COMMUNITY CHOICE AGGREGATION: ASSESSING THE FINANICAL AND POLITCAL VIABILITY IN HUMBOLDT COUNTY

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By

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ABSTRACT

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Michael Landau

The overall feasibility of implementing a Community Choice Aggregation program in Humboldt County is investigated in this thesis by examining its financial viability and likely level of public support. Community Choice Aggregation (CCA) enables the county to procure electrical power, by wholesale market purchases or owning and operating generation facilities, for customers in its jurisdiction. With CCA, a local public agency is responsible for resource decisions, which creates an opportunity to develop renewable energy projects, increase regional jobs, reduce greenhouse gas emissions while simultaneously reducing costs to consumers.

A literature review on CCA provides an overview on program elements, aggregator responsibilities and community benefits and risks. A financial analysis then determines the cost of a CCA program with generation portfolios consisting of 33%, 50% and 75% renewable energy. The total operating cost of each CCA scenario is compared to the incumbent utility company's projected cost of providing generation services. The results indicate that the CCA could provide 50% of the region's electricity from renewable sources and obtain cost savings for CCA electricity customers, assuming a 3%

escalation rate of the incumbent utility company's generation charge, of about $188 million over 20 years, or about $9 million per year. This equates to an estimated savings of about 6% on customers electric bills. The assessment further reveals that even greater savings could be realized by building renewable generation facilities that provide more energy than needed by the CCA and selling the excess renewable energy. In addition, the thesis examines the likely level of community support that CCA service would have in the county by qualitative and statistical analysis of the regions support for climate change mitigation and local control, which are often the motivating force for CCA.

The combined results from the financial and community analysis suggest that Community Choice Aggregation is a viable option for Humboldt County. The results may encourage public discussion, foster support and promote further investigation into establishing a local CCA program.

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INTRODUCTION

Concerns about the planet's ecosystem and climate change are stimulating voluntary and mandatory initiatives designed to mitigate greenhouse gas emissions. Many communities, partially in response to the perception that federal and state progress is inadequate, are taking initiative and are developing local policies and projects to enhance mitigation efforts. The ability of communities to make a genuine contribution to the global climate change challenge is however limited by the dominant or prevailing system of electricity supply. In this thesis I analyze an emerging electricity program called Community Choice Aggregation (CCA) that enhances local control of energy resources and enables communities to develop an energy policy that reflects local goals. The thesis assesses the financial and political viability of the CCA model for Humboldt County, CA.

CCA[1] is a program that gives counties or cities the legal authority to combine the electricity loads of consumers in its jurisdiction and procure electrical power on their behalf. After a community establishes a CCA program, electric customers choose either the CCA or incumbent utility company as their energy service provider. Legally the incumbent utility company is responsible for supplying power to its remaining customers and the transmission, metering and billing for both utility and CCA customers. The CCA is primarily responsible for procuring power, which can be obtained through either

[1] CCA refers to either community choice aggregation programs or community choice aggregator (the entity providing the procurement service).

market purchases or owning and operating generating plants, for the customers that choose to switch providers. A local government that forms a CCA program does not become a municipal utility company because the aggregator does not own the electric distribution system within its jurisdiction.

CCA programs are managed by a local public agency with input from the community. The size and management of CCA programs are features that distinguish them from the prevalent electricity market structure in California. Over two-thirds of California's electricity demand is provided by three regulated Investor Owned Utility (IOU) Companies (CPUC, 2010a). The three IOUs are Pacific Gas & Electric (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E). Humboldt County's electricity provider, PG&E, has over 5.1 million electric customer accounts and a service territory that covers over 42% of California (PG&E, 2011). The local control offered with CCA programs may offer a variety of community-wide benefits not available with regulated IOUs. Some of the potential benefits for Humboldt County are revealed by examining the objectives and status of two existing projects: the City of Arcata's Greenhouse Gas Action Plan and the Renewable-based Energy Secure Communities (RESCO) project.

The City of Arcata took the initiative to create the Greenhouse Gas Action Plan, which sets an emission reduction target of 20% below 2000 levels by 2010 (City of Arcata, 2006a). The city's most recent greenhouse gas (GHG) inventory, performed in 2006 to monitor the progress, showed that "there is much work to be done" (City of Arcata, 2006b p. 3). The city could reduce its GHG emissions and attain its goal by utilizing a cleaner electric grid mix. However, the city has little to no influence on the type and renewable content of energy resources utilized by PG&E. Establishing a CCA program would allow the community to choose their generating resources and the carbon intensity of the city's power mix, thereby ensuring success of the Greenhouse Gas Action Plan.

In addition to the region's GHG reduction goals, the community also has ambitious renewable energy development objectives. The Redwood Coast Energy Authority and the Schatz Energy Research Center are working on a Renewable-based Energy Secure Communities project that is creating a "strategic action plan for Humboldt County to develop its local renewable energy resources in an effort to meet 75% to 100% of the local electricity demand as well as a significant fraction of heating and transportation energy needs" (RCEA, 2010). Along these lines, forming a CCA could allow the county to issue bonds for financing local renewable energy generation facilities. The local facilities, owned and operated by the CCA, would not only help move the RESCO vision forward but also bring direct and indirect economic impact benefits to the community.

As demonstrated from the previous two examples, there are substantial benefits in terms of meeting policy goals with Community Choice Aggregation. CCA provides a community with control over energy resource decisions and rates. A local agency, with input from electric customers, is responsible for selecting generating resources best suited to meet the requirements and goals of the region. Therefore, if a local CCA desired, the amount of electricity obtained from renewable sources could be voluntarily increased above California's Renewable Portfolio Standard (RPS) requirements. Forming a CCA would also allow Humboldt County to leverage its aggregated purchasing power and invest in local renewable energy generation facilities. Other benefits of CCA include opportunities, but potentially not all at the same time, to increase energy efficiency programs, reduce electricity rates and provide rate stability. CCA programs may be able to lower electric rates because they increase competition and, unlike IOU companies or private developers, do not have to pay taxes or pay dividends to retain investors. These benefits will be elaborated upon in the Literature Review chapter.

Although there are clear benefits that can be achieved by forming a CCA, there are also financial risks. The Literature Review chapter provides greater detail on these risks along with a more comprehensive overview of CCA including a description of program fees, customer enrollment procedures and IOU and aggregator responsibilities. In addition, the chapter also includes a historical background section on California's electricity restructuring and its influence on CCA, which is helpful in understanding certain program charges.

The objective of this thesis is to investigate the feasibility of Community Choice Aggregation in Humboldt County. To determine the overall feasibility of forming a CCA the thesis conducts a preliminary assessment of its financial and political viability. The financial component of the analysis compares the total cost of operating a CCA program with that of continuing to purchase electricity from the incumbent utility company. The total cost of the CCA program is composed of five expense categories: power procurement, grid management, utility operations, financing and revenue from market sales.

Before the power procurement cost can be calculated an electrical load analysis is necessary to estimate the demand for the next 20 years and when the demand occurs because wholesale electricity prices vary by the time of day. The Methods chapter describes the procedure and high level assumptions used to forecast electrical load and determine costs for each category over a 20 year planning horizon, beginning in year 2012. Three CCA generation portfolios consisting of 33%, 50% and 75% renewable energy are evaluated to determine a range of potential costs. For reasons explained in the Methods chapter, this thesis assumes that the CCA will finance biomass and wind facilities that can generate enough electricity to meet the voluntary renewable energy goals. Each scenario is then compared to the incumbent utility company's cost of providing generation services to determine the cost impact of reducing the region's greenhouse gas emissions.

Although the focus on financial viability is crucial, the feasibility of establishing a successful CCA program also depends upon community support. Establishing a CCA program is not guaranteed even if the financial analysis reveals net monetary savings. In order to establish a successful CCA program, the community must encourage political leaders to fund feasibility studies and then ultimately participate in the CCA after it is formed. The more a community values the potential external benefits of CCA, the more risk and cost they are willing to accept. In other words, if the goals of a CCA program are aligned with the goals or core values of the community, the CCA program will likely have public and political support. The thesis presumes that the primary goal of a Humboldt County CCA program would be to reduce the GHG emissions from the regions electricity usage, increase local control of energy resources, and to do so while lowering or matching PG&Es electric rates.

Therefore, in order assess the amount of support it is necessary to determine how much the community values reducing GHG emissions and increasing local control of resources. As holding public forums or surveying the community prior to determining the program's cost is premature, the thesis investigates three proxies that provide insight into the likely level of public support. The proxies are partnership in PG&E's ClimateSmart program and county voting results for Proposition 23 and Proposition 16. The Methods chapter provides more detail on each subject to justify and support its use as a proxy for community support along with the statistical analysis used to evaluate the level of support.

The financial analysis determines a range of possible cost impacts to local electric customers and the political component of the analysis assesses the support that CCA might have in Humboldt. In order to perform this analysis, the thesis makes a number of assumptions that could affect the results. The Discussion chapter reveals several potential sources of error and highlights factors that may be unique to Humboldt County. Awareness of potential source of error creates an opportunity for further research to improve the feasibility study. The chapter also includes a description of potential near term regulation changes that could also impact results and concludes with a description of alternative strategies, policies and financing mechanisms that the community could potentially use to obtain similar benefits to that of CCA programs. Should the community choose to pursue CCA, the Conclusion and Recommendation chapter provides a description of the next program implementation steps and a list of recommendations to establish a successful and sustainable CCA program.

LITERATURE REVIEW

The Literature Review chapter provides a brief historical background on the restructuring of California's electricity market initiated in 1997 and the subsequent energy crisis of 2000 and 2001. These events provoked legislation allowing for the creation of CCA programs and the state's solution to the energy crisis continues to have an impact on CCA program costs. Following the historical background section, the development and implementation of CCA in California is presented and then an overview of CCA is provided. The overview describes the CCA customer enrollment process, type of utility fees imposed on CCAs, aggregator responsibilities, and the benefits and risks with CCA. The extent to which the benefits outweigh the risks and costs to Humboldt County ultimately provides an indication of the CCAs feasibility (Burke, 2005).

Historical Background

The restructuring of the California electricity market begun in 1997 was expected to increase competition among power suppliers and thus lower electricity prices. Although the increased competition between power suppliers was expected to reduce rates by more than 10%, electric rates for residential and small commercial customers were frozen by legislation to a level 10% below 1996 prices for a period of four years. As a result, while customers experienced a rate reduction, the frozen rate level was still projected to generate more than enough income for the utility companies to purchase power on the deregulated market. It was intended for the IOUs to collect this retail margin as a means to recover stranded costs, which is a term used to represent the decline in the value of electricity generating assets due to restructuring of the industry (Bushnell, 2004).

In the deregulated market, consumers were given the ability to choose an electricity provider. As each electric consumer had to actively select a new provider in order to switch and because rates were frozen for residential and small commercial customers, few customers in these sectors switched providers (Weare, 2003). More often, the largest consumers of electricity changed providers because they had not received the rate cut and service providers generally focused marketing efforts on their recruitment (Weare, 2003). Residential and small commercial customers typically remained with the IOU because it was inconvenient to the customer and costly to the provider to transfer service when there was not much at stake.

In the California energy crisis of 2000 and 2001, the IOUs cost to deliver power to electric customers increased significantly while revenue was still capped. This caused financial difficulty for the utility companies and both PG&E and SCE suspended payments to generation facilities. The electricity producers that were not receiving payment began to shut down their power plants, which led to several power outages. To prevent additional power outages the California Department of Water Resources (DWR) eventually had to take over power purchasing responsibilities. As the department responsible for the management and regulation of water usage, which entails flood control by means of operating hydroelectric dams, the DWR was already in the power business. The DWR committed to purchasing about $42 billion in long-term power supply contracts (Bushnell, 2004). Although the last of the power supply contracts expires in 2015, debt payment on the bonds will continue until 2022 (DWR, 2009). As detailed in the sections below, CCA customers are responsible for a portion of the DWR costs. Although the state ended retail choice in 2001 in order to recover DWR costs, customers that had already switched were allowed to continue receiving electricity from the provider.

Partially in response to the lack of options for small electric consumers under electricity restructuring and the perceived failure of the IOUs to manage electricity costs, Community Choice Aggregation was established in 2002 with California State Assembly Bill (AB) 117 (Stoner, 2008 p. 10). AB 117 authorizes counties and cities to "aggregate the electrical load of interested electricity consumers within its boundaries to reduce transaction costs to consumers, provide consumer protections, and leverage the negotiation of contracts" (California State Assembly, 2002).

CCA Development and Implementation in California

"At the time AB 117 was passed, there was no experience in California with community choice aggregation" (Stoner, 2008 p. 1). As a result, the California Public Utilities Commission (CPUC) needed to develop rules for how CCA programs should be implemented and how they should interact with the IOU. These rules were primarily developed in two phases by the CPUC. The Phase One Decision, D.04-12-046, was completed in December 2004. The Decision addressed implementation and transaction costs imposed by IOUs on an aggregator, granted prospective CCAs access to utility data and enabled phase-in of CCA service. Phase one also adopted a methodology for determining the Cost Responsibility Surcharge (CRS). The CRS is a cost recovery mechanism that protects existing IOU customers from additional costs that they might incur when a portion of the IOU customers transfer their energy services to a CCA. Therefore, the CRS prevents cost-shifting between utilities and CCAs. A more detailed explanation of the costs included in the CRS and the method of calculation is included in the CCA Overview section.

Phase two, Decision D.05-12-041, was completed in December 2005, and addressed a wide variety of topics dealing with CCA and IOU interactions. Phase two established rules for notifying customers of CCA service, opt-out opportunities and customer reentry fees. There have also been several CPUC Decisions clarifying or modifying previous Decisions; D.07-01-025 adopted modifications to the CRS, D.10-05-050 clarified the permissible extent of utility marketing with regard to CCA programs and D.08-02-013 modified utility tariffs regarding customer notification procedures and requirements for CCA bonds or insurance.

In an effort to help cities and counties understand the CPUC rules and evaluate the feasibility of forming CCA programs, the Community Choice Aggregation Pilot Project was established. The main goal of the project, which was funded by the California Energy Commission's Public Interest Energy Research (PIER) Program, was to investigate if CCA was a realistic and cost effective mechanism to increase renewable power generation in California beyond the state mandated RPS (Stoner, 2008). The project helped communities understand the opportunities and risks with CCA programs, identified critical factors to be considered when evaluating CCA and established an economic model for identifying the potential savings of CCA programs. The CCA Pilot Project economic model was used to determine the financial feasibility of CCA in "12 communities[2] throughout the state with representation in each of the three major investor-owned utility service areas" (Stoner, 2008 p. 2).

One of the 12 communities involved in the Community Choice Aggregation Pilot Project was Marin County. Marin County continued to investigate CCA after the Pilot Project was complete. The county prepared a Business Plan and an Implementation Plan that refined earlier assumptions and specified operating and administrative specifics for their CCA. The Business Plan included a financial analysis that was peer reviewed by a third party consulting firm and PG&E. In May 2010 the County of Marin and seven of its cities began operating the first CCA program in California.[3]

In addition to the County of Marin and the other communities involved in the Pilot Project, the City of San Francisco and the San Joaquin Valley Power Authority have investigated Community Choice Aggregation. The City and County of San Francisco are registered as a CCA, but as of January 2011 have not begun serving customers. The San Joaquin Valley Power Authority has postponed establishing a CCA program.

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[2] The twelve communities involved in the pilot project study are: (1) Berkeley, (2) Emeryville, (3) Oakland, (4) Marin County, (5) Pleasanton, (6) Richmond, (7) Vallejo, (8) Beverly Hills, (9) Los Angeles County, (10) West Hollywood, (11) San Diego County and (12) San Marcos.

[3] The public agency managing the CCA program is called Marin Energy Authority (MEA). The CCA program is called Marin Clean Energy (MCE).

In addition to the numerous reports commissioned by prospective CCAs, PG&E rules and tariffs are important literature sources for the financial analysis. Electric Rule No. 23 specifies the process, terms and conditions for interactions between the utility company and the CCA (PG&E, 2006a). Rule No. 23 also identifies the services that PG&E is authorized to charge the CCA program or its customers. The charges for the services are listed in PG&E Schedule E-CCA and Schedule E-CCAINFO (PG&E, 2006b; PG&E, 2006c).

Mechanics of CCA

The section below describes the mechanics of CCA programs in California.[4] The aggregator must offer the service to all residential customers located within the CCA service area. For the purpose of this thesis the service area is defined as Humboldt County but it could be an individual city or even a group composed of multiple cities or counties within an IOUs service territory. The CCA has the option to also offer the service to commercial, industrial, agricultural and other non-residential sectors (CPUC, 2004). With CCA, a local community organization becomes responsible for supplying power, through either market purchases or ownership and operation of generating plants, and making decisions about electric rates and public benefit programs (Stoner, 2008 p. 10). All aspects of power delivery, such as transmission, distribution, metering and billing remain the responsibility of the IOU. Therefore, unlike a municipally owned

[4] In addition to California, CCA is currently allowed in the States of Ohio, Massachusetts, New Jersey and Rhode Island.

utility company, the CCA is only supplying power to the electric grid and does not own the transmission and distribution system.

CCA programs are subject to the same California Renewable Portfolio Standard (RPS) as IOUs and Direct Access (DA) providers (Stoner, 2008 p. 11). On April 12, 2011, California Governor Jerry Brown signed legislation, SBX1 2, which increases the current 20% RPS target in 2010 to a 33% RPS requirement by December 31, 2020 (CEC, 2011). The law applies to CCAs and all the state's public and private utilities.

Although the intent of AB 117 is to prevent shifting of costs between IOU and CCA customer's, the CPUC determined that "allocating implementation costs to [IOU] ratepayers that are related to the development of the CCA program's infrastructure would be fair, relatively simple to administer and avoid the barrier to entry that might occur if a handful of individual CCAs were required to assume those costs" (CPUC, 2004 p. 57). Without this CPUC ruling, the first CCA would have had to reimburse the IOU for computer software changes and other modifications that enables an IOU to conduct business with all CCA programs. As future CCAs would have also benefited from the development of this infrastructure and the cost would be a challenging financial hurdle for the first CCA to overcome, the implementation costs are distributed amongst all of the IOUs ratepayers. In other words, IOU implementation expenses related to forming CCAs in general but not directly attributable to an individual CCA are recovered from all IOU ratepayer's.

Metering, billing, customer notification and other transaction costs associated with individual CCAs are paid for by that CCA program. IOU fees charged to the individual CCA are based on the incremental cost that the CCA imposes (CPUC, 2004). For example, a CCA can insert a notice in a customer's monthly PG&E bill and is charged a fee only if the envelope needs additional postage.

In addition to the incremental charges, CCA customer's must pay a Cost Responsibility Surcharge (CRS) that assures the "utilities' bundled[5] customers will remain financially indifferent to the departure of load from bundled service to a CCA Program's procurement portfolio" (CPUC, 2006 p. 2). The CRS includes: (1) costs associated with long-term Department of Water Resources power contracts and bonds entered into during the energy crisis; (2) utility power costs from both retained generation facilities and approved power contracts; (3) Competitive Transfer Charge (CTC) and historic revenue or credits applicable to customers at the time of transfer from the IOU to the CCA (CPUC, 2004).

The methodology for determining the CRS is based on the same approach used for direct access customers.[6] The method compares the IOU's average generation cost of its procurement portfolio to a forecasted market price of energy, and charges CCA customers the difference if the IOU cost is higher. The rationale for this methodology is

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[5] The term bundled refers to customers that receive energy, transmission and distribution, and all retail services such as meter reading and billing from a single entity. As the sole provider of all the above services the utility company groups together or bundles the individual charges on the bill and the customer only needs to reimburse one company. Thus, customers that switch providers and begin receiving generation service from the CCA and transmission and distribution services from an IOU are not bundled customers.

[6] Direct access is the ability of a customer to purchase electricity directly from the wholesale market rather than through the incumbent utility company. Direct access is not available for residential customers. Thus, CCA is the only method that currently offers consumer choice for residential customers. Direct access and CCA are similar in concept but the regulations are slightly different.

that a CCA will theoretically be able to purchase electricity at the current market rate and when the CRS is added to its customer's electric bill the cost will equal that of the IOUs. As the CRS is paid by CCA customers to the IOU, this surcharge should protect IOUs from any financial losses that might result from customers switching to CCA service. The CRS is inversely related to the market price of electricity. If market prices decrease, the CRS will increase. The effect of the CRS is that the CCA must procure power below market prices to provide electricity for less cost than the IOU. There is no refund of the CRS if the IOU cost is lower, but any negative differences can be carried forward to offset future higher costs. The CRS amount varies depending on the CCA establishment date, a process referred to as vintaging, to "reflect changes in utility portfolios that might increase or reduce power purchase liabilities" (CPUC, 2005).

California CCA programs use an opt-out customer enrollment approach, where all eligible electric customers within its jurisdiction become customers of the CCA unless they specifically opt out. Customers that opt-out will remain with the IOU. This "removes a huge hurdle for any community wishing to provide electricity to its constituents" because the CCA does not have to actively market to acquire customers (Stoner, 2008 p. 10). While the opt-out customer enrollment approach is advantageous for CCAs, it places a burden on the consumer as they may need to evaluate the alternatives. Customers must be given four opportunities to opt-out of CCA service. The CCA pays to mail opt-out notifications and also pays an IOU processing fee for each customer that transfers to the CCA.

Once enrolled in the CCA, customers can return to the IOU within 60 days of transferring without penalty. After this period, the customer can return to their previous electric provider by providing the IOU six months of advance notice and paying a re-entry fee (CPUC, 2004). The re-entry fee for PG&E, Humboldt County's electricity provider, is $3.94 per account (PG&E, 2006b). CCA programs are also allowed to impose an exit-fee on departing customers. After returning, PG&E specifies that the customer "make a three-year commitment and shall not be allowed to return to CCA service until their three-year minimum period has been completed" (PG&E, 2006a p. 26).

An economic study of CCA suggested that "the consumer opt-out privileges could conceivably be the Achilles Heel of AB 117. Should CCA rates drift higher than IOU rates and several large customers return to IOU bundled service leaving stranded generation[7], CCA rates would have to rise which could prompt more customers to also opt-out, setting off a death spiral of rising rates and departing customers" (Roberts, 2007 p. 8). The intent of the CCA exit-fee is to mitigate the risk of customer attrition.

CCA customers will continue to pay the CPUC authorized Public Purpose Program charge to fund energy efficiency and renewable energy incentive programs. The IOU collects the fee and remains responsible for managing the public energy programs. The CPUC requires that a proportional amount of the funds must be spent in a community that forms a CCA. "The CCA may be able to seek authority to replace the

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[7] Stranded generation refers to excess capacity that an organization cannot utilize and, thus, collect revenue from its electric customers but is still obligated to pay for. Stranded generation can include facilities that are owned by the entity or long term power contracts.

IOU as administrator of energy efficiency programs by submitting a program application to the CPUC" (Stoner, 2008 p. 18). Because CCA customers pay the Public Purpose Program charge, eligible low income CCA customers will continue to receive the California Alternative Rate for Energy (CARE) discount (CPUC, 2005). The discount is calculated as if the customer had remained on bundled service; the generation portion of the discount is based on IOU generation rates and not the CCAs.

Responsibilities

In addition to the responsibility of obtaining power for its customers, the aggregator must forecast electric load, process load information, coordinate with the grid operator and provide ancillary services necessary for grid stability. In order for the CCA to perform these functions the IOU will be required to provide the necessary data to the CCA. The CCA, similar to other electricity service providers, is subject to penalties by the California Independent System Operator (ISO) for failing to meet the resource adequacy program requirements (CPUC, 2005). In order to comply with the resource adequacy program the CCA must demonstrate on a month-ahead basis that they have procured enough capacity to meet 100% of the peak forecasted load plus a minimum 15% reserve margin (CPUC, 2011a).

The aggregator also must interact with the IOU regarding customer opt-out notifications, transfer of service requests and billing. Two billing options, called rate-ready and bill-ready, are available to the CCA after the utility company collects the meter data. With rate-ready service, the CCA provides rate information to the utility, which then determines the bill amount. Bill-ready service is where the CCA receives the meter usage from the IOU and then determines customers bills based on their own rates. With both billing options, the CCA statement is included on a separate page in PG&E's envelope. PG&E receives the full customer payment and then transfers the appropriate amount to the CCA.

The CCA also must perform administrative functions for contract administration, public relations and marketing. If the CCA builds generation facilities they will also need staff to operate and maintain the power plants. All these tasks can be outsourced or performed internally by the CCA.

Benefits

According to the CCA Guidebook the primary benefits of CCA are the local control over energy resources and the potential to reduce electricity rates for customers (Stoner, et al., 2009 p. 2). Although a local organization manages the CCA, the entire community has more influence in energy issues such as setting electric rates because the organization is subject to the Brown Act[8] and must hold public meetings. This collective decision-making allows for the development of an energy policy that reflects community goals and values and can manifest in additional community-wide benefits. The next section outlines several of the opportunities made available with community control of energy procurement.

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[8] The Brown Act is a California law that guarantees the public's right to attend and participate in meetings of local government bodies. Decisions and actions must be made during the public meetings. This process helps the community stay informed and maintain oversight of the government.

Local control over energy resource decisions provides CCAs the opportunity to set electric rates that might either emphasize price stability or subsidize certain sectors. Compared to an IOU, the CCA can potentially achieve greater price stability through a combination of diversifying the energy supply portfolio, expanding energy sources that are less susceptible to fuel price fluctuations, and securing long-term power purchase agreements or creating a rate stabilization fund (Stoner, et al., 2009 p. 16). The CCA program can also use its ratemaking authority to "establish economic development and business-specific rate incentives to help lure desirable businesses and jobs to the community" or help retain businesses considering leaving the region (Stoner, et al., 2009 p. 13).

CCA programs also have the opportunity to positively impact and potentially achieve regional environmental goals through the selection of energy resources used by the community. By developing new power generation, from renewable sources or cleaner conventional sources, the CCA might displace older inefficient power plants and, consequently, reduce air pollution and greenhouse gas emissions (Stoner, et al., 2009 p. 17).

The CCA program can also, if the community desires, establish an RPS that is greater than the IOU. For example, Marin Clean Energy offers two energy options. The "light green" option guarantees a minimum of 25% certified renewable energy for the same electric rates that PG&E charges its customers and PG&E has a portfolio that currently includes 17.7% from resources eligible under California's RPS program. The second MCE energy option is called "deep green" and is from 100% renewable sources.

The current rate for the deep green product adds an additional one ¢/kWh premium on the light green rate (MCE, 2011).[9] Therefore, for a household with an average monthly consumption of 1,000 kWh the additional monthly cost for 100% renewable energy is $10. Expanding renewable energy resources may also help a CCA buffer themselves from fluctuating fossil fuel prices and increase the energy security of the community.

The second primary benefit offered by CCA programs is the potential for reduced energy costs, which can be used to lower rates for CCA customers, contribute to reserve funds, or supplement the community's revenues from public services (Stoner, et al., 2009 p. 14). CCAs can secure lower cost energy supplies by increasing competition among power producers, negotiating inexpensive power purchase agreements, or using public financing to develop generating resources. CCAs have a financial advantage over IOUs because "a CCA, as a public organization, qualifies for tax-exempt financing to support the development of power generation facilities, resulting in a cost of capital that is approximately half that of an IOU" (Stoner, et al., 2009 p. 14). Furthermore, CCAs are public organizations and do not pay state or federal taxes and shareholder dividends. The Pilot Project feasibility assessments for the 12 communities estimated that CCA could reduce the average electric bill of customers by 1-10% while providing a portfolio of at least 40% renewable energy, or provide customer savings of 4-5% with an RPS that matches the IOU (Stoner, et al., 2009 p. 14).

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[9] In April of 2011 MCE eliminated a membership fee of $10 per month for the deep green energy product. Therefore, the one ¢/kWh premium is currently the only additional charge for deep green customers.

The Pilot Project and San Francisco economic studies showed that in order to reliably reduce electric rates the CCA cannot rely solely on electricity market purchases. "The CCA's ability to compete rests with its success in using its tax advantage in financing to develop, own and operate cost-competitive capital intensive generating capacity" (Roberts, 2007). Developing local power generation facilities will also increase direct and indirect economic opportunities for residents.

A UC-Berkeley's Renewable and Appropriate Energy Laboratory report synthesized the results of 29 studies that analyze the economic and employment impacts of the energy industry in the US and Europe. The report's findings show the average employment over the life of conventional and renewable energy facilities (Table 1). To account for the differing capacity factors of generation facilities, the study calculates an "average installed megawatt of power" (MWa) that is de-rated or reduced by a value related to the capacity factor of the technology.

Table 1 Average employment by energy generation technology over life of facility (Wei et al., 2009)

	Manufacturing, Construction, and Installation (Jobs/MWa)	Operations, Maintenance, and Fuel Processing (Jobs/MWa)	Total (Jobs/MWa)
Solar PV	1.43-7.4	0.60-5.00	2.03-12.40
Wind power	0.29-1.25	0.41-1.14	0.84-2.29
Biomass	0.13-0.25	1.42-1.80	1.67-1.93
Small hydro	0.26	2.07	2.33
Coal-fired	0.27	0.74	1.01
Natural gas-fired	0.03	0.91	0.94

The research indicates that every renewable energy technology generates more jobs per average installed megawatt of power in the construction, manufacturing, and installation sectors, as compared to the natural gas sector. The number of jobs created to operate and maintain renewable facilities may be more or less than those required for conventional power plants.

In addition to the benefits of direct employment, local facilities would also provide indirect and induced benefits because the workers would spend some of their earnings in the local community and this in turn contributes to the income of other residents. The RESCO study has developed economic impact assessment models to quantify these benefits and determine the extent to which the Humboldt County economy would benefit from investments in local renewable generation facilities and implementation of energy efficiency measures. The economic impact assessment models, which were customized for the Humboldt economy, provide results not only on the number of jobs created but also the income and economic output from investments in renewable generation facilities such as biomass, wind power and wave energy.

Financial Risks

Although starting and operating a CCA program offers benefits to communities, it also carries financial risk. The financial risks evolve as a community transitions from evaluating a prospective CCA to implementation and operation of the program. The sections below describe activities and expenses for the pre-implementation and start-up phases to better understand the potential financial liabilities. After starting a CCA program there will also be expenses from investing in CCA generation facilities or long-term power purchase agreements.

Pre-implementation expenses include all the costs prior to forming a CCA. Activities in this phase include educating residents and businesses about CCA, commissioning feasibility and planning studies, developing implementation and business plans and performing legal tasks to establish a CCA. The MEA spent about $330,000 on pre-implementation activities. As these upfront costs are not recovered until a CCA is formed and revenue is collected, cities and counties that do not form a CCA will not recover these funds.

After the CCA is formed there will be start-up expenses for hiring staff, industry experts, securing energy contracts, renting office space, and other program initiation costs. The MEA estimated $1.6 million in expenses before the program would begin collecting revenue from customers. The CCA may be able to secure a line of credit to cover some of these expenses, but "creditors may not be willing to extend credit without a loan guarantee by the participating cities" (City of Berkeley, 2010a p. 38).

Ideally pre-implementation, start-up and all other program expenses are recovered through electric rates during the operational lifetime of the CCA program. However, if the electric rates of the CCA program exceed the rates charged by PG&E, customers might choose to either not join the CCA or return to PG&E service. Both conditions could reduce CCA power demand below forecasts, which could subsequently affect the organization's financial stability especially if it was contractually obligated to purchase a fixed amount of power.

Administrative functions such as energy procurement and resource planning are always subject to certain risks that "must be managed by the energy supplier, whether it is the IOU or the operator of a Community Choice Aggregation program. Forming a CCA program does not increase operational risks, but responsibility for their management transfers to the CCA and/or its suppliers" (Stoner, 2008 p. 20). If the CCA does not manage the risks as well as the IOU, the electric rates for CCA customers will increase relative to the IOU. As CCA programs can only be implemented by cities and counties and most of these have little experience in the energy industry, the CCA will likely need to hire energy industry consultants to help mitigate operational risks.

Many CCA risks can be mitigated with careful planning, but not entirely eliminated. Future "energy costs and the path of investor-owned utility rates are both uncertain aspects that could greatly affect community choice aggregation feasibility for a community" (Stoner, 2008 p. 5). If continuing CCA service becomes infeasible for the community, the program can be terminated and customers will be returned to PG&E. The process for voluntary service termination and involuntary service termination are described in PG&E Electric Rule No. 23. Voluntary service completion requires at least one year of advanced notice to the CPUC and PG&E and the CCA is responsible for all costs resulting from terminating the program (PG&E, 2006a). Involuntary termination of the CCA can occur, with approval from the CPUC, when "continued CCA service would constitute an emergency or may substantially compromise utility operations or service to bundled customers" (PG&E, 2006a).

The next chapter, Materials and Methods, uses the above background on CCA and the broadly defined responsibilities of an aggregator and incumbent utility company to develop methods for assessing CCAs financial and political feasibility

MATERIALS AND METHODS

This chapter discusses the materials and methods used for the financial assessment and evaluation of community support. The financial and political components are interrelated factors affecting the overall feasibility of Community Choice Aggregation in Humboldt County. Community support for CCA will depend upon the likely cost to the customer, and the cost to the customer will in turn depend upon community values. A community that values low cost electricity may choose to procure the cheapest possible generation portfolio mix that still complies with the minimum required RPS, with no concern for the environmental consequences. In contrast, a community that values the environmental benefits of CCA programs may choose to procure more expensive clean energy sources. The cost of these two hypothetical CCA programs will likely be different because the program objectives are not the same. The financial analysis of a Humboldt County CCA program evaluates three different generation portfolio scenarios with a voluntary RPS ramping up to of 33%, 50% and 75% in 2031[10] to determine a range of possible costs. In addition, a sensitivity analysis is performed on key variables that impact the financial results.

The financial analysis methods used in this thesis are based on the Community Choice Aggregation Pilot Project. The Pilot Project analysis was developed by energy

[10] This thesis assumes that the earliest a CCA program could be implemented in Humboldt County is 2012. The financial analysis assumes a 20 year program duration, which would conclude in 2031.

industry consultants and peer reviewed by two independent companies, MRW & Associates and JBS Energy. Furthermore, the Marin County feasibility evaluation developed by the Pilot Project became the basis for Marin Counties more detailed Implementation Plan and Business Plan that was again peer reviewed by an independent company and PG&E. Using a similar framework for the feasibility evaluation in this thesis provides consistency and allows for a comparison between communities.

Because there is risk involved with CCA programs and the potential savings, not including the benefits from externalities, may be minimal, most communities pursuing CCA also place some value on the external benefits. The more a community values the potential external benefits of CCA, the more risk and cost they are willing to accept. In other words, if the goals of a CCA program are aligned with the goals or core values of the community, the CCA program will likely have public and political support.

This thesis presumes that the primary goal of a Humboldt County CCA program would be to reduce the GHG emissions from the region's electricity usage and/or increase local control of energy resource decisions. Therefore, in order to assess the amount of support that a Humboldt County CCA might have, it is necessary to determine how much the community values reducing GHG emissions and increasing local control of resources. Although it would have been desirable to conduct a survey after the financial assessment, there was not sufficient time to perform this task by the thesis deadline. Therefore, other methods were used to gauge public support. These methods are discussed in the Community Support section.

Financial Assessment

The financial assessment determines the collective savings to Humboldt County electric customers with implementation of CCA. The collective savings is determined by comparing the cost to the community of purchasing electricity generation services from PG&E to the cost of operating a CCA program that procures the community's electrical power. The financial analysis only needs to evaluate costs associated with power procurement and its related business expenses because PG&E will provide transmission and distribution services for both conditions. Cost savings if any are determined annually for a 20 year planning horizon, beginning in year 2012.

The financial assessment groups PG&E and CCA expenses into categories of cost. Each cost-category has sub-levels as shown in the financial analysis schematic on Figure 1. As will be explained in more detail below, PG&Es revenue requirement[11] for generation services is embedded in a single charge. Therefore, there is only one cost category for PG&E. In contrast, the revenue requirement for the CCA is distributed between five categories. The categories are power supply, electric grid management, utility operations, financing costs and revenue from market sales. Although this analysis excludes economic development opportunities, it assumes that the CCA will construct and operate biomass and wind facilities because the technology is mature and the

[11] Revenue requirement is the amount of money that a utility must receive from its customers to cover its costs, operating expenses, taxes, interest on debt payments and, for IOUs, a reasonable profit.

resources are locally available[12] and, therefore, could also bring benefits to the community by creating local jobs. This thesis also excludes benefits from avoided greenhouse gas emissions because the value of GHGs are difficult to quantify.[13] Furthermore, the financial results may be more persuasive if the analysis excludes benefits from avoided GHG emissions and still demonstrates savings with implementation of a CCA program.

Before the costs can be determined an electrical load analysis is necessary to determine the demand for the next 20 years, and the time of day and day of week when the demand occurs, as wholesale electricity obtained for peak hours is more expensive than off-peak electricity. After discussing the electrical load analysis methods, the cost estimating methods and the high level assumptions for each cost category are presented.

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[12] The Humboldt County Energy Element Background Technical Report published in 2005 estimated 400 MW of local wind capacity and greater than 60 MW of biomass capacity (Zoellick, 2005). Revised local capacity estimates were presented at the Humboldt State University Sustainable Futures Speaker Series on 12/2/2010; local wind and biomass capacity was estimated to be up to 250 MW.

[13] A California Air Resources Board study by Varshney & Associates estimated AB 32 would cost the public and private sector in Marin County $50 million without CCA. MCE estimates that their CCA "will take Marin two-thirds of the way toward meeting the requirements of AB 32 and will cost the ratepayers virtually nothing" (MEA, 2009).

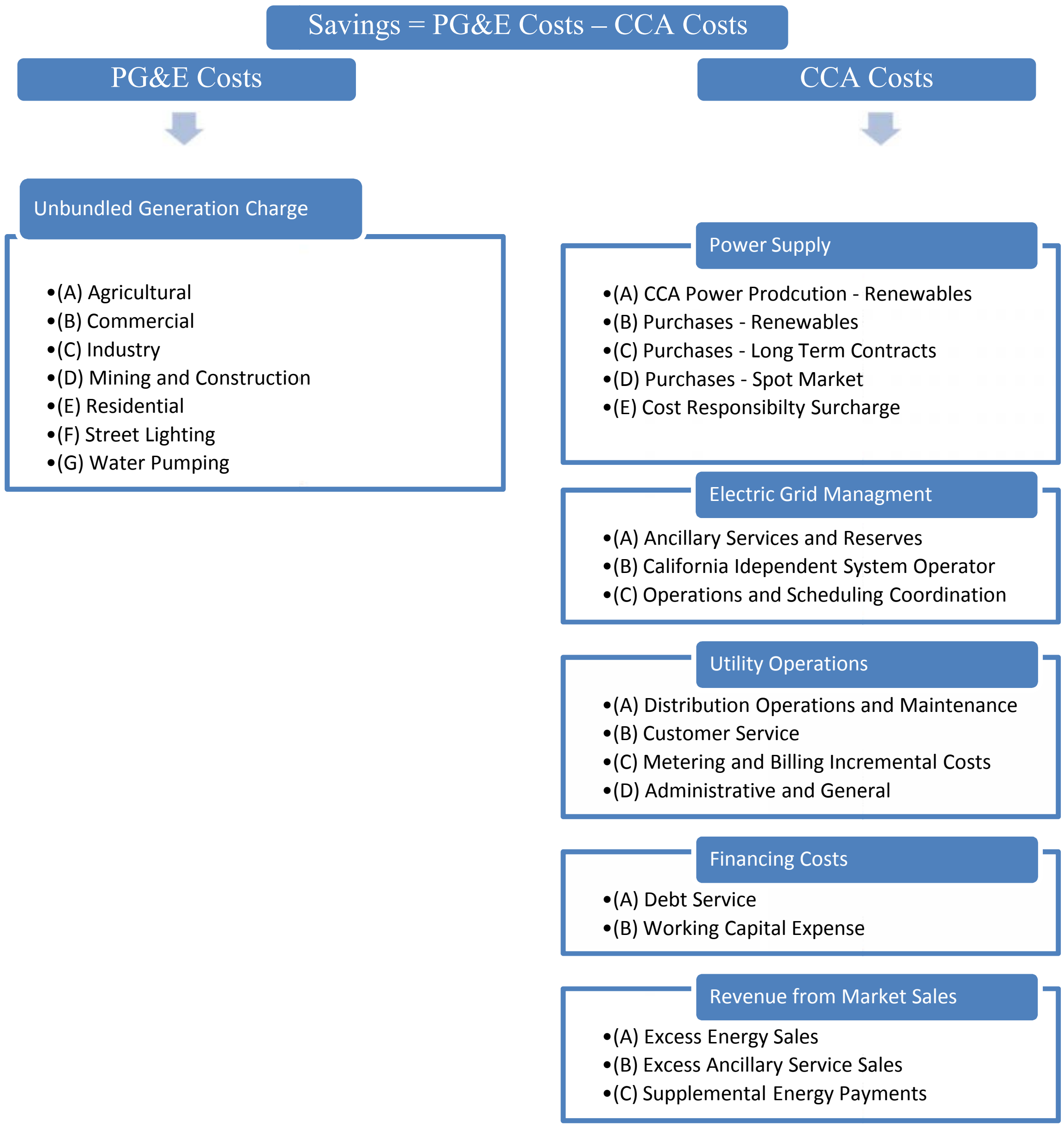

Figure 1 Financial analysis schematic showing PG&E and CCA expense categories. The collective savings to the community is the difference between PG&E and the CCAs costs. In contrast to the CCA, PG&Es revenue requirement for generation services is embedded in a single charge. Therefore, there is only one expense category for PG&E.

Electric Load Analysis

The purpose of the electric load analysis is to determine the CCA's annual electricity demand/consumption and the load profile for each year of the assessment period. The procedure for determining the CCAs annual load for each year from 2012 to 2031 involved: (1) calculating sector level historic electricity consumption and growth rates; (2) selecting an appropriate forward looking growth rate for each sector; (3) forecasting the county's load based on the selected growth rate and (4) applying opt-out percentages to each sector to determine the load and number of customers that would transfer to the CCA. These steps are described in more detail below.

Monthly electricity sales and customer count information, aggregated at the sector level, from 2004 to 2008 was from the California Energy Commission (CEC) but provided by the Schatz Energy Research Center (SERC). The county's electricity sales were divided into nine sectors: (1) agriculture, (2) commercial building, (3) commercial other, (4) industrial, (5) mining and construction, (6) residential, (7) street lighting, (8) unclassified and (9) non agricultural water pumping. The electricity consumption in the unclassified sector was proportionally distributed to the industrial, commercial building and commercial other sectors by the author at the recommendation of SERC staff. The electricity sales for the commercial building and commercial other sectors were then combined resulting in seven primary sectors. Historic annual electricity consumption and growth rates were calculated for all seven sectors.

The 2008 electricity consumption and average annual growth rate from 2004 to 2008 for the seven primary sectors in Humboldt County are shown in Table 2. In 2008 the total electricity consumption in Humboldt County was approximately 906 GWh. This was the energy used to serve end-use needs and, therefore, does not account for power plant and distribution losses. The residential sector accounted for approximately 50% of the total load. The commercial, industrial and agricultural sectors accounted for approximately 32%, 14% and 3%, respectively. The remaining three sectors (water pumping, street lighting and mining and construction) accounted for less than 2% of the total load.

Table 2 Humboldt County electricity consumption and number of customers for 2008 measured at the sector level and the average annual growth rate between 2004 and 2008 (CEC, 2009)

Sector	2008 Electricity Consumption (MWh)	Percent of Total Load (%)	Customer Count	Average Annual Growth Rate (%)
Agriculture	25,751	2.8	729	4.6
Commercial	289,099	31.9	7,524	0.6
Industry	125,493	13.9	423	-1.0
Mining and Construction	1,185	0.1	78	-1.2
Residential	448,202	49.5	56,353	7.1
Street Lighting	4,367	0.5	1,137	0.2
Water Pumping	11,460	1.3	158	2.3
Total	905,557	100.0	66,402	3.5

The average annual growth rate from 2004 to 2008 for all sectors averaged 3.5% (Figure 2). Residential electricity usage in Humboldt County increased at an average growth rate of 7.1%. This is a faster growth rate than was predicted in a 2005 study, which estimated growth in electricity demand over the next 20 years will range from about 0.5% per year to 1.5% per year (Zoellick, 2005 p. 2). The same 2005 study reported that PG&E expected the growth in electricity demand to average 0.6% per year.

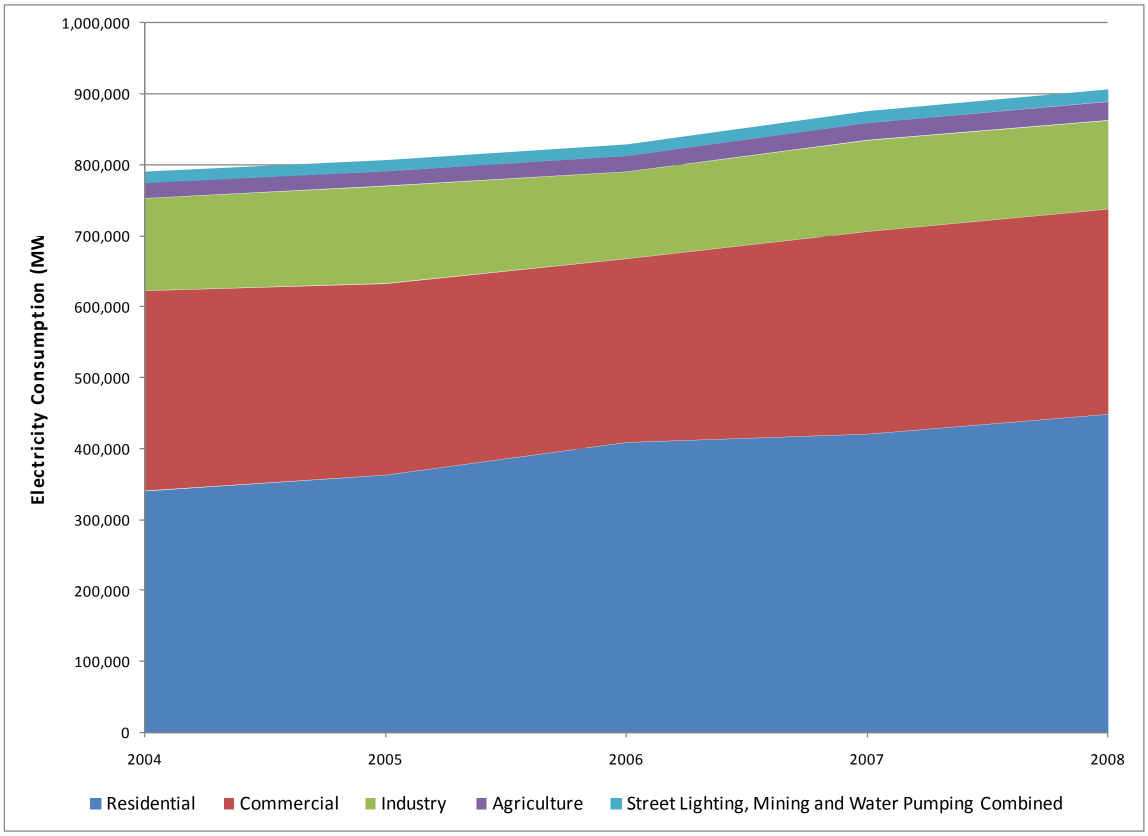

Figure 2 Average annual electricity demand growth rate from 2004 to 2008 for all sectors was 3.5%. The residential sector experienced an average annual growth rate of 7.1%.

The continuance of the historic consumption trend is not certain but it does provide a useful reference point for planning purposes (Zoellick, 2005). PG&Es electricity demand forecast for its entire service territory from 2010 to 2020 is 1.80% for residential, 1.34% for commercial, 0.63% for industrial and 0.08% for the agricultural sector (CEC, 2009). For this assessment it was assumed that Humboldt County would have a smaller demand forecast than PG&Es entire service territory because of the county's historically smaller population growth rate compared to other California regions. This thesis assumes that the residential annual growth rate would average 1.5%

over the next 20 years and the commercial and industrial sector would average 1.0%. The energy demand for all other sectors was assumed to be constant. Using the 2008 measured electricity consumption and the assumed growth rate, the electricity demand of the entire county was forecasted for each year of the CCA assessment period. The quantity of electric customers was also forecasted at the same growth rate.

As CCA provides consumers the ability to choose their service provider, the CCA's total electricity consumption was discounted to reflect the number of customers that would opt-out and remain with PG&E. The default opt-out rates recommended by the CPUC phase two Decision, D.05-12-041, are 5% for residential and 20% for commercial and industrial customers. Marin's CCA program had a 16% opt-out rate for its commercial customers. Residential customers will be able to join the MCE program in early 2012. Thus, the opt-out rate for Marin's residential sector is not known at this point in time (Loceff, 2010).

The analysis also applied a 20% opt-out factor to the agricultural and mining sectors and assumed 0% opt-out for street lighting and water pumping customers. The CCA's load and number of customers was determined by applying the opt-out rate to the county's total load. Table 3 shows the energy consumption for the beginning and end of the CCA assessment period, year 2012 and 2031, respectively.

Table 3 CCA forecasted electricity usage for the beginning and end of the assessment period, year 2012 and 2031, respectively. The forecasted electricity usage is based on measured 2008 data, sector specific growth rates and opt-out rates.

Sector	Annual Electricity Use Growth Rate (%)	Opt-out Rate (%)	Projected 2012 Electricity Use (MWh/yr)	Projected 2031 Electricity Use (MWh/yr)
Agriculture	0.0	20	20,601	20,601
Commercial	1.0	20	240,669	290,755
Industry	1.0	20	104,471	126,213
Mining and Construction	0.0	20	948	948
Residential	1.5	5	451,920	599,676
Street Lighting	0.0	0	4,367	4,367
Water Pumping	0.0	0	11,460	11,460
Total			834,437	1,054,019

After performing the 20-year electric load forecast, the CCA's annual hourly load shape was developed using methods outlined in the CEC Community Choice Aggregation Pilot Project Appendix G Guidebook. The load shape, which reveals how hourly electricity demand changes throughout the day and week during each year, was used to determine the amount of on-peak and off-peak energy. The load shape was generated using PG&E average territory-wide static load profiles. Static load profiles are probability density functions indicating the fraction of annual electricity usage for typical customers in each rate class occurring in each half-hour interval. The profile captures how "different types of customers use different amounts of energy at different times of the day or days of the week. For example, many small commercial customers will be closed on weekends, while many residential customers might use even more energy over the weekend than they do during the week" (PG&E, 2010b). The potential impacts of using territory-wide static load profiles, rather than metered time of use data that is specific to Humboldt County is discussed later in this thesis.

Although PG&E publishes static load profiles for each rate class, the energy consumption data provided by SERC was by sector description and not by the exact rate class.[14] Therefore, the analysis followed the CCA Pilot Project method and selected rate class static load profiles that are "most characteristic of load usage patterns in each of the customer sectors" (Stoner, et al., 2009 p. 37). Table 4 indicates the static load profile that was assigned to the seven primary customer sectors.

Table 4 Static load profile assigned to each customer sector

Sector	Static Load Profile ID	PG&E Description
Agriculture	AG-1	Agricultural Power
Commercial	A-1	Small General Service
Industry	E-20	Commercial/Industrial/General Medium Demand <1000kW
Mining and Construction	E-19	Commercial/Industrial/General Medium Demand <500kW
Residential	E-1	Residential Service
Street Lighting	LS-1	PG&E-owned Street and Highway Lighting
Water Pumping	E-19	Commercial/Industrial/General Medium Demand <500kW

Annual load profiles for each sector were created by using the load profile to allocate monthly energy (kWh) into each hour of the month and then to each of the 8,760 hours within a year (Stoner, et al., 2009). Afterwards, the CCA's community composite annual energy load shape (average kW per hour) was developed by combining loads in each hour from each of the customer sector load profiles. Figure 3 is an annual load profile for 2012. The figure shows 8,760 data points - one data point for each hour –

[14] Communities can be provided the energy consumption per rate class by making a formal request to PG&E. There is no charge for the first request. Subsequent request will cost $207 per PG&E Electric Schedule E-CCAINFO, Information Release to Community Choice Providers. The formal request must be a signed letter from the mayor or chief county administrator stating that the city or county is investigating CCA (CPUC, 2004).

revealing how the CCAs energy demand changes during the year. A higher resolution figure would show CCA energy demands for other time periods, such as monthly, weekly or daily loads.

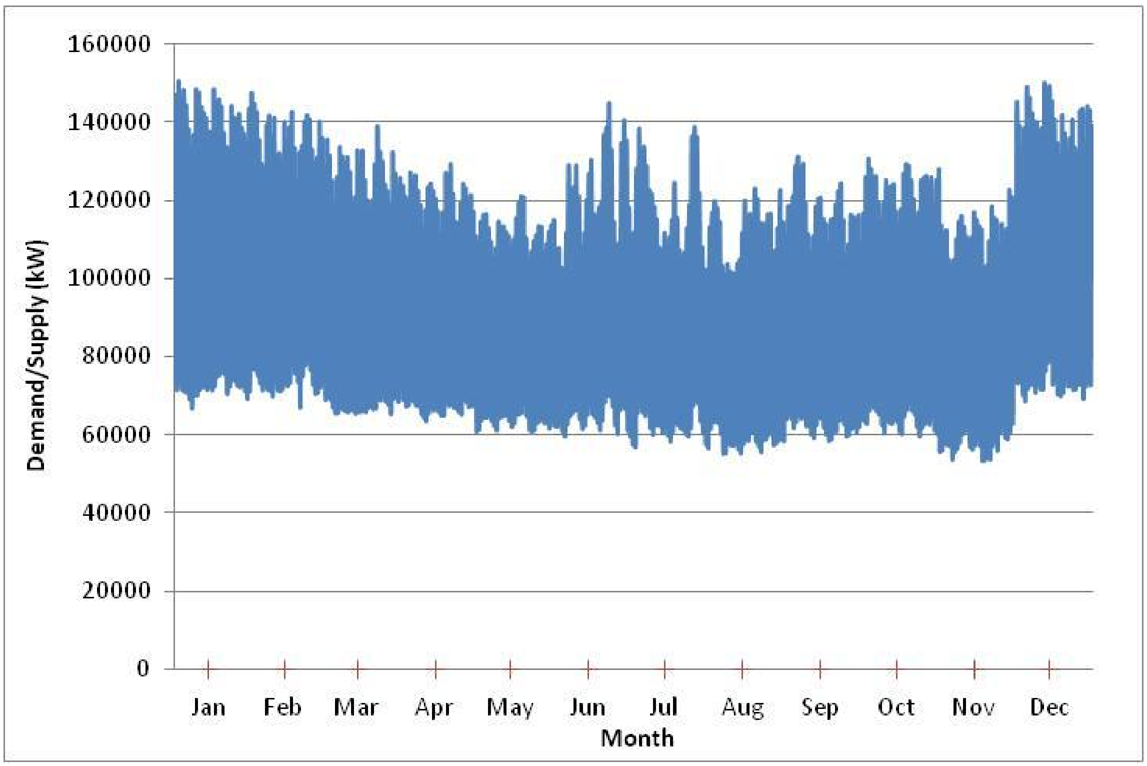

Figure 3 CCA composite annual load profile for 2012

The CCA community composite annual load profile was then decomposed to develop typical weekly load plots for typical weeks in each quarter of each year resulting in 60 load plots. These load plots identify the daily, weekly and quarterly pattern of electricity usage, which is “the basis for ‘sizing’ the portfolio of contacts and generation resources needed to serve the aggregator’s load profile” (Navigant, 2005 p. 50).

For each load plot, a baseload and peak power procurement amount is selected and then numerically integrated to identify: (1) off-peak energy; (2) on-peak energy; (3) spot market purchases and (4) excess energy. Off-peak energy corresponds to electricity usage for the full day on Sunday and for select hours on Monday through Saturday - hours ending 1 through 6 and 23 through 24. On-peak energy corresponds to electricity usage on Monday through Saturday with hours ending 7 through 22 (CAISO). Spot market energy is short term, typically day-ahead or hour-ahead wholesale market purchases used to supplement resources under contract control of the CCA and to balance system demand. Excess energy is when the CCA demand for energy is lower than the amount under CCA contract control.

Figure 4 shows the weekly load plot (beginning on Sunday) for the first quarter of 2012 with the four energy categories identified. Baseload and peak power limits were manually adjusted, as suggested by the Pilot Project Guidelines, to keep spot market purchases below 15% and excess energy below 2.5%.

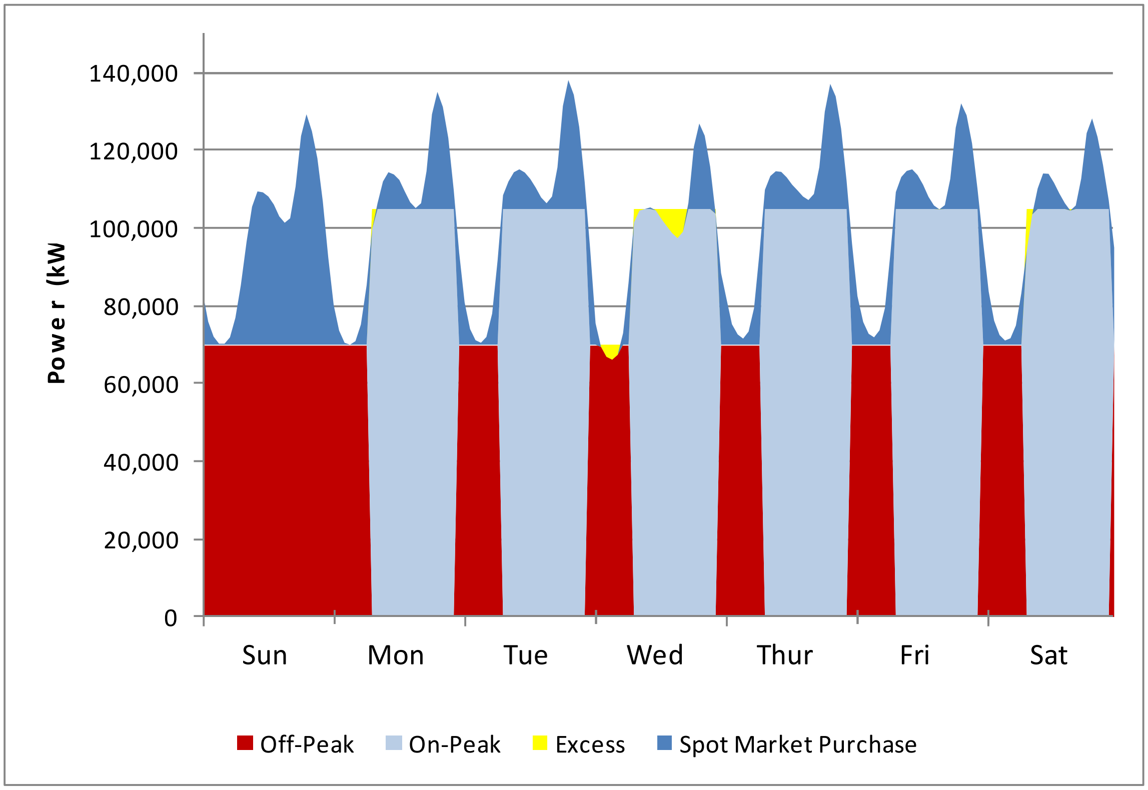

Figure 4 First quarter weekly load plot (beginning on Sunday) for 2012 illustrating the four energy price categories (off-peak, on-peak, spot market purchase and excess energy)

The baseload and peak power limits for the load plot in Figure 4 are 70,000 kW and 105,000 kW, respectively. The analysis assumes that the CCA secures a contract with an energy supplier to provide 70,000 kW during all off-peak hours and 105,000 kW during all on-peak hours. If the demand exceeds this amount, the CCA will purchase additional power in the spot market. If the demand is lower than the amount under contract control – as it is early in the morning and middle of the afternoon on Wednesday in the above example – the CCA has excess energy, which could be sold.

<u>PG&E Costs</u>

PG&Es expenses, typically referred to as revenue requirement, are categorized into three major categories: generation, distribution and transmission. "This categorization not only reflects major areas of utility operations but is also used to decide which customer classes would pay for which categories of costs" (CPUC, 2010a p. 7). CCA and direct access customers that receive power from another provider do not pay the generation portion of PG&E's revenue requirement.[15] This is the "largest component of electric rates and accounts for 56% of the total revenue requirement" (CPUC, 2010a p. 5).

The financial analysis determined the total cost for PG&E to provide generation services to the prospective Humboldt CCA by multiplying each sector's annual forecasted electricity sales by the unit cost of generation ($/kWh). The unit cost of generation for each sector was derived from PG&E electric schedules, which separate or unbundle the total customer charge into multiple components. For instance, the unbundled components include generation, transmission, reliability services, public purpose programs, nuclear decommissioning and the other components indicated in the unbundled residential service example provided in Table 5.

Although the electric schedules unbundle all the charges, the generation component still depends upon a number of variables that are unknown to this

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[15] PG&E earns profit "only on items of cost that are capitalized (e.g. assets and equipment). For many cost categories such as purchased power and fuel cost, they are only reimbursed for their costs" (CPUC, 2010b p. 7). The majority of profit is embedded in the transmission and distribution categories. CCA customers must still pay for these services thus contributing to PG&Es rate of return.

investigation. For example, the agricultural generation rate depends upon the seasonal electric usage and the horsepower of the connected load. Motors rated greater than 35 horsepower have a smaller summer and winter generation charge than motors rated under 35 horsepower by 0.00031 and 0.00251 ($/kWh), respectively (PG&E, 2010c). While all the assumptions used to determine the generation charge for the CCA's electric customers are provided in Appendix E, the residential sector assumptions are specifically mentioned because they have a greater impact on the financial results.

For residential customers, PG&E has a rate structure composed of five tiers or levels of electricity usage with each tier having a different generation charge. The generation rate varies from $0.04587 for baseline usage or tier 1 to $0.20251 for tier 5, which is greater than 300% of baseline usage (Table 5).[16] This analysis calculated a weighted average generation charge assuming the electricity usage distribution is the same as that of Marin County - approximately 62%, 11%, 15%, 8% and 4% for tier 1 through 5 respectively.[17] Based on this assumption for the residential sector and the other assumptions listed in Appendix E, the estimated generation charges are shown in Table 6.

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[16] Assembly Bill 1X enacted a rate freeze for residential electricity usage up to 130% of the baseline threshold (tier 1 and tier 2). The rates for the first two tiers have remained largely unchanged since 2001 while PG&E's revenue requirement has increased. Revenue requirement increases have been collected in tier 3, 4, and 5 rates. Therefore, tier 1 and 2 electric customers are subsidized by higher usage residential customers and non residential customers (CPUC, 2010c).

[17] The distribution of residential sales for PG&E's entire service area for the twelve months ending in September 2009 was 61.7%, 15.5%, 11.6%, 6.6% and 4.6% for tiers 1 through 5.

Table 5 Unbundling of total rates for PG&E electric schedule E-1 (residential services) (PG&E, 2010c)

Component		Unbundling of total rate (¢/kWh)
Generation	Baseline usage	4.587
	101%-130% of baseline	5.491
	131%-200% of baseline	14.149
	201%-300% of baseline	20.251
	Over 300% of baseline	20.251
Distribution	Baseline usage	3.656
	101%-130% of baseline	4.377
	131%-200% of baseline	11.279
	201%-300% of baseline	16.144
	Over 300% of baseline	16.144
Transmission		1.158
Transmission rate adjustments		-0.140
Reliability services		0.069
Public purpose programs		1.223
Nuclear decommissioning		0.029
Competition transition charges		0.554
Energy cost recovery amount		0.226
DWR bond		0.515

Table 6 Estimated 2011 PG&E generation charge for Humboldt County electric customers

Sector	Electric Schedule	Unbundled generation charge ($/kWh)
Agriculture	AG-1	0.08433
Commercial	A-1	0.08509
Industry	E-20	0.07375
Mining and Construction	E-19	0.07770
Residential	E-1	0.06449
Street Lighting	LS-1	0.07427
Water Pumping	E-19	0.07770

The 2011 generation charges are then increased at a constant rate to determine PG&Es forecasted generation costs. The escalation rate is a contested issue between PG&E and MEA consultants. The 2005 County of Marin Feasibility Analysis modeled PG&Es revenue requirement from 2005 to 2024 and estimated that generation rates would increase at a nominal 1.7% per year. The study stated that “the projected annual rate increase of 1.7% is at the low end of historical trends" because generation cost increases are "somewhat offset by the expiration of high cost DWR contracts in the 2004 to 2012 period" (Navigant, 2005 p. 42). As the escalation rate was based on an RPS of 20% by 2017, which was later accelerated by the state to 20% by 2010, subsequent studies increased the escalation rate to 3.5%.

PG&E objected to the 3.5% escalation value in their review of the MEA Business Plan and cited their four forecast scenarios submitted as part of the CEC's 2007 Integrated Energy Policy Report (IEPR) proceeding. "The escalation rates of these four forecasts between 2008 and 2016 ranged from 0.44% per year to 2.45% per year" (JBS Energy, 2008).

The 2011 EIA Annual Energy Outlook estimates that generation prices from 2010 to 2030 will increase at an annual nominal rate of 2.3% for the Western Electricity Coordinating Council,[18] which is an organization that has PG&E as one of its members. (EIA, 2011). Due to this uncertainty, the financial analysis model for Humboldt County's CCA uses a nominal escalation rate of 2%, 3% and 4% to determine future generation costs of PG&E. PG&E costs for the three escalation rates are provided in the Results chapter.

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[18] The Western Electricity Coordinating Council is an organization that is responsible for coordinating electric system reliability in the western interconnection – the electrical grid that includes 14 western states.

CCA Costs

The savings associated with establishing a CCA program is determined by comparing the power generation costs of PG&E to that of a prospective CCA program. In contrast to PG&Es generation costs that are embedded in the single unbundled charge, the CCAs costs are composed of the five categories previously stated: power supply, grid management, utility operations, financing costs and revenue from market sales. Revenue from market sales of excess electricity can be considered a negative cost because profit from this category can be used to reduce the other costs of the CCA program. The cost estimating methods and high level assumptions for each category are summarized in this section.

Power supply costs. The CCA's energy requirements are provided completely from four broad types of generation resources. The resource categories include renewable energy ownership, renewable energy market purchases, spot market purchases and Power Purchase Agreements (PPAs). The section below presents the methods used to estimate the unit cost of generation for each resource followed by the long term resource mix utilized for the three RPS scenarios.

The renewable energy ownership category includes renewable generation facilities fully or partially owned and operated by the CCA. For the purpose of this analysis, the CCA owned facilities are assumed to be biomass and wind plants that have been sized to meet the aggregators RPS goals. Generation costs were estimated using the CEC's Comparative Costs of California Central Station Electricity Generation Report and the accompanying Cost of Generation (GOG) model. The report and COG model provides high, mid and low values for power plant characteristics and other variables impacting the fixed and variable costs. The average value, as opposed to the high or low case scenario, was used in this analysis to calculate renewable energy generation costs. Table 7 shows the capacity factor, capacity factor degradation, heat rate and heat rate degradation values that were used in the analysis. The fixed and variable expenses of the biomass and wind plant were calculated from the plant characteristics and the cost of fuel, operation and maintenance and insurance.

Table 7 Power plant technology assumptions and plant cost data for CCA generation facilities (CEC, 2010)

Power plant characteristic and cost data	Biomass combustion (stoker boiler)	Onshore wind (class 3/4)
Capacity factor (%)	85	35
Capacity degradation (%/year)	0.1	1
Heat rate (Btu/kWh)	11,000	NA
Heat rate degradation (%/year)	0.15	NA
Fixed O&M (2009 $/kW-yr)	160.10	13.70
Variable O&M (2009 $/MWh)	6.98	5.50
Integration cost[19] (2009 $/MWh)	0	25.00

The cost of renewable energy market purchases is based on a "generic renewable portfolio with a cost equal to the weighted average of the renewable resources expected to fulfill California's RPS" (Navigant, 2005 p. 53). Table 8 shows the generic renewable portfolio and levelized cost, in 2009 nominal dollars, used to determine the cost of renewable energy market purchases. The source of the renewable resource levelized cost

[19] Integration cost is a cost allocation mechanism intended to account for additional expenses (wind forecasting contractor) that intermittent weather-dependent resources may impose on the electric grid.

is the CEC Comparative Costs of California Central Station Electricity Generation Report. The 2009 costs were then escalated at an annual inflation rate of 1.5% to determine the cost in 2012, the first year of the CCA program.

Table 8 Weighted average cost of renewable energy market purchases (CEC, 2010)

Renewable Resource	RPS contribution	Levelized cost (2009$/MWh)
Onshore wind (class 3/4)	66%	77.75
Solar (parabolic trough)	1%	238.27
Hydro (small scale)	4%	95.54
Biomass combustion (stoker boiler)	4%	105.87
Geothermal (binary)	25%	93.52
Weighted average cost		85.13

The third type of resource utilized to meet the energy requirements of the CCA is spot market purchases. The spot market is a real-time commodity market for hour-ahead or day-ahead sale and delivery of energy and, therefore, often has higher price volatility than other energy resource types. This thesis relies on the Pilot Project Guidebook methodology to determine the price of these purchases. The average spot market price is calculated from the forecasted price of natural gas and market implied system heat rates. The market implied heat rate is a measurement for the collective efficiency of all California power plants in converting fuel to electricity. The California Independent System Operator (CAISO) average 2010 market system rate of about 8,780 BTU/kWh was used in the analysis. Wholesale on-peak power energy is then priced at a 15% premium and off-peak energy is priced at a 15% discount to the average price according to assumptions in the Pilot Project Guidebook (Stoner, et al., 2009).

The fourth type of resource is Power Purchase Agreements, which are long term fixed price contracts between an electricity generator and a buyer. The PPA is priced at a 5% premium to the expected on-peak and off-peak spot market price. The PPA length of term can vary, but for the purpose of this analysis the term lengths were assumed to be successive lengths of two, three and then five years, which is an assumption from the Pilot Project Guidebook. The Guidebook rationale for this assumption was that the length of terms would start out short and then increase as the CCA program becomes more established.

The CCA's power generation cost depends not only on the types of resource utilized and its unit cost of generation but also the extent of their utilization. The utilization amount of each resource in the CCA's supply portfolio is influenced by state clean energy requirements and the community's values related to cost certainty, environmental considerations, and cost effectiveness (Stoner, et al., 2009 p. 25). This thesis evaluates three supply portfolios with different amounts of renewable content to develop a range of potential costs.

All scenarios comply with Senate Bill X1 2, which requires all retail sellers of electricity to serve 33% of their load from renewable energy sources by 2020. Furthermore, all scenarios disregard Humboldt County's existing renewable generation facilities, such as the three biomass power plants, and utilize either renewable energy market purchases or new renewable generation facilities financed by the CCA to satisfy the RPS requirements. The rationale for excluding the existing biomass power plants as part of the CCA's RPS portfolio is: (1) two of the facilities already have long term contracts with IOUs, which are used by the utilities to help meet their state RPS requirements and (2) purchasing renewable energy from the power plants at market prices overlooks the financing advantage of CCAs. Therefore, this analysis assumes the CCA will invest in new biomass and onshore wind generation facilities to meet its long term RPS goals. Furthermore, this analysis assumes that both these technologies will remain eligible for California's RPS program.[20] The scenarios differ only in the RPS provided in 2031, either 33%, 50% or 75%, and the generating capacity of CCA owned facilities. The type of power plant and the date that the facility is brought on-line or begins to generate electricity is not changed between scenarios.

Supply scenario 1 assumes that the county CCA would begin operating in 2012 with a 22% RPS and annually increase the electricity generated from renewable sources at a constant rate until the program has a 33% RPS in 2020. The RPS is maintained at 33% between 2020 and 2031 since there are currently no state RPS requirements beyond 2020 (Figure 5).

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[20] There is ongoing national and state discussion about the conditions under which biomass is considered sustainable and carbon neutral, which could affect the RPS eligibility or GHG permit requirements of biomass generation facilities. This thesis assumes biomass will remain eligible for California's RPS program.

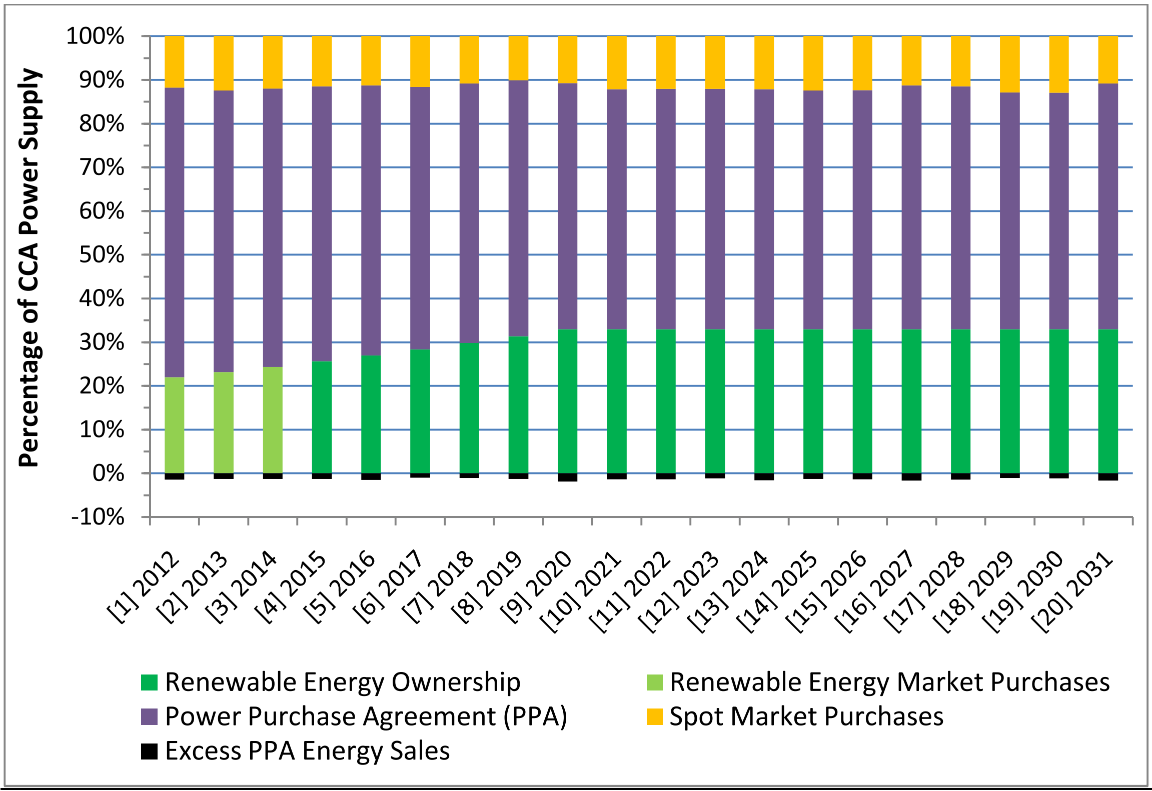

Figure 5 Supply scenario 1 assumes that the CCA has a 33% RPS by 2020. The RPS is maintained at 33% between 2020 and 2031. The renewable energy is provided initially with market purchases until year 4 when CCA owned renewable generation facilities are brought on-line.

In scenario 1 the CCA would initially rely on renewable energy market purchases until its own generation facilities could be constructed. The analysis assumed that 50 MW of biomass capacity would be brought on-line in 2015, three years after beginning the CCA, which allows for time to design and construct the power plant. This analysis also assumes that an additional 15 MW of onshore wind capacity would be brought on-line in 2017. The generation facilities are sized to provide 33% of the CCA's 2031 electricity sales from renewable sources. The renewable energy surplus in years prior to 2031 is sold at prices described in the Revenue from Market Sales thesis section.

Supply scenario 2 assumes that the county CCA would voluntarily provide 50% of the electricity from renewable sources by 2031 (Figure 6). Similar to scenario 1, the CCA would begin operations in 2012 with an RPS of 22%, which is initially achieved through renewable energy market purchases. The electricity generated from renewable sources is increased annually to comply with the 33% RPS requirement in 2020 and the 50% RPS target in 2031. The compound RPS growth rate from 2020 to 2031 is approximately 3.9%. As the quantity of clean electricity increases the amount purchased through a PPA is decreased. The spot market purchases are kept below 15% and the excess PPA energy below 2.5% as recommended by the Pilot Project Guidelines. Supply scenario 2 assumes that 75 MW of biomass capacity and 30 MW of wind capacity would be brought on-line in 2015 and 2017, respectively.

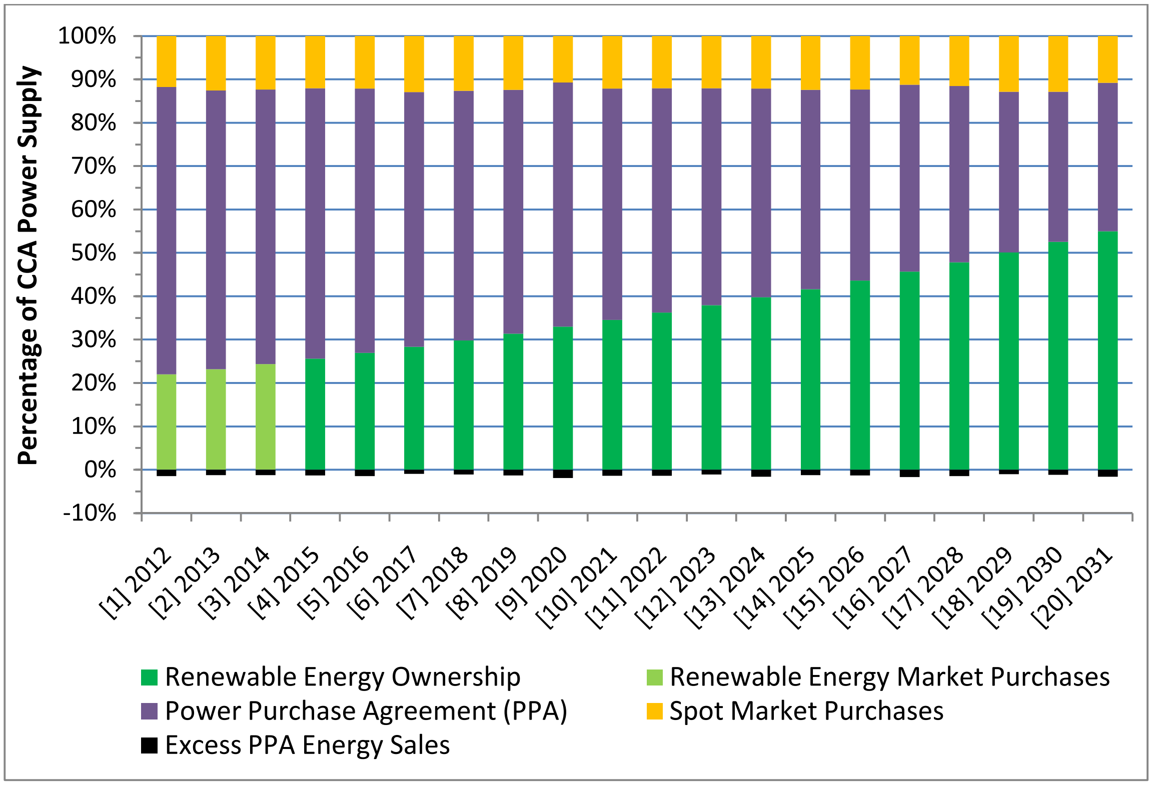

Figure 6 Supply scenario 2 assumes that the CCA has an RPS of 50% by 2031. The renewable content is met initially with renewable market purchases until year 4 when the CCA builds a 75 MW biomass generation facility. An additional 30 MW of wind capacity is brought on-line in 2017.

Supply scenario 3 assumes that the CCA supplies 33% of its electricity from renewable sources by 2020, complying with the intermediate RPS requirement, and achieves a 75% RPS target by 2031 (Figure 7). The compound RPS growth rate from 2020 to 2031 is approximately 7.7%. Like the previous two scenarios, the CCA relies on renewable energy market purchases until its own generation facilities are constructed. Scenario 3 keeps the same timetable for bringing the generation facilities on-line but increases the capacity of the power plants to a 100 MW biomass facility and a 70 MW wind farm.

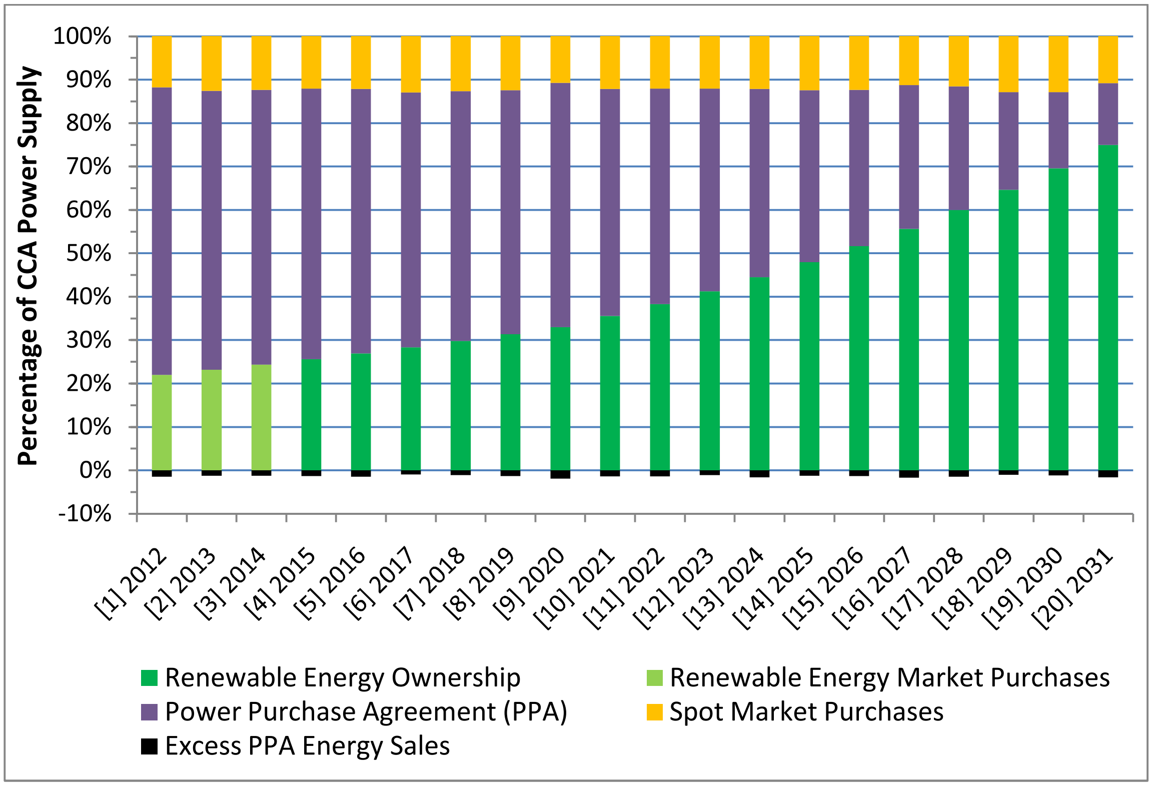

Figure 7 Supply scenario 3 assumes that the CCA has an RPS of 75% by 2031. The renewable content is met initially with renewable market purchases until year 4 when the CCA builds a 100 MW biomass generation facility. An additional 70 MW of wind capacity is brought on-line in 2017.

The power supply cost category also includes the Cost Responsibility Surcharge, the mechanism to recover utility cost obligations from CCA customers and prevent cost shifting. The CRS includes the DWR bond charge, Energy Cost Recovery charge, Competitive Transition Charge, and the Power Charge Indifference Adjustment (PCIA). All of these charges, except the PCIA, are imbedded in electric rates paid by bundled utility customers. Therefore, this cost comparison analysis only needs to include the incremental PCIA cost. The methodology for determining the PCIA is described in CPUC Decision 07-01-025 as follows: "first, the Competition Transition Charge (CTC) is calculated according to Sections 367(A) and is reviewed and approved in each utility's annual Energy Resource Recovery Account (ERRA) proceeding. The "indifference rate" is then calculated by estimating the difference between the average cost of the utility's total portfolio compared to a market price benchmark. The deduction of the CTC from the indifference rate leaves as a residual the Power Charge Indifference Adjustment (PCIA)." PG&E tariffs list the PCIA charge for each rate class. This analysis used the 2010 PCIA charge but the rate would be revised according to PG&E's above-market commitments that are in effect at the time the CCA is implemented.

Electric Grid Management. The CCA will be required to comply with the California Independent System Operator (CAISO) electrical grid management rules. To ensure the reliable operation of the electrical grid the CCA will need to maintain operating reserves at 6% to 8% of the load and regulating reserves at 2.5% to 5% of the load. Operating reserves include spinning[21] and non-spinning[22]. Regulating reserves

[21] Spinning reserves is the "portion of unloaded synchronized generating capacity that is immediately responsive to system frequency and that is capable of being loaded in ten minutes, and that is capable of running for at least two hours" (CAISO, 2011 p. 101).

[22] Non-spinning reserves is the "portion of generating capacity that is capable of being synchronized and ramping to a specified load in ten minutes (or load that is capable of being interrupted in ten minutes) and that is capable of running (or being interrupted)" (CAISO, 2011 p. 71).

include regulation-up[23] and regulation-down[24] and are used to control the power output of electric generators within a prescribed area in response to a change in system frequency. The forecasted price of the reserves is based on its 2010 historical relationship to market prices, which was determined through analysis of CAISO data (Table 9). The grid management cost-category also includes a CAISO transmission charge of about $5.13/MWh (CAISO, 2010).

Table 9 Percentage of CCA load needed to maintain ancillary reserves and the reserves 2010 cost relationship to market prices

Ancillary Reserve	Reserve percentage of CCA load (%)	2010 percentage of market price (%)
Spinning reserve	3.5	0.53
Non-spinning reserve	2.5	0.07
Replacement reserve	1.25	0.49
Regulation-up	2.25	0.76
Regulation-down	2.25	0.67

Utility operations. The utility operations cost category includes customer service, metering and billing and administrative costs for managing the CCA program. Customer service activities include notifying customers of the CCA program, enrolling new customers into the CCA program and processing opt-out requests. These services are performed by PG&E and billed to the CCA program at fees specified in PG&E Electric

[23] Regulation-up is “regulation provided by a resource that can increase its actual operating level in response to a direct electronic signal line from the CAISO to maintain standard frequency in accordance with established Reliability Criteria” (CAISO, 2011 p. 86).
[24] Regulation-down is “regulation reserve provided by a resource that can decrease its actual operating level in response to a direct electronic signal line from the CAISO to maintain standard frequency in accordance with established Reliability Criteria” (CAISO, 2011 p. 86).

Schedule E-CCA: Services to Community Choice Aggregators. Electric Schedule E-CCA also specifies metering and billing costs applicable to CCA customers. The annual cost is determined by multiplying PG&Es unit cost by the unit (account, opt-out request, meter, etc).

Administrative costs include paying staff, hiring consultants, renting office space and purchasing office equipment needed to operate the CCA program. These costs were estimated by deriving a staffing, infrastructure and consultant unit cost from the Marin County Business Plan. The unit costs derived from the Business Plan are \$2.53/MWh for staffing, \$0.13/MWh for infrastructure and \$2.13/MWh for consultant expenses (MEA, 2008). The unit cost was then multiplied by the Humboldt County CCA load. The CCA could develop an organization that manages the CCA program using in-house staff and resources or contract out these activities to third parties. These tasks include electricity procurement, risk and credit management, load forecasting, developing rates, account services and administration.

<u>Financing costs.</u> The analysis in this thesis assumes that the aggregator will invest in renewable biomass and onshore wind generation facilities at the schedule, capital cost and capacity indicated in Table 10. The generation resources are sized to meet the counties renewable energy target. The analysis assumes that the earliest year generation facilities could be brought on-line is 2015. This allows for lead time to design, permit and build the facilities. The capital cost, expressed in 2009 dollars, is from the average plant cost data from the CEC Comparative Costs of California Central Station Electricity Generation Technologies report. “The average cost is based on a set of typical

assumptions that are considered to be the most common values for the respective technologies" (CEC, 2010). Biomass and wind facilities were selected because the technology is mature and the resources are locally available (Zoellick, 2005). Although Humboldt County has abundant ocean-wave energy potential, the CEC cost study estimated that this technology would not be viable in California until about 2018.[25] The CCA could either exclusively own the biomass and wind facility or partner with another public developer and control a portion of the energy.

Table 10 Capital cost of CCA generation facilities for the 33%, 50% and 75% renewable energy supply portfolios

Resource Type	On-line	Unit Cost ($/kW)	33% Renewable		50% Renewable		75% Renewable	
			Capacity (MW)	Capital Cost (Mil $)	Capacity (MW)	Capital Cost (Mil $)	Capacity (MW)	Capital Cost (Mil $)
Biomass	2015	$2,658	50	$133	75	$199	100	$266
Wind	2017	$1,990	15	$30	30	$60	70	$139

This thesis assumes that financing for the capital costs of the facilities would occur by issuing bonds.[26] The bonds are amortized over a 30-year period and financed at a rate of 5.5%. The interest and principal are included in the annual costs of the CCA program. Included in the annual costs are a bond insurance cost of 1.6% and a bond

[25] For a publicly owned utility company the estimated average levelized cost of ocean-wave energy in 2018 is about $189/MWh compared to onshore wind (class 3/4) and biomass combustion (stoker boiler) at $91/MWh and $133/MWh, respectively (CEC, 2010).

[26] There are various financing options available to CCAs. For an overview and comparison of alternative financing methods see the Community Choice Aggregation Guidebook.

transaction cost of 1% of the capital cost, which are assumptions made both in the County of Marin Feasibility study and in this thesis.

The Marin County Feasibility study also included "working capital" expenses in the financing cost category, which is not accounted for in this thesis because the method to calculate the amount was not described. Working capital is the amount of money that the CCA needs to support its business operations while waiting for PG&E to remit payment to the CCA. The Marin County Feasibility study derived the amount of working capital from a 47 day time lag, which is based on PG&Es standard meter reading cycle of 30 days and its payment/collections cycle of 17 days. Recall that PG&E is responsible for reading the electric meters, mailing the bill and collecting both the CCA and PG&E portion of the bill. After collecting the entire payment, PG&E pays the CCA its portion. The working capital in the Marin study increased from about $340,000 in the first year to about $760,000 in year 20. The discussion section describes the extent to which the exclusion of working capital affects the results.

<u>Revenue from market sales.</u> The CCA has the ability to generate revenue from excess energy sales, excess ancillary services sales and renewable energy incentives. The profit can be used to reduce the CCAs cost and lower customer electric utility bills. In this thesis both the potential revenue from ancillary services and the renewable energy incentives are excluded. Renewable energy incentives are excluded due to the uncertainty of future state and federal energy policies. The analysis assumes that excess non-renewable energy under CCA contract control (shown in Figure 4) is sold at market

prices. In addition, renewable energy in excess of the CCAs target RPS is sold at the Market Price Referent (MPR).

According to the RPS program, utility companies must annually increase the amount of electricity generated from eligible renewable energy sources. Regulated utility companies must get approval from the CPUC before finalizing RPS contracts. The MPR, which represents the levelized cost of a long-term combined cycle gas turbine facility, is used as a benchmark to assess the above-market costs of RPS contracts. Bid prices at or below the MPR are typically accepted as reasonable by the CPUC while “bid prices above the MPR may face a stronger burden of proof in justifying the reasonableness of their contract price” (CPUC, 2011b). This thesis assumes that there will be a market for renewable energy in the future and the CCA will be able to sell excess energy at the MPR. The 2009 MPR[27] values are shown in Table 11. The price received for renewable energy depends upon the year and the contract length of term.

[27] The MPR is revised when a utility company requests bids in order to meet its RPS obligations. The updated MPR is calculated using a 12 day average of natural gas prices leading up to the closing of the bid solicitation. The next update of the MPR will likely be in the first quarter of 2011 (CPUC, 2011b).

Table 11 2009 Market Price Referents (nominal – dollars/kWh)

	Contract Length of Term			
Contract Start Date	10-Year	15-Year	20-Year	25-Year
2010	0.08448	0.09066	0.09674	0.10020
2011	0.08843	0.09465	0.10098	0.10442
2012	0.09208	0.09852	0.10507	0.10852
2013	0.09543	0.10223	0.10898	0.11245
2014	0.09872	0.10593	0.11286	0.11636
2015	0.10168	0.10944	0.11647	0.12002
2016	0.10488	0.11313	0.12020	0.12378
2017	0.10834	0.11695	0.12404	0.12766
2018	0.11204	0.12090	0.12800	0.13165
2019	0.11598	0.12499	0.13209	0.13575
2020	0.12018	0.12922	0.13630	0.13994
2021	0.12465	0.13359	0.14064	0.14424

As the MPR is meant to reflect the presumptive cost of electricity, sellers of renewable energy that agree to longer contract lengths receive a higher price because they are absorbing the electricity buyers price risk of potential spikes in the price of fuel. This analysis assumes that the CCA could negotiate a 15-year contract and sell excess renewable energy at the annual price shown in the above table. The 15-year contract length was chosen for two reasons. The first reason is that it is neither the high nor low MPR value and, therefore, does not significantly sway the financial results in either direction. For instance, selecting a contract length of 25 years would have increased the profit from renewable energy sales and, thus, the potential savings from establishing a CCA. On the other hand, selecting a contract length of 10 years would decrease the profit from renewable energy sales. The second reason for selecting the 15 year term length is that the financial assessment duration of this thesis is 20 years with the first generation facility being brought on-line in year four. The MPR is not increased after 2021 and, therefore, remains at 0.13359 $/kWh until 2031.

Community Support

The feasibility of establishing a CCA program in Humboldt County depends not only on the financial results, but also the support of the community. Without community backing, the county is unlikely to spend money and/or time investigating CCA and commissioning feasibility studies. Even after evaluating a prospective CCA, the benefits must outweigh the risks for the community to establish a CCA program, and each community perceives the benefits and risks differently. For example, although the CEC Pilot Project estimated savings for all 12 communities participating in the CCA feasibility study, only Marin County has established a CCA program. For Marin, the opportunity to potentially lower electricity rates, reduce GHG emissions and obtain control of energy resources more than offset the start-up expenses and risks of CCA.

For that reason this thesis also examines the degree of support that a CCA might have in Humboldt County to assess its overall feasibility. Although it would have been desirable to conduct a survey to determine the public's views regarding greenhouse gases, local control and the willingness to accept risk in order to receive the benefits of CCA there was insufficient time to complete both the financial assessment and survey within the thesis deadline. Therefore, another method was used to gauge public support. A survey of the community is one of the recommendations for further development suggested in the final chapter of this thesis.

The chosen method used to gauge public support evaluates participation in environmental programs and voting results on propositions affecting opportunities made available with CCA programs. The data collected on these subjects are used as proxies to provide an initial assessment on whether the benefits of a prospective CCA program are important to the community. The subjects that are investigated include resident participation in PG&Es ClimateSmart program and voting results on Proposition 23 and Proposition 16. Table 12 lists the subject matter, data actually measured and its proxy. The sections below provide more detail on each subject to justify and support its use as the proposed proxy.

Table 12 Program or ballot measure evaluated to gauge the level of public support for establishing a CCA program in Humboldt County

Program or ballot measure	Measures	Proxy to evaluate
ClimateSmart Program	Participation in voluntary program to reduce GHG emissions	Community willingness to pay for reducing GHG emissions
Proposition 23	Voting results for initiative to suspend Global Warming Act of 2006	Community interest in reducing GHG emissions
Proposition 16	Voting results for initiative impacting a community's ability to create CCAs	Community interest in local control of energy

Data were collected on each subject and then quantitatively evaluated and statistically analyzed to gauge the level of support in Humboldt County. The voting results of Humboldt are compared to that of Marin, the only county in California with a CCA program, to determine if the community values, represented by voting preferences, are statistically identical. Figure 8 shows the location of Humboldt and Marin County. The statistical test used is a chi-square test for homogeneity to determine if the proportion of votes is distributed identically across the two different populations. Thus, the null hypothesis is that each population has the same proportion of votes.

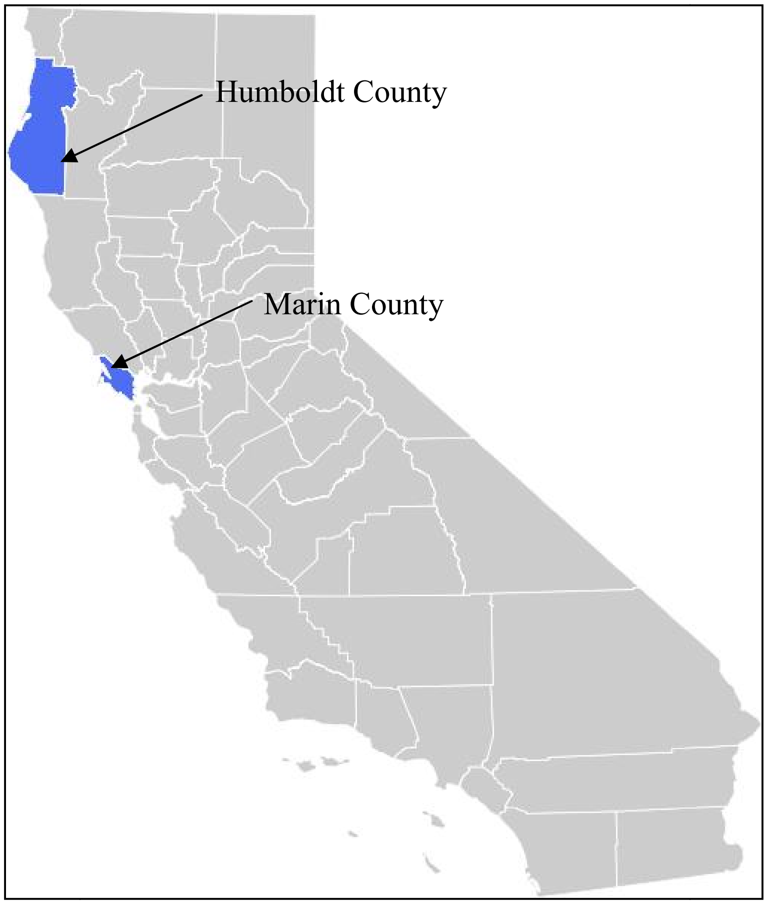

Figure 8 Map of California State showing the location of Humboldt and Marin County

Note that as more Californian counties or cities adopt CCA, eventually these or other proxies (i.e. income, political party or capacity of home solar photovoltaic systems) could be used to develop a regression based prediction model. The Discussion chapter describes several limits with the chosen method of analysis including the assumption that the preference of voters is a representative sample of the county's population.

ClimateSmart Program

ClimateSmart is a voluntary program offered by PG&E that enables customers to offset emissions from electricity generation and natural gas usage by investing in environmental preservation and restoration projects that reduce or absorb greenhouse gases. The program is currently in its fourth year of operation. In 2009 the program had more than 30,000 customers that "balanced out 450,000 metric tons of greenhouse gas (GHG) emissions" (PG&E, 2010a). The emission reductions come from projects such as forest conservation and methane capture from dairy farms and landfills. The reductions, according to PG&E, will be "independently verified and retired according to the rigorous standards of the Climate Action Registry's carbon offset protocols" (PG&E, 2010a).

Customers that participate in the program pay a monthly premium of $0.00254 per kWh of electricity and $0.06528 per thermal unit ("therm") of natural gas (PG&E, 2010a). The more energy a ClimateSmart customer uses, the higher the contributions are to the program and the more GHG emission offsets are purchased. The money goes to the ClimateSmart Charity, a nonprofit organization that is separate from PG&E, and therefore, the contribution is tax deductible (PG&E, 2010a).

This thesis proposes that a community's participation in the ClimateSmart program is an indication of its willingness to pay higher electricity rates and accept more risk to reduce GHG emissions.

Proposition 23

Proposition 23 was an initiative on the November 2010 ballot that would have suspended the implementation of Assembly Bill 32 (AB 32) until California's unemployment rate drops to 5.5% or below for four consecutive quarters (California Attorney General, 2010b). AB 32, called the Global Warming Act of 2006, requires that GHG emission levels in the state be cut to 1990 levels by 2020.

The California Air Resources Board (ARB) was tasked with adopting rules and regulations to achieve the AB 32 greenhouse gas reduction target. The ARB plan includes regulatory measures such as energy efficiency standards for buildings, a "cap-and-trade" program and increasing renewable energy. If proposition 23 was approved it would have suspended AB 32 and the "ARB regulation that is intended to require privately and publicly owned utilities and others who sell electricity to obtain at least 33 percent of their supply from 'renewable' sources, such as solar or wind power, by 2020" (California Attorney General, 2010b p. 41).

This thesis proposes that the voting results for an initiative that would have suspended AB 32 are an indication of the percentage of people in a region that either endorse or oppose actions to mitigate climate change. As one of the advantages of creating a CCA program is the ability to utilize cleaner energy and reduce greenhouse gas emissions, a region that strongly opposed Proposition 23 might endorse CCA.

Proposition 16

Proposition 16 was a proposed constitutional amendment on the June 8, 2010 ballot in California. The stated purpose of Proposition 16 was “to guarantee to ratepayers and taxpayers the right to vote any time a local government seeks to use public funds, public debt, bonds or liability, or taxes or other financing to start or expand electric delivery service to a new territory or new customers, or to implement a plan to become an aggregate electricity provider” (California Attorney General, 2010a).

As the initiative would have required support from two-thirds of the voters in a local election before the local government could enter the retail power business, it would have made it more difficult to form municipal utilities or CCAs (Weissman, 2010). Currently, to establish a publicly owned utility company the local government must hold an election and obtain majority voter approval. To establish a CCA, voter approval is not required. The current law only requires public hearings and approval by the affected local governments. The requirements are different for municipal utilities and CCAs because a municipal utility takes over service to all customers in a given geographical area while no customer would be forced to buy power from a community aggregator (Weissman, 2010). The CCA is the default electricity service provider but customers are allowed to opt-out and continue receiving electricity from the IOU.

The voting results for Proposition 16 are used in the thesis as a proxy to gauge the community’s interest in local control and preserving the opportunity for the local government to become an electricity provider.

RESULTS

The section summarizes the financial analysis results and the findings from the assessment of community support for a CCA program in Humboldt County. Both of these components are considered crucial to the overall feasibility of establishing a CCA program in Humboldt County.

Financial Assessment

Only the findings from the financial analysis are presented below. The intermediary results from the electrical load analysis are provided in the appendices. Appendix B includes the forecasted quantity of CCA electricity sales by sector for the next 20 years. Appendix C provides the community composite load plots for 2012 and the results of the load analysis for the 20 year project duration. Appendix D is the forecast of the CCA's quantity of accounts.

The financial assessment determined the CCAs costs for three RPSs (33%, 50% and 75%) and PG&Es generation costs for three rate escalation forecasts (2%, 3% and 4%). The total nominal cost of these nine scenarios over the 20 year project duration is shown in Table 13 below. PG&Es revenue requirement for 20 years ranged from a nominal $1,656 million at 2% escalation rate to $2,084 million at 4% escalation rate. The CCAs cost decreased from $1,876 million at a 33% RPS to $1,415 million at a 75% RPS. In other words, increasing the renewable content provided by the CCA significantly decreases the program costs. The reason for this, as explained in more detail in the Discussion chapter, is that the analysis assumes the CCA builds renewable generation facilities (in year four and six) that have enough capacity to meet the RPS target in year 20 and all the excess renewable energy is sold. As there is limited ability to transmit power from within Humboldt County to the rest of California, it may not be possible to build local generation facilities and sell 100% of the excess renewable energy. There is limited ability to transmit power from within Humboldt County because of the transmission capacity (≤70MW) and the transmission system in the end of the line near Redding, CA is congested (Zoellick, 2005). The Discussion chapter evaluates impacts resulting from the inability to sell all the excess renewable energy at the MPR.

The financial assessment also determined a variety of financial metrics associated with the scenarios. The financial metrics include the undiscounted total savings for CCA electric customers (Table 13, yellow cells), the discounted or net present value (NPV) of savings (red cells) and the average annual bill difference for CCA customers (blue cells). Positive numbers indicate lower costs for the CCA and, thus, lower electric bills for CCA customers. The net present value (NPV) of savings is determined by discounting the annual savings at a rate of 3.0%. The NPV of savings ranges from a low of about -$69 million for the 2% generation charge escalation rate and the 33% RPS scenario to a high of $154 million for the 4% generation charge escalation and the 75% RPS scenario, which corresponds to about an average consumer electric bill increase of 7% to a decrease of 18%, respectively.

The summary of financial analysis results in Table 13 reveals the effects and importance of the generation charge escalation rate. Not surprisingly, in general there is a direct relationship between the PG&E price escalation rate and the relative savings from a CCA. For example, the 75% RPS scenario indicates CCA savings of $46 million at an annual 2% growth rate on PG&E generation charges. The NPV of savings increases to $97 million at a 3% escalation rate and to $154 million at the 4% PG&E escalation rate.

Table 13 Summary of financial analysis results (in millions of dollars)

					CCA		
					Voluntary RPS (%)		
					33	50	75
					Cost (Mil $)		
					1,876	1,668	1,415
PG&E	Escalation Rate on Generation Charge (%/yr)	4	Cost (Mil $)	2,084	207	416	668
					39	91	154
					4%	11%	18%
		3		1,856	-21	188	440
					-18	34	97
					-1%	6%	14%
		2		1,656	-211	-12	240
					-69	-17	46
					-7%	0%	9%

A more detailed breakdown of the total cost savings for one of the above alternatives is shown in Table 14. The itemization of costs shown below is based on a 3% rate escalation for PG&E and CCA supply scenario two, which ramps up to the 50% RPS by 2031. The results indicate a net monetary loss in the first three years of operation. In 2015 or year 4 the revenue of the CCA increases significantly, which is attributable to the revenue from energy sales. In year four, the analysis assumes that the

CCA brings on-line a 75 MW biomass facility that is capable of annually generating about 560,000 MWh of energy. Based on the 26% RPS goal for that same year, the CCA only needs about 222,000 MWh of renewable energy. The CCA could sell the excess renewable energy at the MPR for about $31.4 million. The revenue is used to lower the program costs of the CCA and, in turn, the electric bills of its customers. The results also indicate a net monetary loss in the last year of the analysis when the CCA is using all of the renewable energy to reach its 75% voluntary RPS target and not selling the excess energy at the MPR. To help explain why IOUs are not building renewable generation facilities if it is this profitable recall from the mechanics of CCA section of this thesis that Community Choice Aggregation programs have a financial advantage over other developers because they qualify for tax exempt financing and do not have to pay taxes or shareholder dividends. Appendix E includes the complete financial model and list of assumptions used to generate these findings.

Table 14 Itemization of total savings (in millions of nominal dollars) for the 50% voluntary RPS alternative with a PG&E rate escalation of 3%

Year	PG&E costs [A]	CCA costs [B = 1 through 5]	Power supply [1]	Grid management [2]	Utility operations [3]	Financing [4]	Revenue [5]	Savings [A-B]	% of total bill
2012	60.9	74.2	63.4	5.8	4.9	0.6	-0.5	-13.2	-12%
2013	63.5	73.4	62.7	6.0	4.5	0.6	-0.5	-9.8	-9%
2014	66.2	74.5	63.5	6.3	4.7	0.6	-0.5	-8.4	-7%
2015	69.0	51.7	55.8	6.5	4.8	16.0	-31.4	17.3	14%
2016	71.9	53.0	56.1	6.8	4.9	16.0	-30.8	18.9	15%
2017	74.9	54.4	61.4	7.0	5.1	20.5	-39.6	20.5	15%
2018	78.0	56.5	62.3	7.3	5.2	20.5	-38.7	21.5	15%
2019	81.3	59.2	63.5	7.6	5.3	20.5	-37.7	22.1	15%
2020	84.8	62.6	65.3	7.9	5.5	20.5	-36.6	22.1	15%
2021	88.3	65.0	65.8	8.2	5.6	20.5	-35.2	23.4	15%
2022	92.1	77.2	75.7	8.5	5.8	19.9	-32.7	14.9	9%
2023	95.9	81.4	76.6	8.8	6.0	19.9	-29.9	14.6	9%
2024	100.0	86.6	79.0	9.1	6.1	19.9	-27.5	13.4	7%
2025	104.2	91.3	80.1	9.5	6.3	19.9	-24.5	12.9	7%
2026	108.6	96.7	82.0	9.8	6.5	19.9	-21.5	11.9	7%
2027	113.2	109.6	91.5	10.1	6.6	19.9	-18.7	3.6	6%
2028	118.0	115.9	93.8	10.6	6.8	19.9	-15.2	2.1	2%
2029	123.0	121.4	94.9	11.0	7.0	19.9	-11.4	1.6	1%
2030	128.2	127.9	97.3	11.4	7.2	19.9	-7.9	0.2	0%
2031	133.6	135.5	100.8	11.9	7.4	19.9	-4.5	-1.9	-1%
Total	1855.5	1667.8	1491.4	170.0	116.3	335.4	-445.4	187.8	6%

The analysis shows that it is possible to reduce electric rates, increase utilization of renewable energy and enhance local control. Furthermore, by increasing local control of CCA owned renewable generation facilities the program could strike a balance between savings for its customers and its own RPS. The counterintuitive finding that CCA savings increases with greater procurement of renewable energy is discussed in more detail later in the thesis.

Community Support

The qualitative and statistical findings from assessing the degree of public support for a Community Choice Aggregation program are described in this section. The level of support is based on the participation rate in the ClimateSmart program and the voting results for Proposition 23 and 16.

In general, the findings from analysis of community support indicate that the proportion of votes between Humboldt and Marin residents differed statistically. However, qualitative assessment reveals that residents of Humboldt County have a strong interest in mitigating GHG emissions and locally managing resources. Based on the voting results from Proposition 23 and 16 it appears that mitigating GHG emissions may be less important to Humboldt residents than Marin residents but, the ability to locally control resources appears to be more important.

While the findings are not a substitute for evaluating support via focus groups, public forums and surveys, they do provide a preliminary indication that a CCA program may possibly receive enough public support. The sections below provide more detailed results for the ClimateSmart program and the voting results for Proposition 23 and 16.

ClimateSmart Program

ClimateSmart is the voluntary PG&E program that allows customers to offset GHG emissions by paying an additional fee that goes towards environmental restoration or preservation projects. The participation rate of customers in the county provides an indication of the regions support for climate change mitigation and willingness to pay for emission reductions. Counties with a large percentage of electric customers participating in the ClimateSmart program may be more willing to participate in CCA programs.

In 2009 the ClimateSmart program had 29,273 residential customers and 772 commercial/industrial customers for a total of 30,045 (PG&E, 2010a). The top 15 counties with the largest percentage of ClimateSmart customer accounts are shown in Table 15. In Humboldt County, 284 of PG&Es electric customers, or approximately 0.22% of its population, participated in the ClimateSmart program. With 1,284 participating electric customers, or about 0.51% of its population, Marin County had the largest percentage of all the counties in PG&Es service territory. Humboldt had the eleventh highest participation rate. Therefore, assuming equal marketing efforts in both counties, the results indicate that Humboldt residents are either less concerned about GHG emissions or less willing to pay for mitigating these emissions.

Table 15 Top 15 counties in California with the highest percentage of ClimateSmart customer accounts through December 31, 2009.

County	Rank	ClimateSmart Participation (% of population)
Marin	1	0.51
Alpine	2	0.48
San Francisco	3	0.40
Alameda	4	0.32
Sonoma	5	0.30
San Mateo	6	0.28
Mendocino	7	0.27
Santa Cruz	8	0.26
Contra Costa	9	0.25
Lake	10	0.23
Humboldt	11	0.22
Yolo	12	0.21
Santa Clara	13	0.21
Napa	14	0.20
Nevada	15	0.18

Proposition 23

Statewide 61.6% of the voters rejected Proposition 23, which would have suspended the implementation of GHG emission reductions specified under AB 32 until California's unemployment rate dropped to 5.5% or below for four consecutive quarters. Regional voting results on Proposition 23, which are used in this thesis as an indication of a community's position on climate change mitigation, ranged from voter opposition levels of 82.3% in San Francisco County to 37.3% in Lassen County (Figure 9).

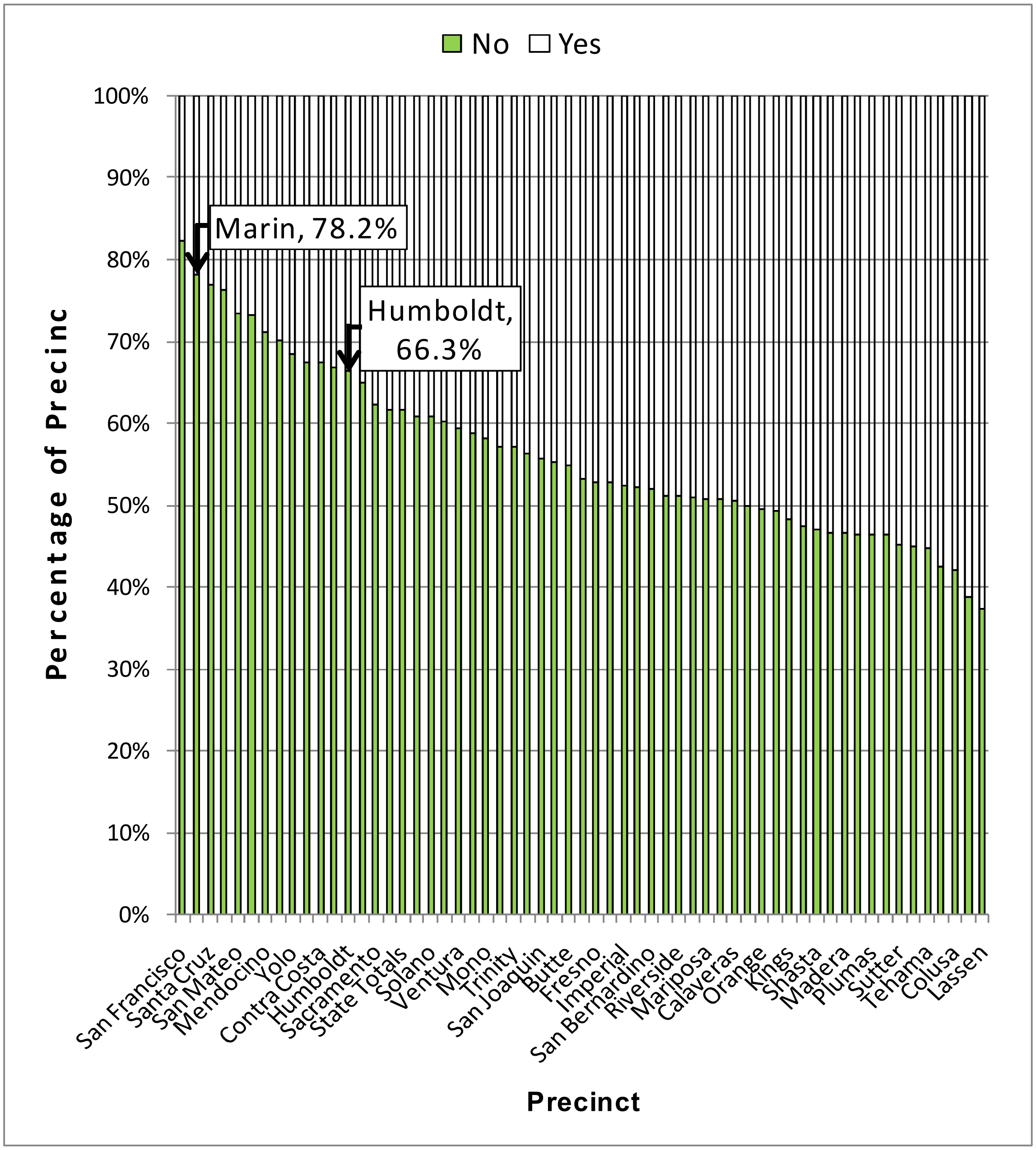

Figure 9 County voting results on Proposition 23, which would have suspended the GHG reductions required by AB 32. Statewide 61.6% of the voters opposed the ballot measure. In Humboldt County 66.3% of the voters opposed Proposition 23, which results in the 13th highest county opposition level.

In Humboldt County 66.3% of the voters opposed Proposition 23 (California Secretary of State, 2010b). This opposition level resulted in Humboldt County having a rank of 13 out of 58 Californian counties. Marin County, which started the first CCA program in California, ranked slightly behind San Francisco with the second highest percentage of voters opposing Proposition 23 (78.2%). Therefore, mitigation of GHG emissions may be more important to Marin residents than it is to the residents of Humboldt County.

The chi-square test for homogeneity was used to determine if Humboldt's voting results differed significantly from Marin's (Table 16). The outcome of the test is a P-value of 0.000 (to three decimal places). Therefore, the null hypothesis that the proportion of votes between the two populations is distributed equally is rejected. Humboldt's voting preferences on Proposition 23 differed significantly from Marin's voting preferences.

Table 16 Humboldt and Marin County's voting results and precinct rank on Proposition 23

Precinct	Rank	Yes		No	
		Votes	Percent	Votes	Percent
Marin	2	23,748	21.8%	85,119	78.2%
Humboldt	13	16,413	33.7%	32,161	66.3%
State Totals		3,733,948	38.4%	5,974,769	61.6%

Proposition 16

Proposition 16, the June 2010 initiative, would have required the support from two-thirds of the voters in an election before the local government could enter the retail power business. The ballot measure would have made it more difficult for local governments to create or expand municipal utility companies or CCA's.

Figure 10 shows the Proposition 16 voting results for each of the 58 precincts in the state. Statewide 52.8% of the voters rejected Proposition 16 (California Secretary of State, 2010a). Regional results on Proposition 16 ranged from voter opposition levels of 70.5% in Santa Cruz County to 39.7% in Riverside County. In Humboldt County 64.7% of the voters opposed the Proposition. In other words, 35.3% of Humboldt County voters were in favor of a measure that would have made it more difficult for local governments to implement CCA programs (California Secretary of State, 2010a). Humboldt County and Marin County had the 8th and 9th highest opposition level in the state, respectively. The strong opposition in Humboldt County to Proposition 16 indicates that a CCA may receive local support.

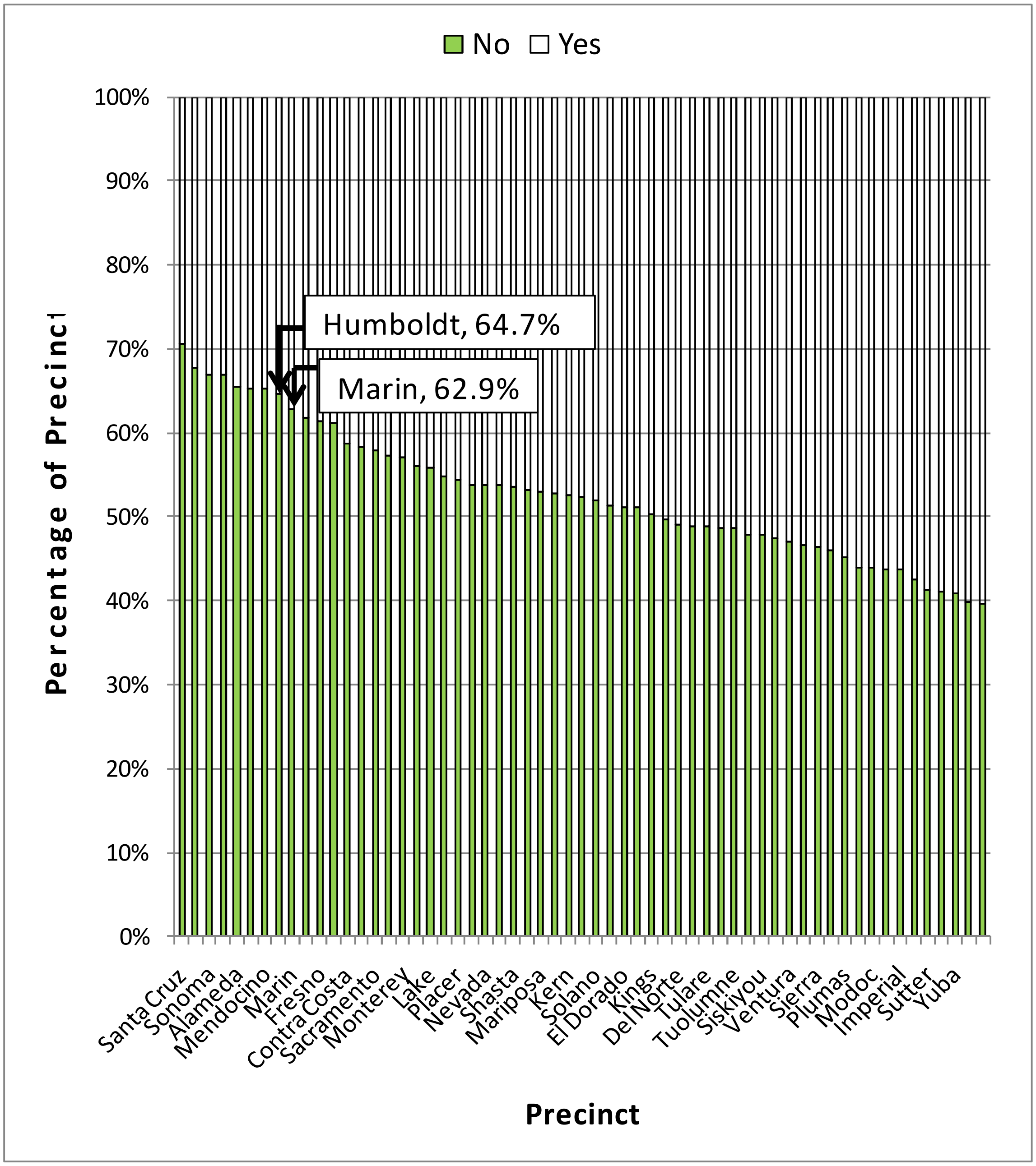

Figure 10 County voting results on Proposition 16, which would have made it harder for local governments to enter the retail power business. Statewide 52.8% of the voters opposed the ballot measure. In Humboldt County 64.7% of the voters opposed the Proposition, which results in the 8th highest opposition level in the state.

Analysis of Humboldt and Marin's voting results for Proposition 16 (Table 17) results in a P-value of 0.000 (to 3 decimal places) for the chi-square test for homogeneity. The test provides evidence that Humboldt's voting results differed significantly from Marin's despite being ranked 8th and 9th, respectively.[28]

Table 17 Humboldt and Marin County's voting results and precinct rank for Proposition 16

Precinct	Rank	Yes		No	
		Votes	Percent	Votes	Percent
Humboldt	8	11,672	35.3%	21,311	64.7%
Marin	9	27,224	37.1%	46,008	62.9%
State Totals		2,526,544	47.2%	2,820,135	52.8%

[28] If 383 Humboldt County voters had cast a "yes" vote instead of a "no"' vote, the proportion of voters between the two populations (Humboldt and Marin County) would have been distributed equally according to the chi-square test with an alpha level of 0.05. With only one degree of freedom with the chosen statistical test, the percentages of votes in the two communities needs to be very close to be considered statistically homogenous.

DISCUSSION

The purpose of this thesis was to investigate the overall feasibility of implementing a Community Choice Aggregation program in Humboldt County by examining its financial viability and likely level of public support. The financial analysis provides evidence that the community could save money by establishing a CCA. The findings from the assessment of community support are less conclusive. The statistical analysis reveals that the Proposition 23 and Proposition 16 voting preferences between Humboldt and Marin County differed statistically. Nevertheless, Humboldt County voters have a strong interest in reducing GHG emissions and an even stronger interest than Marin voters in local control. However, the chosen methods of analysis for both the financial and political components make a number of assumptions that could affect the results. The Discussion chapter describes some of these uncertainties and limitations with the chosen method of analysis and then concludes with a description of alternative strategies, policies and financing mechanisms that the community could potentially use to obtain similar benefits to that of CCA programs.

Limitations and Sources of Error

Both the financial analysis and the analysis of community support make a number of educated guesses about variables that could impact results. Some of the assumptions for the financial assessment and analysis for the assessment of community support are discussed in more detail below.

Financial Assessment

The financial assessment assumptions include electric demand growth rates, forecasts about future gas prices, opt-out rates, type of renewable resources constructed by the CCA and future market prices of renewable energy. The financial spreadsheet model created by this thesis can be updated as assumptions change to calculate revised savings with creation of a CCA. However, there will always be assumptions and risks when managing energy procurement and forecasting financial results. As the CCA Pilot study described the financial impacts of numerous assumptions, this chapter focuses on how selection of some of the variables may uniquely affect Humboldt County. The sections below discuss use of the static load profiles to develop the Humboldt CCA load shape, risks with unpredictable changes in energy demand and sensitivity in CCA savings with changes in the year that renewable generation facilities are brought on-line.

The foundation of the financial analysis is the electrical load analysis. The primary assumptions of the electrical load analysis include the annual growth rate of electricity sales by sector, opt-out rates by sector and use of the static load profiles to determine the amount of premium priced on-peak energy. To some extent all of these factors affect the financial savings because they are used in this analysis to determine the amount of CCA procured on-peak and off-peak energy. Assumptions that underestimate the actual amount of on-peak energy will result in CCA program costs that are too small and, thus, financial savings that are too large.

One factor that could underestimate the actual amount of on-peak energy is the use of static load profiles, rather than metered time of use data, to develop the community composite load profile. Static load profiles assume a typical pattern of electricity usage, which may not be accurate in Humboldt County. For example, after California voters passed Proposition 215, which authorized growing marijuana for medicinal uses, electricity use per capita in Humboldt County has increased while the state per capita consumption has remained relatively stable. According to Dr. Lehman, Director of the Schatz Energy Research Center, Humboldt County residents use 25 percent more electricity per capita than the average Californian (Morehouse, 2010). As electricity demand per capita in Humboldt has diverged from the California average it may be inaccurate to assume that the pattern of electricity usage is typical of the California electric customer.

The cultivation of indoor marijuana has other potential impacts to the feasibility of CCA. If many residential customers are growing marijuana it is possible that the assumed weighted average PG&E generation charge is too low. As described in the methods section, PG&E has a residential rate structure composed of five tiers or levels of electricity usage with each tier having a greater generation charge and this analysis calculated a weighted average generation charge based on the electricity usage distribution of Marin County - approximately 62%, 11%, 15%, 8% and 4% for tier 1 through 5, respectively. Greater electricity use in the upper tiers would result in a larger generation charge for the residential sector. The outcome would be a higher revenue requirement for PG&E and an even greater savings with the CCA program.

Future factors affecting the legality of marijuana could also produce unpredictable changes in Humboldt's electricity demand. If the electricity demand is unexpectedly reduced below levels secured through a long term power contract than the CCA could be placed in financial risk depending on the terms of the contract. Ideally, the long term contract is flexible and allows the CCA to revise its forecasted demand or sell the excess energy.

Findings from the financial analysis surprisingly revealed that savings increases by voluntarily increasing the CCAs Renewable Portfolio Standard. For example, for the 3% PG&E escalation rate scenario the NPV of income increases from -$18 million for the 33% RPS to $34 for the 50% RPS and finally to $97 million for the 75% RPS scenario. This outcome is caused by the thesis assumptions that: (1) the CCA constructs biomass and wind generation facilities, (2) the capacity of the facilities are sized to meet the 2031 RPS target, (3) the facilities are brought on-line in 2015 and 2017, and (4) the excess renewable energy can be sold at the Market Price Referent (MPR). This thesis finds that the amount of money that can be saved by establishing a CCA depends largely on the renewable technology utilized by the CCA, the amount of renewable energy sold, the date the facilities are brought on-line, and the profit received for the electricity. This thesis assumed that the CCA would invest in biomass and wind generation facilities because the resources are locally available, the technology is mature and Humboldt County already has experience with biomass power plants. Another aspect of biomass and wind facilities is that they may have an average levelized cost less than the MPR (CEC, 2010). Therefore, the CCA can make a profit by selling excess renewable energy. Had this thesis assumed that the CCA financed a renewable energy with a levelized cost greater than the MPR, the CCA may not be able to make a profit by selling the renewable energy and thus the monetary savings would be reduced.

Another factor affecting savings is the amount of renewable energy sold at the MPR, which is impacted by the CCAs voluntary renewable target, the year that the renewable facility is brought on-line and the limited ability to transmit power from within Humboldt County. For instance, the scenario with a 50% RPS target brings a 75MW biomass facility on-line in 2015 that is capable of generating about 558 GWh of electricity. This thesis assumes that the CCA gradually ramps up the annual amount of renewable energy used to meet the 50% target. As the amount of electricity needed in 2015 to meet that years RPS target is only about 26% of the annual demand, or about 222 GWh, the CCA can sell the excess energy. In the last year of operation, 2031, all of the electricity from the biomass and wind generation facilities is used by the CCA to meet the 50% RPS target and, therefore, none can be sold to generate revenue for the CCA. However, since there is limited ability to transmit power from within Humboldt County it may not be possible to sell all the excess renewable energy. Figure 11 shows how the NPV of savings is impacted by transmission limitations or the CCAs ability to sell renewable energy. The figure shows that the 75% RPS scenario results in the greatest savings if the CCA is able to sell all the excess renewable energy not used to meet its annual RPS goal. The 75% RPS scenario can also result in the greatest financial loss if none of the renewable energy can be sold.

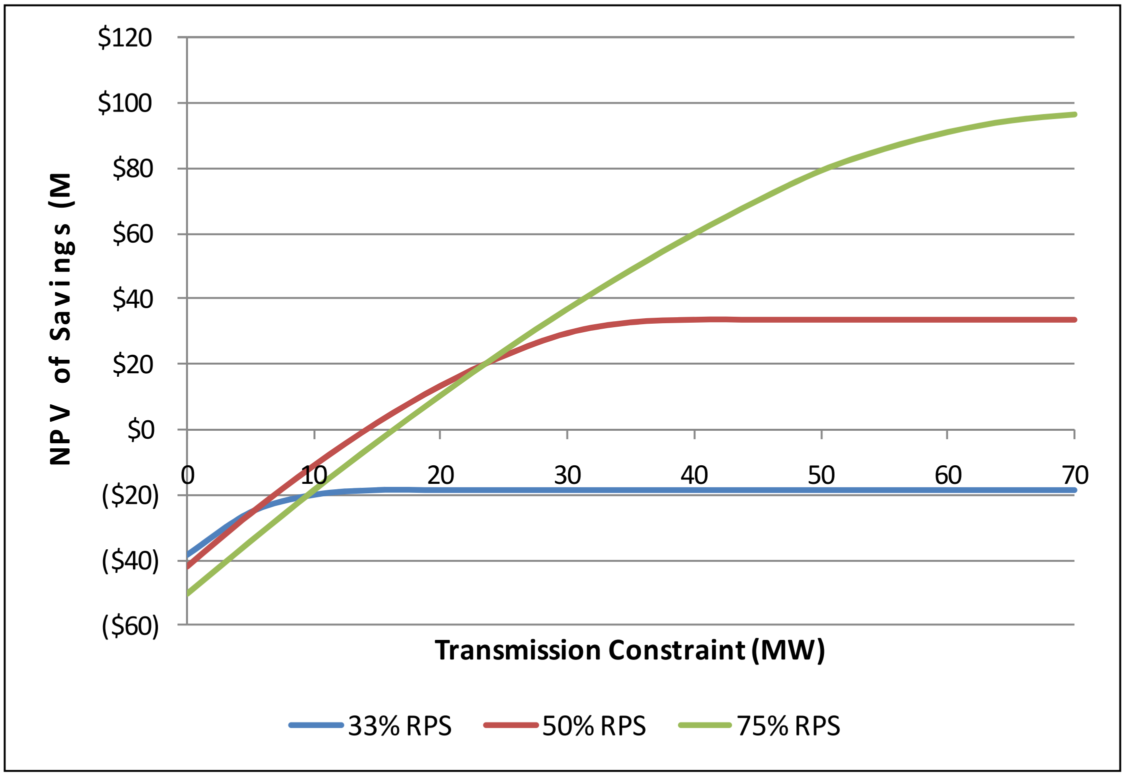

Figure 11 Sensitivity analysis of transmission constraint to net present value of savings for the three CCA supply portfolios and the 3% escalation rate of PG&E generation charges

The year that the renewable generation facility is brought on-line also affects the amount of energy that can be sold to bring in revenue for the CCA. Figure 12 is a sensitivity analysis showing how the variation in the construction date of the 75MW biomass facility affects the CCAs savings. In years prior to construction of the biomass facility the CCA meets its renewable target through renewable energy market purchases. The figure shows that savings are greatest when the power plant is brought on-line soon after establishing the CCA program. If the facility is brought on-line in the first year of operation, as opposed to the originally assumed fourth year, the NPV of savings is over

$70 million. Therefore, the CCA could save about $39 million more than the estimated $34 million NPV from Table 13 by bringing the facility on-line in the first year. In contrast, bringing the facility on-line in the last year, 2031, results in a loss of about $46 million.

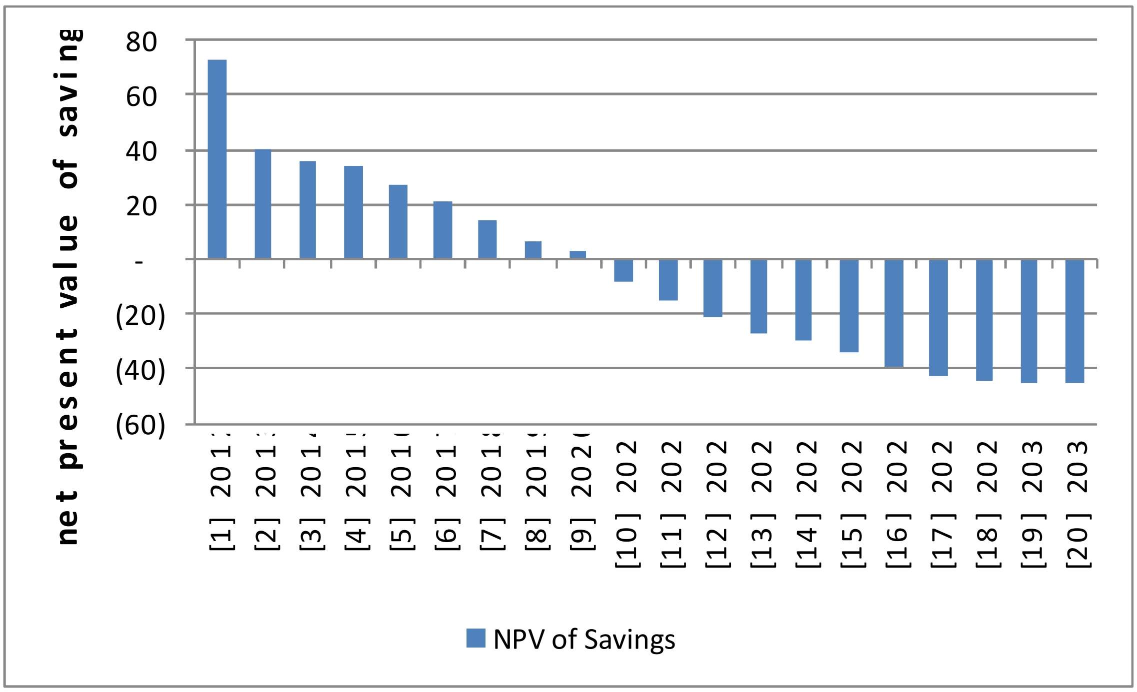

Figure 12 Sensitivity analysis showing how the variation in the year that the renewable generation facility is brought on-line affects the NPV of savings. The results are for the 50% RPS scenario with a 3% PG&E rate escalation.

Community Support

The statistical results from the chi-square analysis of community support shows that Humboldt County voters are statistically distinguishable from Marin's. As Marin is the only county in California with a CCA program, this suggests that the residents of

Humboldt might not support a CCA program or, if they did support CCA, their support would not be as enthusiastic as that of the voters in Marin County.[29] However, there are several limits with the chosen method of analysis. The limits, which are described further in the sections below, include impacts from nonrandom sampling, voter bias and the inability to measure the intensity of support.

The statistical analysis assumes that the preference of voters is a representative sample of the county's population. As voting is not compulsory, there is no way to verify if the voter subset is a random sample, and hence representative, of the population. There also could be self-selection bias resulting from differences in the community's political activity or awareness. Therefore, extending inference from the voter subset to the entire population is speculative.

Furthermore, because the propositions were only one issue among many that voters were considering, the voter subset could be biased. For example, a 2010 poll by the Pew Research Center shows that views about climate change are sharply divided along party lines. The poll found that "a substantial majority of Democrats (79%) say there is solid evidence that the average temperature on earth has been increasing over the past few decades, and 53% think the earth is warming mostly because of human activity. Among Republicans, only 38% agree the earth is warming and just 16% say warming is

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[29] The Marin Clean Energy program is phasing in electric customers over the course of two stages. Phase 1, which has already occurred, enrolled 6,922 customers out of 8,252. 1,330 or about 16% of the eligible customers opted out of the CCA (Loceff, 2010). Most of the phase 1 accounts were municipal and commercial accounts. Phase 2, which will occur in early 2012, intends to make the CCA program eligible to about 60,000 residential customers.

caused by humans" (Pew Research Center, 2010). If ballot issues lure more Democrats than Republicans, the sample subset would most likely be biased in favor of showing support for reducing GHG emissions. As this thesis assumes that there is a correlation between a community's desire to reduce GHG emission and public support of CCA, a biased voter subset would also affect the findings from the analysis of public support.

Another shortfall with the method of analysis is that voters could only respond with a "yes" or "no" vote. Because the voter response was limited to only two options the analysis does not gauge the depth or intensity of support. Furthermore, the respondents vote may be affected by what the Pew Research Center refers to as the "social desirability bias," which is people's natural tendency to want to be accepted and liked. This can lead people to provide inaccurate answers to questions that deal with sensitive topics.

Potential CCA Regulatory Changes

There are several ongoing regulatory discussions that could affect CCA programs. The more important factors that are being evaluated by the CPUC include CCA bond requirements in R.03-10-003 and the methodology impacting the PCIA in R.07-05-025 and potential changes to PG&Es rates in A.10-03-014. Each factor is described in more detail below.

CCAs are required to post a bond, which is currently set at an interim amount of $100,000. The intent of the bond is to pay for re-entry fees in the event that CCA customers are returned to the IOU. The bond provides protection to bundled customers in the event that the CCA is unexpectedly terminated. The CPUC is currently evaluating the methodology for calculating the bond amount. The IOUs have proposed a methodology that CCA proponents claim "would result in bonding requirements for ESPs and CCAs being so large as to act as a barrier to market entry for ESPs and a deterrent to the formation of additional CCAs" (MEA, 2011). CCA proponents also claim that it would burden them with excessive and costly credit requirements. The CPUC will likely propose a draft methodology for calculating the bond amount by May or June of 2011.

The methodologies to determine the Power Charge Indifference Adjustment (PCIA) and the Competition Transition Charge (CTC) are also being discussed in CPUC Docket No. R.07-05-025. As discussed in the Literature Review chapter, the PCIA is a component of the CRS and is charged to CCA and other customers that leave bundled IOU service. Currently the amount charged to CCA customers is based on a method that compares the IOUs average generation cost of its procurement portfolio to a forecasted market price of energy. However, the forecasted market price of energy does not adequately represent the price of renewable energy. Therefore, other methods to calculate the market price benchmark are being investigated. These methods include: using the U.S. Department of Energy's database to determine the price of renewable energy or using market indices for Renewable Energy Credits.

Regulatory changes that decrease the IOUs rates relative to the CCAs would impact the CCA because its customers may become dissatisfied and leave the program. For example, PG&E has proposed modifying its electric rates structure in Application

A.10-03-014 in a way that shifts cost among customer classes in a manner that Marin Clean Energy claims would have significant disproportionate economic impacts to their CCA program. The proposed rate structure is currently being evaluated by the CPUC and the likelihood of implementation is unknown by the author.

Alternative Models and Options

There are a variety of innovative strategies, policies and financing mechanisms that the community could potentially use to obtain similar benefits to that of CCA programs. Each program that increases investment in clean energy and energy efficiency is unique in its objectives, costs, advantages and challenges. As this thesis only evaluated CCA, further research should explore other models. Depending on the program's objectives - improve energy efficiency, reduce GHG emissions, lower electric rates, increase local employment - other options or models that the community might want to explore include: (1) encourage modifications to state or federal energy policy; (2) join an already established CCA program; (3) facilitate design and permitting of renewable energy projects and (4) on-bill financing. Each option is briefly described below.

The community could choose to take no local action and instead initiate or encourage modifications to the state or federal energy policy. PG&E must comply with the state and federal clean energy requirements, which currently requires the IOU to increase their electricity from eligible renewable sources from 20% in 2010 to 33% in 2020 (CEC, 2011). The community could encourage the state and federal government to mandate additional increases in clean energy or to provide residential customer choice. For example, residential customers could be offered the opportunity to purchase either cleaner energy or energy that is locally generated. This top-down approach would likely spread the benefits and risks out across a larger population.

The county and/or cities in the county could potentially get invited to join an already established CCA program. This option could provide the benefits of CCA while reducing the start-up and implementation expenses. The City of Arcata has begun discussing this option with Marin Clean Energy. At the City of Arcata council meeting on February 16, 2011 Shawn Marshall, Vice-Chair of MEA, informed the audience that the start-up costs for the city to implement a program of its own would probably be about \$1.5 – 2.0 million. In contrast, the cost to join MCE was estimated to be about \$125K (City of Arcata, 2011).

The type of benefits available to the joining jurisdiction will ultimately depend on the structure of the CCA governing board. The CCA governing board could decide to not provide the joining entity voting rights in CCA resource decisions. As the joining entity does not have equal representation, the benefit of having local control is diminished. At the council meeting, Shawn Marshall suggested that it would be unlikely for the City of Arcata to obtain voting rights in MEA. As more Californian CCA programs are implemented, the number of opportunities to favorably join CCA programs will expand.

The county could facilitate the development of renewable energy power plants to help bring about an energy policy that reflects community priorities. For example, the local community could acquire land rights, permits, interconnection agreements and all other tasks that must be completed prior to constructing a power plant. The community could then sell the developed project to an investor who finances and constructs the power plant. A flip structure is another option that could be viable under this model. In this option, a taxable entity, owns the system initially, which allows them to collect the tax incentives. After the tax incentives have expired, ownership of the system flips to the non-tax equity investor at a lower price.

On-bill financing is a fourth potential mechanism that could help develop a community scale energy policy. On-bill financing is a loan program that is administered through a utility or another public-purpose program. The loan is paid back over time on the utility bill. PG&E currently offers an on-bill financing loan program for individual bundled, CCA and Direct Access customers. Customers receive a 0% interest loan towards the purchase and installation of new energy efficient measures or equipment (PG&E, 2010e). It may eventually be possible to use on-bill financing for groups of customers and use the loan to construct clean energy facilities.

Even though the above list of policies and financing mechanisms is not exhaustive it does demonstrate the wide variety of options that are potentially available. The options should be evaluated in greater detail to identify the approach that balances the regions views on clean energy, financial risk, local control and job creation. If after performing this comparison CCA is found to be the preferred approach, the section below provides recommendations including steps to further evaluate and pursue CCA.

CONCLUSIONS AND RECOMMENDATIONS

This thesis investigated an emerging electricity program called Community Choice Aggregation (CCA) that enables local governments to aggregate and procure energy on behalf of the citizens and businesses in their community. After creating a CCA program, electric customers are given the opportunity to choose between the CCA and incumbent utility company as the provider of their electricity generating service. The CCA is responsible for obtaining power for customers that switch providers and the incumbent utility company is responsible for supplying power to its remaining customers and the transmission, metering and billing for both utility and CCA customers. Thus, the CCA does not own or operate the electric distribution system within its jurisdiction.

The primary benefits of CCA include increased consumer choice, enhancement of local control of energy resources and the potential to reduce electricity rates for customers. CCA enables local governments to make resource decisions that reflect community goals and values. Therefore, there are numerous potential secondary benefits that will depend upon the structure of the program. Among the secondary benefits are procuring cleaner energy to reduce the community's greenhouse gas emissions, increasing local employment or providing rate stability.

The objective of the thesis was to assess the financial and political viability of utilizing the CCA model in Humboldt County. Both the financial and political components are considered crucial to the overall feasibility of implementing a CCA program. This thesis considers a viable program to be one that increases the community's Renewable Portfolio Standard (RPS) and local control of energy resources and to do so while lowering or matching PG&Es electric rates.

The financial analysis compared the total cost of operating a CCA program with that of continuing to purchase electricity from the incumbent utility company. When the CCAs costs are less than the incumbent utility companies the community collectively saves money. The financial assessment determined the CCAs costs for three voluntary RPSs (33%, 50% and 75%) and PG&Es generation costs for three rate escalation forecasts (2%, 3% and 4%). The total cost of these nine scenarios was determined for a 20 year planning horizon, beginning in year 2012.

The results of the financial analysis indicate savings for six of the nine scenarios. This analysis indicates that the CCA could provide community wide cost savings up to about $154 million, which equates to an estimated savings of approximately 18% on customers electric bills. However, the CCA program might also increase customer's electric bills. CCA customer electric bills are estimated to increase by 7% for the scenario in which the CCA builds generation facilities to meet an RPS goal of 33% and PG&Es electric rates escalate at 2%. The assessment further reveals that the greatest savings occurs when the CCA finances and brings renewable generation facilities on-line soon after establishing the program and maximizes the amount of renewable energy sold.

In order to assess the political viability or support from the community, this thesis investigated Humboldt County's position on opportunities made available by creating a CCA program – reducing GHG emissions and increasing local control. By comparing the position of Humboldt residents with that of Marin County residents, the only community in California that has already established a CCA program, it is possible to roughly gauge the level of support. The findings indicate that mitigating GHG emissions may be less important to Humboldt residents than Marin residents but, the ability to locally control resources appears to be more important.

Next Implementation Steps and Recommendations

The results of the analysis provide evidence that application of the CCA model in Humboldt County is financially and politically viable. Should the community choose to further evaluate and pursue CCA, an advisory board or working group composed of representatives from each city in the county should be formed. Ideally, the board members would represent an interdisciplinary group of experts, such as energy industry consultants, economists, local politicians and attorneys. The working group should begin increasing public awareness of CCA by way of newspaper editorials, public forums, social media and establishing a Humboldt County CCA website, which could be used to post the agenda, meeting minutes and video of the advisory board’s meetings.

In addition to the recommendation of establishing a working group and increasing public awareness of CCA, it would also be beneficial to hire a consulting company with CCA experience. It would be very challenging for the board members, who have existing jobs and responsibilities, to be the project lead of the CCA program. The working group may also want to consider the following four recommendations; (1) conducting a survey to refine certain thesis assumptions, (2) beginning the engineering design and permitting of generation facilities, (3) securing a loan to pay for CCA start-up and pre-implementation expenses and (4) begin discussing CCA with the county's existing independent power producers. These recommendations are described in more detail below.

The analysis of public support performed in this thesis qualitatively indicated that county residents are likely to support a CCA program. The county and/or advisory board should conduct a survey to provide insight in to which cities are interested in CCA and what will be the likely opt-out rate by sector of the participating cities. The Economics of Community Choice Aggregation study by the Bay area economic forum suggested that significant opt-out rates by large industrial customers could result in poor performance by CCAs relative to PG&E's rates. The study stated that "in light of the importance of large commercial and industrial customers to the potential success of CCAs, the process for evaluating the feasibility of CCAs would benefit from surveys or analyses about the attitudes of large businesses concerning the CCA/IOU cost differential thresholds that they would tolerate before opting out. Many large customers are energy intensive, compete in global markets, must operate as efficiently as possible, and may have little flexibility for supporting the aims of CCAs if a CCA cost advantage does not materialize or cannot be sustained" (Roberts, 2007 p. 8). The survey could also help identify the type of generation facilities that the community would most like to finance.

The second recommendation is that the advisory board or its consultants begin the design and permitting process for the generation facilities that the CCA intends to eventually construct. The Economics of Community Choice Aggregation study suggests that "the first stage of CCA feasibility studies should be focused on precisely how, where and when the prospective CCA can site, build, and operate efficient generating facilities, and what the operating characteristics and generation costs of those specific plants will likely be" (Roberts, 2007 p. 17). As the CCAs ability to reliably reduce electric rates depends on its advantage in financing capital-intensive generating capacity, these facilities should be brought on-line quickly. Beginning the design and permitting process while simultaneously implementing CCA will expedite construction of the generation facilities and electric cost savings. However, this may be a challenging task because the CCA program will not collect revenue until it begins to sell power to customers. Therefore, the participating governments would need to fund the design and permitting activities or the CCA needs to secure a loan.

The third recommendation is that the working group start investigating funding sources for CCA start-up and pre-implementation expenses, which based on Marin's experience, could be about $1.5 million. It may be difficult for the CCA to secure capital to cover these expenses because they have not demonstrated their creditworthiness to lenders. Establishing the creditworthiness of the CCA will also be a crucial factor for financing the new renewable generation facilities, which are estimated to be about $405 million for the 75% RPS scenario. As the MEA has not yet utilized bonds to finance generation facilities, little is known about the difficulty that California CCAs will encounter when issuing bonds for large projects.

The fourth recommendation is that the working group begins discussing the potential for CCA with the counties three existing operating biomass facilities (Greenleaf Power in Scotia, Fairhaven Power Company and Blue Lake Power). Each facility is currently selling electricity to regulated IOU's but the advisory board should contact each plant to determine their contract length and terms. It might be possible to establish a partnership between the CCA and the power plants in which excess electricity is sold to the CCA. This might help the CCA avoid purchasing expensive renewable energy market purchases. It is also recommended that the advisory board explore using their financing advantage to upgrade equipment or expand plant capacity. These improvements may be less expensive than constructing a new biomass facility as the infrastructure is already in place.

Community Choice Aggregation has the potential to bring many benefits to Humboldt County but it will take a dedicated group of politicians and citizens to kick start the effort, improve public awareness and build momentum for CCA. The effort may seem daunting but it is not impossible. The County of Marin has already established a CCA program and the City and County of San Francisco will likely be implementing a program soon. By establishing a CCA program, the county has the opportunity to not only become a national leader but to craft an energy policy that reflects the values and goals of the local citizens.

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APPENDIX A: LIST OF ACRONYMS AND ABBREVIATIONS

AB	Assembly Bill
ARB	Air Resources Board
BTU	British Thermal Unit
CARE	California Alternative Rate for Energy
CCA	Community Choice Aggregation
CEC	California Energy Commission
COG	Cost of Generation
CPUC	California Public Utility Commission
CRS	Cost Responsibility Surcharge
CTC	Competitive Transfer Charge
DA	Direct Access
DWR	California Department of Water Resources
EIA	Energy Information Administration
ERRA	Energy Resource Recovery Amount
GHG	Greenhouse Gas
IEPR	Integrated Energy Policy Report
IOU	Investor Owned Utility
ISO	Independent System Operator
MCE	Marin Clean Energy
MEA	Marin Energy Authority
MW	MegaWatt
NPV	net present value
PCIA	Power Charge Indifference Adjustment
PIER	Public Interest Energy Research
PG&E	Pacific Gas and Electric
PPA	Power Purchase Agreement
PV	Photovoltaic
RCEA	Redwood Coast Energy Authority
RESCO	Renewable-based Secure Communities
RPS	Renewable Portfolio Standard
SERC	Schatz Energy Research Center

APPENDIX B: FORECASTED CCA ELECTRICITY SALES

	0	1	2	3	4	5	6	7
CATEGORY	2011	2012	2013	2014	2015	2016	2017	2018
COMMUNITY ELECTRIC LOADS								
COUNTY-WIDE FORECASTED SALES (CCA + PG&E) (KWH)	938,592,691	949,894,364	961,344,204	972,944,220	984,696,450	996,602,958	1,008,665,838	1,020,887,215
AGRICULTURE	25,751,000	25,751,000	25,751,000	25,751,000	25,751,000	25,751,000	25,751,000	25,751,000
COMMERCIAL	297,858,568	300,837,154	303,845,526	306,883,981	309,952,821	313,052,349	316,182,872	319,344,701
INDUSTRY	129,295,984	130,588,944	131,894,833	133,213,781	134,545,919	135,891,378	137,250,292	138,622,795
MINING AND CONSTRUCTION	1,185,000	1,185,000	1,185,000	1,185,000	1,185,000	1,185,000	1,185,000	1,185,000
RESIDENTIAL	468,675,139	475,705,266	482,840,845	490,083,458	497,434,710	504,896,230	512,469,674	520,156,719
STREET LIGHTING	4,367,000	4,367,000	4,367,000	4,367,000	4,367,000	4,367,000	4,367,000	4,367,000
WATER PUMPING	11,460,000	11,460,000	11,460,000	11,460,000	11,460,000	11,460,000	11,460,000	11,460,000
FORECASTED ANNUAL GROWTH RATE								
AGRICULTURE	0.0%							
COMMERCIAL	1.0%							
INDUSTRY	1.0%							
MINING AND CONSTRUCTION	0.0%							
RESIDENTIAL	1.5%							
STREET LIGHTING	0.0%							
WATER PUMPING	0.0%							
OPT-OUT OF CCA SERVICE								
AGRICULTURE	20.0%							
COMMERCIAL	20.0%							
INDUSTRY	20.0%							
MINING AND CONSTRUCTION	20.0%							
RESIDENTIAL	5.0%							
STREET LIGHTING	0.0%							
WATER PUMPING	0.0%							
TOTAL FORECASTED CCA SALES (KWH)		834,436,681	844,666,890	855,033,295	865,537,766	876,182,201	886,968,522	897,898,680
AGRICULTURE		20,600,800	20,600,800	20,600,800	20,600,800	20,600,800	20,600,800	20,600,800
COMMERCIAL		240,669,723	243,076,421	245,507,185	247,962,257	250,441,879	252,946,298	255,475,761
INDUSTRY		104,471,155	105,515,866	106,571,025	107,636,735	108,713,103	109,800,234	110,898,236
MINING AND CONSTRUCTION		948,000	948,000	948,000	948,000	948,000	948,000	948,000
RESIDENTIAL		451,920,003	458,698,803	465,579,285	472,562,974	479,651,419	486,846,190	494,148,883
STREET LIGHTING		4,367,000	4,367,000	4,367,000	4,367,000	4,367,000	4,367,000	4,367,000
WATER PUMPING		11,460,000	11,460,000	11,460,000	11,460,000	11,460,000	11,460,000	11,460,000

CATEGORY	8 2019	9 2020	10 2021	11 2022	12 2023	13 2024	14 2025	15 2026
COMMUNITY ELECTRIC LOADS								
COUNTY-WIDE FORECASTED SALES (CCA + PG&E) (KWH)	1,033,269,241	1,045,814,099	1,058,524,002	1,071,401,195	1,084,447,954	1,097,666,586	1,111,059,431	1,124,628,862
AGRICULTURE	25,751,000	25,751,000	25,751,000	25,751,000	25,751,000	25,751,000	25,751,000	25,751,000
COMMERCIAL	322,538,148	325,763,530	329,021,165	332,311,377	335,634,490	338,990,835	342,380,744	345,804,551
INDUSTRY	140,009,023	141,409,113	142,823,204	144,251,436	145,693,951	147,150,890	148,622,399	150,108,623
MINING AND CONSTRUCTION	1,185,000	1,185,000	1,185,000	1,185,000	1,185,000	1,185,000	1,185,000	1,185,000
RESIDENTIAL	527,959,070	535,878,456	543,916,633	552,075,382	560,356,513	568,761,860	577,293,288	585,952,688
STREET LIGHTING	4,367,000	4,367,000	4,367,000	4,367,000	4,367,000	4,367,000	4,367,000	4,367,000
WATER PUMPING	11,460,000	11,460,000	11,460,000	11,460,000	11,460,000	11,460,000	11,460,000	11,460,000
FORECASTED ANNUAL GROWTH RATE								
AGRICULTURE								
COMMERCIAL								
INDUSTRY								
MINING AND CONSTRUCTION								
RESIDENTIAL								
STREET LIGHTING								
WATER PUMPING								
OPT-OUT OF CCA SERVICE								
AGRICULTURE								
COMMERCIAL								
INDUSTRY								
MINING AND CONSTRUCTION								
RESIDENTIAL								
STREET LIGHTING								
WATER PUMPING								
TOTAL FORECASTED CCA SALES (KWH)	908,974,653	920,198,447	931,572,096	943,097,663	954,777,240	966,612,948	978,606,938	990,761,393
AGRICULTURE	20,600,800	20,600,800	20,600,800	20,600,800	20,600,800	20,600,800	20,600,800	20,600,800
COMMERCIAL	258,030,519	260,610,824	263,216,932	265,849,101	268,507,592	271,192,668	273,904,595	276,643,641
INDUSTRY	112,007,218	113,127,291	114,258,564	115,401,149	116,555,161	117,720,712	118,897,919	120,086,899
MINING AND CONSTRUCTION	948,000	948,000	948,000	948,000	948,000	948,000	948,000	948,000
RESIDENTIAL	501,561,116	509,084,533	516,720,801	524,471,613	532,338,687	540,323,767	548,428,624	556,655,053
STREET LIGHTING	4,367,000	4,367,000	4,367,000	4,367,000	4,367,000	4,367,000	4,367,000	4,367,000
WATER PUMPING	11,460,000	11,460,000	11,460,000	11,460,000	11,460,000	11,460,000	11,460,000	11,460,000

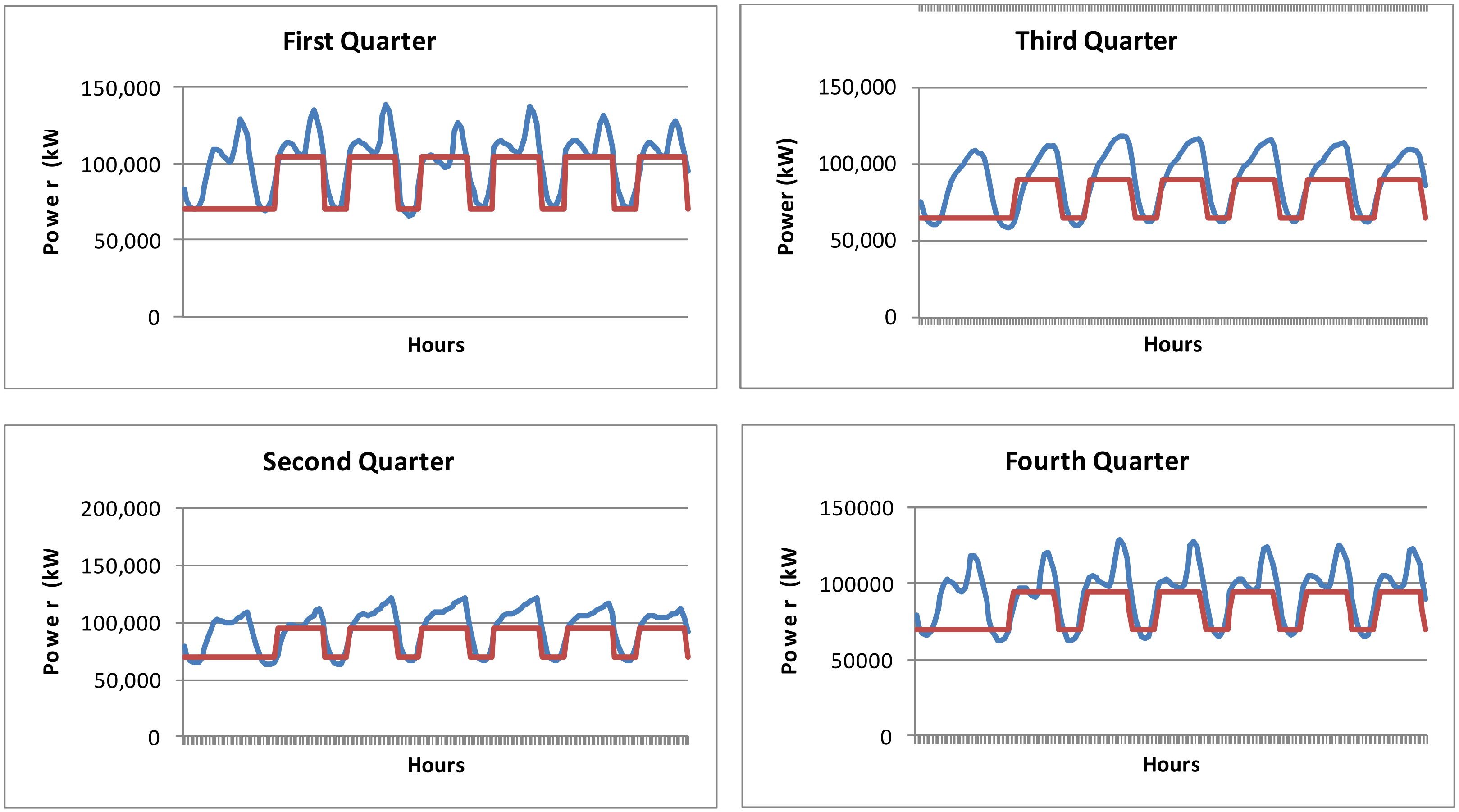
CATEGORY	16 2027	17 2028	18 2029	19 2030	20 2031
<u>COMMUNITY ELECTRIC LOADS</u>					
COUNTY-WIDE FORECASTED SALES (CCA + PG&E) (KWH)	1,138,377,284	1,152,307,137	1,166,420,894	1,180,721,063	1,195,210,188
AGRICULTURE	25,751,000	25,751,000	25,751,000	25,751,000	25,751,000
COMMERCIAL	349,262,597	352,755,223	356,282,775	359,845,602	363,444,059
INDUSTRY	151,609,709	153,125,807	154,657,065	156,203,635	157,765,672
MINING AND CONSTRUCTION	1,185,000	1,185,000	1,185,000	1,185,000	1,185,000
RESIDENTIAL	594,741,978	603,663,108	612,718,054	621,908,825	631,237,457
STREET LIGHTING	4,367,000	4,367,000	4,367,000	4,367,000	4,367,000
WATER PUMPING	11,460,000	11,460,000	11,460,000	11,460,000	11,460,000
FORECASTED ANNUAL GROWTH RATE					
AGRICULTURE					
COMMERCIAL					
INDUSTRY					
MINING AND CONSTRUCTION					
RESIDENTIAL					
STREET LIGHTING					
WATER PUMPING					
OPT-OUT OF CCA SERVICE					
AGRICULTURE					
COMMERCIAL					
INDUSTRY					
MINING AND CONSTRUCTION					
RESIDENTIAL					
STREET LIGHTING					
WATER PUMPING					
TOTAL FORECASTED CCA SALES (KWH)	1,003,078,524	1,015,560,575	1,028,209,823	1,041,028,574	1,054,019,169
AGRICULTURE	20,600,800	20,600,800	20,600,800	20,600,800	20,600,800
COMMERCIAL	279,410,077	282,204,178	285,026,220	287,876,482	290,755,247
INDUSTRY	121,287,768	122,500,645	123,725,652	124,962,908	126,212,537
MINING AND CONSTRUCTION	948,000	948,000	948,000	948,000	948,000
RESIDENTIAL	565,004,879	573,479,952	582,082,152	590,813,384	599,675,585
STREET LIGHTING	4,367,000	4,367,000	4,367,000	4,367,000	4,367,000
WATER PUMPING	11,460,000	11,460,000	11,460,000	11,460,000	11,460,000

APPENDIX C: TYPICAL WEEKLY LOAD PLOTS AND LOAD ANALYSIS

	0	1	2	3	4	5	6	7
CATEGORY	2011	2012	2013	2014	2015	2016	2017	2018
ENERGY SUPPLY FOR END USE LOAD (KWH)		856,654,758	866,033,682	876,699,180	887,698,599	899,917,575	903,870,881	916,956,222
ON-PEAK		515,142,328	520,916,214	526,614,840	534,310,033	542,092,656	548,967,390	559,838,574
ON-PEAK (%)		61%	62%	62%	63%	63%	63%	64%
7X24 Power Block		321,675,000	322,725,000	328,500,000	328,500,000	328,500,000	327,450,000	328,650,000
6x16 Power Block		128,550,000	134,850,000	134,850,000	146,625,000	152,550,000	157,950,000	170,175,000
Spot Market		58,412,646	56,954,498	56,644,203	51,519,421	51,349,264	57,240,709	53,101,207
Dumped On-Peak		6,504,682	6,386,716	6,620,637	7,665,612	9,693,392	6,326,681	7,912,367
OFF-PEAK		341,512,430	345,117,468	350,084,340	353,388,566	357,824,919	354,903,491	357,117,648
OFF-PEAK (%)		39%	38%	38%	37%	37%	37%	36%
7X24 Power Block		280,450,000	279,400,000	284,422,500	284,422,500	284,422,500	285,472,500	284,272,500
6x16 Power Block		0	0	0	0	0	0	0
Spot Market		55,022,912	61,190,723	61,221,568	65,325,402	69,736,614	67,084,873	71,009,258
Dumped Off-Peak		6,039,518	4,526,745	4,440,272	3,640,664	3,665,805	2,346,118	1,835,890
DUMPED ELECTRIC LOAD (KWH)		12,544,200	10,913,461	11,060,909	11,306,276	13,359,197	8,672,799	9,748,257
Dumped (%)		1.5%	1.3%	1.3%	1.3%	1.5%	1.0%	1.1%
PEAK DEMAND (KW)		150,412	152,387	154,390	156,420	158,478	160,565	162,681
PROJECTED LOADS INCLUDING LOSSES (KWH)		916,620,591	926,656,040	938,068,123	949,837,501	962,911,805	967,141,843	981,143,158
ON-PEAK		551,202,291	557,380,349	563,477,879	571,711,735	580,039,142	587,395,107	599,027,274
OFF-PEAK		365,418,300	369,275,691	374,590,244	378,125,766	382,872,663	379,746,735	382,115,883

CATEGORY	8 2019	9 2020	10 2021	11 2022	12 2023	13 2024	14 2025	15 2026
ENERGY SUPPLY FOR END USE LOAD (KWH)	932,608,573	952,981,416	957,327,564	968,949,658	976,280,966	994,596,115	1,003,324,429	1,017,239,382
ON-PEAK	566,300,270	579,347,855	580,270,948	586,656,873	594,419,684	606,676,151	609,281,503	616,654,997
ON-PEAK (%)	64%	64%	64%	64%	63%	64%	64%	64%
7X24 Power Block	334,425,000	340,200,000	340,200,000	346,050,000	350,850,000	352,125,000	357,750,000	363,675,000
6x16 Power Block	170,100,000	181,875,000	181,875,000	181,875,000	181,275,000	187,800,000	187,800,000	187,800,000
Spot Market	52,222,854	42,628,479	47,099,168	47,672,835	53,775,809	53,819,947	53,233,558	54,242,740
Dumped On-Peak	9,552,416	14,644,376	11,096,780	11,059,038	8,518,875	12,931,204	10,497,945	10,937,257
OFF-PEAK	366,308,303	373,633,561	377,056,616	382,292,785	381,861,282	387,919,964	394,042,926	400,584,385
OFF-PEAK (%)	36%	36%	36%	36%	37%	36%	36%	36%
7X24 Power Block	289,537,500	294,560,000	294,560,000	299,630,000	305,870,000	304,595,000	309,767,500	314,882,500
6x16 Power Block	0	0	0	0	0	0	0	0
Spot Market	74,288,914	75,775,122	80,502,624	80,584,953	73,549,595	80,649,748	82,210,297	83,198,015
Dumped Off-Peak	2,481,889	3,298,439	1,993,992	2,077,832	2,441,687	2,675,216	2,065,129	2,503,870
DUMPED ELECTRIC LOAD (KWH)	12,034,305	17,942,815	13,090,772	13,136,870	10,960,562	15,606,420	12,563,074	13,441,127
Dumped (%)	1.3%	1.9%	1.4%	1.4%	1.1%	1.6%	1.3%	1.3%
PEAK DEMAND (KW)	164,826	167,001	169,206	171,442	173,709	176,007	178,338	180,700
PROJECTED LOADS INCLUDING LOSSES (KWH)	997,891,173	1,019,690,115	1,024,340,493	1,036,776,134	1,044,620,634	1,064,217,843	1,073,557,139	1,088,446,139
ON-PEAK	605,941,289	619,902,205	620,889,914	627,722,854	636,029,062	649,143,482	651,931,208	659,820,847
OFF-PEAK	391,949,884	399,787,910	403,450,579	409,053,280	408,591,572	415,074,361	421,625,931	428,625,292

CATEGORY	16 2027	17 2028	18 2029	19 2030	20 2031
ENERGY SUPPLY FOR END USE LOAD (KWH)	1,024,344,425	1,042,253,235	1,049,902,349	1,065,549,484	1,088,911,942
ON-PEAK	620,503,352	635,588,372	640,821,492	647,627,232	659,519,524
ON-PEAK (%)	64%	64%	64%	64%	63%
7X24 Power Block	369,600,000	375,450,000	375,600,000	381,225,000	398,925,000
6x16 Power Block	187,800,000	193,575,000	193,650,000	193,575,000	193,575,000
Spot Market	49,780,150	55,273,692	62,822,385	62,721,723	54,268,441
Dumped On-Peak	13,323,202	11,289,680	8,749,107	10,105,509	12,751,083
OFF-PEAK	403,841,073	406,664,863	409,080,857	417,922,252	429,392,418
OFF-PEAK (%)	36%	36%	36%	36%	37%
7X24 Power Block	319,997,500	325,067,500	324,917,500	330,090,000	345,390,000
6x16 Power Block	0	0	0	0	0
Spot Market	80,173,127	77,858,458	81,870,701	85,484,031	79,116,071
Dumped Off-Peak	3,670,446	3,738,905	2,292,656	2,348,221	4,886,347
DUMPED ELECTRIC LOAD (KWH)	16,993,648	15,028,585	11,041,763	12,453,730	17,637,430
Dumped (%)	1.7%	1.4%	1.1%	1.2%	1.6%
PEAK DEMAND (KW)	180,700	185,524	187,987	190,484	193,016
PROJECTED LOADS INCLUDING LOSSES (KWH)	1,096,048,535	1,115,210,961	1,123,395,513	1,140,137,948	1,165,135,778
ON-PEAK	663,938,587	680,079,558	685,678,996	692,961,138	705,685,891
OFF-PEAK	432,109,948	435,131,403	437,716,517	447,176,810	459,449,887



Appendix C - Figure 1 CCA load plots for 2012. The blue line represents the power demand/supply of the CCA and the red line represents the combined baseload and peak power amounts utilized by the CCA.

APPENDIX D: QUANTITY OF ELECTRIC ACCOUNTS

CATEGORY	0 2011	1 2012	2 2013	3 2014	4 2015	5 2016	6 2017	7 2018
COMMUNITY ELECTRIC ACCOUNTS								
TOTAL ACCOUNTS (CCA + PG&E)	69,216	70,182	71,162	72,156	73,164	74,188	75,226	76,279
AGRICULTURE	729	729	729	729	729	729	729	729
COMMERCIAL	7,752	7,830	7,908	7,987	8,067	8,147	8,229	8,311
INDUSTRY	435	439	444	448	453	457	462	466
MINING AND CONSTRUCTION	78	78	78	78	78	78	78	78
RESIDENTIAL	58,927	59,811	60,708	61,619	62,543	63,481	64,433	65,400
STREET LIGHTING	1,137	1,137	1,137	1,137	1,137	1,137	1,137	1,137
WATER PUMPING	158	158	158	158	158	158	158	158
TOTAL CCA ACCOUNTS		65,376	66,295	67,226	68,172	69,131	70,105	71,092
AGRICULTURE		583	583	583	583	583	583	583
COMMERCIAL		6,264	6,326	6,390	6,453	6,518	6,583	6,649
INDUSTRY		351	355	359	362	366	369	373
MINING AND CONSTRUCTION		62	62	62	62	62	62	62
RESIDENTIAL		56,820	57,673	58,538	59,416	60,307	61,212	62,130
STREET LIGHTING		1,137	1,137	1,137	1,137	1,137	1,137	1,137
WATER PUMPING		158	158	158	158	158	158	158
NEW CCA ACCOUNTS		65,376	918	932	946	959	973	988
AGRICULTURE		583	0	0	0	0	0	0
COMMERCIAL		6,264	63	63	64	65	65	66
INDUSTRY		351	4	4	4	4	4	4
MINING AND CONSTRUCTION		62	0	0	0	0	0	0
RESIDENTIAL		56,820	852	865	878	891	905	918
STREET LIGHTING		1,137	0	0	0	0	0	0
WATER PUMPING		158	0	0	0	0	0	0

CATEGORY	8 2019	9 2020	10 2021	11 2022	12 2023	13 2024	14 2025	15 2026
COMMUNITY ELECTRIC ACCOUNTS								
TOTAL ACCOUNTS (CCA + PG&E)	77,348	78,433	79,533	80,649	81,782	82,931	84,096	85,279
AGRICULTURE	729	729	729	729	729	729	729	729
COMMERCIAL	8,394	8,478	8,563	8,649	8,735	8,822	8,911	9,000
INDUSTRY	471	476	481	485	490	495	500	505
MINING AND CONSTRUCTION	78	78	78	78	78	78	78	78
RESIDENTIAL	66,381	67,377	68,387	69,413	70,454	71,511	72,584	73,672
STREET LIGHTING	1,137	1,137	1,137	1,137	1,137	1,137	1,137	1,137
WATER PUMPING	158	158	158	158	158	158	158	158
TOTAL CCA ACCOUNTS	72,095	73,112	74,143	75,190	76,252	77,330	78,424	79,533
AGRICULTURE	583	583	583	583	583	583	583	583
COMMERCIAL	6,715	6,783	6,850	6,919	6,988	7,058	7,129	7,200
INDUSTRY	377	381	384	388	392	396	400	404
MINING AND CONSTRUCTION	62	62	62	62	62	62	62	62
RESIDENTIAL	63,062	64,008	64,968	65,942	66,931	67,935	68,954	69,989
STREET LIGHTING	1,137	1,137	1,137	1,137	1,137	1,137	1,137	1,137
WATER PUMPING	158	158	158	158	158	158	158	158
NEW CCA ACCOUNTS	1,002	1,017	1,032	1,047	1,062	1,078	1,094	1,110
AGRICULTURE	0	0	0	0	0	0	0	0
COMMERCIAL	66	67	68	69	69	70	71	71
INDUSTRY	4	4	4	4	4	4	4	4
MINING AND CONSTRUCTION	0	0	0	0	0	0	0	0
RESIDENTIAL	932	946	960	975	989	1,004	1,019	1,034
STREET LIGHTING	0	0	0	0	0	0	0	0
WATER PUMPING	0	0	0	0	0	0	0	0

CATEGORY	16 2027	17 2028	18 2029	19 2030	20 2031
<u>COMMUNITY ELECTRIC ACCOUNTS</u>					
TOTAL ACCOUNTS (CCA + PG&E)	86,479	87,697	88,933	90,186	91,458
AGRICULTURE	729	729	729	729	729
COMMERCIAL	9,090	9,181	9,273	9,365	9,459
INDUSTRY	510	515	520	526	531
MINING AND CONSTRUCTION	78	78	78	78	78
RESIDENTIAL	74,778	75,899	77,038	78,193	79,366
STREET LIGHTING	1,137	1,137	1,137	1,137	1,137
WATER PUMPING	158	158	158	158	158
TOTAL CCA ACCOUNTS	80,659	81,802	82,961	84,137	85,330
AGRICULTURE	583	583	583	583	583
COMMERCIAL	7,272	7,345	7,418	7,492	7,567
INDUSTRY	408	412	416	420	425
MINING AND CONSTRUCTION	62	62	62	62	62
RESIDENTIAL	71,039	72,104	73,186	74,284	75,398
STREET LIGHTING	1,137	1,137	1,137	1,137	1,137
WATER PUMPING	158	158	158	158	158
NEW CCA ACCOUNTS	1,126	1,142	1,159	1,176	1,193
AGRICULTURE	0	0	0	0	0
COMMERCIAL	72	73	73	74	75
INDUSTRY	4	4	4	4	4
MINING AND CONSTRUCTION	0	0	0	0	0
RESIDENTIAL	1,050	1,066	1,082	1,098	1,114
STREET LIGHTING	0	0	0	0	0
WATER PUMPING	0	0	0	0	0

APPENDIX E: FINANCIAL MODEL AND ASSUMPTIONS

	1 2012	2 2013	3 2014	4 2015	5 2016	6 2017	7 2018
ENERGY PORTFOLIO							
Renewable Energy Ownership Used by CCA	0%	0%	0%	26%	27%	28%	30%
Renewable Energy Market Purchases	22%	23%	24%	0%	0%	0%	0%
Power Purchase Agreement (PPA)	66%	64%	63%	62%	61%	59%	58%
Spot Market Purchases	13%	14%	13%	13%	13%	14%	14%
Excess PPA Energy Sales	-1%	-1%	-1%	-1%	-1%	-1%	-1%
SUBTOTAL - RPS	22%	23%	24%	26%	27%	28%	30%
RPS GOAL	22%	23%	24%	26%	27%	28%	30%
TOTAL - ENERGY PURCHASES AND PRODCUTION	100%	100%	100%	100%	100%	100%	100%

Scenario	yr start	yr end	RPS start	RPS end	Growth Rate
1	2012	2020	22%	33%	5.20%
	2020	2031	33%	33%	0.00%
2	2012	2020	22%	33%	5.20%
	2020	2031	33%	50%	3.85%
3	2012	2020	22%	33%	5.20%
	2020	2031	33%	50%	7.75%

ENERGY PORTFOLIO	8 2019	9 2020	10 2021	11 2022	12 2023	13 2024	14 2025	15 2026
Renewable Energy Ownership Used by CCA	31%	33%	34%	36%	37%	38%	40%	41%
Renewable Energy Market Purchases	0%	0%	0%	0%	0%	0%	0%	0%
Power Purchase Agreement (PPA)	56%	56%	54%	53%	51%	50%	48%	46%
Spot Market Purchases	14%	12%	13%	13%	13%	14%	13%	14%
Excess PPA Energy Sales	-1%	-2%	-1%	-1%	-1%	-2%	-1%	-1%
SUBTOTAL - RPS	31%	33%	34%	36%	37%	38%	40%	41%
RPS GOAL	31%	33%	34%	36%	37%	38%	40%	41%
TOTAL - ENERGY PURCHASES AND PRODCUTION	100%	100%	100%	100%	100%	100%	100%	100%

	16 2027	17 2028	18 2029	19 2030	20 2031
ENERGY PORTFOLIO					
Renewable Energy Ownership Used by CCA	43%	45%	46%	48%	50%
Renewable Energy Market Purchases	0%	0%	0%	0%	0%
Power Purchase Agreement (PPA)	46%	44%	41%	39%	39%
Spot Market Purchases	13%	13%	14%	14%	12%
Excess PPA Energy Sales	-2%	-1%	-1%	-1%	-2%
SUBTOTAL - RPS	43%	45%	46%	48%	50%
RPS GOAL	43%	45%	46%	48%	50%
TOTAL - ENERGY PURCHASES AND PRODCUTION	100%	100%	100%	100%	100%

CATEGORY	0 2011	1 2012	2 2013	3 2014	4 2015	5 2016	6 2017	7 2018
PG&E COSTS		$ 60.9	$ 63.5	$ 66.2	$ 69.0	$ 71.9	$ 74.9	$ 78.0
REVENUE REQUIREMENT FOR POWER SUPPLY ($)		$ 60.9	$ 63.5	$ 66.2	$ 69.0	$ 71.9	$ 74.9	$ 78.0
(A) PG&E'S UNBUNDLED GENERATION RATES ($/KWH)								
AGRICULTURAL (AG-1)	$ 0.08433	$ 0.08685	$ 0.08946	$ 0.09214	$ 0.09491	$ 0.09776	$ 0.10069	$ 0.10371
COMMERCIAL (A-1)	$ 0.08509	$ 0.08764	$ 0.09027	$ 0.09298	$ 0.09577	$ 0.09864	$ 0.10160	$ 0.10465
INDUSTRY (E-20)	$ 0.07375	$ 0.07597	$ 0.07825	$ 0.08059	$ 0.08301	$ 0.08550	$ 0.08807	$ 0.09071
MINING AND CONSTRUCTION (E-19)	$ 0.07693	$ 0.07924	$ 0.08162	$ 0.08407	$ 0.08659	$ 0.08919	$ 0.09186	$ 0.09462
RESIDENTIAL (E-1)	$ 0.06040	$ 0.06221	$ 0.06408	$ 0.06600	$ 0.06798	$ 0.07002	$ 0.07212	$ 0.07429
STREET LIGHTING (LS-1)	$ 0.07427	$ 0.07650	$ 0.07879	$ 0.08116	$ 0.08359	$ 0.08610	$ 0.08868	$ 0.09134
WATER PUMPING (E-19)	$ 0.07693	$ 0.07924	$ 0.08162	$ 0.08407	$ 0.08659	$ 0.08919	$ 0.09186	$ 0.09462
GENERATION RATE ANNUAL INCREASE	3.0%							
(B) REVENUE REQUIREMENT FOR POWER SUPPLY ($)								
AGRICULTURAL (AG-1)		$ 1,789,277	$ 1,842,956	$ 1,898,244	$ 1,955,192	$ 2,013,847	$ 2,074,263	$ 2,136,491
COMMERCIAL (A-1)		$ 21,092,944	$ 21,942,990	$ 22,827,293	$ 23,747,232	$ 24,704,246	$ 25,699,827	$ 26,735,530
INDUSTRY (E-20)		$ 7,936,321	$ 8,256,154	$ 8,588,877	$ 8,935,009	$ 9,295,090	$ 9,669,682	$ 10,059,370
MINING AND CONSTRUCTION (E-19)		$ 75,121	$ 77,375	$ 79,696	$ 82,087	$ 84,550	$ 87,086	$ 89,699
RESIDENTIAL (E-1)		$ 28,115,288	$ 29,393,128	$ 30,729,046	$ 32,125,681	$ 33,585,793	$ 35,112,268	$ 36,708,120
STREET LIGHTING (LS-1)		$ 334,067	$ 344,089	$ 354,412	$ 365,044	$ 375,996	$ 387,275	$ 398,894
WATER PUMPING (E-19)		$ 908,114	$ 935,357	$ 963,418	$ 992,320	$ 1,022,090	$ 1,052,752	$ 1,084,335
(C) PG&E'S UNBUNDLED DEMAND RATES ($/KW)								
AGRICULTURAL (AG-1)								
Rate A		$ 1.22	$ 1.26	$ 1.29	$ 1.33	$ 1.37	$ 1.41	$ 1.46
Rate B		$ 1.83	$ 1.88	$ 1.94	$ 2.00	$ 2.06	$ 2.12	$ 2.19
COMMERCIAL (A-1)		$ -	$ -	$ -	$ -	$ -	$ -	$ -
INDUSTRY (E-20)								
Max Peak Demand Summer		$ 8.74	$ 9.00	$ 9.27	$ 9.55	$ 9.84	$ 10.13	$ 10.44
Max Part-Peak Demand Summer		$ 1.79	$ 1.84	$ 1.90	$ 1.96	$ 2.01	$ 2.08	$ 2.14
MINING AND CONSTRUCTION (E-19)								
Max Peak Demand Summer		$ 9.15	$ 9.42	$ 9.71	$ 10.00	$ 10.30	$ 10.61	$ 10.93
Max Part-Peak Demand Summer		$ 1.95	$ 2.01	$ 2.07	$ 2.13	$ 2.19	$ 2.26	$ 2.33
RESIDENTIAL (E-1)		$ -	$ -	$ -	$ -	$ -	$ -	$ -
STREET LIGHTING (LS-1)		$ -	$ -	$ -	$ -	$ -	$ -	$ -
WATER PUMPING (E-19)								
Max Peak Demand Summer		$ 9.15	$ 9.42	$ 9.71	$ 10.00	$ 10.30	$ 10.61	$ 10.93
Max Part-Peak Demand Summer		$ 1.95	$ 2.01	$ 2.07	$ 2.13	$ 2.19	$ 2.26	$ 2.33
(D) REVENUE REQUIREMENT FOR DEMAND CHARGES ($)								
AGRICULTURAL (AG-1)		$ 27,938	$ 28,776	$ 29,639	$ 30,529	$ 31,444	$ 32,388	$ 33,359
COMMERCIAL (A-1)		$ -	$ -	$ -	$ -	$ -	$ -	$ -
INDUSTRY (E-20)		$ 605,506	$ 623,671	$ 642,381	$ 661,653	$ 681,502	$ 701,947	$ 723,006
MINING AND CONSTRUCTION (E-19)		$ 5,199	$ 5,355	$ 5,516	$ 5,682	$ 5,852	$ 6,028	$ 6,208
RESIDENTIAL (E-1)		$ -	$ -	$ -	$ -	$ -	$ -	$ -
STREET LIGHTING (LS-1)		$ -	$ -	$ -	$ -	$ -	$ -	$ -
WATER PUMPING (E-19)		$ 59,045	$ 60,816	$ 62,641	$ 64,520	$ 66,456	$ 68,449	$ 70,503

CATEGORY	8 2019	9 2020	10 2021	11 2022	12 2023	13 2024	14 2025	15 2026
PG&E COSTS	$ 81.3	$ 84.8	$ 88.3	$ 92.1	$ 95.9	$ 100.0	$ 104.2	$ 108.6
REVENUE REQUIREMENT FOR POWER SUPPLY ($)	$ 81.3	$ 84.8	$ 88.3	$ 92.1	$ 95.9	$ 100.0	$ 104.2	$ 108.6
(A) PG&E'S UNBUNDLED GENERATION RATES ($/KWH)								
AGRICULTURAL (AG-1)	$ 0.10682	$ 0.11002	$ 0.11333	$ 0.11673	$ 0.12023	$ 0.12383	$ 0.12755	$ 0.13138
COMMERCIAL (A-1)	$ 0.10779	$ 0.11102	$ 0.11435	$ 0.11778	$ 0.12132	$ 0.12496	$ 0.12871	$ 0.13257
INDUSTRY (E-20)	$ 0.09343	$ 0.09623	$ 0.09912	$ 0.10209	$ 0.10516	$ 0.10831	$ 0.11156	$ 0.11491
MINING AND CONSTRUCTION (E-19)	$ 0.09746	$ 0.10038	$ 0.10339	$ 0.10649	$ 0.10969	$ 0.11298	$ 0.11637	$ 0.11986
RESIDENTIAL (E-1)	$ 0.07651	$ 0.07881	$ 0.08117	$ 0.08361	$ 0.08612	$ 0.08870	$ 0.09136	$ 0.09410
STREET LIGHTING (LS-1)	$ 0.09408	$ 0.09691	$ 0.09981	$ 0.10281	$ 0.10589	$ 0.10907	$ 0.11234	$ 0.11571
WATER PUMPING (E-19)	$ 0.09746	$ 0.10038	$ 0.10339	$ 0.10649	$ 0.10969	$ 0.11298	$ 0.11637	$ 0.11986
GENERATION RATE ANNUAL INCREASE								
(B) REVENUE REQUIREMENT FOR POWER SUPPLY ($)								
AGRICULTURAL (AG-1)	$ 2,200,585	$ 2,266,603	$ 2,334,601	$ 2,404,639	$ 2,476,778	$ 2,551,082	$ 2,627,614	$ 2,706,443
COMMERCIAL (A-1)	$ 27,812,972	$ 28,933,835	$ 30,099,868	$ 31,312,893	$ 32,574,802	$ 33,887,567	$ 35,253,236	$ 36,673,941
INDUSTRY (E-20)	$ 10,464,763	$ 10,886,493	$ 11,325,218	$ 11,781,625	$ 12,256,424	$ 12,750,358	$ 13,264,197	$ 13,798,745
MINING AND CONSTRUCTION (E-19)	$ 92,390	$ 95,162	$ 98,016	$ 100,957	$ 103,986	$ 107,105	$ 110,318	$ 113,628
RESIDENTIAL (E-1)	$ 38,376,504	$ 40,120,716	$ 41,944,203	$ 43,850,567	$ 45,843,575	$ 47,927,166	$ 50,105,455	$ 52,382,748
STREET LIGHTING (LS-1)	$ 410,861	$ 423,186	$ 435,882	$ 448,958	$ 462,427	$ 476,300	$ 490,589	$ 505,307
WATER PUMPING (E-19)	$ 1,116,865	$ 1,150,371	$ 1,184,882	$ 1,220,429	$ 1,257,042	$ 1,294,753	$ 1,333,595	$ 1,373,603
(C) PG&E'S UNBUNDLED DEMAND RATES ($/KW)								
AGRICULTURAL (AG-1)								
Rate A	$ 1.50	$ 1.55	$ 1.59	$ 1.64	$ 1.69	$ 1.74	$ 1.79	$ 1.85
Rate B	$ 2.25	$ 2.32	$ 2.39	$ 2.46	$ 2.53	$ 2.61	$ 2.69	$ 2.77
COMMERCIAL (A-1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
INDUSTRY (E-20)								
Max Peak Demand Summer	$ 10.75	$ 11.07	$ 11.40	$ 11.75	$ 12.10	$ 12.46	$ 12.83	$ 13.22
Max Part-Peak Demand Summer	$ 2.20	$ 2.27	$ 2.34	$ 2.41	$ 2.48	$ 2.55	$ 2.63	$ 2.71
MINING AND CONSTRUCTION (E-19)								
Max Peak Demand Summer	$ 11.25	$ 11.59	$ 11.94	$ 12.30	$ 12.67	$ 13.05	$ 13.44	$ 13.84
Max Part-Peak Demand Summer	$ 2.40	$ 2.47	$ 2.54	$ 2.62	$ 2.70	$ 2.78	$ 2.86	$ 2.95
RESIDENTIAL (E-1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
STREET LIGHTING (LS-1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WATER PUMPING (E-19)								
Max Peak Demand Summer	$ 11.25	$ 11.59	$ 11.94	$ 12.30	$ 12.67	$ 13.05	$ 13.44	$ 13.84
Max Part-Peak Demand Summer	$ 2.40	$ 2.47	$ 2.54	$ 2.62	$ 2.70	$ 2.78	$ 2.86	$ 2.95
(D) REVENUE REQUIREMENT FOR DEMAND CHARGES ($)								
AGRICULTURAL (AG-1)	$ 34,360	$ 35,391	$ 36,453	$ 37,546	$ 38,673	$ 39,833	$ 41,028	$ 42,259
COMMERCIAL (A-1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
INDUSTRY (E-20)	$ 744,696	$ 767,037	$ 790,048	$ 813,749	$ 838,162	$ 863,306	$ 889,206	$ 915,882
MINING AND CONSTRUCTION (E-19)	$ 6,395	$ 6,587	$ 6,784	$ 6,988	$ 7,197	$ 7,413	$ 7,636	$ 7,865
RESIDENTIAL (E-1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
STREET LIGHTING (LS-1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
WATER PUMPING (E-19)	$ 72,618	$ 74,797	$ 77,040	$ 79,352	$ 81,732	$ 84,184	$ 86,710	$ 89,311

CATEGORY	16 2027	17 2028	18 2029	19 2030	20 2031	Total
PG&E COSTS	$ 113.2	$ 118.0	$ 123.0	$ 128.2	$ 133.6	$1,856
REVENUE REQUIREMENT FOR POWER SUPPLY ($)	$ 113.2	$ 118.0	$ 123.0	$ 128.2	$ 133.6	
(A) PG&E'S UNBUNDLED GENERATION RATES ($/KWH)						
AGRICULTURAL (AG-1)	$ 0.13532	$ 0.13938	$ 0.14356	$ 0.14786	$ 0.15230	
COMMERCIAL (A-1)	$ 0.13654	$ 0.14064	$ 0.14486	$ 0.14921	$ 0.15368	
INDUSTRY (E-20)	$ 0.11835	$ 0.12190	$ 0.12556	$ 0.12933	$ 0.13321	
MINING AND CONSTRUCTION (E-19)	$ 0.12346	$ 0.12716	$ 0.13097	$ 0.13490	$ 0.13895	
RESIDENTIAL (E-1)	$ 0.09693	$ 0.09983	$ 0.10283	$ 0.10591	$ 0.10909	
STREET LIGHTING (LS-1)	$ 0.11918	$ 0.12276	$ 0.12644	$ 0.13023	$ 0.13414	
WATER PUMPING (E-19)	$ 0.12346	$ 0.12716	$ 0.13097	$ 0.13490	$ 0.13895	
GENERATION RATE ANNUAL INCREASE						
(B) REVENUE REQUIREMENT FOR POWER SUPPLY ($)						
AGRICULTURAL (AG-1)	$ 2,787,636	$ 2,871,265	$ 2,957,403	$ 3,046,125	$ 3,137,509	
COMMERCIAL (A-1)	$ 38,151,901	$ 39,689,423	$ 41,288,907	$ 42,952,849	$ 44,683,849	
INDUSTRY (E-20)	$ 14,354,834	$ 14,933,334	$ 15,535,147	$ 16,161,214	$ 16,812,511	
MINING AND CONSTRUCTION (E-19)	$ 117,037	$ 120,548	$ 124,164	$ 127,889	$ 131,726	
RESIDENTIAL (E-1)	$ 54,763,544	$ 57,252,547	$ 59,854,676	$ 62,575,071	$ 65,419,108	
STREET LIGHTING (LS-1)	$ 520,466	$ 536,080	$ 552,162	$ 568,727	$ 585,789	
WATER PUMPING (E-19)	$ 1,414,811	$ 1,457,256	$ 1,500,973	$ 1,546,003	$ 1,592,383	
(C) PG&E'S UNBUNDLED DEMAND RATES ($/KW)						
AGRICULTURAL (AG-1)						
Rate A	$ 1.90	$ 1.96	$ 2.02	$ 2.08	$ 2.14	
Rate B	$ 2.85	$ 2.94	$ 3.02	$ 3.12	$ 3.21	
COMMERCIAL (A-1)	$ -	$ -	$ -	$ -	$ -	
INDUSTRY (E-20)						
Max Peak Demand Summer	$ 13.62	$ 14.03	$ 14.45	$ 14.88	$ 15.33	
Max Part-Peak Demand Summer	$ 2.79	$ 2.87	$ 2.96	$ 3.05	$ 3.14	
MINING AND CONSTRUCTION (E-19)						
Max Peak Demand Summer	$ 14.26	$ 14.68	$ 15.12	$ 15.58	$ 16.04	
Max Part-Peak Demand Summer	$ 3.04	$ 3.13	$ 3.22	$ 3.32	$ 3.42	
RESIDENTIAL (E-1)	$ -	$ -	$ -	$ -	$ -	
STREET LIGHTING (LS-1)	$ -	$ -	$ -	$ -	$ -	
WATER PUMPING (E-19)						
Max Peak Demand Summer	$ 14.26	$ 14.68	$ 15.12	$ 15.58	$ 16.04	
Max Part-Peak Demand Summer	$ 3.04	$ 3.13	$ 3.22	$ 3.32	$ 3.42	
(D) REVENUE REQUIREMENT FOR DEMAND CHARGES ($)						
AGRICULTURAL (AG-1)	$ 43,526	$ 44,832	$ 46,177	$ 47,563	$ 48,989	
COMMERCIAL (A-1)	$ -	$ -	$ -	$ -	$ -	
INDUSTRY (E-20)	$ 943,358	$ 971,659	$ 1,000,809	$ 1,030,833	$ 1,061,758	
MINING AND CONSTRUCTION (E-19)	$ 8,101	$ 8,344	$ 8,594	$ 8,852	$ 9,117	
RESIDENTIAL (E-1)	$ -	$ -	$ -	$ -	$ -	
STREET LIGHTING (LS-1)	$ -	$ -	$ -	$ -	$ -	
WATER PUMPING (E-19)	$ 91,990	$ 94,750	$ 97,593	$ 100,520	$ 103,536	

CATEGORY	0 2011	1 2012	2 2013	3 2014	4 2015	5 2016	6 2017	7 2018
CCA COSTS		$ 74.2	$ 73.4	$ 74.5	$ 51.7	$ 53.0	$ 54.4	$ 56.5
POWER SUPPLY COSTS		$ 63.4	$ 62.7	$ 63.5	$ 55.8	$ 56.1	$ 61.4	$ 62.3
PROJECTED ENERGY PRICES ($/MWH)								
REFERENCE GAS PRICE ($/THOUSAND CF)	$ 4.99	$ 4.89	$ 4.96	$ 4.97	$ 5.11	$ 5.29	$ 5.60	$ 5.94
REFERENCE GAS PRICE - HIGH ($/MMBtu)	$ 5.01	$ 4.92	$ 4.99	$ 5.00	$ 5.13	$ 5.31	$ 5.62	$ 5.96
REFERENCE GAS PRICE - MID ($/MMBtu)	$ 4.89	$ 4.80	$ 4.87	$ 4.88	$ 5.01	$ 5.18	$ 5.49	$ 5.82
REFERENCE GAS PRICE - LOW ($/MMBtu)	$ 3.67	$ 3.60	$ 3.65	$ 3.66	$ 3.75	$ 3.89	$ 4.11	$ 4.36
(A) POWER PRODUCTION - RENEWABLES ($/MWH)		$ -	$ -	$ -	$ 59.07	$ 60.25	$ 59.08	$ 60.26
ONSHORE WIND - CLASS 3/4 ($/MWH)							$ 44.04	$ 44.85
Plant Characteristics								
Capacity (MW)							30	30
Annual Capacity Degradation Rate (%)							1.0%	1.0%
Capacity Factor							35%	35%
Operating Hours (hrs)							3,066	3,066
Annual Energy (MWh)							91,980	91,069
Heat Rate (Btu/kWh)							0	0
Annual Heat Rate Degradation Rate (%)							0.00%	0.00%
Plant Cost Data								
Instant Cost ($/kW)							$ 2,140	
Fixed O&M ($/kW-yr)							$ 16.06	$ 16.38
Variable O&M ($/MWh)							$ 6.45	$ 6.58
Integration Cost ($/MWh)							$ 28.16	$ 28.58
Insurance ($/kW-yr)							$ 12.84	$ 13.03
Fuel Cost								
Fuel Price ($/MMBTU)							$ -	$ -
Fuel Use (MMBTU)							0	0
Fuel Cost ($/MWh)							$ -	$ -
BIOMASS COMBUSTION - STOKER BOILER ($/MWH)					$ 59.07	$ 60.25	$ 61.57	$ 62.78
Plant Characteristics								
Capacity (MW)					75	75	75	75
Annual Capacity Degradation Rate (%)					0.1%	0.1%	0.1%	0.1%
Capacity Factor					85%	85%	85%	85%
Operating Hours (hrs)					7,446	7,446	7,446	7,446
Annual Energy (MWh)					558,450	557,892	557,335	556,778
Heat Rate (Btu/kWh)					11,000	11,017	11,033	11,050
Annual Heat Rate Degradation Rate (%)					0.15%	0.15%	0.15%	0.15%
Plant Cost Data								
Installed Cost ($/kW)					$2,906			
Fixed O&M ($/kW-yr)					$ 180.38	$ 184.00	$ 187.69	$ 191.46
Variable O&M ($/MWh)					$ 7.86	$ 8.02	$ 8.18	$ 8.35
Integration Cost ($/MWh)					$ -	$ -	$ -	$ -
Insurance ($/kW-yr)					$ 17.44	$ 17.70	$ 17.97	$ 18.23
Fuel Cost								
Fuel Price ($/MMBTU)					$ 2.24	$ 2.28	$ 2.33	$ 2.37
Fuel Use (MMBTU)					6,142,950	6,146,018	6,149,088	6,152,160
Fuel Cost ($/MWh)					$ 24.64	$ 25.12	$ 25.71	$ 26.19
RPS VOLUNTARY TARGET (%)		22%	23%	24%	26%	27%	28%	30%
RPS ENDUSE REQUIREMENTS (MWH)		183,576	195,488	208,175	221,688	236,082	251,413	267,743
RPS GENERATION BY CCA (MWH)		0	0	0	558,450	557,892	649,315	647,847

CATEGORY	8 2019	9 2020	10 2021	11 2022	12 2023	13 2024	14 2025	15 2026
CCA COSTS	$ 59.2	$ 62.6	$ 65.0	$ 77.2	$ 81.4	$ 86.6	$ 91.3	$ 96.7
POWER SUPPLY COSTS	$ 63.5	$ 65.3	$ 65.8	$ 75.7	$ 76.6	$ 79.0	$ 80.1	$ 82.0
PROJECTED ENERGY PRICES ($/MWH)								
REFERENCE GAS PRICE ($/THOUSAND CF)	$ 6.27	$ 6.54	$ 6.89	$ 7.26	$ 7.57	$ 7.90	$ 8.24	$ 8.58
REFERENCE GAS PRICE - HIGH ($/MMBtu)	$ 6.30	$ 6.57	$ 6.92	$ 7.29	$ 7.60	$ 7.94	$ 8.28	$ 8.62
REFERENCE GAS PRICE - MID ($/MMBtu)	$ 6.15	$ 6.41	$ 6.75	$ 7.12	$ 7.42	$ 7.75	$ 8.08	$ 8.41
REFERENCE GAS PRICE - LOW ($/MMBtu)	$ 4.61	$ 4.81	$ 5.07	$ 5.34	$ 5.56	$ 5.81	$ 6.06	$ 6.31
(A) POWER PRODUCTION - RENEWABLES ($/MWH)	$ 61.46	$ 62.77	$ 64.09	$ 65.35	$ 66.71	$ 68.10	$ 69.50	$ 70.92
ONSHORE WIND - CLASS 3/4 ($/MWH)	$ 45.69	$ 46.53	$ 47.40	$ 48.28	$ 49.19	$ 50.10	$ 51.04	$ 52.00
Plant Characteristics								
Capacity (MW)	30	30	30	30	30	30	30	30
Annual Capacity Degradation Rate (%)	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Capacity Factor	35%	35%	35%	35%	35%	35%	35%	35%
Operating Hours (hrs)	3,066	3,066	3,066	3,066	3,066	3,066	3,066	3,066
Annual Energy (MWh)	90,168	89,275	88,391	87,516	86,649	85,791	84,942	84,101
Heat Rate (Btu/kWh)	0	0	0	0	0	0	0	0
Annual Heat Rate Degradation Rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Plant Cost Data								
Instant Cost ($/kW)								
Fixed O&M ($/kW-yr)	$ 16.71	$ 17.05	$ 17.39	$ 17.74	$ 18.10	$ 18.46	$ 18.83	$ 19.21
Variable O&M ($/MWh)	$ 6.71	$ 6.84	$ 6.98	$ 7.12	$ 7.26	$ 7.41	$ 7.56	$ 7.71
Integration Cost ($/MWh)	$ 29.01	$ 29.45	$ 29.89	$ 30.34	$ 30.79	$ 31.26	$ 31.72	$ 32.20
Insurance ($/kW-yr)	$ 13.23	$ 13.43	$ 13.63	$ 13.83	$ 14.04	$ 14.25	$ 14.47	$ 14.68
Fuel Cost								
Fuel Price ($/MMBTU)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Fuel Use (MMBTU)	0	0	0	0	0	0	0	0
Fuel Cost ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BIOMASS COMBUSTION - STOKER BOILER ($/MWH)	$ 64.01	$ 65.37	$ 66.75	$ 68.04	$ 69.45	$ 70.88	$ 72.34	$ 73.81
Plant Characteristics								
Capacity (MW)	75	75	75	75	75	75	75	75
Annual Capacity Degradation Rate (%)	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
Capacity Factor	85%	85%	85%	85%	85%	85%	85%	85%
Operating Hours (hrs)	7,446	7,446	7,446	7,446	7,446	7,446	7,446	7,446
Annual Energy (MWh)	556,222	555,666	555,111	554,556	554,002	553,449	552,896	552,344
Heat Rate (Btu/kWh)	11,066	11,083	11,099	11,116	11,133	11,149	11,166	11,183
Annual Heat Rate Degradation Rate (%)	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%	0.15%
Plant Cost Data								
Installed Cost ($/kW)								
Fixed O&M ($/kW-yr)	$ 195.30	$ 199.23	$ 203.22	$ 207.30	$ 211.47	$ 215.71	$ 220.04	$ 224.46
Variable O&M ($/MWh)	$ 8.51	$ 8.69	$ 8.86	$ 9.04	$ 9.22	$ 9.40	$ 9.59	$ 9.79
Integration Cost ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Insurance ($/kW-yr)	$ 18.51	$ 18.79	$ 19.07	$ 19.35	$ 19.64	$ 19.94	$ 20.24	$ 20.54
Fuel Cost								
Fuel Price ($/MMBTU)	$ 2.41	$ 2.46	$ 2.51	$ 2.55	$ 2.60	$ 2.65	$ 2.70	$ 2.75
Fuel Use (MMBTU)	6,155,233	6,158,307	6,161,383	6,164,461	6,167,540	6,170,621	6,173,703	6,176,787
Fuel Cost ($/MWh)	$ 26.67	$ 27.26	$ 27.86	$ 28.35	$ 28.95	$ 29.55	$ 30.15	$ 30.75
RPS VOLUNTARY TARGET (%)	31%	33%	34%	36%	37%	38%	40%	41%
RPS ENDUSE REQUIREMENTS (MWH)	285,137	303,665	319,253	335,645	352,883	371,011	390,075	410,122
RPS GENERATION BY CCA (MWH)	646,389	644,941	643,502	642,072	640,652	639,240	637,838	636,445

CATEGORY	16 2027	17 2028	18 2029	19 2030	20 2031	Total
CCA COSTS	$ 109.6	$ 115.9	$ 121.4	$ 127.9	$ 135.5	$1,668
POWER SUPPLY COSTS	$ 91.5	$ 93.8	$ 94.9	$ 97.3	$ 100.8	$1,491
PROJECTED ENERGY PRICES ($/MWH)						
REFERENCE GAS PRICE ($/THOUSAND CF)	$ 8.91	$ 9.25	$ 9.58	$ 9.89	$ 10.21	
REFERENCE GAS PRICE - HIGH ($/MMBtu)	$ 8.95	$ 9.30	$ 9.63	$ 9.94	$ 10.26	
REFERENCE GAS PRICE - MID ($/MMBtu)	$ 8.74	$ 9.07	$ 9.39	$ 9.70	$ 10.01	
REFERENCE GAS PRICE - LOW ($/MMBtu)	$ 6.55	$ 6.81	$ 7.04	$ 7.27	$ 7.51	
(A) POWER PRODUCTION - RENEWABLES ($/MWH)	$ 72.47	$ 73.93	$ 75.42	$ 77.03	$ 78.66	
ONSHORE WIND - CLASS 3/4 ($/MWH)	$ 52.98	$ 53.97	$ 54.99	$ 56.03	$ 57.09	
Plant Characteristics						
Capacity (MW)	30	30	30	30	30	
Annual Capacity Degradation Rate (%)	1.0%	1.0%	1.0%	1.0%	1.0%	
Capacity Factor	35%	35%	35%	35%	35%	
Operating Hours (hrs)	3,066	3,066	3,066	3,066	3,066	
Annual Energy (MWh)	83,268	82,444	81,628	80,819	80,019	
Heat Rate (Btu/kWh)	0	0	0	0	0	
Annual Heat Rate Degradation Rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	
Plant Cost Data						
Instant Cost ($/kW)						
Fixed O&M ($/kW-yr)	$ 19.59	$ 19.99	$ 20.39	$ 20.80	$ 21.21	
Variable O&M ($/MWh)	$ 7.87	$ 8.02	$ 8.18	$ 8.35	$ 8.52	
Integration Cost ($/MWh)	$ 32.68	$ 33.17	$ 33.67	$ 34.18	$ 34.69	
Insurance ($/kW-yr)	$ 14.90	$ 15.13	$ 15.35	$ 15.58	$ 15.82	
Fuel Cost						
Fuel Price ($/MMBTU)	$ -	$ -	$ -	$ -	$ -	
Fuel Use (MMBTU)	0	0	0	0	0	
Fuel Cost ($/MWh)	$ -	$ -	$ -	$ -	$ -	
BIOMASS COMBUSTION - STOKER BOILER ($/MWH)	$ 75.41	$ 76.92	$ 78.45	$ 80.11	$ 81.80	
Plant Characteristics						
Capacity (MW)	75	75	75	75	75	
Annual Capacity Degradation Rate (%)	0.1%	0.1%	0.1%	0.1%	0.1%	
Capacity Factor	85%	85%	85%	85%	85%	
Operating Hours (hrs)	7,446	7,446	7,446	7,446	7,446	
Annual Energy (MWh)	551,792	551,241	550,690	550,140	549,590	
Heat Rate (Btu/kWh)	11,200	11,216	11,233	11,250	11,267	
Annual Heat Rate Degradation Rate (%)	0.15%	0.15%	0.15%	0.15%	0.15%	
Plant Cost Data						
Installed Cost ($/kW)						
Fixed O&M ($/kW-yr)	$ 228.97	$ 233.56	$ 238.25	$ 243.03	$ 247.91	
Variable O&M ($/MWh)	$ 9.98	$ 10.18	$ 10.39	$ 10.60	$ 10.81	
Integration Cost ($/MWh)	$ -	$ -	$ -	$ -	$ -	
Insurance ($/kW-yr)	$ 20.85	$ 21.16	$ 21.48	$ 21.80	$ 22.13	
Fuel Cost						
Fuel Price ($/MMBTU)	$ 2.81	$ 2.86	$ 2.91	$ 2.97	$ 3.03	
Fuel Use (MMBTU)	6,179,872	6,182,959	6,186,047	6,189,137	6,192,229	
Fuel Cost ($/MWh)	$ 31.47	$ 32.08	$ 32.69	$ 33.41	$ 34.14	
RPS VOLUNTARY TARGET (%)	43%	45%	46%	48%	50%	
RPS ENDUSE REQUIREMENTS (MWH)	431,206	453,378	476,696	501,219	527,010	
RPS GENERATION BY CCA (MWH)	635,060	633,685	632,318	630,959	629,609	

	0	1	2	3	4	5	6	7
CATEGORY	2011	2012	2013	2014	2015	2016	2017	2018
(B) PURCHASES - RENEWABLE ENERGY ($/MWH)		$ 89.02	$ 89.91	$ 90.81	$ 91.72	$ 92.64	$ 93.56	$ 94.50
RENEWABLE ENERGY LCOE ($/MWH)								
Onshore Wind (Class 3/4 Site)		$ 77.75						
Solar (Parabolic Trough)		$ 238.27						
Hydro (Small Scale)		$ 95.54						
Biomass Combustion (Stoker Boiler)		$ 105.87						
Geothermal (Binary)		$ 93.52						
RENEWABLE ENERGY PORTFOLIO CONTRIBUTION								
Onshore Wind (Class 3/4 Site)		66%						
Solar (Parabolic Trough)		1%						
Hydro (Small Scale)		4%						
Biomass Combustion (Stoker Boiler)		4%						
Geothermal (Binary)		25%						
(C) PURCHASES - LONG TERM CONTRACTS								
MARKET ENERGY PRICE ($/MWH)								
Plant Characteristics								
Capacity (MW)								
Annual Capacity Degradation Rate (%)								
Capacity Factor								
Operating Hours (hrs)								
Annual Energy (MWh)								
Heat Rate (Btu/kWh)		8,750	8,750	8,750	8,750	8,750	8,750	8,750
Annual Heat Rate Degradation Rate (%)								
Plant Cost Data								
Installed Cost ($/kW)								
Fixed O&M ($/kW-yr)								
Variable O&M ($/MWh)								
Variable O&M ($/kw-yr)								
Integration Cost ($/MWh)								
Fuel Cost								
Fuel Price ($/MMBTU)		$ 4.80	$ 4.87	$ 4.88	$ 5.01	$ 5.18	$ 5.49	$ 5.82
Fuel Use (MMBTU)								
Fuel Cost ($/MWh)		$ 41.98	$ 42.58	$ 42.68	$ 43.81	$ 45.35	$ 48.00	$ 50.92
AVERAGE ENERGY PRICE ($/MWH)		$ 41.98	$ 42.58	$ 42.68	$ 43.81	$ 45.35	$ 48.00	$ 50.92
ON-PEAK ENERGY PRICE ($/MWH)		$ 48.28	$ 48.96	$ 49.08	$ 50.38	$ 52.15	$ 55.20	$ 58.55
OFF-PEAK ENERGY PRICE ($/MWH)		$ 35.69	$ 36.19	$ 36.28	$ 37.23	$ 38.54	$ 40.80	$ 43.28
REAL-TIME PREMIUM ($/MWH)		$ 4.20	$ 4.26	$ 4.27	$ 4.38	$ 4.53	$ 4.80	$ 5.09
PPA AVERAGE ENERGY PRICE ($/MWh)		$ 44.08	$ 44.70	$ 44.81	$ 46.00	$ 47.61	$ 50.40	$ 53.46
PPA ON-PEAK ENERGY PRICE ($/MWh)		$ 50.69	$ 51.41	$ 51.53	$ 52.89	$ 54.75	$ 57.96	$ 61.48
PPA OFF-PEAK ENERGY PRICE ($/MWh)		$ 37.47	$ 38.00	$ 38.09	$ 39.10	$ 40.47	$ 42.84	$ 45.44
CONTRACTED AVERAGE ENERGY PRICE ($/MWh)		$ 44.39	$ 44.39	$ 46.14	$ 46.14	$ 46.14	$ 56.26	$ 56.26
CONTRACTED ON-PEAK ENERGY PRICE ($/MWh)		$ 51.05	$ 51.05	$ 53.06	$ 53.06	$ 53.06	$ 64.69	$ 64.69
CONTRACTED OFF-PEAK ENERGY PRICE ($/MWh)		$ 37.73	$ 37.73	$ 39.22	$ 39.22	$ 39.22	$ 47.82	$ 47.82
(D) PURCHASES - SPOT MARKET								
AVERAGE ENERGY PRICE		$41.98	$42.58	$42.68	$43.81	$45.35	$48.00	$50.92
ON-PEAK ENERGY PRICE		$48.28	$48.96	$49.08	$50.38	$52.15	$55.20	$58.55
OFF-PEAK ENERGY PRICE		$35.69	$36.19	$36.28	$37.23	$38.54	$40.80	$43.28
REAL-TIME PREMIUM		$4.20	$4.26	$4.27	$4.38	$4.53	$4.80	$5.09
(E) CAPACITY ($/MW):		$100,000	$102,500	$105,063	$107,689	$110,381	$113,141	$115,969

	8	9	10	11	12	13	14	15
CATEGORY	2019	2020	2021	2022	2023	2024	2025	2026
(B) PURCHASES - RENEWABLE ENERGY ($/MWH)	$ 95.44	$ 96.40	$ 97.36	$ 98.34	$ 99.32	$ 100.31	$ 101.32	$ 102.33
RENEWABLE ENERGY LCOE ($/MWH)								
Onshore Wind (Class 3/4 Site)								
Solar (Parabolic Trough)								
Hydro (Small Scale)								
Biomass Combustion (Stoker Boiler)								
Geothermal (Binary)								
RENEWABLE ENERGY PORTFOLIO CONTRIBUTION								
Onshore Wind (Class 3/4 Site)								
Solar (Parabolic Trough)								
Hydro (Small Scale)								
Biomass Combustion (Stoker Boiler)								
Geothermal (Binary)								
(C) PURCHASES - LONG TERM CONTRACTS								
MARKET ENERGY PRICE ($/MWH)								
Plant Characteristics								
Capacity (MW)								
Annual Capacity Degradation Rate (%)								
Capacity Factor								
Operating Hours (hrs)								
Annual Energy (MWh)								
Heat Rate (Btu/kWh)	8,750	8,750	8,750	8,750	8,750	8,750	8,750	8,750
Annual Heat Rate Degradation Rate (%)								
Plant Cost Data								
Installed Cost ($/kW)								
Fixed O&M ($/kW-yr)								
Variable O&M ($/MWh)								
Variable O&M ($/kw-yr)								
Integration Cost ($/MWh)								
Fuel Cost								
Fuel Price ($/MMBTU)	$ 6.15	$ 6.41	$ 6.75	$ 7.12	$ 7.42	$ 7.75	$ 8.08	$ 8.41
Fuel Use (MMBTU)								
Fuel Cost ($/MWh)	$ 53.78	$ 56.09	$ 59.10	$ 62.26	$ 64.90	$ 67.80	$ 70.68	$ 73.61
AVERAGE ENERGY PRICE ($/MWH)	$ 53.78	$ 56.09	$ 59.10	$ 62.26	$ 64.90	$ 67.80	$ 70.68	$ 73.61
ON-PEAK ENERGY PRICE ($/MWH)	$ 61.85	$ 64.50	$ 67.96	$ 71.60	$ 74.63	$ 77.97	$ 81.28	$ 84.65
OFF-PEAK ENERGY PRICE ($/MWH)	$ 45.71	$ 47.67	$ 50.23	$ 52.92	$ 55.16	$ 57.63	$ 60.07	$ 62.56
REAL-TIME PREMIUM ($/MWH)	$ 5.38	$ 5.61	$ 5.91	$ 6.23	$ 6.49	$ 6.78	$ 7.07	$ 7.36
PPA AVERAGE ENERGY PRICE ($/MWh)	$ 56.47	$ 58.89	$ 62.05	$ 65.37	$ 68.14	$ 71.19	$ 74.21	$ 77.29
PPA ON-PEAK ENERGY PRICE ($/MWh)	$ 64.94	$ 67.72	$ 71.36	$ 75.18	$ 78.37	$ 81.87	$ 85.34	$ 88.88
PPA OFF-PEAK ENERGY PRICE ($/MWh)	$ 48.00	$ 50.06	$ 52.74	$ 55.57	$ 57.92	$ 60.51	$ 63.08	$ 65.69
CONTRACTED AVERAGE ENERGY PRICE ($/MWh)	$ 56.26	$ 56.26	$ 56.26	$ 71.24	$ 71.24	$ 71.24	$ 71.24	$ 71.24
CONTRACTED ON-PEAK ENERGY PRICE ($/MWh)	$ 64.69	$ 64.69	$ 64.69	$ 81.93	$ 81.93	$ 81.93	$ 81.93	$ 81.93
CONTRACTED OFF-PEAK ENERGY PRICE ($/MWh)	$ 47.82	$ 47.82	$ 47.82	$ 60.55	$ 60.55	$ 60.55	$ 60.55	$ 60.55
(D) PURCHASES - SPOT MARKET								
AVERAGE ENERGY PRICE	$53.78	$56.09	$59.10	$62.26	$64.90	$67.80	$70.68	$73.61
ON-PEAK ENERGY PRICE	$61.85	$64.50	$67.96	$71.60	$74.63	$77.97	$81.28	$84.65
OFF-PEAK ENERGY PRICE	$45.71	$47.67	$50.23	$52.92	$55.16	$57.63	$60.07	$62.56
REAL-TIME PREMIUM	$5.38	$5.61	$5.91	$6.23	$6.49	$6.78	$7.07	$7.36
(E) CAPACITY ($/MW):	$118,869	$121,840	$124,886	$128,008	$131,209	$134,489	$137,851	$141,297

CATEGORY	16 2027	17 2028	18 2029	19 2030	20 2031	Total
(B) PURCHASES - RENEWABLE ENERGY ($/MWH)	$ 103.35	$ 104.39	$ 105.43	$ 106.48	$ 107.55	
RENEWABLE ENERGY LCOE ($/MWH)						
Onshore Wind (Class 3/4 Site)						
Solar (Parabolic Trough)						
Hydro (Small Scale)						
Biomass Combustion (Stoker Boiler)						
Geothermal (Binary)						
RENEWABLE ENERGY PORTFOLIO CONTRIBUTION						
Onshore Wind (Class 3/4 Site)						
Solar (Parabolic Trough)						
Hydro (Small Scale)						
Biomass Combustion (Stoker Boiler)						
Geothermal (Binary)						
(C) PURCHASES - LONG TERM CONTRACTS						
MARKET ENERGY PRICE ($/MWH)						
Plant Characteristics						
Capacity (MW)						
Annual Capacity Degradation Rate (%)						
Capacity Factor						
Operating Hours (hrs)						
Annual Energy (MWh)						
Heat Rate (Btu/kWh)	8,750	8,750	8,750	8,750	8,750	
Annual Heat Rate Degradation Rate (%)						
Plant Cost Data						
Installed Cost ($/kW)						
Fixed O&M ($/kW-yr)						
Variable O&M ($/MWh)						
Variable O&M ($/kw-yr)						
Integration Cost ($/MWh)						
Fuel Cost						
Fuel Price ($/MMBTU)	$ 8.74	$ 9.07	$ 9.39	$ 9.70	$ 10.01	
Fuel Use (MMBTU)						
Fuel Cost ($/MWh)	$ 76.43	$ 79.39	$ 82.18	$ 84.86	$ 87.58	
AVERAGE ENERGY PRICE ($/MWH)	$ 76.43	$ 79.39	$ 82.18	$ 84.86	$ 87.58	
ON-PEAK ENERGY PRICE ($/MWH)	$ 87.90	$ 91.30	$ 94.51	$ 97.59	$ 100.72	
OFF-PEAK ENERGY PRICE ($/MWH)	$ 64.97	$ 67.48	$ 69.85	$ 72.13	$ 74.45	
REAL-TIME PREMIUM ($/MWH)	$ 7.64	$ 7.94	$ 8.22	$ 8.49	$ 8.76	
PPA AVERAGE ENERGY PRICE ($/MWh)	$ 80.26	$ 83.36	$ 86.29	$ 89.11	$ 91.96	
PPA ON-PEAK ENERGY PRICE ($/MWh)	$ 92.29	$ 95.87	$ 99.23	$ 102.47	$ 105.76	
PPA OFF-PEAK ENERGY PRICE ($/MWh)	$ 68.22	$ 70.86	$ 73.35	$ 75.74	$ 78.17	
CONTRACTED AVERAGE ENERGY PRICE ($/MWh)	$ 86.20	$ 86.20	$ 86.20	$ 86.20	$ 86.20	
CONTRACTED ON-PEAK ENERGY PRICE ($/MWh)	$ 99.12	$ 99.12	$ 99.12	$ 99.12	$ 99.12	
CONTRACTED OFF-PEAK ENERGY PRICE ($/MWh)	$ 73.27	$ 73.27	$ 73.27	$ 73.27	$ 73.27	
(D) PURCHASES - SPOT MARKET						
AVERAGE ENERGY PRICE	$76.43	$79.39	$82.18	$84.86	$87.58	
ON-PEAK ENERGY PRICE	$87.90	$91.30	$94.51	$97.59	$100.72	
OFF-PEAK ENERGY PRICE	$64.97	$67.48	$69.85	$72.13	$74.45	
REAL-TIME PREMIUM	$7.64	$7.94	$8.22	$8.49	$8.76	
(E) CAPACITY ($/MW):	$144,830	$148,451	$152,162	$155,966	$159,865	

	0	1	2	3	4	5	6	7
CATEGORY	2011	2012	2013	2014	2015	2016	2017	2018
(A) POWER PRODUCTION - RENEWABLE ENERGY								
PERCENTAGE OF PORTFOLIO (%)		0%	0%	0%	26%	27%	28%	30%
LOAD DISTRIBUTION (%)								
ON-PEAK		61%	62%	62%	63%	63%	63%	64%
OFF-PEAK		39%	38%	38%	37%	37%	37%	36%
LOAD (KWH)		0	0	0	243,279,892	259,450,685	274,138,411	292,565,765
ON-PEAK		-	-	-	152,180,553	163,047,989	172,618,409	186,361,363
OFF-PEAK		-	-	-	91,099,339	96,402,696	101,520,002	106,204,402
COSTS ($)		$ -	$ -	$ -	$ 14,370,758	$ 15,633,176	$ 16,196,708	$ 17,630,390
ON-PEAK		$ -	$ -	$ -	$ 8,989,440	$ 9,824,441	$ 10,198,680	$ 11,230,376
OFF-PEAK		$ -	$ -	$ -	$ 5,381,318	$ 5,808,735	$ 5,998,028	$ 6,400,014
(B) PURCHASES - RENEWABLE ENERGY								
PERCENTAGE OF PORTFOLIO (%)		22%	23%	24%	0%	0%	0%	0%
LOAD DISTRIBUTION (%)								
ON-PEAK		61%	62%	62%	63%	63%	63%	64%
OFF-PEAK		39%	38%	38%	37%	37%	37%	36%
LOAD (KWH)		201,656,530	214,463,134	228,391,467	0	0	0	0
ON-PEAK		123,923,767	133,156,442	141,520,564	-	-	-	-
OFF-PEAK		77,732,763	81,306,693	86,870,903	-	-	-	-
COSTS ($)		$ 17,952,047	$ 19,283,049	$ 20,740,742	$ -	$ -	$ -	$ -
ON-PEAK		$ 11,032,052	$ 11,972,511	$ 12,851,800	$ -	$ -	$ -	$ -
OFF-PEAK		$ 6,919,995	$ 7,310,538	$ 7,888,942	$ -	$ -	$ -	$ -
(C) PURCHASES - LONG TERM CONTRACTS								
PERCENTAGE OF PORTFOLIO (%)		66%	64%	63%	62%	61%	59%	58%
LOAD DISTRIBUTION (%)								
ON-PEAK		61%	62%	62%	63%	63%	63%	64%
OFF-PEAK		39%	38%	38%	37%	37%	37%	36%
LOAD (KWH)		607,010,308	597,454,922	595,395,453	593,631,363	588,193,572	569,254,954	566,209,830
ON-PEAK		373,025,381	370,949,403	368,931,036	371,338,332	369,641,650	358,446,247	360,669,800
OFF-PEAK		233,984,927	226,505,520	226,464,417	222,293,032	218,551,922	210,808,707	205,540,030
COSTS ($)		$ 27,873,053	$ 27,484,840	$ 28,457,221	$ 28,421,357	$ 28,184,610	$ 33,269,339	$ 33,161,256
ON-PEAK		$ 19,043,797	$ 18,937,813	$ 19,575,618	$ 19,703,350	$ 19,613,323	$ 23,189,122	$ 23,332,971
OFF-PEAK		$ 8,829,256	$ 8,547,026	$ 8,881,603	$ 8,718,007	$ 8,571,286	$ 10,080,217	$ 9,828,285

CATEGORY	8 2019	9 2020	10 2021	11 2022	12 2023	13 2024	14 2025	15 2026
(A) POWER PRODUCTION - RENEWABLE ENERGY								
PERCENTAGE OF PORTFOLIO (%)	31%	33%	34%	36%	37%	38%	40%	41%
LOAD DISTRIBUTION (%)								
ON-PEAK	64%	64%	64%	64%	63%	64%	64%	64%
OFF-PEAK	36%	36%	36%	36%	37%	36%	36%	36%
LOAD (KWH)	313,029,821	336,497,738	351,045,474	368,985,351	386,089,357	408,474,418	427,921,974	450,558,787
ON-PEAK	198,890,353	215,123,105	224,423,477	235,388,091	245,165,901	261,148,996	272,942,893	286,800,665
OFF-PEAK	114,139,469	121,374,633	126,621,997	133,597,260	140,923,456	147,325,422	154,979,081	163,758,122
COSTS ($)	$ 19,238,064	$ 21,120,950	$ 22,500,187	$ 24,111,471	$ 25,756,293	$ 27,815,270	$ 29,740,607	$ 31,955,777
ON-PEAK	$ 12,223,325	$ 13,502,630	$ 14,384,376	$ 15,381,513	$ 16,355,190	$ 17,783,072	$ 18,969,550	$ 20,341,271
OFF-PEAK	$ 7,014,739	$ 7,618,320	$ 8,115,811	$ 8,729,958	$ 9,401,103	$ 10,032,198	$ 10,771,057	$ 11,614,507
(B) PURCHASES - RENEWABLE ENERGY								
PERCENTAGE OF PORTFOLIO (%)	0%	0%	0%	0%	0%	0%	0%	0%
LOAD DISTRIBUTION (%)								
ON-PEAK	64%	64%	64%	64%	63%	64%	64%	64%
OFF-PEAK	36%	36%	36%	36%	37%	36%	36%	36%
LOAD (KWH)	0	0	0	0	0	0	0	0
ON-PEAK	-	-	-	-	-	-	-	-
OFF-PEAK	-	-	-	-	-	-	-	-
COSTS ($)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ON-PEAK	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OFF-PEAK	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(C) PURCHASES - LONG TERM CONTRACTS								
PERCENTAGE OF PORTFOLIO (%)	56%	56%	54%	53%	51%	50%	48%	46%
LOAD DISTRIBUTION (%)								
ON-PEAK	64%	64%	64%	64%	63%	64%	64%	64%
OFF-PEAK	36%	36%	36%	36%	37%	36%	36%	36%
LOAD (KWH)	562,370,466	575,699,336	550,768,228	544,611,401	534,020,896	528,559,720	514,152,730	505,207,750
ON-PEAK	357,314,392	368,044,758	352,106,293	347,425,819	339,102,106	337,922,852	327,943,742	321,587,155
OFF-PEAK	205,056,074	207,654,578	198,661,935	197,185,582	194,918,790	190,636,868	186,208,988	183,620,595
COSTS ($)	$ 32,921,042	$ 33,739,479	$ 32,278,364	$ 40,403,711	$ 39,584,516	$ 39,228,616	$ 38,142,938	$ 37,465,429
ON-PEAK	$ 23,115,898	$ 23,810,082	$ 22,778,968	$ 28,463,297	$ 27,781,367	$ 27,684,755	$ 26,867,204	$ 26,346,432
OFF-PEAK	$ 9,805,144	$ 9,929,397	$ 9,499,396	$ 11,940,413	$ 11,803,150	$ 11,543,861	$ 11,275,735	$ 11,118,997

CATEGORY	16 2027	17 2028	18 2029	19 2030	20 2031	Total
(A) POWER PRODUCTION - RENEWABLE ENERGY						
PERCENTAGE OF PORTFOLIO (%)	43%	45%	46%	48%	50%	
LOAD DISTRIBUTION (%)						
ON-PEAK	64%	64%	64%	64%	63%	
OFF-PEAK	36%	36%	36%	36%	37%	
LOAD (KWH)	471,171,923	497,865,169	520,825,808	548,936,752	582,567,889	
ON-PEAK	299,329,813	316,855,054	331,571,088	348,693,040	368,029,805	
OFF-PEAK	171,842,110	181,010,114	189,254,719	200,243,712	214,538,084	
COSTS ($)	$ 34,144,543	$ 36,808,957	$ 39,281,278	$ 42,283,733	$ 45,823,769	
ON-PEAK	$ 21,691,615	$ 23,426,230	$ 25,007,471	$ 26,859,275	$ 28,948,580	
OFF-PEAK	$ 12,452,929	$ 13,382,727	$ 14,273,807	$ 15,424,457	$ 16,875,190	
(B) PURCHASES - RENEWABLE ENERGY						
PERCENTAGE OF PORTFOLIO (%)	0%	0%	0%	0%	0%	
LOAD DISTRIBUTION (%)						
ON-PEAK	64%	64%	64%	64%	63%	
OFF-PEAK	36%	36%	36%	36%	37%	
LOAD (KWH)	0	0	0	0	0	
ON-PEAK	-	-	-	-	-	
OFF-PEAK	-	-	-	-	-	
COSTS ($)	$ -	$ -	$ -	$ -	$ -	
ON-PEAK	$ -	$ -	$ -	$ -	$ -	
OFF-PEAK	$ -	$ -	$ -	$ -	$ -	
(C) PURCHASES - LONG TERM CONTRACTS						
PERCENTAGE OF PORTFOLIO (%)	46%	44%	41%	39%	39%	
LOAD DISTRIBUTION (%)						
ON-PEAK	64%	64%	64%	64%	63%	
OFF-PEAK	36%	36%	36%	36%	37%	
LOAD (KWH)	504,009,809	490,974,978	459,562,790	445,946,530	458,718,511	
ON-PEAK	320,191,324	312,469,948	292,569,478	283,272,072	289,789,547	
OFF-PEAK	183,818,485	178,505,030	166,993,313	162,674,458	168,928,965	
COSTS ($)	$ 45,206,447	$ 44,051,774	$ 41,235,733	$ 39,997,707	$ 41,101,991	
ON-PEAK	$ 31,738,811	$ 30,973,434	$ 29,000,809	$ 28,079,208	$ 28,725,250	
OFF-PEAK	$ 13,467,636	$ 13,078,341	$ 12,234,924	$ 11,918,499	$ 12,376,741	

CATEGORY	0 2011	1 2012	2 2013	3 2014	4 2015	5 2016	6 2017	7 2018
(D) PURCHASES - SPOT MARKETS								
PERCENTAGE OF PORTFOLIO (%)		13%	14%	13%	13%	13%	14%	14%
LOAD DISTRIBUTION (%)								
ON-PEAK		51%	48%	48%	44%	42%	46%	43%
OFF-PEAK		49%	52%	52%	56%	58%	54%	57%
LOAD (KWH)		121,376,047	126,415,386	126,116,375	125,023,961	129,561,889	133,028,373	132,798,198
ON-PEAK		62,501,531	60,941,313	60,609,297	55,125,780	54,943,712	61,247,559	56,818,291
OFF-PEAK		58,874,516	65,474,074	65,507,078	69,898,180	74,618,177	71,780,814	75,979,906
COSTS ($)		$ 5,628,151	$ 5,891,484	$ 5,889,075	$ 5,927,327	$ 6,328,679	$ 6,948,627	$ 7,291,324
ON-PEAK		$ 3,280,006	$ 3,243,266	$ 3,233,242	$ 3,018,507	$ 3,114,287	$ 3,675,154	$ 3,616,181
OFF-PEAK		$ 2,348,145	$ 2,648,218	$ 2,655,833	$ 2,908,820	$ 3,214,392	$ 3,273,473	$ 3,675,144
(E) NON-BYPASSABLE CHARGES		$ 11,912,803	$ 10,012,502	$ 8,415,428	$ 7,073,180	$ 5,945,085	$ 4,996,964	$ 4,200,096
AGRICULTURAL (AG-1)		$ 279,141	$ 231,687	$ 192,300	$ 159,609	$ 132,476	$ 109,955	$ 91,262
COMMERCIAL (A-1)		$ 3,314,022	$ 2,778,145	$ 2,328,919	$ 1,952,333	$ 1,636,640	$ 1,371,996	$ 1,150,144
INDUSTRY (E-20)		$ 1,047,846	$ 878,409	$ 736,370	$ 617,299	$ 517,482	$ 433,805	$ 363,659
MINING AND CONSTRUCTION (E-19)		$ 10,741	$ 8,915	$ 7,399	$ 6,141	$ 5,097	$ 4,231	$ 3,512
RESIDENTIAL (E-1)		$ 7,122,259	$ 6,000,147	$ 5,054,824	$ 4,258,437	$ 3,587,520	$ 3,022,306	$ 2,546,142
STREET LIGHTING (LS-1)		$ 8,952	$ 7,430	$ 6,167	$ 5,119	$ 4,249	$ 3,526	$ 2,927
WATER PUMPING (E-19)		$ 129,842	$ 107,769	$ 89,448	$ 74,242	$ 61,621	$ 51,145	$ 42,451
AGRICULTURAL (AG-1) PCIA ($/kWh)		$ 0.013550	$ 0.011247	$ 0.009335	$ 0.007748	$ 0.006431	$ 0.005337	$ 0.004430
COMMERCIAL (A-1)PCIA ($/kWh)		$ 0.013770	$ 0.011429	$ 0.009486	$ 0.007874	$ 0.006535	$ 0.005424	$ 0.004502
INDUSTRY (E-20) PCIA ($/kWh)		$ 0.010030	$ 0.008325	$ 0.006910	$ 0.005735	$ 0.004760	$ 0.003951	$ 0.003279
MINING AND CONSTRUCTION (E-19) PCIA ($/kWh)		$ 0.011330	$ 0.009404	$ 0.007805	$ 0.006478	$ 0.005377	$ 0.004463	$ 0.003704
RESIDENTIAL (E-1) PCIA ($/kWh)		$ 0.015760	$ 0.013081	$ 0.010857	$ 0.009011	$ 0.007479	$ 0.006208	$ 0.005153
STREET LIGHTING (LS-1) PCIA ($/kWh)		$ 0.002050	$ 0.001702	$ 0.001412	$ 0.001172	$ 0.000973	$ 0.000808	$ 0.000670
WATER PUMPING (E-19) PCIA ($/kWh)		$ 0.011330	$ 0.009404	$ 0.007805	$ 0.006478	$ 0.005377	$ 0.004463	$ 0.003704
PCIA DEESCALATION FACTOR		83%						

CATEGORY	8 2019	9 2020	10 2021	11 2022	12 2023	13 2024	14 2025	15 2026
(D) PURCHASES - SPOT MARKETS								
PERCENTAGE OF PORTFOLIO (%)	14%	12%	13%	13%	13%	14%	13%	14%
LOAD DISTRIBUTION (%)								
ON-PEAK	41%	36%	37%	37%	42%	40%	39%	39%
OFF-PEAK	59%	64%	63%	63%	58%	60%	61%	61%
LOAD (KWH)	135,367,592	126,691,853	136,533,917	137,235,833	136,238,182	143,882,574	144,924,925	147,061,608
ON-PEAK	55,878,454	45,612,473	50,396,110	51,009,933	57,540,116	57,587,343	56,959,907	58,039,732
OFF-PEAK	79,489,138	81,079,381	86,137,808	86,225,900	78,698,067	86,295,230	87,965,018	89,021,876
COSTS ($)	$ 7,817,699	$ 7,517,752	$ 8,558,642	$ 9,069,985	$ 9,519,994	$ 10,438,422	$ 10,938,279	$ 11,564,899
ON-PEAK	$ 3,756,473	$ 3,197,746	$ 3,722,761	$ 3,969,907	$ 4,667,904	$ 4,880,349	$ 5,032,119	$ 5,340,040
OFF-PEAK	$ 4,061,227	$ 4,320,006	$ 4,835,880	$ 5,100,078	$ 4,852,090	$ 5,558,073	$ 5,906,160	$ 6,224,859
(E) NON-BYPASSABLE CHARGES	$ 3,530,344	$ 2,967,423	$ 2,494,289	$ 2,096,615	$ 1,762,363	$ 1,481,414	$ 1,245,267	$ 1,046,774
AGRICULTURAL (AG-1)	$ 75,748	$ 62,871	$ 52,183	$ 43,312	$ 35,949	$ 29,837	$ 24,765	$ 20,555
COMMERCIAL (A-1)	$ 964,166	$ 808,260	$ 677,564	$ 568,002	$ 476,156	$ 399,162	$ 334,617	$ 280,510
INDUSTRY (E-20)	$ 304,855	$ 255,560	$ 214,236	$ 179,594	$ 150,554	$ 126,209	$ 105,801	$ 88,693
MINING AND CONSTRUCTION (E-19)	$ 2,915	$ 2,419	$ 2,008	$ 1,667	$ 1,383	$ 1,148	$ 953	$ 791
RESIDENTIAL (E-1)	$ 2,144,997	$ 1,807,053	$ 1,522,352	$ 1,282,505	$ 1,080,446	$ 910,222	$ 766,817	$ 646,005
STREET LIGHTING (LS-1)	$ 2,429	$ 2,016	$ 1,674	$ 1,389	$ 1,153	$ 957	$ 794	$ 659
WATER PUMPING (E-19)	$ 35,234	$ 29,244	$ 24,273	$ 20,146	$ 16,721	$ 13,879	$ 11,519	$ 9,561
AGRICULTURAL (AG-1) PCIA ($/kWh)	$ 0.003677	$ 0.003052	$ 0.002533	$ 0.002102	$ 0.001745	$ 0.001448	$ 0.001202	$ 0.000998
COMMERCIAL (A-1)PCIA ($/kWh)	$ 0.003737	$ 0.003101	$ 0.002574	$ 0.002137	$ 0.001773	$ 0.001472	$ 0.001222	$ 0.001014
INDUSTRY (E-20) PCIA ($/kWh)	$ 0.002722	$ 0.002259	$ 0.001875	$ 0.001556	$ 0.001292	$ 0.001072	$ 0.000890	$ 0.000739
MINING AND CONSTRUCTION (E-19) PCIA ($/kWh)	$ 0.003075	$ 0.002552	$ 0.002118	$ 0.001758	$ 0.001459	$ 0.001211	$ 0.001005	$ 0.000834
RESIDENTIAL (E-1) PCIA ($/kWh)	$ 0.004277	$ 0.003550	$ 0.002946	$ 0.002445	$ 0.002030	$ 0.001685	$ 0.001398	$ 0.001161
STREET LIGHTING (LS-1) PCIA ($/kWh)	$ 0.000556	$ 0.000462	$ 0.000383	$ 0.000318	$ 0.000264	$ 0.000219	$ 0.000182	$ 0.000151
WATER PUMPING (E-19) PCIA ($/kWh)	$ 0.003075	$ 0.002552	$ 0.002118	$ 0.001758	$ 0.001459	$ 0.001211	$ 0.001005	$ 0.000834
PCIA DEESCALATION FACTOR								

CATEGORY	16 2027	17 2028	18 2029	19 2030	20 2031	Total
(D) PURCHASES - SPOT MARKETS						
PERCENTAGE OF PORTFOLIO (%)	13%	13%	14%	14%	12%	
LOAD DISTRIBUTION (%)						
ON-PEAK	38%	42%	43%	42%	41%	
OFF-PEAK	62%	58%	57%	58%	59%	
LOAD (KWH)	139,050,006	142,451,401	154,821,602	158,580,157	142,721,428	
ON-PEAK	53,264,761	59,142,850	67,219,952	67,112,244	58,067,232	
OFF-PEAK	85,785,246	83,308,550	87,601,650	91,467,913	84,654,196	
COSTS ($)	$ 11,318,215	$ 12,152,863	$ 13,744,242	$ 14,493,289	$ 13,400,702	
ON-PEAK	$ 5,089,094	$ 5,869,431	$ 6,905,131	$ 7,119,171	$ 6,357,137	
OFF-PEAK	$ 6,229,120	$ 6,283,432	$ 6,839,111	$ 7,374,117	$ 7,043,565	
(E) NON-BYPASSABLE CHARGES	$ 879,929	$ 739,686	$ 621,801	$ 522,709	$ 439,413	
AGRICULTURAL (AG-1)	$ 17,061	$ 14,160	$ 11,753	$ 9,755	$ 8,097	
COMMERCIAL (A-1)	$ 235,151	$ 197,127	$ 165,252	$ 138,531	$ 116,130	
INDUSTRY (E-20)	$ 74,351	$ 62,329	$ 52,250	$ 43,801	$ 36,719	
MINING AND CONSTRUCTION (E-19)	$ 656	$ 545	$ 452	$ 375	$ 312	
RESIDENTIAL (E-1)	$ 544,227	$ 458,484	$ 386,250	$ 325,396	$ 274,130	
STREET LIGHTING (LS-1)	$ 547	$ 454	$ 377	$ 313	$ 260	
WATER PUMPING (E-19)	$ 7,936	$ 6,587	$ 5,467	$ 4,538	$ 3,766	
AGRICULTURAL (AG-1) PCIA ($/kWh)	$ 0.000828	$ 0.000687	$ 0.000571	$ 0.000474	$ 0.000393	
COMMERCIAL (A-1)PCIA ($/kWh)	$ 0.000842	$ 0.000699	$ 0.000580	$ 0.000481	$ 0.000399	
INDUSTRY (E-20) PCIA ($/kWh)	$ 0.000613	$ 0.000509	$ 0.000422	$ 0.000351	$ 0.000291	
MINING AND CONSTRUCTION (E-19) PCIA ($/kWh)	$ 0.000692	$ 0.000575	$ 0.000477	$ 0.000396	$ 0.000329	
RESIDENTIAL (E-1) PCIA ($/kWh)	$ 0.000963	$ 0.000799	$ 0.000664	$ 0.000551	$ 0.000457	
STREET LIGHTING (LS-1) PCIA ($/kWh)	$ 0.000125	$ 0.000104	$ 0.000086	$ 0.000072	$ 0.000059	
WATER PUMPING (E-19) PCIA ($/kWh)	$ 0.000692	$ 0.000575	$ 0.000477	$ 0.000396	$ 0.000329	
PCIA DEESCALATION FACTOR						

CATEGORY		0 2011	1 2012	2 2013	3 2014	4 2015	5 2016	6 2017	7 2018
GRID MANAGEMENT			$ 5.8	$ 6.0	$ 6.3	$ 6.5	$ 6.8	$ 7.0	$ 7.3
(A) ANCILLARY SERVICES AND RESERVES:			$ 1,128,266	$ 1,173,948	$ 1,219,610	$ 1,267,318	$ 1,315,542	$ 1,378,768	$ 1,430,992
ANCILLARY SERVICE PRICES ($/MWH)									
SPINNING RESERVE	0.53%		$ 0.22	$ 0.23	$ 0.23	$ 0.23	$ 0.24	$ 0.26	$ 0.27
NON-SPINNING RESERVE	0.07%		$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.03	$ 0.04	$ 0.04
REPLACEMENT RESERVE	0.49%		$ 0.21	$ 0.21	$ 0.21	$ 0.22	$ 0.22	$ 0.24	$ 0.25
REGULATION - UP	0.76%		$ 0.32	$ 0.32	$ 0.32	$ 0.33	$ 0.34	$ 0.36	$ 0.39
REGULATIION - DOWN	0.67%		$ 0.28	$ 0.28	$ 0.29	$ 0.29	$ 0.30	$ 0.32	$ 0.34
ANCILLARY SERVICE REQUIREMENTS (KWH)			100,656,934	101,758,958	103,012,154	104,304,585	105,740,315	106,204,829	107,742,356
SPINNING RESERVE			29,982,917	30,311,179	30,684,471	31,069,451	31,497,115	31,635,481	32,093,468
NON-SPINNING RESERVE			21,416,369	21,650,842	21,917,480	22,192,465	22,497,939	22,596,772	22,923,906
REPLACEMENT RESERVE			10,708,184	10,825,421	10,958,740	11,096,232	11,248,970	11,298,386	11,461,953
REGULATION-UP			19,274,732	19,485,758	19,725,732	19,973,218	20,248,145	20,337,095	20,631,515
REGULATION-DOWN			19,274,732	19,485,758	19,725,732	19,973,218	20,248,145	20,337,095	20,631,515
ANCILLARY SERVICE COSTS ($)			$ 21,137	$ 21,671	$ 21,989	$ 22,854	$ 23,983	$ 25,501	$ 27,439
SPINNING RESERVE			$ 6,730	$ 6,900	$ 7,001	$ 7,277	$ 7,636	$ 8,119	$ 8,736
NON-SPINNING RESERVE			$ 663	$ 680	$ 690	$ 717	$ 752	$ 800	$ 861
REPLACEMENT RESERVE			$ 2,211	$ 2,267	$ 2,300	$ 2,391	$ 2,509	$ 2,668	$ 2,871
REGULATION-UP			$ 6,127	$ 6,282	$ 6,374	$ 6,625	$ 6,952	$ 7,392	$ 7,954
REGULATION-DOWN			$ 5,406	$ 5,542	$ 5,624	$ 5,845	$ 6,134	$ 6,522	$ 7,018
PLANNING RESERVES ($)			$ 1,107,128	$ 1,152,277	$ 1,197,620	$ 1,244,464	$ 1,291,559	$ 1,353,267	$ 1,403,553
PLANNING RESERVES REQUIREMENTS (KW)			11,071	11,242	11,399	11,556	11,701	11,961	12,103
Peak Load (kW)			150,412	152,387	154,390	156,420	158,478	160,565	162,681
15 Percent of Peak Load (kW)			22,562	22,858	23,159	23,463	23,772	24,085	24,402
Contribution from Ancillary Reserves (kW)			11,491	11,616	11,759	11,907	12,071	12,124	12,299
(B) CALIFORNIA ISO COSTS			$ 4,702,172	$ 4,872,494	$ 5,055,813	$ 5,247,226	$ 5,452,440	$ 5,613,302	$ 5,836,930
CAISO CHARGE ($/MWH)			$ 5.13	$ 5.26	$ 5.39	$ 5.52	$ 5.66	$ 5.80	$ 5.95
(C) OPERATIONS & SCHEDULING COORDINATION			$0	$0	$0	$0	$0	$0	$0
OPERATIONS AND SCHEDULING COST FOR CONSULTANT									
Operatioins and Scheduling Charge ($/MWh)			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Operatioins and Scheduling Cost ($)			$ -	$ -	$ -	$ -	$ -	$ -	$ -

CATEGORY	8 2019	9 2020	10 2021	11 2022	12 2023	13 2024	14 2025	15 2026
GRID MANAGEMENT	$ 7.6	$ 7.9	$ 8.2	$ 8.5	$ 8.8	$ 9.1	$ 9.5	$ 9.8
(A) ANCILLARY SERVICES AND RESERVES:	$ 1,481,410	$ 1,526,098	$ 1,599,328	$ 1,663,665	$ 1,737,868	$ 1,796,095	$ 1,874,112	$ 1,945,942
ANCILLARY SERVICE PRICES ($/MWH)								
SPINNING RESERVE	$ 0.29	$ 0.30	$ 0.32	$ 0.33	$ 0.35	$ 0.36	$ 0.38	$ 0.39
NON-SPINNING RESERVE	$ 0.04	$ 0.04	$ 0.04	$ 0.05	$ 0.05	$ 0.05	$ 0.05	$ 0.05
REPLACEMENT RESERVE	$ 0.26	$ 0.28	$ 0.29	$ 0.31	$ 0.32	$ 0.33	$ 0.35	$ 0.36
REGULATION - UP	$ 0.41	$ 0.42	$ 0.45	$ 0.47	$ 0.49	$ 0.51	$ 0.54	$ 0.56
REGULATIION - DOWN	$ 0.36	$ 0.37	$ 0.39	$ 0.42	$ 0.43	$ 0.45	$ 0.47	$ 0.49
ANCILLARY SERVICE REQUIREMENTS (KWH)	109,581,507	111,975,316	112,485,989	113,851,585	114,713,014	116,865,044	117,890,620	119,525,627
SPINNING RESERVE	32,641,300	33,354,350	33,506,465	33,913,238	34,169,834	34,810,864	35,116,355	35,603,378
NON-SPINNING RESERVE	23,315,214	23,824,535	23,933,189	24,223,741	24,407,024	24,864,903	25,083,111	25,430,985
REPLACEMENT RESERVE	11,657,607	11,912,268	11,966,595	12,111,871	12,203,512	12,432,451	12,541,555	12,715,492
REGULATION-UP	20,983,693	21,442,082	21,539,870	21,801,367	21,966,322	22,378,413	22,574,800	22,887,886
REGULATION-DOWN	20,983,693	21,442,082	21,539,870	21,801,367	21,966,322	22,378,413	22,574,800	22,887,886
ANCILLARY SERVICE COSTS ($)	$ 29,478	$ 31,413	$ 33,250	$ 35,456	$ 37,238	$ 39,631	$ 41,676	$ 44,005
SPINNING RESERVE	$ 9,386	$ 10,002	$ 10,587	$ 11,289	$ 11,856	$ 12,618	$ 13,269	$ 14,011
NON-SPINNING RESERVE	$ 924	$ 985	$ 1,043	$ 1,112	$ 1,168	$ 1,243	$ 1,307	$ 1,380
REPLACEMENT RESERVE	$ 3,084	$ 3,286	$ 3,478	$ 3,709	$ 3,896	$ 4,146	$ 4,360	$ 4,604
REGULATION-UP	$ 8,545	$ 9,106	$ 9,638	$ 10,278	$ 10,795	$ 11,488	$ 12,081	$ 12,756
REGULATION-DOWN	$ 7,539	$ 8,034	$ 8,504	$ 9,068	$ 9,524	$ 10,136	$ 10,659	$ 11,255
PLANNING RESERVES ($)	$ 1,451,932	$ 1,494,685	$ 1,566,078	$ 1,628,209	$ 1,700,629	$ 1,756,464	$ 1,832,436	$ 1,901,937
PLANNING RESERVES REQUIREMENTS (KW)	12,215	12,268	12,540	12,720	12,961	13,060	13,293	13,461
Peak Load (kW)	164,826	167,001	169,206	171,442	173,709	176,007	178,338	180,700
15 Percent of Peak Load (kW)	24,724	25,050	25,381	25,716	26,056	26,401	26,751	27,105
Contribution from Ancillary Reserves (kW)	12,509	12,783	12,841	12,997	13,095	13,341	13,458	13,644
(B) CALIFORNIA ISO COSTS	$ 6,084,980	$ 6,373,354	$ 6,562,481	$ 6,808,204	$ 7,031,209	$ 7,342,193	$ 7,591,792	$ 7,889,509
CAISO CHARGE ($/MWH)	$ 6.10	$ 6.25	$ 6.41	$ 6.57	$ 6.73	$ 6.90	$ 7.07	$ 7.25
(C) OPERATIONS & SCHEDULING COORDINATION	$0	$0	$0	$0	$0	$0	$0	$0
OPERATIONS AND SCHEDULING COST FOR CONSULTANT								
Operatioins and Scheduling Charge ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Operatioins and Scheduling Cost ($)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

CATEGORY	16 2027	17 2028	18 2029	19 2030	20 2031	Total
GRID MANAGEMENT	$ 10.1	$ 10.6	$ 11.0	$ 11.4	$ 11.9	$170
(A) ANCILLARY SERVICES AND RESERVES:	$ 1,981,699	$ 2,104,466	$ 2,198,543	$ 2,280,358	$ 2,349,565	
ANCILLARY SERVICE PRICES ($/MWH)						
SPINNING RESERVE	$ 0.41	$ 0.42	$ 0.44	$ 0.45	$ 0.47	
NON-SPINNING RESERVE	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	
REPLACEMENT RESERVE	$ 0.38	$ 0.39	$ 0.40	$ 0.42	$ 0.43	
REGULATION - UP	$ 0.58	$ 0.60	$ 0.62	$ 0.64	$ 0.66	
REGULATIION - DOWN	$ 0.51	$ 0.53	$ 0.55	$ 0.57	$ 0.59	
ANCILLARY SERVICE REQUIREMENTS (KWH)	120,360,470	122,464,755	123,363,526	125,202,064	127,947,153	
SPINNING RESERVE	35,852,055	36,478,863	36,746,582	37,294,232	38,111,918	
NON-SPINNING RESERVE	25,608,611	26,056,331	26,247,559	26,638,737	27,222,799	
REPLACEMENT RESERVE	12,804,305	13,028,165	13,123,779	13,319,369	13,611,399	
REGULATION-UP	23,047,750	23,450,698	23,622,803	23,974,863	24,500,519	
REGULATION-DOWN	23,047,750	23,450,698	23,622,803	23,974,863	24,500,519	
ANCILLARY SERVICE COSTS ($)	$ 46,016	$ 48,633	$ 50,709	$ 53,145	$ 56,051	
SPINNING RESERVE	$ 14,651	$ 15,484	$ 16,145	$ 16,921	$ 17,846	
NON-SPINNING RESERVE	$ 1,443	$ 1,525	$ 1,590	$ 1,667	$ 1,758	
REPLACEMENT RESERVE	$ 4,814	$ 5,088	$ 5,305	$ 5,560	$ 5,864	
REGULATION-UP	$ 13,339	$ 14,098	$ 14,700	$ 15,406	$ 16,248	
REGULATION-DOWN	$ 11,769	$ 12,438	$ 12,969	$ 13,592	$ 14,335	
PLANNING RESERVES ($)	$ 1,935,682	$ 2,055,833	$ 2,147,834	$ 2,227,212	$ 2,293,513	
PLANNING RESERVES REQUIREMENTS (KW)	13,365	13,849	14,115	14,280	14,347	
Peak Load (kW)	180,700	185,524	187,987	190,484	193,016	
15 Percent of Peak Load (kW)	27,105	27,829	28,198	28,573	28,952	
Contribution from Ancillary Reserves (kW)	13,740	13,980	14,083	14,292	14,606	
(B) CALIFORNIA ISO COSTS	$ 8,143,229	$ 8,492,739	$ 8,768,944	$ 9,122,122	$ 9,555,180	
CAISO CHARGE ($/MWH)	$ 7.43	$ 7.62	$ 7.81	$ 8.00	$ 8.20	
(C) OPERATIONS & SCHEDULING COORDINATION	$0	$0	$0	$0	$0	
OPERATIONS AND SCHEDULING COST FOR CONSULTANT						
Operatioins and Scheduling Charge ($/MWh)	$ -	$ -	$ -	$ -	$ -	
Operatioins and Scheduling Cost ($)	$ -	$ -	$ -	$ -	$ -	

CATEGORY	0 2011	1 2012	2 2013	3 2014	4 2015	5 2016	6 2017	7 2018
UTILITY OPERATIONS		$4.9	$4.5	$4.7	$4.8	$4.9	$5.1	$5.2
(A) DISTRIBUTION O&M		$ -	$ -	$ -	$ -	$ -	$ -	$ -
(B) CUSTOMER SERVICE		$ 111,071	$ 4,097	$ 4,215	$ 4,336	$ 4,461	$ 4,590	$ 4,722
CCA CUSTOMER NOTIFICATION COSTS		$ 100,644	$ 1,392	$ 1,434	$ 1,477	$ 1,521	$ 1,566	$ 1,613
Customer List Development		$ 2,390	$ -	$ -	$ -	$ -	$ -	$ -
Customer Notification - Direct Mail		$ 84,218	$ 1,193	$ 1,229	$ 1,266	$ 1,303	$ 1,342	$ 1,382
Annual charger per account		$ 1.2	$ 1.2	$ 1.2	$ 1.3	$ 1.3	$ 1.3	$ 1.3
Cutomer accounts		70,182	980	994	1,009	1,023	1,038	1,053
Customer Notification - in PG&E Monthly Bill		$ 14,036	$ 199	$ 205	$ 211	$ 217	$ 224	$ 230
Annual charger per account		$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2
Cutomer accounts		70,182	980	994	1,009	1,023	1,038	1,053
NEW CUSTOMER ENROLLMENT COSTS		$ 8,240	$ 457	$ 470	$ 484	$ 499	$ 514	$ 529
Mass Enrollment		$ 8,240	$ -	$ -	$ -	$ -	$ -	$ -
New Customer Enrollment		$ -	$ 457	$ 470	$ 484	$ 499	$ 514	$ 529
Charger per account		$ 0.49	$ 0.50	$ 0.50	$ 0.51	$ 0.52	$ 0.53	$ 0.54
New accounts to enrol in CCA		0	918	932	946	959	973	988
OPT-OUT REQUEST COSTS		$ 2,187	$ 2,248	$ 2,311	$ 2,375	$ 2,442	$ 2,510	$ 2,581
Internet Opt-Out Cost		$ 1,177	$ 1,210	$ 1,244	$ 1,279	$ 1,315	$ 1,352	$ 1,390
Charger per account		$ 0.49	$ 0.50	$ 0.50	$ 0.51	$ 0.52	$ 0.53	$ 0.54
Quantity of cutomers that opt-out		2,403	2,434	2,465	2,496	2,528	2,561	2,593
Telephone Opt-Out Cost		$ 1,009	$ 1,037	$ 1,066	$ 1,096	$ 1,127	$ 1,159	$ 1,191
Charger per account		$ 0.42	$ 0.43	$ 0.43	$ 0.44	$ 0.45	$ 0.45	$ 0.46
Quantity of cutomers that opt-out		2,403	2,434	2,465	2,496	2,528	2,561	2,593
(C) METERING & BILLING		$ 799,369	$ 427,364	$ 439,708	$ 452,412	$ 465,488	$ 478,946	$ 492,797
METER DATA POSTING		$ 101,564	$ 104,377	$ 107,268	$ 110,240	$ 113,295	$ 116,436	$ 119,666
Annual Cumulative Meter Cost		$ 62,424	$ 64,251	$ 66,133	$ 68,071	$ 70,066	$ 72,120	$ 74,235
Annual cumulative meter charge per meter		$ 0.96	$ 0.97	$ 0.99	$ 1.00	$ 1.02	$ 1.03	$ 1.05
Cumulative meters to read		65,025	65,940	66,868	67,810	68,766	69,735	70,719
Annual Interval Meter Cost		$ 39,141	$ 40,125	$ 41,134	$ 42,169	$ 43,229	$ 44,317	$ 45,431
Annual interval meter charge per meter		$ 111	$ 113	$ 115	$ 116	$ 118	$ 120	$ 122
Interval meters to read		351	355	359	362	366	369	373
BILLING SERVICES		$ 313,805	$ 322,987	$ 332,440	$ 342,173	$ 352,193	$ 362,509	$ 373,131
Annual Billing Charges		$ 313,805	$ 322,987	$ 332,440	$ 342,173	$ 352,193	$ 362,509	$ 373,131
Annual Billing Charge Per Account		$ 4.80	$ 4.87	$ 4.95	$ 5.02	$ 5.09	$ 5.17	$ 5.25
Accounts to Bill		65,376	66,295	67,226	68,172	69,131	70,105	71,092
SERVICE ESTABLISHMENT		$ 192,000	$ -	$ -	$ -	$ -	$ -	$ -
(D) ADMINISTRATIVE AND GENERAL		$ 3,996,117	$ 4,105,786	$ 4,218,518	$ 4,334,400	$ 4,453,520	$ 4,575,971	$ 4,701,846
Staffing		$ 2,111,125	$ 2,169,062	$ 2,228,618	$ 2,289,838	$ 2,352,768	$ 2,417,458	$ 2,483,957
Infrastructure		$ 107,642	$ 110,596	$ 113,633	$ 116,755	$ 119,963	$ 123,262	$ 126,652
Contractor Costs		$ 1,777,350	$ 1,826,128	$ 1,876,267	$ 1,927,808	$ 1,980,789	$ 2,035,251	$ 2,091,237

CATEGORY	8 2019	9 2020	10 2021	11 2022	12 2023	13 2024	14 2025	15 2026
UTILITY OPERATIONS	$5.3	$5.5	$5.6	$5.8	$6.0	$6.1	$6.3	$6.5
(A) DISTRIBUTION O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(B) CUSTOMER SERVICE	$ 4,859	$ 4,999	$ 5,143	$ 5,291	$ 5,444	$ 5,601	$ 5,763	$ 5,930
CCA CUSTOMER NOTIFICATION COSTS	$ 1,661	$ 1,710	$ 1,761	$ 1,814	$ 1,868	$ 1,923	$ 1,981	$ 2,040
Customer List Development	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Notification - Direct Mail	$ 1,423	$ 1,466	$ 1,510	$ 1,555	$ 1,601	$ 1,649	$ 1,698	$ 1,748
Annual charger per account	$ 1.3	$ 1.4	$ 1.4	$ 1.4	$ 1.4	$ 1.4	$ 1.5	$ 1.5
Cutomer accounts	1,069	1,084	1,100	1,116	1,133	1,149	1,166	1,183
Customer Notification - in PG&E Monthly Bill	$ 237	$ 244	$ 252	$ 259	$ 267	$ 275	$ 283	$ 291
Annual charger per account	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2
Cutomer accounts	1,069	1,084	1,100	1,116	1,133	1,149	1,166	1,183
NEW CUSTOMER ENROLLMENT COSTS	$ 545	$ 561	$ 578	$ 595	$ 613	$ 631	$ 650	$ 670
Mass Enrollment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New Customer Enrollment	$ 545	$ 561	$ 578	$ 595	$ 613	$ 631	$ 650	$ 670
Charger per account	$ 0.54	$ 0.55	$ 0.56	$ 0.57	$ 0.58	$ 0.59	$ 0.59	$ 0.60
New accounts to enrol in CCA	1,002	1,017	1,032	1,047	1,062	1,078	1,094	1,110
OPT-OUT REQUEST COSTS	$ 2,653	$ 2,727	$ 2,804	$ 2,883	$ 2,963	$ 3,047	$ 3,132	$ 3,220
Internet Opt-Out Cost	$ 1,428	$ 1,469	$ 1,510	$ 1,552	$ 1,596	$ 1,641	$ 1,687	$ 1,734
Charger per account	$ 0.54	$ 0.55	$ 0.56	$ 0.57	$ 0.58	$ 0.59	$ 0.59	$ 0.60
Quantity of cutomers that opt-out	2,627	2,661	2,695	2,729	2,765	2,800	2,836	2,873
Telephone Opt-Out Cost	$ 1,224	$ 1,259	$ 1,294	$ 1,330	$ 1,368	$ 1,406	$ 1,446	$ 1,486
Charger per account	$ 0.47	$ 0.47	$ 0.48	$ 0.49	$ 0.49	$ 0.50	$ 0.51	$ 0.52
Quantity of cutomers that opt-out	2,627	2,661	2,695	2,729	2,765	2,800	2,836	2,873
(C) METERING & BILLING	$ 507,052	$ 521,725	$ 536,826	$ 552,369	$ 568,366	$ 584,832	$ 601,779	$ 619,222
METER DATA POSTING	$ 122,986	$ 126,399	$ 129,908	$ 133,515	$ 137,224	$ 141,037	$ 144,957	$ 148,988
Annual Cumulative Meter Cost	$ 76,412	$ 78,654	$ 80,962	$ 83,338	$ 85,785	$ 88,304	$ 90,898	$ 93,569
Annual cumulative meter charge per meter	$ 1.07	$ 1.08	$ 1.10	$ 1.11	$ 1.13	$ 1.15	$ 1.17	$ 1.18
Cumulative meters to read	71,718	72,731	73,759	74,802	75,860	76,934	78,024	79,129
Annual Interval Meter Cost	$ 46,574	$ 47,745	$ 48,946	$ 50,177	$ 51,439	$ 52,733	$ 54,059	$ 55,418
Annual interval meter charge per meter	$ 124	$ 125	$ 127	$ 129	$ 131	$ 133	$ 135	$ 137
Interval meters to read	377	381	384	388	392	396	400	404
BILLING SERVICES	$ 384,067	$ 395,326	$ 406,918	$ 418,854	$ 431,143	$ 443,795	$ 456,822	$ 470,235
Annual Billing Charges	$ 384,067	$ 395,326	$ 406,918	$ 418,854	$ 431,143	$ 443,795	$ 456,822	$ 470,235
Annual Billing Charge Per Account	$ 5.33	$ 5.41	$ 5.49	$ 5.57	$ 5.65	$ 5.74	$ 5.83	$ 5.91
Accounts to Bill	72,095	73,112	74,143	75,190	76,252	77,330	78,424	79,533
SERVICE ESTABLISHMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(D) ADMINISTRATIVE AND GENERAL	$ 4,831,243	$ 4,964,262	$ 5,101,004	$ 5,241,576	$ 5,386,087	$ 5,534,647	$ 5,687,373	$ 5,844,381
Staffing	$ 2,552,317	$ 2,622,590	$ 2,694,830	$ 2,769,093	$ 2,845,437	$ 2,923,921	$ 3,004,605	$ 3,087,551
Infrastructure	$ 130,138	$ 133,721	$ 137,404	$ 141,191	$ 145,084	$ 149,085	$ 153,199	$ 157,429
Contractor Costs	$ 2,148,789	$ 2,207,951	$ 2,268,770	$ 2,331,292	$ 2,395,566	$ 2,461,641	$ 2,529,568	$ 2,599,401

CATEGORY	16 2027	17 2028	18 2029	19 2030	20 2031	Total
UTILITY OPERATIONS	$6.6	$6.8	$7.0	$7.2	$7.4	$116
(A) DISTRIBUTION O&M	$ -	$ -	$ -	$ -	$ -	
(B) CUSTOMER SERVICE	$ 6,101	$ 6,278	$ 6,459	$ 6,646	$ 6,838	
CCA CUSTOMER NOTIFICATION COSTS	$ 2,101	$ 2,163	$ 2,228	$ 2,294	$ 2,363	
Customer List Development	$ -	$ -	$ -	$ -	$ -	
Customer Notification - Direct Mail	$ 1,801	$ 1,854	$ 1,910	$ 1,966	$ 2,025	
Annual charger per account	$ 1.5	$ 1.5	$ 1.5	$ 1.6	$ 1.6	
Cutomer accounts	1,200	1,218	1,235	1,253	1,272	
Customer Notification - in PG&E Monthly Bill	$ 300	$ 309	$ 318	$ 328	$ 338	
Annual charger per account	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3	
Cutomer accounts	1,200	1,218	1,235	1,253	1,272	
NEW CUSTOMER ENROLLMENT COSTS	$ 690	$ 710	$ 732	$ 753	$ 776	
Mass Enrollment	$ -	$ -	$ -	$ -	$ -	
New Customer Enrollment	$ 690	$ 710	$ 732	$ 753	$ 776	
Charger per account	$ 0.61	$ 0.62	$ 0.63	$ 0.64	$ 0.65	
New accounts to enrol in CCA	1,126	1,142	1,159	1,176	1,193	
OPT-OUT REQUEST COSTS	$ 3,311	$ 3,404	$ 3,500	$ 3,598	$ 3,700	
Internet Opt-Out Cost	$ 1,783	$ 1,833	$ 1,885	$ 1,938	$ 1,992	
Charger per account	$ 0.61	$ 0.62	$ 0.63	$ 0.64	$ 0.65	
Quantity of cutomers that opt-out	2,910	2,948	2,986	3,025	3,064	
Telephone Opt-Out Cost	$ 1,528	$ 1,571	$ 1,615	$ 1,661	$ 1,708	
Charger per account	$ 0.53	$ 0.53	$ 0.54	$ 0.55	$ 0.56	
Quantity of cutomers that opt-out	2,910	2,948	2,986	3,025	3,064	
(C) METERING & BILLING	$ 637,176	$ 655,655	$ 674,676	$ 694,253	$ 714,404	
METER DATA POSTING	$ 153,131	$ 157,392	$ 161,772	$ 166,275	$ 170,906	
Annual Cumulative Meter Cost	$ 96,319	$ 99,151	$ 102,066	$ 105,068	$ 108,159	
Annual cumulative meter charge per meter	$ 1.20	$ 1.22	$ 1.24	$ 1.26	$ 1.27	
Cumulative meters to read	80,251	81,389	82,544	83,716	84,906	
Annual Interval Meter Cost	$ 56,812	$ 58,241	$ 59,706	$ 61,207	$ 62,747	
Annual interval meter charge per meter	$ 139	$ 141	$ 143	$ 146	$ 148	
Interval meters to read	408	412	416	420	425	
BILLING SERVICES	$ 484,045	$ 498,264	$ 512,904	$ 527,978	$ 543,499	
Annual Billing Charges	$ 484,045	$ 498,264	$ 512,904	$ 527,978	$ 543,499	
Annual Billing Charge Per Account	$ 6.00	$ 6.09	$ 6.18	$ 6.28	$ 6.37	
Accounts to Bill	80,659	81,802	82,961	84,137	85,330	
SERVICE ESTABLISHMENT	$ -	$ -	$ -	$ -	$ -	
(D) ADMINISTRATIVE AND GENERAL	$ 6,005,794	$ 6,171,736	$ 6,342,337	$ 6,517,728	$ 6,698,046	
Staffing	$ 3,172,825	$ 3,260,491	$ 3,350,619	$ 3,443,277	$ 3,538,538	
Infrastructure	$ 161,776	$ 166,246	$ 170,842	$ 175,566	$ 180,423	
Contractor Costs	$ 2,671,192	$ 2,744,999	$ 2,820,876	$ 2,898,885	$ 2,979,085	

CATEGORY	0 2011	1 2012	2 2013	3 2014	4 2015	5 2016	6 2017	7 2018
FINANCING COSTS		$ (0.6)	$ (0.6)	$ (0.6)	$ (16.0)	$ (16.0)	$ (20.5)	$ (20.5)
(A) DEBT SERVICE		($580,011)	($580,011)	($580,011)	($15,968,016)	($15,968,016)	($20,500,883)	($20,500,883)
TOTAL DEBT ISSUANCES		$ 4,371,906	$ -	$ -	$ 223,645,340	$ -	$ 65,879,539	$ -
Startup Costs		$ 4,371,906	$ -	$ -	$ -	$ -	$ -	$ -
Cost excluding bond charges		$ 4,261,117						
Bond charges		$ 110,789						
Generation Development		$ -	$ -	$ -	$ 223,645,340	$ -	$ 65,879,539	$ -
Cost excluding bond charges					$ 217,977,915		$ 64,210,077	
Bond charges					$ 5,667,426		$ 1,669,462	
TOTAL DEBT SERVICE		($580,011)	($580,011)	($580,011)	($15,968,016)	($15,968,016)	($20,500,883)	($20,500,883)
Startup Costs		($580,011)	($580,011)	($580,011)	($580,011)	($580,011)	($580,011)	($580,011)
Generation Development		$ -	$ -	$ -	($15,388,005)	($15,388,005)	($19,920,872)	($19,920,872)
Loan 1		$ -	$ -	$ -	($15,388,005)	($15,388,005)	($15,388,005)	($15,388,005)
Loan 2		$ -	$ -	$ -	$ -	$ -	($4,532,867)	($4,532,867)
Loan 3		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Debt Coverage (1.25)		$ -	$ -	$ -	$ -	$ -	$ -	$ -
INTEREST PORTION OF DEBT SERVICE		($240,455)	($221,779)	($202,077)	($12,481,784)	($12,290,041)	($15,711,127)	($15,447,691)
Startup Costs		($240,455)	($221,779)	($202,077)	($181,290)	($159,360)	($136,225)	($111,816)
Generation Development		$ -	$ -	$ -	($12,300,494)	($12,130,681)	($15,574,902)	($15,335,874)
Loan 1		$ -	$ -	$ -	($12,300,494)	($12,130,681)	($11,951,528)	($11,762,522)
Loan 2		$ -	$ -	$ -	$0	$0	($3,623,375)	($3,573,353)
Loan 3		$ -	$ -	$ -	$0	$0	$0	$0
PRINCIPAL PORTION OF DEBT SERVICE		($339,556)	($358,232)	($377,935)	($3,486,232)	($3,677,975)	($4,789,756)	($5,053,193)
Startup Costs		($339,556)	($358,232)	($377,935)	($398,721)	($420,651)	($443,786)	($468,195)
Generation Development		$ -	$ -	$ -	($3,087,511)	($3,257,324)	($4,345,970)	($4,584,998)
(B) DEBT COVERAGE		$ -	$ -	$ -	$ -	$ -	$ -	$ -
DEBT COVERAGE RESERVE ADDITIONS ($ B.O.Y.)		$ -	$ -	$ -	$ -	$ -	$ -	$ -
DEBT COVERAGE RESERVE ADDITIONS ($ E.O.Y.)		$ -	$ -	$ -	$ -	$ -	$ -	$ -
DEBT SERVICE RESERVE ($)		$ -	$ -	$ -	$ -	$ -	$ -	$ -
(C) WORKING CAPITAL EXPENSE		$ -	$ -	$ -	$ -	$ -	$ -	$ -

CATEGORY	8 2019	9 2020	10 2021	11 2022	12 2023	13 2024	14 2025	15 2026
FINANCING COSTS	$ (20.5)	$ (20.5)	$ (20.5)	$ (19.9)	$ (19.9)	$ (19.9)	$ (19.9)	$ (19.9)
(A) DEBT SERVICE	($20,500,883)	($20,500,883)	($20,500,883)	($19,920,872)	($19,920,872)	($19,920,872)	($19,920,872)	($19,920,872)
TOTAL DEBT ISSUANCES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Startup Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cost excluding bond charges								
Bond charges								
Generation Development	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Cost excluding bond charges								
Bond charges								
TOTAL DEBT SERVICE	($20,500,883)	($20,500,883)	($20,500,883)	($19,920,872)	($19,920,872)	($19,920,872)	($19,920,872)	($19,920,872)
Startup Costs	($580,011)	($580,011)	($580,011)	$ -	$ -	$ -	$ -	$ -
Generation Development	($19,920,872)	($19,920,872)	($19,920,872)	($19,920,872)	($19,920,872)	($19,920,872)	($19,920,872)	($19,920,872)
Loan 1	($15,388,005)	($15,388,005)	($15,388,005)	($15,388,005)	($15,388,005)	($15,388,005)	($15,388,005)	($15,388,005)
Loan 2	($4,532,867)	($4,532,867)	($4,532,867)	($4,532,867)	($4,532,867)	($4,532,867)	($4,532,867)	($4,532,867)
Loan 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Debt Coverage (1.25)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
INTEREST PORTION OF DEBT SERVICE	($15,169,765)	($14,876,553)	($14,567,215)	($14,240,864)	($13,928,463)	($13,598,881)	($13,251,171)	($12,884,337)
Startup Costs	($86,066)	($58,899)	($30,238)	$ -	$ -	$ -	$ -	$ -
Generation Development	($15,083,699)	($14,817,655)	($14,536,978)	($14,240,864)	($13,928,463)	($13,598,881)	($13,251,171)	($12,884,337)
Loan 1	($11,563,120)	($11,352,751)	($11,130,812)	($10,896,667)	($10,649,643)	($10,389,033)	($10,114,090)	($9,824,025)
Loan 2	($3,520,579)	($3,464,903)	($3,406,165)	($3,344,197)	($3,278,820)	($3,209,847)	($3,137,081)	($3,060,313)
Loan 3	$0	$0	$0	$0	$0	$0	$0	$0
PRINCIPAL PORTION OF DEBT SERVICE	($5,331,118)	($5,624,330)	($5,933,668)	($5,680,009)	($5,992,409)	($6,321,992)	($6,669,701)	($7,036,535)
Startup Costs	($493,945)	($521,112)	($549,774)	$0	$0	$0	$0	$0
Generation Development	($4,837,173)	($5,103,217)	($5,383,894)	($5,680,009)	($5,992,409)	($6,321,992)	($6,669,701)	($7,036,535)
(B) DEBT COVERAGE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DEBT COVERAGE RESERVE ADDITIONS ($ B.O.Y.)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DEBT COVERAGE RESERVE ADDITIONS ($ E.O.Y.)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DEBT SERVICE RESERVE ($)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(C) WORKING CAPITAL EXPENSE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

CATEGORY	16 2027	17 2028	18 2029	19 2030	20 2031	Total
FINANCING COSTS	$ (19.9)	$ (19.9)	$ (19.9)	$ (19.9)	$ (19.9)	$335
(A) DEBT SERVICE	($19,920,872)	($19,920,872)	($19,920,872)	($19,920,872)	($19,920,872)	
TOTAL DEBT ISSUANCES	$ -	$ -	$ -	$ -	$ -	
Startup Costs	$ -	$ -	$ -	$ -	$ -	
Cost excluding bond charges						
Bond charges						
Generation Development	$ -	$ -	$ -	$ -	$ -	
Cost excluding bond charges						
Bond charges						
TOTAL DEBT SERVICE	($19,920,872)	($19,920,872)	($19,920,872)	($19,920,872)	($19,920,872)	
Startup Costs	$ -	$ -	$ -	$ -	$ -	
Generation Development	($19,920,872)	($19,920,872)	($19,920,872)	($19,920,872)	($19,920,872)	
Loan 1	($15,388,005)	($15,388,005)	($15,388,005)	($15,388,005)	($15,388,005)	
Loan 2	($4,532,867)	($4,532,867)	($4,532,867)	($4,532,867)	($4,532,867)	
Loan 3	$ -	$ -	$ -	$ -	$ -	
Debt Coverage (1.25)	$ -	$ -	$ -	$ -	$ -	
INTEREST PORTION OF DEBT SERVICE	($12,497,328)	($12,089,033)	($11,658,282)	($11,203,840)	($10,724,403)	
Startup Costs	$ -	$ -	$ -	$ -	$ -	
Generation Development	($12,497,328)	($12,089,033)	($11,658,282)	($11,203,840)	($10,724,403)	
Loan 1	($9,518,006)	($9,195,156)	($8,854,549)	($8,495,209)	($8,116,105)	
Loan 2	($2,979,322)	($2,893,877)	($2,803,733)	($2,708,631)	($2,608,298)	
Loan 3	$0	$0	$0	$0	$0	
PRINCIPAL PORTION OF DEBT SERVICE	($7,423,544)	($7,831,839)	($8,262,590)	($8,717,033)	($9,196,469)	
Startup Costs	$0	$0	$0	$0	$0	
Generation Development	($7,423,544)	($7,831,839)	($8,262,590)	($8,717,033)	($9,196,469)	
(B) DEBT COVERAGE	$ -	$ -	$ -	$ -	$ -	
DEBT COVERAGE RESERVE ADDITIONS ($ B.O.Y.)	$ -	$ -	$ -	$ -	$ -	
DEBT COVERAGE RESERVE ADDITIONS ($ E.O.Y.)	$ -	$ -	$ -	$ -	$ -	
DEBT SERVICE RESERVE ($)	$ -	$ -	$ -	$ -	$ -	
(C) WORKING CAPITAL EXPENSE	$ -	$ -	$ -	$ -	$ -	

CATEGORY	0 2011	1 2012	2 2013	3 2014	4 2015	5 2016	6 2017	7 2018
REVENUE FROM MARKET SALES		$ 0.5	$ 0.5	$ 0.5	$ 31.4	$ 30.8	$ 39.6	$ 38.7
(A) EXCESS ENERGY SALES (EXCLUDING RENEWABLES)		$ 529,573	$ 476,526	$ 485,999	$ 31,400,431	$ 30,765,599	$ 39,605,781	$ 38,748,691
PERCENTAGE OF PORTFOLIO (%)		-1.5%	-1.3%	-1.3%	-1.3%	-1.5%	-1.0%	-1.1%
LOAD DISTRIBUTION (%)								
ON-PEAK		52%	59%	60%	68%	73%	73%	81%
OFF-PEAK		48%	41%	40%	32%	27%	27%	19%
LOAD (KWH)		12,544,200	10,913,461	11,060,909	11,306,276	13,359,197	8,672,799	9,748,257
ON-PEAK		6,504,682	6,386,716	6,620,637	7,665,612	9,693,392	6,326,681	7,912,367
OFF-PEAK		6,039,518	4,526,745	4,440,272	3,640,664	3,665,805	2,346,118	1,835,890
REVENUE ($)		$ 529,573	$ 476,526	$ 485,999	$ 521,723	$ 646,773	$ 444,991	$ 542,748
ON-PEAK		$ 314,049	$ 312,706	$ 324,928	$ 386,164	$ 505,480	$ 349,261	$ 463,294
OFF-PEAK		$ 215,524	$ 163,820	$ 161,071	$ 135,559	$ 141,292	$ 95,729	$ 79,454
RENEWABLE ENERGY SALES								
CCA Renewable Energy Available for End Use Sales (kWh)					519,358,500	518,839,660	603,862,739	602,497,991
Renewable Energy Generated (kWh)		0	0	0	558,450,000	557,892,108	649,314,773	647,847,302
Losses		0	0	0	39,091,500	39,052,448	45,452,034	45,349,311
Voluntary Renewable Energy Needed (kWh of End Use Sales)		183,576,070	209,171,898	222,747,224	237,206,564	252,607,659	269,012,030	286,485,230
Excess Renewable Energy (kWh)					282,151,936	266,232,001	334,850,709	316,012,761
MPR ($/MWH)	94.65	98.52	102.23	105.93	109.44	113.13	116.95	120.90
REVENUE ($)	$ -	$ -	$ -	$ -	$ 30,878,708	$ 30,118,826	$ 39,160,790	$ 38,205,943
(B) EXCESS ANCILLARY SERVICE SALES		$ -	$ -	$ -	$ -	$ -	$ -	$ -
(C) SUPPLEMENTAL ENERGY PAYMENTS		$ -	$ -	$ -	$ -	$ -	$ -	$ -
RPS REQUIRED (%)		22%	23%	24%	25%	26%	27%	28%
MIN. REQUIRED PURCHASED RENEWABLE ENERGY (KWH)		201,656,530	213,130,889	225,136,349				
ENERGY PAYMENT	$ -	$ (3.06)	$ (5.52)	$ (7.91)	$ (9.96)	$ (12.24)	$ (14.78)	$ (17.54)
Renwable Eenrgy Contract Price ($/MWh)	$ -	$ 89.02	$ 89.91	$ 90.81	$ 91.72	$ 92.64	$ 93.56	$ 94.50
MPR - 10 year ($/MWh)	$ -	$ 92.08	$ 95.43	$ 98.72	$ 101.68	$ 104.88	$ 108.34	$ 112.04
SAVINGS		-$13.2	-$9.8	-$8.4	$17.3	$18.9	$20.5	$21.5
NET PRESENT VALUE		$34		At rate =	3.00			
NOMINAL MARGIN		$188						
ANNAUL SAVINGS PER CUSTOMER ($)		-202	-149	-124	254	273	293	303
SAVINGS PERCENTAGE OF TOTAL BILL (%)		-12%	-9%	-7%	14%	15%	15%	15%

CATEGORY	8 2019	9 2020	10 2021	11 2022	12 2023	13 2024	14 2025	15 2026
REVENUE FROM MARKET SALES	$ 37.7	$ 36.6	$ 35.2	$ 32.7	$ 29.9	$ 27.5	$ 24.5	$ 21.5
(A) EXCESS ENERGY SALES (EXCLUDING RENEWABLES)	$ 37,706,921	$ 36,620,878	$ 35,167,658	$ 32,694,411	$ 29,922,618	$ 27,547,959	$ 24,463,705	$ 21,530,072
PERCENTAGE OF PORTFOLIO (%)	-1.3%	-1.9%	-1.4%	-1.4%	-1.1%	-1.6%	-1.3%	-1.3%
LOAD DISTRIBUTION (%)								
ON-PEAK	79%	82%	85%	84%	78%	83%	84%	81%
OFF-PEAK	21%	18%	15%	16%	22%	17%	16%	19%
LOAD (KWH)	12,034,305	17,942,815	13,090,772	13,136,870	10,960,562	15,606,420	12,563,074	13,441,127
ON-PEAK	9,552,416	14,644,376	11,096,780	11,059,038	8,518,875	12,931,204	10,497,945	10,937,257
OFF-PEAK	2,481,889	3,298,439	1,993,992	2,077,832	2,441,687	2,675,216	2,065,129	2,503,870
REVENUE ($)	$ 704,251	$ 1,101,782	$ 854,303	$ 901,790	$ 770,496	$ 1,162,376	$ 977,307	$ 1,082,450
ON-PEAK	$ 590,795	$ 944,537	$ 754,142	$ 791,828	$ 635,801	$ 1,008,209	$ 853,245	$ 925,796
OFF-PEAK	$ 113,456	$ 157,245	$ 100,161	$ 109,963	$ 134,695	$ 154,167	$ 124,062	$ 156,653
RENEWABLE ENERGY SALES								
CCA Renewable Energy Available for End Use Sales (kWh)	601,142,146	599,795,120	598,456,831	597,127,196	595,806,135	594,493,567	593,189,414	591,893,595
Renewable Energy Generated (kWh)	646,389,404	644,940,989	643,501,968	642,072,254	640,651,758	639,240,395	637,838,079	636,444,726
Losses	45,247,258	45,145,869	45,045,138	44,945,058	44,845,623	44,746,828	44,648,666	44,551,131
Voluntary Renewable Energy Needed (kWh of End Use Sal	305,097,103	324,922,072	341,601,120	359,140,663	377,585,289	396,981,906	417,379,863	438,831,074
Excess Renewable Energy (kWh)	296,045,043	274,873,048	256,855,711	237,986,533	218,220,846	197,511,661	175,809,551	153,062,520
MPR ($/MWH)	124.99	129.22	133.59	133.59	133.59	133.59	133.59	133.59
REVENUE ($)	$ 37,002,670	$ 35,519,095	$ 34,313,354	$ 31,792,621	$ 29,152,123	$ 26,385,583	$ 23,486,398	$ 20,447,622
(B) EXCESS ANCILLARY SERVICE SALES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(C) SUPPLEMENTAL ENERGY PAYMENTS	$ -	$ -						
RPS REQUIRED (%)	29%	33%						
MIN. REQUIRED PURCHASED RENEWABLE ENERGY (KWH)								
ENERGY PAYMENT	$ (20.54)	$ (23.78)	$ (27.29)					
Renwable Eenrgy Contract Price ($/MWh)	$ 95.44	$ 96.40	$ 97.36	$ 98.34	$ 99.32	$ 100.31	$ 101.32	$ 102.33
MPR - 10 year ($/MWh)	$ 115.98	$ 120.18	$ 124.65					
SAVINGS	$22.1	$22.1	$23.4	$14.9	$14.6	$13.4	$12.9	$11.9
NET PRESENT VALUE								
NOMINAL MARGIN								
ANNAUL SAVINGS PER CUSTOMER ($)	307	303	315	198	191	173	165	149
SAVINGS PERCENTAGE OF TOTAL BILL (%)	15%	15%	15%	9%	9%	7%	7%	6%

CATEGORY	16 2027	17 2028	18 2029	19 2030	20 2031	Total
REVENUE FROM MARKET SALES	$ 18.7	$ 15.2	$ 11.4	$ 7.9	$ 4.5	$445
(A) EXCESS ENERGY SALES (EXCLUDING RENEWABLES)	$ 18,671,524	$ 15,204,782	$ 11,405,759	$ 7,900,264	$ 4,538,493	
PERCENTAGE OF PORTFOLIO (%)	-1.7%	-1.4%	-1.1%	-1.2%	-1.6%	
LOAD DISTRIBUTION (%)						
ON-PEAK	78%	75%	79%	81%	72%	
OFF-PEAK	22%	25%	21%	19%	28%	
LOAD (KWH)	16,993,648	15,028,585	11,041,763	12,453,730	17,637,430	
ON-PEAK	13,323,202	11,289,680	8,749,107	10,105,509	12,751,083	
OFF-PEAK	3,670,446	3,738,905	2,292,656	2,348,221	4,886,347	
REVENUE ($)	$ 1,409,575	$ 1,283,091	$ 986,995	$ 1,155,605	$ 1,648,064	
ON-PEAK	$ 1,171,108	$ 1,030,773	$ 826,847	$ 986,220	$ 1,284,297	
OFF-PEAK	$ 238,467	$ 252,317	$ 160,148	$ 169,385	$ 363,767	
RENEWABLE ENERGY SALES						
CCA Renewable Energy Available for End Use Sales (kWh)	590,606,033	589,326,651	588,055,373	586,792,123	585,536,825	
Renewable Energy Generated (kWh)	635,060,251	633,684,571	632,317,606	630,959,272	629,609,490	
Losses	44,454,218	44,357,920	44,262,232	44,167,149	44,072,664	
Voluntary Renewable Energy Needed (kWh of End Use Sal	461,390,159	485,114,577	510,064,781	536,304,370	563,900,255	
Excess Renewable Energy (kWh)	129,215,874	104,212,074	77,990,593	50,487,753	21,636,570	
MPR ($/MWH)	133.59	133.59	133.59	133.59	133.59	
REVENUE ($)	$ 17,261,949	$ 13,921,691	$ 10,418,763	$ 6,744,659	$ 2,890,429	
(B) EXCESS ANCILLARY SERVICE SALES	$ -	$ -	$ -	$ -	$ -	
(C) SUPPLEMENTAL ENERGY PAYMENTS						
RPS REQUIRED (%)						
MIN. REQUIRED PURCHASED RENEWABLE ENERGY (KWH)						
ENERGY PAYMENT						
Renwable Eenrgy Contract Price ($/MWh)	$ 103.35	$ 104.39	$ 105.43	$ 106.48	$ 107.55	
MPR - 10 year ($/MWh)						
SAVINGS	$3.6	$2.1	$1.6	$0.2	-$1.9	$188
NET PRESENT VALUE						
NOMINAL MARGIN						
ANNAUL SAVINGS PER CUSTOMER ($)	45	25	19	3	-22	
SAVINGS PERCENTAGE OF TOTAL BILL (%)	2%	1%	1%	0%	-1%	6%

Assumptions

1) Financial

a) Costs expressed in nominal dollars (constant dollars).
b) Forward looking inflation rate equal to 1.5% for non-generation cost unless otherwise stated.
c) Historical inflation rate of 1.5% to adjust pre-2012 costs.

2) Metering and Billing

a) Billing charges from Schedule E-CCA consolidated rate-ready billing services.
b) Metering charges from Schedule E-CCA meter data management services.
c) CCA service establishment fee based on MEA Business Plan estimate of 2,400 hours. Fee covers the cost of establishing a business relationship with PG&E for activities such as establishing information system for customer switching, meter reading and billing services. Rate from Schedule E-CCA.
d) PG&E unit costs for metering and billing services are escalated at 1.5%.

3) 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 for generation development projects and 10 years for start-up costs.
d) Assume from County of Marin Feasibility Study that there is a bond insurance cost of 1.6% of par value.
e) Assume from County of Marin Feasibility Study that there is a bond transaction cost of 1% of par value.

4) Startup and Operations Costs

a) Operational costs from the MEA Business Plan are estimated to be $7.0 million for the first year of full operation, 2011. Costs included staffing at $3.1 million, contractor costs $2.6 million, infrastructure at $158,000 and IOU fees at about $1.1 million. Based on the estimated MEA loads, the unit cost of these services is about 2.53 $/MWh for staffing, 2.13 $/MWh for contractor costs and $0.13 $/MWh for infrastructure. These unit operational costs are applied to the prospective Humboldt CCA.

b) Startup costs also include a utility bond requirement and service deposit of $265,000 (see page 19 of the MEA Implementation Plan).

c) Unit cost of operations is escalated at the forward looking inflation rate.

d) Operational activities include scheduling coordination, procurement/planning, risk management, credit, rates and load research, administrative and general, and IT.

e) The CCA will begin serving customers in January 2012.

5) Resource Adequacy

a) Planning reserves are required to bring total reserves, including ISO required ancillary services, up to 15% of peak load.

b) Spot market purchases limited to 15% of CCA portfolio; the remainder of the portfolio is comprised of long-term contracts and/or resource ownership.

c) Ancillary services and related costs estimated based on 2010 historical relationship to market prices, projected forward.

d) Ancillary services requirements based on percentage of CCA's load per current CAISO practice.

e) Ancillary services types are Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve.

f) California Independent System Operator (CAISO) charges are derived from current rates, escalated at 2.5% annually.

g) Assume the CCA will not pay for electrical grid congestion costs.

6) Renewable Energy Portfolio

a) Renewable purchases are from a generic portfolio comprised of onshore wind - class 3/4, solar - parabolic trough, hydro - small scale, biomass combustion - stoker boiler and geothermal - binary. The cost of the generic renewable portfolio equals the estimated developers cost.

b) The cost of the portfolio is derived from the CEC's Comparative Costs of California Central Station Electricity Generation (CEC-200-2009-07SF), Table 4, page 18. 2009 costs from the report are escalated at historic inflation rate to derive 2012 costs and then at a nominal rate of 1% per year.

c) Market price of renewable energy is equal to the greater of the maximum renewable energy cost or the market price of system energy.

d) The CCA is required to comply with the state RPS. The state requires IOUs and CCAs to have a 33% RPS by 2020. At this point, the state does not have RPS requirements beyond 2020. For supply scenario 1, assume the RPS remains at 33% until 2031. Supply scenario 2, increase Humboldt's renewable content to 50% and supply scenario 3 increase the RPS to 75%.

e) CCAs will rely primarily on large-scale renewable projects to meet and exceed the RPS. Analysis assumes wind and biomass generation facilities will be utilized.

f) Renewable ownership costs are derived from the CEC's Comparative Costs of California Central Station Electricity Generation (CEC-200-2009-07SF) and the CEC Cost of Generation Model (COG). The COG's average ownership cost scenario was used instead of the high or low cost scenarios.

g) Ownership costs incorporate technology specific assumptions regarding installed capital costs, fixed operations and maintenance, capacity factor, fuel cost, capacity degradation and annual heat rate duration.

h) The County of Marin Feasibility Study states that "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." A 25 $/MWh integration cost for wind resources is included based on the operating assumptions from the Marin County Business Plan.

i) The CCA owned generation resources can be online by 2015.

j) Distributed generation options, such as rooftop PV systems, would be in addition to the RPS minimums.

k) CCA owned power plants also include an annual insurance cost of 0.06% of the capital cost.

7) Wholesale Energy Markets

a) Electricity market price forecast based on projected market system heat rates and natural gas price projections.
b) Natural gas price projections are from EIA Annual Energy Outlook 2011, Table 92, for the electricity coordinating council / California region.
c) Constant heat rate value of 8,750 based on average 2010 heat rate for the three California ISO default Load Aggregation Points. The County of Marin Feasibility Study, dated March 2005, assumed that "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." Increasing market system heat rate results in more expensive market prices of electricity.
d) Assume from County of Marin Feasibility Study that on-peak energy is priced at 15% premium and off-peak energy is priced at 15% discount.
e) Assume from County of Marin Feasibility Study that "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.
g) Distribution losses are 7%.

8) Cost Responsibility Surcharges

a) PCIA is the only component of the CRS that is charged to CCA customers.
b) PCIA is based on PG&E tariffs for each sector and decreased at a rate from the County of Marin Feasibility study.

9) IOU Rate Projections

a) PG&E costs for generation are the competitive reference point for assessing CCA cost savings potential.
b) Unbundled generation charges are from PG&E rate schedules (current as of January 2011) and the additional assumptions stated below. PG&E generation revenue requirement is calculated by multiplying unbundled generation charge by electricity sales, aggregated by major sector.
c) PG&E unbundled generation charges escalated at annual rate of 2%, 3% or 4%.
d) Agricultural generation charge from electric schedule AG-1 effective June 1, 2010. Generation charge is weighted average assuming 25% summer usage on Rate A ($0.09498), 25% summer usage on Rate B ($0.09467), 25% winter usage on Rate A ($0.07508), 25% winter usage on Rate B ($0.07257). Generation demand charge ($/kW) assumes 50% of users on Rate A and Rate B.
e) Commercial generation charge from electric schedule A-1 effective June 1, 2010. Generation charge assumes non-time-of-use rate with 50% summer usage ($0.10276) and 50% winter usage ($0.06742). Non-time-of-use is not charged a demand charge.
f) Industry generation charge from electric schedule E-20 effective June 1, 2010. Generation charge and demand rates provided for secondary voltage, primary voltage and transmission voltage. Analysis assumes secondary voltage rate with 20% peak summer usage($0.11226), 20% part-peak summer usage ($0.07528), 20% off-peak summer usage ($0.05945), 20% part-peak winter usage ($0.06542) and 20% off-peak winter usage ($0.05636). Generation demand charge ($/kW) is based on secondary voltage rates.
g) Mining and Construction generation charge from electric schedule E-19 effective June 1, 2010. Generation charge and demand rates provided for secondary voltage, primary voltage and transmission voltage. Analysis assumes secondary voltage rate with 20% peak summer usage ($0.11805), 20% part-peak summer usage ($0.07847), 20% off-peak summer usage ($0.06172), 20% part-peak winter usage ($0.06795) and 20% off-peak winter usage ($0.05848). Generation demand charge ($/kW) is based on secondary voltage
h) Residential generation charge from electric schedule E-1 effective June 1, 2010. Generation charges for the five tiers are: baseline usage = $0.04587, 101%-130% of baseline = $0.05491, 131%-200% of baseline = $0.14149, 201% - 300% of baseline = $0.20251, >300% of baseline = $0.20251. Customers are billed at the baseline rate for electric use up to the baseline limit. Use beyond this level is charged at a higher rate corresponding to the tier level. According to the Marin Feasibility Study Review by MRW Consultants the distribution for Marin was 61.97%, 11.1%, 14.81%, 7.7%, 4.42%. Assume the same distribution and therefore 61.97% of customers do not exceed baseline, 73.07% do not exceed tier 2, 87.88% do not exceed tier 3 and 95.58% do not exceed tier 4 and the remaining use at tier 5 charges. If customers used up to the maximum electricity use in each tier the average rates are $0.04587, $0.04796, $ 0.08069, $0.1213, respectively.
i) Street lighting generation charge ($0.07427) from electric schedule LS-1 effective June 1, 2010.
j) Water pumping generation charge from electric schedule E-19 effective June 1, 2010. Generation charge and demand rates provided for secondary voltage, primary voltage and transmission voltage. Analysis assumes secondary voltage rate with 20% peak summer usage ($0.11805), 20% part-peak summer usage ($0.07847), 20% off-peak summer usage ($0.06172), 20% part-peak winter usage ($0.06795) and 20% off-peak winter usage ($0.05848). Generation demand charge ($/kW) is based on secondary voltage rates.