creation of Strategic/Asset Value

Formation of a CCA program creates strategic value arising from the creation of assets, infrastructure and annual cash flows. The Aggregator would be developing expertise in energy matters, building infrastructure, and positioning itself for an expanded role in the provision of energy services if future circumstances warrant such an expanded role.

3.1.10 Opportunities For Innovation

A CCA program presents opportunities for the Aggregator to provide innovative energy services to customers. The Aggregator could develop programs that respond to the local concerns, needs, and values of their community members. One example would be formation of "green pricing" programs that provide customers the option of choosing to use more renewable energy. Customers that value renewable energy would be able to voluntarily pay for any additional costs of increasing the renewable energy mix, reducing the costs to be paid by more

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[6] Whether greater value can be achieved in practice would depend upon whether an existing contract is in place governing the sale of excess power from the facility and upon the pricing terms and conditions of the contract.

price sensitive customers. Other innovative services could include special rates for population subgroups (e.g., low income, government facilities, enterprise zones, etc.), program-financed distributed generation, or a host of other value-added services.

4 RISK ASSESSMENT

The risks of forming a CCA program evolve as the County begins its implementation planning process and then progresses to startup of program operations. The County's risk exposure also depends greatly upon the implementation approach utilized by the County, as previously discussed in section 2.5.

The major risk associated with forming a CCA program is the possibility that the rates of the program exceed the comparable rates charged by PG&E, causing customers to become dissatisfied with the program or attempt to return to PG&E service. The Aggregator's ratemaking authority and ability to raise rates if necessary would protect the Aggregator from the financial impacts of unanticipated program cost increases. Further, pending the development of switching protocols in Phase 2 of the CCA rulemaking, the Aggregator could terminate the program, if necessary, and return customers to PG&E service. The program could set aside financial reserves to cover any reentry fees that may be applicable in the case of program termination. For these reasons, the risks of the County forming a CCA program generally remain with the customers that elect to participate in the program. Similarly, customers of PG&E ultimately bear the risks of PG&E's energy procurement practices.

4.1.1 Implementation Plan Stage Risks

At the Implementation Plan stage, the County will have evaluated the feasibility of becoming an Aggregator and assessed the expected costs, benefits, and risks of implementing a CCA program. To progress to the next phase, the County will need to commit additional funds for the development of an Implementation Plan. The primary risk at this stage is political, especially if PG&E directly or indirectly opposes the CCA program. Whereas each of the local utilities has publicly supported CCA, there are always caveats that in practice might cause them to oppose a specific implementation effort as it progresses towards an Implementation Plan.

Typical utility responses to local government energy initiatives are to urge the local government's leaders to slow down so as not to rush into something they do not fully understand. The utility may criticize the feasibility study's assumptions and methodology and suggest that becoming an Aggregator entails great risk with little or no commensurate benefits. Furthermore, PG&E may formally oppose elements of the Implementation Plan at the CPUC. For example, each of the utilities has voiced opposition to allowing Aggregators to phase-in operations over a multi-year period, and phase-in proposals contained in an Implementation Plan may be protested. In the extreme case, the utility might sponsor community organizations to oppose the program, as has been done by both SCE and SDG&E in their efforts to oppose municipalities from forming distribution utilities within their historical service territories. While such strong opposition to a potential CCA program is unlikely, the County should be realistic and not expect complete support from the utility for its efforts.

Once a commitment to developing the Implementation Plan is made a fairly intensive effort will be required to decide the particulars of the CCA program. Choices must be made regarding program management and organizational structure, suppliers and resources, rates and customer protections, terms and condition of service, financing and staffing.

At this stage, there is also the regulatory risk that the CPUC will adopt or modify implementation rules to the detriment of the CCA program or in a way that requires modifications to the Implementation Plan. The development of the Implementation Plan can be done in parallel with the CPUC process. The Implementation Plan should be filed with the CPUC after the CPUC issues its final (Phase 2) in order to avoid the potential expense of re-filing the plan. However, delays in the CPUC process can derail the implementation effort if the process is dragged out indefinitely. Elected leaders that were early supporters of implementing a CCA program may finish their terms before the program can be implemented, and newly elected leaders may desire to reconsider the decision to proceed with CCA implementation. Turnover of key staff could also jeopardize timely program implementation.

4.1.2 Operational Planning Stage Risks

Following development and acceptance of the Implementation Plan, the Aggregator will begin making commitments to be able to commence operations. Depending on how the Aggregator elects to structure its program, additional funds will be needed to finance the start-up activities. These may include the following:

- Conduct recruiting and staffing
- 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
  - Electronic data interchange with utility: accept meter and usage data, send billing data, accept payment and remittance information, exchange customer switching information

  - Customer bill calculations
  - Scheduling coordinator services
  - Application of statistical load profiles and submittal of hourly usage data for grid operator settlements
  - Resource planning, portfolio and risk management
  - Ratemaking
  - Load forecasting
  - Wholesale settlements
  - Credit
  - Information Technology
- Execute contracts for electric supply
- Identify generation projects and negotiate participation, if applicable
- Obtain financing for program capital requirements
- Execute service agreement with utility
- Complete utility technical testing
- Establish account with utility
- Send customer notices to eligible and ineligible (e.g., direct access) customers
- Process customer opt-out requests
- Submit notification certification to CPUC

These commitments should not be made until the CPUC has finalized the rules for CCA implementation, which is expected to take place in June 2005. At that point, the regulatory risk diminishes significantly, and the Aggregator has a great deal more certainty regarding the detailed processes that will be required for operating a CCA program.

4.1.3 Operations Stage Risks

The primary risks inherent in the CCA operations are that unanticipated events cause the Aggregator's costs to increase or the rates of PG&E to decrease. In that case the rates charged by the Aggregator could exceed those of PG&E, and customers may become dissatisfied with the program. To the extent customers are not precluded from leaving the program, the Aggregator could face stranded costs and higher rates prompting additional customers to leave the program. Appropriate program rules that limit customer switching or 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. These risks highlight the importance of clear disclosures in the customer notification process so that potential customers are clearly informed of their rights and obligations prior to taking service in the program.

The predominant cost of service variables and risks that might impact the Aggregator's operations cost are as follows:

- 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 Aggregator has locked in electricity prices through long-term electricity or fuel contracts, the CCA customers' total rates will increase. The CRS could also increase if the CPUC allows PG&E to include new power purchase contracts or resources in the CRS, and the costs are above prevailing market prices.

- The Aggregator 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 Aggregator could over-rely on long-term contracts with fixed prices and find itself holding a high cost portfolio if market prices subsequently fall.

- The Aggregator could fail to properly secure its customer base, making debt financing via the capital markets impossible to obtain and exposing the Aggregator 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 Aggregator's energy suppliers could default on supply contracts (credit risk) at times when energy spot markets are high, forcing the Aggregator to purchase energy at excessively high prices. Customers could fail to pay the Aggregator's charges, and the Aggregator'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 shifts costs among customer classes in a manner that disadvantages the customer mix served by the Aggregator.

- 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

Aggregator's cost of providing service. For example, the institution of 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. The County can structure its program in such a way that it would be exposed to very little risk, however. Electricity supply contracts can be structured to transfer many of the risks to the program's suppliers. The following table describes basic risk management techniques for each of the primary risks associated with operating a CCA program.

Risk	Mitigation
Cost Responsibility Surcharge Volatility	Utilizing shorter duration supply contracts to a greater extent than would otherwise be indicated would offset the CRS risk. If market prices decrease, the Aggregator's supply portfolio costs will also decrease, offsetting the increase in the customer's CRS payments to PG&E.
Commodity Price Volatility	Diversify supply portfolio with contracts of various terms and with multiple suppliers, renewable energy, and conventional generation. Layoff commodity price risks to energy suppliers through fixed priced contracts or guaranteed discount pricing structures
Customer Attrition	Establish exit fees following free opt-out period. Negotiate term contracts with large customers.
Credit Risk	Periodic credit and exposure monitoring; supplier diversity; collateral and surety instruments. Require deposits from customers and return to utility for failure to pay bills.
Utility Rate Changes and Other Regulatory Risks	Participate in CPUC process to prevent shifting of costs to program customers

4.1.3.1 Operations Risk Discussion

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 Aggregator will be able to contract for services from a variety of large, experienced energy suppliers that have operational capabilities equal to or better than those of PG&E. 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.

The experiences of PG&E, SCE and SDG&E during the energy crisis of 2000-2001 illustrate what can happen when risks are not properly managed. The investor owned utilities' exposure to commodity price risks during the energy crisis and the ensuing financial devastation experienced by PG&E and SCE stemmed from an artificial constraint imposed by the CPUC on their hedging abilities, coupled with an inability to increase retail rates due the legislated rate freeze. The CPUC's so-called buy/sell requirement forced the utilities to buy 100% of their energy from the state sanctioned (now defunct) California Power Exchange daily market auction and sell 100% of their generation resources into that market. Because the utilities had divested nearly all of their natural gas fired generation resources, they were each heavily short on resources and overly reliant on the spot market. When spot market prices spiked for an extended period of time, the cash drain necessitated the State of California (Department of Water Resources) to take over electricity procurement responsibilities from the utilities. Customers of SDG&E were not protected by the rate freeze and suffered from excessive rates as SDG&E was able to pass through its costs of procuring electricity from the spot markets.

The Aggregator will not be subject to these types of constraints on its procurement practices. Being a municipality, it will exercise its own authority over its resource planning and ratemaking decisions. A professionally managed electricity procurement program, following sound risk management practices, would not expose itself to the risks that the investor owned utilities faced during the energy crisis.

4.1.3.2 Regulatory Risk Discussion

Regulatory risks refer to the potential that decisions by regulators could cause cost increases for the CCA program. The Aggregator can participate in regulatory proceedings at the CPUC or FERC to try to influence the regulatory process to protect its interests and those of its customers. Typically, associations are formed among entities with common interests to participate on their behalf in the regulatory process to effectuate maximum influence on regulators. The amount of influence wielded in the regulatory process depends on the resources the association can devote to participation and the political influence of the associations members. Thus, to some extent the degree by which regulatory risk can be managed depends upon the prevalence of CCA throughout the state. If CCA becomes a widespread phenomenon, with many communities being directly impacted by CPUC decisions, the CPUC is less likely to make decisions that impose additional costs on Aggregators than if only one or two communities would be impacted.

4.1.4 Risk Mitigation Through Physical and Financial Reserves

Physical and financial reserves are important components of a CCA program that reduce program risk. Industry rules dictate certain reserve requirements for all market participants to protect the integrity of the system. These rules ensure no degradation of reliability would result if the County were to implement a CCA program.

4.1.4.1 Physical Reserves

The program will be required to comply with industry rules governing the provision of physical reserves to ensure reliable operation of the electric grid. The California Independent System Operator (CAISO) requires load-serving entities to maintain operating reserves (6% to 8% of load) and regulating reserve (2.5% to 5%) that can be quickly called upon in the event that scheduled resources experience outages or electricity consumption unexpectedly increases. Load serving entities can arrange for their own reserves, or the CAISO will charge the load serving entity for the costs of reserves procured on its behalf. The costs of these reserves are included as an expense item in the pro forma.

On a longer-term basis, the CPUC requires load-serving entities to arrange for a 15% planning reserve margin, approximately one year in advance. The planning reserve requirement was instituted in 2004 and is in intended to both ensure the existence of adequate generation capacity as well as to reduce the ability of power suppliers to charge high electricity prices that can occur when capacity is scarce. The costs of planning reserves are included as an expense item in the pro forma.

4.1.4.2 Financial Reserves

The program will maintain financial reserves in the form of rate stabilization funds or other reserve funds that would be required by the banks to support debt financing of program assets. Rate stabilization funds are maintained at the discretion of program management and the program's governing board. They are used to cushion short-term cost increases as well as to accrue cash for future capital expenditures. To the extent that debt financing is utilized to fund capital expenditures, banks will require minimum debt service reserves equal to approximately 10% of the amount borrowed, and will also impose minimum debt service ratios to ensure adequate debt service coverage. These financial reserves are included in program rates, but these funds are an asset of the program that will ultimately be accessible for future rate reductions or other program purposes.

4.1.5 Risk Mitigation Through Phased Implementation

The County could implement a CCA program in phases to limit any risks associated with program startup and the transition of customers from PG&E to service by the program. An example could be to initially offer the program to non-residential customers for a pilot phase such as six months or one year and then to open the program to all customers after the pilot phase is completed. By starting with non-residential customers, the number of transactions (account transfers, monthly billing, etc.) that must be completed would be a small fraction of what would be required to serve the entire community at one time. Another benefit of this type of phasing arises because non-residential customers are higher margin customers so the initial phase-in period would provide greater margins for the program to help cover program startup costs.

The CPUC will not determine which customers the CCA should serve.[7] However, the County must comply with the legal requirements of AB 117 that requires equitable treatment of all customer classes and the offering of service to all residential customers. The Implementation Plan should describe the phasing approach, if any, that the County intends to utilize and how that approach complies with the law.

[7] See D.04-12-046, Conclusion of Law No. 38.

5 FEASIBILITY ANALYSIS

5.1 Study Approach

In preparing the financial evaluation for a CCA program, NCI did a thorough analysis of: (1) PG&E's forecasted rates (including cost responsibility surcharges); (2) CCA energy or commodity costs (including generation ownership, power purchase contracts, renewable energy contracts and spot-market purchases; (3) CAISO charges; (4) operations and scheduling costs; (5) financing costs; and (6) revenue offsets and available financial incentives. Each of these items was factored into the pro forma analysis. The CCA program's capital costs are amortized over a 30-year period and financed at a rate of 5.5%. The interest and amortization are included in the annual costs of the program. The financial pro forma analysis compares the total costs of operating the CCA program with the total costs of continuing to take retail utility service from PG&E.

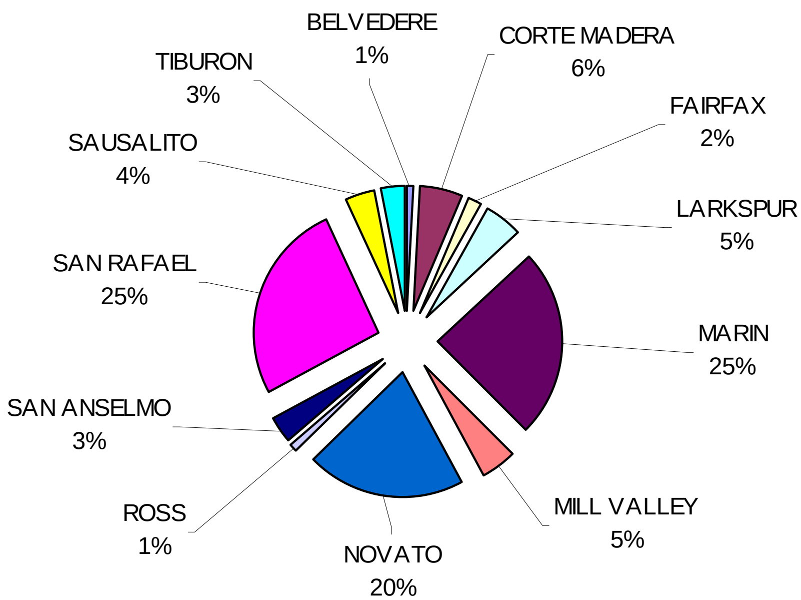
A financial analysis was performed in order to develop financial pro forma, which are then structured as consolidated statements of income for the CCA program. The consolidated statements based on the financial pro forma are located in Appendix E. As noted above, savings or potential income is the margin between current retail power costs, as provided by PG&E, and the Aggregator's projected cost to provide the power. NCI began its evaluation with a planning horizon beginning in the current year (2005) and then projected costs 20-years forward to 2024.

PG&E provides services at regulated cost-based rates. Hence, PG&E's rates are directly tied to a demonstrated "revenue requirement", which is the total revenues the utility is authorized to recover through rates. The revenue requirement includes the utility's expenses, return or profit, and taxes paid by the utility. The financial analysis provided herein compares PG&E's revenue requirement at current and projected rates with the revenue requirement of the CCA program to determine potential savings or income. Pro forma summary tables compare each supply portfolio based on their relative ability to produce operational cost savings or benefits.

In a CCA program, utility service is limited to the electric energy commodity only. PG&E would continue to provide electricity delivery over its existing distribution system and provide end-consumer metering, billing, collection and all traditional retail customer services (i.e., call centers, outage restoration, extension of new service). Accordingly, to evaluate the potential benefits for CCA, only costs associated with wholesale electric commodity procurement and related business expenses are considered.

5.2 Customer Base

The potential customer base for the CCA program is all of the electric customers in the County, assuming the County forms a CCA program in conjunction with the eleven Marin County cities. Otherwise, the customer base would be limited to the electric customers within the unincorporated areas of the County. The distribution of electricity sales with the County are shown in the chart below:



Customers have the option to opt-out of the CCA program and continue to receive their electric service from PG&E. Some customers may choose to not participate in the program, or opt-out during the 60-day opt-out period, and some direct access customers may be contractually prevented from initially joining the program until their direct access contracts expire. The prevalence of customer opt-outs will depend on a number of factors, not the least of which is how the Aggregator's electric rates compare to those of PG&E. Other factors that will influence customers' opt-out decisions include whether the Aggregator provides non-price features important to customers such as increased renewable energy purchases or expanded energy efficiency programs; customer loyalty or enmity to PG&E; and other customer perceptions. Many of these factors are directly dependent on the details of the Aggregator's Implementation plan, and the impacts cannot be reasonably estimated prior to completion of the County's implementation planning process. For the purposes of this feasibility analysis, the report presents the potential benefits from CCA, assuming 100 percent customer participation. Within a reasonable range of assumed opt-out percentages, the study results can be adjusted proportionately.

5.3 Key Assumptions

As described in Section 2.2, the CPUC is in the process of finalizing the rules for CCA implementation. NCI developed several framework assumptions for this feasibility analysis and also adopted a set of detailed assumptions for various unknown costs and implementation rules. This section describes the high level assumptions that provide the framework for the analysis. The detailed assumptions are listed in Appendix B.

1. CCA Rulemaking is completed by the third quarter of 2005, and CCA operations can begin in January 2006

2. Charges authorized by the CPUC for Aggregators and CCA customers are similar to those charged to direct access customers (transaction and implementation fees)

3. Aggregators must maintain adequate capacity reserves to maintain reliability standards and will follow standard industry risk management practices. Aggregators will be held to the same capacity reserve standard as PG&E.

4. Aggregators will match or exceed the renewable energy content of PG&E's portfolio and are eligible for the existing CEC subsidies provided for renewable energy procurement up to the minimum renewable portfolio standard (i.e., subsidies are available for the first 20% of renewable energy)

5. Market prices for renewable energy will reflect the developer's costs, including the effects of available subsidies

6. Aggregators can finance generation projects

7. Aggregators can obtain electricity from the wholesale market on comparable terms with the IOUs

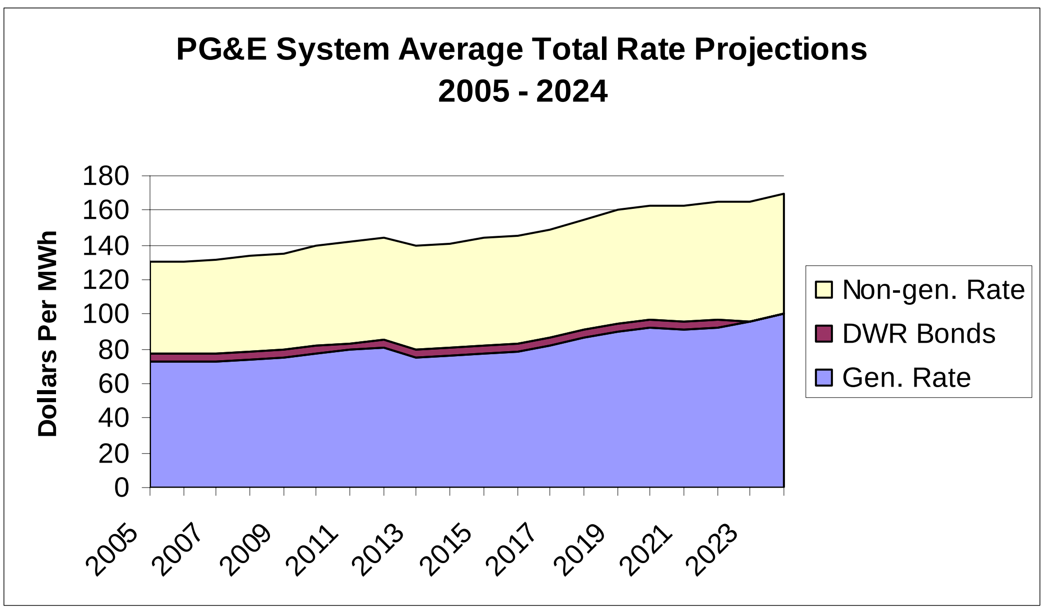
8. The CPUC does not allow IOUs to negotiate special rates or contracts to retain customers

9. CCA operations can be outsourced to third parties

10. Reinstatement of direct access does not preempt CCA rights and customer relationships

5.3.1 Utility Rate Benchmarks

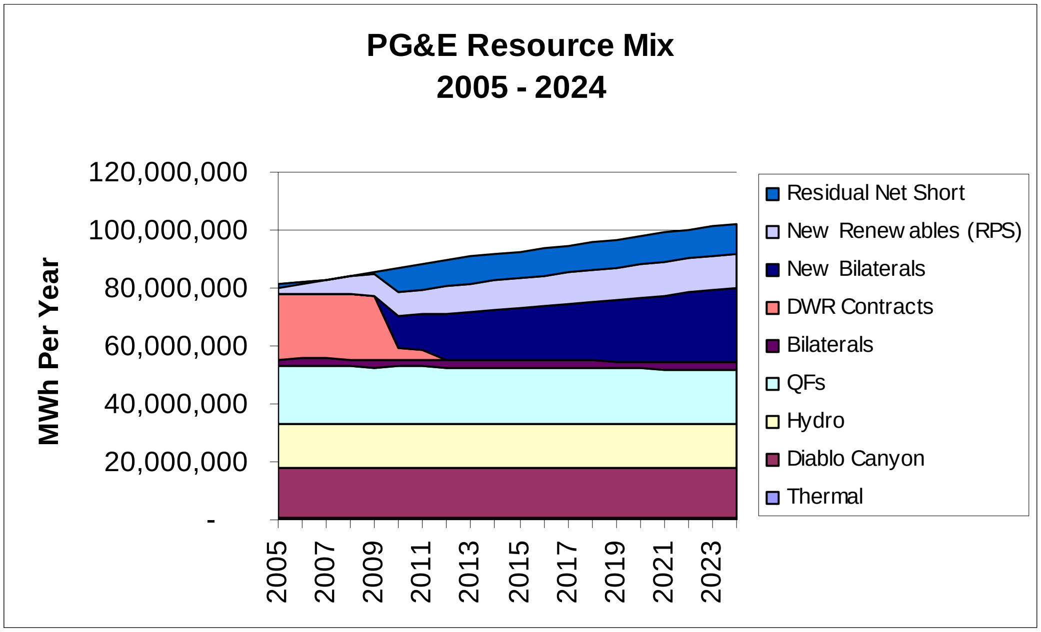
Estimates of CCA cost savings potential are assessed by comparing CCA costs to the rates that would otherwise be charged by PG&E. PG&E's rates derive from its costs or revenue requirement, and NCI modeled PG&E's annual generation revenue requirements for the 2005 to 2024 study period. The resulting rate projection shows generation rates increasing at a modest average rate of 1.7% per year due to offsetting influences on PG&E's generation costs. The projected annual rate increase of 1.7% is at the low end of historical trends.[8] The reason for this is that generation cost increases are somewhat offset by the expiration of high cost DWR contracts in the 2004 to 2012 period, and the net result is a moderately increasing rate forecast. Once the DWR contracts expire in 2012, PG&E's generation costs are expected to show annual increases consistent with general levels of inflation and gas price escalation.



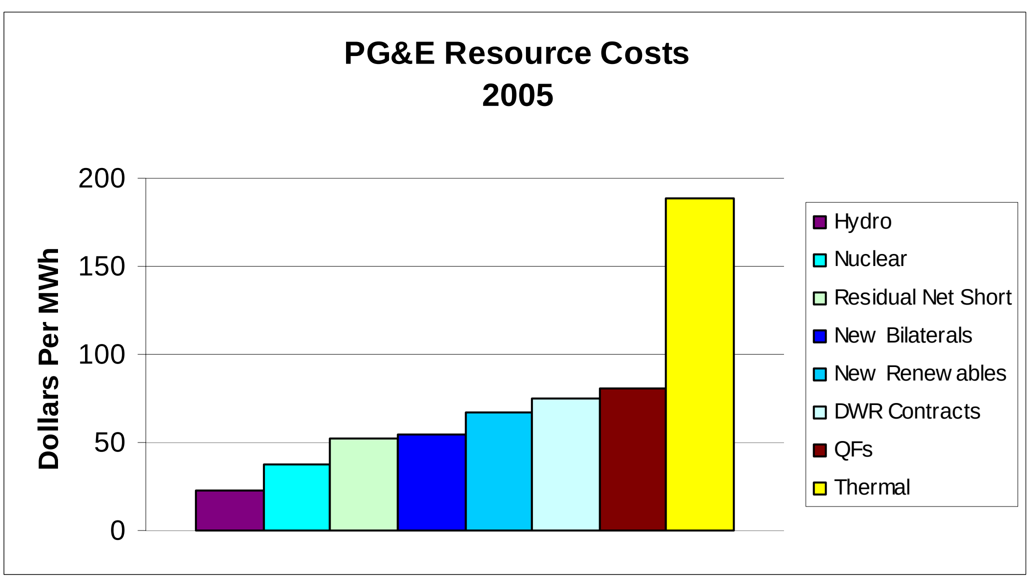
PG&E's generation revenue requirements are modeled for each resource in PG&E's generation portfolio, including the DWR contracts the CPUC allocated to PG&E in Decision No. 02-09-053. As production from existing resources or supply contracts decline over time, they are replaced by new power purchase contracts at prevailing market prices. Short-term "spot market" purchases are

[8] Depending upon the specific timeframe selected for comparison, during the past twenty-five years, SDG&E rates have increased by an average annual rate of between 1% and 4%.

maintained at 15% of the total portfolio. New renewable contracts are added to the resource mix to meet the applicable Renewable Portfolio Standards requirements, and planning reserve requirements of 15% are enforced in the rate projections.



The revenue requirement for each resource type was modeled based on data provided by PG&E in its 2003 Cost of Service Proceeding and FERC Form 1 filings. The current costs are shown below. Costs were projected forward for the study period by calculating annual depreciation, operations and maintenance expenses, taxes, and authorized return on rate base for each resource.



* The per unit cost of thermal resources is high due to the limited energy production from these resources which are primarily used to provide system reserves.

5.3.2 Cost Responsibility Surcharges

The single greatest obstacle to achieving significant cost savings through CCA in the next several years is PG&E's imposition of cost responsibility surcharges on CCA customers, which are designed to shield PG&E from any financial losses or cost increases that might result from customers switching to service by the Aggregator. NCI modeled expected cost responsibility surcharges using the methodology adopted in the CCA Phase 1 Decision (D.04-12-046). According to this methodology, the above market portion of PG&E's generation portfolio, including PG&E contracts and resources and the DWR contracts, are included in the CRS. Other elements of the CRS include the DWR Bond Charge and, for PG&E, the charge for recovery of the "regulatory asset" that was established to enable PG&E's emergence from bankruptcy. The latter two costs are reasonably certain and predictable, while the uneconomic portfolio costs are less easily predicted because they directly depend on future electricity market prices and PG&E's future generation costs.

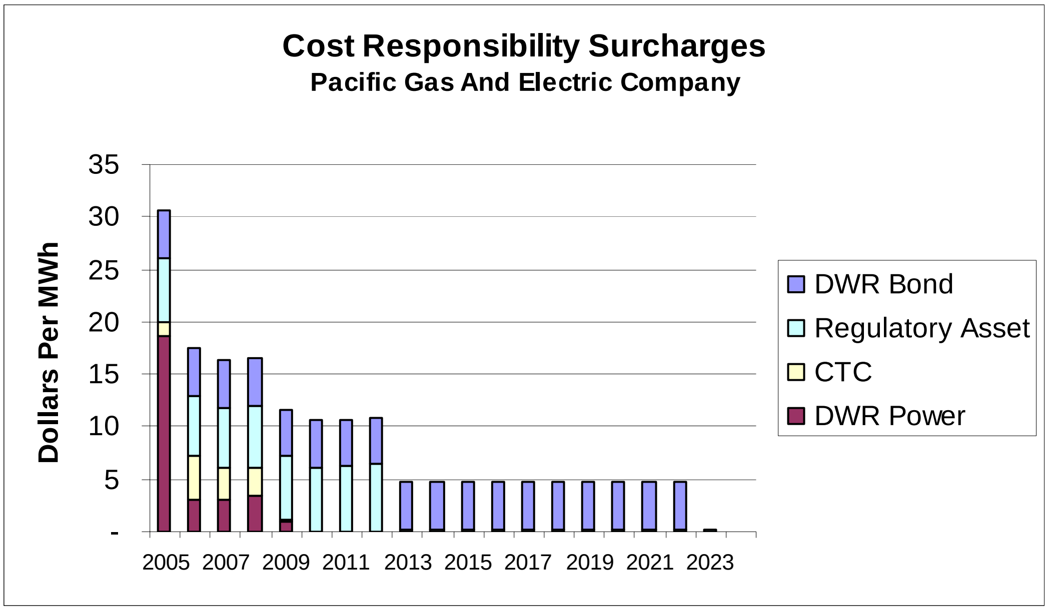
In D.04-12-046, the CPUC adopted an interim CRS of 2.0 cents per kWh.[9] The CPUC established the interim CRS for an 18-month period and ordered PG&E to calculate an updated CRS based on current forecast data. The adopted CRS methodology causes the CRS to be inversely related to electricity market prices: *i.e.*, as market prices increase the CRS declines and vice versa. Because current market price projections are higher than those used by the CPUC to establish the interim CRS estimate, the updated CRS is expected to be lower than the interim amount. NCI used the interim CRS for 2005 and assumed that it would be updated by PG&E prior to 2006.

The CRS cost estimates used in this analysis are consistent with the electricity cost projections underlying the Aggregator's modeled supply portfolio. The electricity market prices are somewhat higher than the estimates used by the CPUC to develop the 2.0 cents per kWh interim CRS. As a result, in NCI's analysis the CRS is projected to decline sharply from 2005 to 2006 as the interim number is replaced with the updated cost figures. If future power prices turn out lower than those used for the base case analysis, the CRS would be higher than the forecasts used in this analysis. However, the cost of procuring power for the CCA program would be lower than the costs used in the analysis. These two impacts tend to offset each other. Therefore, the magnitude of the CRS should not be looked at in isolation, but should be assessed in context with the

[9] The 2.0 cents per kWh interim CRS is in addition to the DWR Bond Charge and the Regulatory Asset.

market price assumptions used in the overall feasibility assessment. The net effect of higher or lower power prices on the overall cost of service for the CCA program can be seen in the sensitivity analysis results presented in Section 6.3.

The following chart shows the components of the CRS for PG&E over the study period under the base case scenario.



With the exception of the DWR bond charge, the CRS is expected to become zero by 2012, as DWR contracts expire, market prices trend upwards, and the cost of the regulatory asset is fully recovered.

5.3.3 Renewable Energy Subsidies

A variety of tax incentives, credits and publicly funded subsidies exist for renewable energy development, which reduce the effective cost of increasing the renewable energy content of the program's supply portfolio. These include the following subsidies:

- Production Tax Credits
- Renewable Energy Production Incentives
- Supplemental Energy Payments (Public Goods Funds)

Some of the incentives, such as the production tax credit for renewable energy production, are short-term and must be reauthorized by Congress on an annual basis. Others, such as the public goods funding for renewable energy development administered by the California Energy Commission

(“Supplemental Energy Payments”), are more long lived, but are contingent on the sufficiency of the public goods fund collected through utility rates. The economic analysis conducted for the County includes the effect of Supplemental Energy Payments available to producers of renewable energy as described in more detail below. The other potential subsidies are not included in the analysis although they may ultimately be available to further reduce the program’s cost of service.

Subsidies are included for renewable energy purchases from the market, to the extent such purchases are needed to supplement production from the Aggregator’s resources. The renewable energy costs for purchases up to the minimum renewable portfolio standard are offset by Supplemental Energy Payments, while the incremental renewable energy above and beyond the minimum requirement is assumed to receive no subsidy. Thus, the costs of renewable energy utilization above the first 20% would be paid entirely by customers of the CCA.

No Supplemental Energy Payments are assumed to be available to offset costs of the Aggregator’s renewable resources that it owns or otherwise finances. The reason for this assumption is that the process for determining Supplemental Energy Payments was premised on the utilities conducting competitive solicitations for long-term supply contracts with producers of renewable energy. Funds are made available to winning bidders to cover the excess of their costs above a market benchmark, determined by the CPUC. The CPUC has so far been focused on how the utilities are to meet the Renewable Portfolio Standards, and the rules and protocols for making Supplemental Energy Payments available to Community Choice Aggregators have not yet been established.

It is unclear at this time how the process developed for the utilities would apply to an Aggregator that develops its own renewable resources rather than procures renewable energy through long-term, competitively solicited contracts. Financing structures that entail prepayment for energy through long-term power purchase contracts with a renewable energy producer should theoretically allow the Aggregator to receive the benefits of its financing advantages and also qualify the producer for Supplemental Energy Payments. However, as stated above, the rules have not been established, and the conservative assumption that no such subsidy would be available was used in this analysis.

5.4 Financial Analysis Structure

CCA customer population electric loads are applied to PG&E’s current and projected generation rates to yield its revenue requirement recovered from the customers in the potential CCA area. CCA operating expenses are projected and subtracted from PG&E's revenue requirement to yield the projected financial benefit. Elements contained in the analysis are summarized below and details of the inputs, assumptions and sources are provided in Appendix B:

Utility Forecast Generation Rates
- Utility Retained Generation
- Qualifying Facility Generation
- Bilateral Power Purchase Contracts
- New Renewable Energy Purchases
- CAISO charges
- Residual Spot Market Purchases or Sales

CCA Energy Cost (Commodity Costs)
- Spot Market Purchases
- Power Purchase Contracts
- Renewable Energy Contracts
- Generation Ownership

California Independent System Operator Charges
- Ancillary Services/Reserves
- Grid Management Charges
- Deviation Charges

Operation and Scheduling Costs
- Electricity Procurement
- Risk and Credit Management[10]
- Load Forecasting
- Scheduling and Settlements
- Rates
- Account Services
- Administration

Non-Bypassable Charges/Cost Responsibility Surcharge
- Uneconomic Utility Retained Generation and Power Contracts
- DWR Power Purchase Contracts
- DWR Bond Charges - Financing Past Purchases

[10] The costs of uncollectible customer accounts are not explicitly included in the pro forma, under the premise that the Aggregator would require customer deposits from customers that pose likely credit risks, similar to the accepted utility practice. Because under current rules the Aggregator cannot cause service to be shut-off to the customers for failure to pay its portion of the bill whereas the utility can, it is important that the Aggregator have the ability to screen customers prior to automatic enrollment for administration of its credit policies and that the Aggregator has the right to return the customer to the utility for failure to pays its charges. This issue should be addressed in Phase 2 of R.03-10-003.

5.5 Load Analysis

Detailed definition of community electric power needs is required to assess the economic viability of the CCA providing electric energy as an alternative to the community's existing supplier, PG&E. Community electric demand and energy consumption, generally referred to as electric load, has been analyzed and described in charts and graphs located in Appendix G. NCI performed load analysis and constructed a load forecast beginning with and based upon data provided by PG&E in response to the Community's formal request (see Appendix C for sample data request letter). The Community's annual hourly load shape was developed, and a determination made regarding associated energy supply requirements. The time-of-use supply requirements serve to define the types of resources necessary to supply electric energy to the CCA.

5.5.1 Load Forecast Methodology

Community electric load data provided by PG&E was 12-month, year-to-date energy consumption and number of customers by rate class as of October 2003. PG&E provided up to 20 rate classes that NCI collapsed into 7 higher-level Customer Sectors. Rate classes and their generic sector rate class description assignments are listed in the following table:

Rate Schedule to Customer Sector Assignment

Rate Schedule	PG&E Description	Customer Sector Description
A-1	Small General Service	Small Commercial
A-6	Small General Time-of-Use Service	Small Commercial
AG-1	Agricultural Power	Small Commercial
A-10	Medium General Demand-Metered Service	Medium Commercial
E-1	Residential Service	All-Residential
E-2	Experimental Residential Time-of-Use Service	All-Residential
E-3	Experimental Residential Critical Peak Pricing Service	All-Residential
E-7	Residential Time-of-Use Service	All-Residential
E-8	Residential Seasonal Service Option	All-Residential
E-9	Experimental Res Time-of-Use Service for Low Emission Vehicle Custs	All-Residential
EML	Master-Metered Multifamily CARE Program Service	All-Residential
ES	Multifamily Service	All-Residential
ETL	Mobile Home Park CARE Program Service	All-Residential
E-19	Commercial/Industrial/General Medium General Demand-Metered Time-of-Use Service	Large Commercial
E-20	Commercial/Industrial/General Demand Greater than 1,000 Kilowatts	Large Commercial/Industrial (C/I)
LS-1	PG&E Owned Street and Highway Lighting	Street Lighting
LS-2	Customer-Owned Street and Highway Lighting	Street Lighting
LS-3	Customer-Owned Street and Highway Lighting Electrolier Meter Rate	Street Lighting
OL-1	Outdoor Area Lighting Service	Street Lighting
TC-1	Traffic Control Service	Traffic Control

The monthly load information was ordered by month; January through December, to reflect monthly seasonal use patterns and treated as prototypical for 2003 energy consumption. PG&E published static load profiles were employed to allocate monthly energy (kWh) into each hour of the month and then to each of the 8,760 hours within a year. Rate class static load profiles where selected as most characteristic of load usage patterns in each of the Customer Sectors as reflected in the following table:

Static Load Profile Assignment

Customer Sector	Static Load Profile
Small Commercial	A-1
Medium Commercial	A-10
Large Commercial	E-19
Large (C/I)	E-20
Street Lighting	LS-1
Traffic Control	TC-1

A twenty-year electric load forecast was performed forecasting electric demand energy requirements for years 2005 through 2024. Electric energy requirements and customer populations were escalated based upon sector specific growth planning statistics provided by the City; if none was provided PG&E system-wide growth rates were applied.

The number of customer accounts and annual energy sales for the initial year (2006) of the program are shown below.

	2003		2004 *		2005 *		2006 *	
	Accts	kWh	Accounts	kWh	Accounts	kWh	Accounts	kWh
Residential	103,499	668,775,747	105,051	678,807,383	106,627	688,989,494	108,226	699,324,336
Small Commercial	12,296	215,177,071	12,480	218,404,728	12,668	221,680,798	12,858	225,006,010
Medium Commercial	1,151	198,929,538	1,169	201,913,481	1,186	204,942,183	1,204	208,016,316
Large Commercial	186	90,023,919	188	91,374,278	191	92,744,892	194	94,136,065
Large C/I	24	137,688,934	24	139,754,268	24	141,850,582	25	143,978,341
Street Lighting	483	7,726,001	483	7,726,001	483	7,726,001	483	7,726,001
Traffic Control	161	542,202	161	542,202	161	542,202	161	542,202
Total	117,800	1,318,863,413	119,557	1,338,522,341	121,341	1,358,476,153	123,151	1,378,729,272

* 2003 Data Provided by Distribution Utility (PG&E) and Escalated by Applying The Following Growth Rates:

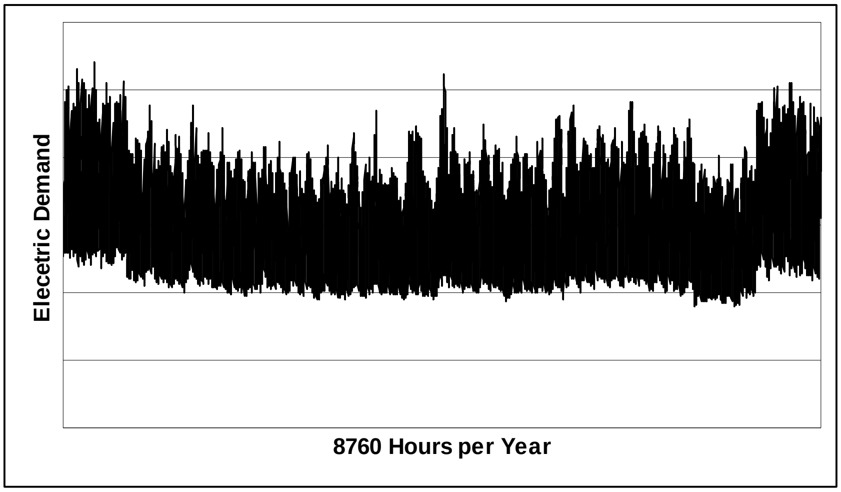
Growth Rates

Residential	1.50%
Commercial	1.50%

5.5.2 Community Energy Load Shape

The community composite annual energy load shape (average kW per hour) was developed by combining average loads in each hour from each of the Customer

Sector static load profiles identified above. A prototypical annual load profile is shown in the following figure.



Electric load was next broken down into quarterly and weekly demand periods to capture seasonal variation in projected loads and electric generation resource requirements. The resulting quarterly minimum, as well as peak power requirements, is the basis for "sizing" the portfolio of contracts and generation resources needed to serve the Aggregator's load profile.

5.5.3 Renewable Portfolio Standards Requirements

The California Renewable Portfolio Standard Program (RPS) established by Senate Bill 1078 requires that a retail seller of electricity purchase a specified minimum percentage of electricity generated by qualifying renewable energy resources. Community Choice Aggregators are required under SB 1078 to procure a specified minimum percentage of total kilowatt hours sold to retail end-use customers each calendar year from renewable resources.

Each distribution utility is required to increase its total procurement of eligible energy resources by at least 1% per year so that 20% of its retail sales are procured from eligible renewable energy resources by year 2017. CCA program aggregated loads are a subset of load currently served by the distribution utilities (SCE, PG&E and SDG&E). Therefore, analyses contained herein assume that customer energy requirements of the prospective CCA will, at a minimum, be equal to the renewable energy percentage required of each distribution utility.

Further, when the County applied for and was accepted into the CCA Demonstration Project it declared as a goal to double the RPS and achieve a renewable energy content of 40% by 2017. The following table reflects distribution utility RPS renewable energy requirements projected forward.

Year	PG&E MIN	SCE MIN	SDG&E MIN
2003		16%	5%
2004	12%	17%	6%
2005	13%	18%	7%
2006	14%	19%	8%
2007	15%	20%	9%
2008	16%	20%	10%
2009	17%	20%	11%
2010	18%	20%	13%
2011	19%	20%	14%
2012	20%	20%	15%
2013	20%	20%	16%
2014	20%	20%	17%
2015	20%	20%	18%
2016	20%	20%	19%
2017	20%	20%	20%
2018	20%	20%	20%
2019	20%	20%	20%
2020	20%	20%	20%
2021	20%	20%	20%
2022	20%	20%	20%
2023	20%	20%	20%
2024	20%	20%	20%

The bill requires the CPUC to adopt rules for implementing the RPS, and CCA planners must understand the renewable energy requirements before they can assess the cost-benefits and make threshold decisions to implement a CCA program. County minimum renewable energy requirements are summarized in the table below.

Renewable Resource Requirements Projected Forward

	Energy MWh	Renewable Capacity Requirement (MW)		Renewable Energy Requirement (MWh)	
		1 X RPS	2 X RPS	1 X RPS	2 X RPS
2007	1,399,286	80	159	279,857	559,714
2008	1,420,151	86	172	284,030	568,061
2009	1,441,330	93	186	288,266	576,532
2010	1,462,826	100	200	292,565	585,130
2011	1,484,644	107	214	296,929	593,858
2012	1,506,790	114	229	301,358	602,716
2013	1,529,267	116	233	305,853	611,707
2014	1,552,082	118	236	310,416	620,833
2015	1,575,240	120	240	315,048	630,096
2016	1,598,744	122	243	319,749	639,498
2017	1,622,601	123	247	324,520	649,041
2018	1,646,816	125	251	329,363	658,727
2019	1,671,395	127	254	334,279	668,558
2020	1,696,341	129	258	339,268	678,537
2021	1,721,663	131	262	344,333	688,665
2022	1,747,363	133	266	349,473	698,945
2023	1,773,450	135	270	354,690	709,380
2024	1,799,928	137	274	359,986	719,971

* Capacity figure is based on a capacity factor of 30%, typical of wind resources.

6 FINANCIAL PROJECTIONS

The supply portfolio modeled for the County contains a diverse mix of resources reflective of a strong commitment to promotion of renewable energy.

The resource types include:

- Spot market purchases – short-term electricity purchases to supplement resources under contract control of the Aggregator
- Contract purchases – longer term, fixed price power purchases. Terms can be monthly, quarterly, annual or multi-year. For purposes of this analysis, the contracts were structured with sequential two, three, or five-year terms.
- Natural gas power production –production from a combined cycle natural gas combustion turbine owned by the Aggregator used for baseload or shaping purposes
- Renewable energy purchases – purchases of renewable energy to meet the Aggregator's renewable resource goals, with a minimum equal to PG&E's renewable energy mix. For purposes of this analysis, purchases are from a generic renewable portfolio with a cost equal to the weighted average of the renewable resources expected to fulfill California's RPS.
- Renewable energy power production – production from renewable energy resources owned by the Aggregator. For purposes of this analysis, an equity position in wind and geothermal facilities sized to meet the Aggregator's renewable resource goals
- Off system sales – sales of excess energy into the spot market at times when the resources under contract or ownership are in excess of the Aggregator's load requirements

The total cost of service for the CCA program was calculated and compared to the generation costs charged by PG&E. The difference represents potential savings or costs associated with the CCA program. These savings are shown for each year in the study period, with positive numbers indicating lower costs for the CCA and negative numbers indicating higher costs. Costs or savings are shown both in millions of dollars per year and as a percentage of customers' monthly electric bills.[11]

[11] The percentage savings are expressed based on total electric bills, including PG&E delivery charges. The percentage savings on the generation component of bills would be approximately double the percentages shown.

Summary Of Electric Cost Savings From Community Choice Aggregation
Base Case Scenario
(Millions of Dollars)

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	108.3	107.2	(1.0)	-1%
2007	108.8	109.1	0.3	0%
2008	116.7	113.1	(3.5)	-2%
2009	111.7	115.9	4.2	2%
2010	118.5	121.8	3.4	2%
2011	122.6	125.7	3.1	1%
2012	126.1	129.9	3.8	2%
2013	114.8	123.3	8.5	4%
2014	117.7	126.9	9.2	4%
2015	125.8	131.3	5.5	2%
2016	127.6	134.5	6.9	3%
2017	132.5	141.2	8.8	3%
2018	139.7	151.5	11.8	4%
2019	146.6	160.9	14.3	5%
2020	156.4	166.2	9.8	3%
2021	158.6	167.7	9.1	3%
2022	161.8	171.5	9.6	3%
2023	160.1	171.8	11.8	4%
2024	168.1	182.2	14.1	4%
Total	2,522.3	2,651.8	129.5	3%

Total nominal savings over the study period are $129.5 million or approximately 3% of customers' total electricity costs. Cost savings average approximately $6.8 million per year.

6.1 Supply Portfolio Details

The CCA program would be supplied from a diverse portfolio of energy resources. The portfolio is designed to achieve the County's 51% renewable energy objective in stages. The Aggregator initially matches the renewable content of PG&E's portfolio and incrementally increases the renewable component to achieve a mix of 51% by 2017. The Aggregator invests in generation resources to meet its baseload energy requirements. The portfolio also includes power purchases through five-year contracts and spot market purchases to supplement the production of the Aggregator's generation resources.

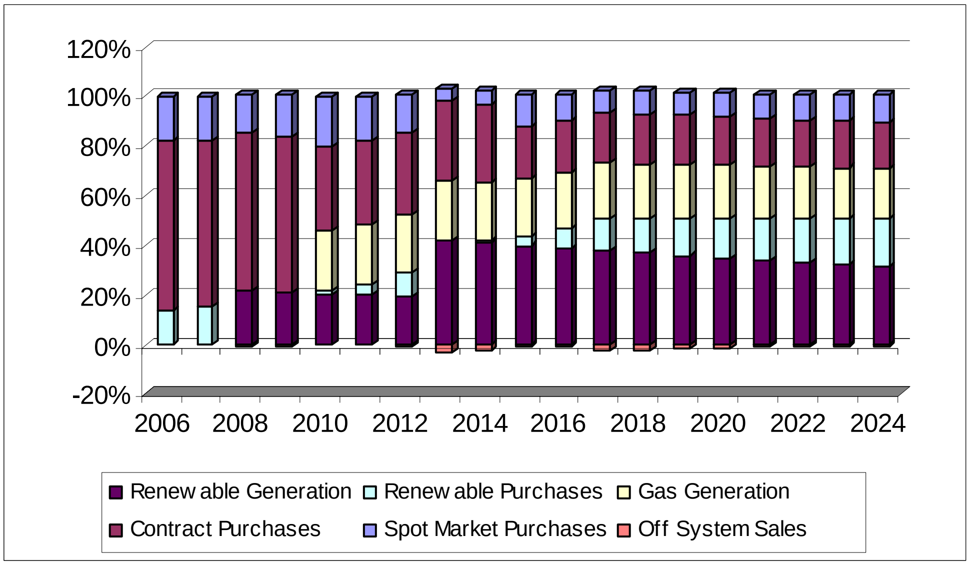
The resource mix includes both conventional and renewable resource ownership. The portfolio initially contains only purchases from the open market, and beginning in 2008, it includes production from wind and geothermal resources. 2008 was selected as the earliest feasible date for the Aggregator to acquire equity in a new generation resources, considering lead times for negotiations, permitting and financing.

CCA Generation Resources In CCA Portfolio

Resource Type	Capacity (MW)	On-line	Capital Cost ($ Millions)
Wind	90	2008	101.1
Geothermal	10	2008	27.6
Gas Combined Cycle	50	2010	40.0
Wind	80	2013	100.2
Geothermal	20	2013	58.1

The assumed renewable generation resources were sized to meet the Aggregator's renewable energy target projected for the next several years. As a result, the portfolio initially contains greater renewable energy than targeted. Later, as load growth continues, the renewable production must be supplemented with renewable energy purchases to meet the County's targeted renewable percentage of 51%.

Long Term Resource Mix Utilized For Financial Pro Forma



No subsidies are assumed to be available to offset costs of the Aggregator's renewable resources. Subsidies are included for renewable energy purchases, to the extent such purchases are needed, consistent with the subsidy treatment discussed in Section 5.3.3.

Capital expenditures associated with the preferred portfolio include startup costs of $400 thousand and generation investments of $129 million in 2008, $40 million in 2010, and $158 million in 2013. Initial financing of $5 million is used to establish a rate stabilization fund to ensure that rates during the initial three years of program operations remain at or below those of PG&E.

6.2 Alternative Supply Scenarios

Financial pro forma were prepared for four additional supply portfolios that differ by varying the mix of renewable energy in the portfolio and by whether the Aggregator owns generation resources used to supply electricity to the program. The pro forma for the alternative supply portfolios are included in Appendix F. Analysis of the alternative supply scenarios can assist the County in understanding the cost effectiveness and tradeoffs among different resources that could be included in a portfolio to supply the CCA program.

6.2.1 Alternative Supply Scenario 1

Supply Scenario 1 assumes the Aggregator doubles the renewable content of PG&E and purchases all of its load requirements from the open market. Inclusion of renewable energy increases the portfolio's cost, even after considering the subsidies potentially available to the Aggregator's renewable energy suppliers. The renewable energy costs for purchases up to the minimum renewable portfolio standard are assumed to be offset by supplemental energy payments administered by the CEC, while the incremental renewable energy above and beyond the minimum requirement is assumed to receive no subsidy. Thus, the second 20% of targeted renewable energy is paid entirely by customers of the CCA.

Capital expenditures associated with Scenario 1 is limited to program startup costs estimated at $400 thousand.

This supply strategy results in a loss over the study period of $218.7 million or 5% of total electricity costs.

6.2.2 Alternative Supply Scenario 2

Supply Scenario 2 assumes the Aggregator matches the renewable content of PG&E and purchases all of its load requirements in the open market. Renewable energy subsidies are available to offset the incremental cost of the Aggregator's renewable energy purchases.

Capital expenditures associated with Scenario 2 is limited to program startup costs estimated at $400 thousand.

This supply strategy results in a loss over the study period of $173.4 million or 4% of total electricity costs.

6.2.3 Alternative Supply Scenario 3

Supply Scenario 3 assumes the Aggregator doubles the renewable content of PG&E and produces electricity from resources that it owns. The portfolio also includes power purchases through five-year contracts and spot market purchases to supplement the production of the Aggregator's generation resources. Supply Scenario 3 includes both conventional and renewable resource ownership. The portfolio initially contains only market purchases similar to Supply Scenario 1, but beginning in 2008, it includes production from wind and natural gas-fired, combined cycle resources. 2008 was selected as the earliest feasible date for the Aggregator to acquire equity in a new generation resources, considering lead times for negotiations, permitting and financing.

No subsidies are assumed to be available to offset costs of the Aggregator's renewable resources. Subsidies are included for renewable energy purchases, to the extent such purchases are needed, consistent with the subsidy treatment described for Scenario 1.

Capital expenditures associated with Scenario 3 include startup costs of $400 thousand and generation investments of $269 million in 2008 and $36 million in 2010.

This supply strategy results in total savings over the study period of $76.9 million or 2% of total electricity costs.

6.2.4 Alternative Supply Scenario 4

Scenario 4 is similar to Scenario 3 except that the portfolio matches the renewable content of PG&E's supply portfolio, with a corresponding increase in the capacity of natural gas fired generation financed by the Aggregator.

Capital expenditures associated with Scenario 4 include startup costs of $400 thousand and generation investments of $135 million in 2008 and $68 million in 2010.

This supply strategy results in total savings over the study period of $72.4 million or 2% of total electricity costs.

Comparing the alternative supply scenarios reveals the cost advantage enjoyed by the CCA in financing capital intensive generation projects. The incremental cost of increasing renewable energy from 20% to 40% is not a significant factor in the program's cost-effectiveness.

6.3 Sensitivities

Sensitivity analyses can help put upper and lower bounds on the expected financial results from implementing a CCA program. NCI performed sensitivity analyses for the major variables expected to impact the financial results. The results of these sensitivities are shown below:

- Natural gas and power prices (+/- 25%)
- Cost responsibility surcharges (+/- 50%)
- PG&E system average rate projections (1% to 3% annual growth)
- PG&E revenue allocation changes to reduce cross subsidies (As proposed in its General Rate Case)

None of the sensitivity scenarios eliminated program savings over the study period. However, the high and low natural gas/power prices scenario

(Scenarios 2 and 3) and the high CRS scenario (Scenario 5) caused revenue losses in the early years of the program. The County should pay particular attention to changes in these variables if and when it proceeds with implementation of its CCA program. A phase-in of program operations would mitigate exposure to these factors. Another method for accelerating financial benefits would be to create a rate stabilization fund by issuing debt that would be backed by the future revenue streams of the program, thereby moving a portion of future savings forward in time.

Annual financial results associated with the sensitivity scenarios are shown in the following tables.

Scenario 2: Natural Gas And Power Prices Are Reduced By 25% From The Base Case (Millions of Dollars)

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	103.2	103.1	(0.1)	0%
2007	104.0	104.8	0.7	0%
2008	115.9	108.5	(7.4)	-4%
2009	110.9	110.9	(0.0)	0%
2010	113.2	111.1	(2.1)	-1%
2011	110.6	113.8	3.2	2%
2012	112.2	116.8	4.6	2%
2013	105.6	109.4	3.8	2%
2014	107.6	112.3	4.8	2%
2015	113.1	116.0	2.9	1%
2016	115.2	118.6	3.4	2%
2017	117.1	124.0	7.0	3%
2018	119.3	132.1	12.8	5%
2019	124.6	139.5	14.9	6%
2020	132.1	143.9	11.8	4%
2021	133.8	145.3	11.4	4%
2022	136.3	148.5	12.1	4%
2023	133.1	147.3	14.2	5%
2024	139.3	155.5	16.2	5%
Total	2,247.1	2,361.3	114.2	3%

Scenario 3: Natural Gas And Power Prices 25% Higher Than Base Case (Millions of Dollars)

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	115.3	111.3	(4.0)	-2%
2007	117.8	113.3	(4.6)	-2%
2008	124.7	117.7	(7.0)	-3%
2009	126.6	120.8	(5.7)	-3%
2010	136.7	132.3	(4.4)	-2%
2011	141.0	137.3	(3.7)	-2%
2012	145.2	142.7	(2.5)	-1%
2013	131.3	136.8	5.5	2%
2014	132.2	141.0	8.8	4%
2015	142.3	146.3	4.0	2%
2016	145.5	150.0	4.5	2%
2017	151.4	158.0	6.6	2%
2018	160.3	170.5	10.1	3%
2019	168.8	181.7	12.9	4%
2020	180.9	188.0	7.1	2%
2021	183.5	189.5	6.0	2%
2022	187.5	193.9	6.4	2%
2023	187.2	195.8	8.6	3%
2024	197.1	208.3	11.2	3%
Total	2,875.4	2,935.3	59.9	1%

Scenario 4: CRS Is Reduced By 50% From Base Case (Millions of Dollars)

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	95.0	104.1	9.1	5%
2007	96.2	105.9	9.7	5%
2008	103.0	109.9	6.9	3%
2009	102.5	112.6	10.2	5%
2010	109.9	118.5	8.6	4%
2011	113.9	122.3	8.5	4%
2012	117.2	126.5	9.3	4%
2013	110.3	119.8	9.5	4%
2014	113.2	123.3	10.1	4%
2015	121.3	127.7	6.4	3%
2016	123.9	130.9	7.0	3%
2017	128.7	137.6	8.9	4%
2018	135.9	147.8	11.9	4%
2019	142.7	157.1	14.4	5%
2020	152.4	162.4	10.0	3%
2021	154.6	163.8	9.2	3%
2022	158.0	167.5	9.6	3%
2023	160.2	171.8	11.7	4%
2024	168.2	182.2	14.0	4%
Total	2,407.0	2,591.9	184.9	4%

Scenario 5: CRS Is Increased By 50% From Base Case (Millions of Dollars)

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	120.0	110.4	(9.6)	-5%
2007	119.8	112.2	(7.6)	-4%
2008	129.2	116.4	(12.9)	-6%
2009	119.3	119.2	(0.1)	0%
2010	126.1	125.1	(1.0)	0%
2011	129.8	129.0	(0.7)	0%
2012	133.6	133.4	(0.2)	0%
2013	120.4	126.8	6.4	3%
2014	120.7	130.4	9.7	4%
2015	128.9	134.9	6.0	2%
2016	131.5	138.1	6.6	3%
2017	136.4	144.9	8.5	3%
2018	143.7	155.2	11.5	4%
2019	150.7	164.7	14.0	5%
2020	160.5	170.1	9.5	3%
2021	162.8	171.6	8.8	3%
2022	165.9	175.4	9.6	3%
2023	160.2	171.8	11.7	4%
2024	168.2	182.2	14.0	4%
Total	2,627.6	2,711.7	84.1	2%

Scenario 6: PG&E Generation Rates Increase At An Annual Rate Of 1% (Millions of Dollars)

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	107.5	107.6	0.1	0%
2007	108.0	110.2	2.2	1%
2008	117.1	112.9	(4.1)	-2%
2009	110.9	115.7	4.8	2%
2010	117.7	118.5	0.9	0%
2011	121.8	121.4	(0.4)	0%
2012	125.4	124.4	(0.9)	0%
2013	114.0	127.5	13.5	6%
2014	116.9	130.6	13.6	6%
2015	125.1	133.8	8.7	4%
2016	127.7	137.1	9.3	4%
2017	132.6	140.4	7.9	3%
2018	139.8	143.9	4.1	2%
2019	146.6	147.4	0.8	0%
2020	156.4	151.0	(5.4)	-2%
2021	158.6	154.8	(3.9)	-1%
2022	161.9	158.6	(3.3)	-1%
2023	160.1	154.4	(5.7)	-2%
2024	168.1	158.3	(9.8)	-3%
Total	2,516.1	2,548.4	32.3	1%

Scenario 7: PG&E Generation Rates Increase At An Annual Rate Of 3% (Millions of Dollars)

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	107.5	111.6	4.1	2%
2007	108.1	116.5	8.5	4%
2008	115.1	121.6	6.6	3%
2009	110.9	126.9	16.0	8%
2010	117.7	132.5	14.8	7%
2011	121.9	138.3	16.4	7%
2012	125.4	144.4	18.9	8%
2013	114.1	150.7	36.6	16%
2014	117.1	157.3	40.3	17%
2015	125.3	164.3	39.0	16%
2016	127.9	171.5	43.6	18%
2017	132.7	179.1	46.3	18%
2018	140.0	187.0	47.0	17%
2019	146.8	195.2	48.4	17%
2020	156.6	203.9	47.2	16%
2021	158.8	212.9	54.0	18%
2022	162.1	222.3	60.2	20%
2023	160.4	224.1	63.8	20%
2024	168.4	234.3	65.9	20%
Total	2,516.8	3,194.5	677.7	14%

Scenario 8: PG&E's Proposed Revenue Allocation To Customer Groups In Its 2003 General Rate Case (Millions of Dollars)

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	107.5	107.0	(0.5)	0%
2007	108.0	108.8	0.8	0%
2008	117.2	112.9	(4.3)	-2%
2009	110.9	115.6	4.8	2%
2010	117.7	121.5	3.9	2%
2011	121.8	125.4	3.6	2%
2012	125.4	129.6	4.3	2%
2013	114.0	123.0	9.0	4%
2014	116.9	126.6	9.6	4%
2015	125.1	131.0	5.9	2%
2016	127.7	134.2	6.5	3%
2017	132.6	140.9	8.4	3%
2018	139.8	151.2	11.4	4%
2019	146.7	160.5	13.8	5%
2020	156.5	165.8	9.4	3%
2021	158.7	167.3	8.6	3%
2022	161.9	171.1	9.2	3%
2023	160.2	171.4	11.3	4%
2024	168.2	181.8	13.6	4%
Total	2,516.7	2,645.8	129.1	3%

7 EVALUATION OF COSTS AND BENEFITS

This section summarizes NCI's evaluation of the costs and benefits of implementing a CCA program in the County. Evaluation criteria are the ability to deliver lower rates, stable prices, and allowance for increased utilization of renewable energy.

7.1 Ability To Deliver Lower Rates

The economic analysis demonstrates that it is feasible for the County to implement a CCA program. Customers would be able to obtain electric service at rates below those charged by PG&E. Under the most likely scenario, expected savings average 3% of total electric bills over the study period.

Based on the year-by-year financial projections, NCI concludes that electric bill savings opportunities would initially be modest and would increase over time. Savings would be dependent upon utilization of municipal debt financing of generation projects or long-term power purchases. The cost savings may be sufficient in and of themselves to justify the decision to pursue CCA. The estimated cost savings also help support and justify the decision to pursue CCA to achieve other benefits, such as rate stability, local control, and increased opportunities for renewable energy development.

7.2 Rate Stability

The Aggregator could structure its portfolio to emphasize cost predictability and provide stable prices to CCA customers. Long-term supply contracts at fixed prices can provide predictable costs for terms of ten years or longer. Investments in renewable resources, such as wind resources, solar, biomass and geothermal, eliminate the dependence on natural gas and the exposure to fluctuations in natural gas prices for that element of the supply portfolio.

The sensitivity analysis shows an expected range of program savings of between 1% and 14% over the study period. The Aggregator's portfolio would demonstrate relatively stable prices to consumers. Under the base case scenario, which reflects very conservative assumptions regarding future increases in PG&E's rates, the CCA program costs are expected to show 17% greater stability than PG&E's rates.

7.3 Increased Utilization Of Renewable Energy

The Aggregator would determine how much renewable energy to include in its portfolio, over and above the minimum percentages required pursuant to the

California RPS. The cost of purchasing renewable energy is greater than the costs of purchasing electricity produced from fossil fuels, so exceeding the RPS via power purchases will increase the average cost of the Aggregator's portfolio to some degree. However, the analysis shows that doubling the RPS would have only a modest overall impact on customer bills, as discussed below.

7.3.1 Cost Of Renewable Energy

The CEC's Renewable Resources Development Report (RRDR) published in November 2003 shows the mix and costs of the renewable resources that will likely be utilized to meet the California RPS. The cost of buying renewable energy can be estimated by creating a generic portfolio of these resources using the contributions for each type projected in the RRDR study to calculate a weighted average cost. The average cost of these resources, weighted by their expected contribution to the RPS, is shown below:

Renewable Resource Technologies Expected To Fulfill The California Renewable Portfolio Standard (2003 Dollars)
Source: CEC Renewable Development Resource Report

Resource	Portfolio Contribution	2005 Levelized Production Cost ($/MWh)
Wind (Class 4 site)	66%	60 *
Concentrating Solar	1%	121
Landfill Gas	4%	44
Solid Biomass (Direct Combustion)	4%	66
Geothermal (Binary)	25%	55
Weighted Average		59

* The cost of wind is based on the levelized cost of $49 per MWh presented in the RRDR plus an additional $11 per MWh capacity cost to reflect that capacity must be acquired separately because of the intermittency of wind resources. These figures do not include production tax credits, which many people believe will be reinstated once Congress passes a comprehensive energy bill.

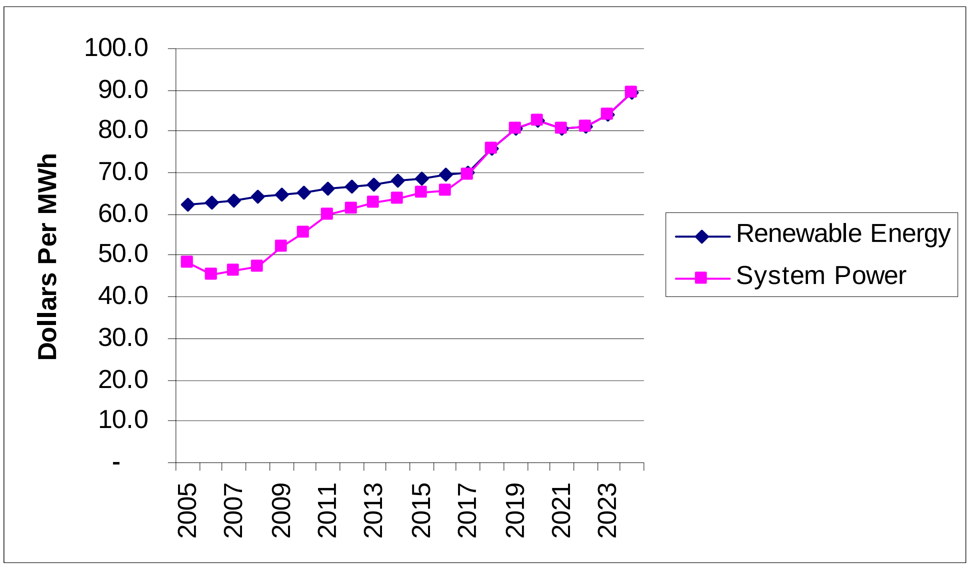
Escalating the cost to 2006 by assuming 2.5% annual inflation yields a 2006 average renewable cost of $62 per MWh. This represents a premium of approximately $18 per MWh above the projected market prices of system power in 2006.

All else being equal and assuming no Aggregator capital financing of renewable energy, the cost of doubling PG&E's 14% renewable mix would be $18/MWh *

0.14 = $2.52 per MWh. A typical household would pay $1.26 more per month to double the amount of renewable energy used to supply its electricity consumption.[12] The premium declines over time as natural gas and electricity market prices are expected to rise faster than the cost of renewable energy production. For instance, assuming average annual increases in the market price of system power of 2.8% used in this study, the renewable price premium falls to $4 per MWh by 2014. By 2018, the market price of renewable energy is expected to be no greater than the cost of conventional generation resources.[13]

The projected costs of renewable and conventional electricity are shown in the following chart:

Northern California Market Price Projections For Renewable And Conventional Electricity



7.3.2 Municipal Financing of Renewable Energy Development

As described in this feasibility study, the Aggregator can reduce the cost of acquiring renewable energy by financing development of renewable resources used to supply its CCA program. The following table compares the total cost of a hypothetical 100 MW wind energy project utilizing the financing structures typical of an investor owned utility vs. those available to the Aggregator. The

[12] Typical residential consumption is approximately 500 kWh or 0.5 MWh per month.

[13] The cost of transmission investments that may be needed to bring large amounts of renewable energy to load centers is not included in this analysis. These costs will be included in transmission rates that are paid by all users of the grid and should not impact the CCA economic analysis.

underlying assumptions are that the utility's capital structure is comprised of 50% debt and 50% equity at an overall cost of capital of 9%, while the Aggregator employs 100% debt financing at a rate of 5.5%. The utility is subject to federal and state income taxes of 40.75% so that the tax-effected cost of capital is 12.9%. The Aggregator makes no return, has no income tax obligation and establishes its revenue requirement based on the cash requirements needed to cover expenses and debt service.

Cost Comparison – IOU Vs. Aggregator Ownership of Wind Resource (Thousand of Dollars)

Cost Element	Investor Owned Utility	Aggregator
Capital Cost ($000)	15,951	7,730
Operations & Maintenance ($000)	2,198	2,198
Firming Capacity ($000)	3,022	3,022
Total First Year Cost ($000)	21,171	12,950
Cost Per MWh ($/MWh)	77	47

During the first year of operation, the Aggregator can produce energy at a cost that is nearly 40% lower than what the investor owned utility would incur if it owned the identical resource. The Aggregator's cost of producing renewable energy would be nearly the same as the market price of system power.

7.3.3 Operational Issues For Renewable Energy

Renewable resources are generally non-dispatchable, operating as either baseload resources or on an as-available basis. Wind and solar resources produce electricity only during certain times of the day when there is sufficient wind or sun. These characteristics place an operational limit on the amount of renewable energy that can be included in the overall resource mix. Depending on a community's load duration curve, which defines its base load requirements, the operational limit could range between 50% and 70%.[14] It would be possible to exceed these amounts by over-procuring, but doing so would require the Aggregator to sell excess energy into the market during many hours of the year, thereby taking on additional risks associated with wholesale sales of energy.

[14] This refers only to the County's program operations and is not intended to imply that the entire system could efficiently integrate such large amounts of renewable energy.

A similar issue exists with reliance on intermittent wind production. If an Aggregator with an average load requirement of 200 MW established a 50% renewable target, it would need approximately 300 MW of wind capacity. With a typical capacity factor of 32%, production from 300 MW of wind capacity would average the 100 MW needed to meet the target. However, at any moment in time, the Aggregator could have between 0 and 300 MW of production. The Aggregator would either need to purchase 200 MW of replacement energy or it would have 100 MW excess energy to sell. These imbalances impose financial risk on the Aggregator as the prices at which it must buy and sell energy may not be identical.

One way that the CCA could safely exceed the operational limits on renewable energy is by purchasing renewable energy certificates (RECs) from producers of renewable energy. The CEC is currently investigating a system that would facilitate trading of RECs, and private markets for RECs have been in existence for several years. The tradable REC concept allows the renewable attribute associated with renewable energy production to be sold separately from the electrical energy. Through appropriate tracking and verification, the buyer can be assured that for each REC purchased a kWh of renewable energy was produced during the year; however, the renewable production need not match the buyer's load requirements on an hour-by-hour basis. By separating the renewable attribute from the electrical energy, a CCA could ensure that enough renewable energy was produced over the course of the year to supply 100% of its customers' load requirements, while avoiding the need to sell excess energy. The price of the REC should be approximately equal to the cost difference between the market price for system power and the cost of renewable energy production, after considering all available incentives.

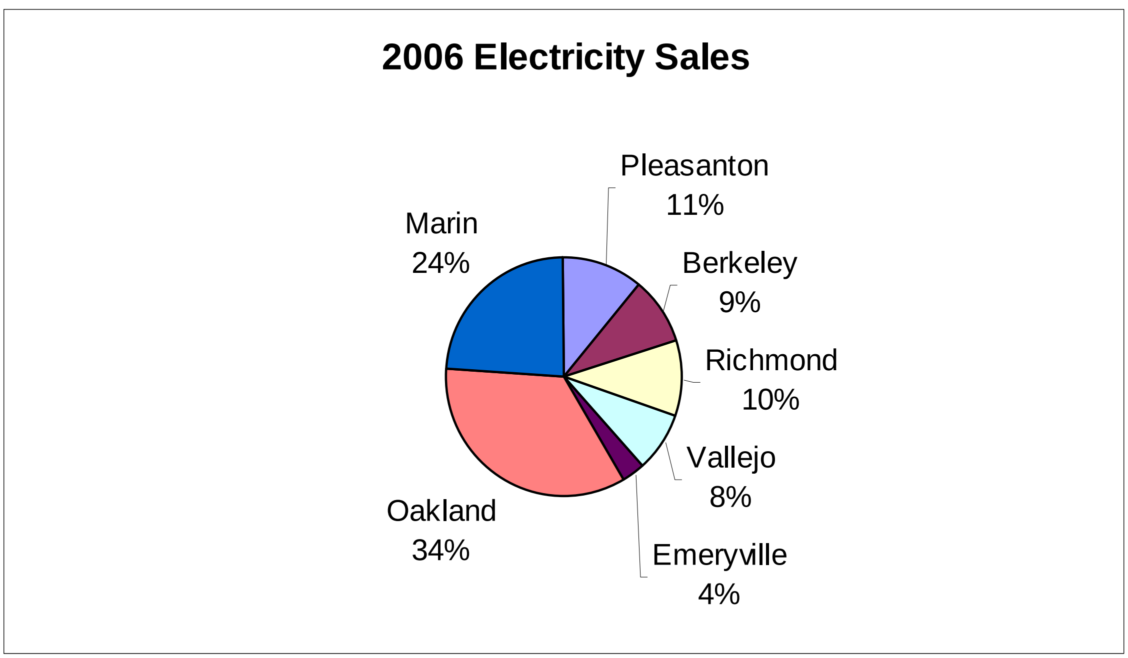
8 REGIONAL COMMUNITY CHOICE AGGREGATION PROGRAM OPERATED UNDER A JOINT POWERS AGENCY

8.1.1 Economies Of Scale From Combined CCA Operations

By combining the electric loads of multiple cities and/or counties for CCA operations, scale economies can be achieved that increase the benefits available to the individual members. Operational cost saving can be captured through common program administration and energy procurement activities. Diversity among community load shapes enables the sharing of capacity reserves, lowering overall procurement costs. The flatter load shape of a combined CCA program reduces the costs of serving the load, thereby increasing the benefits available to each of the participating communities.

NCI performed a financial assessment of combining the seven Bay Area communities participating in the CCA demonstration project for purposes of a common CCA operation. The Bay Area participants are listed below along with the shares of 2006 electricity sales.

Bay Area Participants In The CCA Demonstration Project



Annual financial results of a joint program are shown below.

Bay Area CCA Program Financial Summary (Millions of Dollars)

Year	Total CCA Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	0.0	0%
2006	432.0	457.8	25.8	3%
2007	434.0	465.8	31.8	4%
2008	462.3	483.3	21.0	3%
2009	444.5	495.3	50.8	6%
2010	476.1	520.8	44.7	5%
2011	490.7	537.5	46.8	5%
2012	503.7	555.9	52.1	6%
2013	460.5	527.6	67.0	7%
2014	473.6	543.0	69.4	7%
2015	504.6	562.3	57.7	6%
2016	516.8	576.2	59.4	6%
2017	534.1	605.3	71.2	7%
2018	560.1	649.6	89.6	8%
2019	585.5	690.2	104.7	9%
2020	628.5	713.3	84.8	7%
2021	639.5	719.8	80.3	7%
2022	653.5	736.4	82.9	7%
2023	644.2	739.5	95.4	7%
2024	674.0	784.5	110.5	8%
Total	10,118.3	11,364.2	1,246.0	6%

A combined operation would yield over $300 million in additional financial benefits during the study period compared to the benefits achievable through individual CCA operations. This represents a 34% improvement in financial benefits from joint operation.

8.1.2 Joint Powers Agency Structure Option

Joint Power Agencies (JPA) are common legal structures that many public agencies have formed and used to offer services in a more economical and efficient manner. CCA JPA formation can combine city and county jurisdictions to secure long-term power contracts or development its own generation resources. Multiple member CCA JPAs may benefit from flatter electric load shapes, reducing the overall cost to serve. There are numerous operating examples of jurisdictions forming JPAs to procure electric energy in wholesale markets for delivery to member constituent retail markets. The following describes some of the benefits and impediments of the CCA JPA structure option:

Summary of Benefits

- The JPA structure enables its party agencies to jointly exercise any power common to them. CCA enabling legislation cites eligible jurisdictions as cities, counties or JPAs comprised of cities and counties.
- The CCA JPA will be a non-profit agency and its motives are not profit driven.
- Parties to the JPA would share cost/risk and assist with any JPA project.
- JPA formation can combine its members in securing long-term power contracts or entering into agreements with agencies in the development of generation resources.
- JPA members could benefit from economies of scale associated with building a large project with its greater plant efficiencies and lower unit costs.
- The JPA may authorize the issuance of low cost bonds by ordinance subject to referendum but without a vote of the electros within the public entities comprising the JPA
- A JPA provides a organizational, legal and financial structure to integrate its parties and facilitate the implementation and operation of projects (in this case utilities)
- This structure minimizes direct exposure of the member jurisdictions and at the same time provides a conduit to key capital, political, and intellectual resources for the other JPA members.
- This structure could reduce or eliminate the need for redundant personnel and systems to facilitate energy supply for the multiple member jurisdictions.
- JPA Operational Business Plans could incorporate phased customer segment participation and provide flexibility to subcontract the organizational depth needed during initial CCA operation.

<u>Summary of Impediments</u>

- Forming a JPA is time consuming; It is necessary to establish a working group or advisory panel of all parties, and parties must agree on approach and structure (the fewer the parties the more streamlined the process).
- The challenge for governance is to provide equitable representation for both large and small members without compromising either's options.
- The decision-making process can be cumbersome, during both formation and operation (decisions tend to be "consensus" driven, slowing processes and compromising positions - members seek to protect their own interest).

8.1.3 Purpose and Parties

A JPA is formed when it is to the advantage of two or more public entities with common powers to consolidate their forces to acquire or construct a joint-use facility or when local public entities wish to pool with other public entities to save costs to acquire equipment or to acquire or construct facilities for their individual use. A joint exercise of powers agreement must be approved by all participating entities, and this may include the federal government or any federal department or agency, this state, another state or any state department or agency, a county, county board of supervisors, city public corporation, or public district of this state or another state.

8.1.4 Authorization

A Joint Powers authority is empowered by Chapter 5, commencing with section 6500 of Division 7 of Title 1 of the Government Code, to issue bonds, notes, Commercial paper, including certain kinds of variable rate securities for specified purposes, and to enter into leases to acquire land and equipment or to acquire or construct public facilities. The JPA entity is created when member jurisdictions enter into a joint exercise of powers agreement, forming a joint powers agency and by adopting identical concurrent, ordinances.

8.1.5 JPA Governance

A commission responsible for administering the CCA JPA would be established comprised of representatives from each party to the CCA JPA Joint Powers Agreement. A quorum of the CCA JPA Commission (Commission) would consist of those Commissioners, or their designated alternatives, representing a numerical majority of the Parties. Voting on JPA actions could be facilitated wherein each Party would have the right to cast one vote. In the alternative, voting may be conducted where each party has a number of votes equal to its percentage share of CCA JPA expenses. Such procedures would be developed by a working group or advisory panel of all parties as referenced above.

In addition to voting representation on the Commission, flexibility for Parties to take actions alone or in concert other selected JPA members, and thereby ensure members can protect and pursue individual interests, can be facilitated through the development and use of a hierarchy of structured agreements. In the example below, precedence of agreements can be established where, for example, a Project or Operating Agreement takes precedence over a Facilities Agreement. In this case action can be taken by JPA members without executing a higher-level membership-wide agreement. In this way specific operational arrangements between a limited numbers of Parties take "precedence" over higher-level membership-wide agreements. The names and use of agreement structures would be adjusted to more closely reflect CCA JPA activities. The following is an example of hierarchical of JPA Agreements used by the Northern California Power Agency:

Agreement Hierarchy:

1. Joint Powers Agreement
2. Pooling Agreement
3. Facilities Agreement
4. Project Agreement
5. Operating Agreement

<u>Joint Powers Agreement</u>: Through the Joint powers Agreement a CCA might be established as a public agency pursuant to the Joint Exercise of Powers Act of the Government Code of the State of California authorized to acquire, construct, finance and operate buildings, works, facilities and improvements for the generation of electric capacity and energy for resale. Each of the Parties to the Agreement would be a city or a county jurisdiction authorized to implement a CCA pursuant as defined in enabling legislation AB 117 (Migden – Chapter 838, Statutes of 2002).

<u>Pooling Agreement</u>: Each Party to the Pooling Agreement is a Party to the CCA Joint Powers Agreement. The Pooling Agreement establishes facilities, staff, and the capability for: Planning for the addition of facilities; entering into long-tem and short-term, firm and non-firm interchange transactions; dispatching and scheduling all available resources to meet the combined loads of the Parties.

Facilities Agreement: A Participant in an CCA Facilities Agreement is an CCA JPA member and a signatory to the CCA Joint Powers Agreement (JPA). The Facilities Agreement provides a framework for membership joint design, construction and operation of power supply facilities.

Project Agreement: Establishes the framework for the development, design, financing, construction and operation of specific projects.

Operating Agreement: Detailed descriptions, principles and procedures (including operating and cost recovery) for CCA JPA projects.

8.1.6 Revenue Bond Issuance

The JPA may authorize the issuance of revenue bonds by ordinance subject to referendum but without a vote of the electors within the public entities comprising the JPA. However, JPAs may also issue securities pursuant to a resolution of the authority backed by loan agreements and/or bond purchase agreement with participating member agencies. The law provides that some but not all of the members of a JPA may participate in a bond issue and that only those participating will be obligated to repay the debt incurred.

Below we list a number of financing alternatives to consider once a JPA has been formed.

Figure 12

Comparative Features of Alternative Financing Methods

Financing Method/Characteristics	General Obligation Bonds	Limited Obligations Bonds	Special Assessment	Certificates of Participation	Revenue Bonds
Project Financeable	Acquisition & improvements of land and buildings	Acquisition & improvements of land and buildings	Facilities of local benefit to property	Unrestricted	Revenue producing facilities
Authorization	Issuer's governing board & public election (2/3 vote)	Resolution of issue governing board and 2/3 vote	Resolution of issuer, petition of beneficiaries	Resolution of issuer governing board	Resolution of issuer governing board
Area of Authorization Jurisdiction	Boundary of issuer facilities district (flexible)	Boundary of issuer facilities district (flexible)	Flexible	N/A	Service area of issuer
Hearing Procedure	None	None	Majority protest hearing	Maybe ordinance adoption	None
Validation	None	None	None	None	None
Nature of debt service payments	Unlimited ad valorem tax	Portion of current revenues	Annual assessments based on benefits received; property taxes may not be used	Rental or installment payments	Service charges and fees from users
Source of debt service payment	Property owners in issuer jurisdiction	General revenues of issuer	Annual property assessments	General &/or enterprise revenues of issuer	Service charge and fee collections
Security	Full faith and credit	Revenue collections and coverage test	Tax collections/ Foreclosure	Lease or installment sale contract	Coverage test and contracts
Lessor/Lessee Required	No	No	No	Yes	NO
Refundable	Yes	Yes	Yes	Yes	Yes
Debt Service Funds subject to Gann Limit	No	No	No	Yes	Yes
Structural Features					
Reserve Fund	No	Yes	Yes	Yes	Yes
Capitalized Interest	No	No	Yes	Yes	New enterprise only
Debt Service Coverage	NO	Yes	Value/lien ratio 3:1	No	Yes
Method of Sale	Competitive or Negotiated	Competitive or Negotiated	Competitive or Negotiated	Competitive or Negotiated	Competitive or Negotiated
Advantages	Lower interest rate	No pledge of General Fund	Isolates projects	No voter approval	Higher interest rate
Disadvantages	Voter approval required	Voter approval	Limited security Higher interest rates	Highly structured Limited flexibility	Debt Service Reserve Fund

The overview above provides a broad perspective on the various financing techniques that will be available to a CCA JPA. However, the ultimate method that the CCA JPA chooses will based on a number of factors:

Purposes of Financing: Proceeds of the financing can be used for a number of different uses including but not limited to: Start-up costs, construction of new plant and equipment, initial capital for power purchases, Operations and maintenance expenses among others. As outlined above, the purpose of the financing can and will affect the type of bond issue that the CCA JPA can utilize to finance its various costs. In the end the JPA may execute a series of different products to meet each of its various purposes.

Tax Eligibility: An important consideration in determining the appropriate technique will depend largely on the tax-exempt eligibility of the potential financing. As all the objectives (i.e. purposes and uses of the proceeds) of the specific financing become known, NCI along with counsel for the JPA will have a better sense as to whether the JPA will be eligible to issue tax-exempt bonds. We will obviously attempt to create a structure that maximizes the use of tax-exempt bonds which will ultimately provides the lowest cost of financing to the JPA.

9 CONCLUSIONS AND RECOMMENDATIONS

9.1 Conclusions

There are three general criteria, as described under Section 5, for assessing benefits of CCA. These are the potential for reduced rates, the ability to increase utilization of renewable energy, and enhanced local control/rate stability. This analysis shows it is possible to achieve each of the three objectives by forming a CCA program, under the most likely scenarios. Formation of a CCA program offers benefits but is not entirely without risks, both financial and political. The County should clearly define its reasons for pursuing CCA so that program implementation reflects and fulfills clearly defined objectives. These reasons could include one or more of the following goals:

- Proactively address energy and infrastructure issues in the community
- Expand use of renewable energy resources and increase energy efficiency (e.g., reduce greenhouse gas emissions, reduce dependence on fossil fuels and imported natural gas)
- Reduce energy costs or enhance general fund revenue
- Provide for electric rate stability and local control
- Provide other utility services, such as energy efficiency and distributed generation
- Increase the tools available for economic development and planning
- Position County for provision of expanded electricity service offerings in the future

Ultimately, a primary benefit of CCA is giving consumers greater control over their energy choices and devolving responsibility for energy planning to the local level. The County should take a long-term view in considering the decision to form a CCA program and be prepared to weather challenges that may arise in the short-term. Participation in a regional CCA program via formation of a joint powers agency would offer benefits of scale that would not be available under a standalone program. The County should explore opportunities for joining with other local governments in the region to form a regional CCA program if the County decides to move forward with implementation.

Lower Rates

The analysis indicates the County is likely to obtain cost savings equal to over $6.8 million per year or approximately 3% of customers' electricity bills on average over the study period. These cost savings could be used to reduce rates and/or to create a new revenue stream for the general fund. The scenario analysis shows that savings are not dependent upon the specific financial assumptions underlying the base case. The average program savings range from a low of 1% to a high of 14% across the eight scenarios evaluated to test the sensitivity of these results to changes in wholesale energy market conditions, PG&E rate projections, and cost responsibility surcharges. A conservative interpretation of these findings suggest that over the next several years there would be moderate cost benefits from implementing a CCA program, primarily due to the imposition of cost responsibility surcharges on CCA customers. Cost benefits will be more significant over the longer term as the CRS begins to decline and eventually expires.

Increased Renewable Energy

The analysis shows that a 51% renewable energy target can be achieved with no rate increases for customers if the Aggregator is willing to finance renewable resource development to supply the CCA program. The cost effectiveness of increasing renewable energy utilization to this degree is greatly enhanced by the involvement of the public sector through CCA because of the public sector's access to low cost capital and the contract coverage afforded by the CCA's large customer base. A primary benefit of forming a CCA program is to create the ability to increase utilization of renewable energy. The realistic implementation approach used in this feasibility analysis incorporates a hybrid supply strategy and gradual ramp-up of renewable energy utilization, initially utilizing contracts with third parties to match the PG&E renewable energy mix and eventually progressing to municipal ownership/financing of generation.

Local control/rate stability

Ultimately the long-term benefits of a CCA program in the community resolve around local control. Such control includes the ability for the County and aligned agencies to effect resource planning and infrastructure investment in an integrated fashion responsive to the community's needs and values. Local control also manifests in avoiding the cost consequences of the utility's long-term procurement decisions, which must be made considering the competing interests of shareholders, regulators, and consumers. The County faces no such conflicts and can focus on its primary mission of representing the interests of consumers.

9.2 Recommendations

1. Communicate final study results through community workshops and identify next steps in proceeding toward Implementation Plan filing.

2. Consider whether natural alliances exist among neighboring communities, and explore partnering arrangements to optimize supply side alternatives and regional CCA implementation.

3. Make decision whether to proceed with development of an Implementation Plan.

APPENDICES

Appendix A – Resource Portfolio Planning Template

Fifth Supply Scenario Variables

1. Renewable Energy (RE) Targets
    a. End-State Percentage (20-100% by 2017) ________
    b. RE Ramp Rate 2006 – 2023, Cite Yearly Targets
        1) 2006 min. 14%
        2) 2017 min. 20%
    c. RE Equity Position
        1) Physical Resource Entitlement (ownership/investment)
            a) Yes __ No __
            b) Percentage of Total RE __
            c) In-Service Dates and Capacities (MW)
        2) Market Purchases
            a) Percentage of Total RE __
            b) Contract Schedule and Capacities (MW)
2. Conventional Generation Resource Equity Position
    a. Physical Resource Entitlement (ownership/investment)
        1) Yes __ No __
        2) In-Service Dates and Capacities (MW)
    b. Market Purchases - Contract Schedule and Capacities (MW)
3. Distributed Generation
    a. Capacity (kW)
        1) Existing
            a) Technology (PV/micro-turbine/etc)
            b) Capacity (kW)
            c) Energy (kWh)
            d) Cost
            e) In-Service Dates
        2) Planned
            a) Technology (PV/micro-turbine/etc)
            b) Capacity (kW)
            c) Energy (kWh)
            d) Cost
            e) In-Service Dates
4. Spot Market Purchases (assumed minimized – under 20% energy unless instructed otherwise)
5. Based Upon the 5th or "Preferred" Supply Portfolio Sensitivities Will be Assessed for the Following Variables:
    a. Natural gas/power prices (+/- 25%)
    b. Cost responsibility surcharge (+/- 25%)

c. IOU rate projections (+/- 5%)
d. IOU rate design (GRC proposals)
e. Renewable subsidies (SEP, PTC)
f. Combined operation with other Project participants

Appendix B – Detailed Assumptions

Key Assumptions Used In CCA Feasibility Analysis and Modeling - Pacific Gas & Electric Territory

1) Metering and Billing

    a) No new metering requirements for CCA customers.
    b) Billing charges same as direct access from Schedules E-ESP and E-EUS.
    c) Billing charges based on Rate-Ready Billing Option from Schedule E-ESP.

2) Financing

    a) Tax exempt financing for startup costs and any new generation development @ 5.5%.
    b) 100% debt financing.
    c) Financing term is 30 years.
    d) Minimum debt coverage ratio of 1.25.
    e) Bond insurance cost of 1.6% of par value.
    f) Bond transaction cost of 1% of par value.
    g) Debt reserve of 10% of par value.

3) Startup and Operations Costs

    a) Startup costs include regulatory and legal @ $350,000.
    b) Operational costs are outsourced @ $2.50 per MWh unless and until CCA reaches approximately 1.5 million MWh in sales.
    c) If performed internally, the cost is estimated at $3.9 M per year plus 10 cents per MWh, including IT.
    d) Activities include scheduling coordination, procurement/planning, risk management, credit, rates and load research, A&G, and IT.
    e) The CCA will begin serving customers in January 2006

4) Resource Adequacy

    a) CCAs subject to same resource adequacy requirement as IOUs, per D.04-01-050.
    b) Planning reserves are required to bring total reserves, including ISO required ancillary services, up to 15% of peak load.
    c) Costs of meeting planning reserves equal to market value of capacity.

d) Spot market purchases limited to between 5% and 20% of CCA portfolio; the remainder of the portfolio is comprised of long-term contracts and/or resource ownership.

5) <u>Renewable Energy Portfolio</u>

a) Renewable purchases are from a generic portfolio comprised of Class 4 Wind, Binary Geothermal, Solid Fuel Biomass, Land Fill Gas Biomass, and Concentrating Solar Power.
b) The cost and resource mix comprising the portfolio is derived from the CEC's Renewable Resources Development Report (11/7/03) See RRDR, Table 4, page 37 and discussion at page 87. 2005 costs are escalated at a nominal rate of 1% per year.
c) The cost of the generic renewables portfolio equals the estimated developers' costs, including return on investment. Market price of renewable energy equal to maximum of cost or market price of system energy
d) The cost of wind energy assumes no extension of the production tax credit.
e) Wind energy must be firmed via capacity contracts due to its intermittent nature. The cost of wind energy is adjusted for a capacity adder to firm the intermittent resource, at market value of capacity.
f) Renewable ownership costs are derived by applying municipal financing assumptions to the cost data in RRDR Appendix D, page D-6. 2005 costs are escalated at a nominal rate of 1% per year.
g) Ownership cost incorporate technology specific assumptions regarding installed capital costs, fixed operations and maintenance, capacity factor, fuel cost, and capacity cost adder applied to intermittent resources.
h) The ownership costs of intermittent resources also includes a risk factor of $5 per MWh related to the potential differences between energy prices for sales from excess production versus purchases for production shortfalls.
i) CCAs will rely primarily on large-scale renewable projects to meet and exceed the RPS. These are Wind, Geothermal, Solid Fuel Biomass, and Concentrating Solar Power.
j) CCA owned generation resources can be online by 2008.
k) Distributed generation options, such as rooftop PV systems, are incorporated in the feasibility analysis based on community specific planning. Renewable DG production, if any, will be in addition to the RPS minimums.
l) Supplemental energy payments are available to offset the incremental costs of renewable contract purchases (10-Year Terms) up to the minimum RPS requirement. PGC funds are sufficient to buy down 100% of the cost premium of renewables.

m) Supplemental energy payments are not available for city-owned resources and not available for purchases in excess of the RPS minimums.
n) CCAs are required to match the renewable energy percentage of the respective investor owned utility in the first year of CCA operations.
o) IOU renewable baseline percentages are derived from RRDR Appendix A, page A-2 and increased by 1% per year until 20% is achieved by 2017.

6) Wholesale Energy Markets

a) Electricity market price forecast based on projected market clearing system heat rates and natural gas price projections.
b) Natural gas price projections prepared by NCI in January 2005.
c) Implied system clearing heat rates for 2005-2010 are 8,000, 8250, 8700, 9000, 10,000, 10,500. Market equilibrium assumed at implied system heat rate of 11,000 after 2010.
d) On-peak energy priced at 15% premium; off-peak energy priced at 15% discount; real time energy at 10% premium.
e) Long term contracts priced at 5% premium to expected spot market prices.
f) Capacity costs valued at $100,000 per MW-Year, escalated at 2.5% annually; costs are embedded in energy prices derived as above.
g) Ancillary services and related costs estimated based on historical relationship to market prices, projected forward.
h) Ancillary services requirements based on percentage of CCA's load per current CAISO practice.
i) Ancillary services types are Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve.
j) California Independent System Operator (CAISO) administrative and neutrality charges are derived from current rates, escalated at 2.5% annually.
k) CAISO charges are Grid Management Charge - Control Area Service, Grid Management Charge - Inter-zonal Scheduling, Grid Management Charge - Ancillary Services and Real Time Operations, Unaccounted For Energy Charge, Neutrality Charge, Congestion Charge, De
l) No explicit modeling of impact from move to locational marginal pricing; assumed that loads will be protected from congestion costs by allocation of congestion revenue rights and zonal averaging of prices.
m) Distribution losses are 7%.

7) Generation Cost
a) CCA's choosing to own generation will acquire equity interests in combined cycle gas turbine facilities based on the following cost and operating parameters:
b) Installed cost of $700 per KW.

c) Heat rate of 7,000 mmbtu/MWh.
d) $3 per MWh fixed and variable O&M
e) 0.1 pounds per MWh emissions..
f) $10 per pound cost of NOx emissions.
g) 90% planned capacity factor.
h) 2% forced outage rate.
i) Excess sales sold at prevailing market clearing prices.

8) <u>Cost Responsibility Surcharges</u>

a) Cost responsibility surcharges calculated annually using total portfolio indifference method adopted in direct access proceeding (includes old and new resources) (R.02-01-011) and CCA Rulemaking (D.04-12-046)
b) CRS reduced by pro rata share of cost of ancillary services and planning reserves
c) No cap on cost responsibility surcharge for CCAs.
d) Cost responsibility surcharge includes DWR bonds, DWR power charge, utility CTC, and Regulatory Asset.
e) Uniform "indifference fee" per KWh for all CCA customers, regardless of rate class and CCA startup date. No baseline credits reflecting AB1X protections for residential consumption up to 130% of baseline allocation.
f) Uniform DWR bond charge per KWh, statewide.
g) CTC rate varies by customer class based on current tariffs.
h) DWR bond charge projections based on currently applicable rate as of January 2005.
i) No transfer to CCA of DWR contracts, renewable energy, or capacity contracts implied by payment of cost responsibility surcharges.

9) <u>IOU Rate Projections</u>

a) IOU rates for generation are the competitive reference point for assessing CCA cost savings potential.
b) Current IOU rate schedules (Advice Letter 2570-E-A) as of January 2005 applied to CCA customer billing determinants (estimated), aggregated by major rate group.
c) Generation rates and total rates (generation plus non-generation) projected forward based on percentage changes in IOU system average rates.
d) IOU generation costs projected based on current resource mix, adjusted over time for planned generation retirements, DWR contracts, QF contracts, and renewable energy contracts to meet RPS.

e) PG&E owned generation resources includes Nuclear (Diablo Canyon), Hydro, and Fossil facilities. Production and sales data are from PG&E's Long Term Resource Plan.
f) Generation costs and beginning rate base for each generation type are derived from 2003 General Rate Case filing.
g) Generation costs include operations and maintenance, return, depreciation, uncollectibles, A&G, franchise fees, taxes other than income, taxes based on income, fuel, thermal decommissioning, and other.
h) Future capital additions increased for Diablo Canyon turbine replacement anticipated in the 2007 - 2009 timeframe.
i) Purchased Power includes QF contracts, existing bilateral contracts, DWR contracts, new renewable contracts, new bilateral contracts, and spot market purchases.
j) New bilateral contracts entered into as needed to maintain spot purchases (residual net short) at or below 10% of IOU portfolio.
k) PG&E maintains planning reserves of 15% of annual peak load. Existing ancillary services requirements are included in the 15% planning reserves requirement.
l) Spot market purchases to meet the residual net short are priced at average of NP15 peak (6 X 16) and base (7 X 24) power prices.
m) Majority of QFs (80%) paid according to settlement price through 2005, and then based on annual short run avoided cost formula.
n) QF capacity payments derived from FERC Form 1 data.
o) QF capacity/energy projections derived from the Consultant's Report supporting DWR bond financing.
p) RPS purchases from generic renewable portfolio as described above; Supplemental Energy Payments fully offset incremental costs relative to non-renewable energy.
q) DWR costs and volumes adjusted over time based on terms of the individual contracts allocated to PG&E per D.02-09-053.
r) DWR "remittance rate" calculated using CPUC methodology (D. 04-12-014).
s) Regulatory asset cost calculated based on terms of approved Bankruptcy Settlement.
t) Cost offset for bundled customer generation costs from cost responsibility surcharges paid by Direct Access Customers based on capped collection rate from direct access proceeding (R.02-01-011)
u) Non-generation costs escalated at constant 1.5% per year. Non-generation rates are only used to express the CCA cost impacts as percentage of customers' total electric bills.
v) Same input assumptions as above for wholesale electricity prices, capacity prices, natural gas prices, ancillary services costs, CAISO charges, RPS % and prices, supplemental energy payments, and DWR bonds charges.

Appendix C – Sample Data Request Letter

[DATE]

Pacific Gas & Electric Company

Governmental Affairs

Attention: [LOCAL GOVERNMENTAL AFFAIRS REPRESENTATIVE]

77 Beale Street

San Francisco, CA 94105

SUBJECT: Information Request Per D.03-07-034

Dear [LOCAL GOVERNMENTAL AFFAIRS REPRESENTATIVE]:

The [CITY OR COUNTY] of [NAME] (CITY OR COUNTY) is currently reviewing its options in becoming a Community Choice Aggregator (CCA) in accordance with AB 117, enacted in 2002, for: 1) administering energy efficiency programs; and 2) possibly providing electrical energy as related to this legislation. On July 10, 2003, the California Public Utilities Commission (CPUC) approved an "Interim Opinion Implementing Provisions of Assembly Bill 117 Relating to Energy Efficiency Program Fund Disbursements" (Decision 03-07-034). As part of this Decision, the CPUC directed Pacific Gas & Electric Company (PG&E) to provide certain types of information to cities, counties, and CCAs.

The [CITY OR COUNTY] respectfully requests the information listed below, as enumerated in Attachment C of D.03-07-034 for all electric customers within the [CITY OR COUNTY].

1. Energy consumption for each customer class for a given period of time and a given city.

   The [CITY OR COUNTY] requests the total number of customers and monthly energy consumption in kWh for the following rate groups: residential (E-1 and all other residential services), small commercial (A-1, A-6) medium commercial (A-10), small industrial (E-19), large industrial (E-20), agricultural, and outdoor and street lighting. Please provide the above information separately for customers currently receiving bundled utility service from PG&E and customers currently served under direct access arrangements with energy service providers.

2. System-wide residential and nonresidential load shapes and most recent hourly load shapes for the climate band encompassing the [CITY OR COUNTY].

3. The proportional share in the potential CCA territory, as defined in the Commission's energy efficiency policy manual.

The [CITY OR COUNTY] understands that D.03-07-034 ordered that PG&E "shall provide the information and data described in Attachment C to any city, county or CCA that requests it, as set forth in this order without charge." We also understand through this Decision that this information "should be provided…within one week of the request."

Please send this information in electronic form via e-mail to [E-MAIL ADDRESS]. If you have any questions regarding this request, please contact [NAME] at [TELEPHONE]. The [CITY OR COUNTY OF NAME] appreciates your assistance.

Sincerely,

[NAME]
[TITLE]
[CITY OR COUNTY NAME]

Appendix D – CCA Functional Elements

The operations of a CCA program include all activities needed to procure electricity for end-use customers, schedule delivery of the electricity, conduct financial settlements for wholesale electricity purchases and sales, determine the costs charged to individual customers, and interface with PG&E which would provide billing, metering, and customer services to CCA customers. These activities can be grouped into the broad categories described below.

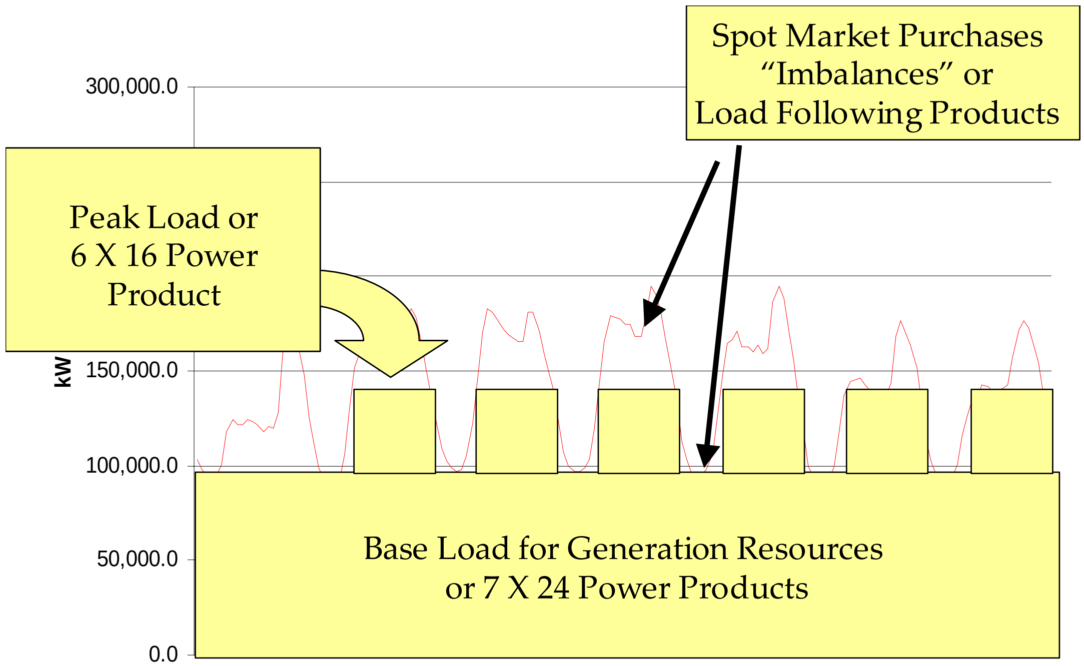
1. Portfolio Operations

Portfolio operations encompass the activities necessary for wholesale procurement of electricity to serve end-use customers. These activities are virtually identical to the supply functions performed by local utilities, municipal utilities, and energy service providers.

   a. Electricity Procurement

The essential purpose of the Aggregator is to assemble a portfolio of electricity supply sources on behalf of its customers. As an Aggregator, the County can choose from various types of resources and wholesale electricity products to achieve a supply portfolio that appropriately reflects the desired balance of cost certainty, environmental considerations, cost effectiveness, and operational and contractual flexibility.

A variety of generation resources or electricity purchase contracts can be employed to provide for the time-varying load requirements of the CCA program. The pattern of aggregate electricity usage typically follows daily, weekly and seasonal cycles, peaking during the afternoon hours and the summer months. The Aggregator must consider these load patterns when assembling a supply portfolio to properly match resources to the aggregate load shape of its customer base. Different types of generation resources and supply contracts supply the base load requirements, intermediate resource needs, and peaking load requirements. These concepts are illustrated in the following diagram.



A typical supply portfolio would utilize generation owned by the Aggregator or long-term contracts for the majority of projected base load requirements. These base load resources would be supplemented with intermediate resources or peak products as well as short-term contracts covering the additional seasonal load requirements of the portfolio, typically in the third quarter of each year. Spot market purchases and sales are used to fill the residual "net short" load requirements.

b. Risk And Credit Management

Risk management techniques would be employed to reduce the Aggregator's exposure to the volatility of energy markets and insulate customer rates from sudden changes in wholesale market prices. Credit monitoring is also important to keep abreast of changes in a supplier's financial condition and credit rating. Common practice in the energy industry is to periodically calculate the financial exposure to a supplier by comparing the value of the supply contract to the contractual price, utilizing so called "mark-to-market" valuation. Exposure to suppliers is greatest when the contractual price is low relative to prevailing market prices, and the risk of default becomes a concern. Collateral and other security instruments, such as letters of credits or surety bonds, are commonly used to manage credit risks between wholesale electricity buyers and sellers.

c. Load Forecasting

In performing the electricity procurement functions, it is necessary to develop accurate load forecasts, both long-term for resource planning and short-term for the electricity purchases and sales needed to maintain a balance between hourly resources and loads.

The CCA will be required to purchase energy on the wholesale market for each hour of the day. To support financial settlements and energy procurement, an accurate record of total, time-of-day specific electricity demand and energy usage is essential. Lacking this, the CCA operator is required to rely on the distribution utility's recorded usage for each individual customer. All customer classes are not metered in the same way. In particular, residential and small commercial consumers (electric demand less the 20 kW) typically have simple electro-mechanical meters capable of metering only cumulative energy consumption. Medium commercial customers (electric demand in the range of 20 to 500 kW) are typically metered with energy and demand meters, but still lack time-of-day recording. Large commercial and industrial customers (electric demand greater than 500 kW) are typically equipped with data recording meters recording electric demand on five, ten or fifteen minute intervals (interval data recording meters or IDR).

Without a time-of-use record of energy consumed, the Aggregator will have to rely on prototypical rateclass load profiles. The California Independent System Operator (CAISO) allows use of load profiles that are approved by the local regulatory agency (CPUC) for scheduling and settlement. These *load profiles* are derived by distribution utility load research based on IDR metering of a stratified random sample from each rateclass (residential, small commercial, medium commercial, industrial). Hence, they represent the average or typical customer and not the CCA's actual customers. To date, the CPUC has approved the use of rateclass load profiles for use by the utilities and energy service providers for electricity scheduling and settlement. The local utilities have opposed proposals made in R.03-10-003 that Aggregators be allowed to use area-specific load profiles for these purposes.

CCAs have the option, under the law, to meter electricity supplied to the jurisdictional territories comprising the CCA to obtain an accurate record of aggregated loads. PG&E is required to "install, maintain and calibrate metering devices at mutually agreeable locations within or adjacent to the CCA's political boundaries" at the request and at the expense of the CCA. PG&E will also be required to "read the metering devices and provide the data collected to the CCA at the aggregator's expense."[15] Utilities are directed under CPUC Order

[15] California Public Utilities Code §366.2(c)(18)

Instituting Rulemaking R.03.09.007 (August 21, 2003) to develop specific tariff language to meet the requirements. Assessing the size, type, location, quantity and installation cost of such CCA wholesale metering will require an analysis of PG&E's distribution system, in concert with utility Service Planners, and, will require PG&E to comply with the CPUC's Order to develop applicable tariff terms and conditions. At this time, it is not clear to what extent the CPUC or the CAISO would have to approve the Aggregator's use of boundary meters for electricity scheduling and settlement.

d. Scheduling Coordination

Scheduling coordination costs are the costs associated with scheduling and settling electric supply transactions with the CAISO. All customer meters must be represented by a CAISO-certified scheduling coordinator. The scheduling coordinator submits schedules to the CAISO of hourly electric demands and supply resources on behalf of the Aggregator. The scheduling coordinator is responsible for costs associated with imbalances or deviations between the actual hourly loads and the actual hourly production of the resources it represents. It is also responsible for the costs of reserves and other services ("ancillary services") provided by the CAISO that are needed for reliable operation of the transmission system.

The Aggregator has several choices for obtaining services of a scheduling coordinator. Some companies act as independent scheduling coordinators and charge service fees for their services. Other companies such as power marketers or energy service providers will provide scheduling coordination services as part of a larger package of energy services, including wholesale electricity supply, load forecasting, and risk management. The charges for providing the scheduling coordinator services are bundled into the overall cost of electricity provided by the supplier. It is also possible for the Aggregator to become a CAISO certified scheduling coordinator, which requires acquisition of specialized software, completion of certification training conducted by the CAISO, and continuous staffing of a scheduling desk for 24 x 7 operations.

2. Rates

The Aggregator is responsible for setting its charges for the generation services it provides to CCA customers. The first step in setting rates is to determine the total dollars that must be collected from customers in order to cover all of the Aggregator's costs of doing business. This amount is known as the revenue requirement and consists of operating expenses, depreciation and amortization, interest and financing expenses, taxes, and reserve funds.

The revenue requirement is allocated to the various classes of customers in the CCA program, such as residential, small commercial, medium commercial, large industrial, agricultural, and street lighting customers. Revenue allocation is typically done on a cost of service basis, so that rates are reflective of differences in the Aggregator's costs of serving the different customer classes. The Aggregator may employ load research to estimate customer class load profiles and cost of service by use of sampling techniques, whereby load research meters that can record customer electricity consumption on a 5 to 15 minute interval basis are installed on a small sample of customers within each rate class. Alternatively, the Aggregator may utilize the customer class load profiles created by PG&E.

Rate design is the process of setting the specific charges applicable to customer electricity usage. Rate schedules define the charges for each kWh, kW or other unit of electric service, and there may be one or more rate schedules applicable to each customer class. Rates are set so recover the Aggregator's revenue requirement on a forecast basis and are adjusted as needed to maintain sufficient revenues for the Aggregator.

3. Account Services

The Aggregator must be able to exchange customer meter usage data electronically with PG&E using the utility's standard electronic data interchange procedures and formats. The Aggregator must receive and process customer payments collected by PG&E. Aggregators may also need the capability to calculate individual customer bills and provide the amount to be collected to PG&E in the formats and by the timelines required for inclusion in the bills sent by the local utilities. PG&E is the only local utility that offers "rate ready" billing service, whereby PG&E will calculate individual customer bills using the rates provided by the Aggregator. PG&E also offers "bill ready" billing service whereby the Aggregator calculates the amounts due from each customer and submits to PG&E for collections. SCE and SDG&E only offer "bill ready" billing.

The Aggregator must also be able to obtain customer meter data and process the data for submission to the CAISO through its scheduling coordinator so that the CAISO can complete its financial settlement process. Customer meter data must be processed in accordance with the CPUC's protocols for verification, estimation, and editing (VEE) of meter data. PG&E will perform the VEE function for Aggregators as part of their metering service function. However, the Aggregator must apply load profiles to the usage data of customers whose consumption is measured on a cumulative monthly basis (e.g. residential and small commercial) in order to create the hourly usage data that must be submitted to the CAISO.

4. Administration

Administration and management of the CCA program includes finance, legal, regulatory, contract management and other program management functions. The scope of the administrative function depends on the complexity of the CCA implementation, which can range from a single contract with an energy services provider for operation of the program to the planning and staffing required for in-house operation and management of all aspects of the CCA program, with variations in between these two extremes. At a minimum, a senior level manager with experience in the electric utility industry should head the CCA program.

Appendix E – Base Case Pro Forma And Supporting Data

COUNTY OF MARIN
SUMMARY OF PRO FORMA RESULTS ($ MILLIONS)
51% RENEWABLE ENERGY

Year	Commodity Costs	Reserves and ISO Charges	Operations & Scheduling	Non-bypassable Charges	Metering & Billing	Financing Costs	Total Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	-	-	-	-	-	-	0.0	0%
2006	71.6	5.7	3.6	25.1	1.1	1.2	108.3	107.2	(1.0)	-1%
2007	73.3	5.9	3.7	23.7	1.1	1.2	108.8	109.1	0.3	0%
2008	72.4	6.1	3.8	24.1	1.1	9.1	116.7	113.1	(3.5)	-2%
2009	75.0	6.6	3.8	16.9	1.2	8.2	111.7	115.9	4.2	2%
2010	80.5	7.0	3.9	15.5	1.2	10.3	118.5	121.8	3.4	2%
2011	83.7	7.5	3.9	15.9	1.3	10.2	122.6	125.7	3.1	1%
2012	86.5	7.8	4.0	16.4	1.3	10.1	126.1	129.9	3.8	2%
2013	75.2	8.1	4.0	7.3	1.4	18.7	114.8	123.3	8.5	4%
2014	78.0	8.4	4.1	7.4	1.5	18.4	117.7	126.9	9.2	4%
2015	85.9	8.8	4.1	7.5	1.5	18.1	125.8	131.3	5.5	2%
2016	88.4	9.0	4.1	7.7	1.6	17.0	127.6	134.5	6.9	3%
2017	92.8	9.5	4.1	7.8	1.6	16.7	132.5	141.2	8.7	3%
2018	99.4	10.3	4.1	7.9	1.7	16.4	139.7	151.5	11.8	4%
2019	105.8	10.9	4.1	8.0	1.8	16.0	146.6	160.9	14.3	5%
2020	115.4	11.3	4.1	8.1	1.8	15.7	156.4	166.2	9.8	3%
2021	117.6	11.5	4.1	8.2	1.9	15.3	158.6	167.7	9.1	3%
2022	121.2	11.8	4.1	7.9	2.0	14.8	161.8	171.5	9.6	3%
2023	127.1	12.4	4.1	-	2.1	14.4	160.1	171.8	11.8	4%
2024	134.7	13.1	4.1	-	2.2	14.0	168.1	182.2	14.1	4%
Total	1,784.5	171.9	75.4	215.4	29.4	245.6	2,522.3	2,651.8	129.5	3%

COUNTY OF MARIN
ELECTRIC SUPPLY RESOURCE MIX
51% RENEWABLE ENERGY

CATEGORY	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Spot Market Purchases	0%	18%	18%	15%	17%	20%	18%	15%	5%	6%	13%	11%	9%	9%	9%	10%
Contract Purchases	0%	68%	67%	64%	63%	34%	33%	33%	32%	32%	21%	21%	20%	20%	20%	20%
Power Production - Natural Gas	0%	0%	0%	0%	0%	25%	24%	24%	24%	23%	23%	23%	22%	22%	22%	21%
Renewable Energy Purchases	0%	14%	15%	0%	0%	1%	5%	9%	0%	1%	4%	8%	13%	14%	15%	16%
Power Production - Renewable Energy	0%	0%	0%	21%	21%	20%	20%	20%	42%	41%	40%	39%	38%	37%	36%	35%
Off System Sales	0%	0%	0%	-1%	0%	0%	0%	0%	-3%	-3%	0%	-1%	-2%	-2%	-2%	-1%
Total	0%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

COUNTY OF MARIN
ELECTRIC SUPPLY RESOURCE MIX
51% RENEWABLE ENERGY

CATEGORY	2021	2022	2023	2024
Spot Market Purchases	10%	10%	11%	11%
Contract Purchases	19%	19%	19%	18%
Power Production - Natural Gas	21%	21%	20%	20%
Renewable Energy Purchases	17%	18%	19%	19%
Power Production - Renewable Energy	34%	33%	32%	32%
Off System Sales	-1%	-1%	-1%	0%
Total	100%	100%	100%	100%

COUNTY OF MARIN
FINANCIAL PRO FORMA ANALYSIS
LOAD AGGREGATION SUMMARY
51% RENEWABLE ENERGY

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012
I. PG&E PG&E'S UNBUNDLED GENERATION RATES ($/KWH)								
RESIDENTIAL	$0.06781	$0.06718	$0.06732	$0.06879	$0.06943	$0.07187	$0.07305	$0.07440
SMALL COMMERCIAL (A-1 & A6)	$0.08194	$0.08116	$0.08133	$0.08313	$0.08392	$0.08690	$0.08835	$0.09000
MEDIUM COMMERCIAL (A-10)	$0.10119	$0.10022	$0.10043	$0.10268	$0.10366	$0.10739	$0.10919	$0.11125
MEDIUM INDUSTRIAL (E-19)	$0.09199	$0.09110	$0.09130	$0.09333	$0.09422	$0.09759	$0.09922	$0.10108
LARGE INDUSTRIAL (E-20)	$0.08456	$0.08375	$0.08393	$0.08579	$0.08660	$0.08969	$0.09118	$0.09289
AGRICULTURAL PUMPING	$0.00453	$0.00453	$0.00453	$0.00453	$0.00453	$0.00453	$0.00453	$0.00453
STREET LIGHTING AND TRAFFIC CONTROL	$0.06307	$0.06248	$0.06261	$0.06397	$0.06456	$0.06682	$0.06791	$0.06916
II. PG&E PG&E'S REVENUE REQUIREMENT FOR POWER SUPPLY ($)								
RESIDENTIAL	$0	$46,977,196	$47,782,012	$49,559,206	$50,770,262	$53,344,472	$55,032,545	$56,890,284
SMALL COMMERCIAL (A-1 & A6)	$0	$18,261,645	$18,574,990	$19,270,991	$19,744,119	$20,753,703	$21,414,469	$22,141,957
MEDIUM COMMERCIAL (A-10)	$0	$20,846,381	$21,204,583	$22,004,457	$22,547,001	$23,708,759	$24,467,797	$25,303,801
MEDIUM INDUSTRIAL (E-19)	$0	$8,576,057	$8,723,330	$9,051,452	$9,274,222	$9,750,535	$10,061,966	$10,404,920
LARGE INDUSTRIAL (E-20)	$0	$12,058,702	$12,265,661	$12,725,755	$13,038,407	$13,705,939	$14,142,709	$14,623,614
AGRICULTURAL PUMPING	$0	$0	$0	$0	$0	$0	$0	$0
STREET LIGHTING AND TRAFFIC CONTROL	$0	$516,567	$517,646	$528,903	$533,794	$552,472	$561,486	$571,810
TOTAL - POWER SUPPLY REVENUE REQUIREMENT	$0	$107,236,548	$109,068,221	$113,140,765	$115,907,806	$121,815,879	$125,680,971	$129,936,386
AVERAGE RATE ($/KWH)	$0.0000	$0.0778	$0.0779	$0.0797	$0.0804	$0.0833	$0.0847	$0.0862
III. OPERATING EXPENSES ($)								
1. POWER SUPPLY COSTS:								
(A) ANCILLARY SERVICES AND RESERVES	$0	$4,330,492	$4,494,999	$4,681,290	$5,086,595	$5,428,282	$5,829,973	$6,084,355
(B) RENEWABLE PORTFOLIO STANDARD (RPS)	$0	$14,057,186	$15,971,762	$0	$215,805	$1,165,107	$5,171,657	$10,979,329
(C) DWR POWER	$0	$0	$0	$0	$0	$0	$0	$0
(D) POWER PRODUCTION	$0	$0	$0	$8,704,720	$8,851,232	$25,451,014	$26,035,734	$26,690,970
(E) CONTRACT PURCHASES	$0	$50,482,630	$50,482,630	$53,394,338	$53,394,338	$37,128,268	$37,128,268	$37,128,268
(F) MARKET PURCHASES	$0	$11,865,485	$11,950,301	$10,852,846	$12,987,269	$17,077,922	$16,395,321	$13,803,105
SUBTOTAL POWER SUPPLY COSTS	$0	$80,735,793	$82,899,692	$77,633,194	$80,535,239	$86,250,593	$90,560,954	$94,686,027
2. OTHER COSTS:								
(A) CALIFORNIA ISO COSTS	$0	$1,346,261	$1,399,768	$1,456,536	$1,531,016	$1,602,668	$1,680,580	$1,749,711
(B) NON-BYPASSABLE CHARGES	$0	$25,092,355	$23,655,081	$24,066,327	$16,885,988	$15,501,960	$15,944,062	$16,435,934
(C) START UP COSTS AMORTIZATION	$0	$475,426	$501,575	$529,161	$558,265	$588,970	$621,363	$655,538
(D) OPERATIONS & SCHEDULING COORDINATION	$0	$3,646,823	$3,698,215	$3,750,379	$3,803,324	$3,857,064	$3,911,610	$3,966,974
SUBTOTAL - OTHER COSTS	$0	$30,560,865	$29,254,639	$29,802,403	$22,778,593	$21,550,662	$22,157,614	$22,808,156

COUNTY OF MARIN
FINANCIAL PRO FORMA ANALYSIS
LOAD AGGREGATION SUMMARY
51% RENEWABLE ENERGY

CATEGORY		[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012
3. UTILITY OPERATIONS:									
(A) DISTRIBUTION O&M		$0	$0	$0	$0	$0	$0	$0	$0
(B) CUSTOMER SERVICE		$0	$0	$0	$0	$0	$0	$0	$0
(C) METERING & BILLING		$0	$1,060,331	$1,103,057	$1,147,505	$1,193,746	$1,241,852	$1,291,898	$1,343,961
(D) ADMINISTRATIVE AND GENERAL		$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - UTILITY OPERATIONS		$0	$1,060,331	$1,103,057	$1,147,505	$1,193,746	$1,241,852	$1,291,898	$1,343,961
TOTAL OPERATING EXPENSES		$0	$112,356,989	$113,257,388	$108,583,102	$104,507,579	$109,043,107	$114,010,465	$118,838,145
IV. INTEREST EXPENSE ($)									
(A) INTEREST EXPENSE ($)		$0	$336,670	$310,522	$7,361,144	$7,234,323	$9,303,044	$9,131,482	$8,950,484
(B) DEBT COVERAGE		$0	$0	$0	$856,273	$0	$0	$0	$0
(C) WORKING CAPITAL EXPENSE		$0	$342,680	$356,354	$373,290	$414,363	$443,347	$457,995	$475,075
SUBTOTAL - FINANCING EXPENSE		$0	$679,351	$666,876	$8,590,708	$7,648,686	$9,746,391	$9,589,477	$9,425,559
V. REVENUES FROM MARKET SALES ($)									
(A) EXCESS ENERGY SALES		$0	$99,101	$111,815	$515,239	$425,243	$89,395	$181,946	$517,576
(B) EXCESS ANCILLARY SERVICE SALES		$0	$0	$0	$0	$0	$0	$0	$0
(C) SUPPLEMENTAL ENERGY PAYMENTS		$0	$4,661,821	$5,005,105	$0	$56,633	$239,532	$836,191	$1,597,307
---		$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - OTHER REVENUES		$0	$4,760,922	$5,116,920	$515,239	$481,876	$328,927	$1,018,138	$2,114,883
VI. REVENUE REQUIREMENT - NET MARKET SALES ($)		$0	$108,275,418	$108,807,344	$116,658,571	$111,674,388	$118,460,570	$122,581,805	$126,148,821
VII. CCA NET MARGIN		**$0**	**($1,038,870)**	**$260,877**	**($3,517,806)**	**$4,233,417**	**$3,355,308**	**$3,099,166**	**$3,787,565**
NET PRESENT VALUE	$38,300,581.11								
NOMINAL MARGIN	$129,471,017.21								

COUNTY OF MARIN
FINANCIAL PRO FORMA ANALYSIS
LOAD AGGREGATION SUMMARY
51% RENEWABLE ENERGY

CATEGORY	[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018	[15] 2019	[16] 2020
I. PG&E PG&E'S UNBUNDLED GENERATION RATES ($/KWH)								
RESIDENTIAL	$0.06960	$0.07055	$0.07194	$0.07259	$0.07509	$0.07932	$0.08296	$0.08444
SMALL COMMERCIAL (A-1 & A6)	$0.08412	$0.08528	$0.08699	$0.08778	$0.09084	$0.09602	$0.10047	$0.10228
MEDIUM COMMERCIAL (A-10)	$0.10391	$0.10536	$0.10749	$0.10848	$0.11230	$0.11877	$0.12433	$0.12658
MEDIUM INDUSTRIAL (E-19)	$0.09445	$0.09576	$0.09768	$0.09858	$0.10204	$0.10789	$0.11292	$0.11496
LARGE INDUSTRIAL (E-20)	$0.08682	$0.08802	$0.08978	$0.09060	$0.09376	$0.09912	$0.10372	$0.10558
AGRICULTURAL PUMPING	$0.00453	$0.00453	$0.00453	$0.00453	$0.00453	$0.00453	$0.00453	$0.00453
STREET LIGHTING AND TRAFFIC CONTROL	$0.06472	$0.06559	$0.06688	$0.06748	$0.06980	$0.07371	$0.07708	$0.07844
II. PG&E PG&E'S REVENUE REQUIREMENT FOR POWER SUPPLY ($)								
RESIDENTIAL	$54,017,205	$55,574,584	$57,520,764	$58,913,064	$61,855,446	$66,324,063	$70,407,299	$72,734,619
SMALL COMMERCIAL (A-1 & A6)	$21,007,444	$21,616,606	$22,378,735	$22,922,811	$24,076,907	$25,831,637	$27,434,628	$28,346,468
MEDIUM COMMERCIAL (A-10)	$23,990,310	$24,689,608	$25,565,427	$26,189,473	$27,517,649	$29,539,115	$31,385,358	$32,433,693
MEDIUM INDUSTRIAL (E-19)	$9,867,783	$10,154,783	$10,514,070	$10,770,279	$11,314,800	$12,143,197	$12,899,860	$13,329,835
LARGE INDUSTRIAL (E-20)	$13,872,728	$14,275,344	$14,779,149	$15,138,697	$15,901,791	$17,062,222	$18,122,265	$18,725,081
AGRICULTURAL PUMPING	$0	$0	$0	$0	$0	$0	$0	$0
STREET LIGHTING AND TRAFFIC CONTROL	$535,090	$542,344	$552,985	$557,975	$577,088	$609,475	$637,307	$648,594
TOTAL - POWER SUPPLY REVENUE REQUIREMENT	$123,290,560	$126,853,269	$131,311,130	$134,492,298	$141,243,681	$151,509,709	$160,886,718	$166,218,290
AVERAGE RATE ($/KWH)	$0.0806	$0.0817	$0.0834	$0.0841	$0.0870	$0.0920	$0.0963	$0.0980
III. OPERATING EXPENSES ($)								
1. POWER SUPPLY COSTS:								
(A) ANCILLARY SERVICES AND RESERVES	$6,305,470	$6,520,153	$6,788,644	$6,980,210	$7,397,730	$8,027,880	$8,592,955	$8,904,696
(B) RENEWABLE PORTFOLIO STANDARD (RPS)	$0	$1,067,123	$4,941,101	$10,295,148	$18,121,829	$21,560,989	$24,937,475	$27,348,253
(C) DWR POWER	$0	$0	$0	$0	$0	$0	$0	$0
(D) POWER PRODUCTION	$36,922,015	$37,541,025	$38,351,715	$38,890,177	$40,211,944	$42,238,711	$44,012,559	$44,925,571
(E) CONTRACT PURCHASES	$37,128,268	$37,128,268	$30,607,467	$30,607,467	$30,607,467	$30,607,467	$30,607,467	$35,796,698
(F) MARKET PURCHASES	$4,836,144	$5,225,859	$13,065,554	$10,884,547	$9,134,414	$10,395,980	$11,598,355	$12,436,105
SUBTOTAL POWER SUPPLY COSTS	$85,191,897	$87,482,428	$93,754,481	$97,657,550	$105,473,383	$112,831,027	$119,748,811	$129,411,322
2. OTHER COSTS:								
(A) CALIFORNIA ISO COSTS	$1,818,456	$1,888,854	$1,965,382	$2,038,599	$2,130,680	$2,240,750	$2,348,662	$2,440,792
(B) NON-BYPASSABLE CHARGES	$7,329,636	$7,434,967	$7,541,858	$7,650,334	$7,760,417	$7,872,132	$7,985,503	$8,100,555
(C) START UP COSTS AMORTIZATION	$691,593	$729,630	$769,760	$0	$0	$0	$0	$0
(D) OPERATIONS & SCHEDULING COORDINATION	$4,023,169	$4,055,208	$4,057,524	$4,059,874	$4,062,260	$4,064,682	$4,067,139	$4,069,634
SUBTOTAL - OTHER COSTS	$13,862,853	$14,108,659	$14,334,524	$13,748,807	$13,953,357	$14,177,564	$14,401,305	$14,610,981

COUNTY OF MARIN
FINANCIAL PRO FORMA ANALYSIS
LOAD AGGREGATION SUMMARY
51% RENEWABLE ENERGY

CATEGORY		[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018	[15] 2019	[16] 2020
3. UTILITY OPERATIONS:									
(A) DISTRIBUTION O&M		$0	$0	$0	$0	$0	$0	$0	$0
(B) CUSTOMER SERVICE		$0	$0	$0	$0	$0	$0	$0	$0
(C) METERING & BILLING		$1,398,125	$1,454,473	$1,513,093	$1,574,078	$1,637,522	$1,703,525	$1,772,191	$1,843,625
(D) ADMINISTRATIVE AND GENERAL		$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - UTILITY OPERATIONS		$1,398,125	$1,454,473	$1,513,093	$1,574,078	$1,637,522	$1,703,525	$1,772,191	$1,843,625
TOTAL OPERATING EXPENSES		$100,452,875	$103,045,560	$109,602,099	$112,980,434	$121,064,262	$128,712,116	$135,922,307	$145,865,929
IV. INTEREST EXPENSE ($)									
(A) INTEREST EXPENSE ($)		$17,465,409	$17,143,766	$16,804,433	$16,446,436	$16,113,415	$15,762,077	$15,391,416	$15,000,369
(B) DEBT COVERAGE		$0	$0	$0	$0	$0	$0	$0	$0
(C) WORKING CAPITAL EXPENSE		$498,404	$509,553	$517,794	$532,983	$569,545	$610,669	$647,601	$667,394
SUBTOTAL - FINANCING EXPENSE		$17,963,813	$17,653,319	$17,322,227	$16,979,419	$16,682,959	$16,372,747	$16,039,017	$15,667,762
V. REVENUES FROM MARKET SALES ($)									
(A) EXCESS ENERGY SALES		$3,655,932	$2,874,434	$501,389	$1,074,070	$3,207,524	$2,923,100	$2,523,059	$2,056,803
(B) EXCESS ANCILLARY SERVICE SALES		$0	$0	$0	$0	$0	$0	$0	$0
(C) SUPPLEMENTAL ENERGY PAYMENTS		$0	$137,513	$582,274	$1,249,010	$2,045,296	$2,434,850	$2,817,508	$3,091,150
---		$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - OTHER REVENUES		$3,655,932	$3,011,947	$1,083,663	$2,323,080	$5,252,820	$5,357,949	$5,340,566	$5,147,953
VI. REVENUE REQUIREMENT - NET MARKET SALES ($)		$114,760,757	$117,686,932	$125,840,663	$127,636,774	$132,494,402	$139,726,913	$146,620,758	$156,385,739
VII. CCA NET MARGIN		**$8,529,804**	**$9,166,337**	**$5,470,467**	**$6,855,524**	**$8,749,279**	**$11,782,796**	**$14,265,960**	**$9,832,551**
NET PRESENT VALUE	$38,300,581.11								
NOMINAL MARGIN	$129,471,017.21								

COUNTY OF MARIN
FINANCIAL PRO FORMA ANALYSIS
LOAD AGGREGATION SUMMARY
51% RENEWABLE ENERGY

CATEGORY	[17] 2021	[18] 2022	[19] 2023	[20] 2024
I. PG&E PG&E'S UNBUNDLED GENERATION RATES ($/KWH)				
RESIDENTIAL	$0.08392	$0.08456	$0.08285	$0.08655
SMALL COMMERCIAL (A-1 & A6)	$0.10165	$0.10242	$0.10134	$0.10587
MEDIUM COMMERCIAL (A-10)	$0.12580	$0.12676	$0.12654	$0.13220
MEDIUM INDUSTRIAL (E-19)	$0.11425	$0.11512	$0.11449	$0.11961
LARGE INDUSTRIAL (E-20)	$0.10494	$0.10574	$0.10477	$0.10945
AGRICULTURAL PUMPING	$0.00453	$0.00453	$0.00000	$0.00000
STREET LIGHTING AND TRAFFIC CONTROL	$0.07797	$0.07855	$0.07663	$0.08006
II. PG&E PG&E'S REVENUE REQUIREMENT FOR POWER SUPPLY ($)				
RESIDENTIAL	$73,376,420	$75,038,335	$74,623,534	$79,128,062
SMALL COMMERCIAL (A-1 & A6)	$28,594,863	$29,244,689	$29,370,196	$31,143,080
MEDIUM COMMERCIAL (A-10)	$32,716,103	$33,461,849	$33,904,064	$35,950,628
MEDIUM INDUSTRIAL (E-19)	$13,446,217	$13,752,320	$13,881,849	$14,719,804
LARGE INDUSTRIAL (E-20)	$18,888,995	$19,318,466	$19,429,498	$20,602,328
AGRICULTURAL PUMPING	$0	$0	$0	$0
STREET LIGHTING AND TRAFFIC CONTROL	$644,664	$649,501	$633,613	$661,931
TOTAL - POWER SUPPLY REVENUE REQUIREMENT	$167,667,262	$171,465,161	$171,842,753	$182,205,832
AVERAGE RATE ($/KWH)	$0.0974	$0.0981	$0.0969	$0.1012
III. OPERATING EXPENSES ($)				
1. POWER SUPPLY COSTS:				
(A) ANCILLARY SERVICES AND RESERVES	$8,981,915	$9,207,288	$9,670,834	$10,289,637
(B) RENEWABLE PORTFOLIO STANDARD (RPS)	$28,682,853	$30,653,272	$33,822,236	$37,895,754
(C) DWR POWER	$0	$0	$0	$0
(D) POWER PRODUCTION	$45,077,702	$45,727,127	$47,137,608	$49,020,390
(E) CONTRACT PURCHASES	$35,796,698	$35,796,698	$35,796,698	$35,796,698
(F) MARKET PURCHASES	$12,875,899	$13,752,404	$15,243,433	$17,245,232
SUBTOTAL POWER SUPPLY COSTS	$131,415,067	$135,136,789	$141,670,809	$150,247,711
2. OTHER COSTS:				
(A) CALIFORNIA ISO COSTS	$2,518,620	$2,610,162	$2,722,100	$2,848,510
(B) NON-BYPASSABLE CHARGES	$8,217,313	$7,915,557	$0	$0
(C) START UP COSTS AMORTIZATION	$0	$0	$0	$0
(D) OPERATIONS & SCHEDULING COORDINATION	$4,072,166	$4,074,736	$4,077,345	$4,079,993
SUBTOTAL - OTHER COSTS	$14,808,099	$14,600,455	$6,799,445	$6,928,503

COUNTY OF MARIN
FINANCIAL PRO FORMA ANALYSIS
LOAD AGGREGATION SUMMARY
51% RENEWABLE ENERGY

CATEGORY		[17] 2021	[18] 2022	[19] 2023	[20] 2024
3. UTILITY OPERATIONS:					
(A) DISTRIBUTION O&M		$0	$0	$0	$0
(B) CUSTOMER SERVICE		$0	$0	$0	$0
(C) METERING & BILLING		$1,917,941	$1,995,255	$2,075,686	$2,159,363
(D) ADMINISTRATIVE AND GENERAL		$0	$0	$0	$0
SUBTOTAL - UTILITY OPERATIONS		$1,917,941	$1,995,255	$2,075,686	$2,159,363
TOTAL OPERATING EXPENSES		$148,141,107	$151,732,498	$150,545,940	$159,335,577
IV. INTEREST EXPENSE ($)					
(A) INTEREST EXPENSE ($)		$14,587,814	$14,152,568	$13,693,384	$13,208,945
(B) DEBT COVERAGE		$0	$0	$0	$0
(C) WORKING CAPITAL EXPENSE		$670,967	$686,797	$720,479	$763,091
SUBTOTAL - FINANCING EXPENSE		$15,258,781	$14,839,365	$14,413,862	$13,972,036
V. REVENUES FROM MARKET SALES ($)					
(A) EXCESS ENERGY SALES		$1,582,248	$1,281,589	$1,072,092	$935,963
(B) EXCESS ANCILLARY SERVICE SALES		$0	$0	$0	$0
(C) SUPPLEMENTAL ENERGY PAYMENTS		$3,243,142	$3,466,998	$3,826,447	$4,288,320
---		$0	$0	$0	$0
SUBTOTAL - OTHER REVENUES		$4,825,390	$4,748,586	$4,898,539	$5,224,283
VI. REVENUE REQUIREMENT - NET MARKET SALES ($)		$158,574,498	$161,823,277	$160,061,263	$168,083,329
VII. CCA NET MARGIN		**$9,092,763**	**$9,641,884**	**$11,781,490**	**$14,122,503**
NET PRESENT VALUE	$38,300,581.11				
NOMINAL MARGIN	$129,471,017.21				

COUNTY OF MARIN
FINANCIAL PRO FORMA ANALYSIS
DEBT SERVICE
51% RENEWABLE ENERGY

I. TOTAL DEBT ISSUANCES

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015
(A) STARTUP COSTS	$0	$6,121,281	$0	$0	$0	$0	$0	$0	$0	$0	$0
(B) GENERATION DEVELOPMENT	$0	$0	$0	$128,694,710	$0	$40,045,767	$0	$0	$158,288,687	$0	$0
SUBTOTAL - DEBT ISSUANCE	$0	$6,121,281	$0	$128,694,710	$0	$40,045,767	$0	$0	$158,288,687	$0	$0

II. TOTAL DEBT SERVICE

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015
(A) STARTUP COSTS	$0	$812,097	$812,097	$812,097	$812,097	$812,097	$812,097	$812,097	$812,097	$812,097	$812,097
(B) GENERATION DEVELOPMENT	$0	$0	$0	$8,854,890	$8,854,890	$11,610,254	$11,610,254	$11,610,254	$22,501,369	$22,501,369	$22,501,369
SUBTOTAL - FINANCING COSTS	$0	$812,097	$812,097	$9,666,986	$9,666,986	$12,422,351	$12,422,351	$12,422,351	$23,313,466	$23,313,466	$23,313,466
(D) DEBT COVERAGE (1.25)	$0	$0	$0	$856,273	$0	$0	$0	$0	$0	$0	$0
TOTAL DEBT SERVICE	$0	$812,097	$812,097	$10,523,259	$9,666,986	$12,422,351	$12,422,351	$12,422,351	$23,313,466	$23,313,466	$23,313,466

III. INTEREST PORTION OF DEBT SERVICE

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015
(A) STARTUP COSTS	$0	$336,670	$310,522	$282,935	$253,832	$223,127	$190,734	$156,559	$120,504	$82,466	$42,337
(B) GENERATION DEVELOPMENT	$0	$0	$0	$7,078,209	$6,980,492	$9,079,917	$8,940,748	$8,793,926	$17,344,905	$17,061,300	$16,762,096
SUBTOTAL - FINANCING COSTS	$0	$336,670	$310,522	$7,361,144	$7,234,323	$9,303,044	$9,131,482	$8,950,484	$17,465,409	$17,143,766	$16,804,433
TOTAL INTEREST	$0	$336,670	$310,522	$7,361,144	$7,234,323	$9,303,044	$9,131,482	$8,950,484	$17,465,409	$17,143,766	$16,804,433

IV. PRINCIPAL PORTION OF DEBT SERVICE

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015
(A) STARTUP COSTS	$0	$475,426	$501,575	$529,161	$558,265	$588,970	$621,363	$655,538	$691,593	$729,630	$769,760
(B) GENERATION DEVELOPMENT	$0	$0	$0	$1,776,681	$1,874,398	$2,530,337	$2,669,506	$2,816,329	$5,156,464	$5,440,069	$5,739,273
SUBTOTAL - FINANCING COSTS	$0	$475,426	$501,575	$2,305,842	$2,432,663	$3,119,307	$3,290,869	$3,471,867	$5,848,057	$6,169,700	$6,509,033
TOTAL PRINCIPAL	$0	$475,426	$501,575	$2,305,842	$2,432,663	$3,119,307	$3,290,869	$3,471,867	$5,848,057	$6,169,700	$6,509,033

V. RESERVES

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015
DEBT COVERAGE RESERVE ADDITIONS ($ B.O.Y.)	$0	$0	$0	$0	$856,273	$856,273	$856,273	$856,273	$856,273	$856,273	$856,273
DEBT COVERAGE RESERVE ADDITIONS ($ E.O.Y.)		$0	$0	$856,273	$856,273	$856,273	$856,273	$856,273	$856,273	$856,273	$856,273
DEBT SERVICE RESERVE ($)	$0	$612,128	$612,128	$13,481,599	$13,481,599	$17,486,176	$17,486,176	$17,486,176	$33,315,044	$33,315,044	$33,315,044
TOTAL DEBT SERVICE RESERVES	$0	$612,128	$612,128	$14,337,872	$14,337,872	$18,342,449	$18,342,449	$18,342,449	$34,171,317	$34,171,317	$34,171,317

COUNTY OF MARIN
FINANCIAL PRO FORMA ANALYSIS
DEBT SERVICE
51% RENEWABLE ENERGY

I. TOTAL DEBT ISSUANCES

CATEGORY	[12] 2016	[13] 2017	[14] 2018	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
(A) STARTUP COSTS	$0	$0	$0	$0	$0	$0	$0	$0	$0
(B) GENERATION DEVELOPMENT	$0	$0	$0	$0	$0	$0	$0	$0	$0
SUBTOTAL - DEBT ISSUANCE	$0	$0	$0	$0	$0	$0	$0	$0	$0

II. TOTAL DEBT SERVICE

CATEGORY	[12] 2016	[13] 2017	[14] 2018	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
(A) STARTUP COSTS	$0	$0	$0	$0	$0	$0	$0	$0	$0
(B) GENERATION DEVELOPMENT	$22,501,369	$22,501,369	$22,501,369	$22,501,369	$22,501,369	$22,501,369	$22,501,369	$22,501,369	$22,501,369
SUBTOTAL - FINANCING COSTS	$22,501,369	$22,501,369	$22,501,369	$22,501,369	$22,501,369	$22,501,369	$22,501,369	$22,501,369	$22,501,369
(D) DEBT COVERAGE (1.25)	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL DEBT SERVICE	$22,501,369	$22,501,369	$22,501,369	$22,501,369	$22,501,369	$22,501,369	$22,501,369	$22,501,369	$22,501,369

III. INTEREST PORTION OF DEBT SERVICE

CATEGORY	[12] 2016	[13] 2017	[14] 2018	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
(A) STARTUP COSTS	$0	$0	$0	$0	$0	$0	$0	$0	$0
(B) GENERATION DEVELOPMENT	$16,446,436	$16,113,415	$15,762,077	$15,391,416	$15,000,369	$14,587,814	$14,152,568	$13,693,384	$13,208,945
SUBTOTAL - FINANCING COSTS	$16,446,436	$16,113,415	$15,762,077	$15,391,416	$15,000,369	$14,587,814	$14,152,568	$13,693,384	$13,208,945
TOTAL INTEREST	$16,446,436	$16,113,415	$15,762,077	$15,391,416	$15,000,369	$14,587,814	$14,152,568	$13,693,384	$13,208,945

IV. PRINCIPAL PORTION OF DEBT SERVICE

CATEGORY	[12] 2016	[13] 2017	[14] 2018	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
(A) STARTUP COSTS	$0	$0	$0	$0	$0	$0	$0	$0	$0
(B) GENERATION DEVELOPMENT	$6,054,933	$6,387,954	$6,739,292	$7,109,953	$7,501,000	$7,913,555	$8,348,801	$8,807,985	$9,292,424
SUBTOTAL - FINANCING COSTS	$6,054,933	$6,387,954	$6,739,292	$7,109,953	$7,501,000	$7,913,555	$8,348,801	$8,807,985	$9,292,424
TOTAL PRINCIPAL	$6,054,933	$6,387,954	$6,739,292	$7,109,953	$7,501,000	$7,913,555	$8,348,801	$8,807,985	$9,292,424

V. RESERVES

CATEGORY	[12] 2016	[13] 2017	[14] 2018	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
DEBT COVERAGE RESERVE ADDITIONS ($ B.O.Y.)	$856,273	$856,273	$856,273	$856,273	$856,273	$856,273	$856,273	$856,273	$856,273
DEBT COVERAGE RESERVE ADDITIONS ($ E.O.Y.)	$856,273	$856,273	$856,273	$856,273	$856,273	$856,273	$856,273	$856,273	$856,273
DEBT SERVICE RESERVE ($)	$33,315,044	$33,315,044	$33,315,044	$33,315,044	$33,315,044	$33,315,044	$33,315,044	$33,315,044	$33,315,044
TOTAL DEBT SERVICE RESERVES	$34,171,317	$34,171,317	$34,171,317	$34,171,317	$34,171,317	$34,171,317	$34,171,317	$34,171,317	$34,171,317

COUNTY OF MARIN
FINANCIAL PRO FORMA ANALYSIS
ANNUAL LOADS AND COMPOSITION OF RESOURCES
51% RENEWABLE ENERGY

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018
SECTION I - PROJECTED MARKET PRICES:														
(A) MARKET ENERGY ($/MWH):														
AVERAGE ENERGY PRICE	$48.30	$45.27	$46.24	$47.48	$52.08	$55.51	$59.70	$61.48	$62.66	$63.65	$65.33	$65.80	$69.35	$75.66
ON-PEAK ENERGY PRICE	$55.54	$52.06	$53.18	$54.60	$59.90	$63.83	$68.65	$70.70	$72.06	$73.20	$75.13	$75.67	$79.75	$87.01
OFF-PEAK ENERGY PRICE	$41.05	$38.48	$39.30	$40.36	$44.27	$47.18	$50.74	$52.26	$53.26	$54.11	$55.53	$55.93	$58.95	$64.31
REAL-TIME PREMIUM	$4.83	$4.53	$4.62	$4.75	$5.21	$5.55	$5.97	$6.15	$6.27	$6.37	$6.53	$6.58	$6.93	$7.57
(B) CDWR CONTRACT ENERGY ($/MWH):														
AVERAGE CDWR CONTRACT PRICE	$74.87	$71.61	$71.95	$70.26	$67.04	$97.01	$76.44	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
(C) RENEWABLE PORTFOLIO STANDARD (RPS):														
RPS REQUIREMENTS (%)	13.0%	14.0%	15.5%	17.0%	18.5%	20.0%	24.4%	28.9%	33.3%	37.7%	42.1%	46.6%	51.0%	51.0%
RPS ENERGY PRICE ($/MWH)	$67.21	$67.88	$68.56	$69.25	$69.94	$70.64	$71.35	$72.06	$72.78	$73.51	$74.24	$74.99	$78.28	$85.40
RPS CONTRACT CAPACITY (MW)	-	24	26	-	0	2	8	17	-	2	7	16	26	29
TOTAL RENEWABLE CAPACITY (MW)	-	24	26	37	37	38	44	53	79	80	84	92	101	103
(D) ANCILLARY SERVICE PRICES ($/MWH):														
SPINNING RESERVE	$10.92	$10.23	$10.45	$10.73	$11.77	$12.54	$13.49	$13.90	$14.16	$14.39	$14.76	$14.87	$15.67	$17.10
NON-SPINNING RESERVE	$6.81	$6.38	$6.52	$6.69	$7.34	$7.83	$8.42	$8.67	$8.84	$8.98	$9.21	$9.28	$9.78	$10.67
REPLACEMENT RESERVE	$10.00	$9.37	$9.57	$9.83	$10.78	$11.49	$12.36	$12.73	$12.97	$13.18	$13.52	$13.62	$14.36	$15.66
REGULATION - UP	$31.93	$29.92	$30.57	$31.38	$34.43	$36.69	$39.46	$40.64	$41.42	$42.07	$43.18	$43.49	$45.84	$50.01
REGULATION - DOWN	$31.93	$29.92	$30.57	$31.38	$34.43	$36.69	$39.46	$40.64	$41.42	$42.07	$43.18	$43.49	$45.84	$50.01
(E) NATURAL GAS PRICE ($/MMBtu):														
AVERAGE NATURAL GAS PRICE	$6.04	$5.49	$5.32	$5.28	$5.21	$5.29	$5.43	$5.59	$5.70	$5.79	$5.94	$5.98	$6.30	$6.88
REFEENCE GAS PRICE - HIGH	$7.55	$6.86	$6.64	$6.59	$6.51	$6.61	$6.78	$6.99	$7.12	$7.23	$7.42	$7.48	$7.88	$8.60
REFEENCE GAS PRICE - MID	$6.04	$5.49	$5.32	$5.28	$5.21	$5.29	$5.43	$5.59	$5.70	$5.79	$5.94	$5.98	$6.30	$6.88
REFEENCE GAS PRICE - LOW	$4.53	$4.12	$3.99	$3.96	$3.91	$3.96	$4.07	$4.19	$4.27	$4.34	$4.45	$4.49	$4.73	$5.16
(F) EMISSIONS CREDIT PRICE ($/LB):	$10.00	$10.25	$10.51	$10.77	$11.04	$11.31	$11.60	$11.89	$12.18	$12.49	$12.80	$13.12	$13.45	$13.79
(G) CAPACITY ($/MW):	$100,000	$102,500	$105,063	$107,689	$110,381	$113,141	$115,969	$118,869	$121,840	$124,886	$128,008	$131,209	$134,489	$137,851

COUNTY OF MARIN
FINANCIAL PRO FORMA ANALYSIS
ANNUAL LOADS AND COMPOSITION OF RESOU
51% RENEWABLE ENERGY

CATEGORY	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
SECTION I - PROJECTED MARKET PRICES:						
(A) MARKET ENERGY ($/MWH):						
AVERAGE ENERGY PRICE	$80.84	$82.40	$80.74	$80.98	$84.19	$89.19
ON-PEAK ENERGY PRICE	$92.96	$94.75	$92.85	$93.13	$96.82	$102.56
OFF-PEAK ENERGY PRICE	$68.71	$70.04	$68.63	$68.83	$71.56	$75.81
REAL-TIME PREMIUM	$8.08	$8.24	$8.07	$8.10	$8.42	$8.92
(B) CDWR CONTRACT ENERGY ($/MWH):						
AVERAGE CDWR CONTRACT PRICE	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
(C) RENEWABLE PORTFOLIO STANDARD (RP						
RPS REQUIREMENTS (%)	51.0%	51.0%	51.0%	51.0%	51.0%	51.0%
RPS ENERGY PRICE ($/MWH)	$91.24	$93.00	$91.13	$91.41	$95.03	$100.67
RPS CONTRACT CAPACITY (MW)	31	33	36	38	40	43
TOTAL RENEWABLE CAPACITY (MW)	104	106	107	109	111	112
(D) ANCILLARY SERVICE PRICES ($/MWH):						
SPINNING RESERVE	$18.27	$18.62	$18.25	$18.30	$19.03	$20.16
NON-SPINNING RESERVE	$11.40	$11.62	$11.38	$11.42	$11.87	$12.58
REPLACEMENT RESERVE	$16.73	$17.06	$16.71	$16.76	$17.43	$18.46
REGULATION - UP	$53.43	$54.46	$53.37	$53.53	$55.65	$58.95
REGULATION - DOWN	$53.43	$54.46	$53.37	$53.53	$55.65	$58.95
(E) NATURAL GAS PRICE ($/MMBtu):						
AVERAGE NATURAL GAS PRICE	$7.35	$7.49	$7.34	$7.36	$7.65	$8.11
REFEENCE GAS PRICE - HIGH	$9.19	$9.36	$9.17	$9.20	$9.57	$10.13
REFEENCE GAS PRICE - MID	$7.35	$7.49	$7.34	$7.36	$7.65	$8.11
REFEENCE GAS PRICE - LOW	$5.51	$5.62	$5.50	$5.52	$5.74	$6.08
(F) EMISSIONS CREDIT PRICE ($/LB):	$14.13	$14.48	$14.85	$15.22	$15.60	$15.99
(G) CAPACITY ($/MW):	$141,297	$144,830	$148,451	$152,162	$155,966	$159,865

COUNTY OF MARIN
FINANCIAL PRO FORMA ANALYSIS
ANNUAL LOADS AND COMPOSITION OF RESOURCES
51% RENEWABLE ENERGY

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018
SECTION II - PROJECTED LOADS AND ANCILLARY SERVICES:														
(A) PROJECTED LOADS (KWH):														
PROJECTED LOADS INCLUDING LOSSES														
ON-PEAK	0	940,872,421	954,900,872	969,139,749	983,592,209	998,261,457	1,013,150,743	1,028,263,368	1,043,602,683	1,059,172,087	1,074,975,033	1,091,015,022	1,107,295,612	1,123,820,410
OFF-PEAK	0	536,940,681	544,946,491	553,072,388	561,320,174	569,691,676	578,188,751	586,813,282	595,567,181	604,452,388	613,470,874	622,624,637	631,915,706	641,346,141
TOTAL	0	1,477,813,103	1,499,847,363	1,522,212,137	1,544,912,383	1,567,953,133	1,591,339,494	1,615,076,650	1,639,169,864	1,663,624,476	1,688,445,907	1,713,639,659	1,739,211,318	1,765,166,552
PROJECTED LOADS EXCLUDING LOSSES														
ON-PEAK	0	879,320,020	892,430,721	905,738,083	919,245,056	932,954,632	946,869,853	960,993,802	975,329,610	989,880,455	1,004,649,563	1,019,640,208	1,034,855,712	1,050,299,449
OFF-PEAK	0	501,813,721	509,295,786	516,890,083	524,598,293	532,422,127	540,363,319	548,423,628	556,604,842	564,908,774	573,337,265	581,892,184	590,575,426	599,388,917
TOTAL	0	1,381,133,741	1,401,726,508	1,422,628,166	1,443,843,349	1,465,376,760	1,487,233,172	1,509,417,430	1,531,934,452	1,554,789,230	1,577,986,829	1,601,532,392	1,625,431,138	1,649,688,366
(B) ANCILLARY SERVICES:														
ANCILLARY SERVICE REQUIREMENTS (KWH):														
SPINNING RESERVE	0	48,615,908	49,340,773	50,076,511	50,823,286	51,581,262	52,350,608	53,131,494	53,924,093	54,728,581	55,545,136	56,373,940	57,215,176	58,069,030
NON-SPINNING RESERVE	0	34,528,344	35,043,163	35,565,704	36,096,084	36,634,419	37,180,829	37,735,436	38,298,361	38,869,731	39,449,671	40,038,310	40,635,778	41,242,209
REPLACEMENT RESERVE	0	16,849,832	17,101,063	17,356,064	17,614,889	17,877,596	18,144,245	18,414,893	18,689,600	18,968,429	19,251,439	19,538,695	19,830,260	20,126,198
REGULATION - UP	0	31,075,509	31,538,846	32,009,134	32,486,475	32,970,977	33,462,746	33,961,892	34,468,525	34,982,758	35,504,704	36,034,479	36,572,201	37,117,988
REGULATION - DOWN	0	31,075,509	31,538,846	32,009,134	32,486,475	32,970,977	33,462,746	33,961,892	34,468,525	34,982,758	35,504,704	36,034,479	36,572,201	37,117,988
TOTAL - ANCILLARY SERVICES REQ.	0	162,145,101	164,562,692	167,016,547	169,507,209	172,035,232	174,601,174	177,205,606	179,849,105	182,532,256	185,255,654	188,019,903	190,825,616	193,673,414
ANCILLARY SERVICE COSTS ($)														
SPINNING RESERVE	$0	$499,622	$517,941	$539,754	$600,904	$649,981	$709,441	$741,569	$767,078	$790,826	$823,740	$842,026	$900,730	$997,403
NON-SPINNING RESERVE	$0	$221,386	$229,503	$239,168	$266,264	$288,011	$314,358	$328,594	$339,897	$350,420	$365,005	$373,107	$399,119	$441,956
REPLACEMENT RESERVE	$0	$158,606	$164,422	$171,346	$190,759	$206,338	$225,214	$235,413	$243,511	$251,050	$261,499	$267,304	$285,939	$316,628
REGULATION - UP	$0	$934,059	$968,308	$1,009,087	$1,123,409	$1,215,159	$1,326,323	$1,386,387	$1,434,078	$1,478,474	$1,540,009	$1,574,195	$1,683,944	$1,864,677
REGULATION - DOWN	$0	$934,059	$968,308	$1,009,087	$1,123,409	$1,215,159	$1,326,323	$1,386,387	$1,434,078	$1,478,474	$1,540,009	$1,574,195	$1,683,944	$1,864,677
TOTAL - ANCILLARY SERVICES COSTS	$0	$2,747,732	$2,848,481	$2,968,443	$3,304,746	$3,574,648	$3,901,659	$4,078,351	$4,218,642	$4,349,244	$4,530,261	$4,630,827	$4,953,678	$5,485,341
(C) PLANNING RESERVES:														
PLANNING RESERVES REQUIREMENTS (I	-	15,442	15,672	15,905	16,143	16,383	16,628	16,876	17,128	17,383	17,642	17,906	18,173	18,444
PLANNING RESERVES COSTS ($)	$0	$1,582,760	$1,646,518	$1,712,847	$1,781,850	$1,853,635	$1,928,314	$2,006,004	$2,086,828	$2,170,910	$2,258,383	$2,349,382	$2,444,052	$2,542,539

COUNTY OF MARIN
FINANCIAL PRO FORMA ANALYSIS
ANNUAL LOADS AND COMPOSITION OF RESOU
51% RENEWABLE ENERGY

CATEGORY	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
SECTION II - PROJECTED LOADS AND ANCILLA						
(A) PROJECTED LOADS (KWH):						
PROJECTED LOADS INCLUDING LOSSES						
ON-PEAK	1,140,593,081	1,157,617,341	1,174,896,965	1,192,435,784	1,210,237,685	1,228,306,614
OFF-PEAK	650,918,033	660,633,503	670,494,706	680,503,826	690,663,083	700,974,729
TOTAL	1,791,511,114	1,818,250,845	1,845,391,671	1,872,939,610	1,900,900,768	1,929,281,344
PROJECTED LOADS EXCLUDING LOSSES						
ON-PEAK	1,065,974,842	1,081,885,365	1,098,034,547	1,114,425,966	1,131,063,257	1,147,950,107
OFF-PEAK	608,334,611	617,414,489	626,630,566	635,984,884	645,479,517	655,116,569
TOTAL	1,674,309,452	1,699,299,855	1,724,665,113	1,750,410,851	1,776,542,774	1,803,066,676
(B) ANCILLARY SERVICES:						
ANCILLARY SERVICE REQUIREMENTS (K						
SPINNING RESERVE	58,935,693	59,815,355	60,708,212	61,614,462	62,534,306	63,467,947
NON-SPINNING RESERVE	41,857,736	42,482,496	43,116,628	43,760,271	44,413,569	45,076,667
REPLACEMENT RESERVE	20,426,575	20,731,458	21,040,914	21,355,012	21,673,822	21,997,413
REGULATION - UP	37,671,963	38,234,247	38,804,965	39,384,244	39,972,212	40,569,000
REGULATION - DOWN	37,671,963	38,234,247	38,804,965	39,384,244	39,972,212	40,569,000
TOTAL - ANCILLARY SERVICES REQ.	196,563,930	199,497,803	202,475,684	205,498,234	208,566,122	211,680,028
ANCILLARY SERVICE COSTS ($)						
SPINNING RESERVE	$1,081,521	$1,118,823	$1,112,701	$1,132,705	$1,195,169	$1,284,985
NON-SPINNING RESERVE	$479,229	$495,758	$493,045	$501,909	$529,587	$569,385
REPLACEMENT RESERVE	$343,332	$355,174	$353,230	$359,580	$379,410	$407,922
REGULATION - UP	$2,021,938	$2,091,676	$2,080,230	$2,117,628	$2,234,407	$2,402,320
REGULATION - DOWN	$2,021,938	$2,091,676	$2,080,230	$2,117,628	$2,234,407	$2,402,320
TOTAL - ANCILLARY SERVICES COSTS	$5,947,957	$6,153,107	$6,119,437	$6,229,449	$6,572,981	$7,066,931
(C) PLANNING RESERVES:						
PLANNING RESERVES REQUIREMENTS (I	18,719	18,999	19,282	19,570	19,862	20,159
PLANNING RESERVES COSTS ($)	$2,644,998	$2,751,588	$2,862,478	$2,977,839	$3,097,852	$3,222,706

COUNTY OF MARIN
FINANCIAL PRO FORMA ANALYSIS
ANNUAL LOADS AND COMPOSITION OF RESOURCES
51% RENEWABLE ENERGY

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018
SECTION III - PROJECTED RESOURCES:														
(A) RENEWABLE PORTFOLIO STANDARD (KWH):														
ON-PEAK	0	131,251,703	147,651,547	0	3,171,316	15,830,166	63,448,135	114,313,230	0	13,953,193	63,000,500	122,559,732	183,784,936	196,634,078
OFF-PEAK	0	74,903,225	84,262,351	0	0	0	8,326,725	36,698,832	0	0	2,307,499	13,352,732	45,287,395	53,311,916
TOTAL	0	206,154,928	231,913,899	0	3,171,316	15,830,166	71,774,860	151,012,062	0	13,953,193	65,307,999	135,912,464	229,072,331	249,945,993
COSTS ($):														
ON-PEAK	0	8,957,849	10,177,900	0	215,805	1,165,107	4,586,708	8,317,336	0	1,067,123	4,785,510	9,317,960	14,544,284	16,970,716
OFF-PEAK	0	5,099,337	5,793,861	0	0	0	584,949	2,661,993	0	0	155,592	977,188	3,577,546	4,590,273
TOTAL	0	14,057,186	15,971,762	0	215,805	1,165,107	5,171,657	10,979,329	0	1,067,123	4,941,101	10,295,148	18,121,829	21,560,989
(B) CDWR CONTRACT ENERGY (KWH):														
ON-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COSTS ($):														
ON-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BALANCE (KWH):														
ON-PEAK	0	809,620,718	807,249,324	969,139,749	980,420,893	982,431,291	949,702,608	913,950,138	1,043,602,683	1,045,218,894	1,011,974,533	968,455,290	923,510,676	927,186,333
OFF-PEAK	0	462,037,456	460,684,140	553,072,388	561,320,174	569,691,676	569,862,026	550,114,450	595,567,181	604,452,388	611,163,375	609,271,905	586,628,311	588,034,226
TOTAL	0	1,271,658,175	1,267,933,465	1,522,212,137	1,541,741,067	1,552,122,967	1,519,564,634	1,464,064,588	1,639,169,864	1,649,671,283	1,623,137,908	1,577,727,195	1,510,138,987	1,515,220,558
(C) POWER PRODUCTION (KWH):														
ON-PEAK	0	0	0	189,378,336	187,529,288	409,429,401	407,725,318	406,089,399	624,217,668	619,011,908	614,014,378	609,216,749	604,611,026	600,189,532
OFF-PEAK	0	0	0	137,702,544	136,358,047	297,708,129	296,469,041	295,279,515	453,886,979	450,101,718	446,467,868	442,979,371	439,630,415	436,415,416
TOTAL	0	0	0	327,080,880	323,887,334	707,137,531	704,194,359	701,368,914	1,078,104,647	1,069,113,626	1,060,482,246	1,052,196,121	1,044,241,441	1,036,604,948
COSTS ($):														
ON-PEAK	0	0	0	5,039,993	5,124,823	14,736,021	15,074,571	15,453,950	21,377,678	21,736,082	22,205,468	22,517,235	23,282,532	24,456,021
OFF-PEAK	0	0	0	3,664,727	3,726,409	10,714,993	10,961,163	11,237,020	15,544,337	15,804,943	16,146,247	16,372,942	16,929,412	17,782,690
TOTAL	0	0	0	8,704,720	8,851,232	25,451,014	26,035,734	26,690,970	36,922,015	37,541,025	38,351,715	38,890,177	40,211,944	42,238,711
BALANCE (KWH):														
ON-PEAK	0	809,620,718	807,249,324	779,761,413	792,891,605	573,001,889	541,977,290	507,860,739	419,385,015	426,206,986	397,960,155	359,238,541	318,899,650	326,996,801
OFF-PEAK	0	462,037,456	460,684,140	415,369,844	424,962,127	271,983,547	273,392,985	254,834,935	141,680,202	154,350,670	164,695,507	166,292,534	146,997,896	151,618,809
TOTAL	0	1,271,658,175	1,267,933,465	1,195,131,257	1,217,853,733	844,985,436	815,370,275	762,695,674	561,065,217	580,557,656	562,655,662	525,531,074	465,897,546	478,615,610

COUNTY OF MARIN
FINANCIAL PRO FORMA ANALYSIS
ANNUAL LOADS AND COMPOSITION OF RESOU
51% RENEWABLE ENERGY

CATEGORY	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
SECTION III - PROJECTED RESOURCES:						
(A) RENEWABLE PORTFOLIO STANDARD (K'						
ON-PEAK	209,432,774	222,189,996	234,914,460	247,614,639	260,298,774	272,974,887
OFF-PEAK	61,279,979	69,197,811	77,071,449	84,906,748	92,709,391	100,484,896
TOTAL	270,712,753	291,387,808	311,985,909	332,521,387	353,008,165	373,459,783
COSTS ($):						
ON-PEAK	19,304,423	20,868,392	21,613,876	22,845,042	24,961,237	27,724,270
OFF-PEAK	5,633,052	6,479,861	7,068,978	7,808,230	8,860,999	10,171,484
TOTAL	24,937,475	27,348,253	28,682,853	30,653,272	33,822,236	37,895,754
						$101
(B) CDWR CONTRACT ENERGY (KWH):						
ON-PEAK	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0
COSTS ($):						
ON-PEAK	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0
BALANCE (KWH):						
ON-PEAK	931,160,306	935,427,345	939,982,505	944,821,145	949,938,911	955,331,727
OFF-PEAK	589,638,054	591,435,692	593,423,257	595,597,078	597,953,692	600,489,833
TOTAL	1,520,798,361	1,526,863,037	1,533,405,762	1,540,418,223	1,547,892,603	1,555,821,560
(C) POWER PRODUCTION (KWH):						
ON-PEAK	595,944,897	591,870,048	587,958,192	584,202,811	580,597,645	577,136,686
OFF-PEAK	433,329,018	430,366,076	427,521,651	424,791,003	422,169,581	419,653,016
TOTAL	1,029,273,915	1,022,236,123	1,015,479,843	1,008,993,814	1,002,767,226	996,789,702
COSTS ($):						
ON-PEAK	25,483,070	26,011,700	26,099,784	26,475,798	27,292,460	28,382,582
OFF-PEAK	18,529,488	18,913,870	18,977,918	19,251,329	19,845,148	20,637,808
TOTAL	44,012,559	44,925,571	45,077,702	45,727,127	47,137,608	49,020,390
BALANCE (KWH):						
ON-PEAK	335,215,410	343,557,297	352,024,313	360,618,334	369,341,266	378,195,041
OFF-PEAK	156,309,036	161,069,617	165,901,606	170,806,075	175,784,111	180,836,817
TOTAL	491,524,446	504,626,914	517,925,919	531,424,409	545,125,376	559,031,858

COUNTY OF MARIN
FINANCIAL PRO FORMA ANALYSIS
ANNUAL LOADS AND COMPOSITION OF RESOURCES
51% RENEWABLE ENERGY

CATEGORY	[1] 2005	[2] 2006	[3] 2007	[4] 2008	[5] 2009	[6] 2010	[7] 2011	[8] 2012	[9] 2013	[10] 2014	[11] 2015	[12] 2016	[13] 2017	[14] 2018
(D) LONG-TERM CONTRACT PURCHASES (KWH):														
ON-PEAK	0	710,080,000	710,080,000	710,080,000	710,080,000	456,480,000	456,480,000	456,480,000	456,480,000	456,480,000	355,040,000	355,040,000	355,040,000	355,040,000
OFF-PEAK	0	295,040,000	295,040,000	258,160,000	258,160,000	73,760,000	73,760,000	73,760,000	73,760,000	73,760,000	0	0	0	0
TOTAL	0	1,005,120,000	1,005,120,000	968,240,000	968,240,000	530,240,000	530,240,000	530,240,000	530,240,000	530,240,000	355,040,000	355,040,000	355,040,000	355,040,000
COSTS ($):														
ON-PEAK	0	50,482,630	50,482,630	53,394,338	53,394,338	37,128,268	37,128,268	37,128,268	37,128,268	37,128,268	30,607,467	30,607,467	30,607,467	30,607,467
OFF-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	50,482,630	50,482,630	53,394,338	53,394,338	37,128,268	37,128,268	37,128,268	37,128,268	37,128,268	30,607,467	30,607,467	30,607,467	30,607,467
BALANCE (KWH):														
ON-PEAK	0	99,540,718	97,169,324	69,681,413	82,811,605	116,521,889	85,497,290	51,380,739	(37,094,985)	(30,273,014)	42,920,155	4,198,541	(36,140,350)	(28,043,199)
OFF-PEAK	0	166,997,456	165,644,140	157,209,844	166,802,127	198,223,547	199,632,985	181,074,935	67,920,202	80,590,670	164,695,507	166,292,534	146,997,896	151,618,809
TOTAL	0	266,538,175	262,813,465	226,891,257	249,613,733	314,745,436	285,130,275	232,455,674	30,825,217	50,317,656	207,615,662	170,491,074	110,857,546	123,575,610
(E) SHORT-TERM CONTRACT PURCHASES (KWH):														
ON-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
COSTS ($):														
ON-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BALANCE (KWH):														
ON-PEAK	0	99,540,718	97,169,324	69,681,413	82,811,605	116,521,889	85,497,290	51,380,739	(37,094,985)	(30,273,014)	42,920,155	4,198,541	(36,140,350)	(28,043,199)
OFF-PEAK	0	166,997,456	165,644,140	157,209,844	166,802,127	198,223,547	199,632,985	181,074,935	67,920,202	80,590,670	164,695,507	166,292,534	146,997,896	151,618,809
TOTAL	0	266,538,175	262,813,465	226,891,257	249,613,733	314,745,436	285,130,275	232,455,674	30,825,217	50,317,656	207,615,662	170,491,074	110,857,546	123,575,610

COUNTY OF MARIN
FINANCIAL PRO FORMA ANALYSIS
ANNUAL LOADS AND COMPOSITION OF RESOU
51% RENEWABLE ENERGY

CATEGORY	[15] 2019	[16] 2020	[17] 2021	[18] 2022	[19] 2023	[20] 2024
(D) LONG-TERM CONTRACT PURCHASES (KV						
ON-PEAK	355,040,000	355,040,000	355,040,000	355,040,000	355,040,000	355,040,000
OFF-PEAK	0	0	0	0	0	0
TOTAL	355,040,000	355,040,000	355,040,000	355,040,000	355,040,000	355,040,000
COSTS ($):						
ON-PEAK	30,607,467	35,796,698	35,796,698	35,796,698	35,796,698	35,796,698
OFF-PEAK	0	0	0	0	0	0
TOTAL	30,607,467	35,796,698	35,796,698	35,796,698	35,796,698	35,796,698
BALANCE (KWH):						
ON-PEAK	(19,824,590)	(11,482,703)	(3,015,687)	5,578,334	14,301,266	23,155,041
OFF-PEAK	156,309,036	161,069,617	165,901,606	170,806,075	175,784,111	180,836,817
TOTAL	136,484,446	149,586,914	162,885,919	176,384,409	190,085,376	203,991,858
(E) SHORT-TERM CONTRACT PURCHASES (K						
ON-PEAK	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0
COSTS ($):						
ON-PEAK	0	0	0	0	0	0
OFF-PEAK	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0
BALANCE (KWH):						
ON-PEAK	(19,824,590)	(11,482,703)	(3,015,687)	5,578,334	14,301,266	23,155,041
OFF-PEAK	156,309,036	161,069,617	165,901,606	170,806,075	175,784,111	180,836,817
TOTAL	136,484,446	149,586,914	162,885,919	176,384,409	190,085,376	203,991,858

Appendix F – Pro Forma Summary With Alternative Supply Portfolios

Alternative Scenario 1 – Millions of Dollars

Year	Commodity Costs	Reserves and ISO Charges	Operations & Scheduling	Non-bypassable Charges	Metering & Billing	Financing Costs	Total Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	-	-	-	-	-	-	0.0	0%
2006	77.6	5.7	3.6	25.1	1.1	1.4	114.4	107.2	(7.2)	-4%
2007	79.5	5.9	3.7	23.7	1.1	1.2	115.0	109.1	(5.9)	-3%
2008	81.6	6.1	3.8	24.1	1.1	1.2	117.9	113.1	(4.7)	-2%
2009	85.1	6.6	3.8	16.9	1.2	1.2	114.9	115.9	1.1	1%
2010	99.9	7.0	3.9	15.5	1.2	1.3	128.8	121.8	(7.0)	-3%
2011	103.7	7.5	3.9	15.9	1.3	1.3	133.7	125.7	(8.0)	-4%
2012	106.5	7.8	4.0	16.4	1.3	1.3	137.3	129.9	(7.4)	-3%
2013	108.9	8.1	4.0	7.3	1.4	1.3	131.1	123.3	(7.8)	-3%
2014	111.3	8.4	4.1	7.4	1.5	1.3	134.0	126.9	(7.1)	-3%
2015	124.1	8.8	4.1	7.5	1.5	1.3	147.3	131.3	(16.0)	-7%
2016	126.4	9.0	4.1	7.7	1.6	0.3	149.0	134.5	(14.5)	-6%
2017	131.2	9.5	4.1	7.8	1.6	0.6	154.7	141.2	(13.5)	-5%
2018	139.1	10.3	4.1	7.9	1.7	0.6	163.6	151.5	(12.1)	-4%
2019	146.3	10.9	4.1	8.0	1.8	0.6	171.7	160.9	(10.8)	-4%
2020	161.8	11.3	4.1	8.1	1.8	0.7	187.8	166.2	(21.6)	-7%
2021	162.5	11.5	4.1	8.2	1.9	0.7	188.9	167.7	(21.2)	-7%
2022	165.1	11.8	4.1	7.9	2.0	0.7	191.6	171.5	(20.1)	-7%
2023	170.8	12.4	4.1	-	2.1	0.7	190.1	171.8	(18.2)	-6%
2024	178.6	13.1	4.1	-	2.2	0.8	198.7	182.2	(16.5)	-5%
Total	2,360.1	171.9	75.4	215.4	29.4	18.3	2,870.5	2,651.8	(218.7)	-5%

Alternative Scenario 2 – Millions of Dollars

Year	Commodity Costs	Reserves and ISO Charges	Operations & Scheduling	Non-bypassable Charges	Metering & Billing	Financing Costs	Total Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	-	-	-	-	-	-	0.0	0%
2006	74.2	5.7	3.6	25.1	1.1	1.2	110.8	107.2	(3.6)	-2%
2007	75.6	5.9	3.7	23.7	1.1	1.4	111.3	109.1	(2.2)	-1%
2008	77.2	6.1	3.8	24.1	1.1	1.2	113.4	113.1	(0.3)	0%
2009	80.3	6.6	3.8	16.9	1.2	1.2	110.0	115.9	5.9	3%
2010	98.4	7.0	3.9	15.5	1.2	1.3	127.3	121.8	(5.5)	-3%
2011	101.8	7.5	3.9	15.9	1.3	1.3	131.7	125.7	(6.1)	-3%
2012	104.2	7.8	4.0	16.4	1.3	1.3	135.0	129.9	(5.1)	-2%
2013	106.3	8.1	4.0	7.3	1.4	1.3	128.5	123.3	(5.2)	-2%
2014	108.5	8.4	4.1	7.4	1.5	1.3	131.2	126.9	(4.3)	-2%
2015	124.6	8.8	4.1	7.5	1.5	1.3	147.8	131.3	(16.5)	-7%
2016	126.6	9.0	4.1	7.7	1.6	0.3	149.2	134.5	(14.7)	-6%
2017	130.4	9.5	4.1	7.8	1.6	0.6	153.9	141.2	(12.7)	-5%
2018	136.0	10.3	4.1	7.9	1.7	0.6	160.5	151.5	(9.0)	-3%
2019	141.3	10.9	4.1	8.0	1.8	0.6	166.7	160.9	(5.8)	-2%
2020	160.4	11.3	4.1	8.1	1.8	0.7	186.4	166.2	(20.2)	-7%
2021	161.8	11.5	4.1	8.2	1.9	0.7	188.2	167.7	(20.5)	-7%
2022	164.2	11.8	4.1	7.9	2.0	0.7	190.7	171.5	(19.3)	-6%
2023	168.6	12.4	4.1	-	2.1	0.7	187.8	171.8	(16.0)	-5%
2024	174.3	13.1	4.1	-	2.2	0.8	194.4	182.2	(12.2)	-4%
Total	2,314.8	171.9	75.4	215.4	29.4	18.3	2,825.2	2,651.8	(173.4)	-4%

Alternative Scenario 3 – Millions of Dollars

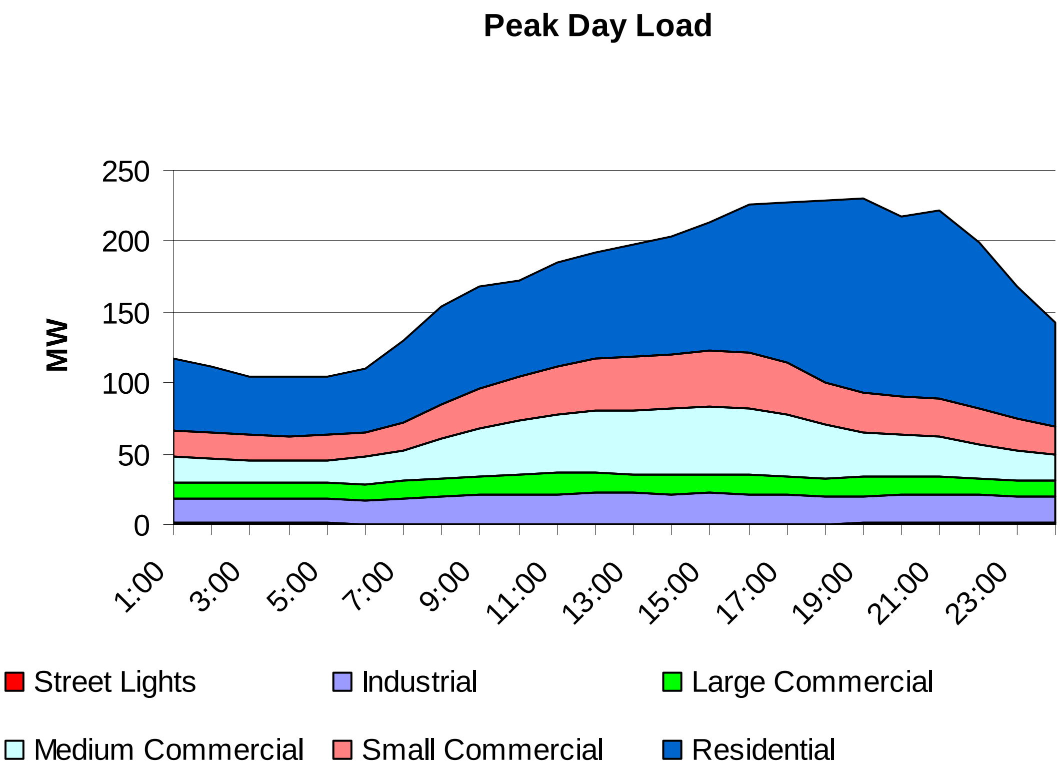
Year	Commodity Costs	Reserves and ISO Charges	Operations & Scheduling	Non-bypassable Charges	Metering & Billing	Financing Costs	Total Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	-	-	-	-	-	-	0.0	0%
2006	77.6	5.7	3.6	25.1	1.1	1.4	114.4	107.2	(7.2)	-4%
2007	79.5	5.9	3.7	23.7	1.1	1.2	115.0	109.1	(5.9)	-3%
2008	65.4	6.1	3.8	24.1	1.1	20.7	121.1	113.1	(8.0)	-4%
2009	67.0	6.6	3.8	16.9	1.2	15.9	111.3	115.9	4.6	2%
2010	73.0	7.0	3.9	15.5	1.2	18.3	118.9	121.8	2.9	1%
2011	75.9	7.5	3.9	15.9	1.3	17.4	122.0	125.7	3.7	2%
2012	78.5	7.8	4.0	16.4	1.3	17.2	125.3	129.9	4.7	2%
2013	81.1	8.1	4.0	7.3	1.4	16.9	118.8	123.3	4.5	2%
2014	83.7	8.4	4.1	7.4	1.5	16.6	121.6	126.9	5.3	2%
2015	92.3	8.8	4.1	7.5	1.5	16.3	130.5	131.3	0.8	0%
2016	94.8	9.0	4.1	7.7	1.6	15.2	132.3	134.5	2.2	1%
2017	98.8	9.5	4.1	7.8	1.6	14.8	136.6	141.2	4.6	2%
2018	104.4	10.3	4.1	7.9	1.7	14.5	142.8	151.5	8.7	3%
2019	109.8	10.9	4.1	8.0	1.8	14.2	148.7	160.9	12.2	4%
2020	120.5	11.3	4.1	8.1	1.8	13.8	159.6	166.2	6.6	2%
2021	122.6	11.5	4.1	8.2	1.9	13.3	161.7	167.7	6.0	2%
2022	125.8	11.8	4.1	7.9	2.0	12.9	164.5	171.5	7.0	2%
2023	130.6	12.4	4.1	-	2.1	12.4	161.6	171.8	10.2	3%
2024	136.8	13.1	4.1	-	2.2	12.0	168.2	182.2	14.0	4%
Total	1,818.0	171.9	75.4	215.4	29.4	264.7	2,574.9	2,651.8	76.9	2%

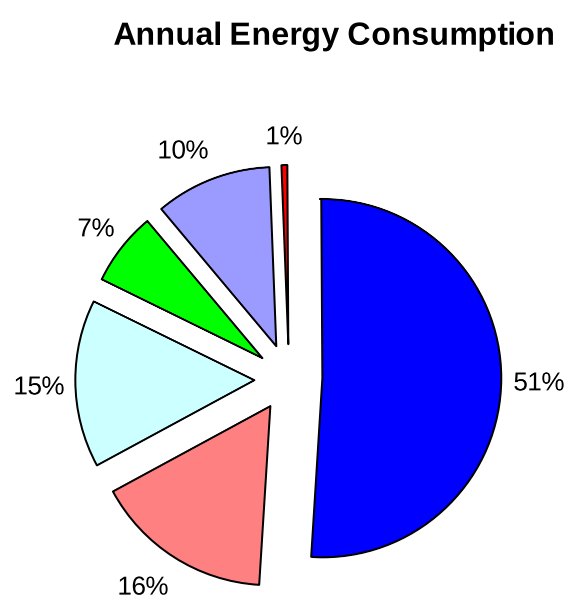
Alternative Scenario 4 – Millions of Dollars

Year	Commodity Costs	Reserves and ISO Charges	Operations & Scheduling	Non-bypassable Charges	Metering & Billing	Financing Costs	Total Costs	PG&E Charges	Savings	Percentage Of Total Bill
2005	-	-	-	-	-	-	-	-	0.0	0%
2006	74.2	5.7	3.6	25.1	1.1	1.2	110.8	107.2	(3.6)	-2%
2007	75.6	5.9	3.7	23.7	1.1	1.4	111.3	109.1	(2.2)	-1%
2008	71.7	6.1	3.8	24.1	1.1	10.9	117.7	113.1	(4.6)	-2%
2009	73.6	6.6	3.8	16.9	1.2	8.5	110.6	115.9	5.3	3%
2010	77.1	7.0	3.9	15.5	1.2	12.2	117.0	121.8	4.9	2%
2011	80.1	7.5	3.9	15.9	1.3	12.1	120.8	125.7	4.9	2%
2012	82.9	7.8	4.0	16.4	1.3	11.9	124.3	129.9	5.6	2%
2013	85.5	8.1	4.0	7.3	1.4	11.7	118.0	123.3	5.2	2%
2014	88.0	8.4	4.1	7.4	1.5	11.5	120.9	126.9	5.9	3%
2015	97.6	8.8	4.1	7.5	1.5	11.4	130.8	131.3	0.5	0%
2016	99.9	9.0	4.1	7.7	1.6	10.3	132.5	134.5	2.0	1%
2017	104.2	9.5	4.1	7.8	1.6	10.1	137.3	141.2	3.9	2%
2018	110.5	10.3	4.1	7.9	1.7	9.9	144.4	151.5	7.2	3%
2019	116.4	10.9	4.1	8.0	1.8	9.7	150.9	160.9	10.0	3%
2020	128.1	11.3	4.1	8.1	1.8	9.5	162.9	166.2	3.3	1%
2021	129.7	11.5	4.1	8.2	1.9	9.2	164.6	167.7	3.0	1%
2022	132.6	11.8	4.1	7.9	2.0	8.9	167.4	171.5	4.1	1%
2023	137.7	12.4	4.1	-	2.1	8.6	164.9	171.8	6.9	2%
2024	144.4	13.1	4.1	-	2.2	8.3	172.1	182.2	10.1	3%
Total	1,909.7	171.9	75.4	215.4	29.4	177.5	2,579.4	2,651.8	72.4	2%

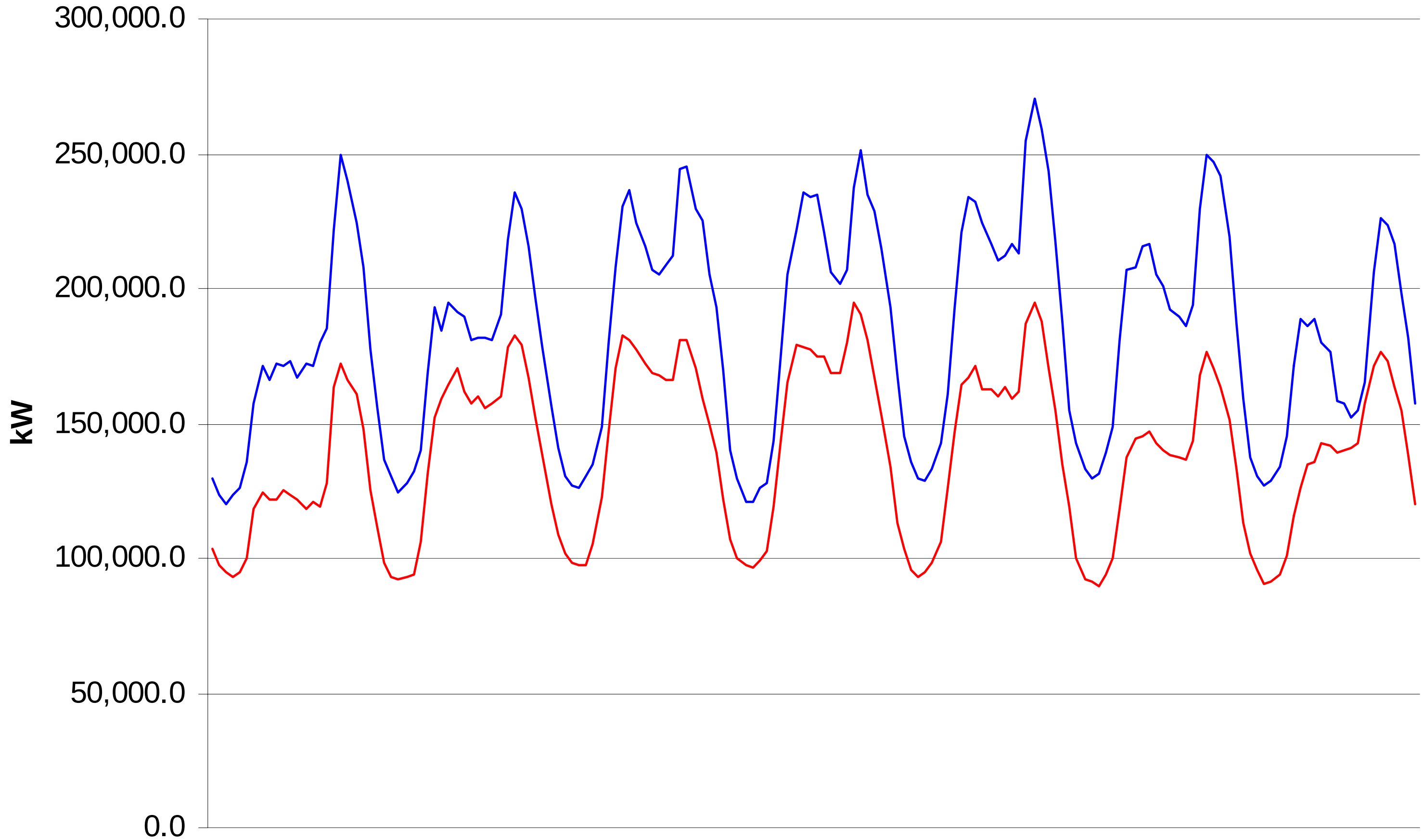
Appendix G – Electric Customers and Load Analysis

County of Marin
Electric Demand and Energy Consumption

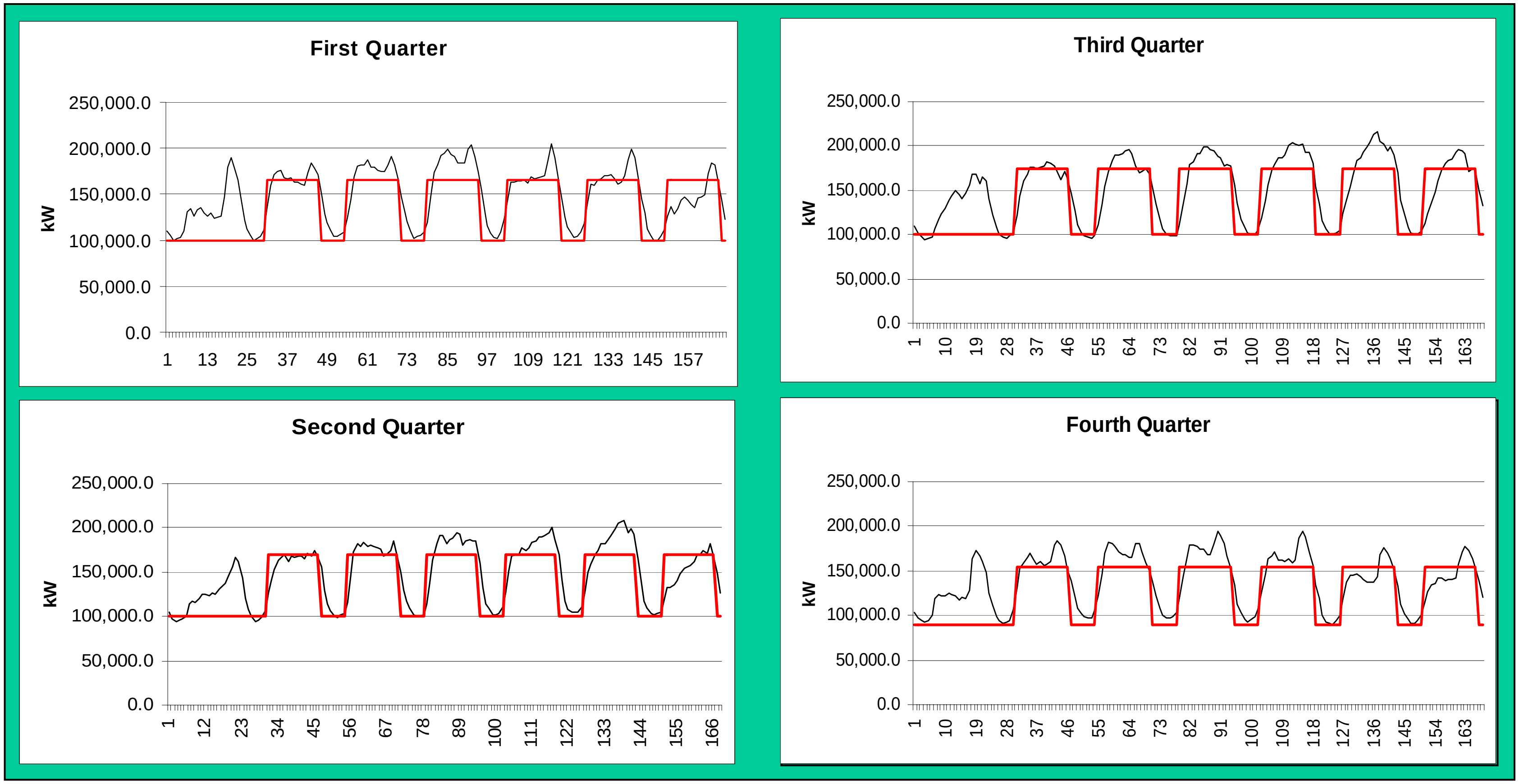




County of Marin
Maximum & Minimum Weeks



County of Marin Load Plots and Power Blocks



Quarter	7X24	6X16	Dumped kWh	Req. kWh	Qtr % kWk
1	100000	65000	3,849,312	355,355,346	1.08%
2	100000	70000	10,773,882	324,932,964	3.32%
3	100000	75000	8,856,809	349,194,085	2.54%
4	90000	65000	2,958,093	349,246,878	0.85%
			26,438,095	1,378,729,272	1.92%

Energy Purchases (kWh)

7X24	853,920,000	60.8%
6X16	338,960,000	24.1%
Spot On-Peak	93,688,355	6.7%
Spot Off-Peak	118,599,012	8.4%
Total	1,405,167,367	100.0%

Total Energy	Spot Purchases
1,378,729,272	15.1%

Appendix H – Implementation Schedule

The County could begin providing electric service to customers in the community as early as 2006 by following the timeline shown below:

COMMUNITY CHOICE AGGREGATION IMPLEMENTATION PROCESS AND TIMELINE

TASK	ESTIMATED START DATE
1 Feasibility Assessment and Evaluation	**3/10/05 – 5/7/05**
1.1 Review Final Feasibility Report	3/10/05
1.2 Conduct Public Workshop(s) and council sessions to consider proceeding to implementation	4/14/05
1.3 Decision to Develop CCA Implementation Plan	5/7/05
2 Implementation Plan Development	**5/14/05 – 7/30/05**
2.1 Obtain Billing Data From Utility	5/28/05
2.2 Issue Request For Qualifications/Offers To Suppliers	6/4/05
2.3 Identify uncommitted generation projects and negotiate participation, if applicable	6//4/05
2.4 Develop program structure, organization, operations plans and funding	6/11/06
2.5 Document participant rights and responsibilities	6/11/05
2.6 Select Preferred electric supplier(s) and	6/25/05

TASK		ESTIMATED START DATE
	partners; Evaluate and document their financial, technical and operational capabilities	
2.7	Develop preliminary energy supply resource portfolio	6/25/05
2.8	Perform Rate Design (cost allocation methodology and disclosure)	7/2/05
2.9	Complete Draft Implementation Plan	7/9/05
2.10	Conduct Public Workshop(s) on Draft Implementation Plan	7/16/05
2.11	Issue Resolution Adopting Implementation Plan	7/30/05
3	**CPUC Implementation Plan Filing**	**8/6/05 – 11/5/05**
3.1	File Implementation Plan and Statement of Intent with CPUC	8/6/05
3.2	Respond to information requests from CPUC or intervenors	8/13/05
3.3	Participate as required in CPUC process to support implementation plan	8/13/05
3.4	Monitor CPUC decisions	11/5/05
4	**Initiate CCA Startup Activities**	**8/13/05 – 12/10/05**
4.1	Conduct Recruiting and Staffing	

TASK		ESTIMATED START DATE
4.2	Develop informational and program marketing materials	8/13/05
4.3	Establish call center for customer inquiries	8/20/05
4.4	Develop in house capabilities or execute contracts for performance of operational services:	8/20/05
	- Electronic data interchange with utility	-
	- Customer bill calculations	-
	- Scheduling coordinator services	-
	- Application of statistical load profiles and submittal of hourly usage data for CAISO settlements	-
	- Resource planning, portfolio and risk management	-
	- Ratemaking	-
	- Load forecasting	-
	- Wholesale settlements	-
	- Credit and finance	-
	- Information Technology	-
	- Legal and regulatory support	-
4.5	Contact key customers to explain program, obtain commitment, and release customer information	8/27/05
4.6	Execute contracts for electric supply	11/12/05
4.7	Update program rates	11/12/05
4.8	Obtain financing for program capital	11/12/05

TASK	ESTIMATED START DATE
requirements	
4.9 Execute service agreement with utility[16]	11/19/05
4.10 Complete utility technical testing	11/26/05
4.11 Establish account with utility	12/3/05
4.12 Register with CPUC, post bond or demonstrate insurance	12/10/05
5 Customer Notification and Enrollment	**12/17/05 – 2/19/06**
5.1 Send first opt-out notice to eligible and ineligible customers	12/17/05
5.2 Send second opt-out notice to eligible and ineligible customers	1/21/06
5.3 Process customer opt-out requests and enroll customers	1/28/06
5.4 Submit notification certification to CPUC	2/5/06
5.5 Notify utility when CCA service will begin to initiate account transfer	2/5/06
5.6 Obtain updated billing data from utility	2/12/06
5.7 Update load forecasts and supply plan	2/19/06
6 CCA Operations	**3/2/06 – Ongoing**
6.1 Activate energy supply resource plan	2/2/06
6.2 Commence mass account transfer	3/3/06

16 The City, as a CCA operator, will need to establish a legal relationship with PG&E. It is anticipated that a service agreement will include processes for information exchange including electronic data interchange, procedures for settling financial transactions, treatment of customer bill payment funds transfer, credit terms, access to confidential customer information, audit provisions, and regulatory oversight and complaint processes.

TASK	ESTIMATED START DATE
6.3 Manage supply portfolio and risk management (ongoing)	3/3/06
- Prepare daily load forecasts	3/3/06
- Balance portfolio with purchases and sales	3/3/06
- Schedule loads and resources	3/3/06
- Monitor credit of suppliers and mark to market exposure	3/3/06
- Maintain risk controls on supply portfolio	3/3/06
6.4 Perform Account Management, Billing and Settlements (ongoing)	3/3/06
- Process customer transfers into and out of program	3/4/06
- Receive and respond to customer inquiries	3/4/06/
- Pay electric suppliers	3/19/06
- Obtain customer meter data from IOU	4/2/06
- Prepare bill calculations	4/2/06
- Provide bill amounts to IOU	4/2/06
- Apply statistical load profiles to meter data and submit to ISO for settlement	4/2/06
- Pay IOU transaction fees	4/2/06
- Receive remittances from IOU from customer collections	4/19/06
- Verify ISO settlement statements and	5/6/06

TASK	ESTIMATED START DATE
pay ISO charges	
6.5 Distribute third opt-out notice	4/2/06
6.6 Complete mass account transfer	4/2/06
6.7 Process opt-outs	4/3/06
6.8 Prepare operating statements and financial reports (ongoing)	4/19/06
6.9 Distribute fourth opt-out notice	5/6/06
6.10 Process opt-outs	5/7/06